

HB

854

(NOTEBOOK)

SEC. 1

HB 854

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

A STUDY OF STATE
PETROLEUM LEASING METHODS
AND POSSIBLE ALTERNATIVES

A REPORT TO THE STATE OF ALASKA, JAY S. HAMMOND, GOVERNOR,
DEPARTMENT OF NATURAL RESOURCES, GUY MARTIN, COMMISSIONER,
AND TO THE
ALASKA STATE LEGISLATURE, INTERIM COMMITTEE ON OIL AND
GAS TAXATION AND LEASING POLICY, CHANCY CROFT, CHAIRMAN

FEBRUARY 1977

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER , 11TH FLOOR, STATE OFFICE BLDG.
POUCH M - JUNEAU 99811

February 17, 1977

The Honorable Jay S. Hammond
Governor of Alaska
Pouch A
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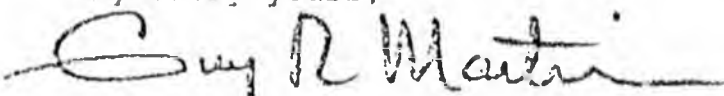
Dear Governor Hammond:

The following report regarding State oil and gas leasing has been prepared by the Department of Natural Resources as a part of a joint Administration-Legislature effort to evaluate the present leasing system and to explore alternatives for the future. The overall study effort, for which I served as Project Director, also includes other Department documents, the reports of independent consultants and miscellaneous other information.

The information in this report, and the entire study, is intended to serve as basic background material to illuminate alternative State objectives and leasing methods which may be desirable for the future. Although some conclusions are reached in parts of the various studies, no final comprehensive conclusions or positions have been reached, pending further analysis of the results of the study project and discussion thereof.

The complexity and importance of the oil and gas leasing issue for the future of the State has thus far sustained an ideal level of constructive cooperation between the Administration and Legislature, and I am hopeful that this report will contribute to an informed outcome on this matter.

Very truly yours,



Guy R. Martin
Commissioner

Acknowledgements

This study was prepared in sections by different people in the Department of Natural Resources. Staff members active in the preparation of the specific sections include:

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In addition, Michael Scott of the Institute of Social and Economic Research and Frank McMordie and David Cook of Garrett Computing Services provided invaluable consulting services.

FOREWORD

This report has been prepared in response to Departmental and Legislative interest in the methods and policies of competitive leasing of state lands for oil and gas purposes. A fairly complete history has been compiled showing pertinent information on past practices of the State. Summaries of all lease sales, bonuses, rentals, receipts and results of drilling and royalty awards are discussed. As a result of this report, it can be concluded that some types of bidding will theoretically yield greater income to the State under specific circumstances than other types will. From strictly a monetary point of view, this study reveals that four major factors will determine which method of bidding would be most advisable for the State to follow. The amount of income to be derived by the State will be determined by the level of risk, the size of the reservoir, the cost of exploration and development, and the value of the oil at the wellhead.

This report has revealed some areas that require further study and this will be done in the coming months. For example, the study reveals that with current economic, royalty, and tax conditions, the minimum size field that an oil and gas operator can afford to look for in Alaska must exceed 55 million barrels in close in areas such as Cook Inlet and could be 100 million barrels or more in remote areas. Also since special cases arise from marginal fields, more detail analysis should be made of effects of reducing royalties to encourage production in sub-economic fields.

Since the purpose of this report is to show variations that can result from various types of bidding most of the emphasis is on types of bidding

other than the cash bonus system. It should not be construed however, as condemning cash bonus bidding nor recommending any alternate type of bidding. The analyses are presented merely to show relative income under specific sets of assumed conditions. A change in some of the input factors can give substantial changes in results.

Risk is the most significant of the variables which would affect income to the State. In unknown, undrilled, untested areas, where the information level is low the risk will be extremely high and these analyses indicate that the cash bonus bidding method would yield greater income to the State. As more information becomes available and as the risk decreases, the method which yields the greatest monetary return revolves around some type of royalty bidding. After a discovery is made, any open acreage on the structure in essence becomes drainage acreage, risk will be low and royalty or some other type of bidding may yield a far greater income to the State than the cash bonus type of bidding. Somewhere then between the extremes of no information and maximum information the method yielding the greatest income probably will switch from cash bonus bidding to some other type of bidding. A significant result of this study indicates that state income can be increased for all leasing methods studied by using a percentage acreage option which is withholding a portion of the structure for later leasing. Other types of bidding are discussed to accomplish other purposes.

There are increasing pressures on government to secure more information about state lands and to know more about the possibilities of petroleum occurrences before the lands are leased. These analyses have been made on the assumption that more information will be available to the State

and if those conditions exist we feel that the values shown give reliable indications of benefits to be derived from one method as compared to another method of bidding.

Risk is dependent on the amount of information available to industry and income to the State is dependent on the knowledge industry has in an area. This study assumes that geological and geophysical information is available to the State at a level above that which it now has. Obtaining this additional information will require expenditure of larger sums of money than in the past. The reader is cautioned not to use the values shown as indicative of all conditions, because as mentioned above, significantly different results are obtained as input factors change. The uncertainty of crude oil prices in remote areas could cause input parameters to change significantly with corresponding changes in analysis results. Therefore, the information presented is to compare one method of bidding versus another method of bidding for a specific set of circumstances.

Administrative costs and number of personnel can vary greatly depending on the leasing method used. An ad valorem type of leasing could cost up to \$240,000 more per year to administer where a net profits system might add \$500,000 with the same number of operators and leases as we now have. In Alberta it is pointed out that 100 people administer 50,000 lease agreements and 60 people are involved with auditing in a cost sharing leasing system.

From an administrative cost standpoint, the present method of operation results in the lowest total operating cost at about \$1.1 million per year. Depending on the level of data acquisition and analysis, costs will increase

from the present quarter million dollars per year. To obtain adequate seismic data for managing an area of 100 miles by 15 miles will cost from \$70,000 to over \$1,500,000. The present budget contains \$110,000 for the purpose in FY 78.

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SECTION I - GENERAL

STATUTORY PROVISIONS

Leasing of public lands for oil and gas is carried out under provisions of AS 38. Section 38.05.180(a) states as follows:

"All tide and submerged lands, mental health lands, school lands, and university lands shall be leased by competitive bidding, and whenever oil or gas is discovered in commercial quantities the Commissioner shall determine the extent of the area of lands in addition to the tide, submerged, mental health lands, school, or university lands in the same general area of the discovery well which, by reason of the discovery, the Commissioner reasonably believes to be capable of producing oil or gas, and the additional lands shall be leased to the highest responsible qualified bidder, by competitive bidding under general regulations, in units not exceeding 2,560 acres (except that tide and submerged lands shall be leased in units of not exceeding 5,760 acres), which shall be as nearly compact in form as possible, upon the payment by the lessee of such bonus as may be accepted by the Commissioner and of such royalty as may be fixed in the lease which shall not be less than 12.5% in amount or value of the production removed or sold from the lease. All lands other than those above provided to be leased by competitive bidding may be leased competitively or non-competitively as determined by the Commissioner to be

in the best interest of the State. Non-competitive leases shall be issued in units not exceeding 2,650 acres in any one lease. Non-competitive leases shall be conditioned upon the payment by the lessee of a royalty of 12.5% in amount or value of the production removed or sold from the lease." (Our emphasis added).

Section 38.05.335(c) states, "The Commissioner shall require each bidder for the competitive leasing of oil and gas lands to submit with his bid a deposit of money equal to 20% of the amount bid."

It is therefore apparent that the present statute provides that when oil and gas leases are to be sold competitively they must be sold by cash bonus bidding and a deposit of money is required to accompany the bid. Because 38.05.335(c) provides that a deposit of money equal to 20% of the amount bid, it is not possible to bid by other methods without determining the total monetary value of the bid at the time of bidding. Accordingly, it is not possible to make bids based on any other basis than cash bonus. There is no other provision which will permit disposal or leasing of the lands for oil and gas in any other fashion at this time. In the event it is felt necessary to change the statute to permit leeway for the Commissioner to accept other types of bidding.

ADMINISTRATIVE

At this time all of the responsibility for the management of the leasing program in the State has been delegated to the Division of Minerals and

Energy Management. This division works under the provisions of AS 38 and makes recommendations on mineral leasing policies and procedures. Within the division there is a leasing section and a petroleum section. In the leasing section there is a Minerals Leasing Manager, who supervises the section and seven other employees. The budget for this section approximates \$212,000 per year. It should be pointed out, however, that during past times when the State was active in leasing lands, this section had 13 employees. The decline in leasing activity has necessitated the transfer of five employees to other segments of the Division of Lands, leaving current personnel at eight. With anticipated increases in leasing activity in the future, it will be necessary to replace some of the personnel and enlarge the staff. The current staff is involved in servicing and maintenance of existing oil and gas, coal and mining claims and leases.

In the petroleum section there is a Petroleum Manager, who supervises the section which includes eight other permanent positions. At present we have not been able to fill all professional positions and two temporary employees are assisting in the petroleum work. This section is responsible for analysis and evaluation of oil and gas problems and making recommendations on future policies regarding leasesales. The current budget of this section approximates \$316,000 per year including approximately \$40,000 for acquisition of subsurface data. Request for next fiscal year includes funding of present positions and \$223,000 for acquisition of subsurface data.

PROCEDURES

In the past decision to lease has been based upon interest of the industry and needs of the State. In at least one instance, Governor William Egan

interrupted a lease sale to announce to the audience that the State had received enough money from the bids up to that point to run the State government on through that fiscal year and that there would be no need to have additional lease sales until sometime next year. This is indicative of the interest and need which the State had in leasing its land. To follow through on the lease sale, after it had been decided that one would be held, the Department of Natural Resources solicited nominations from the industry on prospective areas that they would like to see put up in a lease sale. The interest was gaged, based on the nominations of the various companies, and the area to be included in a lease sale was pared down to a manageable area, approximating 200,000 to 300,000 acres.

Various members of the Department concerned with oil and gas matters were advised that consideration was being given to a lease sale and appropriate representatives of Departments of Fish and Game and Environmental Conservation were contacted. After many meetings, basic leasing criteria and stipulations were agreed upon and approximately 60 days before the lease sale, this information was published and made available to the industry along with the area to be included in the lease sale. All lease sales have been held for bonus type bidding. Prior to 1969, a statutory provision included an award for the first discovery on a structure of $7\frac{1}{2}$ percent of all royalties paid for the first ten years of production.

Actual holding of the lease sale has been the responsibility of the Division of Lands and upon receipt of the bids, the Commissioner of Natural Resources with the aid of his staff, has determined if the bids were responsive to the advertisement and if an adequate price was received for the bids considering the information available at that time. The

Commissioner has had available all geological and engineering information on wells drilled in the State up to that time, however he has had very little geophysical information. In most of the lease sales, some bids have been rejected as being too low or non-responsive. Upon acceptance by the Commissioner money has been paid by the successful bidders into the General Fund and the leases executed by the State.

Upon issuance of the lease, the minerals leasing section, has established records and procedures to ensure that rentals are received in a timely fashion and that development occurs according to the terms of the lease. Close liaison is required with the Attorney General's office in interpreting the terms of the lease and in pursuing administrative actions to cancel leases in the event that rentals are not timely paid.

With the formation of the Division of Minerals and Energy Management we anticipate closer scrutiny of the performance of the operators and performance of the properties themselves, if production is obtained. By doing this, we hope to ensure that timely development is carried out and operations will provide the greatest recovery for the benefit of the State.

SEC. 2

OIL AND GAS LEASING HISTORY - ALASKA STATE LANDS

Introduction and BackgroundPurpose

The primary purpose of this report is to trace the history of oil and gas leasing in Alaska with primary emphasis on state lands and the legal, regulatory and practical framework under which it has developed. Special emphasis will be given to the background under which this system has been operated, so that its effect can be better understood.

Background

The history of oil in Alaska goes back to at least 1867 when the first oil claims were staked at Katalla and Yakataga. The first wildcat well was drilled in 1898 near Iniskian on the Alaska Peninsula, closely followed by the first test in the Katalla area, at Controller Bay in 1901. However, it was not until the second Controller Bay well was drilled in 1902, that the first successful oil producer in Alaska was found, a one foot sand at 250 feet. During the next 50 years, activity was sporadic with very little success. Oil wells were drilled in the Katalla-Yakataga area on the Alaska Peninsula and the Upper Cook Inlet Basin, and the North Slope. The North Slope drilling was to explore the Petroleum Reserve which was set aside by Congress in 1923. Only minor finds of oil and gas were discovered in this effort.¹

In the early 1950's, industry interest in Alaska was revived and with the discovery of the Swanson River Field by Richfield Oil Company in 1957, the oil industry in Alaska was established. In 1956, the year before the discovery at Swanson River, there was a little over 2.8

1. Edmondson, Cameron A., A History of Alaskan Oil, Alaska Petroleum and Industrial Directory 1970-71, Pgs. 11-13

million acres under oil and gas lease in Alaska. At the time of Statehood at the end of 1958, the total had grown to 19.5 million acres, and in 1960 almost 35 million acres were under lease.

The Swanson River discovery was just one of the many dramatic events that greatly affected the future of the oil and gas industry in Alaska. With Statehood, the State of Alaska acquired large blocks of land with oil potential and immediately began leasing them. This led to major important discoveries in Upper Cook Inlet, and there was no longer any question that Alaska had a viable oil industry. The State also acquired a large block of land on the Arctic Slope in the mid 60's which it immediately leased. After several years of drilling with very discouraging results, the Prudhoe Bay discovery was made in 1968, an event which attracted attention to Alaska as no other single event since Statehood had done. Closely paralleling in time the State's North Slope activity, was the Alaska Native Land Claims issue and the land withdrawals that the Secretary of the Interior imposed as a result. These withdrawals ultimately and completely shut down federal oil and gas leasing in Alaska. There has been no significant federal uplands leasing since 1966.

Federal Leasing System It is apparent that the origin of the State of Alaska's leasing system is closely tied to federal mineral leasing laws in effect at the time Alaska became a state. There was a deliberate attempt to conform Alaska's laws to federal laws as much as possible. This is apparent in the following quote from a memo from William E. Dyer, of the Division of Lands, to Phil Holdsworth, Commissioner, Department of Natural Resources on May, 5, 1959, regarding early drafts of the oil

and gas regulations:

"In as much as the State's statute is similar to the Federal procedures, we wonder whether or not it is too risky to introduce a program which is different from the Federal. First, state lands and federal lands will lie side by side. Two different systems might result in confusion to the public. Second, the personnel which the State will undoubtedly hire to administer the regulations will be from BLM. Such persons are already familiar with the Federal system. They would not have to be retrained in new methods. Third, the Federal regulations are long and laborious. They are long and laborious because, for one thing, they have over a period of years been developed to block as many loopholes as possible. The State might wish to take advantage of the Federal experience in that regard by using much of the phraseology contained in the Federal regulations. Fourth, there are considerable number of judicial and administrative decisions concerning the Federal regulations. These decisions would be helpful for those charged with the administration of the State regulations provided that the State regulations follow the Federal."

Mr. Dyer further noted, that Senate Bill #77, which is the basic origin of the 1959 Land Act, "might best be termed a little brother to the Federal system". In a paper prepared by Mr. Holdsworth, then the Commissioner of the Department of Natural Resources, and presented at the Fifth Annual Mining, Minerals, and Petroleum Conference, in College, Alaska in 1960, it is equally apparent that the basic State system is similar to the Federal system. The concern for making this system com-

patible with the Federal system can be easily understood when one realizes that many of the areas the State would eventually select under the Statehood Act would be under federal oil and gas leases and the leases, (under the terms of the Statehood Act), would be transferred to the State for administration. Even today, state noncompetitive lease areas are often interspersed with federally issued leases which must be administered under their terms under Federal law.

The comparison of federal and state oil and gas leasing provisions contained in the previously cited paper by Commissioner Holdsworth, Table 1, gives some of the basic provisions of the Federal leasing system in effect in 1960. For practical purposes, it is generally acknowledged that the Federal system, as it was applied in Alaska, was essentially a noncompetitive leasing system. Only two competitive sales have been held, both in the Arctic area with a total revenue of less than \$430,000 dollars. The reason for the lack of competitive activity is that the Mineral Leasing Act only provides for competitive leasing when the lands are in a known geologic structure. Since essentially all the lands in the State were open for leasing at the time of the revival of interest in Alaska in the early 50's, and because terminated leases were immediately released noncompetitively on the structures that have been proven were under lease at the time the known geologic structure was established.

Thus, at the time of statehood, most Alaska lands were available for federal noncompetitive oil and gas leasing, on a first come, first served basis, for a \$10 filing fee and the filing of the first year's rental.

Rental was \$.50 an acre for each lease year. A lease was issued for a five year primary term with the right to one five year extension. Royalty on production was set at 12.5% by law. The basic lease statistics on federal leasing are included in Table 3, and the statistics on revenue are shown in Table 4.

It is easy to understand how leasing flourished in the late 50's and early 60's on federal lands in Alaska as a result of the success of Swanson River and the attention being given Alaska by the major U.S. oil companies. The peak in leasing of 16, 547 leases, totalling nearly 35 million acres was reached in 1960. The 1960 total included leases in the North Slope, Bethel, Yukon Koyukuk, Bristol, Middle Tanana, Copper River, Yukon Kandik, Gulf of Alaska and Cook Inlet Basins. Most of the wells drilled during that year were in the Cook Inlet Basin, primarily on the Kenai Peninsula. However, wells were also spudded in the Katalla - Yakataga area and the Bethel Basin. The previous year, wells had been also drilled in the Nenana area and on the Alaska Peninsula.²

As can be seen from Table 3, federal leasing activity peaked in 1960 and began to drop off at a rate of several million acres per year. This can be explained in part by the widespread activity throughout the State in 1959 and the success of activity on the Kenai Peninsula. This activity had generated an excessive amount of leasing which, coupled with the fact that the initial wildcats in the other basins were unsuccessful, probably account for the major drop in leasing activity. However, a contributing factor may have also been a shift in emphasis to state lands. With Statehood, the State immediately set out with an aggressive

2. History of Drilling in Alaska Between 1953 and 1966, Alaska Petroleum Directory, 1966-67 Edition, Pgs. 97-119.

leasing program, primarily in Upper Cook Inlet Basin, which attracted considerable industry interest at the time.

State Leasing System

Even though the State leasing system is very similar to the Federal system, they have operated in essentially the same environment with drastically different results. As with the Federal system, the State laws have always provided for both a competitive and non competitive system.

The most significant difference in the systems, and the one that has had the most effect on revenue, is the ability of the State to classify lands as competitive. The initial Land Act, Chapter 169, SLA, 1959, provided, "all tide and submerged lands shall be leased by competitive bidding and whenever oil or gas is discovered in any well on Alaska land in commercial quantities the Commissioner shall determine the extent of the area of any lands in addition to tide and submerged lands in the same general area of the discovery which by reason of such discovery, the Commissioner reasonably believes to be capable of producing oil or gas and such additional lands shall be leased by competitive bidding." The Act was amended, Chapter 61, SLA, 1960, to include mental health lands, school lands, and university lands, in the category to be leased by competitive bidding. However, it still limited other uplands to competitive bidding only where the lands were in the vicinity of a commercial discovery, a concept very similar to the known geologic structure concept under the Federal rules. As is evidenced by the following quote, in a letter dated January 3, 1972, from Roscoe E. Bell, Director, Division of Lands, to Jalmar Kerttula, of the Alaska House of

Representatives, the State early recognized the limitations of the Federal system:

If the wording, "whenever oil or gas is discovered in commercial quantities, "were amended to add," or where sufficient geological or geophysical data were available to provide evidence of a favorable geological structure," there would be an opportunity for the State to encourage oil and gas exploration, to shorten the lapsed time between leasing and exploration, and to materially advance the financial well being of the State by leasing competitively areas that now must be leased noncompetitively.

This letter is also a good indicator of the Department thinking on noncompetitive vs. competitive leasing at the time and a copy is included with this report under Table 2. The law was amended in 1964 to the present language which provides that the Commissioner may lease lands competitively when he determines it to be, "in the best interest of the State."

The State was faced with a unique problem. Most people agreed that oil revenue was one of the best hopes of meeting the rising state needs. Even though the State would receive 90% of the Federal revenue from oil and gas leasing, much of the Federal revenue would be delayed because it would come in the form of future royalties. There was no significant bonus or rental monies associated with Federal leasing. With many well known potential petroleum areas throughout the State open to lease on a first come, first served basis, unique measures were necessary to attract

interest from the Federal lands to State lands. The geologic potential of the harsh offshore waters of Cook Inlet offered the most obvious potential to attract immediate development on state lands. Most of the other lands that the State had or could select immediately were under lease and would be tied up for several years in title transfer. The other offshore areas had not yet attracted much attention.

Therefore, they immediately proceeded with the leasing of Upper Cook Inlet under terms to encourage development as soon as possible and at the same time, earn revenue from the leasing. Major factors in accomplishing these objectives were the discovery royalty incentive on large lease tracts, a short lease term (5 years) and a favorable government attitude towards the industry. The first large sale in Cook Inlet, (#7 in 1961) earned nearly 15 million dollars in bonuses, and the second large sale, (#9 in 1962) earned over 15 million dollars in bonuses. As can be seen from the statistics attached to this report, these two sales alone grossed more than federal payments to the State for all of their leasing activity up to that time.

Of more significance than the lease revenue to the State's future economic wellbeing however, was that the industry immediately proceeded to explore and develop the leased areas. This activity resulted in discovery of the Cook Inlet oil and gas fields, which are the source of the present oil and gas royalty income from state lands. Four of the five oil fields in the Cook Inlet Basin, Middle Ground Shoal, Granite Point, Trading Bay, and McArthur River fields were discovered on leases issued at these sales. It was the discovery and development of these fields

along with the Swanson River field that firmly established Alaska as one of the important oil producing areas in the world.

Thus, the State system operating in essentially the same environment was able to produce considerably more royalty and lease revenue in a much shorter time and with less acreage than the Federal system. The statistics included with this report show the results of the two systems. State revenue from leasing alone through 1975, i.e., bonuses and rental, amounts to \$1,066,079,564. Through 1975 nearly \$210,000,000 have been paid in production royalties. This compares to federal receipts from 1959 through 1975 of nearly \$50,000,000 in oil and gas rentals and nearly \$66,000,000 in oil and gas royalty payments.

Description of Present System

Statutory provisions for Alaska oil and gas leasing are contained in AS 38.05 primarily in sections 38.05.130 through 38.05.180. The regulations are contained in Title 11 of the Alaska Administrative Code, under Chapters 82, 83, and 88. Under these provisions a lease may be issued either competitively or noncompetitively.

The regulations, 11 ACU 82.105, provide that all lands not required by law to be leased competitively or not classified competitive by order of the Commissioner are noncompetitive for mineral leasing purposes. Before lands are available for noncompetitive leasing they must be opened by publishing a notice declaring the lands open for lease. A notice of opening must provide a 30 day filing period. During this time any applications that are filed are considered filed simultaneously and the

top priority for the noncompetitive lease is determined by public drawing. Similarly, after lands are leased and the lease terminates the lands are again made available, unless classified competitive, through a 30 day simultaneous filing period with the winner again being determined by public drawing. Any lands that are not leased through both of these procedures become available, after the end of the 30 day filing period.

The statutes (AS 38.05.180) provide that noncompetitive leases will be for a primary term of five years and can be extended for two years if the lands are in a competitive classification at the time of expiration of the primary term or five years if noncompetitive. The statute further provides that the royalty rate shall be 12.5% in amount or value of the production and that the maximum size of the lease shall not exceed 2,560 acres. The lease shall continue until the end of its primary term or its extension and so long thereafter as oil or gas is produced in paying quantities. The annual rental rate is set at \$.50 an acre and is payable in advance or the lease automatically terminates under its terms and conditions.

Noncompetitive lease terms and regulations have remained essentially unchanged since statehood, except for the classification provisions which are discussed later in this report.

The statute requires that all tide and submerged lands, mental health lands, school lands, and university lands be leased competitively. It also provides that any lands which the Commissioner determines are capable of producing oil or gas as the result of a discovery in an area

must be leased competitively. In addition, the Commissioner may classify any lands competitive where he believes it is in the best interest of the State. Competitive leases are issued under the procedures of 11 AAC 82.400. The regulations provide that the method of bidding shall be either by public auction or by sealed bids. It is generally agreed that the provisions of the regulations and AS 38.05.335 require that the high bidder be determined on the basis of the highest cash bonus submitted at the sale.

Competitive leases are issued for a primary term of ten years except in the Cook Inlet sedimentary basin where the law provides that the leases shall be for a primary term of not more than ten years and not less than five years at the discretion of the Commissioner, and continue so long thereafter as oil or gas is produced in paying quantities. The royalty rate may not be less than 12.5% in amount or value of production. The maximum lease size is 2,560 acres for uplands and 5,760 for tide and submerged lands. The statute provides a rental rate of \$1 an acre, which by the terms of the lease and the regulations must be payable in advance. Some of the basic provisions under the competitive system have changed since statehood. These are discussed in detail later in this report.

Both noncompetitive and competitive leases provide that leases will be extended if drilling has commenced on or before the expiration date until the well has been completed and so long thereafter as oil or gas is produced in paying quantities. They both provide that leases proven capable of production may be extended by shutin production. Provisions for unitization and extension of leases included within a unit are also

standard to both procedures. Acreage that may be held at any one time may not exceed 500,000 acres on tide and submerged lands and 500,000 on all other lands. Producing lands in an approved unit agreement and lands operated under an approved drilling or development contract are excluded for acreage limitation purposes.

Land Availability

With the advent of the modern oil and gas industry in Alaska in the early 1950's, almost all lands in Alaska were open to oil and gas leasing except on the North Slope.

The lands on the North Slope had been closed by executive order to mineral leasing for many years. They were not restored until April 18, 1958, when all of the lands except Petroleum Reserve #4 were opened for mineral leasing. The Secretary of Interiors' opening order provided for leasing through a noncompetitive lease offering in a simultaneous filing period. This was done in a series of six offerings by the Federal Bureau of Land Management beginning in 1958 and ending in 1966. A total of 22,300,000 acres were offered with a little over 5,000,000 acres being issued as leases. See Table 12 included with this report.³

The next significant effect on availability of lands for oil and gas leasing was the creation of the Arctic Wildlife Range, totalling about 8.9 million acres and the Clarence Rhodes Wildlife Range, totalling about 3.1 million acres in 1960. Following this was the so called "land freeze". As a result of protests from the Alaska Natives, the Secretary

3. Jones, Daniel A., Oil and Gas Leasing On The North Slope Alaska; Paper presented at Seventh Annual Mining, Mineral and Petroleum Conference, College, Alaska, March 20, 1964. Pg. 6

of the Interior suspended issuance of oil and gas leases in 1966. Applications would be accepted but leases would not be issued. The Secretary continued accepting applications until January 17, 1969, when Public Land Order 4582 was issued withdrawing all Alaska lands from oil and gas lease applications. During the period from 1966 until the "super land freeze" in 1969, oil and gas lease applications were filed on approximately 21 million acres.⁴

The Federal land freeze did not affect state lands except that new lands could not be transferred to the State which might be made available for leasing. In addition to the tide and submerged lands that were acquired with statehood, the State acquired the right to select approximately 103 million acres. It proceeded to select petroleum lands immediately, primarily in the Cook Inlet Basin and along the fringes of the Gulf of Alaska. The North Slope lands were selected in 1964 and 1969. The 1964 block totalled approximately 1.75 million acres and the 1969 block totalled nearly 3 million acres. Most of the lands selected in 1964 were tentatively approved by the Federal government in 1964 and were thus available for leasing. Petroleum lands along the Alaska Peninsula on the Bristol Bay side were also selected in 1969, however, approval of these lands was not received until recently.

The State immediately proceeded with making newly acquired lands available for oil and gas lease, as can be seen from the sale statistics included with this report. Sales were held frequently throughout the State. The apparent policy was to lease acreage wherever significant industry

4. Simasko, Donald L., Native Land Claims and Their Effect on Leasing in Alaska, Paper Presented at 1971 National Institute For Petroleum Landmen, Pgs. 153-191

interest occurred. Most observers agree that this policy continued pretty much until the large Prudhoe Bay sale in 1969. This attracted considerable attention to the importance of leasing as a revenue earner for the State and leasing decisions became increasingly more involved. Since the Prudhoe Bay sale, the only leasing activity has been in the Cook Inlet Basin primarily in areas of previous leasing.

Noncompetitive lands were immediately opened for leasing upon receipt of title to the lands from the federal government. The early opening orders made all lands available for leasing to which the State had received title up to the date of the opening order. Except for procedural changes, this practice continued up until the State noncompetitive activity was discontinued late in 1975.

Competitive Classifications

As previously noted, the statute presently provides that the Commissioner may classify any lands competitive for purposes of oil and gas leasing, when he determines that it is the best interest of the State to do so. Prior to the amendment in 1964, the statute provided only for competitive leasing of certain types of lands and lands in the vicinity of a discovery. The letter from Roscoe E. Bell, then Director of the Division of Lands, to Representative Kertulla, previously cited in this report and included herewith, is a good indicator of the thinking on this point at that time. The first classification order effective January 8, 1963, was for lands primarily in the Beluga area in the Cook Inlet Basin, as a

result of the discovery of the Beluga Gas field. Since that date, there has been a total of 23 classifications. Most of them are in the Cook Inlet Basin. All of the lands selected by the State on the North Slope have been classified as competitive and most of the lands in the Cook Inlet Basin were classified competitive as company interest developed in the areas. The classification problem was somewhat simplified in the Cook Inlet Basin because many of the areas were interspersed with lands which were competitive by law and the classifications were based largely on the desire to provide only one leasing system in the area.

Comparison Between Competitive and Noncompetitive Leasing

As a consequence of the state's policy of classifying lands competitive where significant interest was indicated (see Roscoe Bell's letter to Jalmar Kertulla), comparisons of the activity and revenue generated by the two systems probably have little meaning, except from a historical viewpoint. From a total of 183 exploratory wells drilled on state issued leases, only 12 were drilled on noncompetitive leases. None of the 12 resulted in oil and gas in paying quantities. For a complete breakdown of wells drilled, see Table 10.

Revenue statistics are equally overbalanced. Approximately \$10,392,730 of the total \$37,826,590 rentals through 1975 were received from noncompetitive leasing. In addition, approximately \$2,647,760 have been received in filing fees from applications in simultaneous filing periods. All the bonus and royalty income has been from competitive leases with exception of minor royalty income from transferred federal leases.

In 1972, an area on the Kenai Peninsula which had previously been under

competitive classification was reclassified to noncompetitive. Competitive interest had been low in the area for several years, and even when areas were leased, bonus was not high. One of the highest interest areas when they were opened to application after the reclassification was Township I North, Range 12 West, Seward Meridian. Nine tracts in this township earned from \$1.13 per acre to \$11.00 per acre in filing fees. In comparison, the most recent competitive sales in that township drew bids of high bonus from \$2.00 to \$3.34 per acre.

A similar comparison can be made for areas on the lower Kenai Peninsula, which have always been noncompetitive except for interspersed lands which are competitive by law, i.e., school, university and mental health. Results on Township 3 South, Range 14 West, Seward Meridian, one of the more active filing areas, noncompetitive leasing earned from \$.75 to \$20.00 per acre in filing fees with most recent competitive sales in the township earning from \$3.15 to \$7.67 per acre in bonus.

It is also interesting to note that lands had been available for competitive leasing in both of these townships in previous sales but had not been nominated for lease, or had not been leased after being offered. The failure to lease through the competitive system would be higher in areas of less interest. This offers support to one of the common arguments for noncompetitive leasing that considerable revenue can be earned from lands that would not otherwise be leased.

Discovery Royalty

The original state land act provided for reduction of the royalty rate

to 5 per cent for the entire lease for ten years following the date of the discovery, for the first discovery of oil or gas in commercial quantities in any geologic structure. This provision was deleted from the law in 1969. To date, only 8 leases have been certified for discovery royalty; however, there may eventually be additional certifications since there are still active leases which were issued before the 1969 law change. See Table 9 for a listing of the certifications.

At the time of statehood, the federal law provided a 5% discovery royalty incentive for federal leases in Alaska issued prior to May 3, 1958. Many federal leases, especially in the Cook Inlet basin, were subject to the discovery royalty provision at the time of statehood. Thus, it was necessary for the state leases to carry a similar provision to be comparable. Most observers agree that the discovery royalty incentive in Cook Inlet on large lease tracts was a very significant factor in the early drilling and development of that area. The 10 year period for all of the leases certified in Cook Inlet has now expired. The total difference between actual payments on discovery leases and the 12½% rate amounts to \$8,754,000 for the 5 offshore leases involved. The total would have been much greater except that the first discovery on the Trading Bay structure was on one of the low quantity producing leases on that structure.

The reduced royalty rate for the discovery lease in the Prudhoe Bay field expires on December 31, 1977. Since production is not scheduled to commence until mid 1977, it is apparent that very little discovery benefits will accrue to this lease.

Bidding Methods

All state sales have been by sealed bid with the bidding variable being the highest cash bonus offered for the lease.

The original land act provided that competitive bidding would be "under general regulations" adopted by the commissioner. A statutory provision was adopted in 1966 to specifically "require each bidder for the competitive leasing of oil and gas lands to submit with his bid a deposit of money equal to 20 per cent of the amount bid", AS 38.05.335(c) (emphasis added). Thus, prior to the 1966 statutory change, the regulations controlled the bidding procedure, but after the law change it was apparent that a system very similar to the cash bonus bidding system was dictated.

The original oil and gas leasing regulations provided that the method of bidding be by sealed bids or at public auction by cash bonus, that the lease shall be awarded to the responsible qualified bidder offering the highest cash bonus, and that the bids must be accompanied by cashier's or certified checks, money orders or cash of at least 20% of the amount bid. These regulations were interpreted to only allow a bidding system where the only bidding variable was cash bonus. The regulations remained essentially unchanged in this regard until the 1974 revision, the last revision. The present regulations are much more general in bidding procedures, but the statutory limitations still apply.

The only alternative bidding method the record indicates has been considered is alternate or slide bidding. At a hearing held in Anchorage on June

30, 1969, the department asked for public input on the possibility of using a system similar to the "alternate" or "slide" bid system used in Canada for the 1969 Prudhoe Bay sale. Under the proposal, bidders who were unsuccessful on a tract would have been allowed to "slide" their bid to another tract. This method was explored as a possible method of allowing each bidder to use all his available money for the sale to his best advantage. The theory being that significant bidders might not have enough money to bid as high as they would like on all tracts. With the ability of "sliding" bids to alternate tracts, the possibility of pyramiding money on a few tracts was a possible benefit of the Canadian system. The availability of money did not prove to be as big a factor as originally anticipated. It was felt that the major bidders would be able to secure enough money to make their best bid on the major tracts in which they were interested and that the system would therefore not result in higher bonus revenue. The system was not adopted for this and other problems with the system, such as complicated mechanics of bidding and sale administration, the difficulty of public understanding and the possibility of charges of collusion between the bidders and the state. The oil industry was also almost unanimously opposed to it.

Royalty

Royalty on noncompetitive leases has always been set by law at 12½%. Competitive leases may be issued with higher royalty rates since the statute has always only provided the minimum royalty rate of 12½%. The first sale that utilized a higher rate was sale #28 in the Cook Inlet

basin. The rate used in this sale and in the last sale in this area was 16 2/3%.

Tract Sizes

The original land act provided a maximum tract size of 5760 acres for tide and submerged lands and 640 acres for all other lands. The law was revised in 1964 to increase the maximum size of upland tracts to 2560 acres.

The trend in the early offshore sales was to large tracts. Tract size in sale numbers 7 and 9, the first large Cook Inlet offshore sales, averaged 3760 and 3546 acres, respectively. There were many tracts over 5000 acres in size in these sales. The standard changed soon after this, however, to a four section block concept (about 2560 acres) when existing land patterns would allow.

Minimum Bid

Minimum bids have not been prescribed for any of the lease sales, except that most sales have provided that a bid of less than one dollar per acre will not be considered, primarily for the purpose of preventing nuisance bids. This provision was dropped in the 23rd sale (the 1969 Prudhoe Bay sale) and several insignificant nuisance type bids were received which caused considerable administrative expense, primarily legal, to resolve.

The regulations have always provided that the state may reject all bids on a tract when determined to be in the best interest of the state. Bids have been rejected in five of the sales under this provision. One high bid was rejected in the 8th sale, 8 rejected in the 9th sale, 3 rejected in the 14th sale, 33 rejected in the 21st sale and 15 bids rejected in the 23rd sale.

Conditional Leases

To avoid a long delay in development, the Statehood Act provided that upon receipt of tentative approval from the Federal government, the State could issue conditional leases on the land. There is often a long period between the determination of availability of the lands for state acquisition and the actual issuance of patent, primarily because of the survey problems.

A law was passed in 1960 to provide for extension of a conditional lease for a period equal to the period during which the lease was conditional. Almost all the Prudhoe Bay development was during the conditional period of the leases. The first leases were issued effective early 1965, but the first patents were not received until 1974. Thus, many of the leases in this area were extended for nearly ten years. Because of this development it was apparent that a conditional lease was not a deterrent to exploration and development and the extension provision was deleted from the law in 1969.

Lease Forms

The basic provisions of both of the lease forms have remained essentially the same. There have been several updates to conform to statutory changes and to correct errors. The original competitive lease form, DL1, was adopted late in 1959 and was revised April 1961, October 1963, April 1971, May 1973 and September 1974. The 1961 and 1963 revisions were apparently to correct typographical errors in the original form. The 1971 revision deleted the reference to water use in the granting clause to be consistent with the Water Use Act, AS 46.15; deleted the clause granting a conditional lease extension to be consistent with deletion of the provision from the statute; deleted the discovery royalty clause for the same reason and added a directional drilling clause and an employment clause regarding hire of Alaska residents.

The noncompetitive lease form, DL2, was first used in 1960 and was revised April 1961, May 1962, and May 1966. The changes in the non-competitive form were comparable to the changes in the competitive form.

Environmental Controls

When Alaska started its oil and gas leasing program, there were essentially no controls on oil and gas lease operators, except for controls on actual well drilling practices by the U.S. Geological Survey and under the Alaska Oil and Gas Conservation Commission. An operator could explore and develop on federal and early state leases without any approvals from other state or federal regulatory agencies. Operation on federal wildlife ranges such as the Kenai Moose Range were an exception. Very stringent surface use requirements were applied in these areas. When the state

started leasing offshore, however, as a result of concern by fishermen in Cook Inlet, they realized the need for more controls for tide and submerged land locations. A standard wildlife stipulation was adopted in August 1962 for inclusion in all offshore oil and gas leases. This stipulation required the written approval of the Department of Natural Resources "for the location and type of each structure before it is erected on tide and submerged lands". The stipulation was similar to the one that is presently used in all leases. Since 1968, a similar stipulation has been included in all leases issued, including both competitive and noncompetitive. In 1970, all lessees were ordered to obtain approval in accordance with the standard stipulation, even if the stipulation had not been included at the time the lease was issued. All operators have complied with this order.

There was also no control over seismic operations at the time of statehood. Neither the state or federal governments required permits or provided operating guidelines. except in wildlife ranges and park lands There was considerable public concern expressed in the late 1960's over damage done by seismic and other geophysical operations, and in 1968, the State Senate adopted a joint resolution requesting the department to adopt regulations. The primary concern was over excessive clearing of trails, damage done during trail construction, debris, damage from repeated use of the same trails, particularly in Arctic areas during the summer months, and disturbance and damage to fish and game resources.

Regulations requiring permits for all seismic operations were adopted

late in 1969. Since then, the major concerns have been taken care of by requiring operators to operate only during periods which will prevent or minimize disturbance, utilize existing trails when possible, remove all debris, utilize equipment which will do the least damage in cross country travel, avoid critical fish and game areas and rehabilitate any disturbed areas. In addition, the operators have gone back and cleaned up some of the debris left over from the past operations.

The state regulations are primarily for environmental control and operators are not required to file survey results. They are required, however, to file the location of trails, camps and seismic lines to facilitate field inspection.

Administration

The Minerals Section in the Division of Lands was the agency primarily responsible for the administration of the state's oil and gas leasing program until October 1976. The program received technical support and direction from the Division of Oil and Gas, and, to a lesser extent, the Division of Geological and Geophysical Surveys. Field surveillance support was also provided by the Division of Lands' District offices. The activity was consolidated with all the land owner mineral functions in a new division the Division of Minerals and Energy Management in October 1976.

The original Minerals Section had responsibility for all coal and locatable mineral activities on state lands, in addition to oil and gas.

They reached a peak of 13 employees in 1962, which gradually decreased to the total of 9 authorized positions at the time of consolidation into the Division of Minerals and Energy Management. There are no exact figures on the number of positions involved with the state leasing program in the other divisions, but it probably has not exceeded four, based on the number of positions transferred in the consolidation. In addition, less than two positions have been directly involved in the two mineral active district offices.

The administration of the present system is simple because of a well understood, highly predictable, and to a large extent, self executing legal and policy framework. The past administration of the present system placed considerable dependence on the "market place" to insure a fair return to the state for its oil and gas resources, thereby requiring a minimum of administrative expense and discretion.

TABLE NO. 1
COMPARISON OF FEDERAL AND STATE OIL AND GAS LEASING PROVISIONS*

<u>Provision</u>	<u>Existing Law (Federal Lands)</u>	<u>HR 10455 (Federal lands)</u>	<u>State Law (State Lands)</u>
(1) Maximum allowable acreage under oil and gas leases and options held by any one person or corporation (excluding leased acreage committed to cooperative or unit plan of development).	100,000 acres under lease and 200,000 acres under option	300,000 acres under lease & option, but not more than 200,000 acres under option, in each of 2 leasing districts.	500,000 acres on tide & submerged lands, plus 500,000 acres on uplds., without regard to lease or option status.
(2) Term of noncompetitive oil and gas leases.	5-year primary term with right to one 5-year extension	10-year primary term-no extension	5-year primary term with right to 1 5-year ext.
(3) Extension of lease term if actual drilling is underway at expiration date.	None provided	2-year extension	Extension until 90 days after such drilling has ceased
(4) Annual rental noncompetitive leases	50 cents per acre first year; 2nd and 3rd years waived; 25 cents per acre for 4th and 5th years; 50 cents per acre for 6th thru 10th years	50 cents per acre per year	50 cents per acre per yr.
(5) Royalties - (Minimum royalty of \$1/per acre in lieu of rental after discovery of oil or gas).	<u>Noncompetitive</u> 12½%	<u>Noncompetitive</u> 12½%	<u>Noncompetitive</u> 12½% except that royalty shall be 5% on production from lease containing discovery well on new geologic structure for 10 years following discovery date.
	<u>Competitive</u> Not less than 12½%	<u>Competitive</u> Not less than 12½%	<u>Competitive</u> Not less than 12½%, except that royalty shall be 5% on production from lease containing discovery well on new geologic structure for 10 years following discovery date.

*Taken from a paper presented at the Fifth Annual Mining, Minerals and Petroleum Conference by Phil R. Holdsworth, Commissioner, Dept. of Natural Resources, April, 1960

January 3, 1962

Mr. Jalmar Kerttula
 Alaska House of Representatives
 Star Route
 Palmer, Alaska

Dear Mr. Kerttula:

This is in response to the question raised by you in my office as to what changes in law would be required to give the Commissioner of Natural Resources more authority to declare lands competitive for oil and gas leasing. The law now provides, Section I, Article 8, Chapter 169, SLA 1959, "As hereinafter provided, lands may be withheld from lease application on a first-come, first-served basis, and offered only on a competitive bid basis when determined by the Commissioner to be in the best interests of Alaska." Thus, the Commissioner now has the authority to open the land for competitive bidding, but as provided in Section I, Article 8, (7)a, "All tide and submerged lands, mental health lands, school lands, and university lands shall be leased by competitive bidding----- and whenever oil or gas is discovered in any well in commercial quantities, the Commissioner shall determine the extent of the area of any lands in addition to tide, submerged, mental health lands, school or university lands in the same general area of the discovery well, which by reason of such discovery the Commissioner reasonably believes to be capable of producing oil or gas, and such additional lands shall be leased by competitive bidding."

If the wording, "whenever oil or gas is discovered in commercial quantities," were amended to add, "or where sufficient geological or geophysical data are available to provide evidence of a favorable geological structure," there would be an opportunity for the State to encourage oil and gas exploration, to shorten the lapsed time between leasing and exploration, and to materially advance the financial well being of the State by leasing competitively areas that now must be leased noncompetitively. At the same time it would not eliminate noncompetitive leasing in wildcat areas where geological or geophysical exploration has not been conducted.

Perhaps it would be worthwhile to review what has recently happened in the last noncompetitive area in the Tyonek. Because there were no producing wells in the area, and because the land was acquired under the general grant provision of the law, we could not offer to lease competitively even though intense interest was expressed by oil companies and suggestions were made by some company representatives that they would consider providing the State with geological and geophysical data if the land could be leased competitively.

We offered 82 tracts of approximately 2560 acres each during a 30 day simultaneous filing period. Following are the results of the opening, as compared with what might have been expected under the above legislative language:

<u>As Held Under Present Law and Regulations</u>	<u>Probable - If Legislation Were Amended</u>
Total number of leasing tracts, 82 of 2560 acres each	Approximately 320 of 640 acres each
Number of applications or bids per tract 15 - 703	0 - 10
Number of applications or bids from oil companies 1 - 30	0 - 10
Number of tracts leased noncompetitively to date 80	Probably 220
Number of tracts leased competitively None	Probably 100
Application fees Received \$267,640	\$100,000
Cost of Processing \$ 50,000	\$ 20,000
Rentals, noncompetitive @ 50¢/acre \$ 96,087	\$ 64,087
Rentals, competitive @ \$1.00/acre None	\$ 64,000
Bonus Bids None	\$7,990,000
Total State Revenue \$313,727	\$8,198,087

The bonus bids were estimated at the same average per acre rate as those received from the nearby Tyonek mental health sale, or \$124.85 per acre. It is believed the past experience in the mental health area might be somewhat comparable, although this cannot be verified. At least for discussion purposes it may be assumed that the mental health sale is a fair indication of the value of the land in the nearby noncompetitive area, providing you applied these values to lands considered to be sufficiently valuable by operating companies that they would nominate

January 3, 1962

them for competitive bidding and back up the nomination with sufficient geological or geophysical data to convince the Commissioner of their oil and gas potential.

It is a known fact that leases actually have been assigned at three to seven dollars per acre with a three to seven per cent overriding royalty. As long as only three of the 82 leases were drawn by and issued to operating oil companies, it may be assumed that most of the leases will be assigned, in fact, 25 leases totaling 63,026 acres have already been assigned.

It can hardly be said that this so-called "noncompetitive lease open-int" was in any sense actually noncompetitive. The tabulation below demonstrates that it was highly competitive since one to thirty (or an average of twelve) oil companies filed on each tract along with the hundreds of other persons who filed:

<u>Tract #</u>	<u>Oil Com. App.</u>	<u>App. Filed</u>	<u>Tract #</u>	<u>Oil Com. App.</u>	<u>App. Filed</u>
S-13-4-1	7	67	S-13-5-1	19	309
2	8	54	2	20	204
3	7	73	3	10	173
4	8	83	4	16	86
5	11	100	5	8	70
6	10	97	6	7	39
7	9	78	7	6	36
8	7	89	8	10	91
9	9	90	9	18	157
10	11	83	10	24	165
11	10	52	11	25	311
12	6	41	12	25	417
13	7	37	13	21	572
14	3	29	14	20	316
15	4	30	15	24	250
16	5	28	16	21	172
17	3	22	17	15	97
18	5	32	18	8	40
19	4	39	19	2	21
20	2	22	20	3	23
21	5	42	21	7	31
22	4	45	22	9	55
23	12	102	23	16	112
24	16	124	24	23	191
25	16	117	25	27	451
26	17	151	26	27	533
27	16	145	27	30	716
28	11	106	28	24	689
29	8	56	29	26	679
30	2	24	30	26	504
31	2	19	31	19	215
32	1	15	32	15	139
33	5	29	33	8	77
34	7	65	34	4	52
35	16	103	35	4	36
36	15	141	36	2	34
37	20	198	37	3	38

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Tract S-13-5-38	2	63
39	4	64
40	7	83
41	7	150
42	19	273
43	23	586
44	26	632
45	29	703

From suggestions made by industry representatives, and from the number of applications filed by oil companies, it may be fairly assumed that sufficient geophysical or geological information was available to have justified substantial competitive bidding on at least one third of the tracts, if it had been possible for the State to offer selected lands competitively.

It should be noted also that competitive bidding, especially where bids are high, results in immediate action in exploration; witness the road building and drilling which has occurred in the Tyonek during the seven months immediately following the sale. On the other hand, the period immediately following noncompetitive leasing is occupied with negotiation of assignments to put together a large enough "package" (twenty to thirty thousand acres), to justify geological or geophysical exploration prior to drilling. If there were the possibility of self protection by competitive bidding, exploratory work would be carried out prior to leasing so that the company could properly evaluate bidding levels.

Any proposal for extension of competitive leasing will be objected to by some companies and many independents because it represents a change and because the "small man" cannot compete with the large companies in seismic exploration, or in dollars paid at the sale, thus, he must depend upon chance and skillful negotiation to block up acreage.

In strictly noncompetitive wildcat areas noncompetitive leasing and independent activity to "package" acreage may serve to promote exploration and ultimate development, thus, there is much to be said for preserving the noncompetitive system. The limited authority provided to the Commissioner by the above suggested legislative language would result in much land being left open to noncompetitive bidding, and probably would adequately protect the "small man". At the same time, the "undue enrichment" of a few individuals who contribute little or nothing to development could be replaced by substantial additional revenues for the State, without necessarily increasing the cost to the oil companies because, as I have pointed out above, the companies compete to buy individual assignments after a noncompetitive opening. The prices may be substantial on individual tracts - in the last sale amounting to more than \$20,000 per tract. In addition, the landman for the company may have to expend a great amount of time and travel to different parts of the United States to complete the negotiations for a block of land.

Mr. Jalmar Kerrettula

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January 3, 1962

I trust these thoughts will be of value to you. All that I have said above supports your expressed belief that it would be in the State's interest to increase the authority of the Commissioner to classify lands as competitive.

I shall be glad to discuss the subject further when you are in Anchorage. So that Commissioner Holdsworth will know of your interest, I am sending him a copy of this letter.

Very sincerely yours,

Roscoe E. Bell
Director

REB:dfo

cc: Phil R. Holdsworth, Commissioner

*This letter was retyped from a copy for reproduction purposes

TABLE NO. 3*
ALASKA OIL AND GAS LEASE STATISTICS
FEDERAL AND STATE LANDS

FY	NO. LEASES		ACREAGE IN EFFECT		RENTAL		ROYALTY		BONUS	
	FED.	STATE	FEDERAL	STATE	FEDERAL	STATE	FEDERAL	STATE	FED.	STATE
1950	9		19,014		3,680					
51	35		77,805		6,850					
52	139		182,379		22,818					
53	783		1,370,783		317,114					
54	1020		1,832,780		138,485					
55	1696		2,519,846		220,016					
56	1901		2,814,742		468,616					
57	3385		6,516,746		839,278					
58	9191		19,552,999		3,643,748					
59	15,083	77	32,100,429	104,917	5,702,639	84,123			223,795	4,020,342
60	16,547	305	34,908,143	306,419	3,006,228	264,297			206,027	7,885,059
61	13,109	567	26,813,368	1,352,561	3,358,582	493,941	499,165			14,978,818
62	10,655	889	21,188,109	1,608,279	5,412,241	1,113,789	2,478,178			19,850,338
63	7713	1122	15,005,988	1,712,559	5,477,454	1,299,258	3,806,851			3,042,681
64	6186	1534	11,006,461	2,251,613	6,150,363	1,924,237	3,749,559	120,475		5,537,101
65	5496	2151	10,046,833	3,196,401	3,805,992	2,664,554	3,629,330	2,606,398		10,819,817
66	5456	2799	9,777,022	3,546,432	4,760,014	2,888,509	3,789,513	2,654,854		8,655,937
67	4285	3420	7,940,751	3,732,036	4,710,585	3,067,195	3,710,258	2,829,571		21,766,565
68	3943	3784	6,902,966	3,939,602	3,215,878	3,123,346	5,505,108	3,444,597		1,042,220
69	4234	3787	6,909,121	4,328,463	3,256,870	3,454,160	5,765,477	3,161,993		900,041,605
70	3995	3379	6,528,138	4,041,249	3,171,575	3,199,772	5,995,666	2,875,755		455,641
71	3132	3282	5,574,400	3,936,600	2,722,038	3,073,624	6,120,799	3,047,279		
72	2794	3545	5,010,526	4,322,914	2,312,025	3,444,048	5,741,175	2,984,076		4,012,847
73	2443	3473	4,509,978	4,316,816	2,171,032	3,404,169	4,940,573	3,336,761		24,819,190
74	2223	3742	4,314,719	4,853,538	1,947,810	3,711,937	7,915,996	3,605,389		1,040,910
75	1955	3264	3,695,933	4,272,785	908,733	3,365,380	8,591,579	3,424,164		

*Based on data from BIA Public Land Statistics and State of Alaska, Division of Lands', Monthly Mineral's Section Reports

ALASKA OIL AND GAS REVENUE STATISTICS
FEDERAL AND STATE LANDS

Calendar Year	FED. REVENUE: O&G PYMTS.		MINERAL INCOME FROM STATE LAND			
	Rental	Royalty	O&G Rental	Oil Royalty	Gas Royalty	O&G Bonus
1959-64	\$23,383,432	\$11,483,598	\$ 3,855,753	\$ 120,475	\$	\$ 51,578,686
1965	3,425,393	3,266,397	2,606,398	96,233		14,889,797
1966	4,092,165	3,600,774	2,654,854	941,562		7,153,332
1967	3,526,398	4,070,551	2,829,571	3,517,136		20,256,124
1968	2,894,533	4,954,597	3,444,597	14,232,822	241,309	4,045,493
1969	2,931,183	5,188,929	3,161,993	17,395,223	391,048	900,046,372
1970	2,854,418	5,396,099	2,875,755	22,146,497	755,861	
1971	2,449,835	5,508,719	3,047,279	23,730,460	897,074	455,641
1972	2,055,751	4,755,461	2,984,076	24,539,420	961,821	1,620,146
1973	1,857,677	3,784,078	3,336,761	22,013,132	1,053,821	7,313,700
1974	1,756,831	5,951,182	3,605,389	35,193,392	1,235,014	20,891,159
1975	858,031	7,830,937	3,424,164	37,234,774	3,028,140	2,524
Totals	\$52,085,647	\$65,791,322	\$37,826,590	\$201,161,126	\$8,564,088	\$1,028,252,974

*Based on data in Division of Lands' Annual Report, 1975

TABLE NO. 5

COMPETITIVE OIL AND GAS LEASING OF STATE LANDS

Sale No. and Date	Acres Offered	Percent Leased	Acres Leased	\$/Acre	Tracts Offered	Tracts Leased	Bonus Received
1. Dec. 10, 1959	88,055.00	87.66	77,191.00	\$ 52.08	37	31	\$ 4,020,342.43
2. July 13, 1960	17,567.51	93.96	16,505.57	24.70	27	26	407,654.54
3. Dec. 7, 1960	73,047.70	31.30	22,866.70	1.54	26	9	35,325.31
4. Jan. 25, 1961	400.00	100.00	400.00	679.04	3	3	271,614.40
5. May 23, 1961	97,876.00	98.06	95,980.00	74.71	102	99	7,170,464.88
6. Aug. 1, 1961	13,257.00	100.00	13,257.00	8.35	6	6	110,671.55
7. Dec. 19, 1961	255,708.44	73.14	187,025.40	79.47	68	53	14,863,049.33
8. April 24, 1962	1,061.70	100.00	1,061.70	4.81	8	8	5,097.00
9. July 11, 1962	315,668.93	87.77	264,437.13	59.42	89	76	15,714,112.60
10. May 8, 1963	167,583.06	84.43	141,490.51	29.23	200	158	4,136,224.92
11. C A N C E L L E D BECAUSE OF U.S. PROTEST ON YAKUTAT BAY AREA							
12. Dec. 11, 1963	346,782.40	71.25	247,089.00	12.31	308	207	3,042,680.74
13. Dec. 9, 1964	1,194,373.00	60.51	722,659.00	7.66	610	341	5,537,100.94
14. July 14, 1965	754,033.00	53.45	403,000.00	15.25	297	159	6,145,472.59
15. Sept. 28, 1965	403,042.06	74.87	301,751.28	15.49	293	216	4,674,343.74
16. July 19, 1966	184,410.05	72.66	133,987.29	52.55	205	153	7,040,880.17
17. Nov. 22, 1966	19,229.70	96.67	18,589.70	7.33	36	35	136,279.67
18. Jan. 24, 1967	47,729.00	88.82	42,397.00	34.87	23	19	1,478,777.23
19. Mar. 28, 1967	2,560.00	R E J E C T E D 12-9-74					
20. July 25, 1967	311,249.89	82.39	256,447.31	73.14	295	220	18,757,340.88
21. Mar. 26, 1968	346,623.00	47.59	164,961.00	18.24	308	147	3,009,224.00
22. Oct. 29, 1968	111,199.48	54.20	60,272.15	17.29	230	125	1,042,219.90
23. Sept. 10, 1969	450,858.47	91.50	412,548.47	2,181.66	179	164	900,041,605.34
24. May 12, 1971	196,635.07	47.10	92,617.97	4.87	244	106	455,640.57
25. Sept. 26, 1972	325,401.42	54.78	178,244.71	7.43	259	152	1,324,673.40
26. Dec. 11, 1972	399,920.96	44.50	177,972.56	8.75	218	105	1,557,848.84
27. May 9, 1973	308,400.81	36.93	113,891.71	9.93	210	96	1,130,324.51
28. Dec. 13, 1973	166,648.04	58.69	97,803.69	253.77	98	62	24,819,189.91
29. Oct. 23, 1974	278,269.43	50.00	127,119.65	8.19	164	82	1,040,909.98
	<u>6,877,591.12</u>	<u>63.57</u>	<u>4,371,567.50</u>	<u>\$ 235.09</u>	<u>4,544</u>	<u>2,858</u>	<u>\$1,027,969,069.37</u>

STATE COMPETITIVE SALE AREAS

Sale#	Area	Sale#	Area	Sale#	Area
1.	Wide Bay; offsh. Kenai to Ninilchik; Kachemak Bay	11.	Yakutat Bay (Cancelled)	20.	Big Lake; Knik; Iliamna Mt; Beluga; N. Cook Inlet; Kalgin Isld; Ninilchik
2.	Kenai Penin; West Forelands; Nushagak Bay	12.	Below Forelands; Knik & Turnagain Arms; Upper Cook Inlet; Kenai Penin.; Tyonek to Katunu River	21.	Port Heiden & Port Moller
3.	Katalla; Kalifonsky Beach; Herenden Bay; offsh. Kodiak	13.	Fire Island; W. Forelands; Trinity Islds; Prudhoe west	22.	Big Lake; Knik; Beluga; West Forelands; Ninilchik; Kachemak & Kenai
4.	Uplds. Ninilchik	14.	Prudhoe west to Canning River	23.	Colville to Canning River
5.	Tyonek; Controller Bay; Pavlov Bay	15.	Fire Isld & N. Cook Inlet; Kalgin Isld & Redoubt Bay; Knik; So. Kenai Penin.	24.	Big Lake; Knik; Kenai; West Forelands
6.	Controller Bay	16.	Kenai Penin & Knik; Middleton Isld; Fire Isld; Redoubt Bay; Kalgin Isld; Iliamna Mt; No. Cook Inlet	25.	Big Lake; Knik; Beluga; North Cook Inlet
7.	Icy, Yakutat, Kachemak Bays; So. Kenai Penin; No. Cook Inlet	17.	Big Lake; Kenai	26.	Cook Inlet (between Forelands and Turnagain Arm)
8.	Big Lake	18.	Katalla; Prudhoe	27.	Tuxedni; Ninilchik; Kenai; Kalgin
9.	Tyonek; W. Forelands; Knik Arm; Kalgin Isld; Chisik Isld; South Kenai Penin; Wide Bay	19.	Lower Cook Inlet	28.	Ninilchik; Kachemak Bay; Beluga
10.	Tyonek; Kenai offsh. & uplds.			29.	Kalgin & West Forelands; Chisik; Ninilchik; N. Cook Inlet; Turnagain; Big Lake

COOK INLET OFFSHORE - COMPETITIVE LEASE SALES

<u>Sale #</u>	<u>Acres Offered</u>	<u>Acres Leased</u>	<u>% Leased</u>	<u>Bonus Paid</u>	<u>\$/PerAcre</u>
1	31,165.00	25,621.00	82.21	\$ 2,976,542.43	116.18
2	9,497.00	8,435.00	88.82	68,788.79	8.16
3	1,851.70	1,851.70	100.00	10,026.25	5.41
7	203,466.00	146,126.00	71.82	14,411,099.13	98.62
9	310,310.46	264,437.13	83.74	15,626,116.56	59.24
10	81,767.00	75,669.00	92.54	1,058,658.96	14.00
12	268,330.00	184,248.00	68.66	2,623,661.46	14.24
13	184,413.00	149,089.00	84.47	1,055,868.09	7.08
15	386,350.36	287,383.36	74.38	4,581,240.94	15.94
16	119,182.32	76,393.61	64.10	1,241,432.01	16.25
19	2,560.00	2,560.00	100.00	2,585.60	1.01
20	189,256.89	175,836.00	92.85	18,124,003.52	103.13
22	1,342.55	894.85	66.65	6,015.72	6.72
24	326.28	198.58	60.86	617.73	3.11
25	74,999.96	12,979.71	17.00	81,489.22	1.59
26	345,174.26	130,273.03	38.00	1,144,060.16	11.38
27	258,545.29	75,344.91	29.00	747,664.34	9.89
28	149,567.15	80,722.80	53.97	24,819,189.91	306.43
29	275,528.66	123,598.88	44.85	933,934.01	7.00
Total	2,893,633.88	1,897,573.56	65.57	39,512,994.83	47.17

TABLE 5-C

NORTH SLOPE COMPETITIVE LEASE SALES

<u>Sale #</u>	<u>Acres Offered</u>	<u>Acres Leased</u>	<u>% Leased</u>	<u>Bonus Paid</u>	<u>\$/PerAcre</u>
13	624,457.00	466,180.00	74.65	\$ 4,376,523.30	9.39
14	754,033.00	403,000.00	53.44	6,145,472.59	15.25
18	37,662.00	37,662.00	100.00	1,469,645.39	13.11
23	450,858.47	412,548.47	91.50	900,041,605.30	2,181.66
Total	1,867,010.47	1,319,390.47	70.67	\$912,033,246.58	691.25

TABLE 5-D

GULF OF ALASKA COMPETITIVE LEASE SALES

<u>Sale #</u>	<u>Acres Offered</u>	<u>Acres Leased</u>	<u>% Leased</u>	<u>Bonus Paid</u>	<u>\$/PerAcre</u>
3	12,275.00	5,257.00	42.83	\$ 5,777.81	1.10
5	23,508.00	23,508.00	100.00	66,203.88	2.82
6	13,257.00	13,257.00	100.00	110,671.55	7.67
7	50,457.00	39,207.00	77.70	269,390.20	6.87
12	6,635.70	0	0	0	0
16	30,969.00	27,152.00	87.67	4,457,131.30	1.64
18	10,067.00	4,735.00	47.03	9,131.84	1.92
<hr/>					
Total	147,168.70	113,116.00	76.86	\$4,918,306.58	4.35

TABLE 5-E

WIDE BAY AND KODIAK COMPETITIVE LEASE SALES

<u>Sale #</u>	<u>Acres Offered</u>	<u>Acres Leased</u>	<u>% Leased</u>	<u>Bonus Paid</u>	<u>\$/Per Acre</u>
1	56,890.00	51,570.00	90.65	\$1,043,800.00	20.24
9 (Uni.)	678.47	678.47	100.00	87,996.04	129.70
9 (Offsh.)	4,680.00	0	0	0	0
13 (Kodiak)	385,503.00	107,390.00	27.85	104,709.55	97.50
<hr/>					
Total	447,751.47	159,638.47	35.65	\$1,236,505.59	77.46

TABLE 5-F

BRISTOL BAY COMPETITIVE LEASE SALES

<u>Sale #</u>	<u>Acres Offered</u>	<u>Acres Leased</u>	<u>% Leased</u>	<u>Bonus Paid</u>	<u>\$/Per Acre</u>
2	4,341.00	4,341.00	100.00	\$ 11,937.75	27.50
3	58,921.00	15,758.00	26.74	19,521.25	1.24
5	16,093.00	16,093.00	100.00	65,727.62	4.08
21	346,623.00	164,961.00	47.59	3,009,224.00	18.24
<hr/>					
Total	425,978.00	201,153.00	47.22	\$3,106,410.62	15.44

TABLE NO. 6*

COMPETITIVE LEASES & ACREAGE BY YEAR

<u>Year</u>	<u>No. Lses. Iss.</u>	<u>Acreage</u>	<u>Cumulative Acreage</u>
1960	54	88,639	88,639
1961	117	132,388	217,970
1962	61	188,085	367,447
1963	161	143,354	487,530
1964	219	279,092	671,095
1965	699	1,387,351	2,035,648
1966	187	154,498	2,007,064
1967	242	300,764	2,103,709
1968	272	225,306	2,170,626
1969	163	410,025	2,415,783
1970	1	2,523	2,128,070
1971	106	92,616	2,063,396
1972	145	169,365	2,073,691
1973	211	301,714	2,291,295
1974	146	225,709	2,476,388
1975	0	0	2,470,013

*Data compiled from Division of Lands, Mineral's Section Monthly Reports

TABLE NO. 7*

NONCOMPETITIVE SIMULTANEOUS FILINGS BY YEAR

INCLUDING 1ST YEAR RENTAL & FILING FEE REVENUE

<u>Year</u>	<u>No. Aplus.</u>	<u>Filing Fees Received</u>	<u>Acreage Leased</u>	<u>1st Year Rentals</u>
1961	13,333	\$ 267,660	192,174	\$ 96,087
1962	13,966	279,320	462,466	231,233
1963	5,187	103,740	230,539	115,270
1964	1,336	26,720	116,971	58,486
1965	2,448	48,960	205,692	102,846
1966	5,585	111,700	203,880	101,940
1967	18,503	370,060	317,071	158,536
1968	13,162	263,240	334,073	167,037
1969	13,963	279,260	409,217	204,609
1970	5,456	109,120	458,400	229,200
1971	6,973	139,460	287,020	143,510
1972	9,420	188,400	391,477	195,739
1973	8,679	173,580	295,923	147,961
1974	6,531	130,620	233,130	116,565
1975	<u>7,796</u>	<u>155,920</u>	<u>189,301</u>	<u>94,651</u>
Totals	132,388	\$2,647,760	4,327,334	\$2,163,670

*Data compiled from Division of Lands, Mineral's Section Monthly Reports

TABLE NO. 8*¹
 NONCOMPETITIVE ISSUED LEASES AND ACREAGE BY YEAR*²
 INCLUDING CUMULATIVE ACREAGE & RENTAL

<u>Year</u>	<u>#Leases Issued</u>	<u>Acreage Issued</u>	<u>Cumulative Acreage</u>	<u>Cumulative Rental*³</u>
1960	72	51,519	51,519	\$ 25,760
1961	132	229,831	280,891	140,446
1962	248	489,654	748,934	374,467
1963	172	328,054	870,352	435,176
1964	124	125,375	782,399	391,200
1965	210	222,212	747,582	373,791
1966	446	559,383	1,192,871	596,436
1967	481	350,241	1,357,678	678,839
1968	273	341,265	1,559,605	779,803
1969	311	419,700	1,806,513	903,257
1970	306	461,487	1,794,434	897,217
1971	227	287,060	1,653,478	826,739
1972	337	391,477	1,666,241	833,121
1973	237	295,923	1,797,146	898,573
1974	423	764,535	2,373,324	1,186,662
1975	<u>243</u>	<u>395,500</u>	<u>2,102,485</u>	<u>1,051,243</u>
Totals	4242	5,713,216	20,785,452	\$10,392,730

*¹Data compiled from Division of Lands, Mineral's Section Monthly Reports

*²Including Transferred Federal Leases & Offers

*³Calculated at 50¢ per acre

TABLE NO. 9

OIL AND GAS DISCOVERY ROYALTY CERTIFICATIONS

<u>Well Name</u>	<u>ADL#</u>	<u>Acres</u>	<u>Structure</u>	<u>Lessee</u>	<u>Discovery Date</u>
Falls Creek Unit#1	00590	3660	Falls Creek	Socal, etal	5/1/61
MGS #1	17595	5106	MGS	Amoco, etal	7/1/62
Cook Inlet State#1A	17589	5002	Cook Inlet	Amoco, etal	9/1/62
Beluga River Unit#1	17599	5001	Beluga River	Socal, etal	1/1/63
Granite Pt. #1	18761	5089	Granite Point	Mobil	6/1/65
Trading Bay #1A	18731	3840	Trading Bay	Union, etal	6/1/65
Nicolai Creek State #1-A	17598	3023	Stedatna Creek	Texaco, etal	5/1/66
Prudhoe Bay State #1	28303	2560	ARCO, etal	Prudhoe Bay	1/1/68

1 10
EXPLORATORY WELLS STATE LEASES

<u>Lease ADL#</u>	<u>Type*</u>	<u>Well Name</u>	<u>Geographical Area</u>	<u>Discovered Oil/Gas in Paying Quantities</u>
00590	C	Falls Creek Unit 1	Cook Inlet Basin	Yes
00591	"	" " " 2	" " "	No
00592	"	Ninilchik 1	" " "	"
00608	"	Wide Bay Unit 1	Alaska Peninsula	"
01804	"	W. Foreland Unit 2	Cook Inlet Basin	"
03174	"	Chuit State 2	" " "	"
03178	"	" " 1	" " "	"
03193	"	Chuitna River State 1	" " "	"
03197	"	Stedatna Creek 1	" " "	"
03264	"	Three Mile Creek State 1	" " "	"
08878	N	Cottonwood State 1	" " "	"
17786	"	Kustatan River	" " "	"
17579	C	North Redoubt State 1	" " "	Yes
17580	"	State 17580 1	" " "	No
17582	"	SRS State 2	" " "	"
17582	"	SRS State 1	" " "	"
17582	"	Tyonek State 17586 2	" " "	"
17585	"	Nicolai Creek Unit 4	" " "	"
17587	"	Tyonek State 1	" " "	"
17587	"	Tyonek State 17587 2	" " "	"
17588	"	Tyonek State 17588 1	" " "	"
17589	"	Cook Inlet State 17589 1-A	" " "	Yes
17589	"	" " " " 1	" " "	No
17591	"	" " " 17591 1	" " "	"
17594	"	Grayling 1-A	" " "	Yes
17594	"	Grayling 1	" " "	No
17595	"	MGS State 17595 3	" " "	"
17595	"	MGS State 17595 2	" " "	"
17595	"	MGS State 1	" " "	Yes
17596	"	E. Trading Bay State 1	" " "	No
17597	"	Trading Bay State 1	" " "	Yes
17597	"	Trading Bay 2	" " "	No
17598	"	Nicolai Creek State 1	" " "	"
17598	"	" " " 1-A	" " "	Yes
17600	"	Ivan River Unit 23-12	" " "	No

*C=Competitive N=Noncompetitive

<u>Lease ADL#</u>	<u>Type</u>	<u>Well Name</u>	<u>Geographical Area</u>	<u>Discovered Oil/Gas in Paying Quantities</u>
17601	C	W. Foreland Unit 1	Cook Inlet Basin	No
17612	"	Coal Bay State 1	" " "	"
17797	N	Johnson Slough 1	" " "	"
17802	N	Bachatna Creek Unit 7	" " "	"
18716	C	Foreland Channel State 1-A	" " "	"
18716	"	" " " 1	" " "	"
18719	"	Oldman's Bay Street	" " "	"
18729	"	Kustatan 1-A	" " "	Yes
18729	"	" 1	" " "	No
18731	"	W. Trading Bay State 1	" " "	"
18731	"	Trading Bay 3	" " "	"
18731	"	" " 1-A	" " "	Yes
18731	"	" " 1	" " "	No
18731	"	Trading Bay State A-3	" " "	"
18740	"	Cook Inlet State 18740 1	" " "	Yes
18741	"	" " " 18741 1	" " "	No
18741	"	" " " 18741 2	" " "	Yes
18742	"	Tyonek State 18742 1	" " "	Yes
18745	"	N. MGS State 18745 2	" " "	No
18745	"	" " " 1-A	" " "	"
18745	"	" " " 1	" " "	"
18746	"	MGS State 18746 1	" " "	Yes
18751	"	E. MGS State 18751 1	" " "	No
18754	"	SRS MGS State 1	" " "	Yes
18755	"	N. Cook Inlet State 1	" " "	No
18758	"	W. Foreland Unit 4	" " "	"
18761	"	Granite Pt. 1	" " "	Yes
18763	"	Knik Arm State 1	" " "	No
18765	"	Tower 2	" " "	"
18765	"	" 1	" " "	"
18772	"	McArthur State 1	" " "	Yes
18774	"	N. Trading Bay 23-7	" " "	No
18775	"	Middle River State 95 1	" " "	"
18777	"	West Foreland Unit 3	" " "	Yes
18777	"	Middle River State 2	" " "	No
18788	"	Starichkof State Unit 1	" " "	"
18790	"	Starichkof State 1	" " "	Suspended
18791	"	Kalgin Island State 1	" " "	No
18775	"	Middle River State Unit 1	" " "	"
20424	N	Campbell Point 1	" " "	"
21067	C	Middle River State Unit 2	" " "	"

<u>Lease ADL#</u>	<u>Type</u>	<u>Well Name</u>	<u>Geographical Area</u>	<u>Discovered Oil/Gas in Paying Quantities</u>
21094	C	Kasilof Unit 2	Cook Inlet Basin	No
21095	"	" " 1	" " "	"
21095	"	Kasilof State 1	" " "	"
21136	"	Susitna State Unit 1	" " "	"
21154	"	Lorraine State 1	" " "	"
21184	"	Middle Lake Unit 1	" " "	"
21095	"	Kasilof State 2	" " "	"
22008	"	Turnagain Arm Unit 1	" " "	"
22064	"	Redoubt Shoal State 22064 1	" " "	"
22106	"	Kustatan Ridge 1	" " "	"
22119	"	Middle River State 1	" " "	"
22170	"	W. Tyonek 1	" " "	"
23601	N	Beaver Lakes State 1-B	" " "	"
25425	C	Kustatan River Unit 43-30	" " "	"
25514	"	Simpson Lagoon 32-14A	North Slope	Yes
25514	"	" " 32-14	" "	No
25518	"	Kavearak Point 32-25	" "	Yes
25532	"	Kalubik Creek 1	" "	No
25551	"	Colville 1	" "	"
25575	"	Kookpuk	" "	"
25633	"	Ugnu	" "	Yes
25635	"	Fast Ugnu	" "	"
25651	"	W. Sak River State 2	" "	"
25651	"	W. Sak River State 2	" "	Yes
25658	"	" " " 3	" "	Suspended
25662	"	" " " 5	" "	"
28239	"	N.W. Eileen State 2	" "	No
28239	"	" " " 1	" "	Yes
28241	"	W. Kuparuk State 03-11-11	" "	"
28248	"	W. Sak River State 6	" "	Suspended
28252	"	Hemi State 03-09-11	" "	No
28255	"	Beechey Point State 1	" "	"
28257	"	N. Kuparuk State 26-12-12	" "	Yes
28263	"	Kuparuk State 1	" "	"
28264	"	S.E. Eileen State 1	" "	No
28264	"	S.E. Eileen State 2	" "	Yes
28275	"	Kup River State 1	" "	Suspended
28281	"	Put River J-1	" "	"
28287	"	" " 33-11-13	" "	"
28289	"	Hurl State 05-10-13	" "	Yes

<u>Lease ADI.#</u>	<u>Type</u>	<u>Well Name</u>	<u>Geographical Area</u>	<u>Discovered Oil/Gas in Paying Quantities</u>
28301	C	West Beach State 2	North Slope	Suspended
28303	"	Prudhoe Bay State 1	" "	Yes
28309	"	Put River	" "	Suspended
28313	"	Put River State 1	" "	"
28315	"	Put River 24-10-14	" "	"
28316	"	Socal 31-25	" "	"
28328	"	Sag River State 1	" "	Yes
28332	"	Lake State 1	" "	"
28343	"	Sag Delta 31-11-16	" "	Suspended
28344	"	Delta State 1	" "	"
28349	"	Sag Delta 31-10-16	" "	"
28350	"	Kadler State 15-09-16	" "	No
28367	"	E. Mikkelsen Bay State 1	" "	"
28377	"	West Staines State 2	" "	"
28380	"	W. Staines State 18-09-23	" "	"
29690	"	Redoubt Shoal Unit 2	Cook Inlet Basin	Yes
29690	"	" " State 1	" " "	No
29691	"	Forelands State Unit 1	" " "	"
29715	"	Clam Gulch	" " "	"
29723	"	Drift River State 1	" " "	"
30021	N	Red Shirt Lake 1	" " "	"
33098	C	Horseshoe Lake State 1	" " "	"
33108	"	Long Lake Unit 1	" " "	"
33238	"	Middleton Island State 1	Gulf of Alaska	"
34101	"	Cohoe Unit 1	Cook Inlet Basin	"
34623	"	Point Storkersen 1	North Slope	Yes
34624	"	N. Prudhoe Bay State 1	" "	"
34625	"	Niakuk 2	" "	Suspended
34625	"	" 1	" "	No
34626	"	Gull Island State 1	" "	Suspended
34627	"	West Beach State 3	" "	"
34628	"	West Beach State 1	" "	"
34630	"	Niakuk 1-A	" "	"
34631	"	East Bay State 1	" "	Yes
34634	"	Sag Delta 33-12-16	" "	Suspended
34638	"	Katalla State 1	Gulf of Alaska	No
35225	"	Trading Bay State 2	Cook Inlet Basin	"
35323	"	West Foreland Unit 5-A	" " "	"

<u>Lease ADL#</u>	<u>Type</u>	<u>Well Name</u>	<u>Geographical Area</u>	<u>Discovered Oil/Gas in Paying Quantities</u>
35323	C	West Foreland Unit 5	Cook Inlet Basin	No
35431	"	Trading Bay State 1	" " "	Yes
35704	N	S. Caribou Hill Unit 1	" " "	No
36448	C	Bachatna Creek State 1	" " "	"
36465	"	State 36465 1	" " "	"
38314	C	Port Heiden Unit 1	Bristol Bay	"
41217	"	Ninilchik 1	Cook Inlet Basin	"
45592	N	Am. Quasar Big Lake 1	" " "	"
46938	"	Bachatna Creek Unit 1	" " "	"
47417	C	Colville Delta State 1	North Slope	"
47433	"	Milne Point 18-1	" " "	Yes
47465	"	Gwydyr Bay State A 1	" " "	No
47468	"	" " South 1	" " "	Yes
47470	"	Delta State 2	" " "	Suspended
47488	"	West Channel 1-3	" " "	No
47506	"	Foggy Island Bay Unit 1	" " "	Suspended
47542	"	Mikkelsen Bay State 13-09-19	" " "	No
47556	"	Alaska State A 1	" " "	Suspended
47440	"	Plagim Beechey Pt. 1	" " "	No
52638	N	Pretty Creek State 1	Cook Inlet Basin	No
53078	"	Bachatna Creek Unit 3	" " "	"
54195	C	Figure Eight Unit 1	" " "	"
54273	"	West Foreland State A 1	" " "	"
58761	"	Isla Grande 1	" " "	"
58784	"	E. Lewis River 1	" " "	"
58801	"	Lewis River 1	" " "	Yes
58838	"	N. Tyonek State 1	" " "	No
59313	"	West McArthur River 1	" " "	"
60579	"	Cape Kasilof 1	" " "	"

COMPARISON OF NONCOMPETITIVE VS COMPETITIVE LEASING
(EXAMPLE OF TWO HIGH INTEREST NONCOMPETITIVE AREAS)

T. 1 N., R. 12 W., S.M.

COMPETITIVE

Date	ADL #	#Bids	Acres	\$/PerAcre
7/67	36540	1	641	2.68
"	41	"	"	"
"	46	"	640	2.15
"	47	"	720	2.68
"	49	"	640	2.15
"	50	"	640	2.15
"	51	"	640	2.15
"	55	"	640	2.15
5/73	60611	2	160	3.34
"	60612	1	1040	2.00
"	13	1	160	2.00
"	14	1	476	2.00

NONCOMPETITIVE

Date	ADL #	#Aplns.	Acres	\$/PerAcre in Filing Fees
3/72	56985	71	641	2.22
"	86	169	558	6.05
"	87	72	1280	1.13
"	88	88	838	2.10
"	89	85	680	2.50
"	90	68	639	2.13
12/72	59609	207	540	6.47
"	59610	175	320	11.00
6/75	68140	135	1880	1.44

T. 3 S., R. 14 W., S.M.

COMPETITIVE

Date	ADL #	#Bids	Acres	\$/PerAcre
12/63	22089	1	80	3.15
10/68	41226	1	800	7.67
"	41227	1	389	7.67

NONCOMPETITIVE

Date	ADL #	#Aplns.	Acres	\$/PerAcre in Filing Fees
2/65	26329	3	80	.75
12/65	31447	190	800	4.75
1/67	34888	550	2560	4.30
"	34891	170	480	7.08
"	34892	499	1600	6.24
"	34894	877	2440	7.19
"	34895	571	2440	4.68
"	34899	91	640	2.84
3/67	35700	54	80	13.50
4/67	36011	71	120	11.83
8/68	40832	240	360	13.33
9/68	41880	180	240	15.00
12/68	43691	606	1280	9.47
"	43697	596	1560	7.64
6/69	47020	1085	1280	16.95
12/69	50171	93	120	15.50
12/71	56379	79	360	4.39
2/72	56591	200	677	5.90
12/72	59628	51	200	5.10
9/73	62677	40	40	20.00
3/74	63845	183	320	11.44
7/74	68140	135	1880	1.44

TABLE NO. 12

NORTH SLOPE

FEDERAL LEASING HISTORY*1

PLO 1621 restored PLO 82 to mineral leasing on April 18, 1958. This order provided for leasing through noncompetitive lease offering in a simultaneous filing period. This was done in the following order:

Drawing Date	Acreage Offered	Tracts Offered	Tracts Rec'd Offers	Offers Received	Acres Leased*2
1958	3,400,000	1364	608	-	1,520,000
6/11/64	3,600,000	1440	1000	14,725	2,500,000
5/13/65	4,000,000	1558	268	31,431	670,000
11/19/65	"	1960	148	1397	370,000
1966	3,000,000	1247	7	8	17,500
12/30/66	4,300,000	1817	215	500	537,500*3
Total	22,300,000				5,615,000

*1 Adapted from August 21, 1968 Alaska Scouting Service Report

*2 Estimated on basis of 2500 acres per parcel

*3 Leases not issued because of "land freeze"



Official Business

Alaska State Legislature

House of Representatives

Committee on Resources

Pouch V
State Capitol
Juneau, Alaska 99811

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- 1a. HB 854-Leasing of state land for oil and gas development
 - b. Fiscal note for HB 854
 - c. Applicable Alaska Statutes
2. Analysis of bill prepared by Legislative Affairs Agency
3. "Study of State Petroleum Leasing Methods and Possible Alternatives" prepared by the Department of Natural Resources, February, 1977.
- 4a. Transcript of Milton Lipton's comments to the joint Senate/
House Resources Committees on State leasing policy (January
25, 1978).
 - b. Prepared testimony/comments on HB 854.
5. "Oil and Gas Leasing Policy, Alternatives for Alaska in 1977",
by Dr. Mason Gaffney, February 1, 1977.

SEC. 3

THE SENSITIVITY OF STATE PETROLEUM INCC
TO VARIOUS LEASING METHODS

SECTION III

SUMMARY

Four leasing methods and one option were analyzed in detail. Economic analyses were run on a computer for each of the studied leasing methods. Model field sizes used, ranged from 100 million to 5 billion barrels of recoverable oil. An analytical comparison shows that state income (immediate, long range, and discounted) varied considerably depending on the leasing method. However, different leasing methods have other advantages and disadvantages to the State such as to encourage or discourage investment capital, exploration, field development, production rates, economic field life, and competition at leasing auctions. The results of this study clearly indicate there is no "one-best-method" of leasing. The data does show that knowledge of the potential petroleum structure is essential and that leasing methods need to be tailored to the structures being leased and to the State's needs.

Bonus bidding maximizes immediate income to the State and is discussed on page II - 20. Sliding scale royalty with cash bonus bidding provides lesser immediate income to the State than does bonus bidding, but provides greater total income to the State as can be seen on Figure II - 10, page II - 22. Royalty bidding and Net Profits Bidding (both with fixed cash bonus) are similar as far as the income stream provided to the State; they generally provide the least immediate income but greatest amount of total income to the State of Alaska - this is shown on Figure II - 12, page II - 25. (Royalty Bid and Net Profits Bid provide increased state income by reducing Federal income tax and by reducing the amount of Oil Company Investment on which a rate of return is to be made.)

A significant result of this study is that State income can be increased for all leasing methods studied by using a percent of acreage option. This option consists of acquiring sufficient knowledge to intelligently withhold some of a structure when leasing.

As is shown in Tables II - 1 and II - 2 pages II - 27C and 27B, bonus income to the State was increased from 48.1 to 174.9 million dollars for our field model with 600 million barrels recoverable oil. This is an increase of 131.1 million dollars.

INTRODUCTION TO THE SENSITIVITY ANALYSIS

Petroleum Development and Past Leasing Policy. In the 74 years that have elapsed since the first commercial oil was found in Alaska at Katalla, the State has seen wave after wave of explosive development crash upon its shores, followed by the inevitable receding wave of bust and recession. After petroleum was found at Swanson River in 1957 (a major oil field of 218 million barrels of recoverable reserves), Alaska was catapulted into the petroleum era and the resulting series of petroleum lease sales have changed Alaska's economic emphasis from hard minerals to oil.

As Alaska moved into the petroleum scene, it found itself in the unique position of being the late comer to the party and winning the door prize. Alaska found that it possessed a great wealth of petroleum at a time when the other states and the Federal government were closing the curtain on the final act of their petroleum resources. The nation has managed to use the majority of its oil and gas resources in seventy years and now finds production falling with demand increasing - a grim situation, to say the least.

Alaska is therefore in a crucial position concerning the national and world energy crisis. The State has over 50% of the nation's remaining potential reserves, and the majority of these reserves lie on Alaska's Continental Shelves and uplands of the State. The nation is now moving to the OCS to develop the last oil resources, and Alaska with 560,000 square miles of shelf has more oil potential area (70%) than all of the other OCS areas

combined. This means that world and Federal actions, native development and state needs will be key factors in the State's future petroleum policies.

Political, economic, environmental and social requirements are now being considered as part of the State's needs, a much more complicated situation than earlier years and certainly more controversial. This report will concentrate on various methods of leasing petroleum lands. The decision of whether to lease or not, and when to lease, are basic policy decisions beyond this report. HOW to lease in light of the changes of recent years is a difficult and complex problem. This study will attempt to analyze some options and insight into this aspect of our natural resource management.

The present state leasing system was initiated in an earlier era when the major leasing consideration was in maximizing the current revenues to the State. Petroleum was leased upon a single variable - the initial cash bonus. In general, this system was effective and workable. It provided the State with the necessary revenue to move from dependence upon the Federal government to true statehood and provided impetus to establish an oil industry in Alaska.

With the 1969 Prudhoe Bay lease sale, the construction of the Alyeska Pipeline, and other changing economic and social circumstances, the public is becoming more interested in future leasing methods.

Management implies benefits, but it requires knowledge, and it assumes risks.

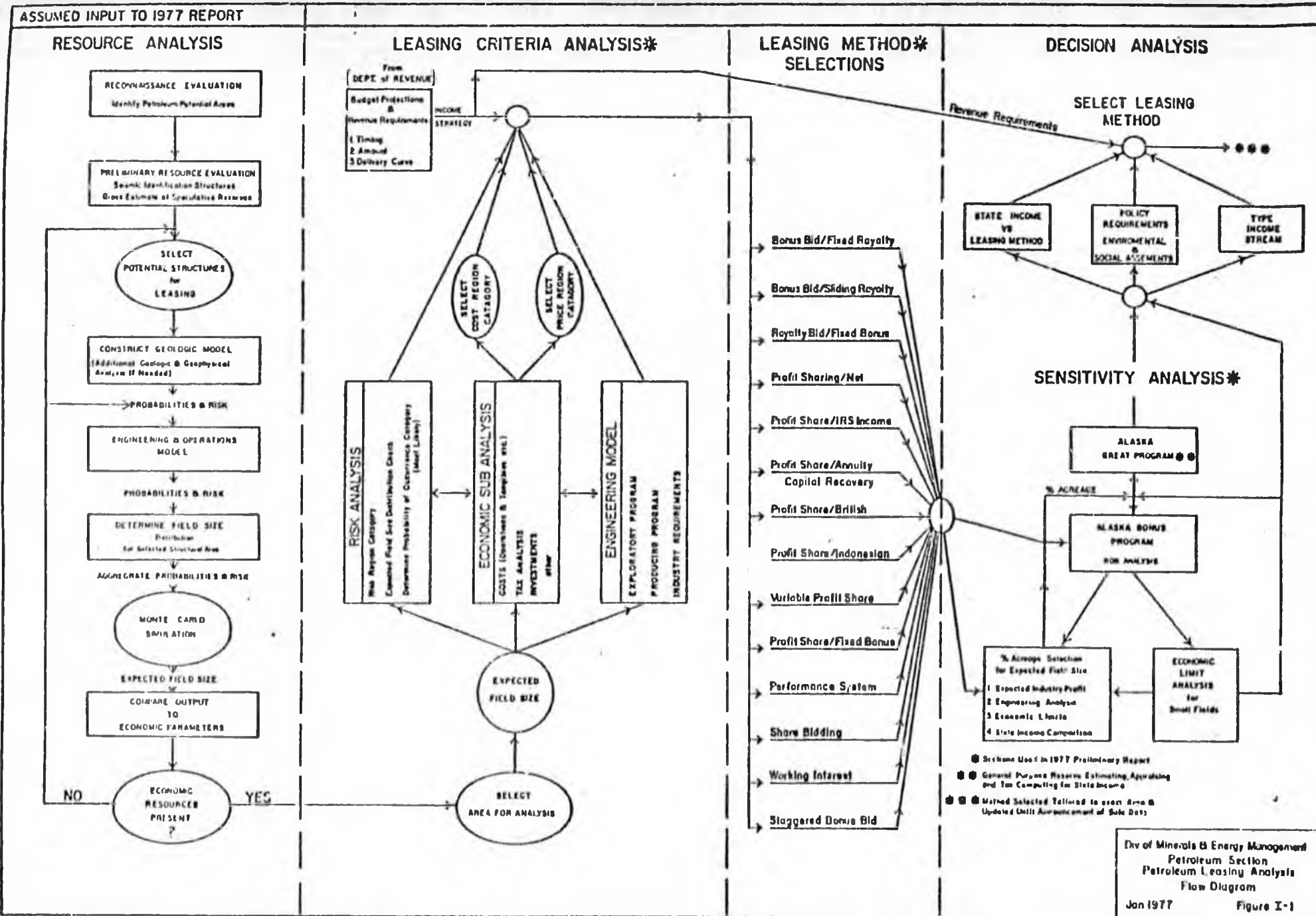
This leasing study indicates that the State may achieve greater economic benefits and the ability to take these benefits when the State needs them if we undertake a managed leasing system. But what is a managed leasing system? If we ACQUIRE KNOWLEDGE of the key factors needed for leasing, ESTIMATE THE RISK in making a decision based on this knowledge, then MAKE THE DECISION THAT WILL GIVE US THE BEST CHANCE OF ULTIMATE GAIN we are "managing".

In our specific case of leasing petroleum we have found that we will need, (1) knowledge of the resource (gained from geologic, engineering and economic research), (2) Understanding of the risk of finding oil and of finding a certain amount of oil, and (3) the ability to choose the best method for capitalizing on knowledge and risk (right time, area and method to lease; in other words a flexible leasing method).

Our Leasing Analysis has shown that income to the State is extremely dependent upon risk and the type of risk we're dealing with is partially a function of knowledge. We have found that if we can quantify the risk, we will be able to lease to our advantage and a leasing program can be tailored to accomplish this.

Leasing Policy Problem. We have approached the leasing problem in the following manner. KNOWING where the potential petroleum may be located and estimating the amount of petroleum is fundamental to the determination of risk. This information is also essential for long range planning, economic projections, budgeting, and many other natural resource development issues. The Resource Analysis section of Figure I-1 indicates the steps involved in obtaining the resource knowledge needed for a State Resource Management analysis.

THE ALASKA RESOURCE EVALUATION & LEASING SYSTEM



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The resource analysis steps shown, comprise a broad based statistical - analytical approach. The amount of exploration information used would be kept to a minimum. Only enough data would be gathered to determine the distribution of the large potential oil and gas fields, the gross expected value reserves of the fields and to ascertain the probabilities of finding petroleum.

The Division of Minerals and Energy Management is tasked with the "Resource Analysis" and would provide the "Expected Field Size" needed for a Resource Management Analysis. This study begins with an expected field size and assumes that adequate knowledge is available for the basic pre-leasing management decisions.

Since we cannot manage without knowledge, our only other option is to lease by an open bidding system that permits anyone to bid at competitive auction and establish a true value between the parties on that day. In retrospect this may prove to be either beneficial or detrimental to the best interests of the State.

Determination of Risk. The need to recognize the effects of uncertainty associated with oil and gas leasing, exploration, and production, especially in frontier areas, lead to the use of expected value as the method of accounting for risk and uncertainty. The probabilities of finding a certain amount of petroleum are determined using modern computer technology. This "Risk" oil field is then fed into a RISK Determination analysis that accounts for the uncertainties that affect income such as costs and prices. Finally Risk is again considered in the economic computer program, so that the final output is the EXPECTED dollar income to the State from a chosen leasing procedure.

Decision Analysis. The final step in a resource management analysis would be to compare the economic results of the resource analysis with budgetary requirements, environmental and service needs, and policy guidelines. A decision on when, how, where, and how much of the resource to lease would then be made.

With the formation of the Division of Minerals and Energy Management, the State now has the technical ability to undertake a resource management analysis.

The Leasing Sensitivity Study. The questions naturally arise, should we manage? Is it worth it? To find the answers we have used models to determine the sensitivity of state income to various leasing factors. Since the leasing method is the factor over which the state government can have the greatest possible control, we have compared various leasing methods against the key income variables of RISK, FIELD SIZE, COST, AMOUNT OF ACREAGE and PRICE OF OIL.

Five potential oil field sizes, small, medium, large, subgiant, and giant, were selected as being representative of the range of potential hydrocarbon fields remaining in Alaska. Cost regions and price regions were selected as were various probabilities of success. (Details of these key factors are given in Appendix A, C & D).

Each combination of oil field size, cost region, and probability of success was analyzed using an appropriate computer model. Likely bid variables (bonus, royalty or profit share) were estimated by performing a discounted cash flow analysis of the exploration, development, and production of a field

from an oil company's point of view. Sensitivity analysis procedures were used to determine a profile of bid variable versus expected rate-of-return. Using the value for the bid variable which yields the target rate-of-return, the cash flow to the State was projected via computer simulation for various size fields, cost regions, risk conditions and State income. All of these variables fluctuate with each bidding method. Bidding methods are described in Section VI. Special versions of GREAT, a widely used petroleum economics system developed and supported by Garrett Computing Systems, Inc. of Dallas, Texas, were prepared to fit the specific needs of the State.

Natural Gas Fields. The exploration and discovery of natural gas fields has been considered and our decision was to evaluate the sensitivity of natural gas fields to leasing at a later date. The uncertainties at this time of prices, markets, transportation systems and many other factors would have called for a risk analysis -- sensitivity study even greater than the one we have used for oil.

If we are to have flexibility in leasing, the oil sensitivity analysis has plainly demonstrated a need. The evidence being what it is for chance, we prefer to undertake the gas study as a direct consequence of our lease planning system and will begin work on this project in the near future.

The results of the oil field sensitivity study are very conclusive. Proper management in leasing will lead to higher income for the State at the risk we assumed. If the probability of occurrence is higher than we have assumed the resulting income to the State in all cases will be higher. If it turns out to be lower than we have assumed, the income will be lower in all cases.

Since evaluation of the produced gas depends on several variables the effects of solution gas are not handled separate from oil in this analysis. The effects on the study are in the order of less than 1%.

SENSITIVITY ANALYSIS OF SELECTED LEASING METHODS

Various specific parameters are important to an analytical study of income from various leasing methods. These parameters are discussed in the following sections and are briefly identified here.

A sensitivity analysis of leasing methods must include all income to the State from the leasing and production of petroleum properties. These include bonuses, royalties, various production and property taxes and state income tax. These income sources are explained more completely in the section titled "State Petroleum Income Sources".

A discussion of leasing methods must include an analysis of the oil field models used in the study. As was done in this study, the models used should be based on existing Alaska oil fields. Parameters of field size (reserves), investments, operating costs and production rates were based on actual Alaska fields. The models used in this study are described in the section "Expected Petroleum Field Models".

The Chance of Finding The Expected Field Size (a following section) is important to the validity of any study which is based on analytical comparisons. National field discovery statistics, modified by Alaska data, is used to develop field sizes and probability of finding the expected size field.

Income from any venture is dependent on the risks involved. State petroleum income varies directly with the risks involved. The concepts of risk and how it affects income is discussed in the following sections titled "The Risk Factor" and "Importance of the Risk Factor".

STATE PETROLEUM INCOME SOURCES

Since statehood, at the present, and for the foreseeable future, petroleum revenues have constituted a major portion of the State's income. These revenues accrue from leasing bonuses, royalty interest, severance tax, conservation tax, advalorem tax rentals, and from State income tax.

The State has been leasing potential petroleum lands at 12.5% royalty by soliciting sealed cash bonus bids (the State's last lease sale was at 16 2/3% royalty but that sale in "Katchemak Bay" sale has been environmentally questioned, and the State is now negotiating a buy-back of the leases. The royalty represents the State's retained interest in the oil and gas. The bonus constitutes the amount of money a bidder is willing to pay for the privilege of exploring for petroleum and for the privilege of developing and producing the oil and gas which may be found.

The State commonly collects four different types of taxes from the oil companies which are actively engaged in the production of oil and gas in Alaska. The severance tax is based on gross value of production, the conservation tax is based on the amount of oil and gas produced, the advalorem tax is based on the value of oil and gas property, and the state income tax is based on taxable income.

Tax rates are set by the legislature, therefore, State income from the severance tax, conservation tax and the advalorem tax is essentially fixed, dependent on the amount and value of production and the valuation of the producing properties. The State income tax is based on taxable income

of the particular company. The company is able to manipulate taxable income and therefore the amount of State income tax actually paid. As will be discussed later in this report, the State also has the capability of influencing the taxable income of companies producing oil and gas from State lands. The royalty represents the State's ownership of the oil and gas. Therefore, the State has the prerogative of specifying the ownership percent, or utilizing it as a bid parameter. That is, the amount of ownership the State would have in its resources could be a bid item.

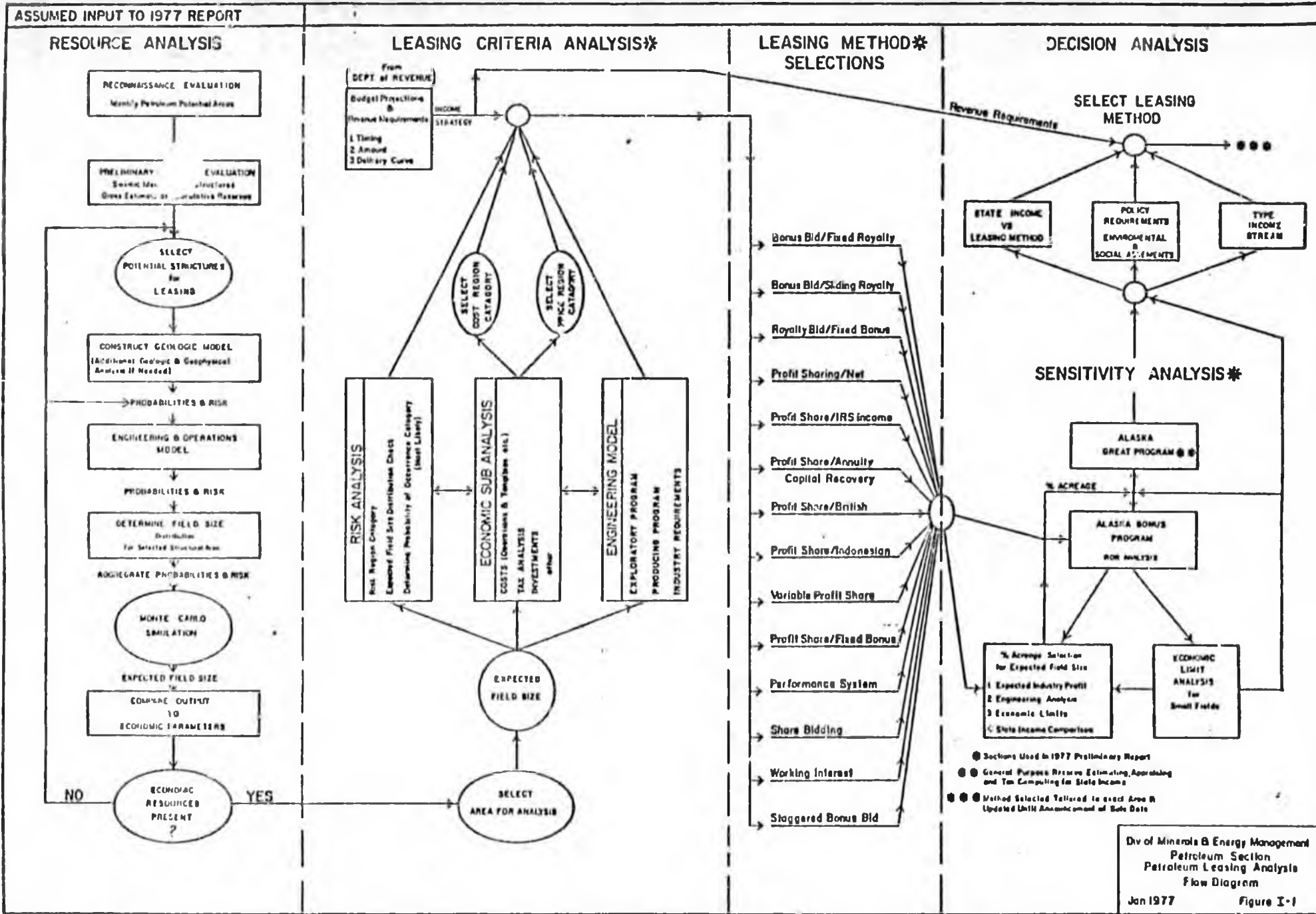
Of course, the size of the bonuses bid are determined by the oil companies. From an engineering and geologic model, they determine the probable size of the oil field and the probability of occurrence. The cost of development, cost of production, expected value of the production and required return on investment are input into a computer program which calculates the return of investment at different discount rates. From these data, the oil company determines the maximum bonus it would be willing to pay to acquire the right to explore and to develop and produce the oil and gas property. The final selection of the bonus is based on what the company believes it will have to bid to acquire the property. That is, if only one company is interested in a lease, their actual bonus bid would be less than the maximum they would be willing to pay. On the other hand in a highly competitive bidding case, one of the bidders will overbid.

EXPECTED PETROLEUM FIELD MODELS

As shown on the Resource Evaluation and Leasing System flow sheet (Figure I-1), the input to our leasing criteria and Sensitivity Analysis is the EXPECTED PETROLEUM FIELD SIZE. In order to show the sensitivity of various leasing methods to State income, we have modeled five expected field sizes. A detailed discussion of the field models is given in Appendix A. The models range from a small field with an expected value of 50 million barrels of oil recoverable (Mercury) to a super giant field with an expected value of 5 billion barrels of oil recoverable (Jupiter). These models are assumed in each case to be the expected recoverable quantities resulting from an analysis of the field size distribution considered. The expected value concept will only briefly be covered since this approach has been discussed in other papers and is used in our study as a routine application of the probability theory.

Figure II-2 taken from the Cornell University study shows the field size distribution of all the oil fields discovered in the United States between 1943 and 1968. It is important to note the rapid decrease in field size as the number of fields discovered increases. The field size distribution for each petroleum province, although log normal in nature, would differ from this aggregated United States field size distribution, but some important observations can be used for concentrating our attention on optimum leasing strategies. Because field sizes within a province follow a log normal distribution, it is important to know the approximate location on this curve of the state owned fields. Since it

THE ALASKA RESOURCE EVALUATION & LEASING SYSTEM



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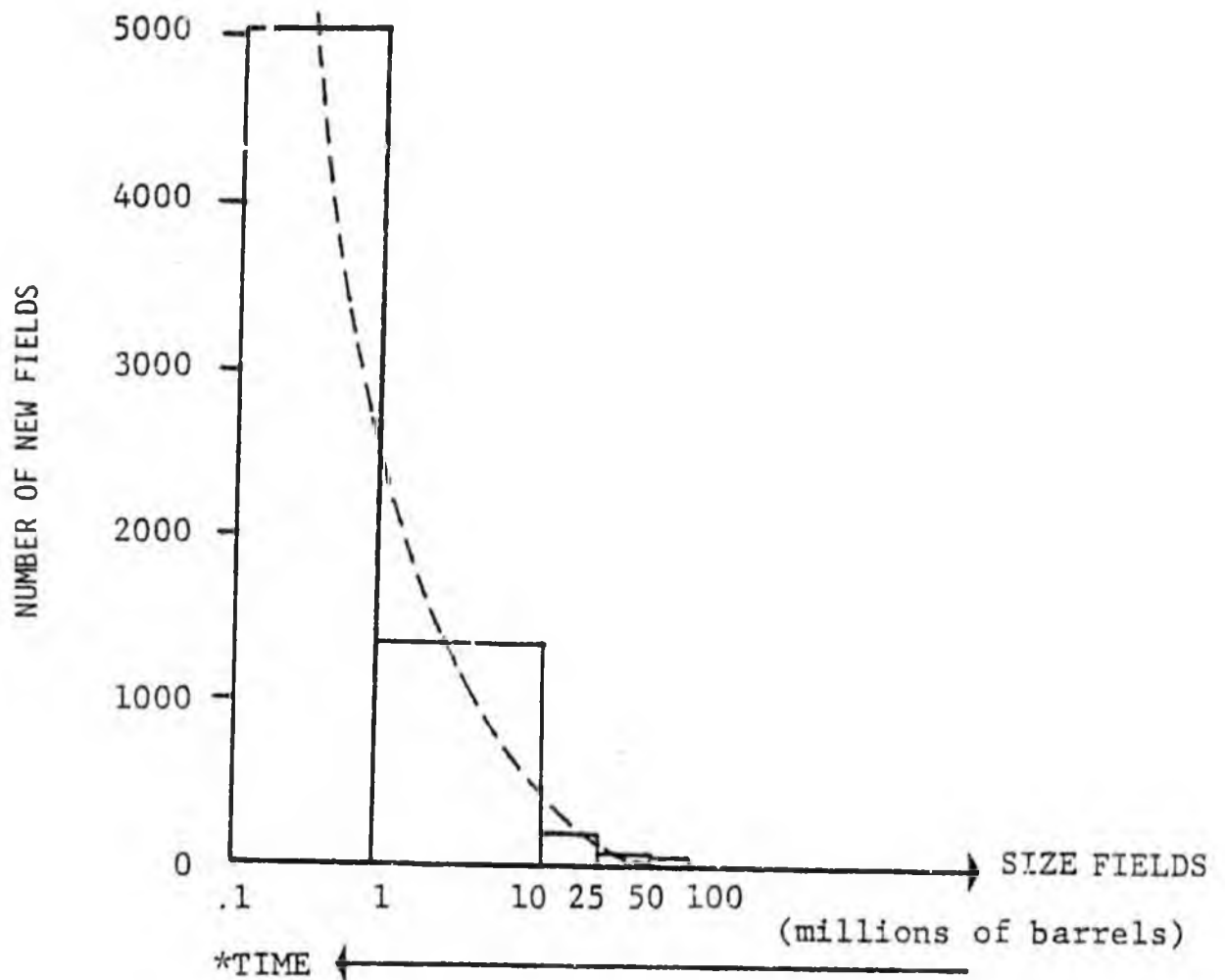
Figure II-1

Div of Minerals & Energy Management
 Petroleum Section
 Petroleum Leasing Analysis
 Flow Diagram
 Jan 1977 Figure I-1

Figure II-1

--NUMBERS OF NEW OIL FIELD DISCOVERIES OF VARIOUS SIZES
(1946-1968)

Modified from *Alternative Leasing Strategies
and Schedules for the Outer Continental Shelf*
Kalter, Tyner & Hughes



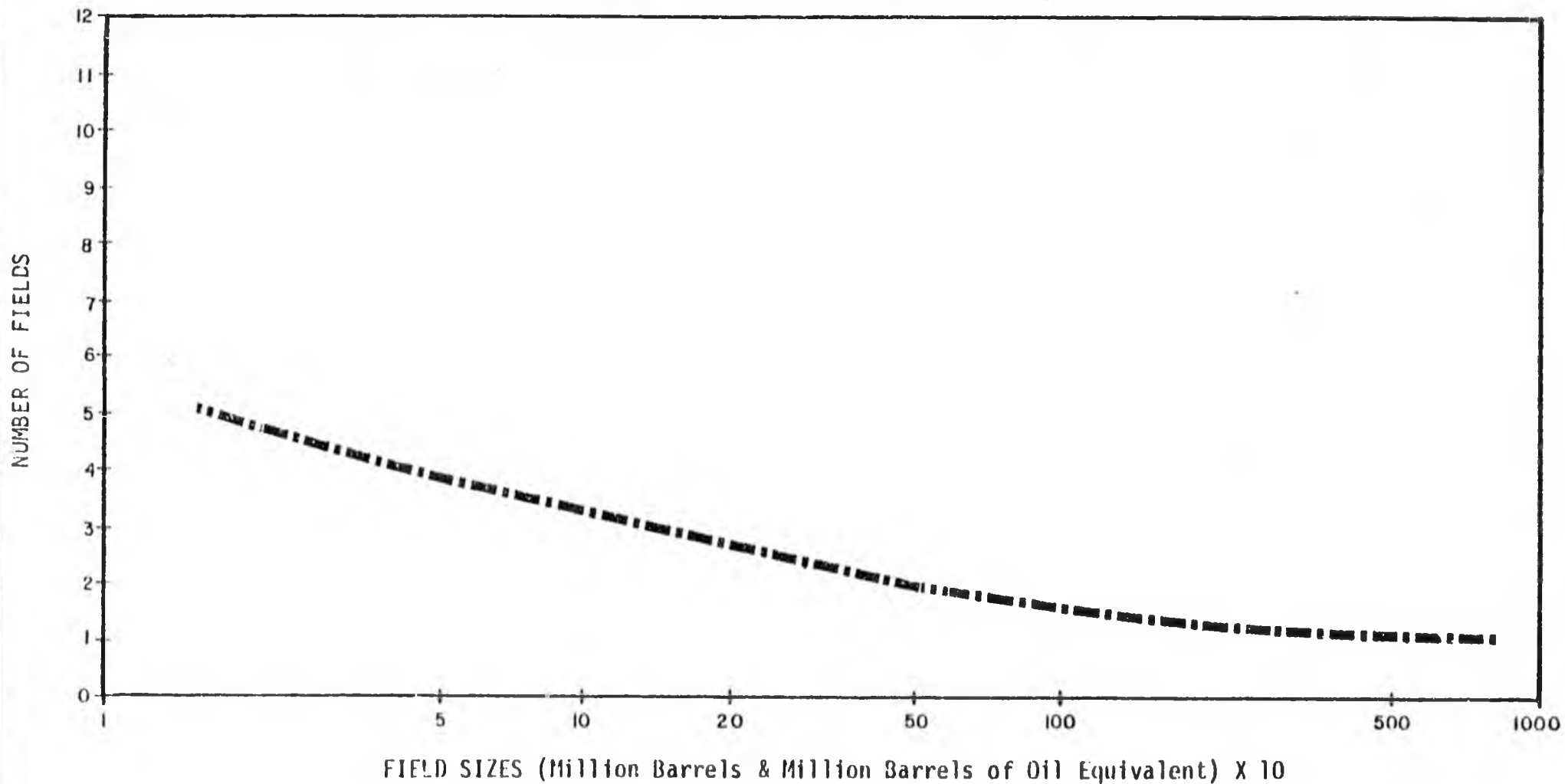
*Since larger fields are statistically found first,
the size of new fields found will generally decrease
with time.

is expected that large fields generally will be discovered early in the exploration time horizon (Cornell Study). Figure II-2 can also be used as a rough time versus discovery plot.

As expected, when Alaskan fields are plotted on a semilog graph (Figure II-3) the field distribution is on the flat far right portion of the United States (province) log normal distribution curve. This is illustrated on Figure II-4 which shows that Alaska's petroleum development stage is in the early time distribution zone and the expected value field distribution is on the flat or larger field portion of the curve.

What is the significance of this to the State? It means that with fairly inexpensive geologic/geophysical analysis and the use of probability theory we should be able to determine the expected risk field sizes to be found before a sale. It will be important for us to understand that as provinces in the State change in maturity, we will see the expected field sizes decrease with time and move along the distribution curve. A flexible leasing system will be necessary to take advantage of this knowledge.

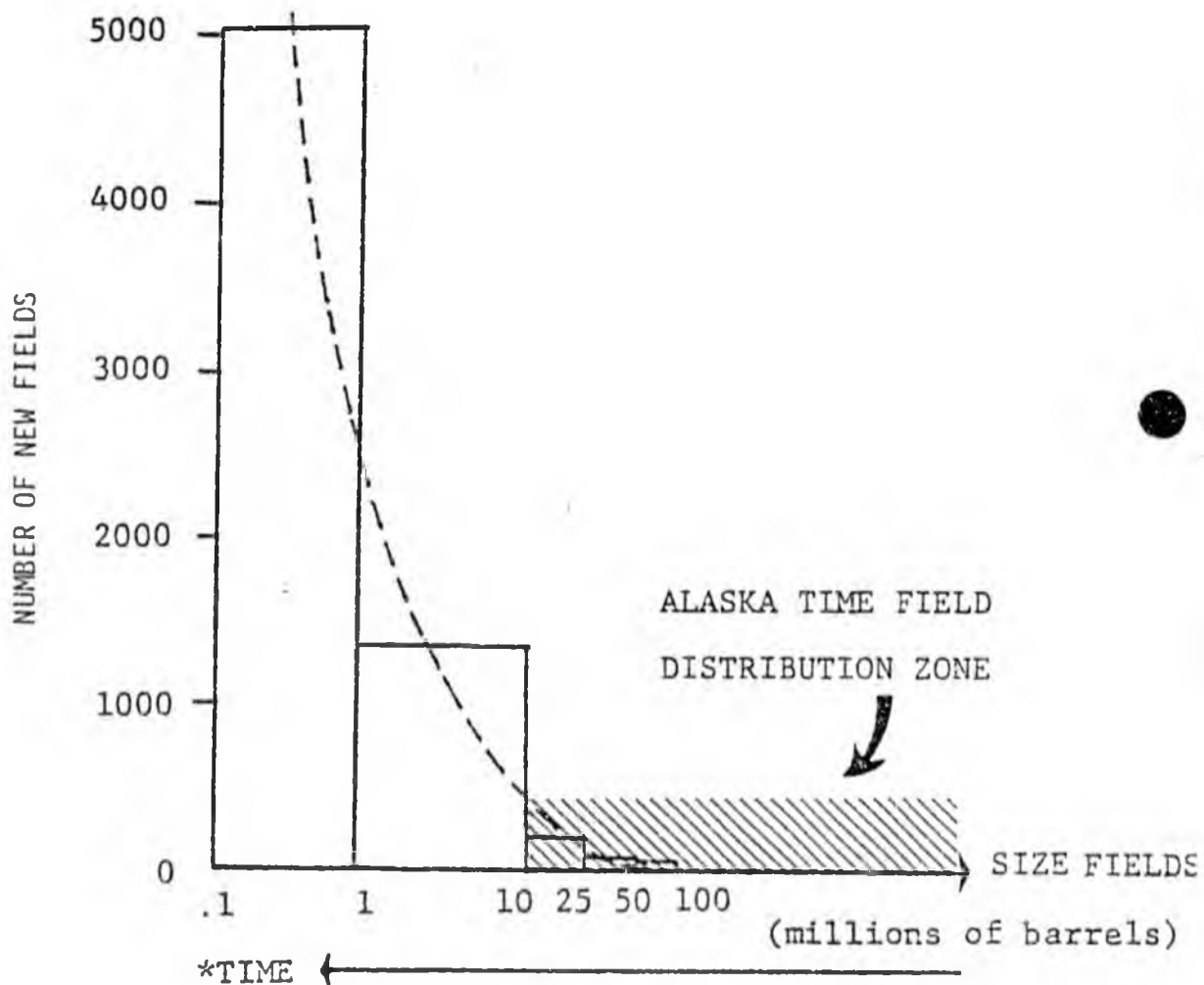
* APPROXIMATE ALASKA FIELD SIZE DISTRIBUTION TO 1977



* Because of the immaturity of Alaskan development, field discoveries are larger and, as expected, the distribution curve resembles the flat portion or early time zone of the national curve.

--NUMBERS OF NEW OIL FIELD DISCOVERIES OF VARIOUS SIZES
(1946-1968)

Modified from Alternative Leasing Strategies
and Schedules for the Outer Continental Shelf
Kalter, Tyner & Hughes



*Since larger fields are statistically found first,
the size of new fields found will generally decrease
with time.

CHANCES OF FINDING THE EXPECTED FIELD

A discussion of the risk factor follows this section but before defining risk with relation to income, we must understand the relationship of expected field size to possible discovery.

Once we have determined through analysis what the expected field size will be, the chances of finding that amount of oil or gas in the structure will follow the normal rules of probability for the structure. In other words, the chances of finding more or less petroleum than expected are a function of the accuracy of information available and the assumptions made for THE SIZE STRUCTURE WE ARE CONSIDERING FOR LEASE. For this study we have assumed a normal distribution for the expected reserves in the structure. Based on this distribution, the odds are equal that we will have more oil in the structures rather than less oil. Therefore, whether we find any petroleum or not will be the significant variable and that will be a function of the risk parameters of discovery.

THE RISK FACTOR

The risk factor used in our sensitivity analysis for petroleum leasing is the percent chance of discovering the expected field in question. This percent chance can range from around 90% (a drainage situation) to 10%, the rough average used for wildcat ventures.

In general, to lease acreage when the risk would be below 10% would be unwise for government and in some cases uneconomical for Industry. This follows from the general rule that risk is a function of knowledge. For example, to lease acreage with a 1,000 to one chance of finding the expected field size would probably result in uneconomic overbids by Industry on small fields and very low bids for the State on large fields.

We have shown in our sensitivity analysis that income to the State increases as the uncertainty of finding petroleum decreases. It is better therefore for the State to ensure that as much knowledge as possible is available to the public and Industry before leasing.

What are some examples of chance of finding, or risk? In 1976 the success rate of new field wildcats finding oil or gas in the United States was 18% (Petroleum Information Corporation, reported in January 1977 Alaska Report). In Alaska on the North Slope after the initial discoveries, the expected chance of finding oil on the remaining Prudhoe Bay structure tracts was reflected by the high price bid in the 1969 lease sale.

IMPORTANCE OF THE RISK FACTOR

Income from oil and gas fields on State land is distributed as follows: for repayment of investment, for operating costs; to the State for royalty and various taxes, to the Federal government for income tax, and to the oil company as profit, (a distribution is shown on Figure II-8).

Income to the State is shown on Figure II-6 for a typical, medium size Alaskan oil field with an expected recovery of 600 million barrels. Income is for a bonus bid at 12.5% royalty case and is based on the expected field size, and the estimated parameters of cost, price, and recovery (the computer input parameters are explained in Appendix B). As shown on Figure II-6, at a risk factor of 10% (10% chance of finding the expected field) expected income to the State would be 0.34 billion dollars; at a risk factor of 90% (90% probability of occurrence) the State would expect to receive 3.0 billion dollars.

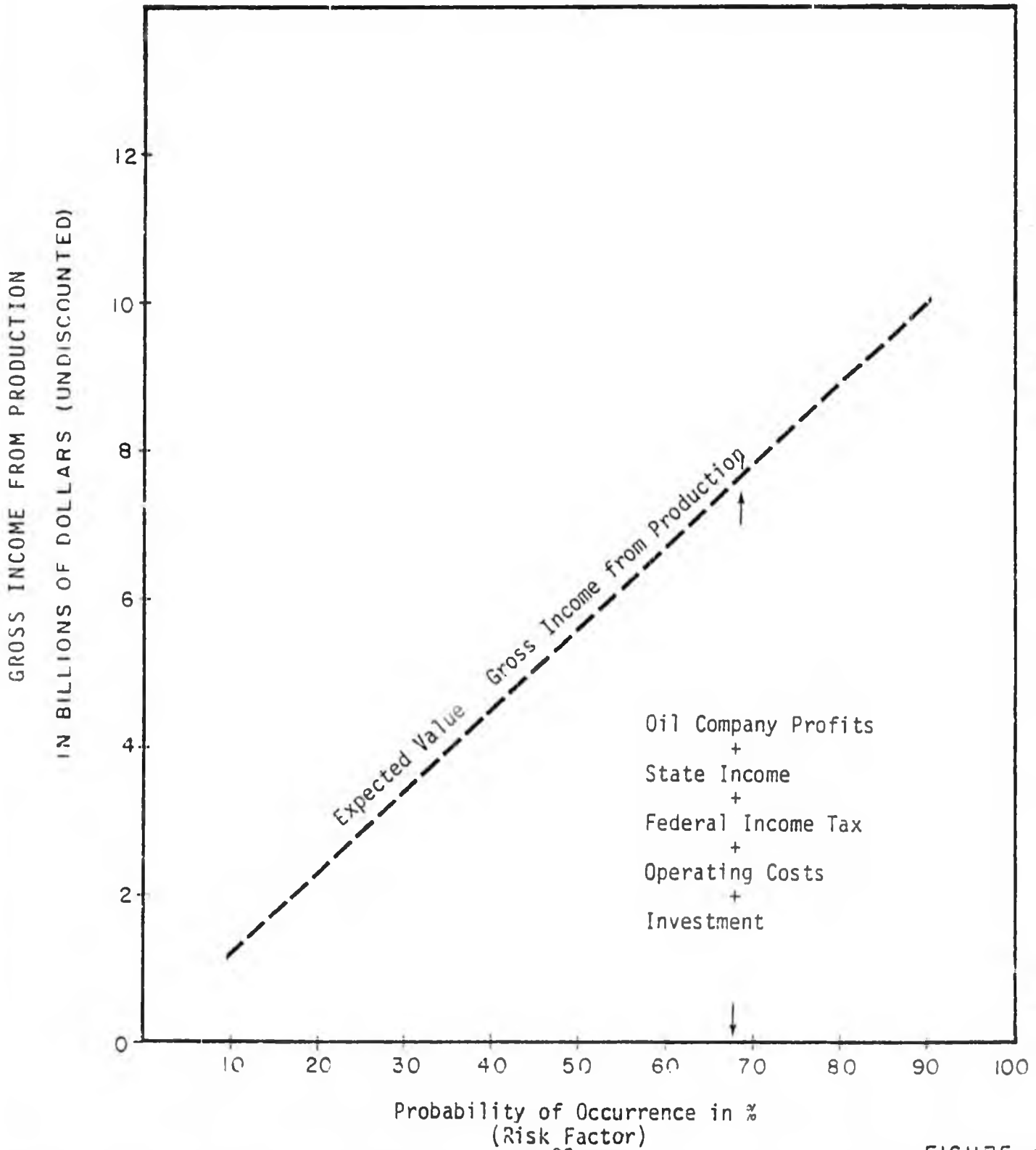
As the confidence level increase from 10% to 90%, income to the State increases. Most of the income at 10% risk results from non-bid sources of royalty and taxes. However, the cash bonus bid, at a risk factor of 10%, is 48.2 million dollars while at a risk factor of 90%, the cash bonus bid would be 377.5 million dollars. This is nearly an 8-fold increase.

It becomes immediately obvious that the State can increase it's income from petroleum properties by influencing the acquisition of data so that probability of success is increased. This is also concluded by Richard Norgaard on page 2 of his report titled "Uncertainty, Competition and Leasing Policy" prepared for the Department of Natural Resources.

GROSS INCOME FROM PRODUCTION VERSUS RISK

(Based on Expected Values)

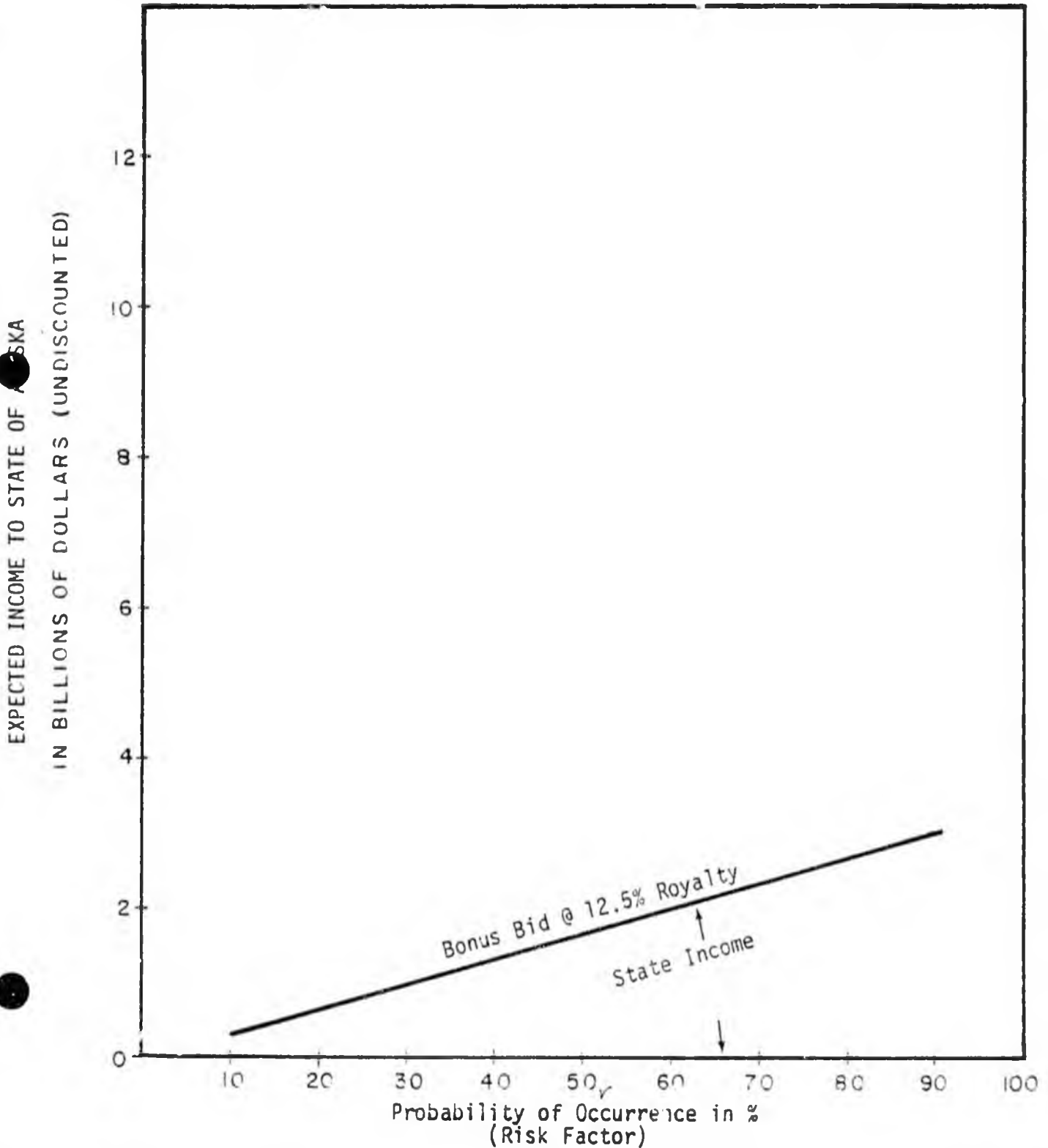
Medium Expected Oil Field
(600 Million Barrels Recoverable)



STATE INCOME VERSUS RISK

(Based on Expected Values &
Current Leasing Method)

Medium Expected Oil Field
(600 Million Barrels Recoverable)



EXPECTED VALUE CONCEPT

Direct (and total) state income from leasing will increase as the probability of occurrence increases because the expected value of the leased structure also increases. It is the "expected value" amount of oil or gas in a structure upon which oil companies calculate their bids. The expected value is a direct function of probability of occurrence.

The expected value is the mean (or average) value of the dry structures plus the producing structures. For example, if 9 dry structures are drilled per each discovery, then the probability of a discovery for any specific structure is 1 in 10, or 10%. This means that the average oil recovery for each of the 10 structures drilled is 10% of the productive structure. If the field size is 600 million barrels of recoverable oil, the average amount per structure expected is 60 million barrels.

As additional information is obtained, it's possible that only 4 structures will be drilled for each discovery (some structures will not be drilled because of the extremely low probability of an economical field). With 4 dry structures drilled for each discovery drilled, the expected value (average amount) of recoverable oil for each structure will increase to 120 million barrels. Therefore, for each field leased, the income to the State should be increased. This increase should be in direct proportion to the increased probability of the expected event occurring, in this case a discovery.

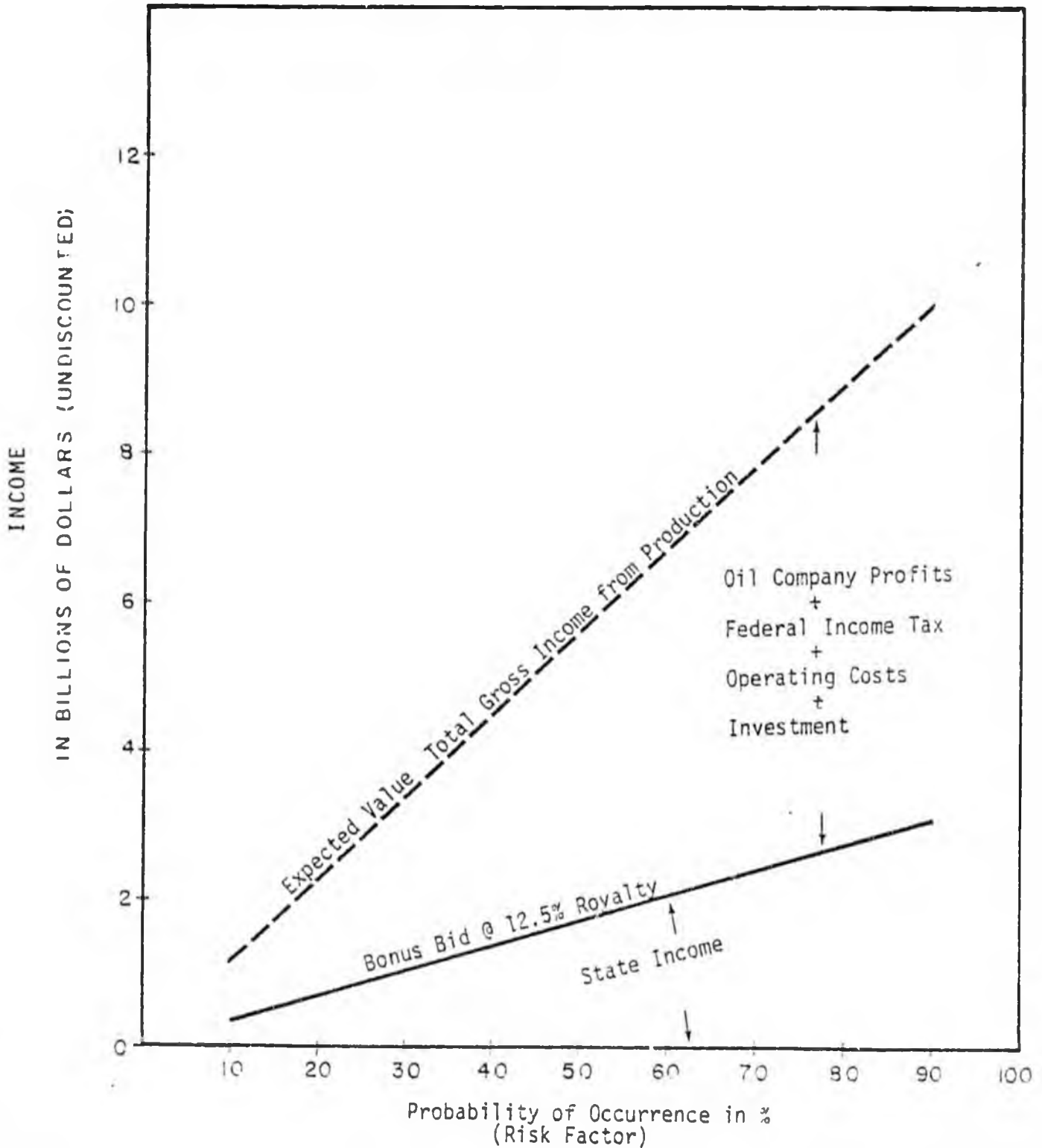
The expected value of gross income from production also increases as the probability of occurrence (a discovery) increases. For the medium size expected oil field (600 million barrels of recoverable oil), as the probability of occurrence increases from 10% to 90%, the expected value of gross income increases from 1.1 billion dollars to 9.9 billion dollars-- this is shown graphically on Figure 11-7.

STATE INCOME VERSUS GROSS INCOME

RISK SENSITIVE

(Based on Expected Values &
Current Leasing Method)

Medium Expected Oil Field
(600 Million Barrels Recoverable)



THE SENSITIVITY OF STATE PETROLEUM INCOME
TO VARIOUS LEASING METHODS

ANALYTICAL COMPARISON OF
ALTERNATE LEASING METHODS

ANALYTICAL COMPARISON OF LEASING METHODS

There are a large number of possible leasing criteria. Some involve how much of the structure is leased at different times. Others involve which parameter of royalty or cash bonus are fixed by the owners and which ones are bid items. Five leasing methods based on different bidding parameters versus probability of occurrence at 1%, 10%, 50% and 90% are analyzed in this study. The method currently used by the State, cash bonus bid at 12.5% fixed royalty, is compared to 4 alternate methods: 1) cash bonus bid at 25% royalty; 2) cash bonus bid at sliding scale royalty; and 3) royalty bid at fixed cash bonus; 4) net profits bid at fixed bonus; and 5) percent of acreage.

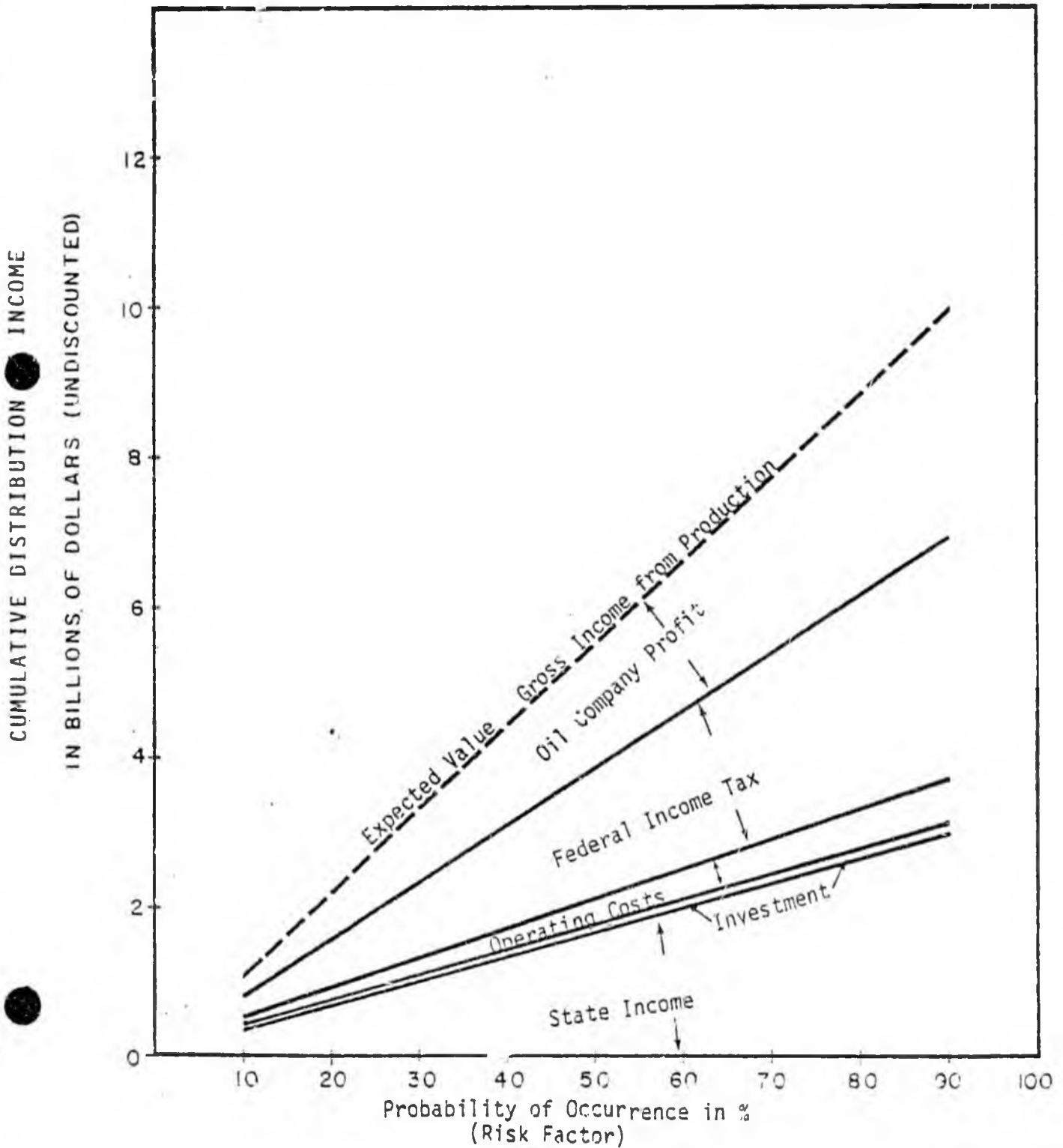
State income from various leasing methods was determined by an economic analysis utilizing a special adaptation of a Garrett computer program. This program is explained in Appendix B. Input data included bonus payment, dry hole costs, investment schedules, production schedules, operating costs and crude oil prices. Output data combine the following sources for total state income: bonus, severance tax, royalty, conservation and advalorem tax, and state income tax. The output also includes operating costs and schedules for depreciation of investment and for amortization of the bonus. Total State income is given at various discount factors. The oil company income is discounted at 10%.

Gross income from production is distributed as follows: for repayment of investment; operating costs, State income such as cash bonus, royalty, income tax, and other state taxes, Federal income tax, and as oil company profit. For the cash bonus bid at 12.5% royalty leasing method, the percent distribution of the gross income is approximately the same at a risk factor of 10% as it is at a risk factor of 90%

DISTRIBUTION OF GROSS INCOME

Based on Current Method of Leasing
(Bonus Bid @ 12.5% Royalty)

Medium Expected Oil Field
(600 Million Barrels Recoverable)



(Figure II-8). Averages are as follows:

Operating cost and investment - 6%

State income - 31%

Federal income tax - 32%

Oil company profit - 31%

Note that State income, Federal income and oil company profits are about evenly divided. While the income distribution percentages remain approximately constant at probability of occurrence of 10% and 90%, the total income for distribution increases from 1.1 billion at 10% probability to 9.9 billion dollars at 90% probability.

Bonus Bid at 12.5% Royalty. This is the method currently used by the State. (All recent competitive leases have been issued with a 16-2/3% royalty requirement.) If there is little available knowledge about a structure, assumed probability of occurrence is low. At a low probability of occurrence, there is little difference between the various leasing or bidding methods. This can be seen in Figure II-9 at the 10% probability of occurrence where the plotted curves tend to converge.

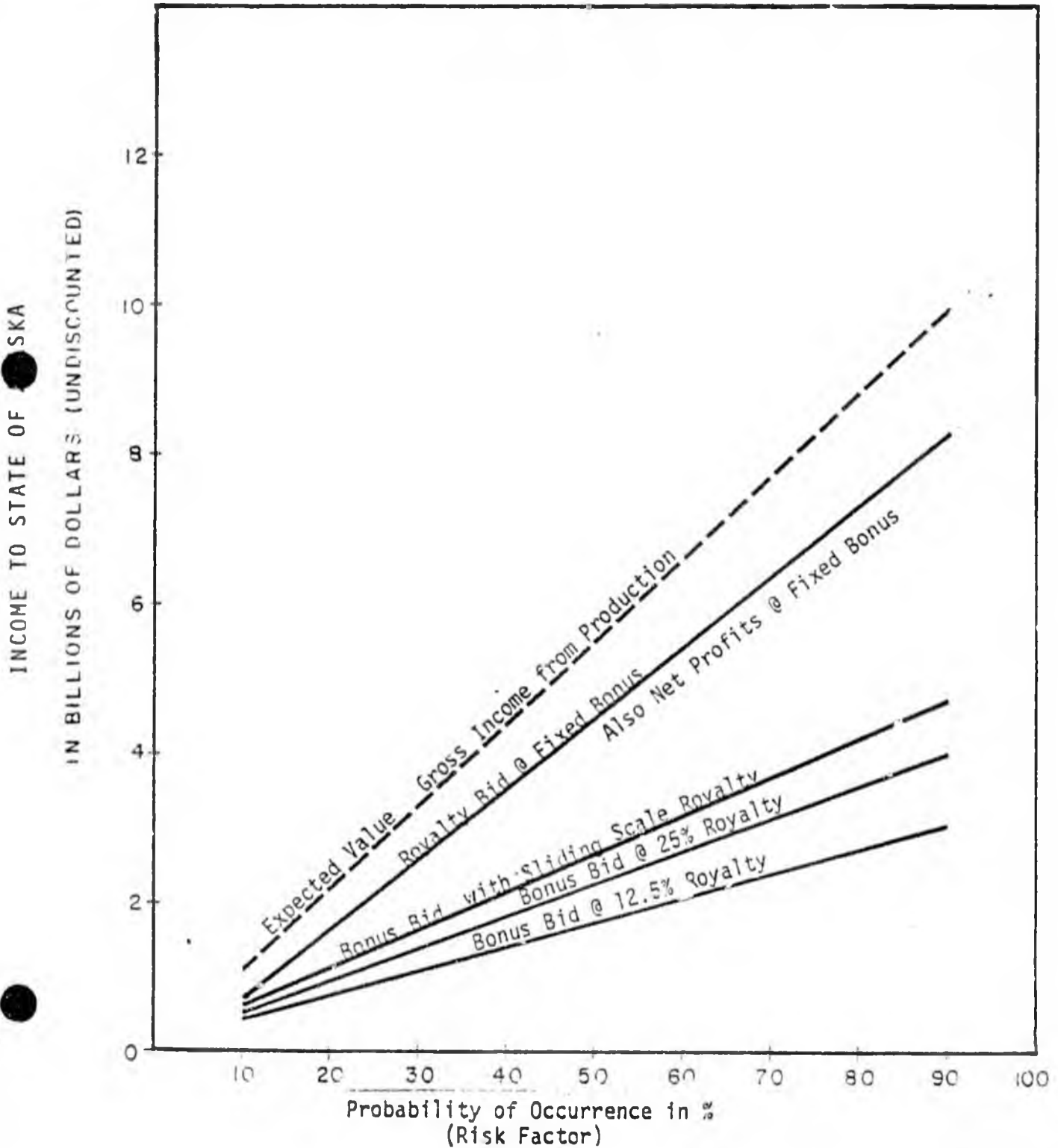
In the past, not much has been known about the structures in Alaska prior to bidding, therefore cash bonus bids at 12.5% or 16.67% royalty were not too bad a method. For small field size (100 million barrels recoverable) with a 10% probability of success, income to the State is not significantly affected by the bidding methods. However, as can be seen from an inspection of Figure II-10, as the probability of occurrence increases there are methods of leasing which provide much higher income to the State. The percent probability of occurrence can be improved (some of the risk removed) by obtaining and analyzing specific structures.

COMPARISON OF STATE INCOME

Resulting From Various Leasing Methods

Shows Risk Sensitivity of All Methods

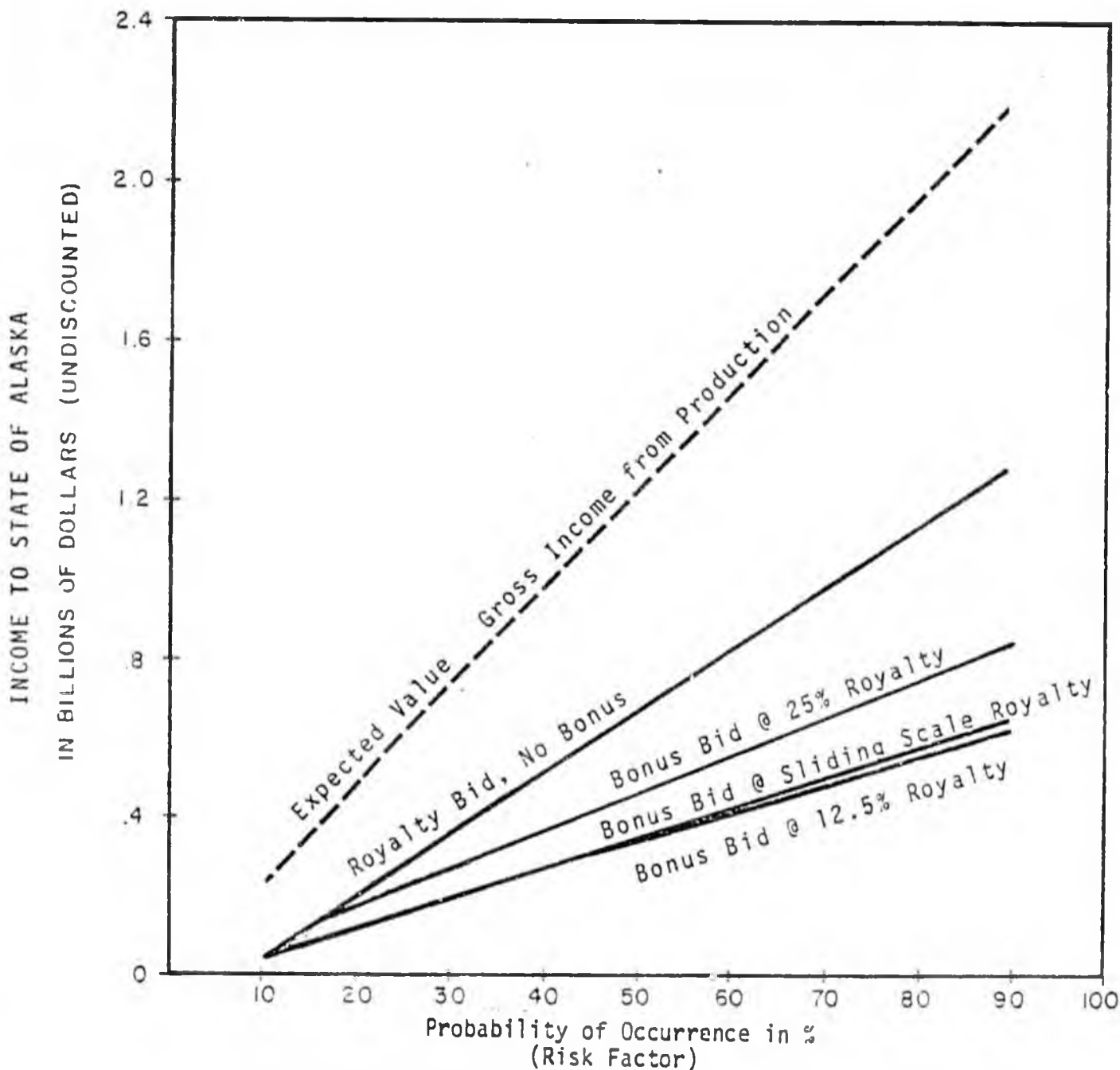
Medium Expected Oil Field
(600 Million Barrels Recoverable)



COMPARISON OF STATE INCOME
 RESULTING FROM VARIOUS BIDDING METHODS

Shows Risk Sensitivity Of All Methods

Small Expected Oil Field
 (100 Million Barrels Recoverable)



NOTE: For each bid case, the difference between
 Gross Income and state income includes
 Operating Costs
 Investment
 Federal Income Tax
 Oil Company Profit

FIGURE II-10

Bonus Bid @ 25% Royalty. This bid method does provide greater income to the State than does a bonus bid at 12.5% royalty. The bonus is approximately 25% less than at 12.5% royalty, but total income is approximately 25% to 30% greater, depending on the specific cases being compared - this is shown on Figure II-9 and II-10. At discount rates of 6% and 10% (Figures II-19 and II-20 bonus bid at 25% royalty provides more present worth income to the State than does the current leasing method (bonus bid at 12.5% royalty).

Sliding scale royalty with bonus bid. The royalty scale is set by the State prior to advertising leases for bid. When leasing small fields with low production rates, this method provides the same income to the State as does the cash bonus bid at 12.5% royalty. As field size increases, production rates increase and State income from a bonus bid with sliding scale royalty increases considerably over the income provided by a cash bonus bid with a fixed 12.5% royalty. Figure II-11 gives the income distribution in the sliding royalty case for a medium sized oil field. This leasing method allows the State to participate in the operators good fortune, if the operator finds a large field, the State's royalty increases. If the operator finds a field of lesser size than he expected, he is not burdened with a high royalty such as he would be with a royalty bid.

Another important aspect is that as a good field declines, the royalty percent will also decline, thus extending the economic life of the field. Of course, as the economic life of the field is extended, the ultimate recovery increases and the amount of oil left in the reservoir decreases. The aspect of encouraging more ultimate recovery so the oil or gas left in the reservoir is decreased is good for the conservation of a depletable natural resource.

DISTRIBUTION OF GROSS INCOME
FOR AN ALTERNATE LEASING METHOD

Sliding Scale Royalty With Bonus Bid

Medium Expected Oil Field
(600 Million Barrels Recoverable)

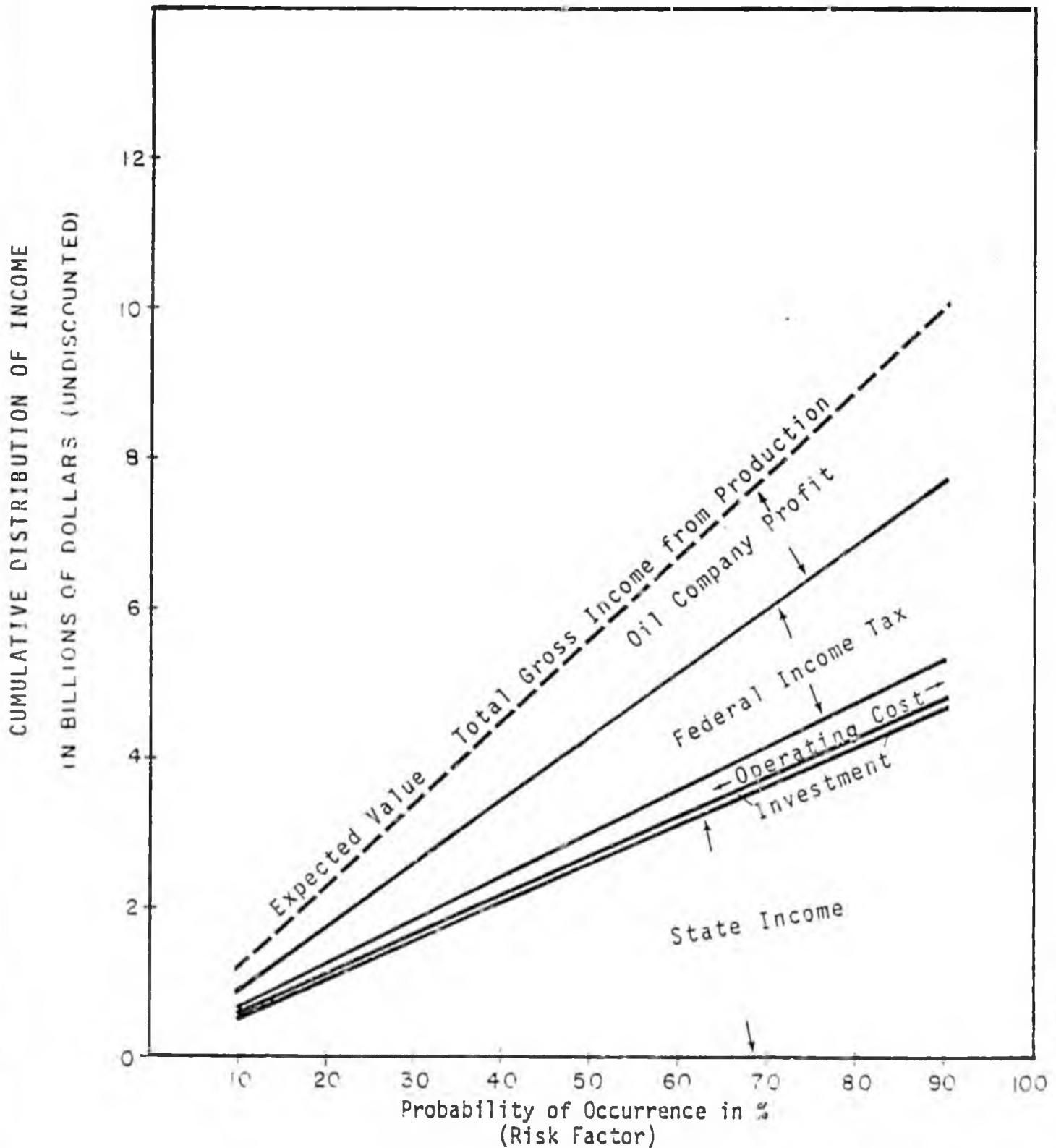


FIGURE II-11

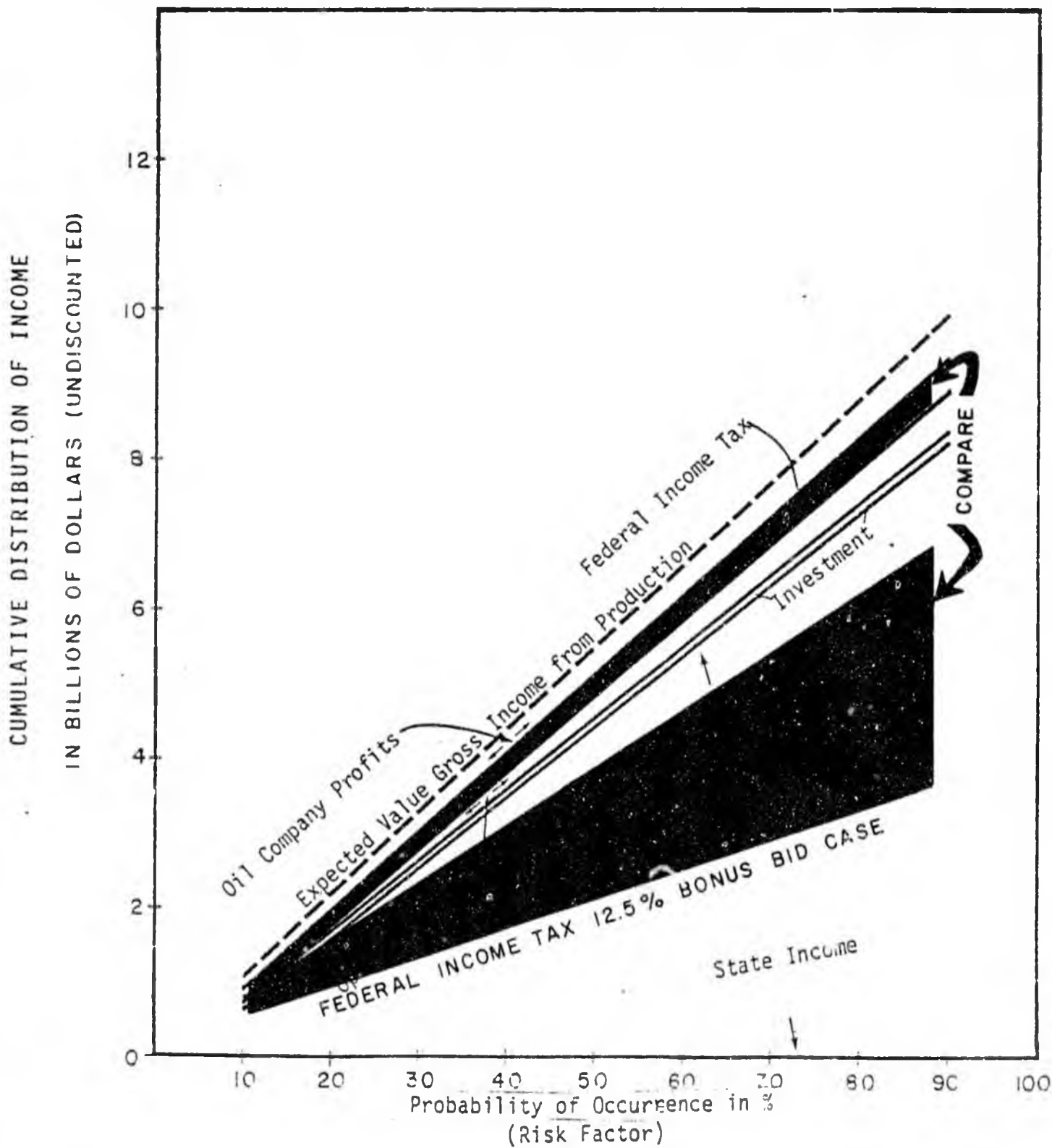
Royalty Bid at a Fixed Cash Bonus. The fixed cash bonus is utilized to encourage only earnest bidders and is calculated at 2.5 cents per expected volume of recoverable oil. As with all of the leasing methods, the main data was based on the operator (oil company) earning an 18% rate-of-return. As is shown on Figure II-9, the royalty bid (and net profits bid) provide more income to the State than do any of the other analyzed methods except at small field sizes. At an oil field size of 100 million barrels recoverable oil, (Figure II-10), income to the State from the royalty bid (65.8 million) was essentially the same as for the cash bonus bid at 12.5% royalty (61.2 million) at 10% risk.

In our models the major economic advantage to the State from royalty bidding over the bonus bid case is from a reallocation of Federal income taxes. Figure II-12 showing the income distribution for an expected field size of 600 MM/bbls in the royalty bidding case should be compared with Figure II-8 in the bonus bid case (an overlay of the Federal income tax revenues from Figure II-8 has been provided for easy reference). As can be seen by the comparison, the State takes a much larger income in the royalty case at the expense of the Federal government. The absence of a large front end investment, the bonus, allows a company to have a smaller profit profile in the royalty case but still make the same rate-of-return on investment as the bonus bid case, 18%. The "Tax Break" illustrated here is an incentive for seeking higher royalties whenever, or however possible.

DISTRIBUTION OF GROSS INCOME

Based on an Alternate Leasing Method
(Royalty Bid at Fixed Bonus)

Medium Expected Oil Field
(600 Million Barrels Recoverable)



Net Profits at a Fixed Cash Bonus. For this leasing method, a small fixed bonus is required as earnest money. The companies then bid on the percent of net profits they will return to the State after they have recovered their investment. Income to the State for the net profit cases is essentially similar to the income from royalty bidding, (Figures II-9 and II-10). For those examples where the two cases diverged, the net profit data is shown separately.

Listing of Leasing Model Results. The data listed in Tables II-1 and II-2 (pages 27b and 27c) constitute the major portion of the results of this leasing study. This data is the computer calculated results of the economic models for the leasing methods considered. Most of the graphs in Section II of this report were plotted from data contained in these tables.

Data on Tables II-1 and II-2 show that at risk factors of 10% and 90% (% probability of finding the expected field size), the bonus bid at 12.5% royalty method provides the least expected value income to the State of all the methods analyzed in this report. The net profits bid method provides the largest expected value income to the State, being only slightly higher than the royalty bid method. The sliding scale royalty with bonus bid method provides an income stream which is between the net profits bid method and the bonus bid method. Section III of this report contains additional factors which must be considered when selecting a leasing method.

RESULTS OF LEASING MODEL SIMULATIONS @ 10% RISK AND LOW COST REGION

LEASING METHOD	OIL REC MM/BBLS	OIL CO. PROFIT		EXPECTED VALUE STATE INCOME				
		*TOTAL	*PW @ 10%	*BONUS	ROYALTY	BONUS, ROYALTY & TAXES		
						*TOTAL	*PW @ 6%	*PW @ 10%
BONUS 12 1/2%								
Mercury								
Mars	137.6	72.6	14.7	.5	27.6	61.2	24.9	14.6
Venus	633.8	376.3	93.2	48.1	127.0	338.9	171.6	118.7
Neptune								
Jupiter	5238.1	3189.1	697.2	385.3	1048.1	2807.0	1347.8	917.1
BONUS 12 1/2% Acreage Withheld (initial sale)								
Mars								
Venus 40%	633.8	1524.8	289.9	179.9	533.5	1408.3	711.0	490.4
Neptune								
Jupiter 60%	5238.1	17905.3	2950.6	1780.0	6079.1	15900.8	7510.1	5035.4
BONUS 25%								
Mercury								
Mars	uneconomic							
Venus	633.6	316.9	77.9	38.5	292.5	445.1	214.3	141.8
Neptune								
Jupiter	5236.9	2698.2	582.8	316.3	2095.7	3693.4	1681.2	1091.1
SLIDING ROYALTY								
Mercury								
Mars	137.6	71.1	14.2	.1	31.0	63.9	26.2	15.4
Venus	633.9	274.6	64.7	30.0	344.8	519.8	249.0	161.3
Neptune								
Jupiter	5238.5	1388.6	265.1	117.1	4891.8	6046.5	2591.7	1568.3
ROYALTY								
Mercury								
Mars	137.5	70.0	14.1	0.0	33.1	65.7	26.6	15.5
Venus	632.6	178.9	42.4	15.0	547.9	688.9	311.4	193.4
Neptune								
Jupiter	5230.1	1400.5	281.0	125.0	4861.2	6024.1	2555.6	1544.1
NET PROFITS								
Mercury								
Mars								
Venus	634.0	169.8	40.4	15.0	567.0	705.6	318.6	197.1
Jupiter								

* In millions of dollars

RESULTS OF LEASING MODEL SIMULATIONS @ 90% RISK AND LOW COST REGION

EXPECTED VALUE STATE INCOME

LEASING METHOD	OIL REC MM/BBLS	OIL CO. PROFIT		STATE INCOME				
		*TOTAL	*PW @ 10%	*BONUS	ROYALTY	BONUS, ROYALTY & TAXES		
						*TOTAL	*PW @ 6%	*PW @ 10%
BONUS 12 1/2%								
Mercury								
Mars	137.6	635.0	98.6	44.5	249.0	603.4	275.2	180.8
Venus	633.8	3247.7	585.0	377.5	1143.3	3012.2	1520.2	1048.0
Neptune								
Jupiter	5238.1	27716.2	4452.9	2709.9	9433.1	24630.1	11618.3	7780.9
BONUS 16 2/3%								
Mercury								
Mars								
Venus	633.7							
Neptune								
Jupiter								
BONUS 25%								
Mercury								
Mars	137.4	523.1	79.2	30.6	49.7	815.5	358.0	226.8
Venus	633.6	2737.5	492.6	308.9	2285.9	3984.8	1917.6	1267.6
Neptune								
Jupiter	5236.9	23473.1	3745.7	2228.6	18861.8	32734.2	14723.2	9443.5
SLIDING ROYALTY								
Mercury								
Mars	137.6	622.1	95.5	42.1	279.0	628.4	287.2	188.1
Venus	633.9	2376.0	407.6	256.1	3103.4	4678.2	2249.0	1461.2
Neptune								
Jupiter	5238.5	12200.0	1832.0	820.6	44026.2	54260.4	23201.8	14001.0
ROYALTY								
Mercury								
Mars	136.8	308.4	42.9	2.5	972.7	1219.5	516.4	314.2
Venus	629.2	495.3	80.5	15.0	7261.1	8216.0	3665.7	2238.2
Neptune								
Jupiter	5216.7	5666.5	836.4	125.0	58312.9	66525.9	27704.6	16370.0
NET PROFITS								
Mercury								
Mars	137.7	271.6	38.6	2.5	1054.8	1295.5	538.8	323.7
Venus	634.0	433.8	71.6	15.0	7419.0	8369.7	3712.6	2255.9
Neptune								
Jupiter								

* In Millions of Dollars

TABLE II-3

RESULTS OF SIMULATIONS ON AN EXPECTED 600 MILLION BARREL OIL FIELD

HIGH RISK

<u>LEASING METHOD</u> (18% rate of return for industry)	<u>UNDISCOUNTED EXPECTED STATE INCOME (MILLION DOLLARS)</u>
Bonus + 12 1/2%	338.9
Bonus + 25%	445.1
Sliding Royalty	519.8
Royalty Bid	688.9
Net Profits	706.6
% Acreage	1408.3

LOW RISK

<u>LEASING METHOD</u> (18% rate of return for industry)	<u>UNDISCOUNTED EXPECTED STATE INCOME (MILLION DOLLARS)</u>
Bonus + 12 1/2%	3012.2
Bonus + 25%	3984.8
Sliding Royalty	4678.2
Royalty Bid	8216.0
Net Profits	8369.7

EXTREME HIGH RISK CASE

(1% Chance of Success)

<u>LEASING METHOD</u> (16% rate of return for industry)	<u>UNDISCOUNTED EXPECTED STATE INCOME (MILLION DOLLARS)</u>
Bonus Bid 12 1/2%	71.7
Royalty Bid	79.7
	DISCOUNTED 6%
Royalty Bid	41.5
Bonus Bid 12 1/2%	53.2

THE PERCENT OF ACREAGE OPTION

This option has the capability of significantly increasing State income from petroleum leases. The main elements of this option are that only a part of the structure is leased initially; the remaining acreage is leased after a discovery has been made. The remaining acreage leased will be "probable reserves," and will therefore bring a much higher price than will wildcat acreage. Leasing of the Prudhoe Bay structure is a good example of the percent of acreage option. The initial leases were auctioned off for about 12 million dollars. After oil was discovered the remaining acreage (generally marginal tracts near the oil water contract) were leased in 1969 for 900 million dollars.

For comparison purposes, the income to the State from leasing a whole structure at the initial auction was compared to leasing only 60% of the structure at the initial auction (See Figure II-13). Bidding method for both cases is the "Cash Bonus Bid at 12.5% Royalty" method. Comparisons were made for a medium size field; calculations for both cases were at 10% and at 90% probability of success.

For the base case at 10% probability, each of the ten structures (9 dry and 1 productive) were leased in total at the auction, but all of the structures were not necessarily leased at the same auction. For the percent of acreage option, only 60% of each tract was leased initially; out of 10 structures leased in this manner, statistically, 9 would be barren and the remaining 40% of the structure acreage could not be leased. However, after discovering oil in the one good structure, the remaining 40% of the acreage in that

structure could be leased with an expected confidence level of 90% probability of success. The remaining 40% of the acreage in the discovery structure was leased as before - 12.5% royalty, cash bonus bid. Since the expected probability is now 90%, the cash bonus bid would be increased, resulting in increased income to the State.

At a risk factor of 10%; expected value income from the base method was 0.34 billion dollars versus 1.4 billion dollars from the percent of acreage option. (Some of the increased expected value is due to taxes which would also be received by the base method; however, there is an actual increase due to the difference in the bonuses). The bonus for the base method was 48.2 million dollars as compared to 179.9 million dollars for the percent of acreage option, this represents an actual value increase of 131.7 million dollars.

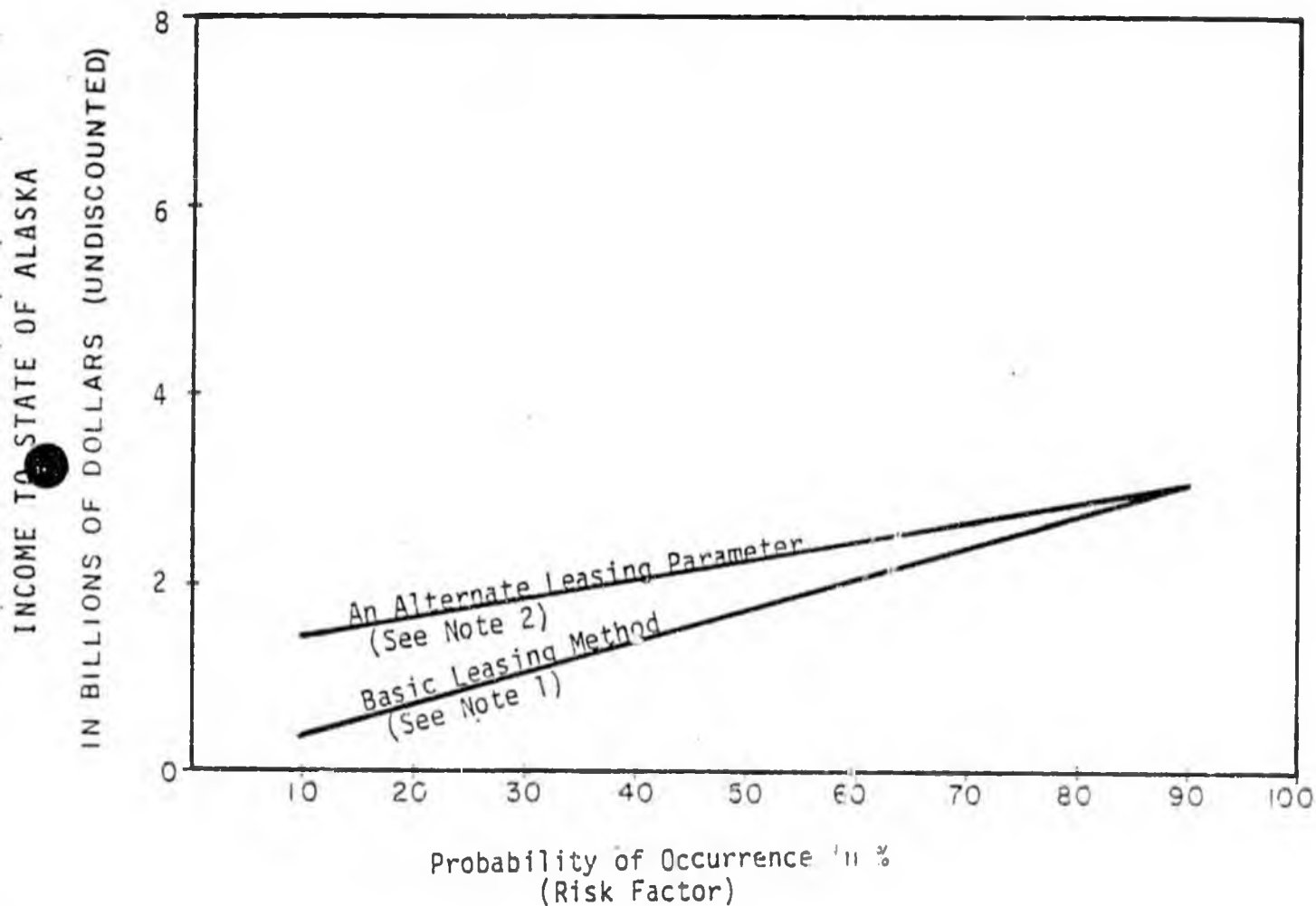
If at the time of initial leasing, enough data is available so that the bidders consider the probability of occurrence to be 90%, then there is no gain in state income by withholding acreage, this is shown on Figure II-13. However, it would be very rare for any group to consider any undrilled structure as having a 90% probability of occurrence (90% chance the expected amount of oil is present).

While for this example, the calculations and discussions were based on an oil field having an expected recovery value of 600 million barrels, income to the State can also be increased for other field sizes. Figure II-14 shows a similar comparison for a giant field where 60% of the acreage was held back. However, as the field size decreases, there becomes a size whereby it's not feasible to have the oil companies bid on only a part of the field. Since this is a somewhat subjective factor, calculations

INCOME TO STATE OF ALASKA

Comparison of an Alternate Leasing Parameter

Medium Expected Oil Field
(600 Million Barrels Recoverable)



NOTE 1: Basic Leasing Method
All Acreage Leased at the Same Time
Bonus Bid @ 12.5% Royalty

NOTE 2: Percent of Acreage - An Alternate Parameter
60% Leased Initially by Bonus Bid @ 12.5% Royalty
Expected Value Based on Risk: 10%
40% Leased 2 Years Later by Bonus Bid @ 12.5%
Expected Value Based on Risk: 90%

and analysis as used on larger structures will not necessarily delineate the minimum size structure on which acreage can be withheld at the time of initial leasing. However, it will be possible for the DMEM to determine, depending on location and other conditions, the minimum field size on which acreage can be advantageously withheld.

For this comparison, the data for both the base case and the percent of acreage option were obtained from a bonus bid at 12.5% royalty method. If other methods considered in this report were used with the percent of acreage option, (royalty bid, net profits, or sliding scale royalty) equivalent or even greater income gains would be realized.

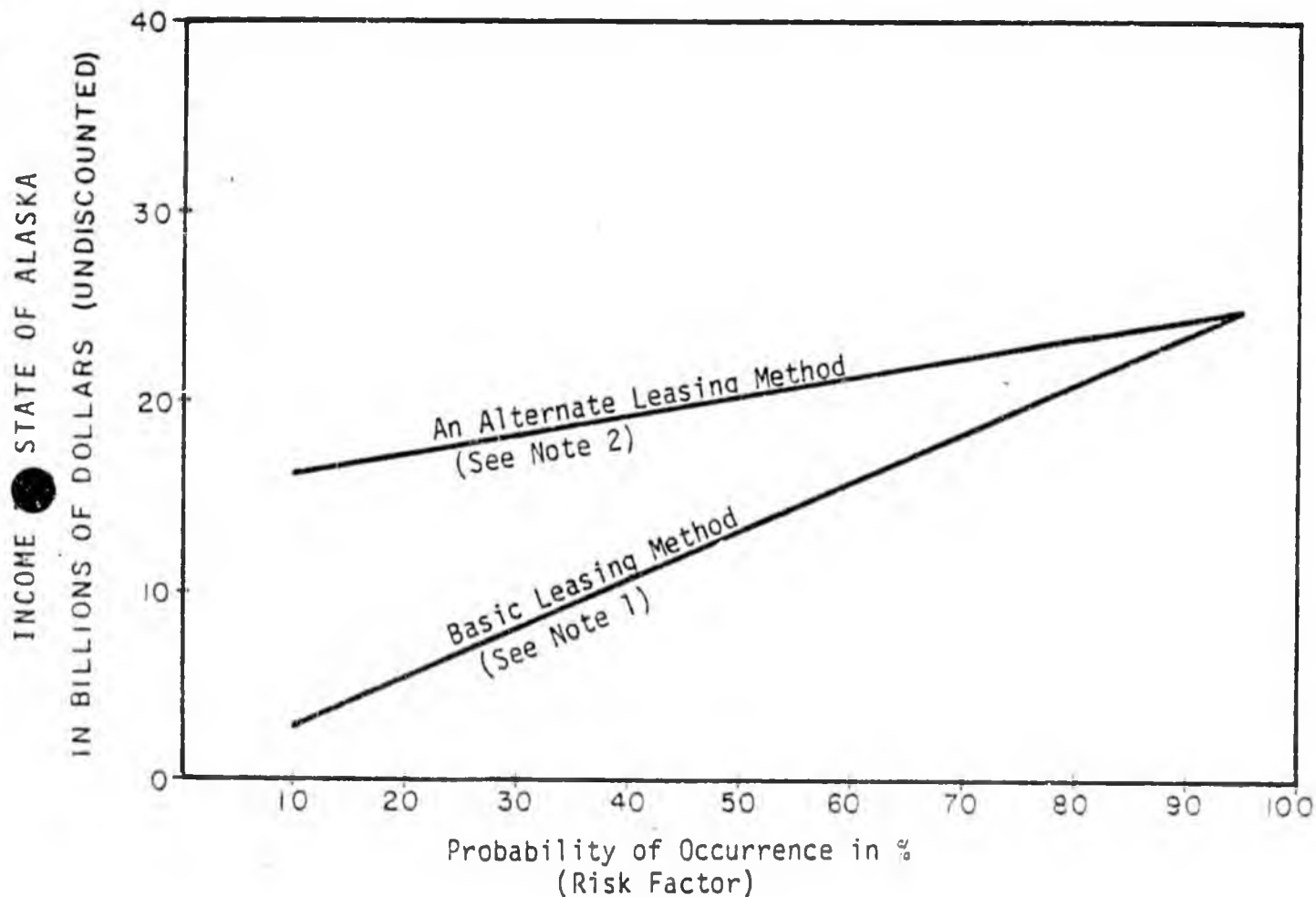
Of course, there are other possibilities under the percent of acreage option. For example, after oil has been discovered in the portion initially leased, the remaining acreage need not be leased but could be held by the resource owner (State of Alaska) for direct participation in the unit. The value of this alternative or any alternate depends on the State's income needs and their willingness to share risks.

This model study indicates that State income can be greatly increased over the long run by mapping structures, analyzing the potential petroleum reserves and then on the basis of resource econometric calculations, finding the optimum percent of acreage to lease.

INCOME TO STATE OF ALASKA

Comparison of an Alternate Leasing Method

Giant Expected Oil Field
(5 Billion Barrels Recoverable)



NOTE 1: Basic Leasing Method
All Acreage Leased at the Same Time
Bonus Bid @ 12.5% Royalty

NOTE 2: Percent of Acreage - An Alternate Method
40% Lease Initially by Bonus Bid @ 12.5% Royalty
Expected Value Based on Risk: 10%
60% Leased 2 Years Later by Bonus Bid @ 12.5%
Expected Value Based on Risk: 90%

MARGINAL FIELDS REQUIRE FLEXIBILITY IN LEASING

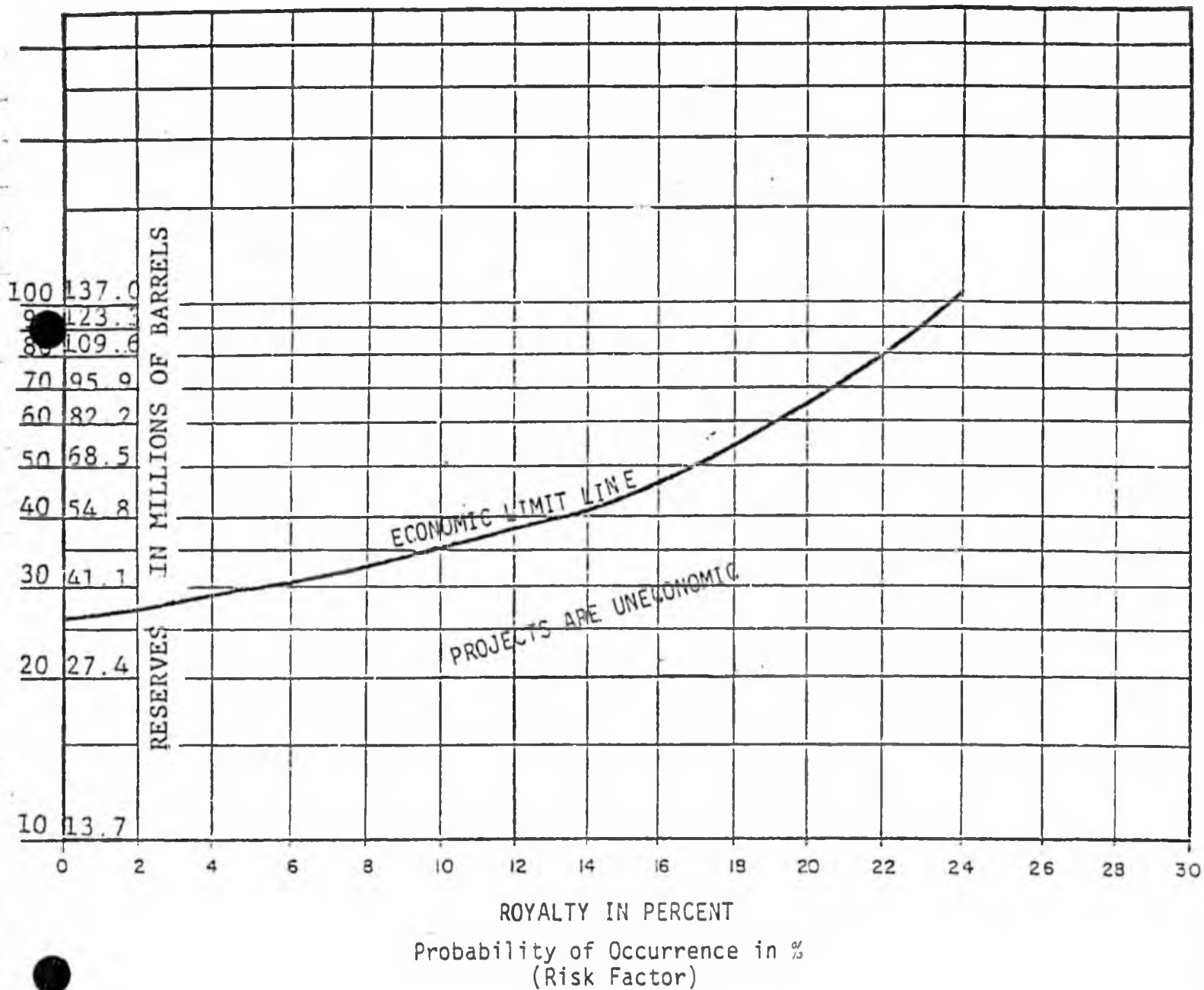
Minimum economical field size in Alaska is much larger than in the lower 48 states. Considering the Cook Inlet area where development and production costs are high, the minimum field size is very dependent on the price of crude oil. As shown by Figures II-15 and II-16, for 12.5% royalty and 18% rate-of-return, at a crude oil price of \$10.50/Bbl, the minimum field size is about 54.8 million barrels recoverable. However, at an average crude price of \$17.40/Bbl the minimum field size (reserves) is only about 13 million barrels recoverable.

Small fields which are uneconomic at specific values of crude oil price, royalty, and rate-of-return can be made economical if any one or a combination of these three factors are appropriately changed. The preceding paragraph explained that as crude oil prices increase, the minimum field size decreases. The same Figures (II-15 and II-16), also show that for a given oil price and a fixed rate-of-return, as the royalty is decreased, minimum economical field size is also decreased. This means that small fields which would not be economical to produce at a 12.5% royalty, could be economical if the royalty percent was decreased.

Minimum economical field size can also be decreased if industry is willing to accept rate-of-returns lower than the 18% used in this report. This is unlikely however, because the anticipated rate-of-return from a high risk venture must be much higher than for a low risk venture. Where one would be willing to buy secure bonds at a 10% rate-of-return, he would not be willing to invest in a risk venture if the best possible rate-of-return was only 10%. In business, as the amount of risk increases, the anticipated rate-of-return from a successful

ECONOMIC LIMIT DEFINED BY
 ROYALTY VERSUS RISK
 FOR OIL WITH AVERAGE VALUE OF 10.5 DOLLARS/BARREL

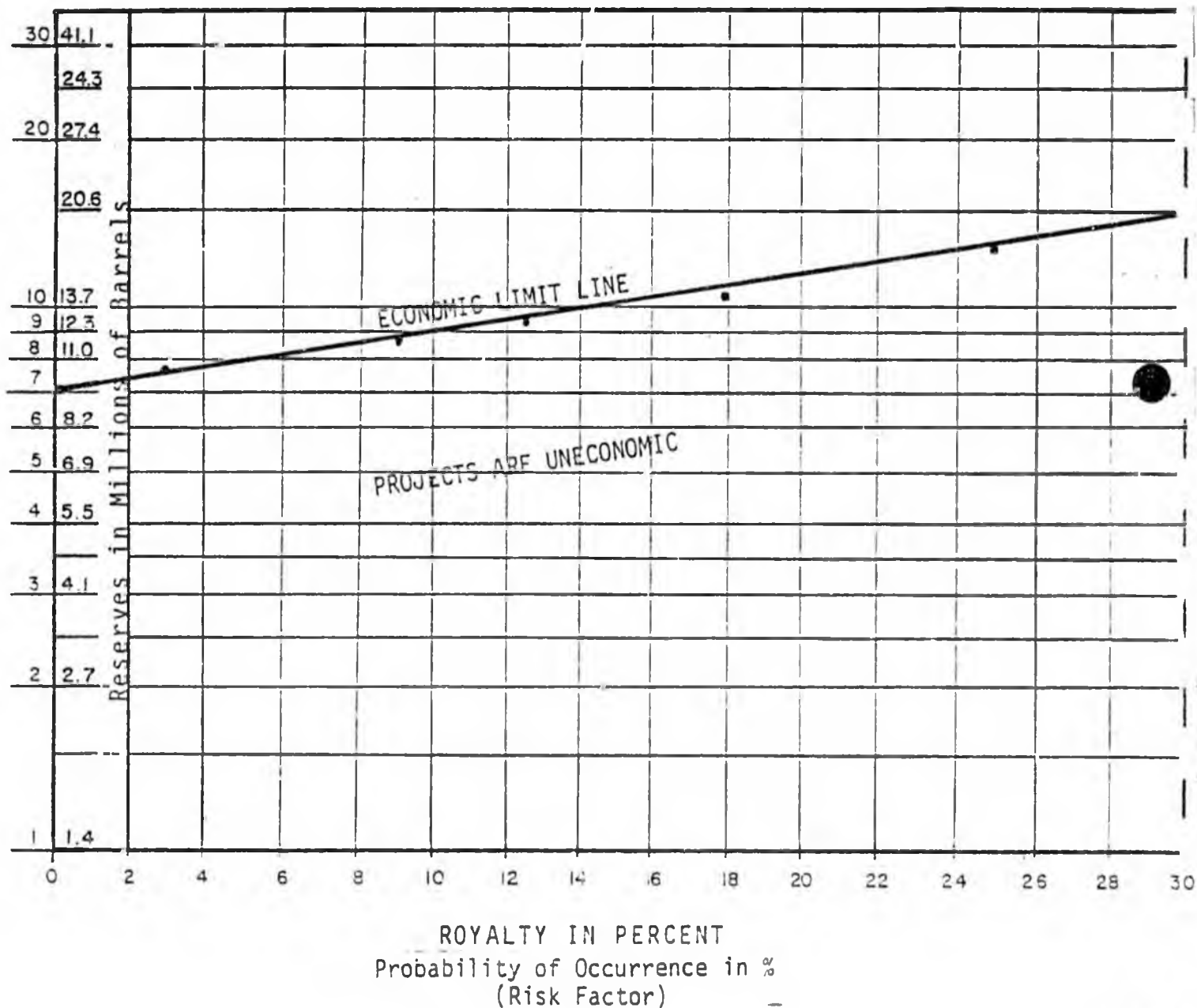
Also Shows Royalty Versus Reserves
 At The Economic Limit



ECONOMIC LIMIT DEFINED BY
ROYALTY VERSUS RISK

For Oil With Average Value
Of 17.40 Dollars/Barrel

Also Shows Royalty Versus Reserves at Economic Limit



venture must also increase to compensate for the losses from the unsuccessful ventures. Because of the high risks involved with finding and developing an oil field, it is entirely probable that the 18% rate-of-return used in this report is low, depending on the specific structures being leased and on the bidding methods being used to auction off the leases.

The State has the capability, and perhaps the obligation to influence the timely development and production of small fields. Of the three parameters which most influence the minimum economical field size, the State has the capability of adjusting only one of the parameters - the royalty percent. Even if the royalty were reduced to zero, the State would realize income from severance tax, conservation tax, advalorem tax and from income tax. These tax revenues would not be realized unless the field were produced. The oil company makes some profit and derives benefits from supplying refineries with feed stock. The nation benefits from an increased supply of crude oil.

Marginal fields must be developed and produced on a timely basis. For a specific set of conditions of field size, oil price, royalty, and rate-of-return, the location and development timing are related and are critical. For example, any oil field which is near already producing fields is more economical to develop and to produce than if it is remotely located. This is because the facilities, equipment and personnel required for the operating field can be utilized in the operation of a small, nearby field. While some additional direct labor may be required, the repair crews and supervisors could cover both fields; in other words, the fixed operating costs would not significantly increase. Thus, it is critical that the marginal fields be developed and produced while there are large producing fields in the area.

The State has the capability of encouraging the development of marginal fields. The State benefits development as does industry and the nation. Therefore, if the State is to encourage this development, a flexible leasing program will be necessary so the leasing system can be tailored to existing conditions.

SENSITIVITY OF THIS ANALYSIS TO CHANGES IN VARIOUS PARAMETERS

Extremely High Risk Cases. Two leasing methods were analyzed at a 1% probability of success to determine if the results obtained from this study would be valid for extremely high risk situations. The bonus bid @ 12.5% royalty case and the royalty bid at fixed bonus case were run at extremely high risk.

The major elements of these extremely high risk cases were that 100 bonuses would be received and 100 structures would be drilled. The bonuses were appropriately factored to reflect the 1% probability assigned to this venture. Since our study assumes 3 wells are drilled per structure, there were a total of 297 dry holes drilled - 300 exploratory wells total. The cost of drilling these wells was included in both cases as dry hole exploratory costs. For a dry structure, the bonus and the well cost were expensed at significant tax loss to the State; as a matter of fact, the tax loss constitutes 42.3% of the bonus received.

The rate-of-return from high risk ventures must be adequate to compensate for the statistical losses. The bonus bid method requires relatively larger bonuses than does the royalty bid methods. The bonus is a leasehold investment item while royalty operates like a cost of production. Therefore, the investment risked on a bonus bid case is significantly higher than the investment risked on a royalty bid case.

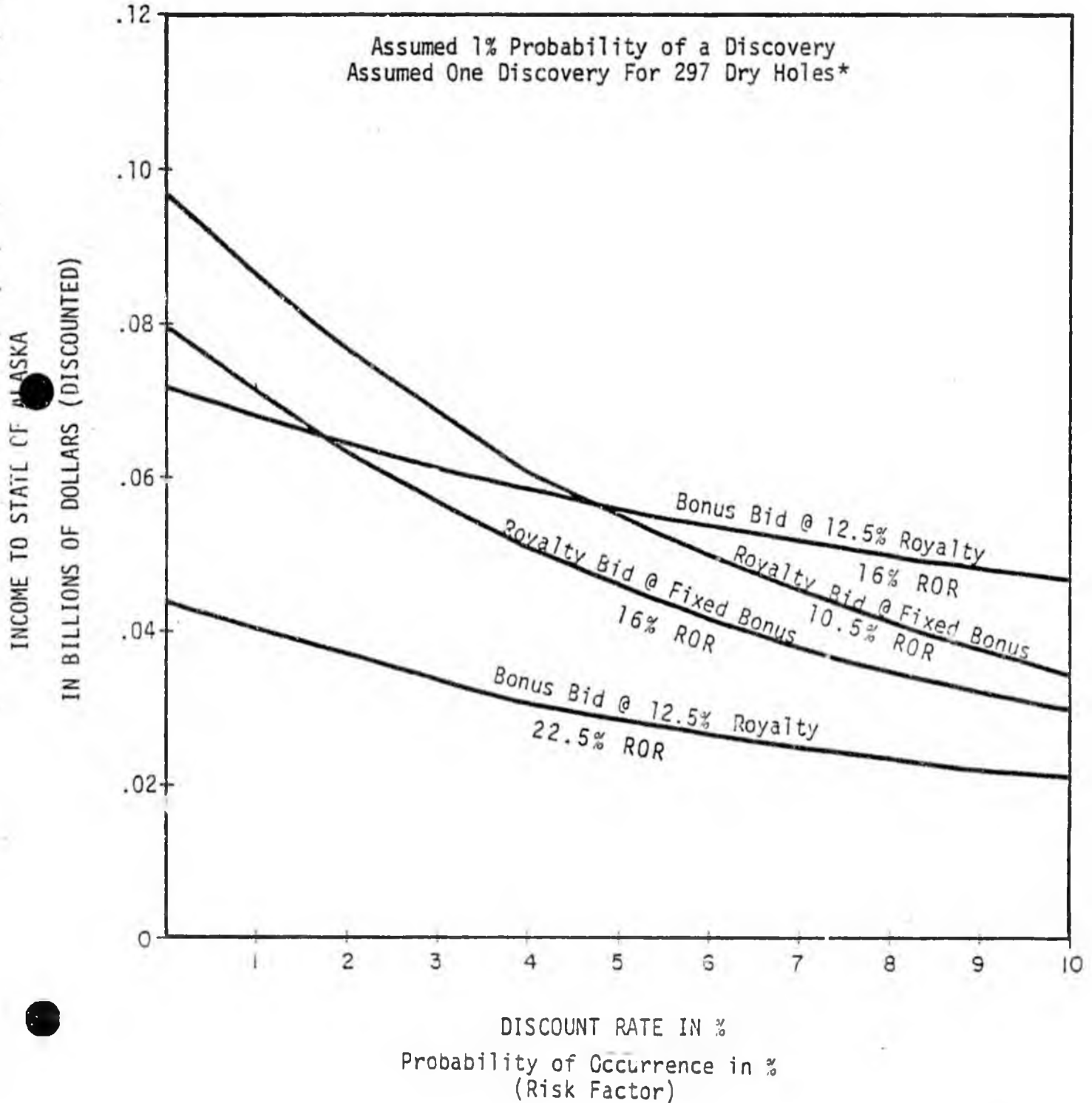
In recognition of the relative risks, the bonus bid case was run at a higher rate-of-return than was the royalty bid case. A rate-of-return of 22.5% was deemed reasonable for the bonus bid case. From the oil company's viewpoint, the royalty bid case is much more secure; therefore, we assumed a 10.5% rate-of-return for this case. The results of the economic calculations are shown graphically on Figure II-17. For these conditions at all discount rates from 0% to 10%, the royalty bid method provides significantly more income to the State than does the bonus bid method.

Next, the cases were compared at equal rates-of-return (16%). At this rate-of-return, undiscounted income from the royalty bid case is higher than for the bonus bid case. But at a discount rate of 2%, the present worth income from both cases is equal - at discount rates above 2%, the bonus bid case provides more income to the State than does the royalty bid case.

Changes in Crude Oil Prices. Crude oil prices used in this report are the Tier II prices for Cook Inlet. These prices are then escalated at a rate of 5% per year to a maximum value of \$18.00 per barrel. The maximum value of \$18.00 per barrel is reached in the twelfth year after the lease sale, 7 years after production starts. The average price per barrel for the cases studied is \$17.40 per barrel. The initial price is \$10.86/Bbl.

The possibility exists that the Federal government will set crude oil prices for newly discovered fields. Therefore, we reran the computer programs, changing only the crude oil prices. The comparative effects on the selected leasing methods is shown in Figure II-18. This figure shows state

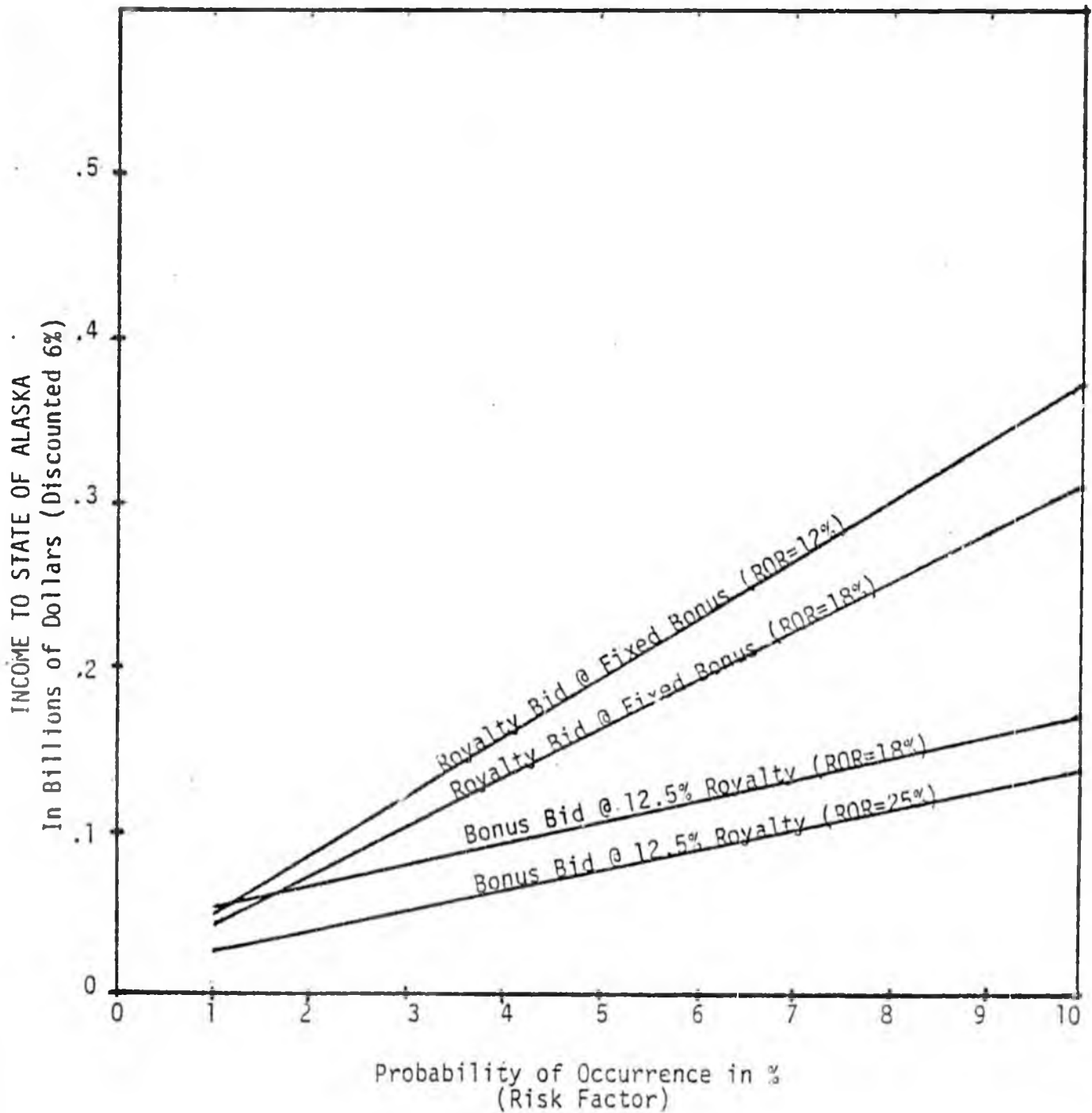
STATE INCOME VERSUS DISCOUNT RATE
 FOR BONUS BID AND ROYALTY BID CASES
 AT DIFFERENT INDUSTRY RATES OF RETURN



DISCOUNTED STATE INCOME VERSUS RISK

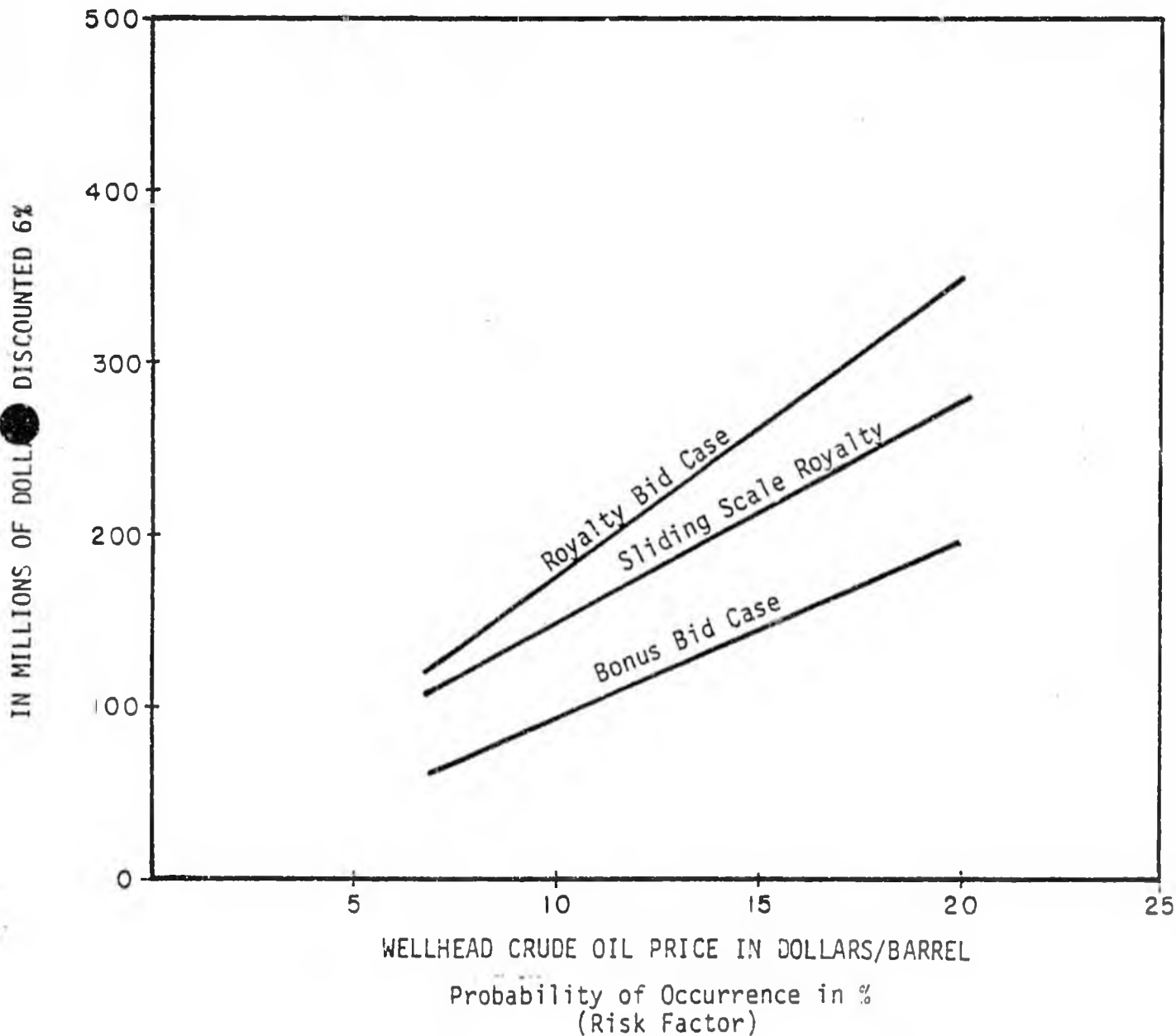
Based On

Expected Value Oil Field, 600 Million Barrels Recoverable.



DISCOUNTED STATE INCOME VERSUS
CRUDE OIL PRICES
FOR VARIOUS BIDDING METHODS

Venus Field
(600 Million Barrel Recoverable)
All Cases At Risk Factor = 10%



income (discounted 6%) versus wellhead crude oil price.

For the range in crude oil values studied, the comparative relationship of the selected bidding methods did not significantly change. The range of crude oil prices considered was \$7.00 to \$20.00 per barrel. Over this range, the discounted income curves for the bonus bid case was always lowest, the royalty bid case the highest, and the sliding scale royalty case was in between; a net profit bid case would be similar to the royalty bid case. Thus a change of crude oil prices from a low of \$7.00 per barrel to a high of \$20.00 per barrel does not change the comparative results of this study.

Effects of Produced Gas. Wellhead gas production was considered in this study. There are many unknowns which effect the value of gas removed from oil. Some of these unknowns are:

1. First, how much gas is produced - what is the producing gas/oil ratio?
2. Next, how much of this gas will be required for lease fuel - fuel usage depends on the field location, availability of commercial electricity, gravity of the oil, water content, emulsion condition, temperature of the production, and distances from the gathering centers to the cleaning facilities and sale point.
3. Third, marketability of the gas - some Cook Inlet gas is handled at a loss, some is sold at various values from about 16¢/MCF to 64¢/MCF.
4. Lastly, what is the present worth of profits (PWP) resulting from reinjection of the produced gas?

Since evaluation of the produced gas depends on several variables the effects of solution gas are not handled separate from oil in this analysis. The effects on the study are in the order of less than 1%.

Government and Discount Rates. What discount rate should governments use? Discount rates are used by businesses to compare alternative investments. The Net Present Value (NPV) of future cash flows that would result from alternate investments is a uniform comparison base; it's about the only one available to business (governments use a "cost to benefit ratio").

Goals of businesses differ from those of governments. A business's only goal is to make money for their stockholders. A government's goal is to provide those services for the populace which they cannot provide for themselves. A business wants to continue making profit to pay monetary dividends in perpetuity while a government needs money to supply services in perpetuity. A business uses Present Worth of Profits (PWP) to compare investments; to be consistent, a government should use Present Worth of Services (PWS) to compare various options. PWP is not comparable to PWS. Since a Discounted Cash Flow (DCF) is used to determine PWP, it cannot also be used to determine PWS, therefore, it may be wrong for governments to utilize a (DCF) as does business.

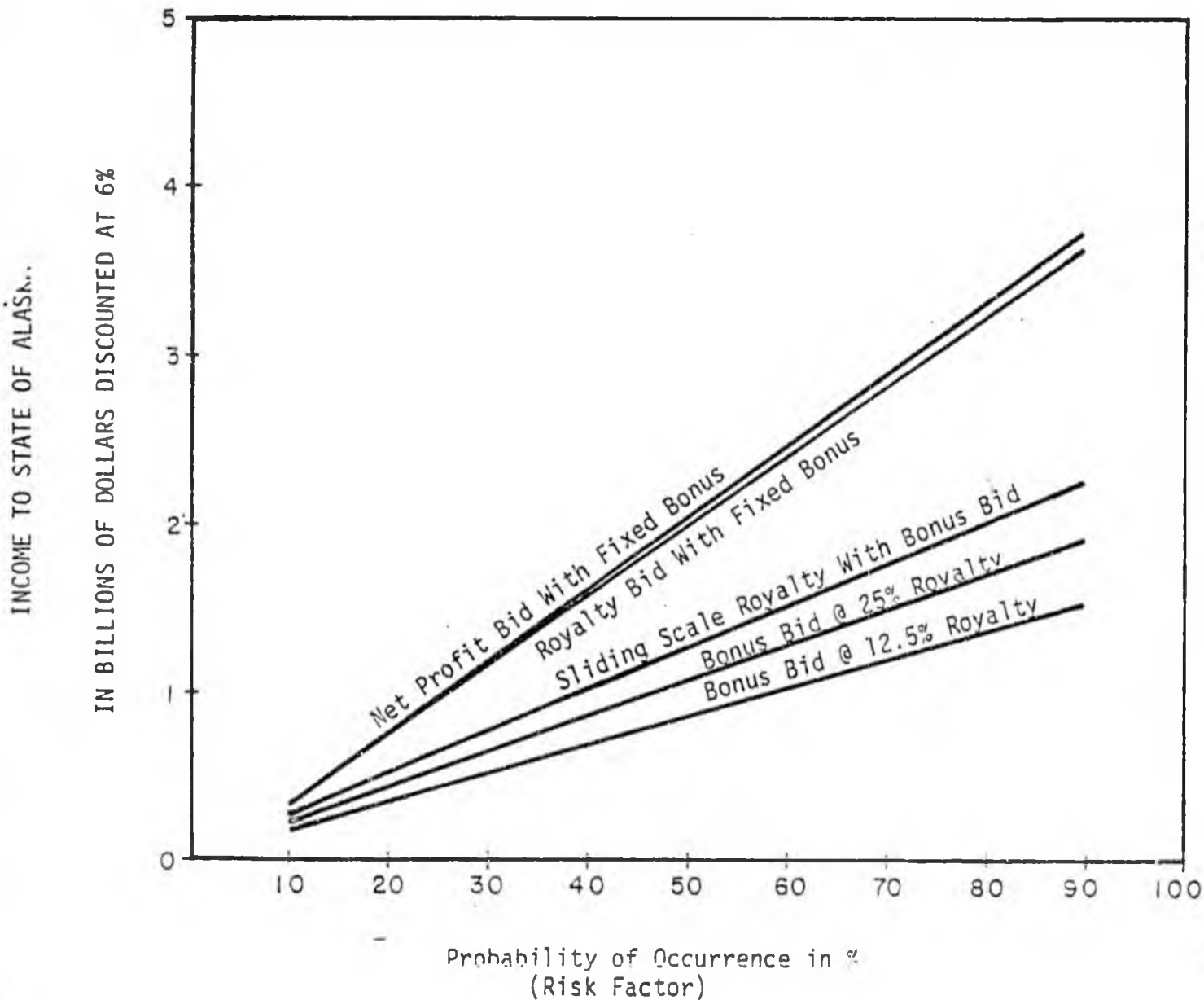
A government has a requirement for a sustained income in perpetuity. Money in a bank provides no services to the populace - at best, the interest earned is useful for future services. Since the value of oil and gas is increasing with time (a recent USGS prediction indicates crude oil prices of \$80.00 per barrel by the year 2,000, if that's accurate or even 50% accurate), more State income may be gained by leaving it in the ground to mature than by "banking it" or spending it frivolously. Indeed, if the price escalation of crude oil is greater than the bank interest, a loss will result from early removal of crude oil. At this point in time, this is a real possibility. Perhaps current income over and above current requirements should be discounted to appropriately reflect the price loss resulting from early removal of crude oil.

While it is uncertain that governments should utilize discount rates to evaluate future cash flows, data is presented for discount rates of 6% and 10%. Shown on Figure II-19 and II-20 is discounted income to the State for the leasing methods analyzed. At these discount rates, (6% and 10%), the relative positions of the income curves for the various leasing methods do not change, they only shift downward.

DISCOUNTED INCOME TO STATE OF ALASKA

Risk Versus Income

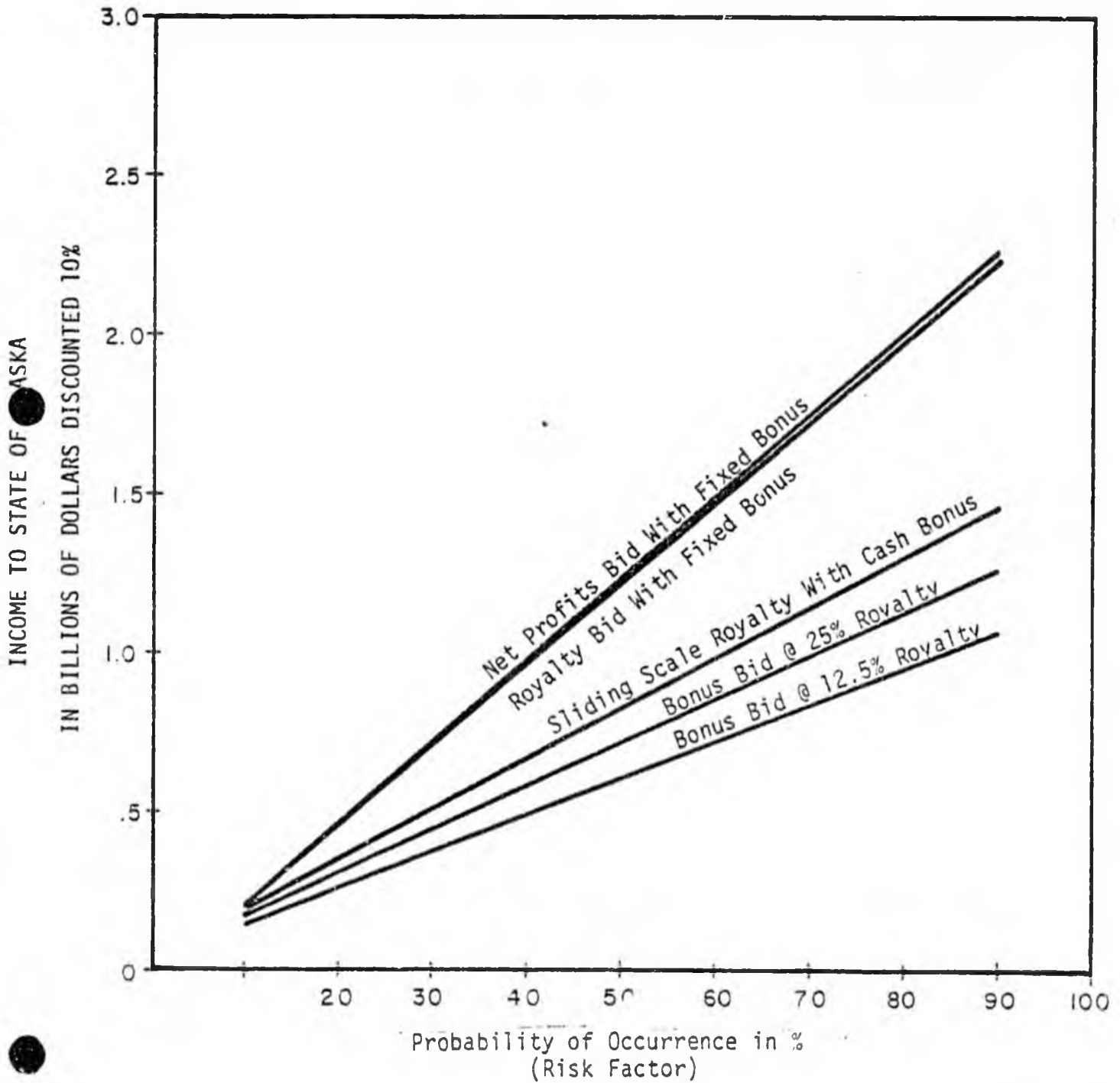
Medium Expected Value Oil Field
(600 Million Barrels Recoverable)



DISCOUNTED INCOME TO STATE .
VERSUS PERCENT RISK

For Various Leasing Methods

Medium Expected Oil Field
(600 Million Barrels Recoverable)



EFFECTS OF VARIOUS LEASING METHODS

To obtain the amount of bonus to be bid under a cash bonus bid system, the interested companies make geological and engineering models of the field. This data is put into a computer program along with the rate-of-return the company requires. The computer output lists the present worth of profits at various rates-of-return and the bonus which can be paid for each complement of discount rate and rate-of-return. Company management then selects the bonus based on the historical success of the company in obtaining the reserves calculated by the engineers and geologists.

To determine the amount to be bid under the Royalty Bid system, the Net Profit system or the Bonus Bid for Sliding Scale Royalty system, input variables are changed to reflect the required output data. In all cases, the bid parameter is listed in the output for various rates-of-return at the company's discount rate of money. This data is frequently displayed on a normal distribution curve so management can readily perceive the bid value versus risk.

The geological and engineering risks are incorporated into the respective models. However, the final risk applied to the bid quote is done by top management based on the statistical success of the company in obtaining the reserves calculated by the geologists and the engineers.

Bonus Bid Method. This is the method currently used by the State of Alaska, the Federal government and various other state governments. The advantage to the State is that immediate income is maximized. The cash bonus can be utilized by the resource owner before any production is obtained. In the likely event of a dry structure, the resource owner still has obtained the bonus; the

implications of a resource owner obtaining large revenues for nothing is beyond the scope of this report. However, it does seem wasteful of capital resources. It should also be noted that tax deductions taken by industry in the unsuccessful ventures result in a reduction of the net bonus to the State of Alaska.

The State of Alaska's income needs have been great while the sources of income have been few. Generally, the cash bonus has been spent before the field is developed, and in many instances, the bonus has been spent even before a discovery has actually been made.

Compared to cash bonus bidding there is no other leasing method which maximizes the immediate income to the State of Alaska.

The disadvantages of the bonus bid, from the State's position, is that considerable future income may be sacrificed to obtain immediate cash income. The best example of this is that for all the State's petroleum leases on the North Slope bonus bids totaled 912 million dollars. Estimated reserves of the Prudhoe Bay Field are 9.6 billion barrels. Total State bonuses collected from all North Slope leases to date amount to only 9.5 cents per barrel of oil for the Prudhoe Bay Field. As additional reserves are developed on the already-leased North Slope acreage, the bonus value will drop below this 9.5 cents per barrel figure. Bonus wise, the State of Alaska virtually gave away the Prudhoe Bay oil.

In addition to the above considerations, the amount available for the bonus bid is based on the cost/price assumptions made at the time of bidding. If the costs or prices change after a lease has been awarded, the comparative value of the bonus changes. If costs decrease, the bonus was too low; if costs

increase, the bonus was too high. Similarly, if crude oil prices decrease, the bonus was comparatively high; however, in the more probable event that crude oil prices increase, the bonus would then be too low. The 1969 Prudhoe Bay lease sale occurred when Cook Inlet prices averaged 2.63 \$/bbl.

From the producing companies consideration, they are making a considerable investment several years before they can possibly get any return for that investment. The cash bonus is wasted if the structures are dry. It has not purchased anything of value and does not assist in the exploration or development of resources. For small companies, this cash bonus or "Front End Money" imposes a large problem. For even large companies bidding on large structures, an equitable bid may be a significant part of the very high costs needed to bring the field to production. Here again the Prudhoe Bay Field is a good example. When the \$0.9 billion bonus is added to the \$8-10 billion for pipeline cost plus the field development costs of \$5-6 billion, the aggregate cost strains the financial markets of even a group of large companies such as ARCO, BP, EXXON, and SOHIO.

In anticipation of the ability to finance a venture (bonus + development + transportation), a company would reduce their bonus bid based on the availability of capital and especially on the basis of their ability to obtain the needed capital.

Royalty Bid Method. On the other end of the bidding spectrum is the royalty bid. This is the bidding method most frequently compared to bonus bidding. Generally, a small fixed cash bonus is required to reduce speculation by those who have no intentions of exploring the leases. The winning bidder is the company which bids the highest fractional royalty to the resource owner.

The royalty bid is a means by which the resource owner can share in the benefits of a large field such as the Prudhoe Bay Field. However, the resource owner

must also share the risks in the dry structures, from which he would get nothing except the small fixed bonus.

Based on the same geologic, engineering and economic models, an operator would be more willing to promise large future payments contingent on the success of the exploration and development than he would be willing to pay an equivalent amount as a lump sum cash bonus at the lease sale when the first income from production is 4-6 or more years away; and when income from the investment may never be realized.

From the resource owner's consideration, a disadvantage of royalty bidding is that the owner shares the risk with the operator. For a dry structure, the owner would realize only the small fixed bonus whereas under the bonus bid, the owner would normally have received a larger bonus.

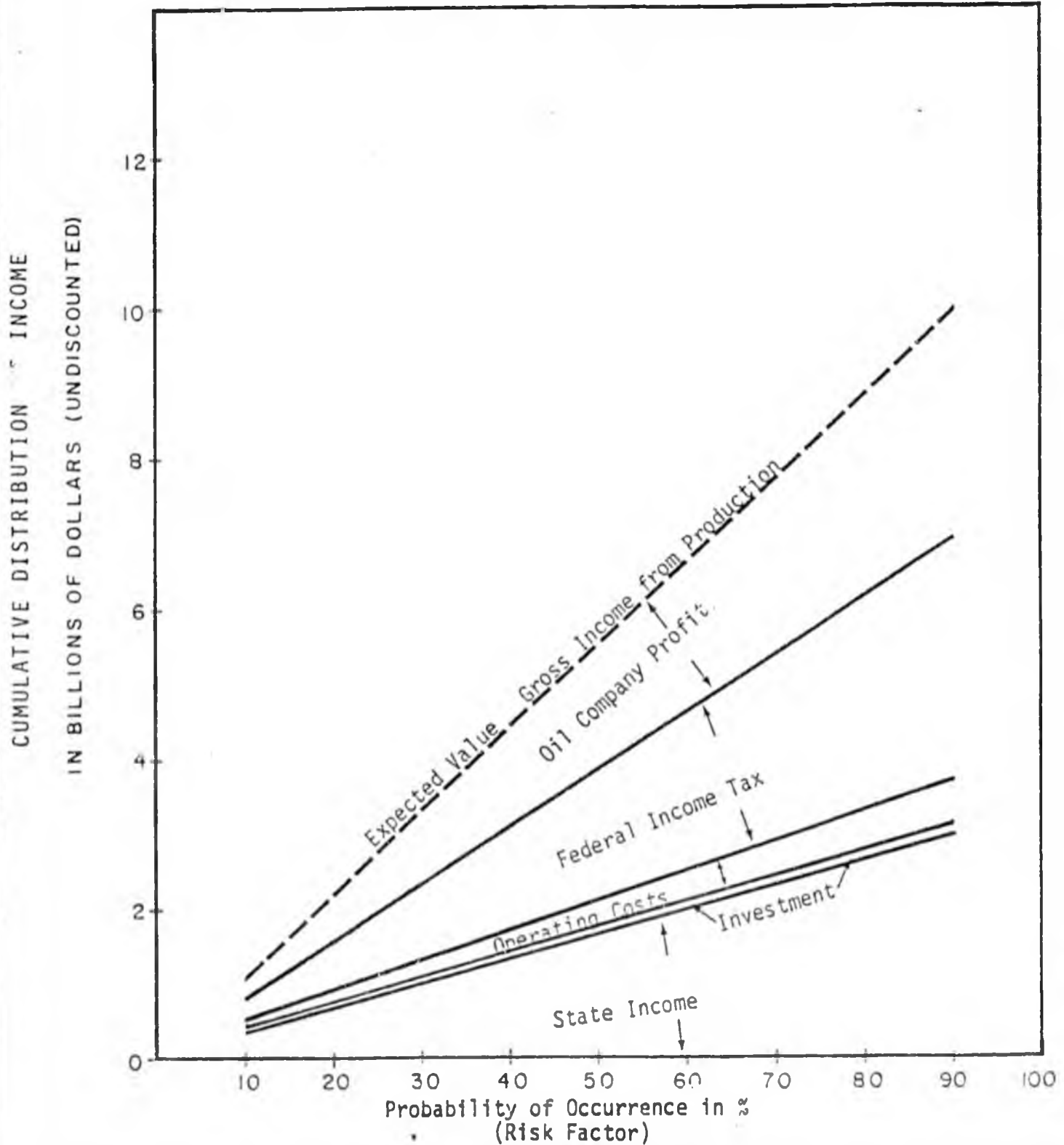
Royalty income to the State can be influenced by the crude oil prices set by the Federal government. The income gain to the State from royalty bidding as opposed to bonus bidding results in part from a reduction in Federal income tax (Figure III-1&2). This occurs because the royalty oil is not income to the operating company, therefore, it is not subject to Federal income tax. Since the Federal government through the FEA sets crude oil prices, they have the capacity to affect the royalty income to the State of Alaska. Decreased crude oil prices would not necessarily decrease income to the Federal government because they can make up the lost taxes downstream of the refinery. Any consideration of royalty bidding should include the possibility of the FEA setting crude oil prices which would affect income to the State.

Another disadvantage from the owner's viewpoint is that the royalty is a cost of

DISTRIBUTION OF GROSS INCOME

Based on Current Method of Leasing
(Bonus Bid @ 12.5% Royalty)

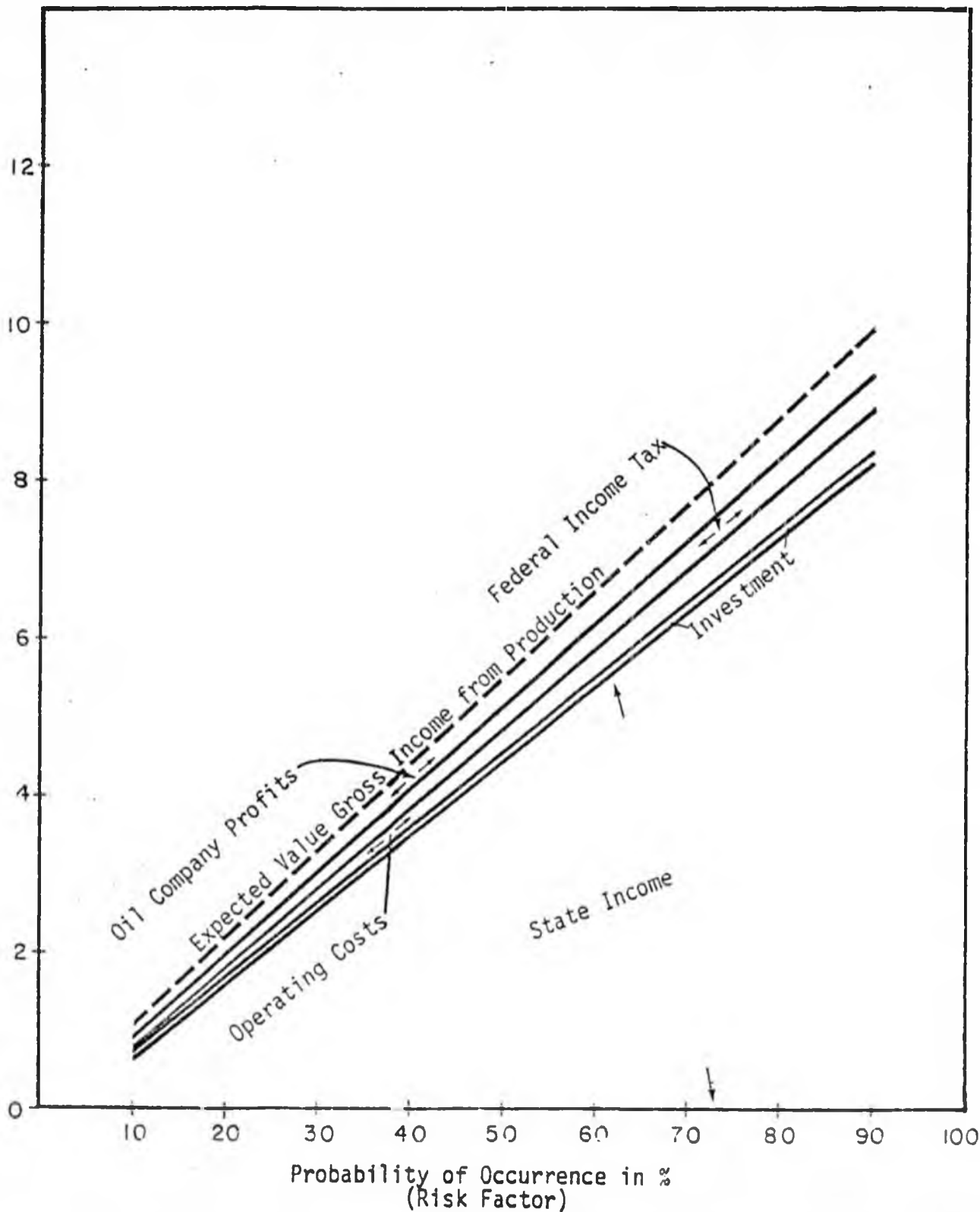
Medium Expected Oil Field
(600 Million Barrels Recoverable)



DISTRIBUTION OF GROSS INCOME

Based on an Alternate Leasing Method
(Royalty Bid at Fixed Bonus)

Medium Expected Oil Field
(600 Million Barrels Recoverable)



UNDISCOUNTED GROSS INCOME

production and, economically speaking, acts like a production expense. As the cost of production increases, the minimum economic production rate is increased. This means that the economic limit is reached sooner in terms of cumulative production as well as in years of field life. When the economic limit is reached at a lesser cumulative production, the amount of the resource left in the ground is increased, thus wasting a valuable resource. Reaching the economic limit sooner in years also reduces the number of Alaska jobs available. This problem could be resolved by having the royalty decrease as production declines in the field's old age period.

Royalty bidding should entice more competition in the leasing auctions. During OCS lease sale No. 36 in the Gulf of Mexico, some tracts were put up for royalty bid plus fixed cash bonus while other tracts were offered at a cash bonus bid plus 16.67% royalty. The tracts leased on the royalty basis averaged 7.1 bids per tract as compared to only 2.2 bids per tract for those leased by bonus bid.

From industry's viewpoint, royalty bidding takes much of the uncertainty out of bidding. The majority of their commitment is based on the contingency of production. If they develop production, they pay. If no production is developed, they don't pay. This aspect increases competition for the leases and allows the allocation of more capital for exploration; however, it also makes it much easier to walk away from poor prospects. By keeping the front end investment low, industry's capital financing is much easier to obtain. Indeed, if the capital market is weak, they may have a difficult time financing the entire project, e.g. the TransAlaska Pipeline.

Since royalty is based on production, it has the effect of increasing the minimum production costs and therefore, the minimum production rate for an economic

operation. Theoretically, as the minimum economic rate is increased, the economic life of the field is shortened; therefore, the company may discontinue production of a field at a lesser percent recoverable under royalty bid than would occur under bonus bidding. This is speculative reasoning because an integrated oil company may operate a field at a loss because refinery feed stock is needed and because operating losses can be made up downstream. In actual practice, very few fields have been abandoned. They may be shut in or production suspended awaiting recompletion, stimulation, or secondary recovery, but they are seldom abandoned to the extent of recovering the equipment, plugging the well bore and cutting off the casing below ground level.

Net Profit Bid Method. Under this system, industry bids on the percent of net profits (after capital recovery but before taxes) which will be returned to the resource owner. Profits which are to be split are those obtained after the lessee has recovered all of this invested capital plus a nominal interest value. Also, at the time of leasing, a small fixed cash bonus is required as earnest money. In this study, the fixed bonus was based on expected reserves within the leased acreage.

Economically, this system is very similar to the royalty bid system. That is, the front end money required is low. The majority of return to the resource owner is predicated on the profitable production of the resource. Similar to royalty bidding, the resource owner shares the risk of not obtaining profitable production. If profits are not made, the resource owner's only income is the small fixed bonus paid at the time of leasing.

Some of the financial advantages of this system are very similar to those of royalty bidding. Since the front end money is low, financing exploration and

development costs is much easier for the company than under the current bonus bid system. The lessee should be willing to bid more money contingent on future profits than he would be willing to bid for a lump sum cash bonus bid.

Similar to the royalty bid system, the net profit system operates as an increased cost of production. That is, it raises the minimum economic value of production. As this minimum economic value of production is increased, the economic life of the field is reached at a lesser cumulative production and at a shorter time in years. However, as was discussed under royalty bidding, the economic limit is not necessarily the cut-off point as far as the company's willingness to produce a field. This is because the company may need the feed stocks to operate their refinery; and because profits lost from operation can be made up downstream of the refinery. Also, marginal on-shore fields are generally kept in operation pending some remedial work, stimulation, secondary recovery plans or pending significant crude oil price increases.

A disadvantage of the net profit system is that since the resource owner's income is based on the net profits of the company, the resource owner will want to know what the actual profits are. To ensure that only applicable costs are deducted from income, it would be necessary that the resource owner do extensive auditing of the books of all of the companies which were producing from leases obtained under the net profits system of bidding. Also, there could be a good deal of controversy regarding the need for and the chargeable costs of some investment items.

Another disadvantage could be that the companies would attempt to consolidate

profitable ventures with losing ventures (this is sometimes called cross subsidy). This is possible within the same lease or field as when a profitable option is coordinated with an unprofitable one - for example; field extensions, pool extensions, secondary recovery projects, production acceleration projects, facilities expansion and others.

Sliding Scale Royalty Method. For this leasing method, royalty rates which increase with production rates are set by the resource owner; bids are awarded to the bidder who offers the highest cash bonus.

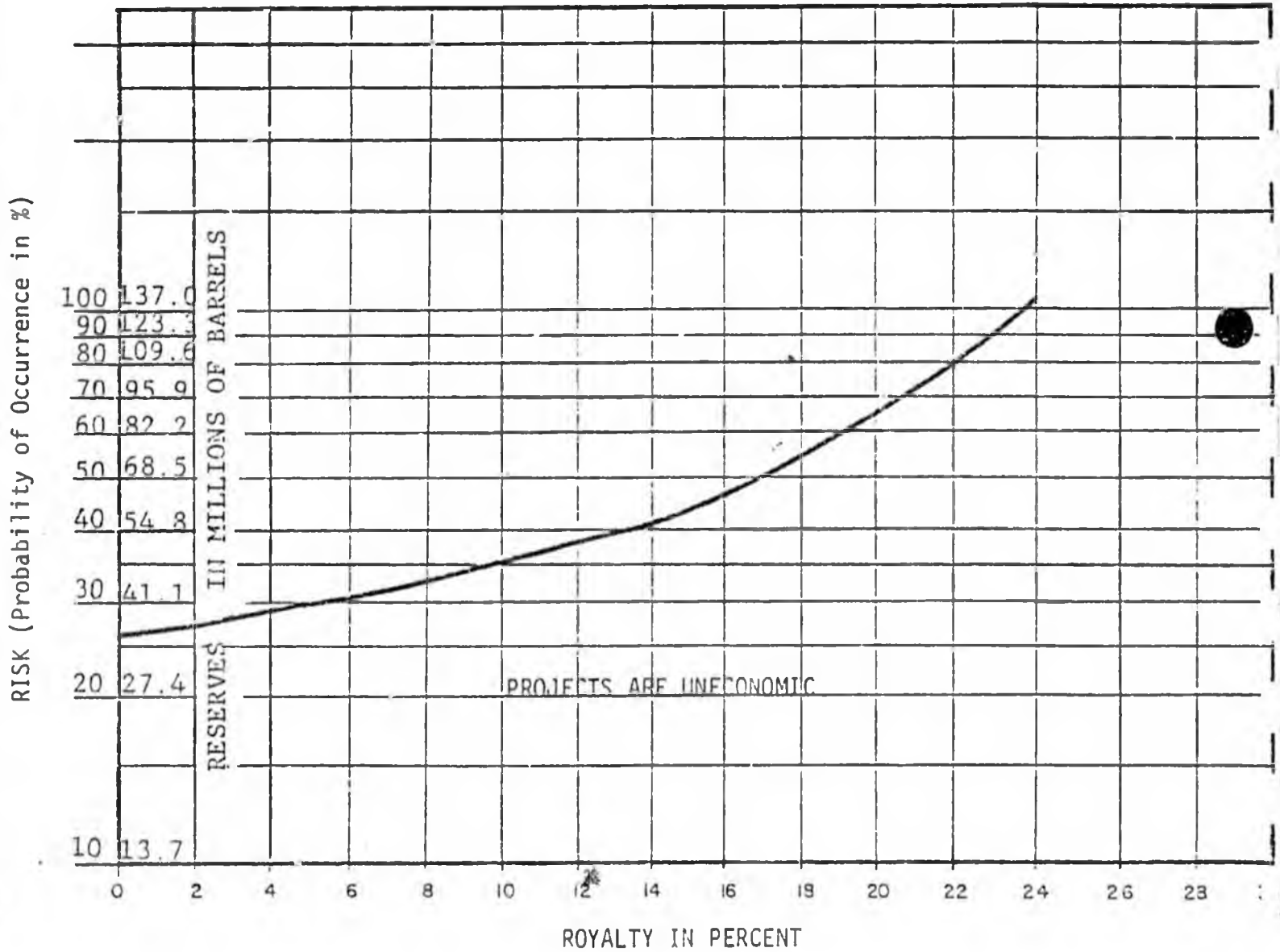
This method of leasing combines the good points of the cash bonus bid at fixed royalty system with the good points of the royalty bid system. In effect, it's a compromise between the two systems.

The sliding scale royalty system has the advantage of allowing the resource owner to realize some immediate income from lease sales and still allows some participation in the profits should a large field be discovered - for example, Prudhoe Bay. The cash bonus received would be less than under bonus bidding at fixed royalty, but would be more than the bonus required for either the royalty bid or the net profit systems. The royalty received would be greater than for bonus bidding and less than under the royalty bid or the net profit bid systems.

Under this method of leasing, prior to the sales, the State sets a predetermined sliding scale royalty rate which can be based on a variety of parameters. A very common one is production rate of the wells, individually or based on the average well production rate for the month. The interested bidders then bid on the

ECONOMIC LIMIT DEFINED BY
 ROYALTY VERSUS RISK
 FOR OIL WITH AVERAGE VALUE OF 10.5 DOLLARS/BARREL

Also Shows Royalty Versus Reserves
 At The Economic Limit



amount of a fixed cash bonus which they will give to the resource owner for the privilege of exploring, developing, and hopefully producing from the leased tract.

The sliding scale royalty method is a very convenient tool which the State can utilize to prolong field life and increase ultimate recovery. As normally used, sliding scale royalty increases the percent royalty above a base percent (usually 12.5% or 16.67%) depending on production rate. However, for very small fields (and as large fields decline), the royalty percent could be decreased. Figure III-3 shows that for a crude oil price of \$10.50/Bbl, and a rate-of-return of 18%, a field of 30 million barrels recoverable is only economic if the State is willing to accept about 6% royalty. It could also be economic if industry was willing to accept lower rates-of-return; however, for high risk ventures, a reasonable rate-of-return would probably be nearer to 25% than the 18% used in this report.

Percent of Acreage Option. Withholding a percent of the acreage is a leasing option which has resulted in increased income to resource owners. The elements of this option are that only 40 to 60 percent of the acreage is leased at the initial auction; the balance of the acreage is leased after a discovery is made. If only dry structures are found, the remaining acreage would not be leased.

At the initial leasing, all bids will be discounted for the risks involved. After exploratory wells have been drilled, either reserves will be found or the structure will be dry. If dry structures are found, the remaining acreage will not be leased. If reserves are found, the remaining acreage can be leased as proven reserves and will thus bring in premium bids.

This of course is what happened with the Prudhoe Bay oil field. Prior to discovering oil in 1969, Arctic Slope competitive bid bonuses totaled only 12 million dollars. After oil was discovered, competitive bonuses for the remaining acreage totaled 900 million dollars - most of this acreage straddled the oil/water contact and was definitely inferior to previously leased tracts.

Withholding acreage can increase income to the resource owner because irrespective of the risks initially applied, after a discovery is made the remaining acreage may be considered as probable reserves by the bidders. Thus, the increased income is due to a decrease in risk, not because of the bidding method utilized. In fact, any bidding method could be used in conjunction with the percent of acreage option.

There are some dangers in withholding acreage. In areas where a great deal of uncertainty exists, if too little of the structure or basin is offered at the initial auction, there may be few bidders. If too much of the basin is offered at the initial auction, it may turn out that the productive acreage is entirely within the leased tracts. Therefore, the bidding methods should be as carefully tailored to the particular structure or basin being leased as if the whole would be leased at the first auction.

The percent of acreage leasing option is a technique of withholding a part or a block of the leaseable acreage; it should not be confused with "checker boarding". Checker boarding is a leasing option whereby only alternate sections are leased initially. In the lower 48 states where fields are small, cost are relatively low, and well spacing may be as close as one to each 5 or 10 acres, checker boarding may be equitable to the operator. However, in

Alaska where well spacing is 1 well for each 160 acres and cost are high, fields must be large to encourage economic development. Checker boarding alternate sections in Alaska would be uneconomic to leasees and would probably result in the tracts not being leased. In the percent of acreage option, we are considering that only 40-60% of the structure is leased initially - that is, a few large blocks would be withheld.

OTHER CONSIDERATIONS

The purpose of an auction is to allow the bidders to set the fair market value of the commodity being sold. The fair market value can only be obtained when there is a sufficient number of bidders to insure actual competition. Anything that increases the number of bidders increases the competition and therefore increases the probability of the seller obtaining the true market value for his goods. On the other hand, anything that decreases the competition decreases the probability that the sale price will be the fair market value.

For a variety of reasons, the large oil companies tend to combine in partnership groups and make joint bids. This practice tends to spread their risks, but it also tends to reduce competition in bidding. In an attempt to encourage competition, the Federal government has prohibited the 9 largest oil companies from bidding together - the companies are listed in the Federal Register Announcement dated September 27, 1976. This is an option that Alaska ought to consider emulating in all future lease sales.

Also, the State should consider allowing industry to pay their cash bonus bids on an installment basis. This would spread out the income to the State and would ease financing problems for the companies. In Alaska where bonus bids, and exploration and development costs tend to be high, small companies are virtually excluded from competing. If they could pay their cash bonus bids on an installment basis, they could possibly compete in the bidding, (a bond should be required to insure payment of the balance). As discussed earlier, the winning bid at an auction is more apt to approach the fair market value when there are a large number of participants.

This report has presented analytical comparisons and discussions of four bidding methods and of one leasing option. Model fields were constructed based on existing Alaska fields. Income to the State was computer calculated for each of the analyzed bidding methods. The advantages and disadvantages of each of the four bidding methods was discussed, one method at a time. The major advantages and disadvantages which should be considered are summarized in the following paragraphs.

Proper selection of a bidding method can optimize benefits to the State in various ways:

1. Increase immediate income
2. Sustained yearly income
3. Increased total income
4. Encourage exploration activity
5. Prolong field life
6. Encourage development of marginal fields.
7. Increase the number of bidders.

There is no "one" best method which can maximize all of the above possible advantages to the State. To select a bidding method for a particular lease sale, the selector must know the relative importance of the above criteria at that point in time.

For each of the analyzed leasing methods, there are relative disadvantages as well as the advantages. The methods which have the most distinct advantage in one criteria will have a distinct disadvantage in another criteria. Some

of the more obvious disadvantages of the various leasing systems analyzed are:

1. Reduction in total state income
2. Reduction in immediate income
3. Decreased exploration activities
4. Shortened economic field life
5. Discourage development of marginal fields
6. Require strict State surveillance of oil industry accounting
7. Decrease the number of bidders.
8. Varying degrees of risk assumed by the State

These disadvantages are a compilation of the disadvantages of the various leasing systems analyzed. They are not all attributable to any one system.

Selection of the leasing method to be used for selling resources in a specific structure must include consideration of the disadvantages to be minimized, as well as the advantages to be maximized or at least optimized. A flexible leasing system based on analytical research will allow not only the selection of the "best" method but the combination of various methods to produce a product that will maximize the benefits listed and minimize the disadvantages.

There is no single leasing method which is the best in all situations. The selection of a leasing method for a particular lease is dependent on the structures being leased and on the State's income requirements at the time of leasing. Analytical data has been presented which show some methods maximize immediate income while others maximize total income. All of the methods discussed in this report have advantages and disadvantages relative to the other methods. Only by understanding the atmosphere in the State and requirements of the State at the time of leasing can the "best method" be selected: e.g. the one which has advantages we want to maximize along with disadvantages we can tolerate.

PETROLEUM FIELD MODELS

APPENDIX A

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PETROLEUM FIELD MODELS

This study concerns the effect of different leasing methods on the income received by the State of Alaska from the development of its petroleum resources. Therefore, the study team chose known Alaskan fields as the foundation on which to build five oil field models. Each of the leasing methods was tested on the models, and the income to the State and to industry was measured, thereby enabling evaluation of the leasing methods. The discussion of the Engineering/Geologic models follows:

Proven Alaskan oil fields range in size from less than 80 million to about 8 billion barrels of recoverable oil. Five model fields which range from 50 million to 5 billion barrels of recoverable oil were chosen as representative of the sizes of oil fields which may be found in Alaska in the future. The smallest of the model fields, Mercury, contains approximately 50 million barrels. Mars 110 million, Venus 600 million, Neptune 1 billion and Jupiter 5 billion barrels. These fields are ranked as marginal, small, medium large and giant (as compared with Alaskan oil fields).

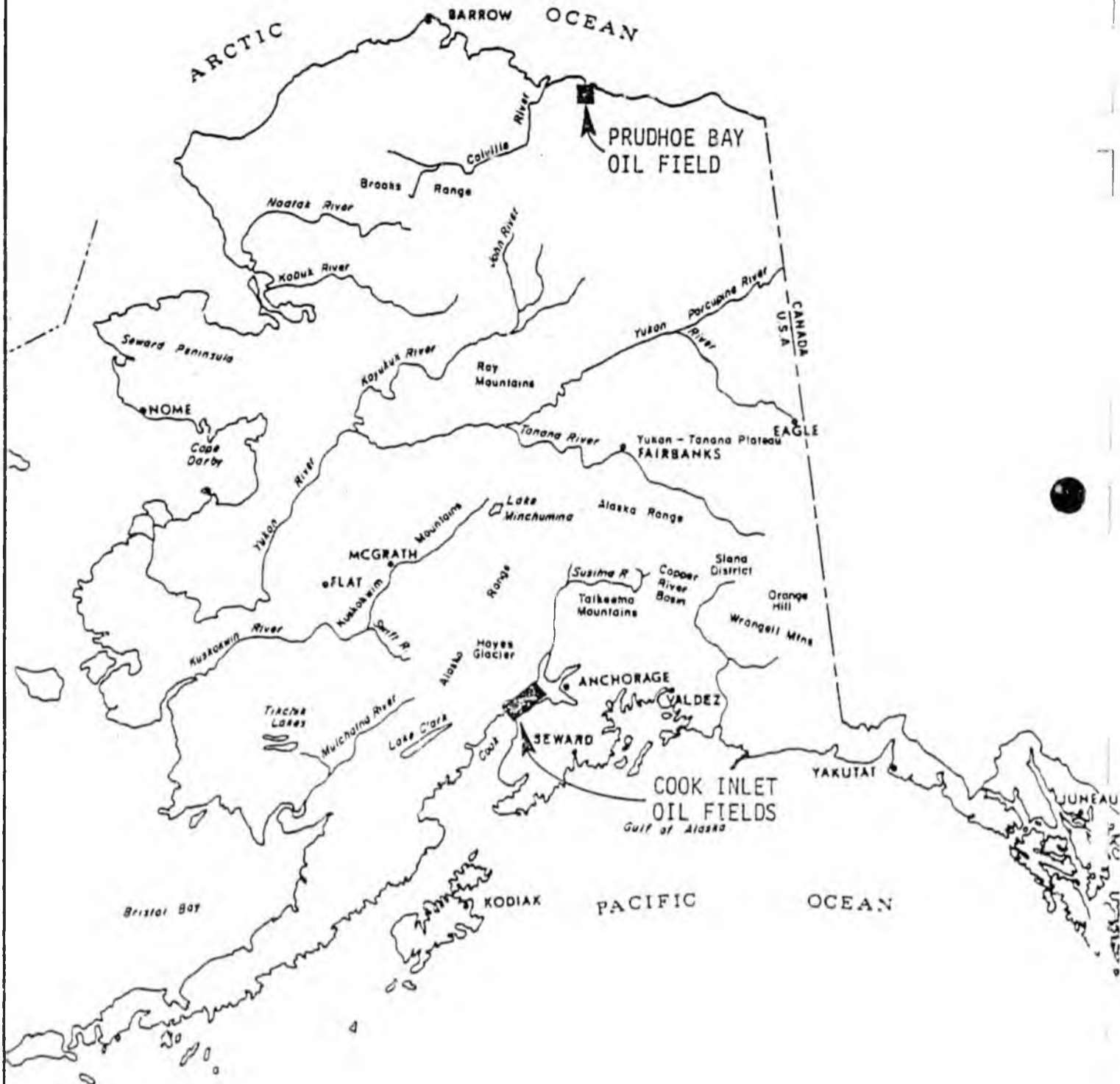
The 50 million barrel field is smaller than the smallest currently producing Alaskan field, but using this size of field reflects the future of development in a pioneer area such as Alaska. In the normal course of petroleum development in an area, the largest fields are discovered and produced first. As time passes, better technology and economics allow the discovery and development of smaller fields which were previously unknown and would have been uneconomic. Alaska may be entering this second stage of development in areas such as the Upper Cook Inlet.

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, porosities 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		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 ⁰)	SULFUR CONTENT OF CRUDE (WT. %)
NAME	CLASSIFICATION										
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

¹Based on Trading Bay field - Recoverable reserves of 75 million barrels (MMB)

²Based on Granite Point field - Recoverable reserves of 110 million barrels

³Based on McArthur River field - Recoverable reserves of 503 million barrels

⁴Based 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.

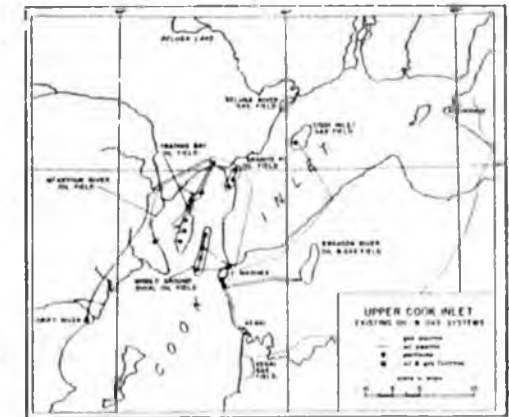
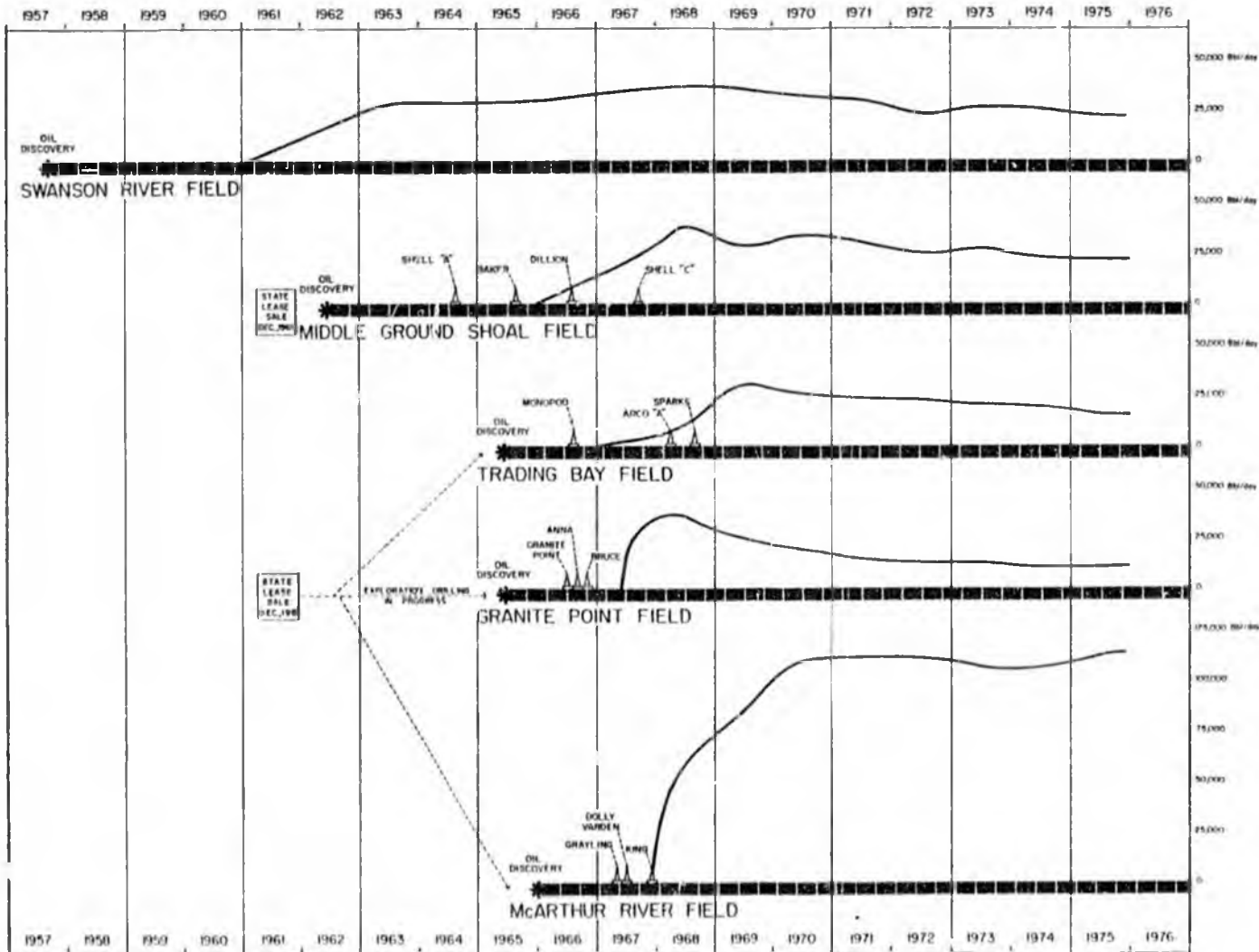
Production of the various fields begins to decline from 12 to 16 years after the lease sale. Decline rates vary from 10 to 20 percent, and the production rates at the end of the economic life of the fields range from 25,000 to 330,000

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

<u>FIELD</u>	<u>SALE DATES</u>	<u>DISCOVERY</u>	<u>TIME TO DISCOVERY</u>	<u>FIRST PRODUCTION</u>	<u>TIME TO PRODUCTION</u>
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	<u>20.7</u> "
				Average	5.2 "

Table K-2

PRODUCTION HISTORIES
OF MODEL FIELDS

Name	Fields	Class.	Exploratory Wells		Number of		Initial ⁵ Prod. Rate	Water Inject.		Prod. Decline starts	Decline Rate	At Assumed Economic Limit	
			No. of Wells	Yrs. to Compl.	Plat- forms	Prod. Wells		No. of Wells	W. I. starts			Final Prod. Rate	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.

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

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

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

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

⁵For all cases, production starts 5 years after the lease sale.

PRODUCTION HISTORIES OF MODEL FIELDS

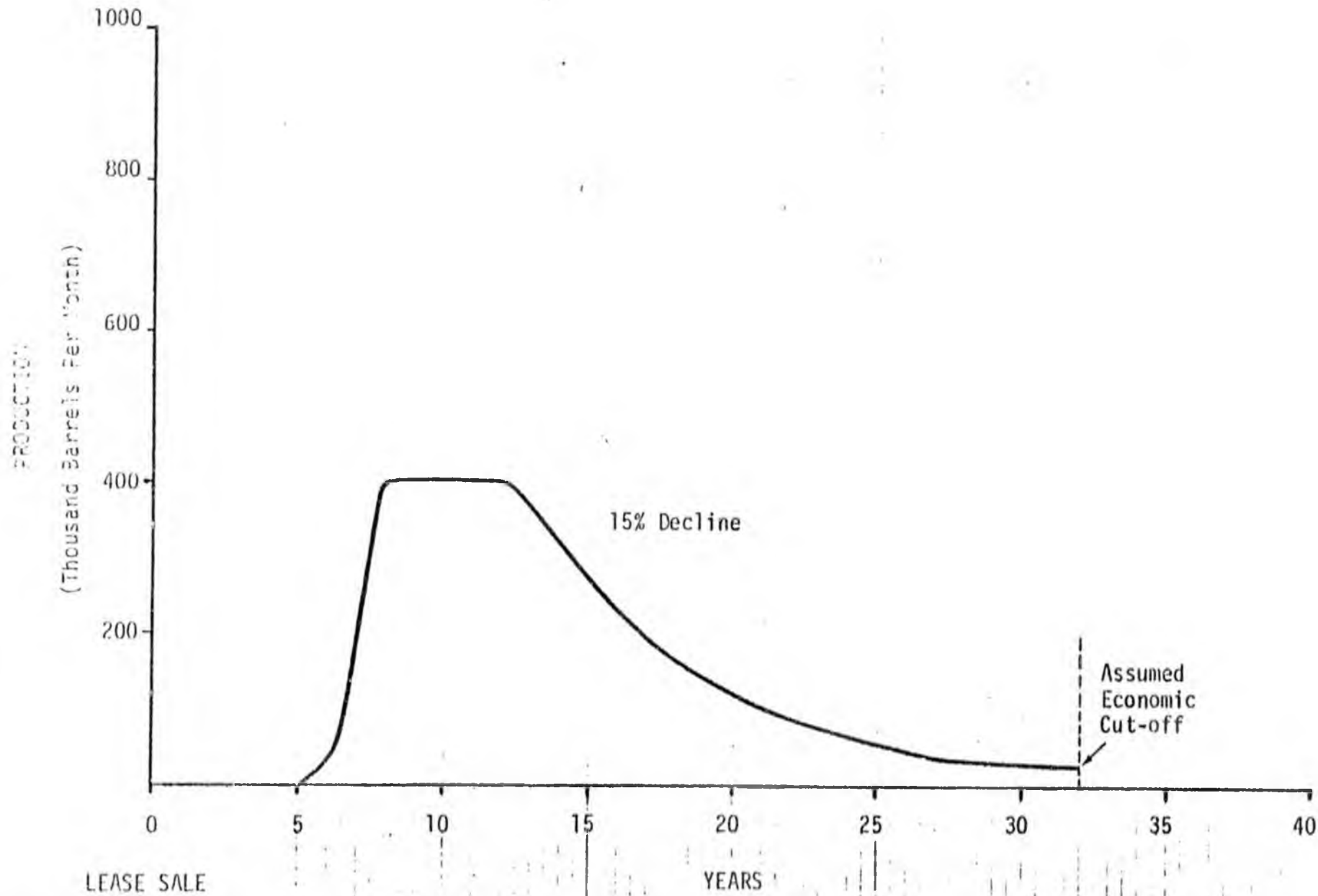
The Sensitivity of State Petroleum Income
to Various Leasing Methods

January, 1977

Table K-3

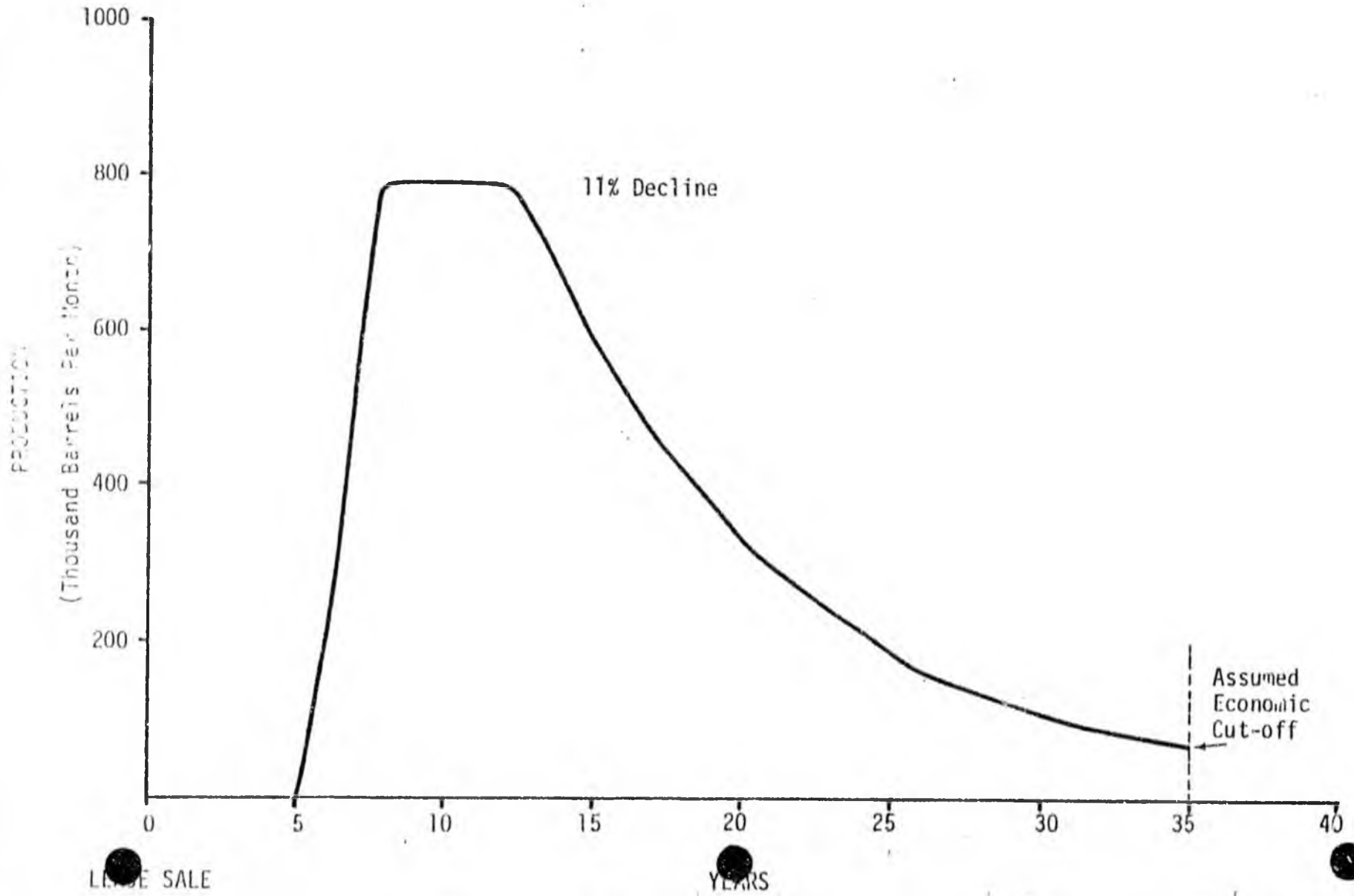
PRODUCTION HISTORY OF MERCURY OIL FIELD

(Recoverable Reserves 50± Million Barrels)



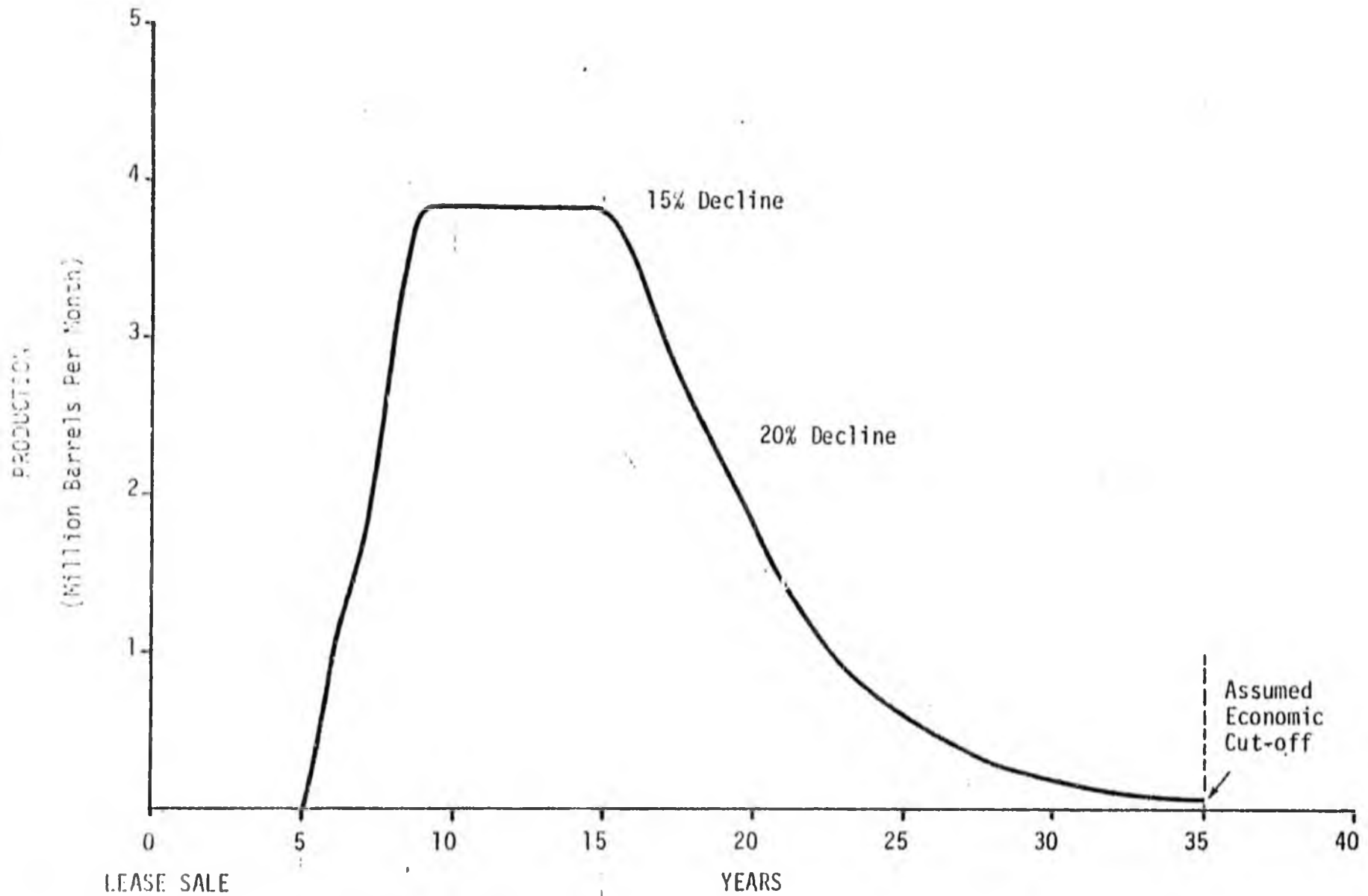
PRCDUCTION HISTORY OF MARS OIL FIELD

(Recoverable Reserves 110± Million Barrels)

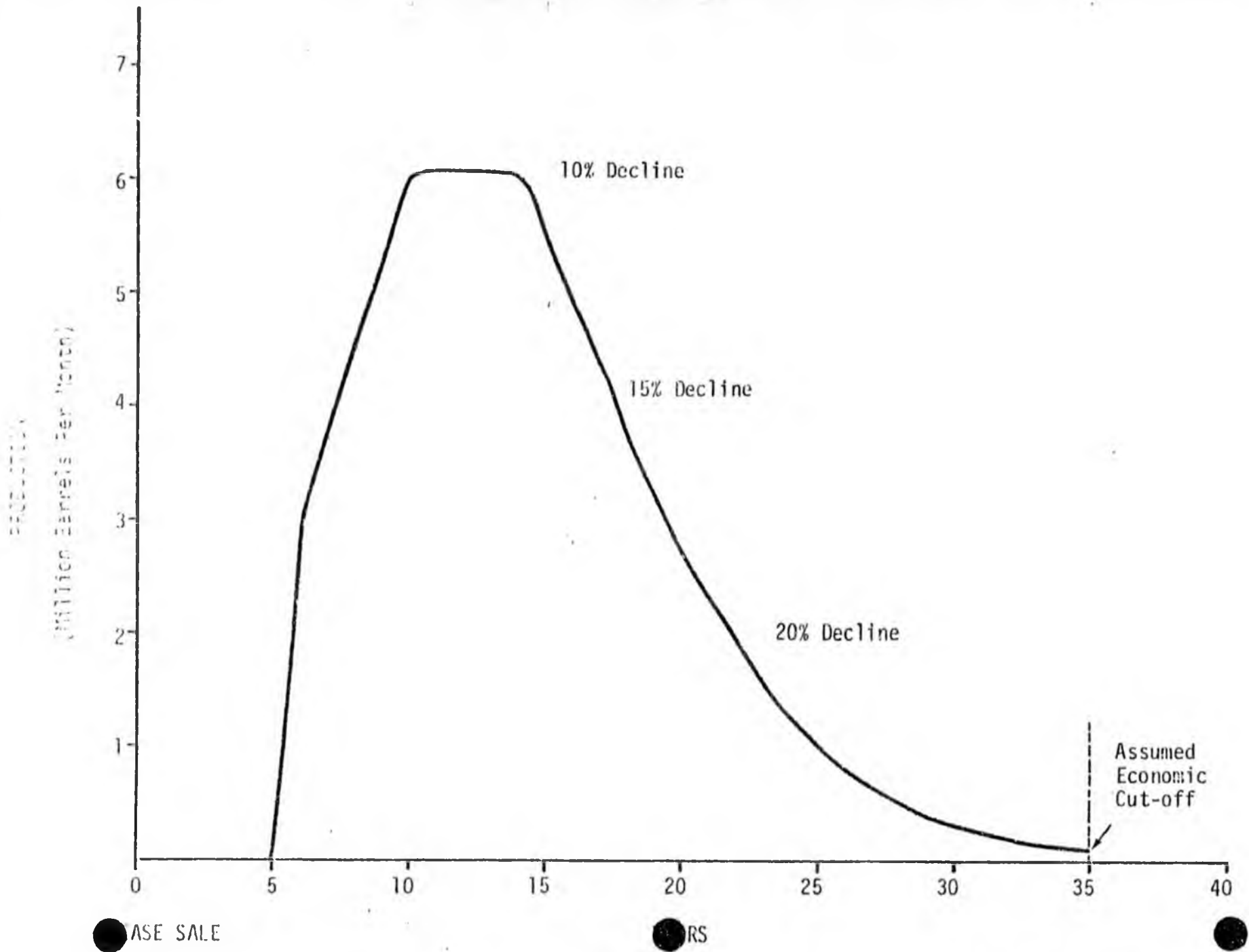


PRODUCTION HISTORY OF VENUS OIL FIELD

(Recoverable Reserves 600± Million Barrels)



PRODUCTION HISTORY OF NEPTUNE OIL FIELD
(Recoverable Reserves 1± Billion Barrels)



● ASE SALE

● RS

Figure K-6

PRODUCTION HISTORY OF JUPITER OIL FIELD

(Recoverable Reserves $5 \pm$ Billion Barrels)

10% Decline

15% Decline

20% Decline

Assumed
Economic
Cut-off

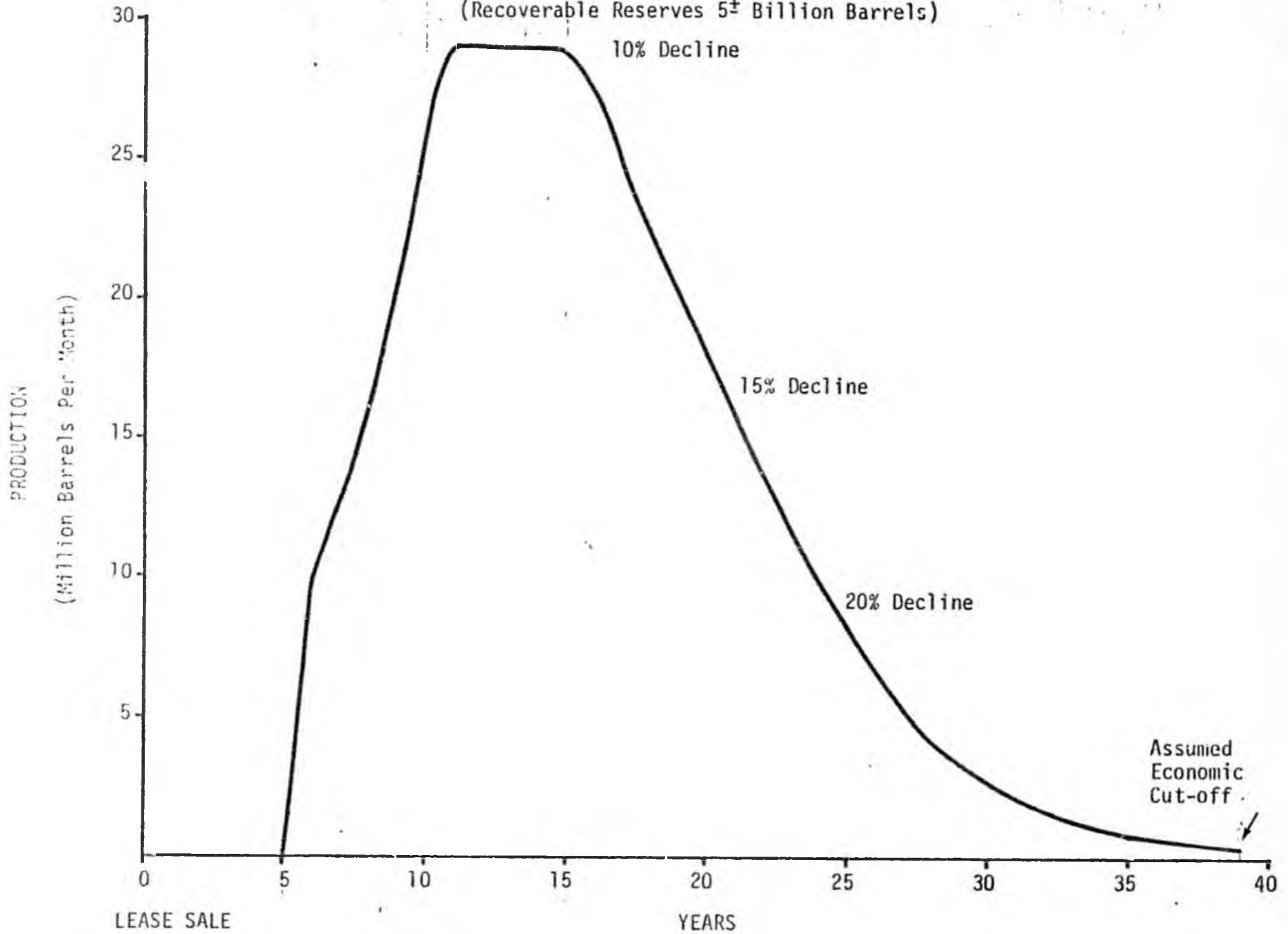
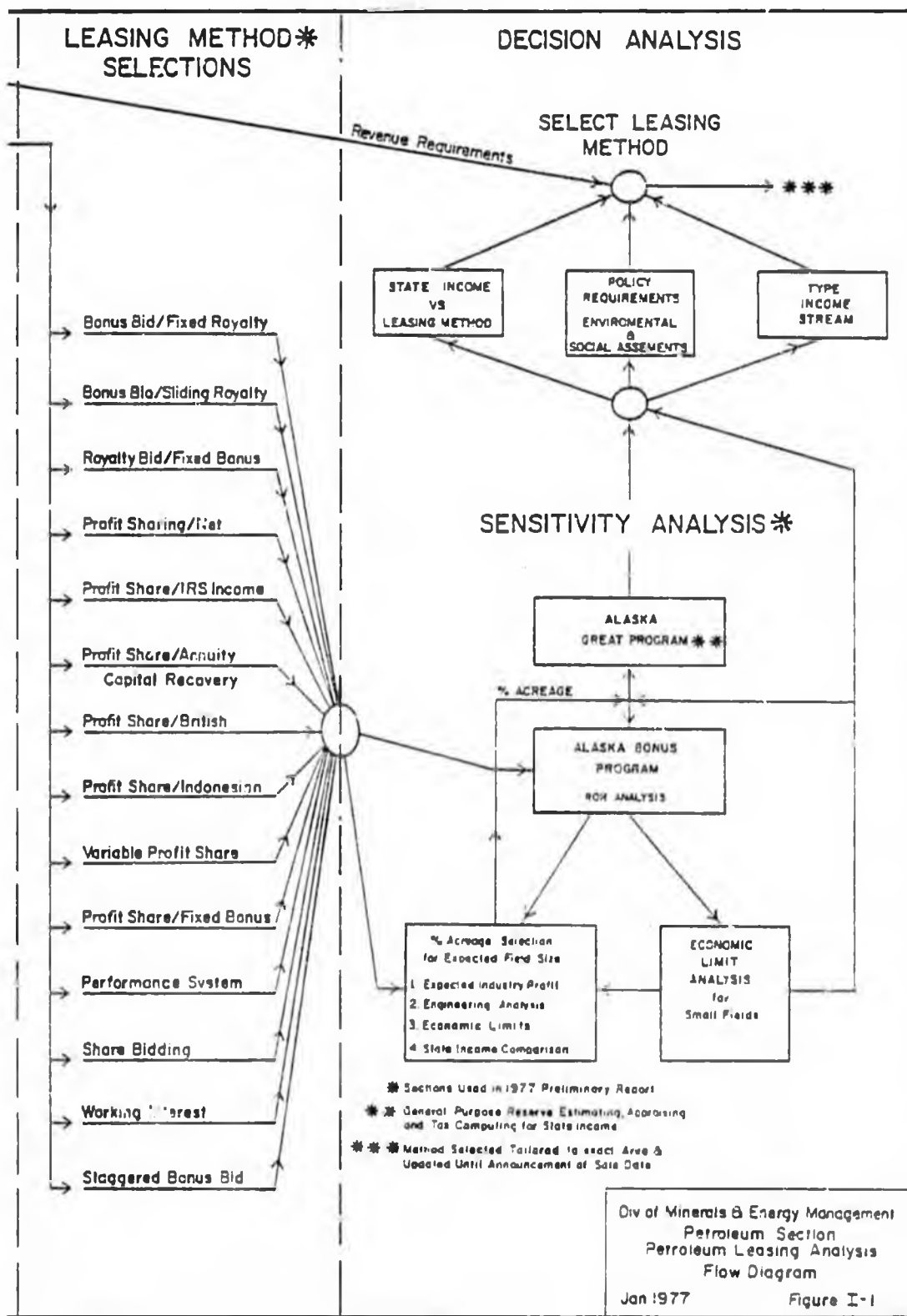


Figure K-7

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.



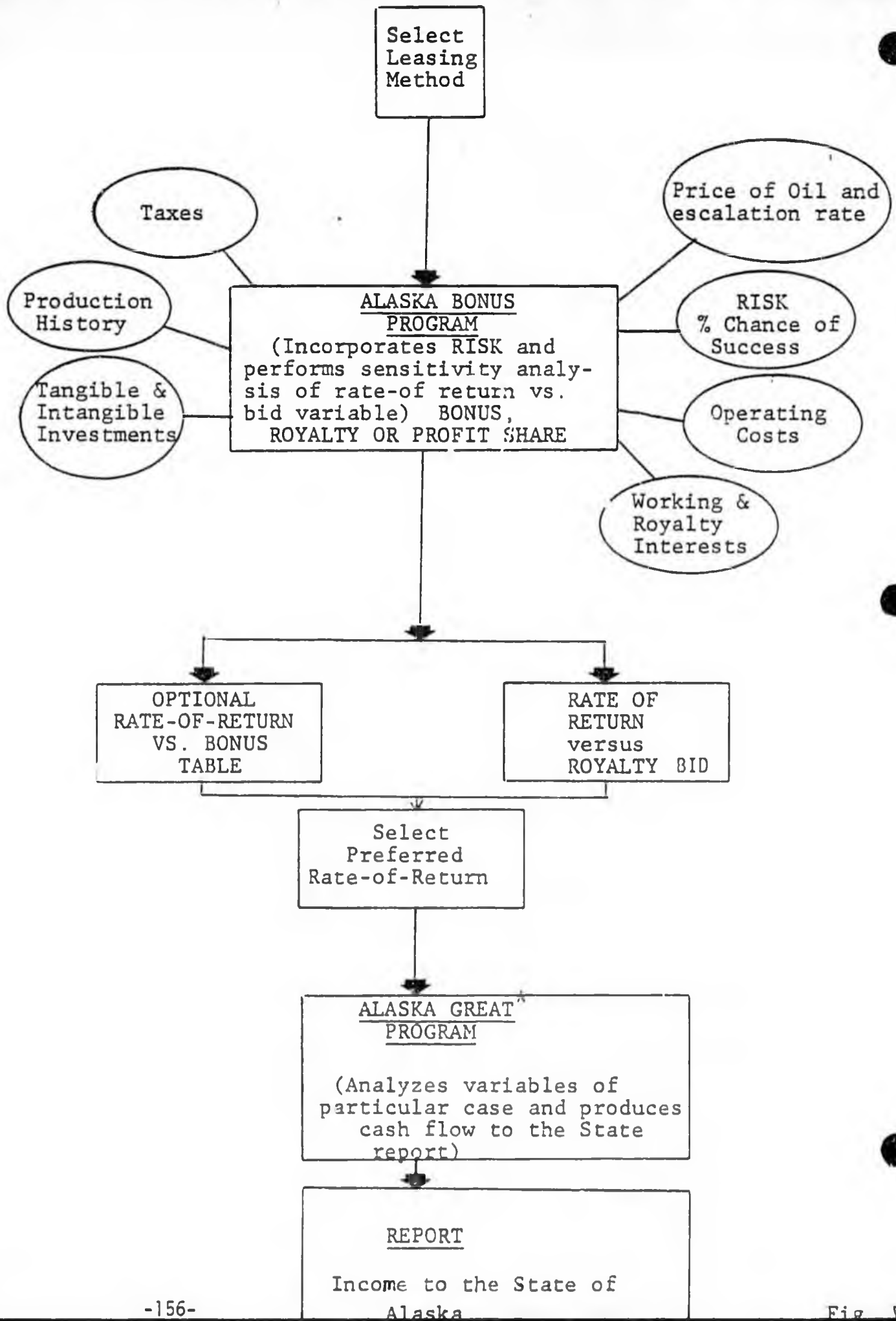
The computer model system employed uses a modern econometric approach designed for an industrial cash flow analysis for a potential venture. Since it is assumed that the State already owns the entire potential field it can approach the problem from a combined average position. In other words, the State 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



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 PCI CHANCE OF SUCCESS

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

PRICE = \$10.06 + 5% TO \$13.00
BONUS BID + 12.5% ROYALTY

INCOME TO THE STATE OF ALASKA

AS OF DATE: 12/31/1976

YEAR	NON-TAX REVENUE MS	GROSS TAX SEVERANCE MS	CONSERVE+ ADVAL TAX MS	STATE INC. TAX MS	TOTAL INC TO STATE MS
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.	3740.	14670.
10	8490.	5325.	539.	5162.	20017.
11	8914.	6117.	539.	5192.	20762.
S TOT	202036.	19904.	1875.	-15242.	208575.
AFTER	98038.	67275.	5556.	57334.	228203.
TOTAL	300074.	87179.	7432	42092.	436777.

PEAK INCOME	SINGLE PERIOD		5 YRS W/BONUS		5 YRS W/O BONUS		LIFE (YEARS)		NET PRESENT VALUE
	2.	4.	2.-	4.	13.-	17.	37.3		

GROSS PRODUCTION

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

DISC%	PI - MS	DISC%	PI - MS
2.00	362149.032	10.00	210138.872
4.00	307033.700	12.00	191110.735
6.00	255511.910	15.00	169530.964
8.00	234402.472	20.00	145315.032

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 STPFAI -33
301 0 0 0 0 0 0 12150000 15795 000

302 18225000 19440000 20655000 21870000 23085000 24300000 25515000 25515000
303 25515000 25515000 25515000 25515000 25515000 25515000 25515000 22680000
304 19845000 16200000 19440000 125 5000 8910000 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 3930000 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 PLATFORM 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 =	29.5 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	70660. M\$, ROR =	15.0 PCT.
WHEN BONUS IS	141336. M\$, ROR =	10.3 PCT.
WHEN BONUS IS	247338. M\$, ROR =	5.7 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 =	1.8 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

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

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 = $(\text{Oil Co. Revenue} - \text{Operating Cost} - \text{Depreciated Tangible Investment} - \text{Amortized Bonus} - \text{C \& A Tax}) \times .094$

Fed Income Tax less Investment Tax Credit = $(\text{Oil Co. Rev} - \text{Operating Cost} - \text{Depreciated tangible Investment} - \text{Amortized Bonus} - \text{C \& A Tax} - \text{State Income Tax}) \times .48$

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.

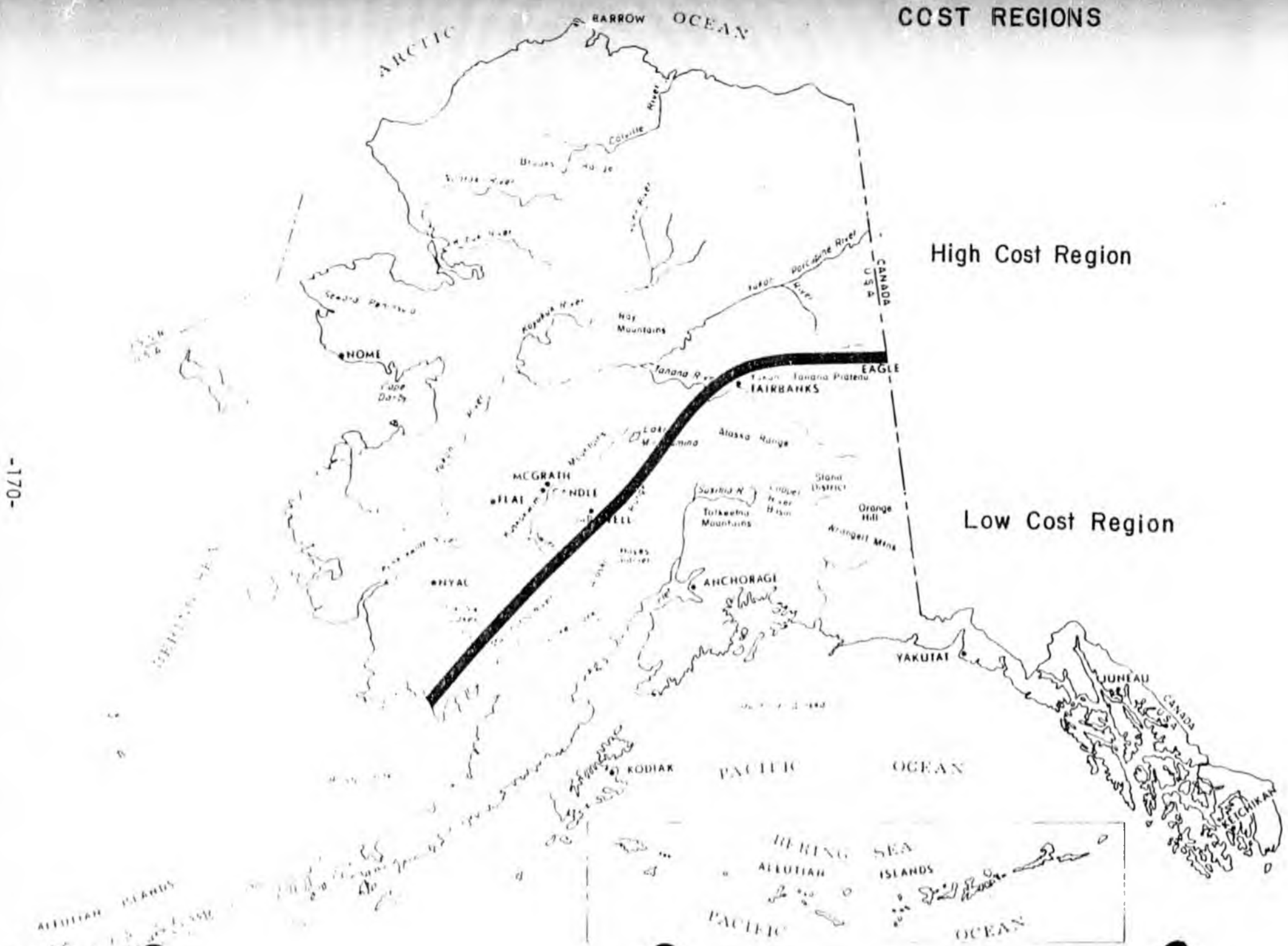
All costs, such as geological and geophysical costs, are considered "sunk" at the time of lease sale, and are given no consideration in investment costs of the project. Sunk costs and the costs of borrowing money are considered, though, when choosing a rate-of-return equitable to the oil company. The 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

-170-



High Cost Region

Low Cost Region

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.

APPENDIX D

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 competition 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 of 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

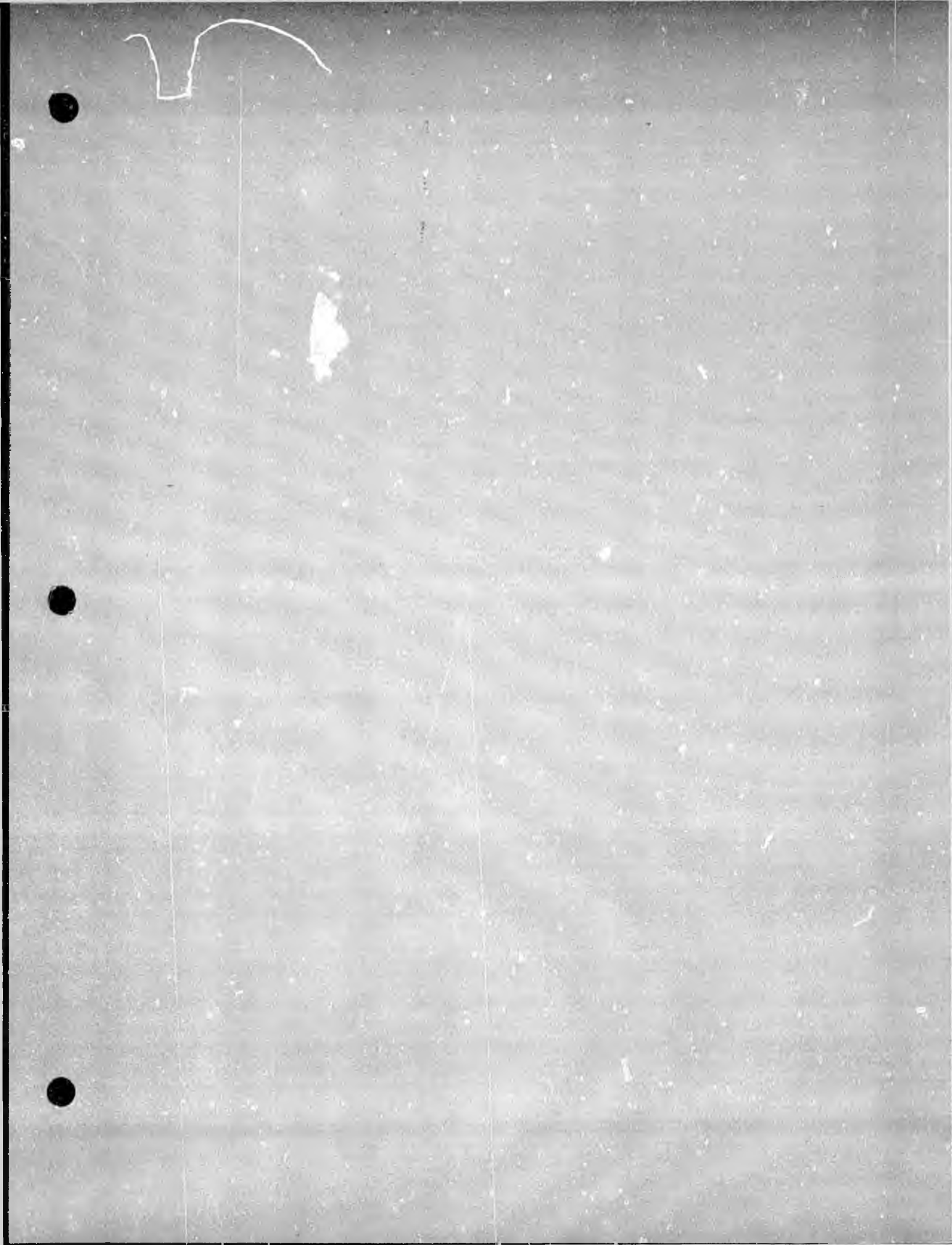
The annuity, with a pre-specified interest rate and length of capital recovery period, is derived from all of the capital investment plus interest to the time production begins. To obtain the profit share base, the amount of the annuity is subtracted from net operating profits. After the investment capital 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.

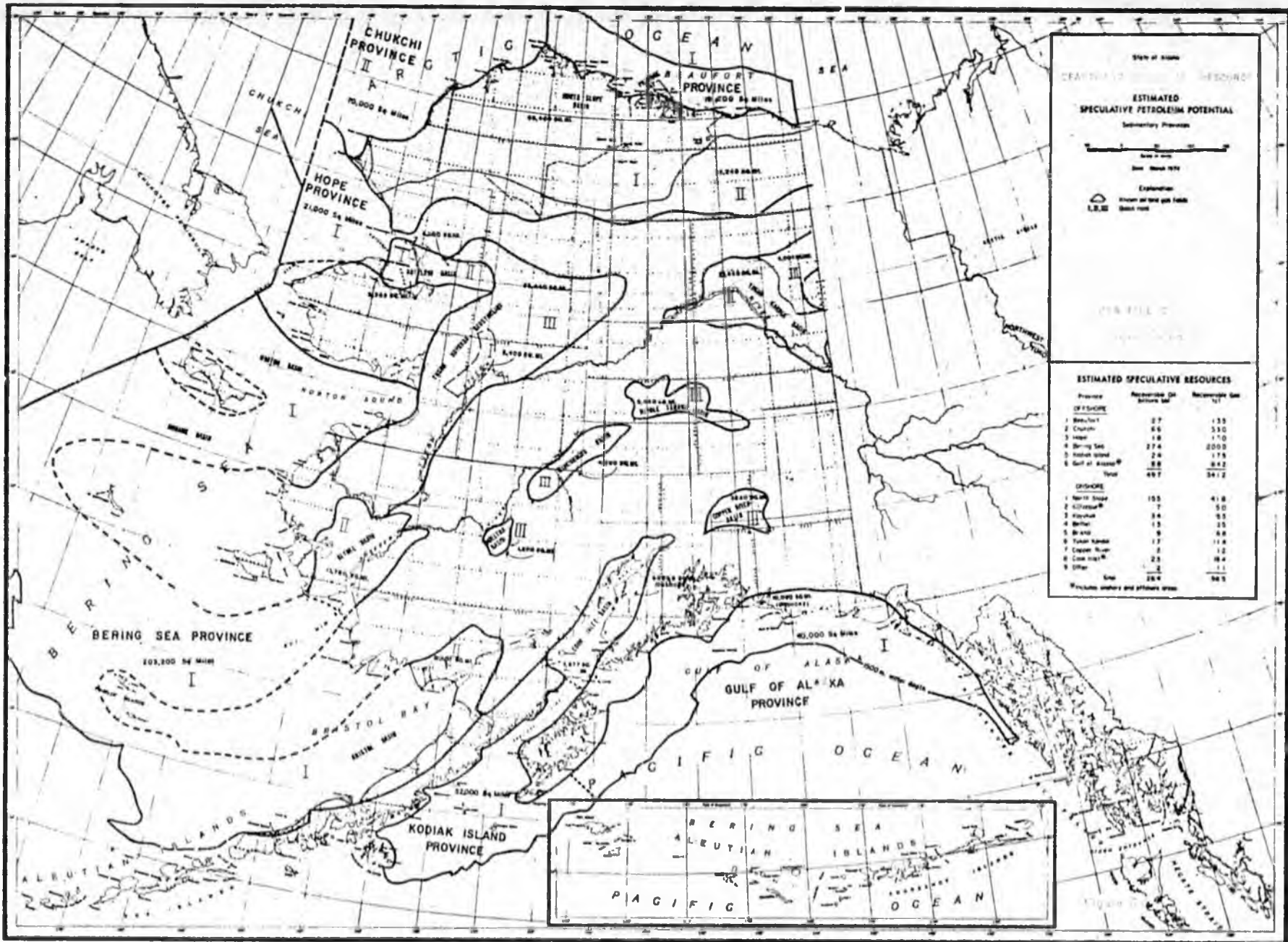
The lessons learned here and the technical abilities developed can be used for determining the cost/benefit of leasing other Energy and Minerals. Coal and Uranium would both fall easily into this type of analysis. Uranium is leased everywhere in the United States but Alaska on a royalty per pound basis. 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.



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 is 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

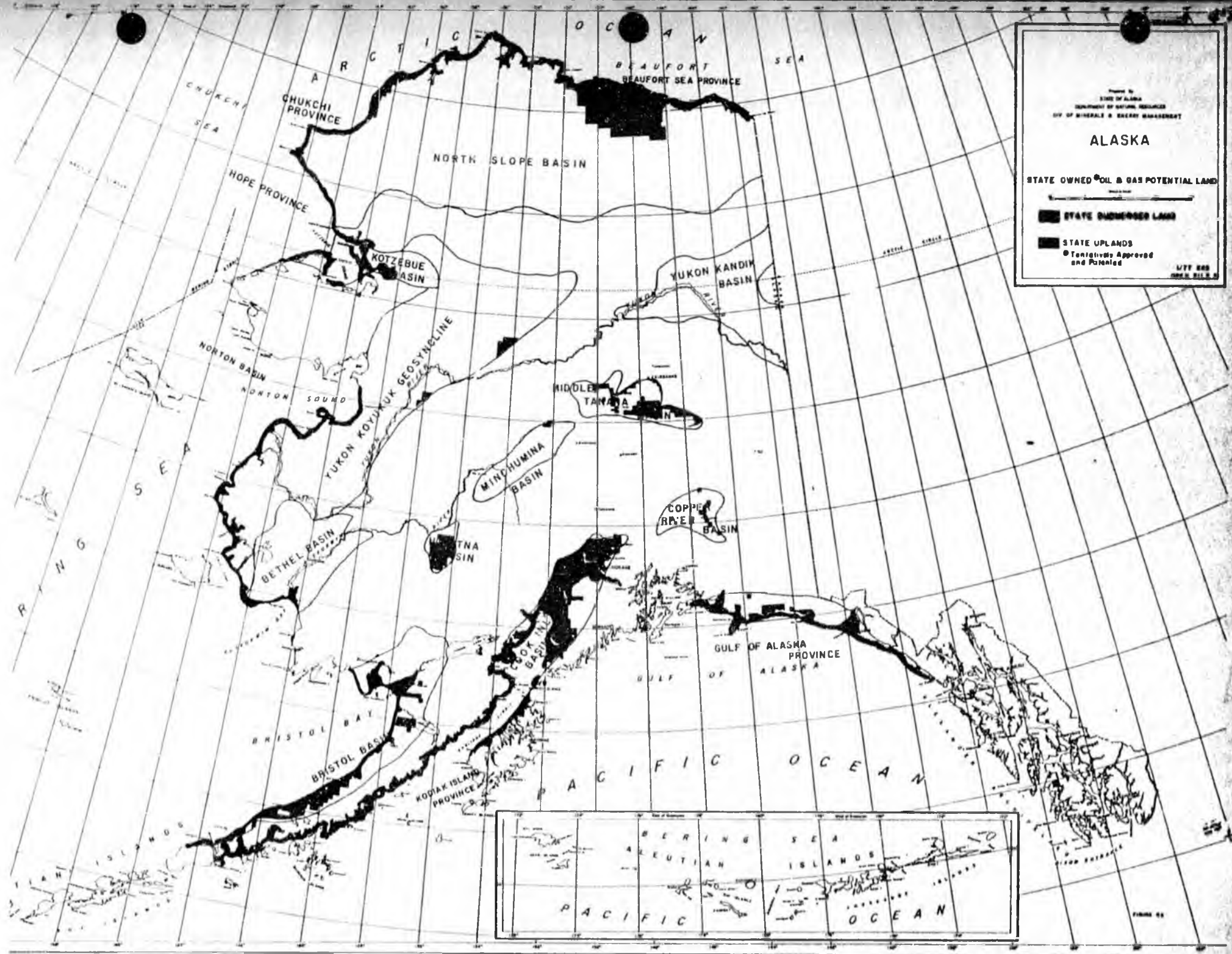
high in petroleum potential, with the exception of those on the North Slope and in Bristol Basin. Generally, interior areas have a greater potential for gas than oil.

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,



Prepared by
 STATE OF ALASKA
 DEPARTMENT OF NATURAL RESOURCES
 DIV. OF MINERALS & ENERGY MANAGEMENT

ALASKA

STATE OWNED OIL & GAS POTENTIAL LAND

STATE SUBMERGED LAND
 STATE UPLANDS
 Territory Approved and Potential

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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		O-G RATIO	AMOUNT OF GAS		PERCENT RELIABILITY
				LOW (MMB)	HIGH (MMB)		LOW (TCF)	HIGH (TCF)	
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

Low Cost, High Price
 Med. Cost, Med. Price
 High Cost, Low Price

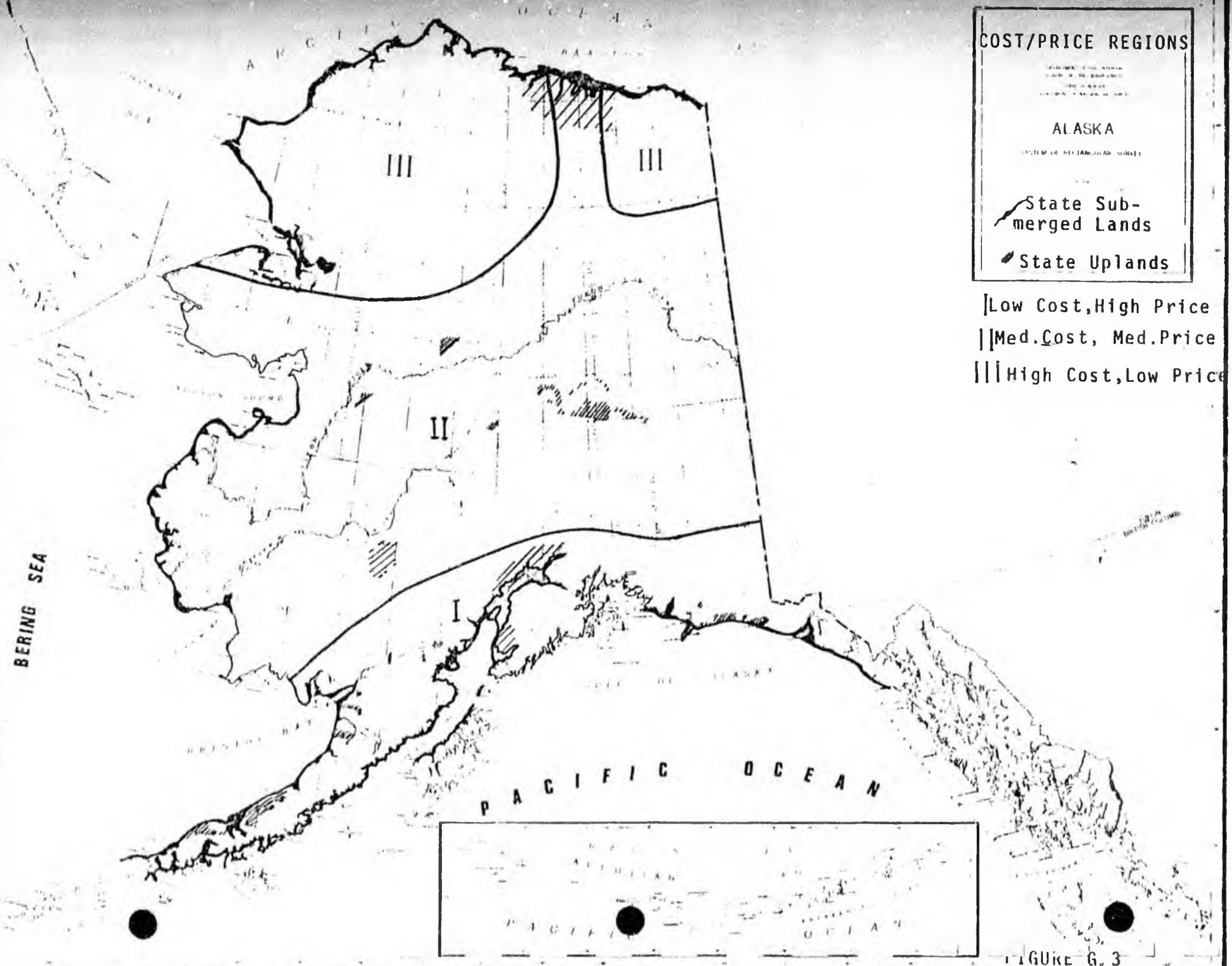


FIGURE G. 3

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

Kodiak Island

Med Risk

Gulf of Alaska
Lower Cook Inlet
Bristol Basin and Alaska
Peninsula

Low Risk

Upper Cook Inlet

II - Middle Alaska Provinces and Basins

Medium Cost and high price parameters

High Risk

Bering Sea (Norton)
Bering Sea (Yukon-Koyukuk)
Yukon-Koyukuk Geosyncline
Bering Sea (Bethel Basin)

Med Risk

Low Risk

III - Northern Provinces and Basins

High cost and high cost parameters

High Risk

Kotzebue Province
Hope Province
Chukchi Province
Middle Tanana
Minchumina
Copper River
Hollitna

Med Risk

North Slope
Beaufort Sea Province

Low Risk

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 priorities 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

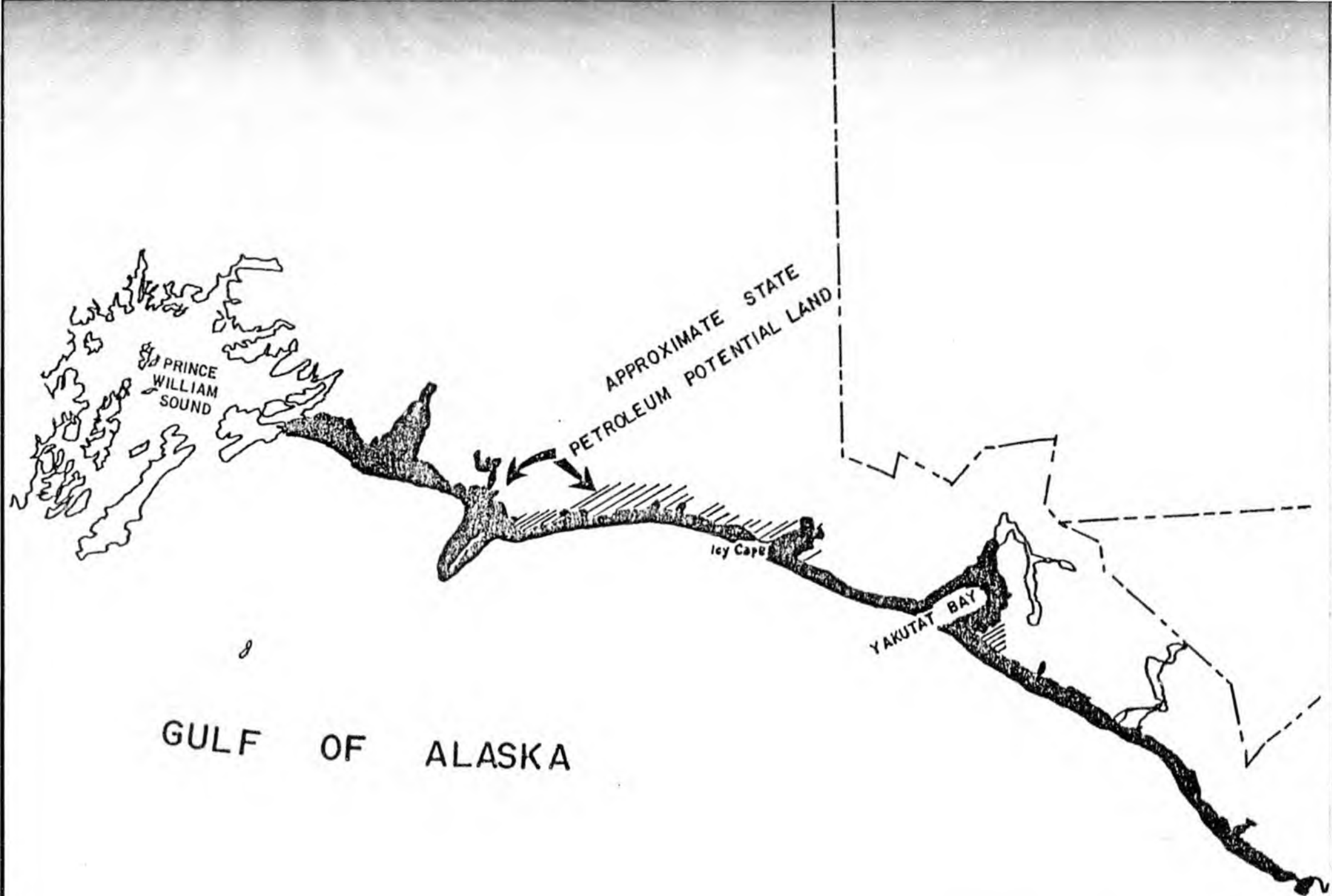


FIGURE G-4

recoverable oil and gas resources on remaining state submerged lands.

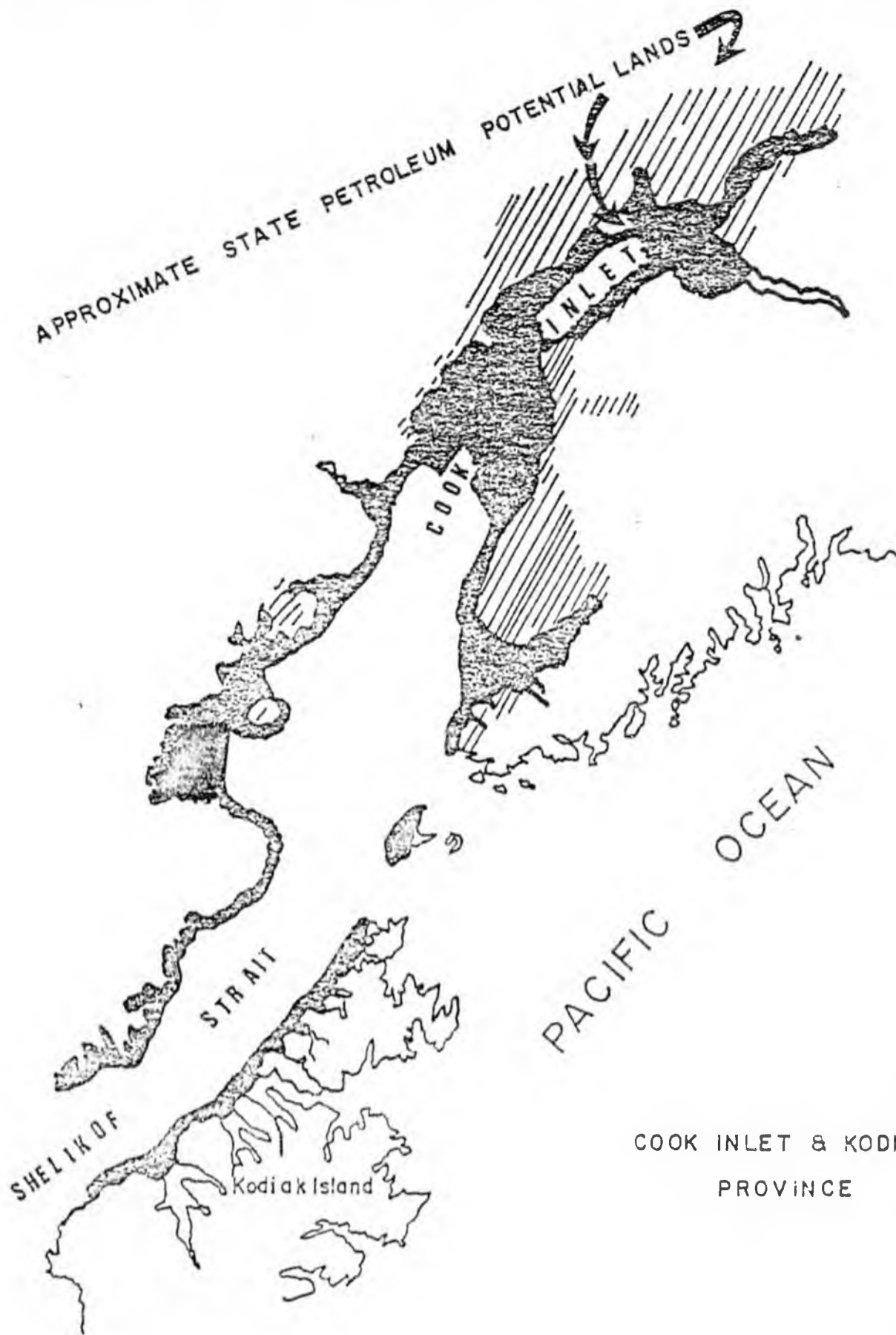
Onshore areas of the Upper Cook Inlet contain a large amount of both patented and tentatively approved state lands. These lands were believed to be of high petroleum potential, but exploration in the northern onshore areas has not been as successful as anticipated. Therefore, the estimation in this area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



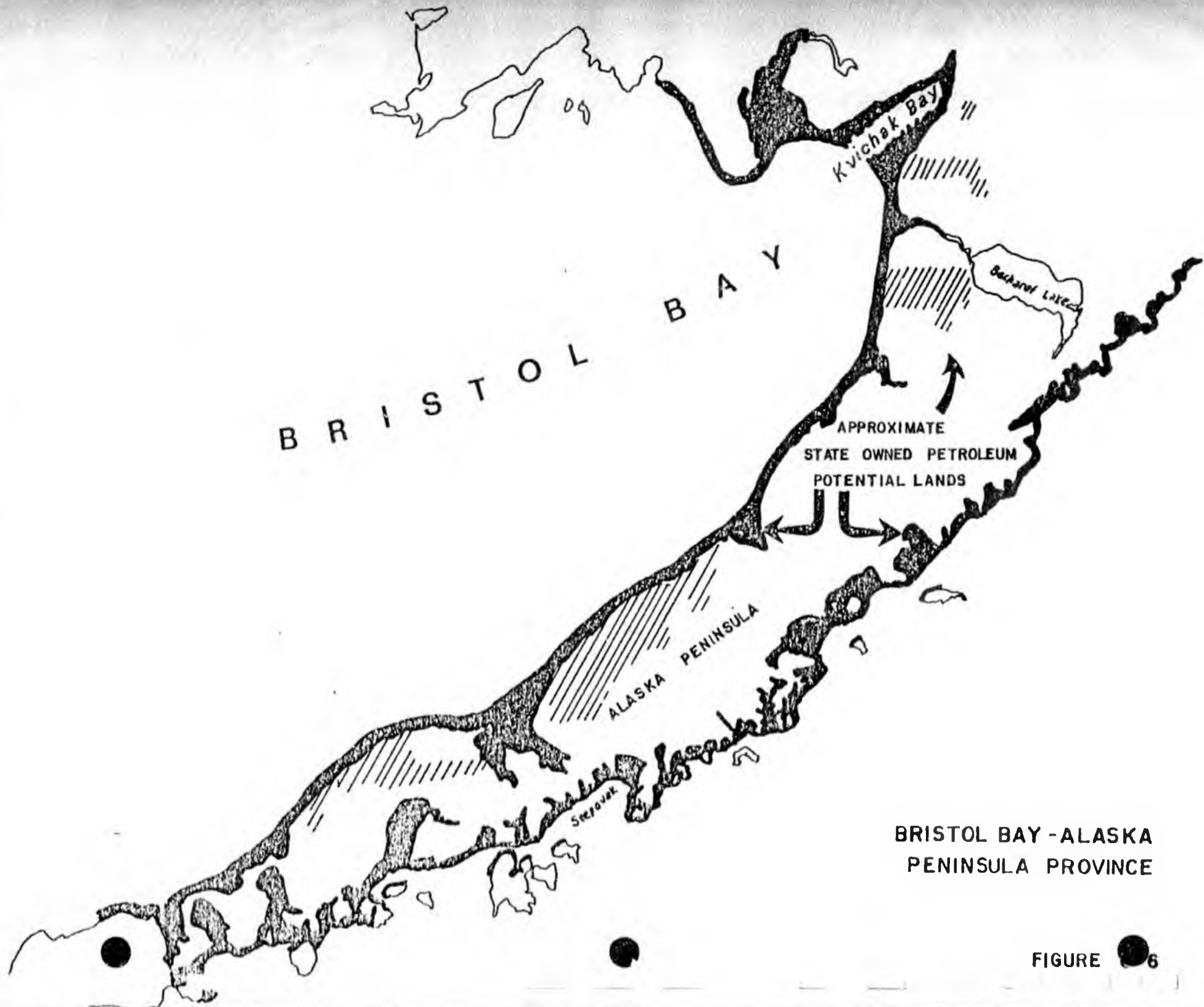
COOK INLET & KODIAK ISLAND
PROVINCE

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

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



NORTON SOUND

APPROXIMATE STATE PETROLEUM
POTENTIAL LANDS

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

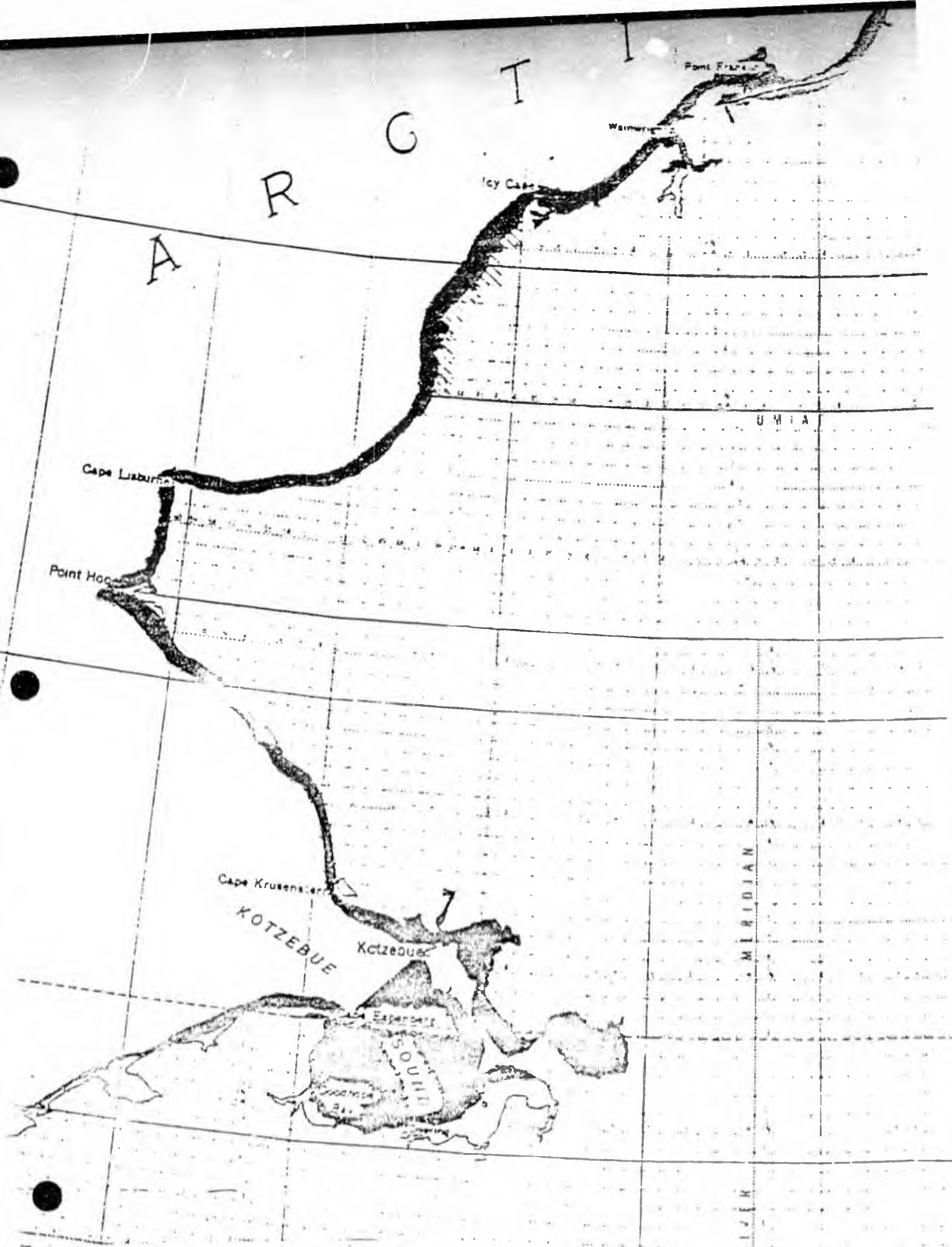
Figure G-8

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

6458

307-

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:

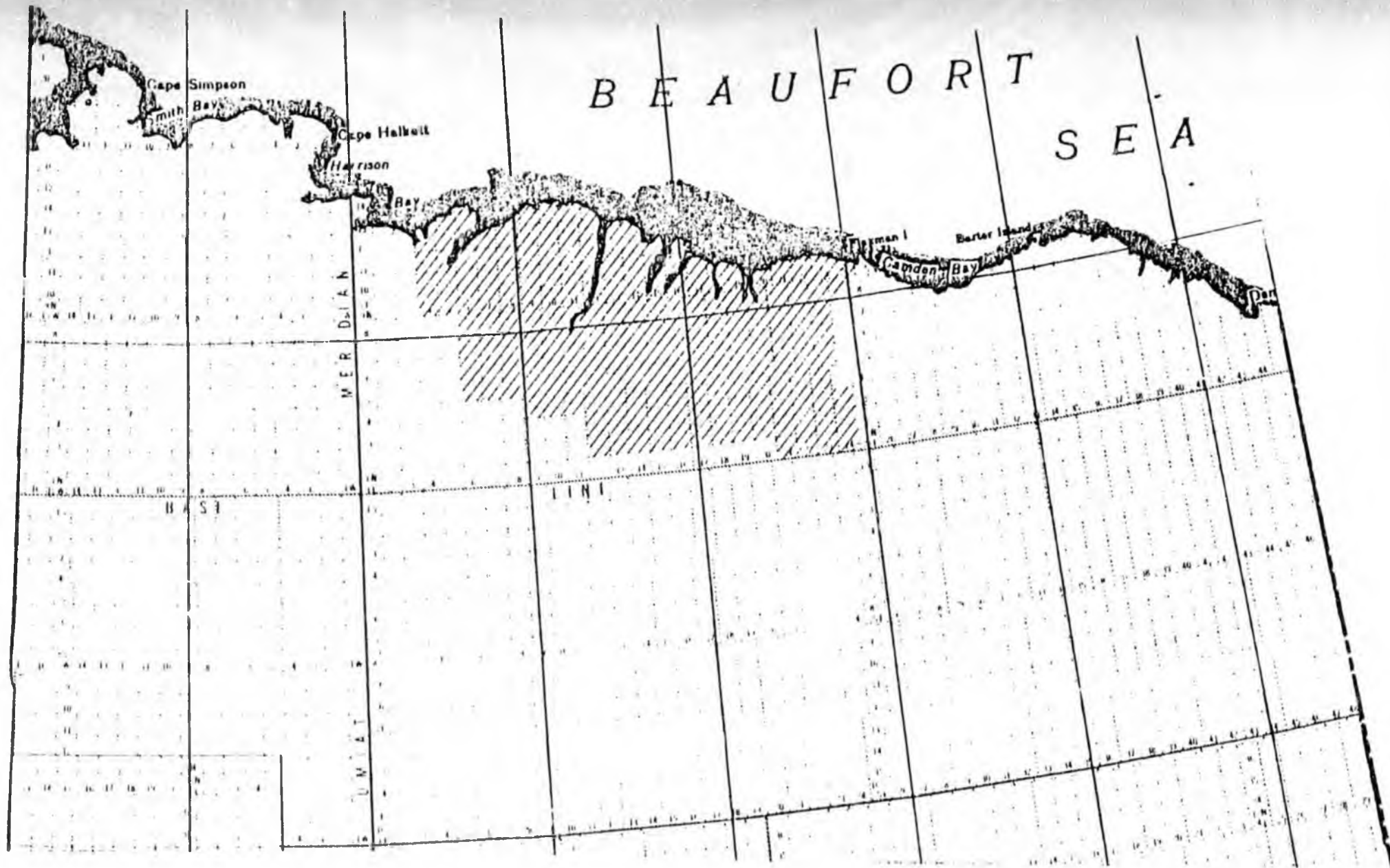
There are approximately 6,624 square miles of state lands contained within the North Slope uplands. This total is about ten percent of the entire number of potential lands on the Slope. Taking ten percent of the potential recoverable reserve figure in Open File 50, there are about 1,200 MM3 of recoverable 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.



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 appraisers	40,000
1 petroleum economist	30,000
3 research analysts	45,000
4 contract petroleum engineers	<u>100,000</u>
Total salaries	<u>\$240,000</u>

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 "proprietary" 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 nominal 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

of Energy and Management's 1977 fiscal budget calls for \$40,000 for acquisition of geophysical information, and \$110,000 for Fiscal '78.

In summary, the present bonus bid leasing system used by Alaska takes the fewest state personnel to administer. It is the easiest to administer because most all evaluative decisions are left to the operators. As one moves away from this system, administrative costs will likely rise.

They will rise significantly as the need for additional petroleum appraisers and reservoir engineers grows, and will go even higher if the State asks to participate in the knowledge of costs and profits of the oil and gas operators. (The ultimate would appear to be the need for information to protect an equity interest.)

Auditors, similar but, perhaps, even more expert than income tax inspectors, would be necessary in a true "net profits" system. The incentives for the operator are all toward increasing the costs allowable. The level of monitoring depends to some extent on the level of confidence the State and operators have in each other.

Lastly, the amount of physical information required by the State before and after a discovery of petroleum needs to be addressed. It is costly and it is available. How it is used and for what purpose is critical to the health of the State's role in exploration.

And finally, no system will work well unless there are qualified people making the decisions. The administrator, located between the elected official and the public, traditionally has tended to lay back. Judgments made in the oil and gas exploration business inevitably results in being proved "right" or "wrong". There's either oil and/or gas there in paying quantities, or there is not.

This is not the traditional role of government administrators, but they have been and can be attracted to government service.

SEISMIC DATA ACQUISITION AND
COST MODELING

for a

PETROLEUM RESOURCE ANALYSIS

By

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SEISMIC DATA ACQUISITION AND COST MODELING
FOR A PETROLEUM RESOURCE ANALYSIS

INTRODUCTION

In order to have controlled development of its petroleum reserves, the State of Alaska must be able to determine the location and the potential quantity of this valuable resource. Exploration seismology is the primary method available to achieve this objective. The following text discusses the various methods by which the State can acquire seismic exploration data and, through a model study, the approximate cost of data acquisition.

CONCLUSIONS

The procuring and interpretation of geophysical data in order to determine Alaska's petroleum reserves is an integral part of having an intelligently managed energy evaluation and development plan. The cost of acquiring the data could vary from negligible, if picked up by regulation, to considerable, if the State must contract proprietary data. Currently, the least cost route to obtain reconnaissance data would be through obtaining USGS Open File Reports, purchasing old data and being an original participant in group industry seismic programs. Structural detail information could possibly come from group shoots but would probably have to be gathered as contract proprietary work.

In order to determine some approximate costs for geophysical data that would be needed to evaluate an area considered for leasing 100 by 15 miles containing at least one major structure, an exploration model was developed. Results

indicate that costs can range from around 70 thousand dollars to 2.5 million dollars depending on a variety of factors.

METHODS OF ACQUIRING SEISMIC DATA

There are several routes the State can take to acquire geophysical and specifically seismic data. Given an area of interest the State can (1) obtain United States Geological Survey open file data, (2) participate as a partner in a group industry seismic program, or (3) contract original work. A fourth method would be to require copies of seismic data as a stipulation of exploration permits on state lands. This fourth method would be following the precedent set by the Federal government and its implementation would probably be similar to the Federal method. For each of these data acquisition methods the cost of acquisition, location, grid spacing, data quality and time of acquisition must be considered. Each method now will be discussed in detail.

Federal and Public Data. The primary concerns of the USGS in obtaining seismic data in Federal waters are to evaluate the energy potential of the area, to determine the potential environmental hazards, and to perform basic geological research. Many of its older surveys extend into state waters and this data can be obtained for the cost of reproduction of its Open File Reports. Through the State's personnel participation and sharing of expenses with the USGS, there is the possibility of the USGS extending its Federal Water Surveys into Alaskan State waters. Such a cooperative effort in the acquisition and interpretation of the USGS Exploration data would be to the advantage of both parties. The data's location grid spacing, and time of acquisition would not be completely controllable, but it would provide a low cost addition to the State's data base. Data is also available

from public sources such as universities and other Federal agencies.

Industry Group and Speculative Seismic Surveys. The least costly method of obtaining technologically up-to-date seismic data in current areas of exploration interest is through the State's participation in the petroleum industries group seismic survey. An original participant in a group seismic survey has the advantage of influencing the decision on line location and grid spacing. To buy into a group after the original participant closing date, generally costs up to twice the original amount thereby making it advisable to be an original participant. Also, the late participant cannot influence the group's decisions. Old group survey and contractor speculative survey data is available to the State at varying costs depending upon location and age. This old data would give the State an original data base to expand upon. Group surveys are the least expensive way to obtain good quality reconnaissance data in a current area of interest.

Original Contract Data. The greatest control over all but the cost factor is obtained by the contracting of original seismic programs. The line location, grid spacing, and acquisition time would all be dictated by the State. This kind of control is necessary when one desires to perform a detailed structural investigation. Although original contract work is very expensive, relative to the other methods, the cost can be held down by sufficient planning and foresight. By keeping informed of crew location and contracting for small amounts of structural detail data the major expense of crew mobilization can be avoided. The amount of detail data contracted would depend upon whether the State had acquired copies of industry data, permit stipulations and other factors.

Regulative Requirements. By requiring that a copy of all geophysical data taken in the State be turned over to the State as part of leasing state land or obtaining a geophysical operations permit, Alaska would be guaranteed obtaining both reconnaissance and structural detail data. This data, of course, would be in current areas of interest and may not be timely with respect to long range planning. But it would allow detailed structural analyses after a lease sale. The cost of acquisition would be, at most, the cost of reproduction. For structures that lie wholly in state waters a complete structural evaluation would be possible. For structures which lie partially in Federal waters, a total evaluation would not be possible if the State only receives the data covering the position of the structure in state waters. Planning for future lease sales should include a seismic analysis to identify structural areas that lie both on State and other lands. Cooperative leasing ventures can then avoid drainage of State resources.

EXPLORATION COST PREDICTION

The actual cost of obtaining seismic data varies considerably and depends not only on the source of the data, as discussed previously, but also on the area of the State being evaluated. For the purpose of this cost analysis, the State has been divided into three cost of exploration areas. The areas are the Arctic Submerged Lands, the other submerged lands, and the State uplands. Assuming good data quality, the probability of finding a particular size field in the above mentioned areas is strictly dependent upon the seismic line grid spacing. (See Appendix A-A.)

Probabilities of Finding a Structure. Table 1 shows the probabilities of finding a structure of a specific size given a particular size seismic line

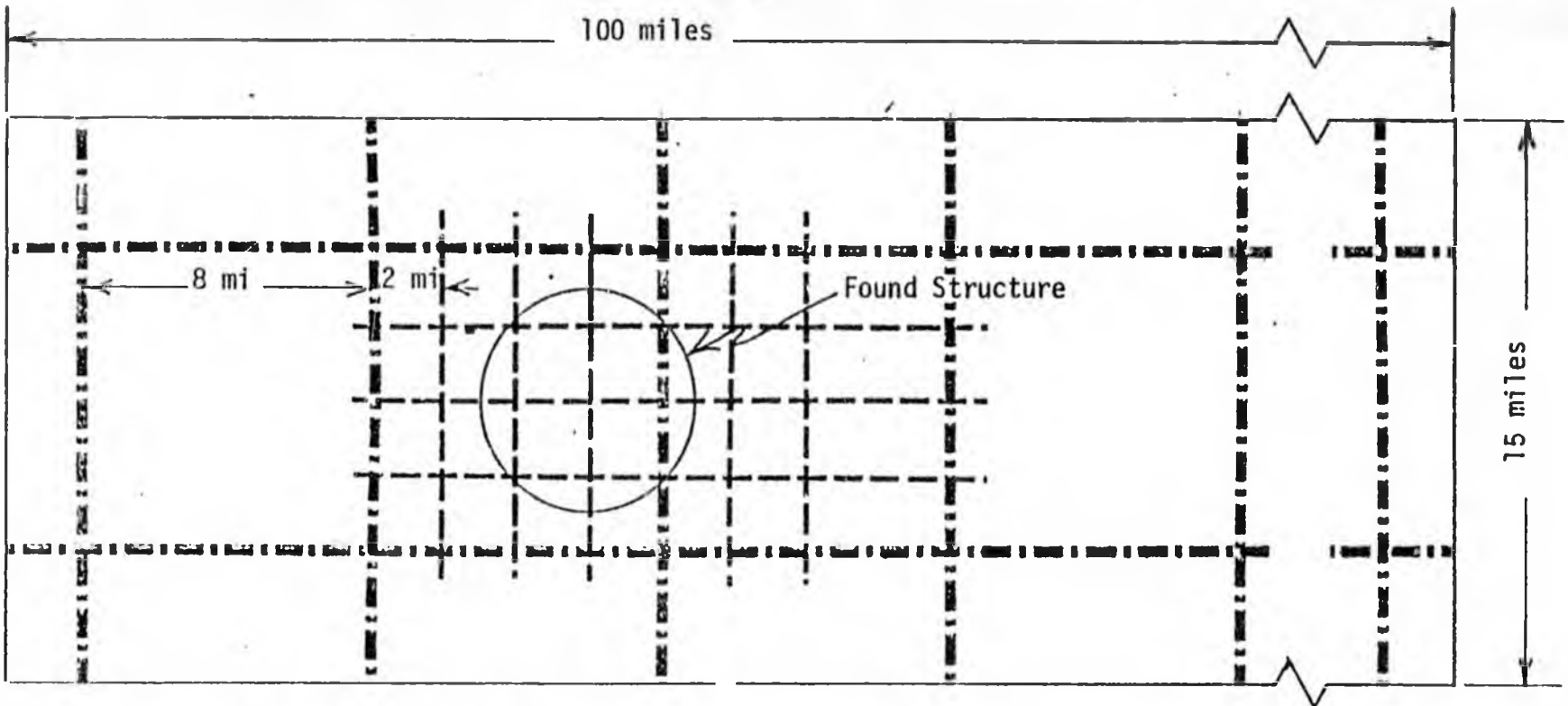
grid spacing. Four oil fields were chosen to represent a range of structures over the State's current structure size range of interest. The MacArthur River field was chosen as the target size field for this cost study. It is a 500,000 BBL field with an approximate structural area of 28 square miles, which gives a structural equivalent diameter of 5.9 miles. Table 1 presents the various probabilities of finding a structure of this size given a seismic grid spacing of twenty, ten, eight, and five miles. They are respectively 0.35, 0.63, 0.74 and 0.96. Also, if the grid spacing is 8 miles, the probability of finding a Prudhoe Bay size field is 1.0 (100%), of finding a MacArthur size field is 0.74, a Granite Point size field 0.52 and a Trading Bay size field 0.41.

Model Lease Area and Costs. Figure 1 displays a portion of a fifteen by one hundred mile area chosen as the model reconnaissance area. An eight mile reconnaissance seismic grid and a two mile structural detail seismic grid are displayed in the figure. These grid spacings were used in the cost determinations. Three hundred and ninety-five (395) miles of reconnaissance data and one hundred and three (103) miles of detail data were needed to find and adequately describe the MacArthur River field size structure.

The actual costs to explore the size area defined by the model in each of the cost regions is given in Table 2. The cost per mile of the seismic data, the cost to acquire 395 miles of reconnaissance data, and the cost to acquire 103 miles of detail seismic work are arranged by cost region and data source. The total cost is the sum of the original group shoot reconnaissance costs and the original contract detail data costs. The cost figures for the original contract work are only close approximations from a telephone survey and are not actual bid figures. The cost figures can be considered accurate within 15%.

If more than one structure is found in the model area then the cost of the reconnaissance data is distributed to each structure and thereby reduces the structure finding cost.

For the model, the lease area is considered to be the 154 square miles that were detailed by the contracted proprietary data.



- Model Area Outline
- · · · · Reconnaissance Seismic Lines (395 miles)
- Detail Seismic Lines (103 miles)

MODEL FOR FINDING STRUCTURE

Figure 1

		FIELD			
		Prudhoe Bay	McArthur River	Granite Point	Trading Bay
Recoverable Reserves		8.0 mm	500 mm	110 mm	75 mm
Structure Area		500 mi ²	28 mi ²	11 mi ²	6 mi ²
Equivalent Diameter		25 mi	5.9 mi	3.7 mi	2.8 mi
Probability of Finding Structure with Seismic Grid Spacing = L	L = 20 mi	0.97	0.35	0.24	0.19
	L = 10 mi	1.0	0.63	0.42	0.34
	L = 8 mi	1.0	0.74	0.52	0.41
	L = 5 mi	1.0	0.96	0.74	0.61

TABLE OF PROBABILITIES
SEISMIC GRID SPACING
VS
STRUCTURE SIZE

TABLE 1

Cost Region			
Data Source	Arctic Submerged Lands	Other Submerged Lands	Coastal Uplands
Contracted State Proprietary	\$2,200.00/Mile* Recon. \$869,000.00* Detail \$226,600.00*	\$500.00/Mile Recon. \$197,500.00 Detail \$51,000.00	\$5,000/mile Recon. \$1,975,000.00 Detail \$515,000.00
Original Group Shoot	\$400.00/Mile Recon. \$158,000.00 Detail \$41,200.00	\$50.00/Mile Recon. \$19,750.00 Detail \$5,150.00	\$400/Mile Recon. \$158,000 Detail \$41,200.00
Late Participant Group Shoot	\$800/Mile Recon. \$316,000.00 Detail \$82,400.00	\$60.00/Mile Recon. \$23,700.00 Detail \$6,180.00	\$50.00/Mile Recon. (Old data) \$19,750.00 Detail No Data
Total Cost Group Recon Contract Detail	\$384,600.00*	\$70,750.00	\$534,750.00

Data: 8 mile reconnaissance seismic grid, 2 mile detail seismic grid, recon. line mile = 395, detail line mile = 103, model field size = 500 MM.BBLs, (McArthur River Field), resultant lease area 154 square miles.

*If crew is not in area there is a mobilization cost of, from \$100,000. to \$250,000.00, from Kenai to North Slope.

Interior Alaska seismic costs could be very high, but the State owns very little oil potential land in the interior at this time. The shallow Holitna Basin could possible be evaluated using a combination of cheaper methods, such as gravity and shallow refraction seismic.

TABLE OF SEISMIC EXPLORATION COSTS, BY COST REGION

TABLE 2

Seismic Data Grid Size Determination

When performing a seismic reconnaissance survey, the grid spacing of the seismic lines is a major factor in determining the cost of the survey. The two factors which control the grid spacing are the size of the structures being sought and the probability of finding a structure of a particular size. In a specific geologic province knowledge of structural character and orientation will influence the type and orientation of the grid size used.

The development that follows is a generalized probabilistic approach to the problem of what size grid spacing to use when a structure of a particular size is being sought. The basic geometric assumptions are that the structure is circular with a diameter of "D" and the grid is equilateral with a side length of L. The structure is considered found if one of the sides of the square grid passes through the structure a distance less than or equal to "S" from the center of the structure, as displayed in Figure 1a. For the purposes of this discussion "S" is chosen to be one third of "D."

$$S = 1/3 D$$

Figure 1b displays a portion of a seismic grid. The center of a structure of diameter "D" has an equal probability of being at any point within the representative grid. The crosshatched region of width "S" within the grid is the region where the center of the structure must lie in order to be considered found. If the center of the structure lies in the central non-crosshatched region it is considered missed. The ratio of the Find Area to the Total Area enclosed by the grid represents the probability

of finding the structure "P_f." So that:

$$P_f = \frac{\text{Find Area}}{\text{Total Area}}$$

$$P_f = L^2 - (L - 2S)^2$$

$$P_f = 1 - \left(1 - 2 \frac{S}{L}\right)^2$$

Now, since

$$S = \frac{1}{3} D,$$

then

$$P_f = 1 - \left(1 - \frac{2}{3} \frac{D}{L}\right)^2.$$

The ratio D:L is the ratio of the structural diameter to the seismic grid spacing. The above final equation is plotted as Figure 2. Displayed on Figure 2 is the following example. Given a grid spacing of 5 miles when looking for a structure of 3 miles in diameter, the ratio would be 3/5 or 0.6. The probability of finding a structure of that size with the given grid spacing would be about 0.64. In a similar manner, given the grid is 5 miles and the structural diameter is 5 miles the probability of recognizing that a structure has been found is 0.89.

Figure 2 can therefore be used to determine the probabilities of finding structures of various sizes given a particular size seismic grid spacing. Conversely, it can also provide the answer for the size grid spacing to use to find a particular size structure within a particular probability.

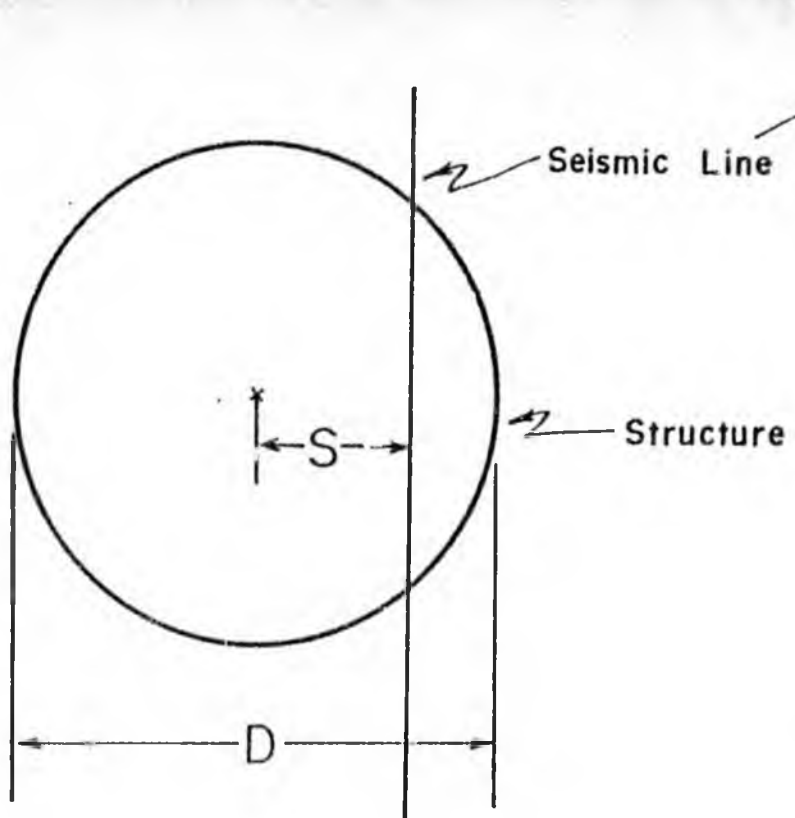


Figure 1a

Structure Find Criteria

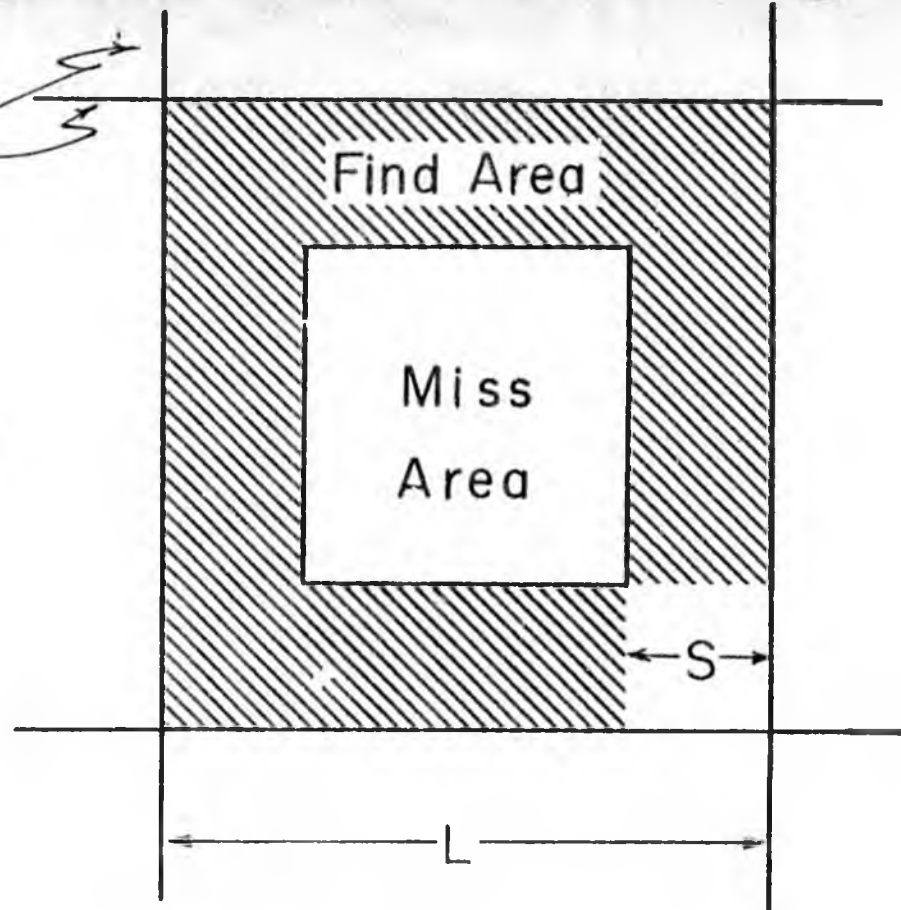
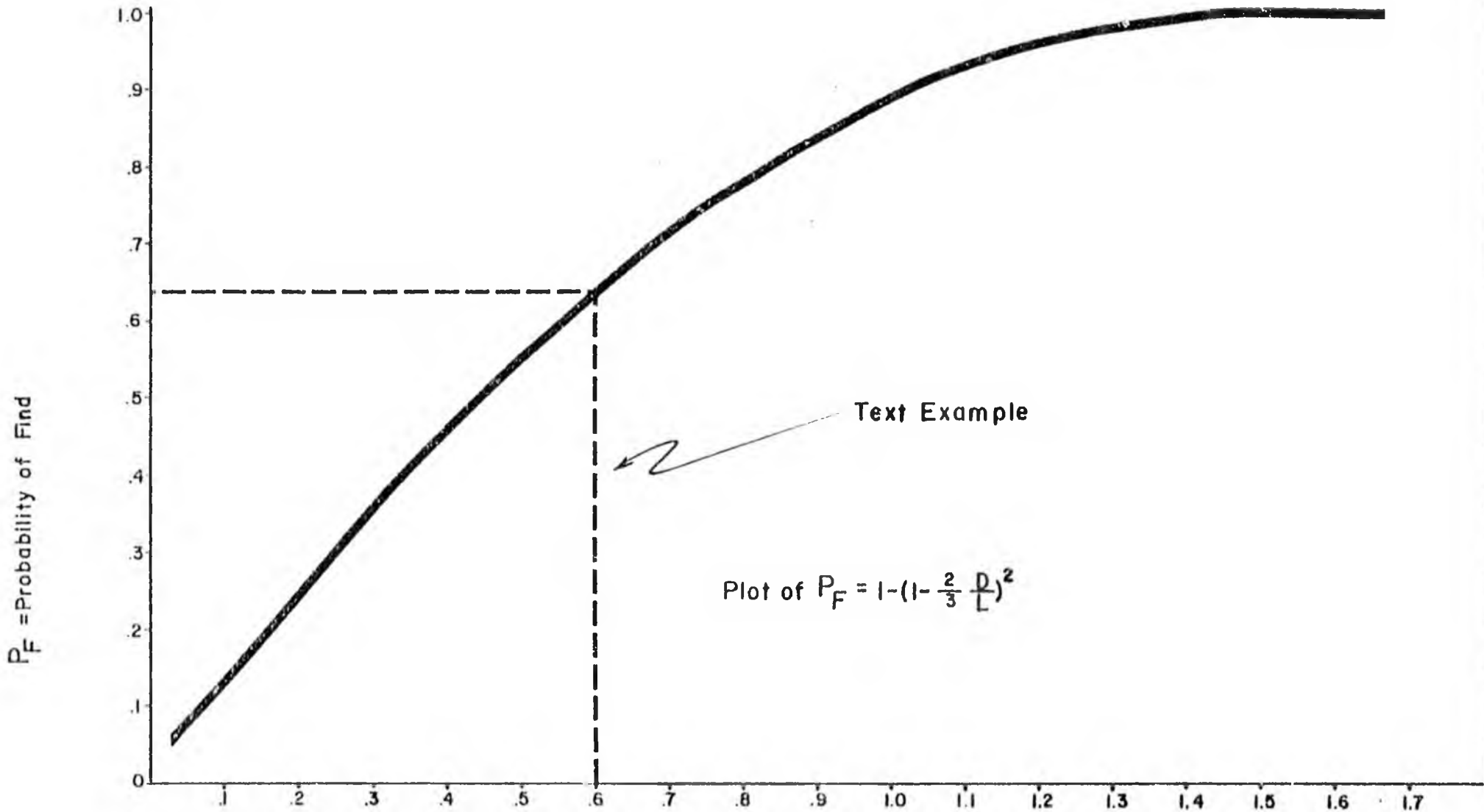


Figure 1b

Seismic Grid, Structure
Find and Miss Areas



$$\frac{D}{L} = \frac{\text{(Structural Equivalent Diameter)}}{\text{Seismic Grid Spacing}}$$

Figure 2

SECTION VI

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GLOSSARY

ADVALOREM TAX - the tax derived from the value of oil and gas property.

ALASKA GREAT COMPUTER PROGRAM - projects the cash flow to the State of Alaska resulting from leasing of natural resources, includes bonus, royalty, severance tax, conservation tax, advalorem tax and income tax used to compare various leasing strategies. A commercial program of GARRETT Computer Corporation adapted for the Division of Minerals and Energy Management.

ANALYSIS - an examination in detail, so as to determine the nature or tendencies for the purpose of understanding and/or comparison of parallel systems.

BONUS BID - the amount of money a bidder is willing to pay for the privilege of exploring for petroleum and for the privilege of developing and producing the oil and gas which may be found.

BONUS COMPUTER PROGRAM - determines the expected rate of return to be obtained from a lease as a function of the probability of finding commercial quantities of hydrocarbons, bonus paid, royalty percentage, and/or profit share percentage.

CONSERVATION TAX - tax based on the amount of oil produced.

DISCOUNT RATE - the time value rate of money which is used to evaluate future income and expenditures at present value -- generally equatable to a company interest rate at which the company borrows or lends money, or the average rate of return.

DMEM - Division of Minerals and Energy Management within the Department of Natural Resources, State of Alaska.

ECONOMIC LIMIT - The production rate at which the cost to produce a field is equal to the revenue received.

EXPECTED VALUE - the average value obtained from a number of attempts which include the successes and the failures.

EXPECTED PETROLEUM FIELD SIZE - the average field size obtained from a number of attempts which include the successes and the failures.

FEA - Federal Energy Administration

FIXED BONUS - a predetermined sum of money required by the resource owner to ensure that only earnest bidders participate in the auction. Syn: earnest money.

FRONT END MONEY - cash bonus paid at the time of leasing.

GREAT - Generalized Reserve Estimating, Appraising Tax Computing System, developed and operated by Garrett Computing Services, Inc.

INCOME - the money or other gain received for labor, services, property or investments.

MODEL - a set of estimated parameters which are assumed to reflect reasonable values as compared to actual fields.

NORMAL DISTRIBUTION - a symmetrical bell-shaped curve, where the relative frequency with which a variable will take on values between two points is the area under the curve between the two points on the horizontal axis.

OIL, LOWER TIER - FEA regulated oil price applicable to all old oil produced on old discoveries.

OIL, UPPER TIER - FEA regulated oil price applicable to a new oil discovery or oil produced above a base level.

PARAMETER - any measurable characteristic of the defined universe.

PRESENT WORTH - the present value of future income or expenditures which is determined by discounting future income and expenditures at an acceptable discount rate.

PROBABILITY - relative frequency of particular events in a very long sequence of trials.

PROBABILITY OF SUCCESS - the chance of finding the expected value resource (field size).

RATE OF RETURN - discount rate which results in the discounted present worth of future net income becoming equal to the discounted investment.

RECOVERABLE RESERVES - the amount of production that can profitably be removed with present technology.

REVENUE - the income, royalties, rentals and fees, collected by government.

RISK - percent chance of success.

SEVERANCE TAX - tax derived from the gross value of production.

STATE INCOME TAX - tax based on taxable income.

TAXABLE INCOME - all company income less operating cost, less depreciation on investment, less amortized pre-leasehold costs (bonus), less conservation and advalorem tax.

SEC. 4

MILTON LIPTON:

The comments that I would like to offer and then open up to your questions are based upon the draft for a bill that amends the leasing policy of the state. To begin with, I call your attention to a rather unique and I think a very progressive statement of the preamble which says that among the purposes of this is to maximize the state's share from profitable oil and gas production while minimizing revenue from unsuccessful exploration wells and from marginal economic oil and gas production. It is a most unusual approach for a state or a government that is leasing property to take....that is...what you are saying in effect is that you are not trying to maximize your revenues come oil or high water, but that you'll take your revenues from successful oil and gas exploration and you are prepared to forego under certain circumstances optimum revenues that you might have gotten from bonuses paid to the state where the venture was unsuccessful. I would think that the industry would look with great favor upon this as a principle of leasing, and as I said before, it's a most unusual thing to see a government proposing this itself.

A major change which is now being proposed in your leasing policy has to do with bidding methods and on page 4 of the proposed draft bill there are actually eight (8) different bidding methods itemized which would be available to the commissioner and from which he could select in any particular lease sale. The eight different bidding methods break down really into four different bid variables. The first is the very familiar front end bonus bid, and there are three (3) different ways this can be done.

The second is royalty bidding and there are two different ways the commissioner can do that. The third is bidding for a net profit interest to the state out of the proceeds of successful oil and gas exploration development and production. The fourth is bidding on the basis of work obligations, how much a company will commit itself to work obligations. As I said, the bonus bidding is the familiar one which as been used most commonly, I think, almost exclusively here in Alaska in which the blocks which are up for competitive bidding will go to that company that offers to the state the highest bonus, and then the terms of the lease specify certain fixed commitments on the part of the leasing company, in the past, it has been almost universally 12 1/2% royalty. Under this proposed legislation, if the commissioner can solicit competitive bidding on the basis of a front-end bonus but with one of three alternative sets of fixed commitments written into the lease. One is a straight royalty which shall not be less than 12 1/2%. Second is a sliding scale royalty, that is beginning initial production at one level and then moving upward. And the third is a combination of a fixed royalty and a net profit interest to the state where the fixed royalty shall not be less than 12 1/2% of the fixed profit, interest shall not be set by the commissioner at less than 30%. So in effect this deviates from your present practice only insofar as it gives the commissioner a choice of three different elements which he can write into the leases when he opens them up for competitive bidding on the basis of the bonus. The royalty bidding is quite different. Here the two alternatives are that the companies would bid competitively; offering, competing on the basis of a sliding scale royalty which cannot begin at less than 12 1/2% and which carries thereafter a fixed bonus. The bonus is fixed by the commissioner, the companies bid on what kind of a sliding scale royalty they are prepared to offer the state or alternatively there's a fixed bonus and they offer a

fixed royalty. They bid competitively on royalty not a sliding scale royalty, but one says I'll offer 12 1/2%, another one says I'll offer 15%, yet another one says I'll offer 18%..... A few words about royalty, competitive royalty bidding, in previous discussions with committees of this legislature we have argued that royalty bidding is not a preferred form of bidding, except under very exceptional circumstances. If, for example, you have semi-proven acreage where the volume of the oil to be found is reasonably calculable, and the risks are not that great, location of the oil in terms of distance from ports or whatever else is pretty well known because other production is close by, under those circumstances you might have royalty bidding. But under most circumstances we would feel that royalty bidding is not a preferred form of bidding. You remember from our discussion of severance tax that the nature of the royalty or of the severance tax is that it becomes a percentage of gross value. Taken off the top of the gross value without regard to what the profitability of the venture is and when companies don't have to pay a very large bonus, the bonus is fixed at a modest rate, everybody pays the same bonus bids, but competitively on the basis of the royalty there may be a tendency for companies in their exuberance to obtain the lease to push the royalty which they offer the state progressively higher, they don't know what their competitors are going to offer, so they stretch their bid in order to win the lease. And then subsequently it may turn out that this royalty to which they commit themselves and which must be paid on every barrel of production over the entire duration of the lease becomes a very burdensome one; it could lead to earlier abandonment. But this is particularly relevant, what I'm saying now in the context of paragraph "D" at the bottom of page 4, which says regulation shall be established for all bidding methods to allow reduction of royalty to compensate for these increasing costs in the later stages of production decline, to prolong the

economic life of the field. And then it goes on, it says that the commissioner cannot really abate the royalty before at least two years of production have transpired. But, I put it to you, that although discretion on the part of the commissioner to abate royalties is something which you had in your lease a long, long time ago in your leasing bill; although this may be good legislative practice and good administrative practice when fields are beginning to reach the end of their natural life and you would like to encourage the maintenance of production even if it means taking a lesser royalty; to have this in the statute at the time when companies are bidding competitively on the royalty and then there is a temptation to say, well, if we bid too high a royalty, we come running back to the commissioner and we ask for abatement of the royalty. So, you put the state, you put the commissioner in a very bad hole and and you have perhaps without intending to, you encouraged the companies to bid not the highest royalty that they think they can afford to pay in light of their exploration expectations, but to over bid because when worse comes to worse they will go running back for abatement of royalty. So I would think that if you are going to maintain this feature in the leasing law which says that in order to encourage the continuation of marginal production there will be the possibility of abating royalty then you certainly, I think, want to consider very, very carefully whether you want to have among the options, under which the commissioner can lease, bidding competitively on royalty. The third alternative or the third form of competitive bidding is bidding a percentage of net profit to the state. What this means in effect is that the companies who are bidding competitively to obtain a lease will say to the state, well, your lease requires us to pay a fixed bonus so we all have to do that and in another version your lease requires us to pay a fixed bonus, plus no less than 12 1/2% royalty whatever the commissioner specifies. Now, each company

bids competitively by saying to the state that after we have paid the bonus and after we pay a royalty of 12 1/2% of gross well head value on every dollar of production, thereafter, each year we convey to the state a percentage of our net profits and the companies bid competitively; the company that commits itself to turning back to the state the largest percentage of net profits is the company that wins the lease. Net profits can be defined, they are not defined in the statute, and I think correctly not so. The commissioner before any lease sale where the bidding component or the bidding variable is net profit, tells all companies who are entering the bidding precisely how net profit will be computed. It does not have to be and, hopefully, will not be the same way net profit is computed for income tax purposes. It is a notional concept of net profit which says you start with this gross value or whatever it is and you subtract certain specified costs everyone knows precisely without too great argument or debate how the accounting will be done in the course of the year and relatively simple accounting can be mandated by the commissioner before the lease sale. We have felt for a long time that the net profit bidding variable is a particularly attractive one, both in the standpoint of industry and for the standpoint of whatever government it is that's putting up acreage for lease. Not necessarily to the exclusion to other possibilities, but under certain circumstances a very attractive approach. What it does is, it removes a great deal of the capital available for exploration from the front-end bonuses so that the money that's available goes to productive work instead of just to front-end bonus. Where there is highly successful exploration the lessor, State of Alaska in this case, can expect to have very, very substantial revenues from the lease quite apart from taxation or anything else. Revenue from the

lease as the percentage of net profits. You might even think of net profit as a royalty based upon net value instead of a royalty based upon gross value. Sometime it's referred to as a net royalty or a net profit carried interest. What it means in effect is that the State of Alaska takes on a very considerable proportion of the risks in the exploration game. It does get a bonus but the bonus is a small bonus fixed by the commissioner as being appropriate to this bidding variable. And it may get, say, a fixed royalty but after that the larger proportion of the income which the state might expect to receive it would receive only if the lease proves to be a productive lease and how much the state gets depends upon how much oil or gas is found, what the value the oil or gas is, and how profitable the operation. So the state in a sense becomes a partner with the explorer in both the failures and the successes of the venture. But the state does not become a working partner, the state does not become an active partner, the state is not in the oil and gas business.

The decision as to whether or not the exploration should take place, the competitive bidding on what the net profit conveyed to the state is... all of these are private decisions by private industry in a competitive environment. Then the final variable, and it is the eighth item among the alternatives available to the commissioner, is bidding on the basis of work commitments. And there in a sense, the commissioner says when the sale is being advertised, that there is going to be a fixed bonus, and there is going to be a stipulated royalty. Now the winner of this lease who is entitled to do the exploration is the company who commits the largest amount of money to exploration process. This kind of bidding, perhaps, would be utilized in very, very difficult environment areas where the state wants to be sure that all potentials of the acreage are really explored, where the costs of exploration may be very, very high and where in the absence of work commitments the companies may be inclined to back out too quickly in terms of the results of one

unsuccessful well or whatever the case might be and the state would like to get the best possible exploration of the prospects within the area put up for lease and therefore says to the companies, we will reduce your bonus commitments, we won't have a bidding on the basis of royalty, but we will allow you to bid on how much you are prepared to commit to the exploration of this acreage which the state is putting up for lease. Well, just a few comments, I've already indicated that I think, that we think, that gross royalty bidding except in rare circumstances, is not the most attractive form of competitive bidding, and particularly not if you are going to allow abatement of royalty under certain circumstances. Bonus bidding, net profit bidding, work bidding, each one a reasonable approach to competitive bidding depending upon the nature of the area which is up for lease; how the state, the commissioner, and his technical staff regard the potentials. So I think that by providing these alternatives, the state is in effect creating a reasonable basis for a leasing policy within Alaska. I wonder, however, whether it is necessary in legislation to itemize all eight possibilities, that is to say, a bonus bid with not less than a 12 1/2% royalty, or a bonus bid with a sliding scale royalty, or a bonus bid with not less than 12 1/2% royalty and not less than 30% net profit. There are many variations which are itemized here, and for example, a bonus bid with not less than 12 1/2% royalty, and not less than 30% net profit is hardly, I would suspect in most areas, is hardly going to get much competition in terms of the bonus. Why not less than 30% net profit? It seems to me that if you lay out in gross terms what the permissible bid variables are, bonus under certain circumstances royalty, perhaps net profit, work commitments, and then leave it to the commissioner as to the combination of variables and the minima for the fixed items he wants to put in there, how far can one anticipate in legislation itself, what combination of fixed commitments

should underlie the selection of a bid variable, like a bonus variable and I would think that perhaps it might be advisable for the legislature to consider presenting to the commissioner a greater option of more bidding variables and perhaps set certain minima, but not itemize them in the details which appear here. Now there is one other aspect of the bidding that I would like to refer to and it is an item that appears on page 9. It says lands which have been offered for lease within the previous five years, but which received no bids at public auction may at the discretion of the commissioner be immediately offered for lease under regulations promulgated in advance upon terms most advantageous to the state including leasing non-competitively. The commissioner shall utilize a sliding scale of royalty based upon such formula as he determines to be equitable, but need not adhere to the rental schedule in subsection (k) of this act nor to the 57 (indesc.) acres per lease and so on. What I am calling your attention to is the option here available to the commissioner where a lease that is offered for bidding has not been taken up very quickly, to put it back for lease including under noncompetitive circumstances. I think that this could open up some dangerous precedents. Particularly if it's offered too quickly. I mean that the fact that a lease is not taken up in competitive bidding does not mean that there is no oil and gas there, it does not mean that the prospects are not good for oil or gas, it means that given the state of the knowledge at that moment of time, given the way the industry perceives the attractiveness at the moment of time they have'nt been interested in bidding on it.. They had other things that were more attractive, whatever the case might be. But let some time go by before opening this up for leasing again and particularly under competitive conditions again, what may have been learned about the geology of the state in the interim period. The way in which

company perspectives may have changed for a lot different reasons, I don't know what the case may be, I think may lead to the ability to lease under more favorable terms rather than for the state to conclude that nobody wanted cur lease, well, we would like to have it explored anyway, let's get it on the market as quickly as possible, even if under noncompetitive circumstances. I would strongly suggest that you hear from the department, as well as from me, and others about why there is a sense of urgency about leasing noncompetitively just because the lease has not been taken up. I pass to other aspects than the terms of bidding and leasing. On page 5, there is a very pregnant one line clause which says the commissioner is authorized to withhold acreage from leasing in a particular lease sale. Now again, for those of you who remember one of the first reports we made for the legislature on leasing policy many, many years ago, one of the things that was discussed was the advisability, under appropriate circumstances, of the state leasing less than the full acreage in which there might be industry interest. Now enough acreage has to be put up for lease so that the companies that win the leases have a reasonable aggregation of acreage to provide for viable production of oil or gas or whatever is discovered. It doesn't necessarily mean that everything within a particular area of prospective interest has to be put up for lease simultaneously, there is good reason particularly if the purpose is to maximize the states share from profitable oil and gas production and minimize revenue from unsuccessful exploration wells and from marginal production for the state to withhold a certain amount of acreage. Now the acreage which was withheld may be condemned as absolutely sterile if the exploration around it finds nothing, (indesc.) the state may have withheld may turn out to be condemned by the industry you will never be able to lease it in which case you will not have gotten any bonus revenue

or whatever the case may be. But on the other hand, if it is successful you may come up with a subsequent lease sale with a net profit bidding for example, which makes it very attractive to the state in terms of the income that they will receive. So I would think that this thing is that the commissioner is not only authorized, but subject only to circumstances which make it undesirable which in case the commissioner has to exercise his judgment, that he should in fact withhold acreage it should be a more positive thing. I wouldn't want to make it binding under all circumstances. discretion must lie (indesc.) some areas where it may not be feasible where whatever acreage is put up really has to encompass the most of the structure which is in interest. If it can be done, I think it would be advisable to do so. The next feature that I would like to touch on briefly has to do with the period of exploration and on page 6 the appropriate paragraph says that an oil and gas lease shall cover a reasonably compact area and be for a period of five years. And there is no provision here for extension of the exploration period except under specific circumstances if production is eminent or a well has to be completed or the property goes into unitization. What under normal circumstances is a 5 year exploration period. I would suggest that there should be provision for at least some reasonable extension of the exploration period particularly in a country as difficult to operate in as the State of Alaska, where the geology, the environment, the climate, the circumstances all make it impossible to conclude an ongoing exploration period precisely within the five years. A whole exploration season may be lost because of a combination of circumstances; because drilling equipment couldn't get out there, or at the end of one season the

seismic work never got completed and one has to wait for the proper time of the year to go back and finish it and one loses a year of exploration. I would think it would be advisable to allow an extension of the exploration period. If in the view of the commissioner, good faith has been exercised by the leasing company in the previous 5 years. I think it does no violence to the interest of the state. But there is another very interest feature that's introduced here at the bottom of page 9, paragraph v, the state shall have the right to purchase not to exceed 16 2/3% by volume of the oil and gas produced pursuant to a lease, and it goes on. That is to say, the state is assuring itself that if it chooses, it can have as much as 1/6th of the oil or gas produced on the lease. Now included within that would be the states royalty oil and gas and the volume metric equivalent of whatever the state may get on a net profit share. But if those fall short of 2/3rds of the oil and gas the state has the right to buy at the market value at the field price enough to make up 2/3rds. There is no obligation on the state to do it, the state has the right to do it. I see a tremendous advantage of the state in this, I seen no great diadvantage to the industry in this if exercised judiciously. It could be unattractive to the industry if it is arbitrarily applied and particularly out of small production where the lease holder really needs a substantial volume of oil to provide the economics for his export out of the state for example, and taking away 1/6th of the volume of oil starts cutting things too narrow for him, then I would say that this could be a burden to any company who is undertaking the exploration and who successfully is doing the development. So I would think there ought to be at least some proviso where by the lease holder is protected against simply a determination to take 16 2/3rd

no matter what, and in particularly small areas where the increment of the state gets may matter very little to the state but may matter very much to the producing company. I think some kind of clause should be put in to provide the protection.

That's the sum of the remarks that I think I could make about the special features of this proposed bill and if there are any aspects of it that I touched on or things that I have not chosen to talk to that you would like to address yourself to, I'm at your mercy.

SENATOR POLAND I will ask you one question Mr. Lipton, and that is, have you felt for sometime that our leasing policy needed to be updated or overhauled?

MILTON LIPTON Well, I think that if only to broaden increase, the number of options available for leasing, yes, I think so. I think the traditional front end bonus bidding and there is a lot to be said for it under the proper circumstances, and, but for this to be the sole basis of competitive bidding, I think it places a burden in rank wildcat areas upon the industry which is unnecessary, that you have to put so much money that ought to be used constructively, pay out as a bonus and it puts the state in a position where in many rank wildcat areas what the state gets is miniscule in terms of bonuses compared to what may be the profitability. If you add up the sum total of bonuses received by the state from the producing areas of Prudhoe Bay, it is miniscule bonus income because the companies were bidding on rank wildcat areas at a time when even if they were

successful no one ever knew if it could be developed, tremendous volumes of oil had to be found and if prices had ever stayed at \$3.00 per barrel it never would have been produced you see, under those circumstances obviously the bonuses are very very little. Now, I think there is no great virtue in the state having competition on the basis of front end bonuses when the total amount of bonus income you may get, particularly in the less attractive areas of the state. What seemed to be the less attractive areas of the state will be very very little and may prove to be the most attractive producing areas after they are developed. So that if you minimize the front end bonus under certain circumstances and go to a net profit interest then you have a chance of sharing much more considerably in the profitability of successful ventures and without doing great violence to the incentives of the industry. Because no company is going to bid away such a large share of the net profits that it leaves them without the incentive of very very profitable operations on the remaining shares. Now it is something which I think can be equitable both to the state and to the company. So yes, I do think that the leasing warranted amendment if for no other reason than to introduce a greater variety of bidding variables without going mad with you know giving the commissioner so many options that the poor man will never know on what basis he can make a selection. But I think to introduce several other options is a major step forward.

Q: Senator Huber - Milt, can you tell me from industries viewpoint if we would do any harm to this bill, in particular, or good or otherwise, your comments in regards to us putting an Alaska hire clause into the leasing requiring Alaska hire based not upon our regulatory rights but upon our proprietary contract rights?

Lipton: Senator Huber, you know, you ask me from the standpoint of the industry you really should ask that of the industry, not of me, but I would give you a very quick impression and if you put an Alaska hire clause, in, what it

means to the industry depends really on what you intend by Alaska hire. I mean there, if the industry doesn't have sufficient flexibility to obtain competent people, whatever their origin, then I think it does harm to the industry. But if the way in which it is applied is sufficiently flexible then I suspect not only wouldn't the industry object, but the industry would be delighted. You know, I think the industry would like to make the maximum possible contribution to Alaska hire. But it must be a very difficult thing to administer, I suppose.

Q: Senator Huber - I apologize for asking the industry viewpoint. I was asking basically for the economics of the industries viewpoint.

Lipton - Well, as I said the economics are affected depending upon how this either contributes to, or intereferes with the efficiency of the industries exploration and producing operations.

Q: Senator Huber - I was referring to a particularity in the difference between our regulatory powers as a government and our proprietary rights as a contract maker in this particular case.

Lipton - Well Senator Huber, this suggests to me that if you are doing this as part of a contract rather than by regulation, does that mean it's going to be less flexible, because it is in the contract?

Q: Senator Huber - Madame Chairman, Mr. Lipton, the intention is to make it less flexible because we are presently finding that our leases do not contain this and that hiring is not being done from the North Slope from Alaska where it could be done when there is qualified people sitting on the benches. And we want something to get a handle on this, so that it is not going to be struck down by the Supreme Court saying that you cannot make

such a law we want to work on our proprietary rights being that is our oil that we are selling.

Lipton - Senator Huber, I find it very difficult to give you a responsive answer because if you say that there are qualified people sitting up there who are not being hired, now obviously that is bad and if you had it in the lease they would be hired. On the other hand, if the industry may interpret qualified people differently. I don't know it's very very, it's difficult to say. But if the whole idea is to make it a firmer obligation through the lease that is one thing. But if you make it a firmer obligation and there is no flexibility then I think it could be very difficult.

Q: Senator Huber - Well Madame Chairman, I won't dwell on it but just one more short thing, so that you understand what I am talking about. When the industry on the North Slope makes a deal, with for instance, a Hawaiian corporation to supply them with the personnel and to do the hiring for them and then the hiring is done in Houston Texas we become concerned when there is qualified Alaskans sitting on the bench. But if we have a handle, a way that we can get a handle on this, using our proprietary rights we should be doing it, or trying to find a way to do it when we know that we can't do it with our regulatory rights and that is why I wanted to get your expertise on this.

Senator Meland - Madame Chairman, I, has Mr. Lipton spoken to any type of questions about all the legislature or are we just talking about (inaudible). Because I did have some questions that were left over from Wednesday, but we can certainly wait on that and talk about this legislation before us.

Senator Poland - Well what we had though we would do is talk about this and when there are no more questions on this we will go to the royalty oil proposals and then throw it open for all types of questions.

Q: Senator Radar - There are many question Madame Chairman. I had two items that I would like to have Dr. Lipton comment on. One of them is the concept of limiting from 500,000 acres to 200,000 acres the amount that any one entity can hold in leased lands and that concept actually appears in several faces in the bill. I assume it is to prevent or to insure a competitive market here so that we don't end up with one company dominating the field. Comment on this and give us your observations on that and what problems and benefits might flow from that.

Lipton - I think there is great virute in limiting acerage holding by an individual company. On the other hand, I have no feel really, for whether 200,000 acres as an amendment to the 500,000 alternative is too little or not. I would strongly urge that in order to acheive the same purpose, that is, I think that two things are of value. Acerage limitation I think could go in there. I don't think it does violence, providing that it is not so narrow that in a sense very soon you start reducing the number of competitors and a company that is successful in a couple of lease sales and then suddenly finds itself barred from further competitive bidding for acerage. You defeat your own purpose if you do that. But I sense that the purpose of the legislature and certainly the interest of the state is that acerage shall not be held. The purpose of winning acerage under a lease is to get on with the business of exploration. And therefore I would suggest that whether there is compitive bidding on work obligations is one of the options or not. I think there should be work obligations in every lease. The commissioner should in every lease stipulate minimum, not maximum work obligations. We are not trying to tell the companies how to conduct their exploration activities. But there should be certain minimum work commitments which the companies have to perform in order to hold that lease. Let them get on with the business of exploration. It does no violence to the purpose of the companies, unless they want to get in that bidding and then sit back and wait for

somebody else to do some work or they wanted to be sure they were represented in the area but they had other fish to fry elsewhere in the state or somewhere else. I think you have a five year duration of the lease and I have already suggested that you might be willing to extend it, if the companies really need it and they have been going about their business. On the other hand, there should be minimum work obligations in every lease there. I think also there is a certain virtue in putting a ceiling on the amount of acreage which a given corporate or individual can hold as a result of leasing from the State of Alaska. I certainly would not want you to cut that down so small that you lose the competitive bidding and the third, fourth and the fifth lease sale because one company has already not exhausted it's interest, not even exhausted it's dollars but has exhausted it's ability to hold acreage in the state.

Q: Senator Radar - Would you comment on the provision as to the lessee or permittee conducting any exploration for development or production of oil and gas, the state shall provide the commissioner access to all data obtained from such activities and shall provide copies of such specific data as the commissioner may request. I don't know whether that is intended to change the public disclosure of that information or whether there is still proprietary interests or not but what is your understanding of that provision and your comment? It is on the top of page ten. It starts on the second line.

Lipton - I assume that your statutes prevent public disclosure of this for some minimum period. What is it two years in Alaska. Two years, I think I believe. Two years by statute.

Q: Senator Radar - Cause I take it that the proposal here does not suggest that we alter that proprietary -

Lipton - I would hope not. I would hope not. I think the right to proprietary information for at least two years. For any company operating here considering the amount of money which goes into

exploration. I think that should be protected.

Q: Senator Radar - Well let me ask you this. Would that be true. I assume the reason for your statement is that a company therefore gets the value of it's own work product. But what if the state, for example, should for reasons unknown, at the time of exploration, should withhold in the leasing for a period of three years. Then under those circumstances we would have deprived the company of the value of it's own work product. I don't know how to avoid that but I can see a problem here and perhaps discretion should be available here. Although I am not certain as to the purpose of this particular section or what the discretion or the thrust of the discretion should be. Whether the purpose here basically is to give the state the right to deprive them of the work product, within two years or what?

Lipton - Well I don't know how you can set the period of confidentiality so that it conforms with the amount of, the lapse of time between one lease sale and another lease sale. I mean that is a pretty difficult thing to do. I don't think, see the point is the state has access to this information. It is just that the competitors don't have access to this information. And in that respect there is a certain value in extending the period of confidentiality to a reasonable period of time because the value of the information is not just for another lease sale in exactly the same area. There is an awful lot of information. It becomes valuable because one correlates it with what one knows from other wells elsewhere. One builds up ones geologic and geophysical knowledge as this stuff becomes public. So there is virtue in keeping it confidential for a reasonable length of time. But I don't know, one can't do it for too long a time or you deprive the industry as a whole of what is really basic knowledge necessary for it to advance. So there is some kind of a compromise has to be struck between the virtue of the confidentiality to the company doing the work and how important it is for the whole industry to know more and more about the State of Alaska.

Q: Senator Radar - Well let me ask you. You have suggested in a number of instances discretion in the commissioner. Do you think that in this particular instance that we should provide administrative discretion in perhaps, write in a minimum or maximum or something of that nature. Or do you think the two year -

Lipton - Senator Radar I don't think this is an area where the commissioner ought to have discretion. This is protection which the legislature is going to give to an exploring company as they are taking the risks in putting it's money in. It depends upon the legislature to know exactly what it's protection is.

Q: Senator Radar - Well what if you wrote in a minimum of two years, an extension of that period of time before it was made public?

Lipton - Senator Radar, I don't know of any place where that exists. That of course doesn't mean that it's a bad idea. I don't know that it exists anywhere else. I am not familiar with it. I think normally two years is pretty ample time. Again I would certainly defer to the judgement of people in the administration you know they have alot more experience with what the circumstances up here in Alaska have been.

Q: Senator Huber - Madame Chairman, I would like to just ask Milton just one thing, one question that was raised here by Senator Radar and I would hope he would concur with me. Milton will you take a look into the matter that Senator Radar brought out to determine in your opinion how our laws stack up on this at this time and give us some kind of a report on it. I think I know and the question I would like to ask you would be if you thought that two years was the best period of time and compare this with our current law and give us another report.

Lipton - Yes. I would be pleased to.

Q: Senator Radar - Madame Chairman, perhaps if I might ask Dr. Lipton, he said he had no particular feel to the 200,000 acre limitation for single holdings. I might ask him if it is possible for you to develop a feel for that. At least give us your best judgement as to whether or not -

Lipton - Yes.

Bristol
Bay
Native
Corporation

445 E. 5TH AVENUE / P.O. BOX 220 / ANCHORAGE, ALASKA 99510 / PH (907) 278-3602

March 10, 1978

The Honorable Alvin Osterback
Chairman
House Resource Committee
Pouch V
Juneau, Alaska 99811

RE: H.B. 854

Dear Mr Chairman:

It is my understanding your committee will be holding hearings on H.B. 854 on March 16th and 17th, 1978. Unfortunately, we will have no representative at the hearings to testify and therefore, we respectfully request this letter be included in the official record of the hearings.

First of all, we object to most sections of this Bill as it is very complex, creates a multiple choice system that is unworkable, discourages exploration on State lands, and above all would have a serious impact on the development of our lands. We strongly urge that no action be taken on H.B. 854 this year.

Previous State selections and proposed selections in our region total several million acres with oil and gas potential in the Nushagak Basin (Bristol Bay Basin). BBNC lands in the onshore portion of this sedimentary basin would total about 1,750,000 acres surrounding 17 villages, several of which the Native lands are not contiguous. In other words, most of our lands with the new proposed State selections would be adjacent to or surrounded by State lands. In many instances, a drilling unit would involve both State and Native lands and in some instances, Federal lands. Therefore, any changes in leasing of State lands will have a direct effect on BBNC lands. Most of the provisions of H.B. 854 would change the economics of State and Native lands in a producing unit. The net result will be that the portion of the unit under State leases would become uneconomical and abandoned first and the Native portion of the unit would then become less economical followed by early abandonment and thusly leaving large amounts of oil or gas in the ground. This could hardly be called conservation.

Mr Osterback
March 10, 1978
Page 2

BBNC has had a joint agreement with a major oil company whereby, with commercial production, we will become a producing oil company. We do not lease our lands! Knowing some of our selected lands might not be adequate to cover undefined seismic structures, we anticipated leasing State or Federal lands in order to form drilling units for early development of our lands. About three years ago, we filed the necessary qualifying documents to hold both State and Federal oil and gas leases and have filed offers to lease on several thousand acres of Federal lands.

We have no problem with the present leasing system as it has been tried, tested, proven and above all, is understandable. Such a mixed bag of radical, czarist possibilities as proposed in H.B. 854 is incomprehensible, unjustified and will no doubt have the opposite effect of the original intent, unless the intent was to retard development of State lands indefinitely and in effect retard development of much of our lands.

Again, we strongly urge the postponement of any action on this Bill.

Sincerely,

W. C. Bishop

W. C. Bishop
Manager, Subsurface Resources

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OIL AND GAS LEASING POLICY:
ALTERNATIVES FOR ALASKA IN 1977

A Report to the State of Alaska, Jay S. Hammond, Governor
Department of Natural Resources, Guy R. Martin, Commissioner,
and to the
Alaska State Legislature, Interim Committee on Oil and
Gas Taxation and Leasing Policy, Chancy Croft, Chairman

February 1, 1977

OIL AND GAS LEASING POLICY: ALTERNATIVES FOR ALASKA IN 1977

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Summary

The purpose of this report is to be of service to the Alaska State Legislature and the Department of Natural Resources in their review of oil and gas leasing policy. It is written from the State's viewpoint. It treats the State's interests as being frequently adverse to those of the State lessees, without being hostile to them. Where the State's interest is adverse to the federal interest, we take the State's position. Otherwise, the purpose is to be as objective as possible. The Report lists the pros and cons of alternative policies and indicates what the Legislature needs to do to make each policy work. Recommendations are made in a tentative way.

This is a survey rather than an intensive study of any one alternative. The purpose is to display the full range of alternatives and the full range of issues to be considered regarding each one, so as to keep individual matters in the larger perspective so that no one issue is overweighted. The purpose is to compare, and to show how different leasing elements complement or substitute for each other. The purpose is to serve as a springboard for legislative review and a guide to additional, more selective investigations.

As a unifying theme, the list of alternatives proceeds sequentially, showing how each more complex alternative emerges as an answer to faults perceived in prior ones.

As a set of criteria for judgment the Report seeks to lay on the table assumed goals of the State. These are the following:

-- Business-like management. This is taken to mean in practice the maximization of discounted

-- Equity. This is taken in avoiding giveaways; reducing the lottery element in leasing; hewing to the productivity basis of distribution of income; collecting for the State the rent of its lands; basing industry incentives on productivity rather than acquisition of State assets; and reducing the differential advantage accorded to accumulated wealth.

-- Workability. This means a minimum of arbitrary regulation, achieved by binding the lessor and the lessee in a community of interests when writing the lease.

-- Avoiding economic waste. In addition to physical waste, there are the wastes of producing at excessive cost and doing things at the wrong time. The Report suggests abandoning the criterion of maximizing ultimate recovery in favor of maximizing discounted cash flow; avoiding the dissipation of rent by overspending, particularly on capital. It warns against the twin dangers of using proven resources too slowly and searching out new ones too early.

-- External impacts. These are seen as negative by environmentalists and as positive by developmentalists. The reconciliation lies in a wider distribution of benefits.

-- Coordination with federal and native landowners.

The Report now surveys leasing alternatives in sequence:

-- Noncompetitive leasing is faulted for giving away too much and encouraging premature leasing and production.

-- A high bonus partially cures these problems but creates a serious front-end filter problem. Professor Norgaard's postmortem analysis of bonus bidding in Alaska indicates that too little has been received for leases.

-- A high annual rental cures the problem of the front-end filter by replacing it. It may overaccelerate production, however, unless made to dwindle over time. A rental whose level is set before discovery reduces the buyer's risk since he may drop the lease at will, but does not alleviate the State's risk of selling for too little. A rental based on assessed value avoids this problem and also dwindles over time.

-- High royalty rates solve much of the risk problem. They eliminate the front-end filter and they collect revenue. However, they allow too much speculation. They also put a drag on production, especially marginal production. Premature shutdown turns out to be a minor problem. Others are greater: slow production and future shift; leakage of rent into private hands from better deposits; excessive deferral of State revenues; and lower success ratios for exploration. These problems can be alleviated by imposing specific work terms, by using sliding scales, and by limiting the term of the lease.

-- Specific terms. These must be used with high royalties to compensate for the disincentive effects. Mandatory liability for environmental damage is also suggested.

-- Profit sharing. This means letting lessees write off costs against royalties and also raising the rate to compensate. This lets the State receive more per barrel from the richer deposits, and avoids

sterilizing the marginal ones. It gets us into the same problems as administering an income tax: the rate is high, padding costs is likely, depreciation paths and lives must be determined according to complex and sometimes arbitrary formulas. There remains a loophole for unrealized capital gains.

-- Rent-sharing. In addition to costs the lessee deducts interest on the value of his improvements by one of three methods: by allowing deduction of capital over time with interest at a specified rate; by allowing front-end recovery of capital and by applying an ad valorem charge to the assessed value of the leasehold interest. The first two alternatives engage us in severe auditing problems, and both are biased against exploration on long-shot ventures. The third alternative removes the auditing problem and replaces it with an assessing problem. It also puts a bite on unrealized capital gains. It avoids many faults seen in prior systems: it raises money; it defers payments but not excessively; it puts no drag on production; it requires little direct regulation; it imposes no shift towards the future; there is little opportunity to pad expenses; and there is only a limited bias against long-shot exploration (because what is hard to find is often hard to produce and therefore low-valued). Its problem is discouraging postleasing exploration. Some remedies are suggested.

-- Regulating field operations. Some form of unitization is required. It is suggested that this will work much better if the State accepts the criterion of maximizing discounted cash flow, eliminating a conflict between the State and the operators. A two-tier system is suggested as an alternative to 100 percent unitization.

-- Three alternatives are passed over lightly, although without prejudice. These are: checkerboarding; the sale of undivided interests; and the sale of a fixed volume of oil and gas.

-- Handling information. The Report considers the pros and cons of the State's buying more information on contract as an alternative to relying on industry nomination. The weight of argumentation is in favor of the State's taking a more active role.

-- Direct State intervention in the market is considered, primarily to aid in monitoring prices used as bases of evaluation for royalty and assessment purposes, and to guarantee to all lessees equal access to transportation.

Next a criterion and procedure is developed for timing lease sales. State lands are to be ranked according to maturity or "ripeness." Ripeness is defined as a condition where the percentage growth rate of the DCF of the State's interest slows down. The State's wealth is maximized by selling leases when this anticipated growth rate slows down below the rate of interest. The appropriate rate of interest should be the State's borrowing rate. The question is raised whether the State should set a reservation price when auctioning leases. The Report addresses the question of whether the proposed procedure will cause leases to be sold at a sufficiently even rate.

The Report considers the administrative load and personnel requirements associated with alternative leasing systems. The use of royalties entails ancillary regulation to compensate for the disincentive effects of the royalty on production. The profit share system entails an

auditing staff to avoid the deduction of unjustified expenses. So, also, do the first two rent-sharing systems where capital costs with interest are deductible. The ad valorem charge system entails a staff of valuation engineers or appraisers, whose services are also required to operate a system of timing lease sales optimally.

Leasing is seen as supplementary to taxation, and taxation is not seen as an adequate substitute for leasing policy because taxation is addressed to persons or corporations while leasing policy is addressed to parcels of real estate. The exceptions to this are a net proceeds tax and a property tax, either of which might be used as a substitute for leasing policy.

Recommendations are submitted tentatively in light of the complexity of the subject and the several imponderables involved. I recommend screening out systems based on ex ante forecasts of resource values like the bonus bidding system, because of the front-end filtering out of leaner firms and because so much has to be gambled on so little information. We consider the lease elements whose value depends on actual disclosure of resource values and rank them in the following order: the ad valorem charge, the profit share, the sliding scale royalty, and the front-end recovery. We recommend a vigorous program of State-financed contract exploration with publicity of findings. We recommend scheduling lease sales according to the ripeness criterion described above. We prefer that unitization be administered by an organization of local leaseholders.

Our most immediate and unambiguous recommendation is for a greatly expanded program of information-collecting and valuation, to serve as a necessary base for all other decisions.

A. Reasons for this study and Report

This study was commissioned by Guy R. Martin, Commissioner of Natural Resources, State of Alaska, in cooperation with the Legislative Interim Committee on Oil and Gas Taxation and Leasing Policy, chaired by Senator Chancy Croft. The present Report is part of a larger study being conducted by the Department of Natural Resources, a study described in Commissioner Martin's statement of July 10, 1976, entitled "Alaska Oil and Gas Leasing Study," copies of which have been submitted to the Legislature. The primary focus of the present study is Section 4 of the July 10th memo which reads as follows: "A description and analysis (legal, economic, other as necessary) of all alternative systems which are practically applicable to State use in Alaska, with emphasis on broadening the State capability to employ alternatives rather than making final decisions on which systems to use. This task should consider the practical experience of other states and nations as well as leasing theory and research.

a. Special attention in the analysis should be given the risk element in alternative systems as it relates to public administration of oil and gas resources.

b. The analysis should include, in some form, an overview of this entire leasing issue of use to State officials and legislators."

This Report also responds to Section 5: "An economic/legal analysis of the interrelationship of leasing (ownership interests) alternatives with taxation alternatives. Ongoing coordination with the taxation

segment of the administration/legislative study."

This Report also responds to Section 7: "Design of a system (a criterion) for decision-making by public administrators regarding various leasing alternatives. What information must be available; what factors should be considered; what process should be followed to decide between new alternatives."

In keeping with the spirit of the assignment, the tenor of this Report is expository and not advocatory. The main purpose is to lay out major alternatives in a systematic way to serve as a basis for legislative review, debate and decision. The report does offer its own recommendations at the end and the consultant offers his own judgments from time to time where it seems appropriate, and where they may be identified as such. The overall spirit of the Report, however, is to define and articulate alternatives, to spell them out in a logical sequence, stating the advantages of each, the faults of each, and what the Legislature would have to do to make each one work. Most of them will "work" --sort of-- and are in operation in various jurisdictions around the globe. It is a question of what might work better in light of your own objectives, circumstances, and visions of the future.

In developing alternatives, the Report proceeds from the simple and basic to the more complex and sophisticated, showing how each complexity develops as a logical effort to overcome some fault in the simpler system. Before breaking down in complexities, however, the effort is made to apply Adam Smith's dictum that the evolution of successful inventions is not, in the end, into greater complexity but

greater simplicity -- an observation dramatized by Igor Sikorsky when he exhorted his engineers, "Simplify, simplify -- and then add more lightness!"

A purpose is to cut down the seeming number of alternatives without reducing the real number by boiling proposals down to their essentials and showing how few of them there really are. The number of possible combinations is still extremely high because there are so many elements in a lease but the number of reasonable combinations is much smaller because they need to be combined so as to balance each other and countervail each other's faults.

A correlative purpose is to develop commensuration, that is conversion factors among the apples and the oranges. By doing so we develop a common tongue for communication, a common currency for trade-offs, and a unitary standard for decision-making.

Alaska's interest in this topic is timely and in step with a worldwide trend to study and improve leasing systems. This is a natural result of increased valuation of oil and gas resources in the ground. As the retail price rises there is enormous leverage on field prices. The farther the field is from the gas pump the greater the leverage, so that the percentage increase in the field value of Alaska's resources is at a rate so high that few would have credited it a few years ago. Field prices everywhere are rising out of all proportion to other costs. This is reflected in extremely high bonus bids offered for tracts which were previously considered marginal or submarginal. A recent survey indicated that costs of land acquisition

by oil and gas companies increased by nearly 700 percent from 1970 to 1974 (Joint Association Survey, 1976) in comparison with all other costs which increased by considerably less than 100 percent. Clearly, the world is recognizing the high value of remaining oil and gas lands and it behooves any prudent landowner to protect his interests and to economize on the resource with much greater care than ever before.

Most analysts now foresee continued upward pressure on energy prices and this consultant, although forecasting is not his forte, is inclined to agree. This is the more reason to guard our future interests by using care in drawing leases now. The lease contract is binding and irrevocable, unlike tax policies. No legislature can bind or limit the tax power of a future legislature; but neither can a legislature in the United States, with its strong tradition of judicial review, rewrite a lease contract executed by its predecessors. Other nations may force renegotiation of contracts considered unfair in the light of changed circumstances. This is not unknown even in the United States but much rarer and harder than in countries of different traditions.

The result is a growing interest in public landowners' participating in future profits from oil and gas. For generations past, many governments virtually gave away land simply to get it used; while private landowners sold their future rights for a little money up front. Now these attitudes are changing drastically and there is ferment everywhere. The U.S. Congress has entertained several bills in both branches calculated to increase government participation in future profits in spite of

the government's having secured large revenues from bonus bids following the OCS Act of 1953. There has been some support of a federal oil and gas corporation to explore in advance of leasing. Equity participation in corporations has been a strong trend, exemplified for example in Norway, in Canada, in Saudi Arabia and elsewhere. Indonesia has pioneered its own interesting leasing system, characterized by rapid capital recovery to the lessee followed by very high royalties. Papua-New Guinea has recently adopted the same principle in more sophisticated form, basing its law on the careful advice of economists Ross Garnaut and Anthony Clunies-Ross. The academic world which ignored this topic for many years past is beginning to spawn several research projects and will soon be awash with reports and articles and proposals and econometric studies and models and new philosophies. The world is moving. Alaska is in step, although perhaps a step behind. The present assignment indicates an intent to catch up or pull ahead.

B. Objectives of the State

Only individuals, it is said, can have objectives. By "objectives of the State" this Report means the objectives of the effective majority of Alaska's voters as expressed through their political representatives and other leaders. No one thinks that representative government can completely succeed in representing everyone or, perhaps, anyone. But it is what we have, and this report addresses these leaders as though they were the State.

The Report does not presume to say what the State's objectives should be. It, rather, purports to distill what the consultant observes them to be; and to articulate and organize ambient ideas which are often heard but want greater system and organization. This entails the consultant in some interpretation. Those with more data and better interpretation may improve on this statement. The present report only begins the job of laying out our goals on the table.

A further purpose is to begin to define and expand on their specific implications. This inevitably entails even more interpretation and perhaps even some presumption by the consultant. Seeing these implications as he interprets them, one may sometimes recoil and say "no! -- That's not what I really want." So be it -- then we may go back and spell out more realistic objectives we can live with and we are well down the road to our present goal which is to be prepared for decision-making.

The following are what I take to be the State's objectives in framing a leasing policy:

1. Businesslike management of State property

The State holds property in trust for the people of the State and has a duty to manage it prudently for their maximum benefit. This means several things but one is certainly money. The State is a landlord. It wants to secure maximum income. It does not do this by fostering maximal use of resources but optimal use -- that is, it encourages lessees to maximize the bottom line, recognizing that income is net of costs. "Maximum income" is still ambiguous, however, because rival schedules of land use and income differ in their time-distributions: a fast start means a slow finish and vice versa. To resolve this ambiguity we deduct interest on capital between the dates capital is committed and later recovered.

This goes far towards resolving ambiguities but still leaves a large one, the treatment of the investment in withholding unproduced reserves from year to year. The final resolution is achieved by maximizing the Net Present Value of future cash flows. This procedure is also called maximizing wealth; and also called maximizing Discounted Cash Flow (DCF).¹ This report uses the last, which seems to be in common

¹There are references in Alaska reports to maximizing the "DCF rate of return." This usage seems ambiguous since the rate of return is held fixed at a rate determined by outside markets when one discounts the cash flow. It is the present value of the cash flow that one maximizes. It is mathematically quite possible and simple to hold the present value fixed and maximize the rate of return instead, using the same mathematical formulae, but treating the interest rate as the unknown to be maximized rather than as a "given." Sometimes this is done when one is out of contact with outside capital markets but there is no need for it here; and it would not affect the findings anyway because, as a rule, maximizing the internal rate of return as it is called will not lead to strikingly different results from maximizing the Discounted Cash Flow, so long as one makes no mistakes in mathematics.

use in Alaska. Businesslike management means adopting the criterion of maximizing DCF.

Maximum DCF is not to be applied rigidly or dogmatically or narrowly as a standard. It does not always comprehend all relevant values and factors. It does, however, comprehend a great many more than critics of the "almighty buck" might realize because it is the net balance arrived at after a long process of adding and balancing all manner of pluses and minuses. In addition, it provides a logical analytical framework within which newly recognized goods and bads may be added to the analysis in carefully measured perspective. One of these, on the minus side, is environmental damage. Some environmental damages are measurable in reduced cash flow. Damage to commercial fisheries is an example. Others are indirectly measurable in the marketplace. For example, the loss of residential and recreational amenities on privately owned land which reduces their service flow is measured in reduced selling prices of titles to the real estate.

Damage to sports fishing reduces an amenity service-flow which is harder to measure than cash flow but no less important on that account. Economists are developing techniques for measuring such service-flows. These techniques are still imperfect, like the rest of this world, but they at least let us set an upper and lower bound on the values and so let us begin to measure them in the same balance with other things.

On the plus side, increased payrolls and commercial sales deriving from oil and gas income will increase residential and

commercial values in some areas. Part of this increase is a "secondary benefit" from oil and gas development and should also be entered into the balance. This obviously gets complicated and extended. It is beyond the scope of this Report to resolve all such issues. The present point is that the use of the crassly materialistic and narrow concept of Discounted Cash Flow does not in any way box us in and preclude us from broadening the scope of the analysis when we have the will and resources to do so. It provides a framework of analysis which is almost indefinitely extensible to comprehend as many variables as we have the ambition to try to consider.

The concept of "discounting the future" disturbs many people but it is only the choice of words which is unfortunate. Discounting does not imply neglecting, abusing or short-changing the future but, rather, charting the most advantageous path into the future. The mechanism discounts poorer paths to the future because there are better ones -- "better" meaning a higher rate of increase of wealth. It is not prodigal to decline a 3 percent path in preference to a 10 percent path.

It is often suspected that discounting the future leads us always in the direction of faster resource use. Not so. We will see that this criterion may well lead the State to retard lease sales and production, so long as the anticipated proceeds to the State are growing faster than money in the bank. On marginal and submarginal lands these net proceeds begin growing from a base near zero. From such a low base they need not grow much in order to grow faster than money in the bank.

Discounting the future requires a discount rate. The State's rate need be no higher than its borrowing rate but it can be a good deal lower when Alaska has surplus funds to invest. There is no suggestion here that the "social" rate of discount is lower than the market, a concept wanting in both precision and rationale. It is, rather, a practical question. If the State cannot invest its surplus for high returns then an investment in the growing value of oil and gas in the ground may be a superior alternative.

Maximizing DCF as a criterion solves two problems for us, problems of timing. One is the optimal rate of production from proven reserves. These timing decisions are largely in the hands of lessees except to the extent that the State interferes with their natural desire to maximize DCF by controlling the rate of production. An equally or more important timing decision is when to begin production. Here the State is in the saddle with its decision of when to sell leases. The DCF criterion says that we should sell leases at that time when we expect that their future value will be growing more slowly than money in the bank. This rationale has been developed in the consultant's previous work, "Extractive Resources and Taxation." The relevant pages are attached as Appendix A.

The State's concern with money is not narrowly centered on lease-hold income but includes tax revenues of course. On the minus side, there will be associated public costs with increased economic activity. An exclusive or unbalanced attention to either the revenues or the costs without the other will always be misleading. It is the

net balance of advantage that we seek to maximize. This should provide a reasonable basis for compromise between the advocates of growth on the one hand and restraint on the other.

While leasing policy should help to protect State revenues, the State has minimal interests in protecting federal revenues from oil and gas. Since the federal rate is much higher than the State rate, especially after the Multistate Tax Compact (MTC) sharing formula is applied, leasing policy may often achieve a net increase of State revenues by being bent to consider the foibles of federal tax law applied to oil and gas, a law which the State follows. Much as we may deplore the peculiar federal tax treatment of income from oil and gas, there seems little reason for the State in its capacity as a landlord to conduct its affairs so as to maximize federal taxation of lessees where that would cut into State revenues from its property.

2. Equity

There is a strong feeling that the distribution of benefits from oil and gas production in Alaska should be equitable. Equitable does not mean equal although there is some suggestion of that in it and it might be more equal than now. There is support for the productivity theory of distribution, however. This means that rewards should be shared in relation to productive contributions rather than other factors like luck of the draw and the weight of superior wealth accumulated in the past.

Tolerance of gambling and the lottery principle has not altogether died. There are residuals of it in the lottery system for allocating noncompetitive leases which are filed on "simultaneously," that is, within one 30-day period, and of course there are lottery elements in the bonus-bidding system. There is a growing interest, however, in shifting from Lady Luck to productivity as a basis for distributing wealth. This is a corollary of a desire for greater equality since productivity is usually more equally distributed than luck, and certainly moreso than accumulated wealth. The Alaska attitude is Jeffersonian: "...there is a natural aristocracy among men. The grounds of this are virtue and talent....There is also an artificial aristocracy, founded on wealth and birth, without either virtue or talent....The natural aristocracy I consider the most precious gift of nature, for the instruction, the trust, and the government of society."

The implication of this is that we should seek to identify and measure that value which belongs to the State, that is the rent of

land, and then collect it. At the same time we leave to lessees all the other values, the ones which they create. Jefferson continued, "What is needed is a wise and frugal government, which shall restrain men from injuring one another, which shall leave them otherwise free to regulate their own pursuits of industry and improvement, and shall not take from the mouth of labor the bread it has earned."

As a happy corollary, if we succeed in this we will protect necessary incentives to the industry and other lessees. A skillful system of discriminating rent collection will leave more incentive to lessees than a blunt instrument such as a royalty accomplishes. A rent-collecting device will take more from the flush deposits in their flush years and less or none from the marginal deposits, leaving incentives unimpaired.

Collecting rent will, to be sure, reduce certain kinds of incentives but these are ones that should be reduced in the interests of efficiency. Resource economists have repeatedly observed that the failure of landlords to collect rent results in overstimulation of resource use by interlopers, resulting in the dissipation of rent, as on the open sea fishery, or an open range. In such a case, reducing incentives is a good thing. It is not enough for incentives to be large; they should motivate people to allocate resources productively.

The prevailing concept of equity also implies that rewards should be related to ability and application more than to the weight of accumulated wealth. In practice this amounts to a suspicion that the present bonus-bidding system with its high requirements for money up

front is filtering out large numbers of potential lessees whose productivity might be high but whose accumulated wealth is low.

A corollary concept here is that reducing the bonus money screen would increase the number of competitive bidders. This, if properly handled, should allow the State to increase its revenues.

3. Practicality

Alaska has traditionally operated with a minimal bureaucracy. While it is increasingly recognized that some additional staff may be very productive, beginning from this low base, there is a presumption against any proposed system that presupposes a large and elaborate and expensive bureaucracy. It is also desirable that there be a low burden of compliance in the form of paper work imposed on lessees and that minimum policing be entailed.

Alaskans have traditionally left considerable latitude of judgment to their higher public officials as well as to technical specialists like reservoir engineers. There is a growing interest in stating objective criteria for these persons to follow, minimizing the burden of judgment and making it easier to evaluate the performance of individuals.

A practical system will be as automatic as possible, minimizing direct regulations and controls which are required when people have to be forced to go against what they perceive to be their economic interests. This is accomplished by drawing leases so as to bind the contracting parties in an identity of interests. The lease should make

the interests of the lessee as nearly as possible identical with those of the State, so he is moved to act in the State's interest by economic incentives rather than orders controlling his rate of production, work commitments, spacing, diligence, and so on.

A very simple system like a royalty system without other features might seem to avoid many problems, but in fact has the shortcoming of involving the lessor in extensive direct regulation in order to offset the disincentive effects of the high royalty rate. A profit share system, allowing for extensive deduction of costs by the lessee, precludes such direct regulations but on the other hand requires extensive audit of expenditures. A rental which is proportional to the appraised value of reserves like the Alaska Reserves Tax avoids the foregoing sets of problems but requires personnel with the ability to place a value on reserves. It is hardly possible to avoid demands for additional personnel under any system designed to protect the interests of the State. It will be a question of determining which system is least costly and most effective to administer.

4. Avoiding economic waste

There is a new and explicit concern with avoiding "economic waste." This is quite a change from and quite an improvement over the prevailing concepts which are limited to preventing "physical waste." The State presently legislates against various kinds of physical waste, for example against flaring and venting gas; against producing from "rate sensitive" reservoirs too fast to maximize "ultimate recovery." In this legislation waste is perceived only in concrete, materialistic terms.

Any subsidy to the industry tends to prevent the "physical waste" of not producing submarginal oil and gas. The State has extended a few such subsidies such as a tax holiday to a pipeline in Cook Inlet. Nonuniformity in taxation is a sort of subsidy to those taxed less, and the term "tax subsidy" is commonly applied to it nowadays. Federal income tax law traditionally extends enormous tax subsidies to the oil and gas industry through preferential treatment. The State has followed along by adopting the federal tax law and in addition has joined the Multistate Tax Compact (MTC) whose allocation formulas minimize State tax revenues from oil and gas. The attitude might perhaps be summed up as "as much as possible, as early as possible."

Producing subeconomic reserves entails not only the economic waste of the excess of costs over revenues, there is also the waste of selling the reserves when they are cheap, instead of later when they probably will have become dear. Our initial criterion of maximizing Discounted Cash Flow (DCF) would tell us to hang on to reserves as long as their value was growing faster than money in the bank.

Past policy in administration has been disposed to take an "infant industry" posture towards oil and gas. Raising money or maximizing State wealth has been secondary to attracting activity and capital. Lease sales have occurred at the initiative of industry nominations more than the State's, with the State not much disposed to hold back for the best price. Encouraging and establishing the industry was ipso facto a good thing.

A policy of leasing on demand will undoubtedly stimulate early exploration which will result in locating deposits that might otherwise not be produced, at least for a while. This might be construed as minimizing physical waste -- the waste of not finding something. There has been little concern about the economic waste inherent in premature and duplicative preleasing exploratory investments. In an earlier phase this was carried to even greater extremes when noncompetitive leases were issued. But leasing on demand at the rather low prices that have been received is only a halfway step between noncompetitive leasing of the free entry, first-come first-served, variety and an economical system which would maximize the discounted cash flow of the State.

As to duplication of effort, this is generally rationalized on the grounds that a second explorer might use a different concept from the first and therefore find something overlooked by the first. That is beautiful so long as cost is no object, but it is really no substitute for a benefit cost analysis that would at least purport to tell us how the cost of a second pass at the shot lines relates to its probability of success.

In regulating field production the concept of maximum efficient rate (MER) has been accepted rather uncritically with the thought that it must be good to maximize ultimate recovery. MER has been accepted not for what might be the legitimate reason that prices are rising or the partly legitimate reason that it requires fewer wells and that saves capital, but rather almost entirely on the grounds that faster flow might cause physical waste. In this case the goal "as early as possible" clashes with the goal "as much as possible" and the latter wins.

The net result of overstimulating preleasing investigation, and decelerating production, is to attract lots of capital into the industry and slow down the rate of recovery. Capital requires to be paid for every year that it is tied up without being recovered. This payment necessarily detracts from the surplus that remains to be captured by the State. This is a kind of economic waste which I believe the State would like to learn to avoid. It dissipates rent.

The traditional conservationist feeling in favor of wide spacing developed at a time when the land surface was subdivided into small private properties, smaller than most oil-bearing structures, so that some offset was needed. The result today is rather one-sided preaching for the benefits of wide spacing without due note of its costs. Such preaching, which is widespread in the literature of this business, also suggests more solicitude for lessees than lessors because the interest of lessors is generally to have lessees apply more capital rather than less, where royalty is being charged. This bias is understandable in an industry where lessees have traditionally dominated lessors by virtue of being larger and fewer; and lessees' agents have written the books.

Where there is a high royalty rate the lessor's interest is to see prompt in-filling at high density. The lessee, on the other hand, might prefer to invest capital by stepping out to someone else's land while dawdling on this.

There is a growing awareness in the State that exclusive pre-occupation with physical waste is a one-track goal which lacks adequate

balancing of benefits against the costs of achieving them. There should be an equal awareness that the problem of one-track goals is not peculiar to oil and gas. Specialists in any resource or activity become interested parties and tend to overvalue it and undervalue the costs of promoting it -- since costs represent a sacrifice of the interests of specialists in other resources and activities. This is a universal problem in an over-specialized world.

Legislators are called on to be generalists, arbitrating among the claims of competing specialists. There is no suggestion here that oil and gas interests are better at this game than other specialists, that their technical inside language is more obscure or intimidating than that used in other professions, or that their high "standards" are more unreasonable than those imposed by other groups of whom we could all supply examples. Focusing on "physical waste" is an overpleading technique not peculiar to the oil and gas industry. We bear down on oil and gas here because it is our subject matter and not because it is outstandingly bad. No industry or profession has any monopoly on self-serving, special pleading, and careerism.

Economic waste occurs whenever we prevent physical waste at a cost higher than the value of the oil saved. This would be simple enough to see and correct if all costs were present costs and all production flows occurred right away. The problem is more subtle because it usually involves the factor of time and therefore questions of capital and compound interest. Some major economic wastes of timing are described in what follows. Please note that I speak not only of what has been and

what is but also of what might be if we adopt certain alternative leasing policies that have been proposed.

a. Slow use of proven reserves

Slow production occurs if the State requires it through MER regulation or if it simply fails to build a fire under lessees whose cost of waiting is virtually nil when there is no substantial delay rental, and who might be "stepping out" with other leases which preoccupy them from attending to this one. Not maximizing DCF means ignoring the cost of interest -- first, the cost of drilling wells and equipping the lease and, second, the holding cost of the unproduced reserves. To schedule production this way is the same as assuming that no profit is required on investments, an assumption inconsistent with the idea usually accepted that some very high rate of return is required in order to interest lessees in taking a lease. This paradox is too often resolved by sloughing the cost onto the State in the form of lower bids for leases, from which lower base the lessee can still earn a good rate of return. This clearly is a bad resolution for the State.

The MER standard developed historically as a reaction to the rule of capture and has had at times a useful history therefore, lending some aura of engineering "authority" to restrictions on production. But it became abused and harnessed to the purpose of helping rationalize price maintenance restrictions; and then it became habitual and traditional, applied in a rote way. It is not appropriate to Alaska today. It can easily become another case of a fixed professional "standard" applied without regard to circumstance or cost, forgetting

that "cost" means more than money. It means an invasion of the standards of other professions and other people who have to make the economic sacrifice.

b. Premature investment

We noted above how a noncompetitive claim-staking system based on priority of claim leads to premature and duplicative investment; and that a system of leasing upon industry demand or nomination halfway resembles a simple claim-staking system. The result is to sink too much capital too soon in the initial phases of exploration, proving up, social infrastructure, equipping leases, mobilizing support facilities, and so on. Money at 10 percent doubles every seven years. Money at 20 percent doubles every four years. To advance investment by a few years, therefore, is the same as doubling the costs.

But as well as neglecting cost-- and often more serious -- premature investment neglects price, the price of the product reflected in the price of the lease. The lessees who buy early aren't neglecting it for they can ride up the escalator, having obtained a lease and being under little pressure to produce quickly. It is the State that is neglecting price when it sells leases too soon at too low a figure. It then plays the lessees' game if it permits or, worse, requires them to produce slowly and at the same time encourages them to go out and acquire more leases.

There should be no implication that the State should hold onto its unsold leases indefinitely, waiting for the top dollar. To everything there is a season and a time for every purpose. The criterion

of maximizing DCF is in keeping with the wisdom of Ecclesiastes for it tells us exactly the best time to sell, namely when the anticipated selling proceeds stop growing faster than money in the bank. Early sale may waste the resource by releasing it for a low price. Later sale may conserve the resource but waste the capital tied up in it. Optimal timing balances the two considerations.

Some things are happening too soon and others are happening too late. Is this just random confusion with no pattern? No, there is a pattern which may be summarized as slow recovery of capital. Capital is put in too soon and taken out too late. The cost of all those extra dollar years of capital time is borne by the State.

A waste imposed by slow turnover is loss of flexibility and adaptability. Each time capital is recovered and replaced it may be brought up to date with new technological developments. The advantage of flexibility is perhaps most obvious in respect to contractual commitments. "Old" gas may be subject to Federal Power Commission (FPC) regulation and tied to a particular pipeline, or it may in any event be under a long-term contract. In an inflationary period there is always an advantage of bringing new supplies on the market at new prices.

There are also more fundamental reasons not dependent on inflation. I have analyzed these in the work already cited and append the relevant pages as Appendix B.

Another route to understating costs is to accept the plea of those with an interest in supplying oil fields that one man's cost is another man's income and therefore to cancel these out. The result of

heeding these arguments is to conceive of benefits in gross rather than net terms. This almost always results in premature development inasmuch as the gross value of a resource is not only greater than the net value but it is positive during that early period when the net value is negative. This kind of argument can be carried even farther by some "economic base" analysts who compute "multipliers" of still more extended benefits proliferating downstream and upstream and sidestream from the resource development, all being dependent on it. If there is much unemployed labor and idle industrial capacity such a case might sometimes be made. In Alaska, which imports labor and oil field materials and steel, there seems little basis for it.

Unfortunately, economic development which is sought after by some and shunned by others is defined by none. This leaves the door open to considerable uncertainty. The extreme prodevelopment posture is that resource discovery creates value and then provides an economic base for multiple benefits all around. Current thinking seems to be moving away from this. Discovery does not create value all alone. It is a cash-register payoff from the larger development of infrastructure, community support facilities, and so on. All activities are mutually supportive, discovery no more so than others, and the other contributors need support, too. The new emphasis on the problems of community impact is some acknowledgment of this.

It is not surprising that people who see mainly the costs of development and disregard the benefits are disposed to wait a longer time before permitting it to take place. They, too, may get carried

away and overstate their position, becoming like Oscar Wilde's crabbed economist who "knew the cost of everything and the value of nothing." In this Report we will not try to resolve these complex and extended issues, but treat the question of multipliers and extended benefits and costs as something of a standoff, except where very specific external costs or benefits may be identified and measured.

Another economic waste to guard against is "cross-subsidy." This is a generic term for what occurs whenever accounts are consolidated and costs are deductible so that high-cost and losing ventures may be rolled in with low-cost and winning ventures. Cross-subsidy is a hazard in every profit-sharing scheme such as the corporate income tax, and it would be a hazard in any profit-sharing lease resembling the corporate income tax. It is a hazard in any lease that resembles utility rate regulation where a lessee is guaranteed a rate of return. The resulting overinvestment of capital is known in the trade as "goldplating," or more formally as the "Averch-Johnson effect."

Goldplating today might often take the seductive form of an excessive lack of resistance to the claims of some worthy cause like environmentalism. The caribou lobby specialists may overvalue that, the energy specialists may overvalue energy but they can join forces in undervaluing the costs of having both, the costs being shifted to others.

Perhaps the commonest manifestation of cross-subsidy is the overextension of subeconomic feeder lines. This is nearly universal elsewhere and will undoubtedly happen here without vigorous efforts to prevent it.

When we combine this pattern of waste with the pattern of improper timing described earlier, they tend to reinforce each other in a general pattern of overdecentralization. Too much capital is applied too early to expand exploration and allied transportation lines. Too little is applied and too late to more intensive development in and around proven reserves. The overall pattern has much in common with imperialism. All of this can be avoided by hewing faithfully to the concept of businesslike management with maximum DCF. That will be our lodestar.

5. External impacts

To allow for the externalities of oil and gas production both positive and negative the State seems evenly divided between those who perceive more pluses than those who perceive more minuses. This is appropriate since there are both kinds. The issue between the polarized parties is sharper, however, than can be resolved by such devices as measuring the value of the sports fishery, for example, and trading off these values for equivalent energy values because some of the very things seen as positive by some like added payrolls, added spending, and increased property values seem negative to others. Change viewed as progress by some is seen as retrogression by others. To measure and then reconcile these attitudes would be far beyond our scope.

We need not, however, leave the matter completely unresolved. A key to reconciliation is in the distribution of gains and losses. There are probably more gains than losses from general economic development since the actors reinforce one another, but the gains are not equally distributed. One man's windfall is another man's wipeout. Many gains are

unearned and received by absentee investors. As the problem is distributive so is the probable solution. Wide distribution of the benefits of oil and gas development will make it much more acceptable. Leasing policy can contribute to this solution, although it is by no means the whole story.

Another external cost imposed on society by extractive industries is frequently instability, and many people fear the boom and bust characteristics of oil and gas and other mining industries. This consideration argues for leases that yield steady revenues and encourage steady activity and it also may argue for a steady flow of lease sales. Neither of these is an absolute, obviously, and must be balanced against the question of getting top dollar by turning production and sales on and off.

6. Coordination with leasing on federal and native lands

Federal and native lands will share common transportation lines and support bases with State lands. They may be on the same structures. State and federal lands especially have extraordinarily long common boundaries in oil-prone areas. The State evinces strong desires not to be led by federal policy and to have some input into federal policy. At the same time, there is no drainage treaty or compact between the different landowners even though England and Norway have managed to work this out on an international basis. Until this is done, clearly a strike near the boundary will force a drainage sale on the other side. If the Feds and the natives get and keep ahead of the State, the State

might do very well by specializing in drainage sales, a policy favored by many. But there is an uncomfortable feeling that this loss of initiative might also impose high costs by letting others determine the location of activity as well as the timing. There is also some fear that division among the three kinds of landlords might divide them for easier conquest by the industry. The State's objective therefore is clearly to achieve a higher degree of cooperation.

C. Elements of Leasing

There are several elements in a lease, most of which are optional and variable along a wide spectrum. Kinds of leases are frequently distinguished by identifying the bid variable; but the constant elements may be more important than the bid variable where they are set at very high rates. Thus we discuss the pros and cons of each element in leasing first, and only at the end discuss the choice of a bid variable.

1. Prior claim: the noncompetitive system

A substantial acreage in Alaska remains under noncompetitive lease. Figures forwarded by Mr. Denton of the DNR for noncompetitive acreage of "oil companies" totaled to 625,000 acres. In addition there is acreage held by individuals. Ranking the companies in order of their net acreage held, we find that the top 10 percent hold 58.9 percent of the noncompetitive net acreage. This compares with 64 percent when we do the same thing for competitive net acreage. Major holders of noncompetitive acreage are Texaco, Union, Cities' Service, Amoco, and Atlantic Richfield. (Major holders of competitive acreage are the same firms plus Sohio, Phillips, BP Alaska, Exxon, Standard of California, and Mobil.) (See Appendix C.)

Noncompetitive systems are widespread outside the United States. Major faults appear to be that they give away State property without payment, and so encourage premature claims and, where there is a work requirement, premature use. The claim-staker rather than the State gets in on the ground floor of the elevator and holds the resource while it appreciates from a zero value up to whatever value its natural richness

warrants. Any rate of return beginning from a base equal to 0 is mathematically infinitely high and therefore not to be lightly given away.

We append an analysis by Professor Michael Crommelin, Faculty of Law, University of Melbourne, Australia (Appendix D).

2. The bonus

There are several advantages to using a high bonus in allocating leases and it has many staunch advocates, including Walter Mead and Milton Lipton. Advantages of a high bonus include:

- a. Large commitment by the lessee -- he will not walk away.
- b. There is no marginal disincentive imposed on the lessee.
- c. The State receives its money up front.
- d. Major corporations have access to market funds at rock bottom interest rates, about 7.5 percent on bonds today, and therefore presumably will discount future expectations at correspondingly low rates. Some of them have access to internal funds whose opportunity cost or alternative use may be even lower in the event the management is embarrassed with more assets than it can manage effectively. Some utilities, in seeking to support their rate bases, have advanced money to invest in leases. This last kind of investment is being cross-subsidized by the profit-making parts of the firm and may yield extremely low marginal rates to the company. Historical evidence presented by Mead from the Gulf of Mexico indicates rates of return of about 7.5 percent.
- e. If the State should be exploited inadvertently it can use the tax mechanism later on to compensate.

f. The transfer is complete and there is no need for policing prices later on, auditing costs and so on.

On the con side, major problems with high bonus payments are the following:

a. High capital barrier to entry, reducing the number of bidders. This is undesirable both because of the concentration of wealth and power which it implies but also because reduced competition might prevent the State's receiving fair value. Data supplied by Mr. Denton when ranked by net acreage indicate that the top 10 percent of the holders of competitive net acreage have 64 percent of the acreage. These top 10 percent consist of Arco, Phillips, Union, SoCal, Exxon, Sohio, Mobil, and Cities' Service. While this degree of concentrated control is not unusual in other places and other industries, it is still higher than many would consider socially desirable.

b. As low as the industry's internal cost of capital may be, the State's effective rate is probably lower. This is a considerable change from the past and calls for a change in policy. The State is no longer desperate for front money but on the contrary is looking for outlets for its permanent fund. The industry, on the other hand, may be entering an era of higher internal interest rates. It is freely alleged that figures like 20 percent are used in determining bonus bids although this is difficult to nail down. It is certain, however, that monumental capital requirements are projected for oil and gas related investment requirements in the next decade, presaging increasing tightness of capital and therefore lower bonus bids relative to resource values.

c. The bonus aggravates the cash crunch since it is synchronized with the need to find capital for drilling and equipping. This may result in underallocation of money to the latter, especially for small firms.

d. The time preference and therefore the production scheduling of different firms is ruled by their internal interest rates which vary from one firm to another. The allocation of credit among companies is based not on marginal productivity but on collateral security. The result is too much time pressure on some lessees and too little on others. The one may depend on extremely rapid use while the other may depend on speculation and delay above and beyond the social interests.

e. The payment is determined and made before enough is known about actual reserves. There is a large lottery element in the outcome and the outcome is not closely correlated with the price paid. The State might sell \$10 billion worth of oil for \$6 million as it apparently did at the 1965 auction at Prudhoe Bay. At the same time it sells some barren land for a high price. The rule of caveat emptor is applied, frequently intentionally by the seller. This constitutes a fraud with malice aforethought, which would not be tolerated in private business dealings and it is questionable if the State should observe a lower level of elementary morality than is expected of private sellers.

f. The distribution of petroleum reserves in nature is extremely unequal as among different deposits and tracts. The result is extreme inequality in the distribution of gains to wealth when all the payments are made up front and the results of successful and unsuccessful gambles fall entirely on the lessee.

g. If, as is generally believed, most investors are risk-averse, then the lottery element in having a high bonus acts as an additional filter screening out possible entrants. This leads to higher concentration and less active competition in the bidding for State property. Also, to the extent that accumulated wealth and a positive attitude towards gambling are factors determining the high bidder, productivity and cost control are less determinants.

h. Use of bonus bidding lends itself to preemptive, preclusive buying by wealthier firms concerned with controlling the market and discouraging competitors.

i. Once a bonus is paid and then a discovery made it is hard and costly to deny production if the environmental damage turns out to be high relative to the value of production. We have just lucked out of one such trap; we might do worse another time.

j. Transfer or sale of lease for a high bonus is a de facto sale of land but without much property tax liability imposed on capital or land (notably excepting the special Alaskan reserves tax). The capital invested in drilling and equipping is partly exempt and the intangible capital developed from exploratory drilling is not taxed. The leasehold interest itself is not always taxed. While such tax relief should result in higher bonus bids, this exacerbates the problem of the front-end filter.

k. The front-end filter becomes even tighter when lease sales are large and there is no slide bidding and the usual 20 percent advance bonus is required.

1. If oil and gas prices are regulated, and of course they are vulnerable to this risk, a bonus paid in the past is not treated as a current cost and not rolled in, resulting in lower prices received, whereas certain kinds of subsequent participation demands by the State might be treated in the regulatory mechanism as costs. In distinguishing between old oil and new oil, regulation may also distinguish between old costs and new costs.

Our worst suspicions of bonus bidding are confirmed by the brilliant, succinct and damning analysis of Alaska's past experience researched and written by my associate, Professor Richard Norgaard of the School of Resource Economics, University of California, Berkeley (Appendix E). Bonuses captured only from 9 percent to 16 percent of the surplus DCF value above costs and royalties in Cook Inlet. There were too few bidders to assure effective competition. Outcomes were wildly unrelated to bonuses bid and paid. Bidders have successfully used advanced gaming strategies and statistical analyses to take advantage of a State without expert staff in these fields. The State has not set adequate reservation prices or screened out fishing bids and overnomination: only 2 percent of the offshore Cook Inlet tracts leased through 1968 have produced. Dr. Norgaard recommends drastic changes.

3. The delay rental

Delay rentals are the smallest of the three major payments in the usual bid, the other two being bonus and royalty. They have been by no means negligible, however, and in Alberta, for example, have run at 50 percent as much as royalties and bonuses at various times. In addition,

as compared with royalties they come earlier, and when we figure compound interest are blown up into an even larger figure.

Delay rentals are usually an annual yearly payment that ceases when production and royalties begin but there is room for many variations. They might continue until production ends, for one. For another, they need not be at a fixed level but might increase in proportion to some index such as cost of living or they might be made proportional to the assessed value of reserves, giving them the character of a property tax on reserves. Another possibility is to pay the bonus on the installment plan over several years. Yet another possibility is the production bonus, a contingent payment which is due only when and if commercial pay-rock is struck. This has some of the character of a bonus and some of the character of a rental and will be treated here.

The advantages of delay rentals and other rentals are the following:

a. Payment is deferred. This has the same effect as extending credit to payers of bonuses and letting them pay on the installment plan. This is of greater advantage to the leaner interloping firms and tends to increase competition.

b. The payment is fixed with respect to production and places no drag on it therefore. Thus it achieves two goals at once that the State is seeking. It shifts payments into the future and it does so without disincentive effect. If anything, it applies positive leverage to accelerate production.

c. At present when the firms need more time they simply request that leases be extended and the request is frequently granted. This involves arbitrary exercise of judgment by officials. It would be better for lessees to pay so much a year and make their own decisions. The pressure would be on them, of course, to accelerate production once the lease was signed. Firms would be less anxious to nominate acreage and insist on lease sales many years in advance of the availability of transportation.

d. Alaska has millions of acres out under lease. It could all be returning more money each year or else be relinquished for future sale at a more propitious time. Alaska is getting \$1.00 per acre year for these lands. OCS lands are yielding \$3.00 per acre year in practice and go higher on drainage and development tracts. Norwegian rentals go up to \$21 per acre year.

e. Most capital is subject to property taxation and must therefore yield a return high enough to cover both interest and property taxes. The investment in withholding oil reserves from production, however, need only yield a competitive interest rate. A delay rental serves to compensate for the lack of property taxation so that the same discount rate is applied in both cases.

f. A rental is terminable in practice when a lease is dropped due to lack of interest. This reduces the risk imposed on the lessee considerably and should result in higher bids on the bid variable, whatever that might be.

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f. A rental is terminable in practice when a lease is dropped due to lack of interest. This reduces the risk imposed on the lessee considerably and should result in higher bids on the bid variable, whatever that might be.

g. A delay rental is smoothly convertible to an ad valorem base at such time as enough is known about the reservoir and its contents to allow reasonably accurate assessment. Thus, instead of being a fixed amount per year it would be a fixed percentage of the assessed value of the reserves, still retaining its key qualities of shifting payments into the future and not varying as a function of production.

On the negative side are the following considerations:

a. Early shutdown. This traditional argument against fixed charges would apply only to one of the several alternative forms of rental, the nonterminable level payment. It can be prevented by adopting one of the declining forms. Professor Rooney's studies (Appendix F) indicate that the problem of early shutdown is not a serious one in general unless there is a substantial bias against investments in pressure maintenance. A constant rental contains no such bias. An ad valorem rental based on the value of as yet unproduced minerals would exempt the value of capital in place and therefore leave the lessee with a substantial investment even at such time as the rental charge approached zero.

b. Rentals are traditionally lowest of the three kinds of lease payments. This suggests that the industry doesn't like them and would not accept them readily. While this point is often made, this consultant discounts it because of other evidence, presented later (Section 7c).

c. Some federal tax provisions favor delayed production, advantages which might be lost by any lease provision which promotes early production.

d. A lessee might promise to pay a high rental and then walk away from the lease in a short number of years if it proves to be unproductive. Some would consider this to be a disadvantage of the system although it is included among the positive aspects as well.

e. The rental is normally fixed ex ante. It therefore has the same lottery qualities as a bonus.

The pros and cons discussed above indicate there are alternative forms of rental, which are listed here:

a. One might pay the bonus on the installment plan over a specified number of years at a specified rate of interest.

b. The traditional "delay rental" terminates when production begins and royalties are paid. It is usually at some fixed level per acre independent of value, although BLM policy permits figures of \$3.00, \$5.00 and \$10.00 per acre, depending on the class of acreage.

c. A rental might increase yearly at a fixed or an accelerating rate during the preproduction period in order to emphasize the landlord's intent to force action.

d. A rent might be level for the term of lease. This is the pattern that must be faulted for forcing early shutdown.

e. A rental might be a specified percentage of the bonus bid, for a fixed number of years. If the percentage were rather high, say 20 or 30 percent, the effect would be nearly the same as option (a.), that is paying the bonus on the installment plan, but with a substantial down payment. If the rate were 100 percent you would have exactly the same effect as an installment plan payment.

f. The rental might be a specified percentage of the appraised value of the unproduced minerals in the ground. This is an ad valorem charge (AVC). It closely resembles the ad valorem property tax in its impact and administration. Administrative aspects of this form of levy, mainly the technique of assessing minerals in the ground, have been ably discussed before this body by Robert Paschall. Basic principles of the application of such a charge are laid out in Appendix H with a numerical example showing how one would use the data in the Van Poollen report on the Sadlerochit Formation to levy the charge, and how it would diminish over time.

The ad valorem charge differs sharply from those discussed previously in that it is based on progressive disclosures of the value of minerals actually present while the others are based, like bonus bids, on ex ante surmising about what might be there. The ad valorem charge (AVC) is ex post discovery, while the other forms of rental are ex ante.

Thus AVC has some of the good and some of the bad qualities of a royalty. Like a royalty, it is based on what is actually in the ground rather than an uninformed guess as to what might be there, and is a function of actual outcomes. It therefore prevents many of the distributive inequities which flaw the system of high bonuses.

On the negative side, again like a royalty, it has some disincentive effect on discovery since discovery and proving of reserves result in higher assessments. The effect is much weaker here than with a royalty, however, because the ad valorem charge is based only on the value of the resource in situ whereas the royalty is also, in effect, a

charge on all the costs of extracting the deposit as well. In the extreme, on a marginal deposit the ad valorem charge will be zero whereas a royalty, could it be collected, would be substantial. Similarly, at the end of life the ad valorem charge falls to zero while royalties continue with a fixed rate.

The two more substantial weaknesses of the ad valorem charge appear to be, first, there is some question about whether assessments can be tolerably accurate in practice, and second, there is some disincentive effect on exploratory drilling. These weaknesses may be substantially overcome by a combined system which would work as follows: There would be two stages in the life of a lease, before and after the discovery of commercial petroleum. Before discovery, the rental would be a specified percentage of the bonus bid (as in paragraph (e.) above). Following discovery, the same percentage would be applied to the assessed value of the discovered reserves. It would progressively rise as more reserves were proven and decline as they were exhausted (see Appendix H).

The presence of several lessees on any one structure would probably prevent substantial concealment of reserves. However, if experience suggested such concealment to be a problem, it might be offset by programs of compulsory disclosure, State participation in drilling, penalties for concealment, and so on. Professor Norgaard (Appendix E) and Professor Rooney (Appendix F) both suggest schemes for State exploration.

g. Lease terms might be quite short, say five years, with rents "renegotiable" at that time. Such "renegotiation" would be rather

unilateral with the State holding the upper hand and would seem to impose unreasonable risks on lessees. Unilateral renegotiation of terms is actually practiced in many countries around the world in the wake of multiplying petroleum prices which made the original lease terms seem egregiously favorable to the lessees. Even American law occasionally permits change of contracts in the face of gross unforeseeable, external change of conditions. In general, however, this seems an unsystematic and arbitrary approach and less desirable than AVC which, although it might be criticized for some arbitrariness in the assessment process, is subject to objective administration and evaluation of performance.

4. The royalty

Production-based royalties are traditionally a large element in mineral leases. The most frequently heard proposal for reducing high front-end bonuses today is to increase royalty rates either directly or through making them the bid variable. The advantages of high royalties would be the following:

a. Payment is deferred. This eases entry for leaner firms and conserves front money for actual drilling and equipping leases. It increases competition and aids small business.

b. Major payments are contingent on the lessee's finding commercial petroleum and are in proportion to the volume, although not the value of what he finds. This reduces the risk element in lease bidding. It also reduces the premium now placed on prior knowledge of what is there and reduces the advantage of firms that can afford extensive early investment in preleasing surveys.

c. It removes the possibility of the lessee's paying a high price for something that is not present and removes the probability of wind-falls when more is present than the market expected.

d. The State now has a lower discount rate than many potential bidders and can better afford to participate in future income at the expense of immediate cash. This must be tempered with the thought that the median voter is poorer than the median corporate shareholder and has a higher time preference. On the other hand, the State is free from federal income tax so that a given percentage return on investment is more attractive to the State than it is to a taxable private body. If it were just a matter of avoiding State taxes this advantage would be spurious, but if the State can successfully avoid federal taxes where private lessees cannot there appears to be a net advantage from the State's own viewpoint. Countering this is the observation that some large energy corporations have succeeded in lowering their effective federal income tax rates to a low percentage of profit, but the answer to that is that it is not an objective of the State to encourage a small number of large firms but to maximize the number of potential entrants into the field, including those too small to take full advantage of tax loopholes.

e. A royalty is the exact opposite of the depletion allowance. Oil and gas firms, in their eagerness to secure depletion allowances, will be willing to pay higher royalties than otherwise, a relationship which might be exploited to benefit the State. However, this again runs counter to the desire to benefit smaller firms inasmuch as the depletion

allowance is now limited to smaller wells and is programmed to shrink progressively over the next few years.

f. A properly attuned royalty might substitute for unitization of a common pool. It may also substitute for direct controls on well-spacing and rates of flow.

In spite of its attractive features, the royalty has a long list of problems.

a. There is no commitment by the lessee. He may tie up land at little cost by merely promising to pay high future royalties and wait for a free ride on his neighbor. A successful bidder who overbids may abandon the lease, but there is no symmetry. The bidder who successfully underbids cashes in at the expense of the lessor, who cannot back out.

b. Marginal deposits are made submarginal and marginal effort on rich deposits is made submarginal. This applies to entire tracts, to the high-cost fringes of low-cost deposits, to the extra wells and capacity needed to give better control of timing, to equipping the lease, to work-overs, to the date of beginning production, to the stretch-out of the entire period of production, to the date of terminating production, to pressure maintenance and secondary recovery, to exploration for smaller and marginal deposits, and to production during high-cost seasons. Vastly more is involved here than the problem of early shutdown usually emphasized.

Royalties are not automatically passed on to consumers. Prices are determined by supply and demand in world markets. The burdens of the royalty system are borne primarily by the landowner in the form of lower net income.

c. A good deal of leakage of surplus cash flow is suffered by the landlord on the low-cost flush deposits, especially during their flush years when the surpluses are yielded. To be sure the prospect of winning these surpluses tends to raise bids all round but as noted, high royalties on low-value deposits are uncollectible whereas low royalties on low-cost deposits are irretrievable.

d. The lessee's incentive to defer production is exaggerated. There is a strong future shift. The mathematics of this are developed in Appendix J. The basic idea may be simply expressed: It costs more to produce faster, and royalties discourage incurring costs (because the resulting output is shared with the landlord but the costs are borne entirely by the lessee). In addition, there is an exaggerated motive to wait for higher prices. A royalty makes a marginal field or unit of production submarginal, but by waiting for higher prices the lessee can wait until it becomes somewhat better than marginal even after paying the royalty.

By the same token, if fluctuating prices are expected or experienced the lessee's motivation to turn production on and off at his convenience is exaggerated. The lessor's royalties are therefore afflicted by instability beyond what would be an optimal adjustment to changing markets. Instability also has negative external effects on impacted communities, of course.

It may be shown mathematically (see Appendix J) that the disincentive of a royalty operates with greatest force on investments that are incurred immediately before their effects are felt in increased


production. That is, it strikes hardest at workovers, at pressure maintenance, secondary recovery, and so on. Its effects are relatively less in respect to investments that occur well in advance of production such as exploration. The overall result of this pattern is a stretch-out of the commitment of unrecovered capital between first outlay and ultimate recovery. This pattern increases overall capital requirements which in turn works to the advantage of wealthier firms and helps to screen out the leaner firms. Thus the royalty system works to the disadvantage of the very firms that it is designed to help.

e. The deferral of revenues hurts the State, of course. The additional deferral caused by the future shift of production hurts even more. Deferral of State revenues is acceptable if it serves the function of encouraging more competitive firms; but deferral of revenues after discovery serves little or no such function. The lessee who discovers commercial pay-rock may cash out immediately in several ways. Companies regularly borrow or issue stock on the basis of discoveries. Not only does this take cash out of them, it does so without incurring any federal tax liability and is thus substantially subsidized by the workings of income tax law. Economists regard the nontaxation of unrealized capital gains to be a major source of bias in tax law. Unrealized gains are an unpreempted potential tax source. It is a good principle of State policy to go after unpreempted revenue sources, as noted earlier, and a royalty fails to do this. On the contrary, it widens the loophole.

f. The lessee may shortchange the lessor by understating the price of produced oil and gas. This has to be policed carefully at some expense.

g. Environmental damage from oil and gas production is more a function of the fact that some production is taking place than it is a variable function of the flow of volume in any year. The royalty-induced stretch-out therefore increases the total environmental damage.

h. There are many more little finds to be discovered than big ones, more poor ones than rich ones. The effect of royalties is to screen out the little ones. This greatly reduces the success ratio where success is defined as simply finding a commercial find that is producible. It screens out the little ones without succeeding in capturing all the rent on the big ones. It tends, therefore, to reduce sharply the number of viable firms since the expected success ratio is an important consideration, especially for the leaner firms which cannot afford a large number of failures. Once again it fails in one of its primary objectives, which is creating an economic environment more favorable to the leaner firms.



The discussion of pros and cons of royalties has centered on the simple concept of a high royalty rate. Some of the disadvantages may be overcome by the use of step royalties, sliding scale royalties, and using royalty as the bid variable which results in different rates on different deposits. Professor Rooney has outlined a workable step-royalty system (Appendix F). In our recommendations we include this among the workable alternatives.

There are many drawbacks, however. The problem with sliding scales is that they slide only with volume, and volume is only one of several factors that need to be considered. In addition, a scale which

is progressive with respect to volume worsens the tendency of royalties to shift production into the future, since the high rate brackets may be avoided by reducing production now and stretching it out. If the rate is progressive per well it may be avoided by drilling more wells.

If it is progressive per tract it also depends arbitrarily on the size of the tract. It causes future shift. And it has a built-in bias against the marginal fringes of superior tracts which may exist where the tract is fractured and complicated.

It takes no account of cost differences which are independent of the volume factor. Thus, a high-volume well in a difficult, remote location gets a high rate while a low-volume well in a convenient location without much depth gets a low rate. It is a blunt instrument.

It makes no distinction between high volume which is the result of natural pressure achieved at no cost, and high volume which is the result of costly pressure maintenance such as that now experienced in several Cook Inlet fields whose volume has been maintained over the years at some cost.

It might be possible to adjust for all these and other variable factors by an extensive and complex system of variable rates based on extended observation of particular circumstances. All this would accomplish is the same thing that might be accomplished generally and accurately by letting costs be deducted. Deducting costs, however, has its own problems, and this lets us avoid them.

One problem with royalties may be solved by the use of a State marketing board. That is the problem of price determination if it

appears that the lessees are fiddling the transfer prices which are used to determine the State's share. This is the approach taken by British Columbia in marketing its natural gas through a provincial marketing board. The royalty is taken as an excess profit of the marketing board. Unfortunately, this only solves one of the several problems of the royalty system. The British Columbia experience has been one of having progressively to raise the field price and reduce its profits in order to stimulate more exploration and production. The basic fault is that it fails to distinguish between the low-cost and the high-cost deposits.

A very useful adjustment in a royalty system is to let the rate increase as a function of an index of petroleum prices. This offsets part of the future shift problem since it removes the incentive to hold back waiting for higher prices. It fails to account for cost changes, however.

Another device similar to a royalty would be taxation levied on a major pipeline. There is a case against any taxation of pipelines, especially underutilized ones, because of their economies of scale.¹ The "six-tenths rule" implies that optimal rates would cover only 60 percent of costs. This implies the need for a subsidy, rather than a tax. I.C.C. regulation is not geared to accommodate this kind of thinking, so we can forget about the subsidy idea. There is also a special case for taxing, TAPS, to recoup the windfalls at Prudhoe. In general, however, taxing

¹ There is an engineering rule of thumb, the "six-tenths rule," that the cost of incremental capacity is 60 percent as high as the unit cost of the capacity before the increment. The rule is inaccurate and not universal but gives a rough notion of what is normal.

pipelines has the same faults as a royalty. (Inflating pipeline rates for reasons other than taxation, as I.C.C. regulation seems to do, has all the bad effects of a royalty without the benefit of raising revenue.)

Another feature of a royalty which may be an advantage or disadvantage is that it may be taken in kind and marketed by the State. This has aroused great enthusiasm in Alaska recently but the kind of enthusiasm suggests the kind of problems that would be encountered, namely domestic use at low productivity in preference to export at higher prices. This is a subsidy. The recipient has to take his subsidy in the one form of underpriced petroleum products and will use them wastefully. Industries which use lots of cheap energy do not constitute an unusually seminal economic base. Energy-intensive industries tend to be capital-intensive, and frequently polluting. Located in remote areas, they generate a minimum of associated activity. As an example there is Kitimat, British Columbia, with its hot house aluminum industry dependent on underpriced power. What would be the effects of reallocating this power to a more diversified community in a more attractive area where it would attract more labor-intensive industry?

5. Specific terms

Here we treat specific terms that are not generally specified in money; but we do not treat field regulations, which are in Section 8. The use of specific terms generally runs counter to the goals of administrative simplicity and objectivity, since terms tend to be arbitrary or discretionary and are usually discrete with sharp black and white boundaries as opposed to incremental pressures which run along a spectrum.

The present treatment is abbreviated in order to reserve more time and space for matters of higher current priority.

a. The term in years

i. The term before beginning production. Five years is usually allowed subject to discretionary extension. It might be better to substitute a delay rental increasing at an increasing rate. Lessees naturally will argue in favor of longer terms. That is their interest. Ours is to sit on the landlord's side of the table. From this position there is much to be said for holding feet to the fire.

ii. The term after beginning production. The practice, of course, is to let the term continue as long as production continues. An alternative is to terminate the lease after the lessee has recovered a volume of reserves previously agreed upon. This is discussed in a later section.

b. Size limits

i. Size per parcel. Professor Stephen Cheung, an authority on leasing systems, has emphasized the landlord's advantage in keeping parcels small. This helps to assure that each lessee, in making a viable operation, will apply a certain minimum of labor and capital to the landlord's land. Lessees argue in favor of larger parcels. Again that is clearly their interest, but it is adverse to the landlord's.

ii. Cumulative total acreage by state and by substate region. There is an argument for limiting the holdings of one firm in any area, in order to increase the operating base of as many potential competitors

as possible. This also assures closer attention to each individual parcel. There are nine firms who currently hold more than 200,000 acres each of competitive leases in Alaska. It is not clear that one firm can effectively explore and operate that many acres at once. However, acreage maxima are difficult to enforce, so that in general we prefer the use of general economic incentives rather than acreage limitations.

iii. A "market-structure impact statement." The State might reasonably mount a substantial antitrust operation, presumably in the Attorney-General's department. Winning bids might be rejected if the Attorney-General's office determined that accepting the bid might tend to reduce competition.

c. Joint bidding

There is a good case for prohibiting joint bidding, which reduces the number of competitors. Professor Norgaard's statement (Appendix E) speaks to this point. Like Professor Mead in an earlier study, Professor Norgaard found that the number of independent bidders is a most important variable determining the size of bids. The counter-argument that joint bidding permits bids to occur which would not otherwise be made, owing to high capital requirements, is unpersuasive where the bidders are large multinational firms, which are simultaneously bidding elsewhere in Alaska and the world.

d. Liability for environmental damage

It would make sense for environmental damages anywhere in Alaska to be made a first lien on the lease from which the offending oil

originated. We might further introduce a progressive element in this by making the liability a first lien on all leases held by the offending company.

For damages beyond the amount thus recoverable, it probably is desirable to make participation in environmental damage insurance a mandatory feature of all State leases.

None of these terms should be imposed in a punitive or negative spirit. The objective is never to damage the industry, but to help the State. The objective is never to penalize larger firms for being large, but to open the door to help smaller firms. We should carefully avoid referring to "the industry" as a block, and praising or blaming it as a whole. Lease terms which favor small business over big business are not hostile to "the industry." They are, rather, designed to help most firms in the industry by offsetting unfair advantages enjoyed by the large and wealthy firms. Whenever the State can help itself by helping the industry it should do so. Whenever the State can help itself by weakening oligopolistic elements in the industry in order to strengthen competitive elements in the industry, it should do so. None of this is "hostile to industry" in general.

In addition, the State's interest as landlord is generally adverse to that of the industry as tenant. In asserting its legitimate property interests, the State is adverse to industry without being hostile to industry. These are all important distinctions which should be held firmly in mind to avoid confusion. The American Petroleum Institute, in one of its publications, argues in favor of larger parcels,

bigger sales at one time, longer terms, and the absence of any reservation price. In opposing the Institute's position, the State is not being "hostile." Rather, it is asserting its own legitimate interests and at the same time being friendly to smaller firms whose interests seem neglected in the API positions.

6. Profit sharing

To overcome the weaknesses of the royalty system the lessor may allow the lessee to deduct from royalty payments an allowance for costs. In return he raises the basic rate charged per barrel. Thus the royalty, which resembles a sales tax, is converted into a profit share resembling an income tax.

The concept is simple enough in regard to regular expenses of operation and routine maintenance which are deducted from production payments in the year in which they are incurred. The allocation of deductions becomes more complicated with respect to capital outlays, and since these are normally quite high relative to ongoing expenses the matter cannot be overlooked.

Capital outlays must be deductible over a considerable period of years, presumably the useful life of the capital. This immediately engages us in a number of complexities and tricky questions which we will discuss under the negative aspects of the proposal.

Since we are dealing with a lease and not a tax on the total income of the multinational corporation, only those costs can be deductible which are expended on site, or in such close conjunction with it that we have no difficulty identifying them. This means that overhead

expenses are not deductible. Neither are federal taxes. The proposal thus resembles what is called a "net proceeds" tax rather than a pure income tax. The distinction is important and fundamental. The income tax is in personam; that is, it is levied on a person or corporation as such. The net proceeds tax, on the other hand, is in rem: it is levied on the income and expenses attributable to a particular "thing," in this case the leasehold.

This also means that interest payments are not deductible. The deduction is based on the value of the capital applied to the site regardless of whether it is debt financed or equity financed. It might seem preferable to allow some deduction for the cost of capital whether it be equity capital or debt capital, but this proposal is considered in the following section, #7.

The lessee might recover his capital on a per year basis or, alternatively, on a per barrel basis. If the latter, it must be subject to some yearly maximum to avoid his recovering his capital '1 in one or two years as would happen with a flush producer. Such accelerated recovery would mean in effect that the lessee's capital would not be tied up for any appreciable number of years and that there was no base remaining on which he could legitimately be said to be contributing to the profit. This in turn would convert the arrangement from profit sharing to simple rent collecting, which is discussed in Section 7. The present proposal is that the State share in the lessee's profits, which presupposes that the lessee still have some unrecovered capital outstanding which contributes to the joint profit.

The per barrel recovery basis resembles the depletion allowance of the income tax and may be thought of in similar terms with this difference: the present proposal limits the depletion allowance to recovery of costs actually incurred. On the surface the per barrel basis might seem much superior to the per year basis of cost recovery, because the per barrel cost credit comes in the form of a depletion allowance and would offset the disincentive effects of the royalty element. Actually this is a minimal advantage for two reasons. One is that there must be an upper limit per year in any event to keep this a profit share system, and the other is that the deduction of current expenses eliminates the disincentive effects of the royalty in the short run in any event. In fact, adding to this a per barrel depletion allowance would have a slight tendency to accelerate production.

Therefore, we do not sharply distinguish between the per barrel basis and the per year basis in discussing the pros and cons.

The advantages of the net proceeds or profit sharing approach are the following:

a. Allowing costs to be deducted overcomes the problems that plague the royalty system without incurring the problems that plague the bonus system. It succeeds in binding the lessor and the lessee in much more of a common interest -- they share the profits and they also share the costs.

This means that we succeed in preserving incentives at the margins, both intensive and extensive, and reduce (without eliminating) the "deadweight loss" that is caused by the disincentive effects of a

royalty. Second, we can and indeed we must charge a basically higher rate which rifles in on the flush producers who have little cost to deduct per barrel and succeeds in extracting a large amount of rent which leaks away when we depend on royalties.

b. Because costs themselves are deducted, this approach obviates the complex schemes of sliding scales and so on which one might use to modify the royalty system to make it approximate a cost sharing system.

c. This approach sustains over a long period of time the union of interests between lessor and lessee.

d. The nonacknowledgement of overhead costs creates minimal bias since this merely results in lower bids for the bid variable. Overhead costs will be roughly proportionate to on-site costs for many firms. For some others, overhead costs will be large relative to on-site costs and they will be discriminated against, but it may be desirable to discourage such firms since their overhead costs will be incurred outside the State and since they tend to be the larger firms. The intent is not to discourage larger firms but to encourage smaller ones relatively.

e. The income received by the State from different leases will be now made progressive with respect to profitability. That is, the State's share per barrel on marginal oil will be zero while its share per barrel on profitable oil will be quite high.

On the negative side, we now create some new problems and are left with some old ones:

a. The basic problem of the royalty system is only partially solved because a large share of the economic costs remains undeductible,

that is, the interest on the lessee's investment. This is normally a high figure compared with current operating costs because in this industry capital costs are very high relative to operating costs. As a result, there will still be some deadweight loss because some marginal opportunities will be made subeconomic and there will also be some leakage of rents because the basic rate cannot be set high enough to extract all the rent from the best deposits.

b. The problem of future shift, which is so exaggerated in the royalty system, is compensated for by cost deduction but not 100 percent compensated for. This point requires mathematical exposition and is treated in Appendix J.

c. There are new and formidable administrative problems in allowing cost deductions, several of which have been suggested above. Substantial staff will be required to frame the system properly in all its details initially and then to administer it. Administrative problems will resemble and approximate those involved in the corporate income tax. They might be considerably ameliorated by legislation requiring disclosure of corporate income tax returns to DNR personnel. This is not altogether on the negative side. Information about the costs of the industry would be of great aid to DNR personnel and administrators in performing their functions effectively. On the negative side, the industry would avoid such exposure and this might reduce bids.

d. The slow recovery of capital allowed, which is an inherent feature of this system, will be harder on the leaner firms which we want to encourage. Of course, the fact that some capital is recoverable is

attractive to all. The fact that it is recoverable only slowly is more acceptable to the richer firms than it is to the leaner ones.

e. The ability to deduct exploratory costs is not worth much where the probability of success is low. Thus, if the success ratio is one in ten, only 10 percent of the preproduction exploratory costs will ever be eligible for deduction. On the other hand, the costs of working over a producing field would all be deductible. This constitutes a large bias in the treatment of different kinds of costs and different parcels, which would need to be compensated for although there may be no simple and administrable way of doing so. It constitutes a serious drawback to a parcel-by-parcel system.

f. There will be some padding of costs and some gold plating which will leak through our best efforts to prevent them. These problems will be greatest on drainage tracts where production is a sure thing. Professor Rooney indicates that padding of costs is a very serious problem in the profit share leases in Long Beach, California.

g. If there is no inflationary adjustment made, the actual capital recovery allowance will be less in constant dollars than the amount of capital invested.

h. The allowance of fixed capital recovery has a negative leverage effect on incentives. It is the opposite from a regular fixed charge which has a positive leverage effect. After the lessee has recovered his allowable capital quota for the year, his incentives will be less. And after he has recovered it for the life of the deposit, his incentives will be permanently less. This pattern is bound to create some distortions.

Another and very different approach to profit sharing is through the State's taking an equity participation in one or more private corporations, as Canada has done with Panarctic Oils and Great Canadian Oil Sands, Limited. This does not directly solve the problem of land disposal, however, unless the State secures its equity by trading land for shares in the corporation. This, however, then makes the State a partner in all the affairs and ventures of the corporation around the world and gets far beyond the basic question of leasing policy which this study addresses.

A distantly related proposal is that offered by Phillips Petroleum that the bonus bid should be recoverable by the lessee as a deduction from royalties. This would either constitute a net cost to the State or else result in higher initial bonus bids in anticipation of later recovery. The latter has no particular advantages and would raise the bonus higher than otherwise and worsen the problem of the front-end filter.

7. Rent-sharing

We have seen how the landlord may share the lessee's costs in effect by letting him write them off against royalties. We've discussed profit sharing where the lessee may write off his operating costs and also his capital costs. The next and last logical step is to let him write off interest on his capital costs as well. What remains, then, for the landlord is the net contribution of the land; that is, the contribution to output which may be attributable to the resources which the landlord contributed. In theory this divides the product exactly as it

should be. The lessee gets a return in proportion to his investment and the landlord gets a return based on the value of his contribution. The question is whether this theoretical ideal can be approached in practice.

There are three basic approaches which are sufficiently different that we will discuss them separately:

a. Guaranteed rate of interest

In this scheme the lessee may deduct from his royalty base the operating costs, the capital costs, plus interest on unrecovered capital. The interest rate would be set at some market-derived figure like 8 or 9 percent. The capital could not be written off immediately. It would have to be depreciated over several years. There are many alternative rates of depreciation and many alternative ways of selecting the life over which capital may be depreciated. Were we to opt for this alternative, we would have to give detailed consideration to the complex choice of depreciation paths and life. An extended discussion of this is premature at this point, however. We would also have to decide whether to allow carry-forward of unused depreciation in years of no production.

b. Front-end recovery of capital

We can let the lessee have the first cut at production, letting him keep the entire proceeds until such time as he shall have recovered all of his deductible capital expenses. In a flush producer this will occur so rapidly that the question of interest rate is not critical. His capital is tied up for such a short period that interest on it is not a large amount. Following this, the State takes the lion's

share of the operating profit, leaving 15 or 20 percent to the operator as an incentive. There will be a bid variable, probably a bonus, to soak up any residual net advantage which operators anticipate.

(An unnecessary variation on this scheme would be to let the bonus also be deductible. As discussed in Section 6, this merely adds to the capital which the lessee has to put in and take out without achieving any particular purpose. Another elegant variation would be to let operators write off their capital outlays against the bonus. This, too, would result in inflating bonus bids and simply constitute lost motion with little net effect. We do not, therefore, discuss these bonus recovery options any further.)

c. Ad valorem charge based on reserves in place

This method has been alluded to earlier in Section 3, dealing with rentals. Like a rental it is based on time rather than production, but unlike the traditional concept of a delay rental it is not determined simply ex ante or per acre, but is based on a continuing assessment of the capacity of a reservoir to produce. It is determined ex post the disclosure of reservoir contents rather than ex ante. Therefore we continue and complete the discussion of it in this section.

There are pros and cons of rent sharing by whichever of the three methods, and then they have their individual pros and cons. First we consider all three collectively. On the positive side, they all have the following benefits:

1. There is a theoretically attainable degree of perfection where there is no deadweight loss. This theoretical perfection is not

attainable in practice but is worthy of note because other systems would impose deadweight losses on the State, even if they could be perfectly administered at zero cost, because of fundamental conceptual defects. In the rent-share schemes every cost of developing any resource is deductible. On marginal resources where the costs just equal the gains the rent share equals zero, so there is no charge levied to have a disincentive effect on the producer.

2. The counterpart of zero deadweight loss is zero leakage of State income into private hands. This again presupposes perfect administration and administrability. Rent is exactly the income properly attributable to the State's share in the joint effort, that is, the share contributed by land which the State owns.

3. The rent share is progressive with respect to profitability, like the profit share, only more so. Oil produced from strictly marginal deposits where costs equal gains yields the State no share whatsoever. But oil produced after the lessee has recovered his capital from rich tracts goes nearly 100 percent to the State. The State gets a higher share from the more "profitable" -- only now we should say "rentable" -- deposits because the basic rate can be so much higher. By virtue of allowing the deductibility of all costs, including interest on investment, we can now increase the basic rate nearly to 100 percent (subject to administrative feasibility).

Ideally, the State's share will be progressive only with respect to that profitability that derives from the land input. Extra profits that come from more efficient management, cutting costs and so on

should accrue to the operator. Whether this can be accomplished depends on how effectively we can audit the deduction of costs. Under alternatives (1.) and (2.) especially, this poses serious problems which we discuss later.

4. Rent sharing is based on ex post disclosures of the outcomes of exploration rather than ex ante guessing.

On the negative side, there are these problems:

1. Rates must be much higher than under other systems. This accentuates incentives to evade, and it makes all valuation questions more critical.

2. By virtue of its efficacy in collecting rents, the system reduces incentives for preleasing exploration. This forces us either to provide substitutes or to come to a decision that the present level is economically excessive and costly. Even if we do so conclude, this will leave a number of firms with a substantial investment in preleasing information subject to some capital loss, which they will resist.

a. Capital recovery with fixed interest

The proposal is to let the lessee write off capital investments against royalties at so much per year. He may write off capital together with interest on unrecovered capital at a fixed rate of interest like 8 or 9 percent. The advantages of this arrangement are the following:

1. The State starts recovering money right away. The lessee's capital continues to work for the State and the lessee remains entangled for a considerable period of time.

2. There is an upper limit on what the lessee can get. He is guaranteed a reasonable rate of return on his investment and little more. He is not relieved of all risks because the guarantee depends on production.

3. In case the State's share is left too low, there is a safety valve in the fact that there is still a bid variable, like the bonus, to soak up any excess of expectations.

4. The guarantee of interest reduces risk, and so reduces any risk premium needed or alleged to attract capital.

5. Full cost recovery with interest eliminates the tendency to slow down production which the royalty imposes (Appendix J).

6. There is no intertemporal bias against early costs incurred long before there is income from the lease. Exploratory drilling is recoverable. Compound interest accrues and may finally be recovered. (This does pose severe auditing problems, however.)

7. There is no temptation to pad capital costs in the declining years, because they can only be taken at so much per year.

Disadvantages are the following:

1. Padding expenses and gold plating. With a high basic royalty rate and generous deductions allowed with interest, the temptation towards boondoggling is at a maximum. The landlord may expect severe problems of monitoring, surveillance and evaluation. This system makes a lessee think and act like a regulated utility. This probably gives some practical notion of its impact. We have learned to survive with regulated utilities even though utilities pad their rate bases. We might similarly learn to survive with this system, in spite of its problems.

There are special aggravated problems in remote areas where "base maintenance," rather than drilling per se, is the largest cost. "Base maintenance" comprises a wide range of the necessities, amenities, follies and recreations of life, a bottomless sink of unauditible expenses.

Just as with profit sharing schemes, there is underrecovery of capital on long-shot, wildcat acreage. The British and Canadians have tried to compensate for this by extending somewhat beyond the individual parcel the area in which accounts may be consolidated, so that the costs of losers may be written off against the gains of winners over some considerable area. They call the boundary of this area the "ring fence." They are vague about how this fence line is drawn. Their system delegates more arbitrary power to civil "servants" than ours does, and may not be tolerable here (or there).

To be sure, federal income taxation contains a bias in favor of risky ventures; leasing upon industry demand, as Alaska has done, has a similar bias. It is difficult to evaluate countervailing biases and this has not been undertaken. If this idea is one that the Legislature wishes to pursue such an investigation would be desirable.

3. The guaranteed interest rate is the same for all firms regardless of their own cost of capital. This is a relative advantage to the wealthier firms whose cost of capital is lower. It is not as great an advantage, however, as that in the bonus element, because the discounted present value of the bonus is derived by discounting all future revenues, not simply those imputable to the lessee's capital.

The lower cost of capital to larger, wealthier firms may be inferred from data in Appendix K. Larger firms make less use of their credit ratings than smaller firms do, even though the credit ratings are better. This is to say that the larger firms could, if they wished, borrow a good deal more at 7.5 or 8 percent but are choosing not to. This displays the presence of internal funds such that the internal cost of capital is no greater than 7.5 percent.

b. Front-end recovery

The proposal is to let the lessee recover his capital at the front end before the State gets anything. The lessee recovers his capital with maximum feasible speed. His stake is in and out so rapidly that it need earn little interest.

The advantages are the following:

1. The incentive is towards haste. The lessee will not dawdle just to have interest pile up. He avoids interest costs by minimizing the period of capital commitment rather than writing off interest at a given rate.

2. There is reduced temptation to pad the early, preproduction outlays, because no interest is allowed. Exploratory drilling is already largely expensible for federal tax, and further temptation by the State might be redundant.

3. There is minimum feasible risk imposed on the lessee except as before where there is wildcat acreage.

4. This system favors the leaner firms. It shifts payments into the future more than any other system. The lessee owes the State

nothing until he has recovered almost everything -- everything that is his.

5. Lessees' capital is kept working in the industry, going in and out in a rapid reciprocating movement. A maximum of work is performed with a minimum of capital tied up. Small firms, particularly, depend on high capital turnover.

6. There is no need to determine depreciable lives and depreciation paths.

7. There is no inflationary leakage because so little time passes between investment and recovery.

The negative points are the following:

1. The premium on early inception may be excessive and in some cases cause wasteful haste. Presumably this could be controlled.

2. There is no explicit provision for the lessee's receiving interest on his capital. He would, however, adjust for this by reducing his bid (for the bid variable, whatever that might be). The best arrangement probably is for the State not to try to capture 100 percent of the cash flow after capital is recovered but to set the rate at 80 percent or so, leaving the bid variable to soak up the remainder.

3. The nominal royalty rate will be extremely high. This will lend itself to exaggeration and misinterpretation by critics who might succeed in having the system changed after the lessees had already recovered their capital, resulting in severe losses to the State. There is no protection against this other than widespread understanding.

4. The problem remains of a bias against wildcat acreage and other long-shot acreage. If the system is attractive enough on other grounds, some means could probably be devised to compensate for this. It would have to be something other than simply letting large firms pool their entire accounts within the State, because this contains a built-in bias in favor of the larger firms just as the corporate income tax does.

5. The temptation to expense dubious capital outlays against any flush producer is overwhelming, posing a severe auditing problem. To be sure, the auditor must be shown that the capital is to be productive on the same parcel, with its diminishing returns from a limited resource. So the possibilities of fraud are finite. In addition, this encourages intensive infilling and development as opposed to overdecentralization, probably a needed antidote to other biases. But this remains a drawback.

c. The ad valorem charge (AVC)

We touched on this method earlier in Section 3, the discussion of rentals, because it has some of the character of a rental, being an annual charge independent of production. We continue the discussion here because it also is a device for sharing rent. The ad valorem charge or AVC resembles a property tax. It consists of a base which is the current appraised value of the resource; and a percentage rate. The charge is the product of the base times the rate. The rate is high and common to all. The base varies from zero up to very high values for superior deposits.

The advantages of this leasing element are the following:

1. It cures the major fault of a high bonus by shifting payments into the future.

2. It cures the major fault of delay rentals by depending on ex post disclosures of what the ground contains rather than ex ante estimates made in the dark.

3. It cures the faults of a high royalty by not varying with production and by allowing for cost differences automatically in the evaluation procedure. That is, high-cost production carries a low AVC base. (In the extreme a marginal deposit has no value at all and hence there is no ad valorem charge.) As a counterpart, AVC minimizes the leakage of rents from low-cost resources out of the State treasury. They carry a high AVC base; and the common rate is high.

4. It cures the fault of profit sharing by allowing interest on the lessee's capital, again automatically in the valuation process. The "automaticity" depends on the appraiser's having proper legislation to work with and upon the legislation's having competent appraisers to implement it, so it is only automatic on the assumption of careful preparation and continued vigilance. The present point is that an appraisal of the resource in situ is always made net of the full costs of developing it and one of these costs is interest on the capital required for the purpose.

5. This lease element cures the fault of other rent-sharing techniques by having no place for padding costs or gold plating. A lessee cannot reduce the assessed value of his property by overdeveloping it. The major risk indeed is the reverse. He might inadvertently get it

increased that way, although this would constitute an error in administration rather than the intent of the system.

The intent is that the appraiser would calculate that schedule of production which maximizes discounted cash flow (DCF). He would value the deposit based on the assumption that that schedule was followed and that only those costs were incurred which were necessary to follow that schedule. Incurring additional costs would not lower the valuation, nor increase it either.

There should be no difficulty about recognizing this concept and procedure because it is what any buyer in the market place goes through when determining what to pay for bare land; and it is what any appraiser goes through when estimating what a market price would be, based on highest and best use.

6. AVC cures the fault of noncompetitive leasing, which is to overstimulate investment in exploration (which occurs whenever landlords fail to collect rent). A concern is that it might overcure the problem, leaving us with inadequate exploration. This is considered further on the negative side, and also in Section 11 on how to motivate exploration.

Overinvestment in exploration is just as much padding and gold plating as any other kind of overinvestment. It is insidious and seductive because it is invisible and hard to evaluate, and because there is in the "cultural subconscious" a proexploratory bias. There is also a federal tax bias for exploration to which the State need not add.

Nevertheless, one could go too far, and we must be careful to preserve enough motive to explore. There are several possible ways of

doing this. One would be to let the lessee recover his postleasing costs of exploratory drilling before the ad valorem charge is imposed. Other options are discussed in Section 11.

7. Like options a. and b., this method of rent collection is progressive with respect to rentability -- the State gets a high share per barrel from rich deposits and little or nothing from marginal deposits. This option scores better on this count than the first two because of the absence of padding and gold plating (which would dissipate rent from richer deposits).

8. Because of advantage #7, this method permits the State to schedule the timing of lease sales in an optimal way, and to get more money from bid-variable-bonuses. Compare it with a high royalty rate. A high royalty rate means that at the time a deposit has risen to marginal status (owing to increased prices or any other cause) it is still worth less than nothing to a lessee after paying the royalty: yet it has a large positive value to the State, or would have if the State could induce a lessee to produce it. This gives the State an interest in selling leases at a time when lessees have little interest in buying them.

This in turn puts the State at a bargaining disadvantage at the time a lease is sold. When, on the other hand, the State's share is based merely on the net value of the resource, the State has an accurate criterion to follow in timing leases. Maximizing the DCF of the State is now socially optimal. This point is discussed in more detail in Section D below.

9. Where the AVC element is large, and appraisals are kept current (as they must be), the State assumes almost all the "passive" risks. Those are the risks imposed by price changes, cost changes, and changes of market interest rates. When prices rise, valuations rise and vice versa. This is appropriate since price basically affects the value of land which is the State's contribution. This also removes a good deal of risk from the lessee. It accomplishes for the lessee just what a perfect hedging market would accomplish.

As to interest rates, when market interest rates rise the capitalization or "cap rate" used in valuation should rise, too. This lowers the valuation and reduces the tax. Mathematically, it reduces the valuation exactly by that amount required to let the lessee continue to earn a market rate of interest at the new market rate. The mathematics is shown in Appendix H.

This is quite an important feature whose importance might not be as immediately obvious as the price hedging feature. It makes the investment less risky than investment in a government bond with a fixed coupon. When market interest rates rise, the value of fixed coupon bonds falls below par. Under the AVC system a rise in market interest rates does not reduce the valuation of mineral deposits by nearly the same amount -- the State's claim falls, protecting the holder from the same degree of price risk that he would experience with a government bond.

Both these features would be attractive to risk-averse investors. This probably would increase the number of bidders for State lands.

10. The valuations of reserves required to operate this system would constitute an inventory of proven reserves, an inventory much more accurate than what is available today and much more objective. This inventory information would be useful in planning community facilities, transportation, and allied infrastructure. The sum total of information known might be little greater than now, but it would all be of public record and centralized in one location and accessible to all State planning agencies as well as to private individuals, local governments, native corporations, and firms interested in exploration on comparable or adjacent lands. The benefits of better planning extend outside the State into consuming states and federal regulatory agencies which are concerned about supply adequacy when pipelines are authorized. This national interest in improved inventory would justify Alaska's requesting financial support for its program.

11. AVC is free from the fault of a royalty, that there is no early commitment. There is an immediate and growing commitment from the lessee to the lessor. This is accomplished without imposing such a heavy front-end load as the bonus does, but without deferring state revenues as much as front-end capital recovery would do. In this respect it is comparable to the Alaska tax on mineral reserves.

This time pattern may approach optimality in terms of the credit needs of all the parties involved, beginning from the assumption that it is desirable to encourage smaller firms as well as to prevent speculation and to protect State revenues. When we look at borrowing rates and credit ratings we note that small firms can borrow for short

periods of time at a small disadvantage compared with large firms. The greater disadvantage of small firms in capital markets is long-term borrowing. The present proposal calls for some short-term advance of capital by the lessee, but not very much in comparison with a high bonus payment.

A pure bonus bid would be derived by discounting future expectations over the next 30 or 40 years, including future gas production which may be way down the line. This means that the same 30 or 40 years will in general be required to recoup the investment. The unrecovered investment must be financed over that whole period. Access to long-term money is what gives larger multinational conglomerated firms their special edge in financial matters. The present proposal cuts deeply into the prospects of future gain from leases and thereby minimizes the need for long-term financing to purchase leases initially.

12. A minor and uncertain potential advantage is that under price regulation by FEA and FPC, with their "cost plus" philosophy, an AVC might be construed as a current operating cost and rolled into the price, in contrast to historical bonuses which might be ignored.

13. AVC moves into one of the largest loopholes in federal tax law, the exemption of unrealized capital gains. After discovery, and before production, there is a large increase in the wealth of the lessee. The increase is bankable and bondable and therefore realizable in cash, but not taxable. AVC, like the Alaska reserves tax, taps this unpreempted source of revenue.

By taking early cash from lessees this might seem to hurt the leaner firms, but not so: they are not asked for cash until they have a bankable asset to raise cash on. At this point they are on the way from lean to fat.

On the negative side are the following drawbacks:

1. AVC is not in common use. We would start near the bottom of a learning curve when introducing a new system. In addition, there must be a lingering suspicion that there could be some reason why it is not in common use.

Tempering this, however, the components of the system are in common use and are acceptable business practices. In 1973 five of eight majors operating in Alberta voluntarily chose an AVC in preference to increased royalties. (Alberta did not follow through.) The concept of a variable payment based on an index determined by fallible human beings is not uncommon. The variable rate mortgage has been successfully introduced. Another acceptable practice is setting farm rents in midwestern counties by "county average yields." This allows for the effect of weather fluctuations. Property taxation everywhere, of course, depends on assessed variations. Almost every investment everywhere in real estate is made subject to this hazard. While valuations vary in quality and complaining is constant, the system has lasted for 2,000 or 3,000 years and undoubtedly will continue. Mr. Paschall has explained how the system works in California and has emphasized that successful appraisal does not presuppose a 100 percent accurate estimate of ultimate reserves. Professor Adelman says: "The development of known oil pools can

be calculated with tolerable accuracy even on the basis of incomplete data" (Adelman, 1969:26), and in his research has demonstrated how one can draw inferences from limited data.

Oil companies buy and sell their reserves, and also each other, based on appraisal. A frequent practice is to hire two recognized appraisers and agree in advance to accept the average of their two appraisals. In a recent case this resulted in a price increment of \$6 million.² Loans and credit ratings are based on appraisals of property value and many outstanding contracts involve payments which are indexed or tied to the consumer price index or other price index.

The question is whether firms would have confidence that an objective assessment would be made by a State employee, and not whether such an objective assessment is possible or acceptable. It is up to the State, therefore, to set up procedures assuring objectivity. Judicial review is one of these and it might be desirable to create a court specializing in this kind of case, to be sure the judge understood the issues. This is the practice in Australian property taxation and is reported to work better than the use of general courts.

2. AVC is a tax on successful exploration to the extent that exploration identifies the reserve whose value is the tax base. Large private landholders in the lower 48 have sometimes deferred exploration in order to avoid property taxation, at least by their own account. This fault is not peculiar to AVC: any system of tapping revenues from proven

² The purchase of McAlester Fuel Co. by Alaska Interstate Co. for \$45.8 million instead of \$39.4 million originally announced (Wall Street Journal, January 6, 1977).

reserves is also a tax on exploration. The problem is worse with AVC, however, by virtue of its greater efficiency in identifying and capturing the rent of proven reserves. Other systems, by their very inefficiency and inaccuracy, allow a considerable leakage of mineral rent out of the State treasury, which in turn serves as an incentive for more exploration.

Preleasing exploration is not the problem, so long as there is a lease sale with a bid variable. The lease sale would provide the same opportunity as it does now for firms to limit the size of their bids in light of the need to earn a rate of return high enough to recoup investment in preleasing exploration. The problem centers about post leasing exploratory drilling.

To keep this problem in perspective, this problem concerns one-tenth of all costs. The Joint Association Survey reported the following breakdown of expenditures from its respondents in 1974. These respondents were estimated to comprise about 76 percent of the revenues of the industry in the United States (Joint Association Survey, 1976).

	<u>Billion \$</u>	<u>%</u>
Exploratory wells	1.6	11
Acquiring undeveloped acreage	5.7	38
Geological and geophysical	.6	4
Development wells	2.7	18
Lease equipment	.8	5
Production expenditures and overhead	<u>3.5</u>	<u>23</u>
Total	14.9	99 ³

³Differences due to rounding

Ad valorem taxes, that is property taxes resembling in their impact our AVC, were included among production expenses and overhead and were equal to \$.4 billion or almost two-thirds as much as was spent on preleasing exploration. Spending on exploratory wells is a substantial but not an overwhelming part of the total, being substantially less than the costs of development and production. While there is a problem to be solved yet, it is not as great a problem as it would be if exploratory drilling were a larger share of total costs.

A partial solution to the problem of motivating exploration adequately is simply to adopt a lower percentage rate for the charge.

Another mitigating factor is that deposits which are expensive to produce, and which therefore carry a low ad valorem base for the AVC, are on the whole the same ones that are expensive to find by virtue of being small, deep, remote and so on. AVC therefore does not take a large bite out of the value of deposits that are expensive to discover but mainly out of those that are cheap to discover. In this respect it is less discouraging to exploration than would be a royalty which raised the same total revenue.

This problem is further explored in Section 11. In general there is a choice to be made between leaving some rent as bait for explorers or paying for exploration by direct contract before leases are signed.

3. As with other rent-collecting devices, the AVC rate is going to be high; so all judgments and decisions are more critical. In order to work properly the system must be more fine-tuned than a royalty

for example. It is something like licensing surgeons to operate instead of giving aspirin. More careful training and control are called for, and personnel capable of more discriminating judgments. I would not overstate this point, because the judgments called for are primarily of one kind -- valuation -- and are subject to review according to preannounced objective criteria. Nor are they regulatory kinds of judgments which involve ordering lessees to do or not to do specific acts. They are nonetheless judgments and the consequences of error may be severe, and this must be reckoned as a fault of this lease element.

Another disadvantage of high rates is the ease with which they may be misinterpreted. A high rate on a small base raises no more money than a low rate on a large base, but more easily evokes images of confiscation. This problem may be ameliorated by using a capitalization rate rather lower than the 18 percent currently in use in the Alaska reserves tax. Eight percent, a market rate of interest, seems more reasonable today. Inflated capitalization rates are the same as underassessment of the base. As indicated, the State is assuming a large share of the risk under this system so that a low, riskless capitalization rate is appropriate.

4. The first few annual payments are preproduction. As compared with some other systems, therefore, this one has a larger front-end load. This issue is discussed under advantage #13.

8. Regulating field operations

In issuing a lease, the State reserves the right to regulate field operations in the interest of preventing waste. This primarily involves control over rate of flow, unitization and spacing.

a. Rate of flow

Where many independently owned tracts overlie a common communicating pool, everyone recognizes that some regulation of flow is needed. This is true even where production is not rate-sensitive, in order to obviate the excess costs of hyperaccelerated withdrawals. Even where physical waste is caused by rapid recovery, it may be the lesser economic waste: capital sunk in excess capacity may be the greater one. The most frequently heard rationale, however, is to prevent physical waste, because of the traditional overemphasis on physical waste. Whichever we emphasize, all hands can agree that some control is needed over rate of flow. This may be accomplished through total unitization, or through prorating allowable flows to individual wells and parcels based on an overall reservoir plan.

It would be most desirable to stipulate that the objective of such a plan, by whatever means administered, be to maximize discounted cash flow (DCF) rather than ultimate recovery. The latter is no criterion at all for reservoirs which are not "rate sensitive," and it is the wrong criterion for those that are.

In Appendix I we present discounted cash flow values derived from different production schedules for the reservoir at Prudhoe Bay as presented in the Van Poollen report. It is clear that the fastest option

which they presented is the one that maximizes the gross DCF without deducting costs. Information on costs is not given in the report. In Appendix I, however, we show what to do with such cost information when it is available. Shifting from the 1.2 MBD schedule to the 1.8 MBD schedule increases gross DCF by \$5.6 billion when a 10 percent discount rate is used. All we need to do now is match this gain against the cost of additional wells required to achieve it. The number of wells and the cost per well are figures that knowledgeable people could supply readily. It is quite likely that they would be less than the gain in DCF, and therefore be justified (in the absence of major considerations not listed here). Even as we complete this Report, the operators are announcing their intent to increase capacity in daily flow towards the upper figure.

Appendix I indicates that optimal flow is not very sensitive to the rate of interest. The gain in gross DCF from speeding up flow is calculated over a wide range of interest rates and is not much affected. To the extent it is affected, the effect is the opposite from what one normally expects in other kinds of investments: at a higher rate of interest more investment in drilling wells is justified rather than less. Most long-term investments, of course, look worse at higher rates of interest. Investment in recovering minerals looks better, because we shift cash flow towards the present.

It might be thought that anticipated rising prices of petroleum products would reduce the optimal rate of flow. So they do but not by very much. The effect of well-head prices rising at 5 percent per year is the same as the effect of lowering the discount rate from 15

percent to 10 percent and Appendix I shows that this effect is not very great.

We must distinguish sharply, however, between anticipated rising prices and absolute high prices at a fixed level. While anticipated future increases tend slightly to reduce optimal flow, high prices today and continuing into the future (but not rising) increase the payoff from investment in additional wells and argue strongly in favor of speedier production. The existence of today's elevated price level, therefore, calls most urgently for review of traditional flow regulation based on MER or maximizing ultimate recovery. In the DCF analysis a slight loss of ultimate recovery is a minimal consideration. Even a substantial loss of ultimate recovery may be small relative to the interest costs of holding unproduced reserves longer than necessary. Tradition has elevated the minimal factor to a maximal and almost the sole criterion of rate determination.

Interest on assets which one owns is an "invisible" cost and all too easily relegated to the limbo of irrelevant, abstruse, philosophical speculation by those who don't actually have to pay it. Proper economy of valuable natural resources would be achieved if we regarded the managers as being saddled with a mortgage equal to the value of the resource, on which interest is due regularly, thus converting the invisible cost into a tangible, painful cash outflow.

A lessee, left to his own devices, will in his own interest act so as to maximize DCF. If the State prohibits this in advance of lease sale, it makes the lease that much less attractive. The cost of

this kind of regulation is thus borne by the State in lower bids. If the State imposes an uneconomical concept of regulating flow it has little gain to show for its cost. By the same reasoning, future leases can be sold at considerably advanced values if they are free from flow regulation based on the concept of MER.

Should the State decide to abandon MER, this also opens the possibility of renegotiating old leases. The State can calculate the present value to the lessee of being allowed to produce faster and offer to sell him that right for that price.

b. Unitization

Unitization may be partial or complete and it may be under the control of the operators exclusively or it may involve extensive State participation and surveillance.

There are advantages in keeping unitization partial. It is always tempting to view the potential gains from total rationalization of a large works project, consisting of many parts, but there is also the danger of losing individual initiative, enterprise and familiarity with the local scene; and there is the danger of doing too much at once. Not all producers are ready to move simultaneously, as we see today at Prudhoe Bay.

A two-tier approach is recommended, analogous to that used in irrigation areas for administration of aquifers overlain by many competing landowners, each with his own water pump. Landowners join in forming a water conservation district which is given the task of aquifer management, and certain powers over withdrawals by individuals. Water

conservation districts generally have inadequate powers, but an analogous petroleum conservation district in Alaska, beginning de novo, need not suffer such limitations. The State might initiate such a district for each communicating pool and make membership compulsory among its lessees.

The argument for this two-tier approach is weaker with petroleum management than it is with aquifer management inasmuch as we cannot visualize a water agency taking over the minutiae of operating every farm, where the water input is relatively much less important than petroleum to an oil firm. Even so, the Joint Association Survey data cited earlier indicate that development and production costs in field management outweigh exploratory well drilling costs by a substantial amount, and it might be letting the tail wag the dog to let unitization become total. Partial unitization could involve trade-offs and adjustments among separate lessees. Where wells need to be divided unevenly among tracts, cash payments could be made to compensate the losers from the gains of the winners. The same can be done when one producer is ready to go and another wants to wait. Whether this is a feasible and superior arrangement in the circumstances would call for extended study, so in this Report we advance the suggestion without endorsing it.

It is desirable as a general principle to minimize the intervention of State officials in decisions which might be left to operators in the field who have a proprietary economic interest in the outcome. The arguments for this are numerous and traditional and need not be repeated here. A great advantage of abandoning the MER criterion and substituting the DCF criterion is that it eliminates the conflict of

goals between the State and the lessees concerning flow regulation, thus making it possible to delegate fuller authority to the lessee operators themselves and minimize State intervention. The presumption today is that the State needs to prevent the operators doing something which is advantageous to them but somehow disadvantageous to the State. Things go better when we can presume that the operators are serving the public interest by attending to their private interests.

The State cannot impose unitization unilaterally where oil-bearing structures straddle the border with federal lands, to say nothing of subjecting federal structures to regulation by State officials. On the other hand, if communicating pools were subject to regulation by an organization of the operators, using a two-tier system like that suggested, it should make it easier to achieve successful unified management in the field. The delegation of operating control and planning to local organizations should obviate the question of which central agency is in charge.

Much of the above presupposes that the State accept DCF in preference to MER as the criterion for regulating flow. Let us therefore recap how we justify spending more money to speed up flow even when that will result in physical waste. Can we accept real physical waste merely for the purpose of saving something as vulgar as money, in a form as profane as interest, and as imaginary as interest foregone on investments which we might have made?

Say it costs \$100 to discover \$50 worth of oil in the ground. The world is telling us something by the way it prices petroleum, as well

as the resources required to develop it. It is telling us that the resources which we sacrifice to gain the petroleum are worth more than the petroleum. This is clear enough when the resource cost is materialistic in the form of steel and when it is personal in the form of labor. It is harder for some people to accept when the cost is entirely financial in the form of interest payments on a mortgage, but interest too is a real social cost.

Interest is the cost of getting your hands on wealth today which you do not own, in order to build something today which will yield you a much greater return in the future. Thus, if you put \$100,000 into a building to be rented, you will get your \$100,000 back in less than ten years, normally, in voluntary payments made by renters. After that everything is a surplus above the cost of production. Over a life of 50 years the unit will probably yield five or six times its initial cost in net cash flow to the owner. Thus, having wealth at your disposal today instead of years down the line is very productive, which is why interest is paid. The rate of interest is the rate of exchange between wealth this year and wealth next year. It is determined in the same kinds of markets that determine conversion factors between apples and oranges.

Economists and businessmen are saying we are in greater danger of running out of capital to develop resources, than we are out of resources in the ground themselves. There is nothing vulgar or profane, therefore, about economizing on capital in a resource-short world. Nor is there anything sacred about economizing on physical resources when the cost is wasting capital.

Let us consider the feeling sometimes expressed that there would be something prodigal about producing rapidly from proven reserves at Prudhoe Bay. A purpose of faster production at Prudhoe Bay would be to fill the pipeline and thus delay the need for new lease sales. The pressure will be on, obviously, to increase production from some source until the pipeline is full. By producing slower at Prudhoe, we would not reduce the withdrawal of petroleum from Alaska; we would rather cause some to be withdrawn from other areas instead. Speeding the flow from Prudhoe means getting the same flow from fewer acres and from a lesser investment in exploration, drilling and equipping wells, and equipping leases.

This is not to argue against advance planning to keep the pipeline full. It is, rather, a matter of planning to do so at the least cost. Doing anything at the least cost involves a small risk of not accomplishing the goal, but that is acceptable. Keeping the pipeline full is not an absolute. It is a desirable thing, if at a reasonable cost. What is required is a careful cost-benefit analysis of the whole picture. It would be a mistake to let leasing policy be dominated by any absolute commitment to keep the pipeline full regardless of cost. When we look at the chaos at the marketing end of the pipeline it would be ludicrous to demand absolute certainty at the production end at the expense of the people of Alaska.

c. Well spacing

This is largely the same issue as rate of flow. Higher flow rates require more wells, more closely spaced. It is not very fitting that the State of Alaska should impose wide spacing requirements on its lessees. This may be a throwback to another situation in another state where surface subdivision caused excessive well density, which had to be countered by public regulation. In Alaska the State is the landlord collecting royalties. The interest of such a landlord is to maximize the capital invested by the lessee. The royalty reduces the operator's incentive to apply capital, and this needs to be countervailed.

Closer spacing in addition to increasing rates of flow may also have some effect in increasing ultimate recovery. In fractured reservoirs with noncommunicating pools, this is obviously true. In other reservoirs it may be true. Little is published on this. It may be desirable for the State to commission a study on this subject: what is the optimal well spacing, well diameter, and rate of flow to be adopted, assuming that the goal is to maximize discounted cash flow net of costs? Most past analysis is not on target because it is premised on the goals of minimizing physical waste, and prorating excess capacity to market demand. Alaska, 1977, is no time and place to be invoking "standards" and going by the book when the standards and the books were developed for other conditions in other places and times.

It sometimes happens that regulators, operating under what appear on the surface to be counterproductive criteria, modify them in practice and make regulation work out better. We have not reviewed

actual procedures, and limit these comments to the criteria which appear to be followed as guidelines, whether by legislative mandate or professional tradition. No criticism is intended or implied of any individual or group.

9. Acreage reservation (checkerboarding)

The Alberta system of crown reservations has attracted considerable attention. Professor Andrew R. Thompson of the University of British Columbia Faculty of Law has been an exponent, although his enthusiasm is reported to be waning. Alberta, too, is modifying and backing away from the system. The concept as explained by Professor Thompson is for ". . . free entry on unproven lands under an exploratory reservation or permit which carries the right to lease, but requires that at least half the acreage, or some other fraction, be relinquished to the State on a checkerboard or corridor pattern after the lapse of a sufficient period of time for completing exploratory work and evaluation. Thus, it is the oil company that . . . must decide when and what to lease . . ." (Thompson 1969:86-87). An attractive feature of this system is, as Thompson points out, that it relieves State officers of a "tremendous burden of decision."

On the negative side, this may also relieve the State of a large quantity of oil since the State (or the Alberta crown) gets the leftovers after the lessee has picked the eyes out of the land.

It does seem advantageous for the Commissioner of Natural Resources, in his discretion, to lease out some areas for exploratory drilling while holding back adjacent and interstitial tracts for later

drainage sales to benefit from the spillover of exploration on the leased tracts. This is discussed further in Section D on the timing of lease sales.

It does not seem advantageous to let the lessee have the choice of lands to select. This is another "blunt instrument" whose results may be capricious and arbitrary. Since finer instruments are available, we do not pursue this further at this time. Authorities who have studied this subject in some depth are Professor Michael Crommelin, Faculty of Law, University of Melbourne, Australia; Professor Andrew R. Thompson; Dr. Campbell Watkins, Petroleum Consultant in Calgary; and Professor Anthony Scott, Faculty of Economics, University of British Columbia. For a fuller description of the Alberta system we are submitting along with this Report a copy of Crommelin, Scott, and Peter Pearse, "Management of Oil and Gas Resources in Alberta: An Economic Evaluation of Public Policy."

10. Sale of undivided interests

It has been proposed that communicating pools or even larger units should be sold as such, rather than as volumes of the earth's crust underneath tracts of land measured on the flat. There are certain advantages:

a. The "transactions costs" of negotiating among the several surface owners would be obviated. Unitization is inherent and automatic.

b. Small firms could take a small interest. The scheme allows for ownership to be divided into many units, let's say 100. Each bidder would indicate a price and also the number of units he wished to acquire

at that price. These would then be ranked in order of price until they added up to 100 percent. The winning bidders would then automatically become an operating consortium.

c. There is a dramatic reduction in risk, since offsetting risks are pooled. There is much less need for preleasing survey, therefore. The structure itself can be confirmed before there is great concern about just where upon it to take a position.

On the negative side, here are some considerations:

a. Entire structures or geologic features would have to be marketed at one stroke. The possibility of the State's withholding acreage for later drainage sale at high price is precluded.

b. The degree of centralized administration may be unnecessary, and the loss of autonomous action by the smaller individual firms undesirable. The controlling operator presumably would be the largest owner of shares and production would be presumably regulated more for his benefit than that of others. Smaller firms would tend to lose some freedom of action. There are alternative unitization methods available which do not impinge on freedom of action to the same degree (see Section 8 above).

c. Professor Rooney's analysis of the Long Beach case sheds some light on problems inherent in undivided interests. The dominant interest there evidently gains considerably by integrating the Long Beach production into its vertically integrated operation. If the smaller interests represented other firms their interests would tend to be neglected.

On the whole this represents an interesting possibility for solving one of the many problems of petroleum leasing, but it is neither broad enough nor promising enough to warrant further discussion in this Report of limited scope.

11. Handling information: generation, control and disclosure

Preleasing investment in geological and geophysical investigation accounted for 4 percent of the expenditures recorded by the firms in the Joint Association Survey (JAS Survey, 1976). For a fairer picture of the importance of these expenses we should multiply by three or so, to account for the time difference. These expenditures take place many years before the others do and before their results show up on the positive side of the income statement. Remember that money doubles every seven years at 10 percent. Then we should multiply by another factor because preleasing work is bigger in Alaska than the lower 48.

The industry pays these costs on the first round but the State inevitably bears them in the form of lower bids. Alternative methods of financing preleasing exploration have therefore been suggested. We will consider the existing system and a couple of alternatives.

- a. The present system: open access to State unleased lands; timing of leasing dependent on industry initiative through the nomination system

Some advantages are the following:

1. It is hard for the State to play the sleeping landlord.

Enterprising private businessmen are free to call the attention of State officials to economic opportunities.

2. Judgmental decisions are in the hands of highly motivated private firms. Several of them are in competition so that many concepts are applied to the same land by people who are rewarded by being creative.

3. The State does not have to bear the cost of conducting its own survey.

4. The system is time-honored and familiar and acceptable to the industry.

On the minus side:

1. Preleasing investment is another front-end filter like a high bonus. It is a tighter screen as well for the leaner firms, at least per dollar involved, because of the long waiting period between investment and recovery and the uncertainty of recovery. A firm possessing no real estate but only intangible wealth in the form of information is not very creditworthy, especially for long-term loans, so that this activity is nearly unfinanceable and requires equity capital. The advantage then is to firms with accumulated wealth.

2. Preleasing exploration adds no value to any real asset owned by the firm and therefore has to find its reward in the firms' acquiring State lands at a low value. An extreme case, of course, is the 1965 sale of 90 percent of the oil in the Prudhoe Bay field for \$6 million. Application by the State of a low "discovery royalty" rate to early finds aggravates this situation. The State gets a lot of wildcat acreage surveyed in this manner, but there is no guarantee that the cost to the State is less than the benefit. It is more likely to be the other

way around. And the State does not get the information. (Nomination does not convey much information, because overnomination is the standard operating procedure.)

3. A counterpart to point #2 is that the firm with a large investment in preleasing exploration may neglect intensive infilling and development of acquired leases, and instead buy more leases. This is implied by the common allegation that many firms do not look at investments that yield less than 20 percent, even though they can borrow at 7.5 or 8 percent. The excess of 20 percent over 8 percent presumably reflects, among other things, some allowance to cover the overhead of preleasing exploration. But if a firm spurns investment opportunities on leases which yield less than 20 percent, it will not apply adequate capital to develop them. This would lead to a pattern of decentralization of development in the State.

4. Duplication and prematurity. Since access is open, the competitive edge in exploration comes only in part from doing the job better. In large part it comes from doing it sooner. The result is "soonerism," somewhat akin to behavior in the Oklahoma land rush when the race went to the swift. In addition, there is a certain amount of costly duplication, some of which may be justified and some of which has been prevented by cooperative line-shooting, but not all of which has been or could be eliminated.

Even where the lines are shot jointly, costly interpretations are duplicated many times without there being any occasion to ask if the first exploratory well might not be a cheaper alternative. By the

time many firms are interested in duplicating the same interpretation it is most likely that the existence of a structure is well known and the purpose of incurring this expense is primarily acquisitive and redistributive rather than productive: that is, it is a matter of jockeying for competitive advantage over other firms wishing to acquire the same resource rather than a matter of increasing the resource.

5. Each firm's information is held tightly secret. Secrecy is almost always counterproductive and expensive to maintain. Secrecy prevents any positive spillover value from information in advance of disclosure. State planning agencies cannot use it and environmentalists cannot use it. Peg Tileston, spokesperson for Alaska Center for the Environment, advises me that industry secrecy about future plans for activities with large environmental impacts ranks at the top of environmentalists' concerns and that full disclosure would go far towards abating many of these concerns. Tina Stonorov, Executive Secretary, Alaska Conservation Society, writes "Thorough public discussion of lease proposals . . . should precede every such decision. . . . If an area is so poorly known that . . . guidelines can't be written, lease sales are obviously premature" (Stonorov, 1976). These concerns are much aggravated by the fact that overnomination is routine on the part of many firms seeking to hide their real intentions.

6. The system is vertically integrated. The firms that explore and nominate a tract early have every advantage in bidding for it at the time, more or less of their choosing, when they nominate it and push for it to be auctioned. There are, to be sure, some firms which

specialize in preleasing exploration and acquisition and then try to sell their acquisitions to production and marketing firms. Such sales are, however, subject to taxation at that time, which the vertically integrated firm is spared.

7. Larger deposits are generally easier to find than smaller ones. This system draws most exploratory effort into the search for big ones where it is least needed and away from the smaller ones. An elephant in the bush looks much better than several birds in the hand. This reinforces the propensity towards decentralization.

8. Preleasing exploration does not necessarily or even generally increase the value of State lands. It may reduce the value if the absence of petroleum is confirmed. This information is of value to potential buyers but not to the State and the State need not feel obligated to pay for it.

9. State officials, to recoup losses, may turn around and knowingly sell bad acreage for high prices as in 1969. It should, I believe, be considered beneath the dignity of a sovereign state, equipped with the powers and immunities of sovereignty, to withhold information that would prevent a businessman from damaging himself by bidding high for defective real estate. The sovereign should be above this game, not part of it.

10. Independent exploratory firms which acquire leases for sale to majors may be exploited by the latter's superior bargaining power.

Because of these several criticisms, alternatives have been suggested which we now consider:

b. Exploration by contract

The State may employ firms specializing in exploration to perform geological and geophysical investigations on the understanding that the results would be made public. Contracts might be drawn in a variety of ways with or without substantial bonus incentives, based on results of investigations. Professor Rooney suggests one method (Appendix G). The State would also do its best to secure greater cooperation from the U.S. Geological Survey, NOAA, and the Department of Interior in order to use information derived from federal lands to learn more about adjacent State lands. Cooperation with native corporations would also be desirable. The advantages would be the following:

1. Preleasing investigations would be unitized, obviating the cost of duplication. The State would recoup its investment in the form of higher bids and it should recoup more than its investment because the bidding firms need not cover the overhead of their duplicative preleasing investments. Entry would be open to many more bidders, resulting in keener competition as well.

Once information has been gathered it costs little to disseminate it. It is a "public good" (a good which, once created, may be provided to any number of people at little extra cost). It probably costs less to publish data than to keep it secret. Some analogous cases where government publicizes valuable information are: weather reporting, earthquake fault-mapping and prediction; navigation aids; road maps; public land survey; the Torrens system of land title registration used in Canada and Australia; farm market reports; farm extension services; public health information; and public education.

2. The State may control timing of lease sales better, reducing industry initiatives with demands for premature nomination. In order to time lease sales in an economic way, State officials need have some basis for predicting expected sale proceeds and this procedure supplies them some of that information. The State at the time of sale can set its own reservation price as well.

3. Contracting explorers would come from the same geo-data industry that presently exists in firms now doing contract work for the industry.

4. The State's exploratory function would not be preclusive. Any firm that can do the job better still has the option of doing so. Thus, while it may be true that the Postal Service is unenterprising, this criticism should be directed against the Post Office and not against the present proposal, which does not contain any prohibition on competition.

5. There is no built-in propensity towards underpricing or overpricing leases, as with the present system. All parties on the buying and selling sides have available all the information that there is.

6. A substantial barrier to entry would be eliminated. Many more firms could bid on any given lease. The State itself would also become an effective "bidder" in the sense that it could set an effective reservation price. Leaner firms have a greater need for foreknowledge and a lesser ability to finance it.

7. The State would assume the riskiest element in the petroleum business, a risk it is able to bear because of its diversification, and a risk which it should bear because the risk is inherent in the land which the State owns.

8. Contracting exploratory firms will be motivated by a desire to enhance their reputations and get future contracts. In addition, various bonus and incentive systems may be adopted which reward them with percentages of what they find.

9. The problem of secrecy is dispelled. Planners and environmentalists can know as much as anyone about what is planned and what is going on.

On the minus side, here are some weak points:

1. Firms in the geo-data industry are not used to allowing disclosure.

2. Incentives are less acute than when the firm is gambling its own money. In the extreme, we might visualize a group of long-haired geology professors out practicing art for art's sake, mindless of any payoff.

We might alleviate this problem by spelling out objectives clearly, keeping contracts short, and shifting away from poor performers. We could give performance bonuses based on findings, even though we know this is a function of what there is to find as well as the skill of the finder. At least we would not be giving it all away in order to get it found.

We could allow two or more contracting firms to explore the same ground, provided we had some rational reason based on evidence to think that might be worth the extra cost (as opposed to the present system of letting all comers in regardless of any evidence of productivity) and the door is always open to others if the government is botching the work. Experience would soon show if officials were capable of being productive. Competition and exposure would stir them up, too -- pride of performance is an important element in competition, regardless of remuneration. Most workers in competitive industry also work on fixed salaries.

A variation of the contract system is the Alberta practice. The province contracts with private firms to put up 30 percent of their costs in return for which it gets their information after a lapse of one year. The Province can, but normally does not, publish the information before a sale of the land in question. Canadians are great compromisers and this system appears to compromise between two or three different principles. The results, we may surmise, will be equally mixed.

Another variation is the incentive-bonus contract. Instead of paying the exploring firm a fixed fee or a cost-plus fee, we may reward it with a percentage (or other function) of the value of its findings. This is similar to the contract system except with greater performance bonuses built into the contract, and lesser cost-plus payments.

Either method has the advantage that the State breaks into a joint in the vertically integrated industry and creates a market at that joint. In this case it is a market for the "products" of exploration

firms. It gets the job done cheaper and without giving away its right to dispose of the resource once its outlines have been discovered.

Incentive-bonus has the advantage of keying motivation more to results. It has the disadvantage that the value added by exploration depends on luck. No matter how skillfully you search and how hard you work you cannot find what isn't there; while a fool may stumble on an elephant in the dark. A good job of exploring barren land will reduce its value by confirming its barrenness. It is hard to find a system for rewarding the effort of exploration on small tracts on an incentive basis.

There is a federal tax problem, too. Cash rewards paid out become ordinary taxable income in contrast to capital gains, only 50 percent of which would be taxable, and in even greater contrast to unrealized capital gains enjoyed by vertically integrated corporations which are not taxable at all. The weight of bias in the federal tax system would work against this proposal. Simple contract exploration doesn't share this fault in the same degree, since the capital gains would be realized by the State which is not taxable. While we should in general be chary of exploiting the State's nontaxability, in this case it seems justified in order to offset the special tax privilege accorded to private firms which are vertically integrated.

Another approach which becomes feasible in the event that we announce our intention to recapture the lion's share of any findings (by any of the various methods described in earlier sections) is to abandon the distinction between preleasing and postleasing exploration. We could

divide State lands into large tracts and lease them as wildcat acreage. In order to be sure that lessees were highly motivated we would subject them to a delay rental which rose annually at an increasing rate or a constant percentage rate of about 10 percent per year. This would assure that no one took out any such lease without exploring diligently.

Instead of the delay rental we might use the shrinking concession as Iran does. Iran progressively takes back a percentage of concession acreage after five, ten, and finally, twelve years, charging \$3.00 per acre year in the meantime.

Another variation on this plan would be modeled on the proposal frequently made and sometimes implemented to base property tax assessments on self-assessment by the landowner. In this case the leaseholder would set his own delay rental, which would be considered an Ad Valorem Charge at a specified percentage of a base value. To prevent his setting a low base value, the lease would contain a reservation stipulating that the State might repossess it for the base value declared by the lessee. Another reservation would open the area to exploration by others who might acquire the lease from the sitting leaseholder by paying him his declared value plus 15 percent. The idea is to allow a reasonable security to the leaseholder but to keep everyone on his toes and avoid exploiting the State by underpayment.

There is little doubt that such a system could be made to work, even though it is novel and would require much explanation and discussion. Among its prominent advocates are Professor Arnold Harberger, University of Chicago, and Professor Daniel Holland, editor of

the National Tax Journal. At this point we merely pose this as a beguiling alternative without lengthy discussion.

d. Postleasing incentives

All systems that take a bite of mineral rents based on ex post disclosures have some tendency to discourage postleasing exploration, primarily exploratory drilling. This is no problem with the bonus system or with delay rentals. A high royalty rate still leaves an incentive to explore for large, rich deposits which still will yield a surplus but biases exploration away from possums in favor of elephants. Profit-sharing and rent-sharing schemes allow the deduction of exploratory outlays, solving the problem but creating another problem of padding.

The Ad Valorem Charge, in most ways ideal, may leave inadequate incentive for exploratory drilling. We can now see several solutions to this problem. One is to allow a deduction for drilling costs, guarding as best we can against padding of costs. Second is the use of high and rising delay rentals. The level of such rentals might be the bid variable. This has the advantage over the first method of raising money instead of giving it away. Third is a time limit on leases. Fourth might be a reservation by the State, in its capacity as assessor, of the right to enter the leasehold to investigate sections not being actively produced. It could also reserve a right to repossess them for the purpose of resale to others.

12. Sale of fixed volume

The State might contract with lessees to sell them a specified volume of oil, subject to the lessee's finding it at the lessee's expense. After the lessee had withdrawn the specified quantity, the lease would terminate and possession revert to the State for future resale, along with capital invested by the lessee. All information generated by the lessee would belong to the State.

The purpose is to get the State's land explored at a reasonable cost without having to give away or sell below value those few extraordinarily valuable deposits.

The effect of the proposal would be similar to paying explorers a fixed finder's fee for any commercial deposit, regardless of its size. It has the advantage that there need be no dispute over whether a deposit is "commercial" or not. The lessee would search until he found one that he himself considered commercial.

The proposal seems potentially workable. It is, however, novel and untried and, insofar as we are aware, undiscussed. It contains several possible pitfalls to guard against, all of which would require further analysis. We omit further discussion here, leaving this for future study if there is interest.

13. State intervention

The State cannot achieve its goal of business-like management without knowing a great deal about the nuts and bolts of the industry with which it is dealing.

On the price side, almost all leasing schemes presuppose accurate knowledge about price. Internal transfer prices of vertically integrated corporations can rarely be taken at face value. In addition to the obvious kinds of fiddling which are possible and frequently discussed, there is the question of volume discounts. There may be a spot market for petroleum at a considerably higher level than the price for firm wholesale supplies. There may be independent refineries that would pay a higher price than the major firms' internal transfer price. What, then, shall we consider the prevailing price?

In a perfectly competitive industry we would find a central market somewhere in which we could have some confidence. In an industry dominated by vertically integrated firms, where oil is frequently swapped for oil rather than for money, where certain markets are dominated by a small number of refineries and marketing networks, these questions assume great importance. The question of marketing is beyond our scope, but it seems obvious that the State would benefit by moving aggressively and definitively in this area to preclude its being exploited by underpricing. A very productive use of royalty oil might be to supply a state marketing agency to "test the waters" and find out what price might be fetched by independent oil offered outside of regular marketing channels.

The possibility should not be overlooked, particularly with natural gas, of dealing directly with governments of the consuming states. These governments, after all, regulate the distribution of gas within their boundaries. California has taken some halting steps in the direction of looking into securing its own supplies of gas reserves.

Here, however, arises another hazard. Consuming states would like nothing better than to capture oil and gas reserves in Alaska, subject to mandatory delivery at regulated low prices. A paramount consideration in leasing policy should always be to blunt the impact of regulation by the FPC and the FEA, agencies whose policies seem calculated to effect a large transfer of wealth from producers to consumers. There need be no sense of guilt about this. California has no more claim on the resources of Alaska than Alaska has on the resources of California; and if California did have such a claim, underpricing gas and oil would be a most inefficient way to assert it. We are not suggesting that Alaska exploit consumers in a monopolistic way; we are, rather, suggesting that Alaska avoid being exploited by consumers in a monopolistic way by consumers with the club of federal power at their command.

Dealing with vertically integrated concerns (with dedicated reserves designated for specific plants and consuming regions) lends itself to this kind of exploitation. Long-term leases dedicated to costly pipelines financed by consumers make the State vulnerable. The shorter the term of the lease, the later it is written, and the more the State depends on the free market, the stronger is its position. All these are complex and ramifying questions beyond our present scope. The present point is that they urgently require attention when a leasing policy is being formed.

Closer to home, access to any common carrier pipeline needs to be aggressively assured by exercise of the good offices of the State. Attorney John Lamont has indicated that equal access to common carrier

pipelines is far from automatic (Lamont, 1974). In order to sell additional North slope leases the State clearly must guarantee potential buyers full and equal access to the pipeline. In the event that producing capacity may exceed transporting capacity, the formula for allocating capacity needs to be specified in advance. Second-class treatment for non-owners of the line will result in second-class bids for State leases.

The choice of a bid variable

There should be a bid variable. There should be an auction at some point in the leasing process. Otherwise we are back at a noncompetitive system with its propensity towards prematurity or "soonerism." We now ask which of the leasing elements makes the best bid variable.

An argument for choosing the royalty as the variable is that a sliding scale is needed to make high royalty rates tolerably workable, and one way of making the scale slide is to let the bidders decide what the rate is to be.

The trouble is, variable royalties will slide on ex ante expectations rather than ex post disclosures. If we do opt for sliding royalties, it would be more feasible in my opinion to base them on objective ex post conditions such as depth, location, size, pressure, bearing strength of surface, length of working season, and so on.

The same considerations, pro and con, apply to profit share bidding in somewhat lesser degree.

When we get to the rent share element there is no need for any sliding scale. Sliding scales are simply means to make royalty and

profit share systems more nearly approximate rent share systems. The idea is to capture as close to 100 percent of the rent as the State can. There is no need to settle for less because rent is a surplus above necessary payments for costs and incentives. It is exactly the value imputable to the natural resource which the State contributes to the production process.

The bonus makes a logical bid variable because it is hard to set in any other way. It is not a percentage of anything fixed or known. To be sure, it could be set equal to the State's appraisal, but this is based on imperfect knowledge ex ante. An additional advantage of the bonus as the bid variable is familiarity and custom.

The problem with the bonus bid variable is that whatever is variable may tend to increase over time in relative importance and we are trying to get away from heavy reliance on bonuses. We may solve this problem easily by tying the bonus and the rental together at a fixed percentage, with the rental being a high percentage of the bonus. If the percentage were 50 percent the bonus bid would be converted to a rental bid with a double rental paid in year 1.

An annual rent has most of the good qualities of a bonus with few of its failings. We would recommend, therefore, that the rent-to-bonus ratio be set quite high. Indeed, the main reason for retaining the bonus element at all is its familiarity.

If we choose to let the ad valorem charge (AVC) be a large element in subsequent lease income, there is attractiveness in using the same rate for both the charge and the rent-to-bonus ratio, let's say 25

percent. Then there may be a smooth transition from the bonus bid as the basis of valuation to an assessment of reserves as the basis, maintaining the same 25 percent rate on each.⁴

If we choose a high delay rental and a system of production-based payments, we can probably improve on the present concept of letting the delay rental lapse when production is shown to be commercially feasible. This contains an arbitrary element, permitting token production or token shows of producibility to terminate the rental. It might be better to let the rental continue and be creditable against production payments. This will pose another arbitrary decision later on when pressure is dropping and production falling, but later arbitrary decisions are less harmful than earlier arbitrary decisions and in this case probably less consequential.

⁴Looking farther ahead, the State may wish to consider actually transferring land title, and go out of the leasing business. The Legislature could create a special class of property, to wit, oil and gas rights transferred to private hands after the date of legislation, subject to a 25 percent ad valorem property tax. The proposed system would lend itself to a smooth transition from public to private property, without there being any giveaway element.

D. Timing Lease Sales

Our position on this question has now been foreshadowed at several points. We will only summarize and recapitulate here.

Decisions about timing lease sales entail the following sequence:

1. The State must determine which leasing procedure and method of repayment it will use before it is possible to determine rationally the optimal timing of lease sales.

2. Potentially leasable lands should be ranked according to "ripeness" or maturity for lease sale. This ranking will be roughly in the order of value. Economists generally agree that it makes sense to use the best resources first, but value is not the only criterion nor is it unambiguous since it could mean value per acre, value per barrel, value per well or value per parcel. The correct criterion does not involve these ambiguities, because it is a percentage.

We are discussing the value of the State's share of the income from the lease and not the value of the leasehold interest. We mean the present value or discounted cash flow of the State's share. This reduces it to a unitary figure. It will be a substantial job to make these estimates and to attach appropriate degrees of certainty to them. This job is indeed impossible so long as preleasing exploration is a monopoly of the potential lessees and the information is not shared with the State. The State must buy or otherwise acquire more information. Professors Rooney and Norgaard both address this vital point (Appendixes G and E).

The next step is to arrive at a forecast of how rapidly we anticipate the present value of the State's share will be rising. This is not a mysterious concept. If we had a simple bonus bidding system it would mean how fast we expected that bonus bids would be rising. If we have a State participation system it means that we calculate the present value or DCF of anticipated State revenues, first on the assumption that we begin the process this year, second on the assumption that we begin next year, third on the assumption that we begin the year after that, and so on.

This all might be done by hunch, but it would be much better to lay the whole process out explicitly on paper in a very systematic way with all the assumptions being stated. This will involve a substantial amount of work the first few times, but specialized personnel may quickly become familiar with the routines involved and devote most of their time to the few questions of judgment which have to be factored in.

3. The basic criterion for ripeness is now assessable. We calculate each year the anticipated percentage growth in the present value of the State's interest in the lease. So long as this figure is higher than the relevant interest rate the time is still unripe for selling.

This is a very different criterion from a "high display of interest" by the industry. It is likely that the "sooner" interest will be high at a time when sooners anticipate future values to be rising at a very high percentage rate. They would like to get in on the fast

part of the growth curve, but there is no advantage in this for the State.

In calculating the State's share, we must be sure to deduct all associated costs and figure only the net value of the State's share. The gross share will always be growing at a slower percentage rate than the net share, so if we focus on the gross we will sell too soon.

We should add State tax collections to the gross, but be sure to subtract associated public costs from the total to arrive at the net. Adding taxes without subtracting public costs will cause us to sell too soon.

We should resist the blandishments of those whose incomes are our costs. Their interest will be to urge us to sell before the time that is optimal for the State.

We should not accept the argument to speed up selling so that development can occur before costs of development rise further. No cost of development is rising anywhere like as fast as the value of oil in the ground, a fact documented earlier. The wellhead price of Swanson River Oil in 1961 was \$1.50 a barrel. If we produced that oil beginning today, fifteen years later, and had it classified as new oil and sold it for \$12.00 a barrel, that is an eightfold increase in fifteen years, which works out to 15 percent per annum compounded. The State can borrow money at a much lower rate than that.

We should not give in to the pressure applied by "socners" who see the value of their map files depreciating with each passing year. The State owes them nothing.

We should not think that selling for top dollar will tend to screen out leaner firms. Lean, efficient firms can pay well for something they can sell quickly. It is long waiting periods that screen out lean firms: they work with impatient money. We can also reduce the price of entry by shrinking the size of the units we sell, as the price per barrel goes up. The later we sell the more profit is to be made on each barrel and the fewer barrels it requires to make a viable operation.

We should remain constantly aware that the owners of the pipeline have much less interest than the State does in waiting for higher prices. Since they own the pipeline and the costs are mostly fixed, their value for oil is at Valdez while ours is at Prudhoe. The percentage increase in value at Prudhoe will always be greater than the percentage increase at Valdez because of the leverage effect.

In forecasting needs for production from new leases, the State should bear in mind the finding from other areas that the major increment to new reserves each year does not come from new discoveries but from the revaluation of proven reserves on extant leases (Lovejoy and Homan, 1967).

4. The appropriate interest rate for the State to use should be no higher than its borrowing rate and might be lower if the State has surplus funds which it is being forced to invest in ventures of questionable marginal productivity merely in order to do something with the Permanent Fund. The State should add a "shadow cost" to its interest rate to account for its freedom from its own State and local taxes. It does not make sense for the State to invest capital or withhold assets

earning 4 percent from its own citizens who might be earning 5 percent, where the extra 1 percent goes to pay State and local taxes. But as to the extra 3 or 4 percent required to pay federal taxes, that is another question. This is 99 percent leakage from the State and so, as a matter of State policy, should not be considered. Federal policy is something else, but that is not our present concern.

5. Just as there is an optimal time to sell leases, so there is an optimal time to begin preleasing exploration. Where the State is contracting this out, the time to begin should be calculated essentially in the same way as the time of selling leases. This will necessarily be done on a much lesser base of information.

6. At the time of lease auctions the State should set a reservation price. The Public Land Law Review Commission found that where all bids were rejected, they were substantially higher at the next auction. Professor Norgaard's analysis (Appendix E) pinpoints this as one of the most needed reforms.

7. The State should give some concern to maintaining a steady flow of lease sales, but should not let that dominate policy. For one thing, it tends to follow automatically from the criteria suggested. That is, a bulge in lease sales will overload the industry and reduce present bids and create, therefore, an expectation of higher future bids.

An artificially contrived steady flow in the face of roller coaster world prices is not advisable. It is extremely costly in lost revenues and one of its major effects is to help the largest firms overcome their diseconomies of scale, that is, their large commitment of

fixed capital. Smaller, more flexible firms are better able to move in and out and take advantage of unstable conditions.

Something along the line of the procedure sketched above has been attempted by Kalter, Tyner and Hughes in their "Alternative Energy Leasing Strategies and Schedules for the Outer Continental Shelf" (Kalter, et al., 1975). I do not vouch for everything in the Kalter report and I believe it leaves out some of the steps specified, yet I recommend it as a first step towards demonstrating how to apply these procedures.

A particular problem in the context of current federal price controls is the need to watch federal regulators carefully with their tendency to discriminate against what they call "old oil." In many natural resource tenure questions there is a grandfatherhood principle of favoritism applied. This indeed is the basis of "soonerism." Federal price control of oil and gas has taken exactly the opposite tack, a reverse grandfatherhood principle, with new producers being allowed better prices than old producers. So long as we may expect this regulatory philosophy to continue, the interest of the State obviously is to defer leasing commitments longer than otherwise. This consideration reinforces other arguments for deferral of leasing and argues strongly for withholding lands from lease. This would not be an antisocial gesture towards the lower 48, but a defensive posture forced on the State by a counterproductive, uneconomical, and irrational Federal policy to which the State has no choice but adapt as best it can.

The State should guard against losing control of its own priorities by being forced into drainage sales along the boundaries of federal and native lands. Some are born decisive, some achieve decisiveness, and some have decisions thrust upon them, often by others with other axes to grind. The State should push for early resolution of uncertain tenures: native over-claims and State selections. It should push for a drainage agreement with federal and native landowners. The more oil- and gas-prone lands it selects, the greater its decision-making role in the energy industry. Whether the recreation industry, one alternative, will be equally consequential in a future of higher energy and transportation costs is a question to which State officials should give much thought.

Another argument for deferring lease sales is the State's desire to extract more tax revenue from the windfalls at Prudhoe Bay. Heavy taxes on petroleum income received by private firms would be borne by the State in lower bids for new leases. If there is to be a period of high taxation of corporate income from petroleum, it would be well not to sell many new leases until this phase shall have ended.

E. Procedural Implications: Administrative Load and Staff Needs

We may now summarize and recapitulate our observations about staff needs.

Past policy has been dominated and limited by a traditional emphasis on economy of staff. Sales policy over a considerable period was dominated by the short-run cash needs of the State, a passive posture of nonmanagement. These traditions are inappropriate now that the State's oil and gas assets have become so large and are ripening into even higher values.

Yet the Legislature is appropriately cautious about plunging ahead blindly, building a costly administrative empire without making careful, discriminating judgments as to what is most required. One need not look far for examples of valuable public resources whose administrations eat up much of the rents that might be returned to the Treasury.

Economists are aware of a serious perceptual bias, however, which makes most people more aware of padded payrolls than padded capital budgets, the latter being in general a worse problem. The capital-intensive and land-intensive bias of bureaucracies is easily explained: once capital is acquired and captured, its annual cost no longer appears in the budget. Payrolls, on the other hand, are a regular cash outflow, highly visible and much easier to jump on, fairly or not.

A recommendation, therefore, is to make a conscious effort to compensate for this bias. An excellent way is to maintain a constant appraisal of the value of the assets disposed over by the bureaucracy and impose a

"shadow mortgage" on the agency equal to the appraised value of its resources. If we discover that the annual value of the nonlabor input, measured in this way, is much greater than the cost of the personnel we are using to administer it, it will give us a better perspective on the potential productivity of additional personnel.

Having said that we still want to economize on personnel. This does not mean underpaying them, which is one of the more expensive "economies" known to public administration. It does mean adopting those leasing methods which involve the least lost motion. Lost motion results when the basic leasing concept fails to bind the lessee and the lessor in a community of interest. The cheapest leasing method to administer is the one which sets up the least conflict.

High royalties rate poorly on this score. The State shares in the gross income but not in the costs. The State is a landlord administering a share-cropping system. Historical experience with sharecropping shows that successful landlords always oversee many details of their tenants' operation. They have to require the tenant to apply minimum amounts of labor and capital per acre. Thus, a royalty system leads inevitably towards work commitments, with extensive State intervention into operating decisions, which in turn presupposes large staff requirements. Thus, the royalty system, which at first seems so simple, is not simple to administer successfully.

The next step beyond royalty is profit sharing. This in turn requires constant auditing of expenditures. Staff requirements here may be compared with Internal Revenue Service requirements in the kind and

quantity of personnel. Some staff requirements could be obviated by borrowing information from the federal agency. However, the kind of information required for the net proceeds approach, presupposed with individual leases, might be difficult to obtain. In addition, federal tax returns are limited by the peculiar institutions of federal taxation of oil and gas, which we do not wish to emulate.

If we use a profit share system or a rent share system where the interest rate is guaranteed, we must solve complex problems about the useful lives and depreciation paths of capital assets. Many of these are treated as current expenses for federal purposes so that we cannot simply borrow the federal rules, even if we regard them as well conceived in the first place.

An advantage of the front-end recovery system is that we do not have to decide about depreciation lives and paths.

All cost sharing schemes, however, pose us a choice between two evils. We may submit to exploitation through cost padding or we may build up a large audit staff whose job is to trace down the endless and mind-bending maze of avoidance devices which may be and have been utilized to transfer profits to controlled companies elsewhere.

If we opt for the ad valorem charge approach, we need to staff up a large appraisal section. We need a staff of professional appraisers supported by additional reservoir engineers. On the other hand, we can dispense with the auditors and we need to be involved in imposing work commitments on lessors. Appraisal itself is a species of audit, and the ad valorem charge imposes its own kind of work commitment on the

person who has to pay it. Where the administration of cost sharing may be compared with the Internal Revenue Service, the administration of the ad valorem charge may be compared with property tax assessment.

Whether we choose royalties or cost sharing or ad valorem charge, we cut into private motivation to explore the underground and will need to allocate some cash to acquire the information in other ways, either in-house, or by contracting out exploration, or by Rooney's Exploration Expenditure Bidding (Appendix G). Either way, the appropriations committee will see the cash outflow and have to use inference and analysis to be persuaded that the bids received for State property are higher as a result. We should guard against the resulting perceptual bias leading us to overestimate the costs relative to the gains.

The next step in eliminating administrative costs is to move back to an ex ante system with emphasis on the bid bonus and/or a corresponding delay rental. These systems appear to relieve us of some administrative burden.

Note well, however, that in order to time sales properly we need the services of an appraisal staff, even if we use a simple bonus system. We need to be able to set a reservation price in case the bids are all too low, and above all we need to know the rate at which probable sales prices are increasing, in order to know the optimal time to sell. We would obviate the simpler appraisal task of valuing resources ex post discovery and description, but make more critical the more difficult task of appraisal before disclosure of outcomes.

An appraisal staff is also needed to assess environmental impacts which may be measured as the difference in the value of property before and after the impact.

Our most unambiguous staffing recommendation is, therefore, the creation and staffing of an appraisal section. Appraisal gets right to the heart of the rent-collecting business which is to distinguish high-cost deposits from low-cost deposits. It gets right to the heart of timing leasing sales which is putting a value on the State's share and its rate of growth. It gets to the matter of environmental impacts as just mentioned. It supplies an inventory to be used in planning. It is a means of collecting and organizing information in the most generally useful way.

Whatever leasing method is selected, staff resources should be set aside for constant review and evaluation. There should be a postmortem on every sale. How did we do? What mistakes did we make? How can we avoid them next time? Few of us would welcome intensive scrutiny of all our past decisions and understand the reluctance of others to be similarly scrutinized. Yet we all recognize the potential value in such review when applied to others, like the surgeon who just took out our kid's tonsils. It would be desirable, therefore, to institutionalize the postmortem review procedure.

While these are all important matters an excessive concern with them would be premature at this time. The first priority is to legislate basic businesslike guidelines for managing the State's extremely valuable resources. No administration can perform any better than its legislative

mandate allows and an excessive concern with administrative questions at this time would interfere with putting full priority on the larger question of specifying the basic conceptual guidelines and criteria for businesslike management.

F. Leasing and Taxation

Comparisons of leasing alternatives and taxation alternatives have been made throughout this Report. We will not repeat, but bring out points not made elsewhere.

Various lease elements have their counterparts in various taxation elements, but a lease is a binding contract which cannot be unilaterally changed by future legislatures, unlike a tax. A lease can discriminate against interstate commerce unlike a tax (for example, by allowing deduction of in-State costs but not out-of-State costs). A lease is an interest in real estate from which the State can reserve all manner of powers to itself, which it can hardly do when imposing a tax.

A lease differs from most familiar taxes in that it is in rem, that is it is attached to a piece of real estate rather than being in personam, that is an obligation of individuals as such. While this differentiates it from most taxes, it makes it similar to the property tax which is also in rem.

Any attempt to use the corporate income tax in lieu of an adequate leasing policy meets with only limited success because the tax is in personam, and requires an audit of all the affairs of the corporation, and requires interstate sharing, and is subject to the interstate commerce clause. The alternative, "net proceeds" tax, has been criticized by Ziefman and Ainsworth. (Ziefman and Ainsworth, 1977).

The tax instrument that we see as most capable of substituting for leasing policy would be a special, classified property tax to be imposed

either on leasehold interest in oil and gas, or on title to oil and gas after that had been passed from the State to a private buyer. This would closely resemble the proposed ad valorem charge, but would be subject to future changes of rates since the present legislature cannot bind future legislatures in tax matters.

G. Tentative Recommendations

Recommendations are offered tentatively by listing alternative leasing elements in what the consultant now believes to be their order of preference. This listing is not designed to persuade. On the contrary, it may serve to put readers on notice of the consultant's personal judgments which may have unconsciously affected his marshaling of the arguments. Nor is our position ready to be chiseled in stone. This is a complex new field; we have a lot to learn and the consultant reserves the right to change his mind subject to new information and new insights.

I would screen out the systems based on ex ante forecasts, and go with one of the ex post systems. This means primarily that I would not continue depending on a high front-end bonus. This is not because of any universal antipathy to bonuses. In the analogous matter of timber sales from federal forests, I prefer the bonus system as practiced by the BLM in preference to a stumpage rate based on scaled volume as practiced by the Forest Service. Standing timber may be cruised with tolerable accuracy before bids are made and accepted, and the period of time involved is or can be short.

Here on the other hand, we are dealing with resources much less well known in advance and whose extraction extends over two or three decades following the investment in the bonus. Even a five-year contract, as used in some forest sales, screens out many worthy operators without accumulated wealth and would much better be payable on the installment

plan to avoid this problem. To require bidders to pay in advance for an unknown possibility of acquiring a 20- or 30-year supply is virtually to substitute wealth for productivity as the effective basis of allocation. The possession of great wealth suggests there may have been past productivity, although predation and privilege are also sources of wealth. It is no guarantee of present or future productivity.

Whatever system is chosen it needs to be accompanied by vigorous inquiry into the transfer prices being used as the basis of valuation. If costs are to be made deductible the same holds true in spades.

I would place greatest emphasis on that lease element I have called the ad valorem charge (AVC). As indicated earlier, use of this element detracts from the motivation for exploratory drilling and this needs to be compensated for. A high and rising delay rental is recommended.

If we wish to retain the form and terminology of the bonus system, we could describe this as a low signature bonus paid on the installment plan followed by a high production bonus or discovery bonus whose size depends on the flow of production.

To strengthen the State's hand in appraisal and minimize concealment of reserves it would be desirable to accompany this system with a program of State-financed contract exploration with publicity of findings. (Appendix E and Appendix G) This is not, however, absolutely necessary. We could have AVC postleasing, while continuing to rely on the present system of privately financed preleasing exploration.

An ad valorem charge (AVC) at a high rate obviates reservations of acreage for the purpose of getting top dollar at drainage sales. AVC

assures that the State will collect these surpluses anyway.

My second choice would be profit sharing, without front-end recovery or recovery of interest at a guaranteed rate. This is a compromise among the pros and cons of different systems. Royalties, on the one hand, impose too much deadweight loss as the landlord shares revenues without sharing the costs. Sharing costs, on the other hand, in a high degree at a high rate is not administrable. There will be excessive padding.

Profit sharing is somewhat less paddable and hence, with severe policing, would be workable. Since costs may be written off against royalties, but without interest, its bias is mostly against costs which are incurred long before they result in increased production. We have noted that there is too much of that anyway, that several factors conspire to stretch out the period between investment and recovery of capital.

There is a substantial policing benefit to compensate for the social cost of not letting interest costs be deductible against production payments. Interest costs are invisible to most people, and somewhat mysterious, and not so easily perceived as padding. Most people perceive padding in terms of putting relatives on the payroll, featherbedding, girlfriends, and other labor-related offenses. These are highly visible and easily understood, hence likely to be overstressed relative to padding of interest payments. But capital can be lazy, too, and undoubtedly will be if interest payments are guaranteed. Profit sharing avoids this problem.

My third choice is a variable royalty with rates varying according to a variety of objective criteria which could be combined in a point system. Rates would be high where costs are low and vice versa. It would

not do simply to assume that volume of flow is the only important factor affecting costs and to have a sliding or step scale increasing with flow. Several other cost factors, probably including several not even alluded to in our previous discussion, need to be entered into the formula. We could remove the future shift effect by limiting the term of the lease to about 25 years or less.

The advantage of this system over actual deduction of cash expenses is the absence of opportunities for padding. Royalty rates would be low where the characteristics of deposits indicated that a prudent operator of average capability would incur high costs. Individuals who performed better than this standard would reap the rewards of their own efficiency.

The system could be progressively amended and improved over the years as experience indicated that the cost of overcoming certain handicaps had been overestimated or underestimated.

In some ways this system resembles the AVC, being based on an outside objective appraisal of the differential value of different deposits. It is something like having the Legislature play the role of assessor when it sets up the point system. Whether this is practicable is partly a question of how many variables there are which affect costs of production. If there are only a few whose effects on costs can be accurately specified then this system might be workable.

My fourth choice would be front-end recovery. This is preferable to guaranteeing a rate of interest because fast recovery is so much more important to lean firms than to rich ones. This system is to be compared with the privilege of expensing capital investments for income tax purposes.

The problem is that any capital expenditure could be written off immediately against a flush producer, opening the door to extensive goldplating and dissipation of rent. Auditing problems are not insurmountable: there is a limit to the credulity of any auditor as to what may legitimately be justified in expending to develop a specific mineral deposit, and auditors would be highly specialized in the oil and gas business.

If either the profit-share, variable royalty, or front-end recovery system is adopted it needs to be preceded by a substantial delay rents to commit the lessee to performance.

We would not recommend returning to the non-competitive or other claim-staking system. We would not recommend high front-end bonuses. We would not recommend exclusive reliance on annual rentals determined ex ante. We are mildly enthusiastic about unitization, but prefer a two-tier system coupling individual operation of tracts with overall reservoir management subject to control by lessees themselves, and encouraged by the State to maximize discounted cash flow for the group. An effective two-tier system might permit parcels to be smaller than now, a subject we have not explored.

We would not object to putting an upper limit on the acreage controlled by any one lessee, but regard this as difficult to enforce, somewhat arbitrary, and probably unnecessary if other suggested changes are made. We would not object to leases' being subject to an antitrust impact evaluation by the Attorney-General, although we view this as legalistic, potentially arbitrary, and less desirable than generalized incentives designed to encourage competition.

We believe that liability for environmental damages downstream from a lease should be a lien on the leasehold interest (not on the State's interest) up to the full value of the leasehold interest, provided the damages occur in Alaska. It would be desirable for this lien to extend to all the leasehold interests held by the company committing the damages, introducing a progressive element into risk liability.

Leases should be transferable. All information generated on State-owned lands should be reserved to the State and made public immediately. The State should extend its good offices in the form of a guarantee to all leaseholders that they may have equal access to common carrier transportation. Differences among different leaseholders on the same structure as to desired rates of production are to be resolved by transfers from those preferring slower rates to those who prefer faster rates at a field price to be set by State authority, based on an appraisal of true market value.

Various lesser recommendations on a variety of points have been made from time to time as we proceeded.

We believe the measures recommended would constitute an effective response to the challenge of oil and gas leasing policy in Alaska.

Acknowledgments

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rates of extraction from the Sadlerochit Reservoir; the Tanzer report to the State Legislature; the Lipton statement; the work of Campbell Watkins on the economics of oil reservoir development; and Martin Stern's paper, "A Policy Impact Model for the Supply of Depletable Resources." All of these have proved to be fertile sources of information and ideas along with many other works too numerous to list, some of which no doubt should be listed on the same level with those already mentioned if memory only served and time were long enough.

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SEC. A

1 IN THE HOUSE

BY THE RULES COMMITTEE BY
REQUEST OF THE GOVERNOR

2 HOUSE BILL NO. 854

3 IN THE LEGISLATURE OF THE STATE OF ALASKA

4 TENTH LEGISLATURE - SECOND SESSION

5 A BILL

6 For an Act entitled: "An Act relating to the leasing and exploration of
7 state land for oil and gas development."

8 BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

9 Section 1. AS 38.05.180 is repealed and re-enacted to read:

10 Sec. 38.05.180. OIL AND GAS LEASING. (a) The legislature finds
11 that

12 (1) the people of Alaska have an interest in the develop-
13 ment of the state's oil and gas resources to

14 (A) maximize the economic recovery of the resources;

15 (B) minimize the exploitation of these natural resources
16 in protection of the public interest;

17 (C) maximize competition among parties seeking to
18 explore and develop the resources;

19 (D) maximize use of Alaska's human resources in the
20 development of the resources;

21 (2) it is in the best interests of the state to encourage
22 an assessment of its oil and gas resources and to allow the maximum
23 flexibility in the methods of issuing leases to

24 (A) recognize the many varied geographical regions of
25 the state and the different costs of exploring for oil and gas in
26 these regions;

27 (B) recognize the need for stimulating development in
28 particular regions of the state;

29 (C) minimize the adverse impact of exploration, develop-

1 ment, production, and transportation activity on the environment
2 of the state;

3 (D) maximize state revenue from profitable oil and gas
4 production, while minimizing revenue from unsuccessful explora-
5 tion and from marginal economic oil and gas production.

6 (b) The commissioner shall prepare, review, revise, and maintain
7 an oil and gas leasing program as follows:

8 (1) The leasing program shall be submitted to the legisla-
9 ture for its information within 10 days after the convening of each
10 regular session of the legislature. The leasi program must indicate
11 as precisely as practicable the size, timing, and location of leasing
12 activity which the commissioner determines will best meet state needs
13 for the following five-year period. The commissioner shall establish
14 the timing and location of leasing, to the maximum extent practicable,
15 so as to obtain a balance between the potential for environmental
16 damage, the potential for the discovery of oil and gas and the poten-
17 tial for adverse impact on the local communities in the state.

18 (2) After the leasing program has been prepared by the
19 commissioner, a lease shall be issued if it is for an area included in
20 the leasing program; however, leasing may continue until January 1,
21 1980 or until a program is prepared, whichever is sooner, and leasing
22 under (t) of this section may be excepted from the leasing program if
23 the commissioner finds it to be in the best interests of the state.

24 (3) The commissioner shall review the leasing program at
25 least once each year, at which time he may revise and reapprove the
26 program.

27 (4) The commissi~~on~~ shall, by regulation, establish proce-
28 dures for

29 (A) receipt and ~~con~~sideration of nominations for any

1 A lessee who fails to discharge a work commitment in its entirety is
2 liable to the state for the undischarged portion of the commitment.
3 At his discretion, the commissioner may terminate the work commitment
4 if he finds that the work would be unnecessary or cumulative.

5 (i) At his discretion, the commissioner may enter into an agree-
6 ment whereby, with the consent of the lessee, the state's royalty
7 share of oil and gas production may be stored or retained in storage
8 by the lessee, or the commissioner may enter into an agreement with
9 one or more of the affected field lease holders to trade current
10 royalty production from a field for a like amount, kind, and quality
11 of future production, on the condition that the state receives back
12 its stored or traded royalty share during the first half of the esti-
13 mated field life or no later than 15 years after start of production,
14 whichever is sooner.

15 (j) An oil and gas lease must cover a reasonably compact area
16 not exceeding 5,760 acres, and must be for a period of five years.
17 The commissioner may grant a lease for a term greater than five years
18 but not to exceed 10 years, where he finds that the longer period is
19 necessary to encourage exploration and development in areas where
20 environmental conditions severely restrict operations. An oil and gas
21 lease shall be automatically renewed if and for so long thereafter as
22 oil or gas is produced in paying quantities from the lease or, if the
23 lease is committed to a unit approved by the commissioner. A lease
24 issued under this section covering land on which there is a well
25 capable of producing oil or gas in paying quantities does not expire
26 because the lessee fails to produce oil or gas unless the lessee is
27 allowed reasonable time to place the well on a producing status. Upon
28 renewal, the commissioner may increase lease rentals so long as the
29 increased rental rate does not exceed 150 per cent of the rate for the

1 preceding year. The commissioner may provide by regulation and in the
2 lease that the lessee may earn production rights only to the depth
3 drilled at the beginning of production from the lease. If drilling
4 has commenced on the expiration date of the primary term of the lease
5 and is continued with reasonable diligence, including such operations
6 as redrilling, sidetracking, or other means necessary to reach the
7 originally proposed bottom hole location, the lease continues in
8 effect until 90 days after drilling has ceased and for so long there-
9 after as oil or gas is produced in paying quantities.

10 (k) The commissioner may establish by regulation that after a
11 well has been plugged and abandoned, the rental rate which was in
12 effect during the year of abandonment is maintained for the remainder
13 of the term. Rental is payable in advance and continues un'til income
14 to the state from royalty, net profit, or exploration work commitment
15 exceeds rental income to the state for that year; after the rental
16 income schedule has been exceeded for three consecutive years, the
17 rental terminates. Oil and gas leases shall provide for payment to
18 the state of rental on the following basis:

- 19 (1) for the first year, \$1.00 per acre;
- 20 (2) for the second year, \$1.50 per acre;
- 21 (3) for the third year, \$2.00 per acre;
- 22 (4) for the fourth year, \$2.50 per acre;
- 23 (5) for the fifth year, \$3.00 per acre.

24 (1) Upon timely application as provided by regulation, the state
25 may issue to the holder of a federal or private lease, a state shore-
26 lands lease covering land within the exterior boundaries of the federal
27 or private lease which has been excluded on the basis of navigability
28 or which is later administratively or judicially determined to be
29 shoreland. The term of such a state shoreland lease shall be the same

1 as the term of the federal or private lease, but may not exceed five
2 years.

3 (m) To conserve the natural resources of all or a part of an oil
4 or gas pool, field, or like area, whether or not the part is then
5 subject to a cooperative or unit plan of development or operation,
6 lessees and their representatives may unite with each other, or jointly
7 or separately with others, in collectively adopting or operating under
8 a cooperative or a unit plan of development or operation of the pool,
9 field, or like area, or a part of it, when determined and certified by
10 the commissioner to be necessary or advisable in the public interest.
11 The commissioner may, with the consent of the holders of leases
12 involved, establish, change, or revoke drilling, producing, rental
13 minimum royalty, and royalty requirements of the leases and adopt
14 regulations with reference to the leases, with like consent on the
15 part of the lessees, in connection with the institution and operation
16 of a cooperative or unit plan as he determines necessary or proper to
17 secure the proper protection of the public interest. The commissioner
18 may require oil and gas leases issued under this section to contain a
19 provision requiring the lessee to operate under a reasonable coopera-
20 tive or unit plan, and he may prescribe a plan under which the lessee
21 must operate. The plan must adequately protect all parties in interest,
22 including the state.

23 (n) A plan authorized by (m) of this section, which includes
24 land owned by the state, may contain a provision vesting the commis-
25 sioner, or a person, committee, or state agency with authority to
26 modify from time to time the rate of prospecting and development and
27 the quantity and rate of production under the plan. All leases
28 operated under a plan approved or prescribed by the commissioner are
29 excepted in determining holdings or control under sec. 140 of this

1 chapter. The provisions of this section concerning cooperative or
2 unit plans are in addition to, and do not affect AS 31.05.

3 (o) Producing acreage on a known geologic structure of a produc-
4 ing oil or gas field is excluded from chargeability as against the
5 acreage limitation provisions of sec. 140 of this chapter.

6 (p) When separate tracts cannot be individually developed and
7 operated in conformity with an established well-spacing or development
8 program, a lease, or a portion of a lease, may be pooled with other
9 land, whether or not owned by the state, under a communitization or
10 drilling agreement providing for an apportionment of production or
11 royalties among the separate tracts of land comprising the drilling or
12 spacing unit when determined by the commissioner to be in the public
13 interest. Operations or production under the agreement are considered
14 as operations or production as to each lease committed to the agreement.

15 (q) The commissioner may, on conditions which he prescribes,
16 approve drilling, or development contracts made by one or more lessees
17 of oil or gas leases, with one or more persons, when, in his discretion,
18 the conservation of natural resources or the public convenience or
19 necessity requires it or the interests of the state are best served.
20 All leases operated under approved drilling or development contracts,
21 and interests under them, are excepted in determining holding or
22 control under sec. 140 of this chapter. Drilling or development
23 contracts may include, at the discretion of the commissioner, pro-
24 visions authorizing the state to share in the costs of exploration.

25 (r) To avoid waste or to promote conservation of natural resources,
26 the commissioner may authorize the subsurface storage of oil or gas
27 whether or not produced from state land, in land leased or subject to
28 lease under this section. This authorization may provide for the
29 payment of a storage fee or rental on the stored oil or gas, or,

1 instead of the fee or rental, for a royalty other than that prescribed
2 in the lease when the stored oil or gas is produced in conjunction
3 with oil or gas not previously produced in paying quantities.

4 (s) Each oil or gas lease issued by the state must contain a
5 provision requiring the lessee to furnish the Department of Labor a
6 quarterly report regarding the employment of state residents on the
7 leased property. The commissioner of labor shall adopt regulations
8 necessary to implement this subsection. No lease issued under this
9 chapter is valid unless it contains provisions requiring the employ-
10 ment of qualified Alaska residents in accordance with AS 38.40.030,
11 and complies in all respects with the requirements of ch. 40 of this
12 title.

13 (t) Notwithstanding any other provision of this section, land
14 which has been offered for lease within the previous five years but
15 which received no bids at competitive sale may be, ^{Upon a written} ~~at the discretion~~
16 ^{of the commissioner, immediately} offered for lease, under regulations
17 adopted by him, upon terms appearing most advantageous to the state,
18 including leasing noncompetitively. The commissioner shall use a
19 sliding scale royalty based upon such formulae as he determines to be
20 in the public interest but not less than 12 1/2 per cent at the begin-
21 ning of production from the lease in amount or value of the production
22 removed or sold from the lease or unit area encompassing the lease. A
23 lease must provide for payment to the state of rental but need not
24 adhere to the rental schedule in (k) of this section nor to the 5,760-
25 acres-per-lease limitation in (j) of this section. The lease term may
26 not exceed five years except as provided in (j) and (k). ^{on}

27 (u) The commissioner may, by regulation, restrict joint bidding
28 ^(change) ~~by~~ major or multi-national oil and gas companies) to encourage competi-
29 tion.

1 (v) The state has the right to purchase not more than 16 2/3 per
2 cent of the volume of oil and up to 100 per cent of the volume of gas
3 produced from a lease issued in accordance with this section, at the
4 regulated price, or, if no regulated price applies, at the fair
5 market value at the point of sale, except that any oil or gas obtained
6 by the state as royalty or net profits shall be credited against the
7 amount that may be purchased under this subsection. Oil and gas
8 purchased under this section may be used by the state in the same
9 manner as it uses its royalty oil and gas.





10 (w) A lessee or permittee conducting any exploration for, or
11 development or production of, oil or gas on state land shall provide
12 the commissioner access to all data obtained from that activity and
13 shall provide copies of specific data, as the commissioner may request.

14 * Sec. 2. AS 38.05.135(b) is repealed and re-enacted to read:

15 (b) When minerals are to be leased, in addition to any other
16 notice given, notice must also be given as provided in secs. 305 and
17 345 of this chapter.

18 * Sec. 3. AS 38.05.140(c) is amended to read:

19 (c) No person may take or hold at one time phosphate leases on
20 state lands exceeding in the aggregate 10,240 acres. No person may
21 take or hold sodium leases or permits during the life of sodium leases
22 on state lands, exceeding in the aggregate acreage 5,120 acres, except
23 that the commissioner may, where it is necessary in order to secure
24 the economic mining of sodium compounds, permit a person to take or
25 hold sodium leases or permits for up to 15,360 acres. No person may
26 take or hold at any one time oil or gas leases exceeding in the aggre-
27 gate 500,000 acres granted on tide and submerged lands, and 200,000
28 [500,000] acres on all land [LANDS] other than tide and submerged land
29 [LANDS], including leases held both as lessee and under option or



1 operating agreement from others. A person has five years from the
2 effective date of this Act to conform to the 200,000-acre upland
3 limitation. Where more than a single person holds an interest in an
4 oil or gas lease, each person shall be charged only with that percentage
5 of the total acreage which corresponds to its percentage share of the
6 total beneficial interest in the lease.

7 * Sec. 4. AS 38.05.145(b) is repealed.
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SEC. B

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES

A STUDY OF STATE
PETROLEUM LEASING METHODS
AND POSSIBLE ALTERNATIVES

A REPORT TO THE STATE OF ALASKA, JAY S. HAMMOND, GOVERNOR,
DEPARTMENT OF NATURAL RESOURCES, GUY MARTIN, COMMISSIONER,
AND TO THE
ALASKA STATE LEGISLATURE, INTERIM COMMITTEE ON OIL AND
GAS TAXATION AND LEASING POLICY, CHANCY CROFT, CHAIRMAN

FEBRUARY 1977

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

JAY S. HAMMOND, GOVERNOR

11TH FLOOR, STATE OFFICE BLDG.
POUCH M - JUNEAU 99811

February 17, 1977

The Honorable Jay S. Hammond
Governor of Alaska
Pouch A
Juneau, Alaska 99811

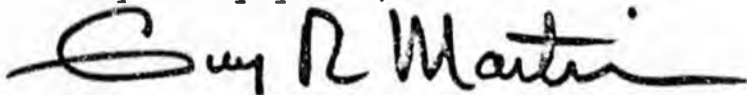
Dear Governor Hammond:

The following report regarding State oil and gas leasing has been prepared by the Department of Natural Resources as a part of a joint Administration-Legislature effort to evaluate the present leasing system and to explore alternatives for the future. The overall study effort, for which I served as Project Director, also includes other Department documents, the reports of independent consultants and miscellaneous other information.

The information in this report, and the entire study, is intended to serve as basic background material to illuminate alternative State objectives and leasing methods which may be desirable for the future. Although some conclusions are reached in parts of the various studies, no final comprehensive conclusions or positions have been reached, pending further analysis of the results of the study project and discussion thereof.

The complexity and importance of the oil and gas leasing issue for the future of the State has thus far sustained an ideal level of constructive cooperation between the Administration and Legislature, and I am hopeful that this report will contribute to an informed outcome on this matter.

Very truly yours,



Guy R. Martin
Commissioner

Acknowledgements

This study was prepared in sections by different people in the Department of Natural Resources. Staff members active in the preparation of the specific sections include:

For the Sensitivity of State Petroleum Income to Various Leasing Methods

Patrick Dobey	Blair Wondzell
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For the Variation of Petroleum Leasing Criteria with Geographic Location

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---------------	------------------

For the History of Leasing in Alaska

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For the Staff and Budgeting Needs of Some Leasing Methods Considered

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---------------	----------

Foreword, Statutory, and Administrative

O. K. Gilbreth, Jr.

In addition, Michael Scott of the Institute of Social and Economic Research and Frank McMordie and David Cook of Garrett Computing Services provided invaluable consulting services.

FOREWORD

This report has been prepared in response to Departmental and Legislative interest in the methods and policies of competitive leasing of state lands for oil and gas purposes. A fairly complete history has been compiled showing pertinent information on past practices of the State. Summaries of all lease sales, bonuses, rentals, receipts and results of drilling and royalty awards are discussed. As a result of this report, it can be concluded that some types of bidding will theoretically yield greater income to the State under specific circumstances than other types will. From strictly a monetary point of view, this study reveals that four major factors will determine which method of bidding would be most advisable for the State to follow. The amount of income to be derived by the State will be determined by the level of risk, the size of the reservoir, the cost of exploration and development, and the value of the oil at the wellhead.

This report has revealed some areas that require further study and this will be done in the coming months. For example, the study reveals that with current economic, royalty, and tax conditions, the minimum size field that an oil and gas operator can afford to look for in Alaska must exceed 55 million barrels in close in areas such as Cook Inlet and could be 100 million barrels or more in remote areas. Also since special cases arise from marginal fields, more detail analysis should be made of effects of reducing royalties to encourage production in sub-economic fields.

Since the purpose of this report is to show variations that can result from various types of bidding most of the emphasis is on types of bidding

other than the cash bonus system. It should not be construed however, as condemning cash bonus bidding nor recommending any alternate type of bidding. The analyses are presented merely to show relative income under specific sets of assumed conditions. A change in some of the input factors can give substantial changes in results.

Risk is the most significant of the variables which would affect income to the State. In unknown, undrilled, untested areas, where the information level is low the risk will be extremely high and these analyses indicate that the cash bonus bidding method would yield greater income to the State. As more information becomes available and as the risk decreases, the method which yields the greatest monetary return revolves around some type of royalty bidding. After a discovery is made, any open acreage on the structure in essence becomes drainage acreage, risk will be low and royalty or some other type of bidding may yield a far greater income to the State than the cash bonus type of bidding. Somewhere then between the extremes of no information and maximum information the method yielding the greatest income probably will switch from cash bonus bidding to some other type of bidding. A significant result of this study indicates that state income can be increased for all leasing methods studied by using a percentage acreage option which is withholding a portion of the structure for later leasing. Other types of bidding are discussed to accomplish other purposes.

There are increasing pressures on government to secure more information about state lands and to know more about the possibilities of petroleum occurrences before the lands are leased. These analyses have been made on the assumption that more information will be available to the State

and if those conditions exist we feel that the values shown give reliable indications of benefits to be derived from one method as compared to another method of bidding.

Risk is dependent on the amount of information available to industry and income to the State is dependent on the knowledge industry has in an area. This study assumes that geological and geophysical information is available to the State at a level above that which it now has. Obtaining this additional information will require expenditure of larger sums of money than in the past. The reader is cautioned not to use the values shown as indicative of all conditions, because as mentioned above, significantly different results are obtained as input factors change. The uncertainty of crude oil prices in remote areas could cause input parameters to change significantly with corresponding changes in analysis results. Therefore, the information presented is to compare one method of bidding versus another method of bidding for a specific set of circumstances.

Administrative costs and number of personnel can vary greatly depending on the leasing method used. An ad valorem type of leasing could cost up to \$240,000 more per year to administer where a net profits system might add \$500,000 with the same number of operators and leases as we now have. In Alberta it is pointed out that 100 people administer 50,000 lease agreements and 60 people are involved with auditing in a cost sharing leasing system.

From an administrative cost standpoint, the present method of operation results in the lowest total operating cost at about \$1.1 million per year. Depending on the level of data acquisition and analysis, costs will increase

from the present quarter million dollars per year. To obtain adequate seismic data for managing an area of 100 miles by 15 miles will cost from \$70,000 to over \$1,500,000. The present budget contains \$110,000 for the purpose in FY 78.

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DESCRIPTION OF LEASING METHODS IN HB854

Currently, the State of Alaska's leasing system is a cash bonus bid with a minimum fixed royalty of 12.5 percent. The methods outlined below include the present system with different fixed royalties, sliding scale royalty with bonus bid, sliding scale royalty bid with fixed bonus, net profit share bid with fixed bonus, royalty bid with fixed bonus and exploration work commitment. The basic elements of these methods are summarized below.

(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 or auctioned 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. To avoid early termination of production, royalties need to be flexible during a field's declining years.

(2) Sliding Scale Royalty With Bonus Bid (or Sliding Scale Bid with Fixed Bonus)

Under this system, the government receives a cash bonus bid and a sliding scale royalty. We used 12.5 percent as a minimum figure and 62.5 percent as a ceiling wherein the rate in any period is dependent upon the production of that period.

The royalty rate is graduated in much the same manner as the federal personal income tax. Table I gives two examples of a sliding scale royalty schedule. The royalty is progressive, that is, the royalty on additional production increases. For example, in the South Central Area, the initial 500 barrels pay a royalty of 12.5 percent, the next 500 barrels pay 25 percent. The royalty rate increases by 12.5 percentage points per 500 barrels until 2000 barrels of output are achieved. All production beyond 2001 barrels pays a royalty of 62.5 percent. Thus, if production reaches 5000 barrels, the average royalty rate is 50 percent. In the limit, the average rate would converge towards 62.5 percent as daily production continues to increase.

As field productivity declines and well production falls, the producer backs down the schedule and royalties decline. In order to optimally exploit the field, the royalties should decline to zero near the end of field life. Actually, final rates of five or six percent would result in minimal early shut down.

TABLE I
TYPICAL SLIDING SCALE ROYALTY SCHEDULES

SOUTH CENTRAL AREA

Daily Average Prod. Rate (Bbls./day)	Incremental Royalty Rate (%)	Royalty For Specific Producing Rates		
		Producing Rate (Bbls./day)	Royalty Production (Bbls./day)	Average Royalty Rate (%)
-500	12.5	500	62.5	12.50
501-1000	25.0	1000	187.5	18.75
1001-1500	37.5	1500	375.0	25.00
1501-2000	50.0	2000	625.0	31.25
2001-2500	62.5	2500	937.5	37.50
		3500	1562.5	44.64
		4500	2187.5	48.61
		5000	2500.0	50.00

NORTH SLOPE AREA

Daily Average Prod. Rate (Bbls./day)	Incremental Royalty Rate (%)	Royalty For Specific Producing Rates		
		Producing Rate (Bbls./day)	Royalty Production (Bbls./day)	Average Royalty Rate (%)
-1000	12.5	1000	125	12.50
1001-2000	25.0	2000	375	18.75
2001-3000	37.5	3000	750	25.00
3001-4000	50.0	4000	1250	31.25
4001 and above	62.5	5000	1875	37.50
		7000	3125	44.64
		9000	4375	48.61
		10000	5000	50.00

Note: The Sliding Scale Royalty Schedule for the North Slope area is significantly higher than for the South Central area because the higher North Slope operating costs result in a much higher economic limit.

Hopefully, this illustration clarifies the relationship between production rates and royalty rates.

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

A 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.

(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 could encourage speculation causing an overbid. Royalty bidding should encourage more competition among bidders and may allow the smaller companies a better chance of winning the tract.

(5) Work Commitment With Fixed Bonus, Royalty or Net Profit Share

The government itemizes the performance criteria such as the rate and amount of work to be performed on each tract. The total bid specified in dollar terms and a portion of the bid used for exploration and development activities. This system gives the government some control over the rate and extent of resource development.

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINERALS AND ENERGY MANAGEMENT

DATE: February 28, 1978

Robert E. LeResche
Commissioner Natural Resources

FILE NO:

TELEPHONE NO:

FROM: SUBJECT: Rationale and Apparent
Objections to HB 854-
Oil and Gas leasing Bill.

Predictability, certainty and an acceptable political climate. These are the three things the petroleum industry looks for in an area attractive for exploration.

I contend it is the availability of land, not the method by which land is offered, that is the critical consideration. In other words, Alaska will become more attractive, less subject to severe criticism by the industry, once land is made available for leasing. The methods of leasing will quickly become secondary.

This contention, of course, will be disputed by the industry. They will argue that because the law allows administrators to choose from a wide variety of leasing methods the industry will remain uncertain about what to expect. I contend that the industry will be given plenty of advance notice of what method will be used in a sale and will therefore have enough time to plan financial strategy.

Industry's contention that Alaska must compete with other areas in the world within company budgets is, of course, correct. This does not mean, however, that Alaska has to settle on one, or perhaps two, leasing methods so as to make the Alaska budget dollar compete within a particular company. The company can estimate how much Alaska's prospective oil is worth to them and can calculate how much will be spent on a particular sale based on the method of lease offering, along with a multitude of other considerations. My basic assumption, of course, is that the oil is here and, eventually, the companies will come looking for it.

Which brings me back to my first point. Certainty and predictability will be established once the industry is convinced that a regular, stable procedure for offering oil and gas lands has been established by Alaska. Once lands are available and administrators are directed to offer leases to the public, most of the pressure will relax.

Industry's objection to the two reports to the legislature by the executive, I think, dramatizes my point. I think the industry will eventually accept the 5-year leasing program as a giant step toward predictability and, even though given wide public accountability, will come to believe that the report will not result in more governmental interference. Industry looks,

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however, I think on the annual leasing method report as a way for the legislature to probably work its way into the day-to-day leasing decisions best left to the governor. They fear "politics" in leasing, and I am less sure of this one than I am the leasing program report.

The underlying criticism of HB 854 you will hear, I believe, is that Alaska is "experimenting" with leasing methods. We are said to be trying to adapt all the good features used in other states and jurisdictions and are trying to make them work where they were not designed to work. Alaska is frontier; Alaska is different, goes the argument.

I believe I was to take the first cut at a comprehensive review of Alaska's oil and gas leasing law following Dr. Gaffney's study. I do not claim infallibility but I do claim to have weighed the many considerations which make Alaska like and unlike other jurisdictions. As I have told you, I have tried to confront, head-on, the question of the number of participants in exploration in Alaska. You have mentioned the concept of "incentives", at least as it applies to information, and I have indicated that whereas incentives are not directly dealt with in the legislation I think we may get there in the future.

So, with that background let me set forth the rationale for and some of the anticipated objections to HB 854.

Several concepts were examined and rejected. Found to be not applicable, at least at this time, are the so-called dual-leasing system (Ted Stevens' amendment to S-9). Congress may yet include something like it in OCS legislation. Also, the concept which involves distinguishing between exploration leases and those development and production activities which would be allowed after oil or gas is discovered. We have not included this concept because we believe that Alaska can know before it offers its land for drilling what development and production activities it expects to take place. (Incidentally, the conference committee on S-9 and HR 1614 is scheduled shortly.)

We examined the "ante" versus "post" royalty impact. The post (after) charge is the economic recommendation Dr. Mason Gaffney drew in his study of February, 1977 for the legislature. Dr. Gaffney concluded that the ideal way for a government (any lessor) to determine its economic rent was to determine such rent after a discovery at the price then existing and based upon the size of the field discovered. Determining the value of the field after the discovery is much like the present

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calculations of the reserves tax. Its newness, being untried and the unsettling effect its introduction and application would have had on exploration activities in Alaska we felt would be primarily negative. Also, we felt that the legislature could follow-up on Dr. Gaffney's recommendations if they wished. Canada, in its new law for leasing of the North and offshore, has proposed a "progressive incremental royalty" similar in concept to Dr. Gaffney's ad valorem charge. Perhaps, it will be in Alaska's future.

We examined the incentive programs existing in the Province of Alberta, and other jurisdictions, and determined that although some incentives may be needed in the future, they should not be dealt with in this bill. Giving direct tax and other incentives to exploration operators may be necessary, particularly to stimulate the much needed geological and geophysical information data, but we felt future legislatures could deal with this basic policy charge. Rather than incentives, we believe the pace of exploration can best be determined at the time and by the terms of the original lease. And, as I note later, the work commitment lease method can be used to offer incentives.

We examined the trends all over the world toward governments retaining ownership interests (equity) in leases, and toward government-owned and operated exploration companies. We rejected both of these ideas for Alaska. Equity interests in leases makes no sense so long as the state has the flexibility to deal with the many and varied leasing situations which will confront it. Government sponsored exploration, if at all, can be achieved by contract with industry rather than by bureaucrats.

Again, the petroleum industry, not unlike any business, needs certainty and predictability in order to be comfortable doing business. A "stable and predictable leasing policy" - Tom Kelly. "The industry will initially tend to go where it's wanted and an orderly contract and dependable lease sale schedule would undoubtedly provide an impetus to further exploration in the state" - Pennzoil.

The state's need for a flexible, comprehensive, all-inclusive means of leasing appears to conflict with the industry's desire for predictability. One company (Chevron) in an informal paper went so far as to say that giving these many alternatives to the state (HB 854, before a significant change) amounts to "overkill" and makes Alaska an "experimental laboratory in oil and gas leasing." They conclude by saying: "We consider this to be capricious".

In the name of predictability and certainty, oil operators of size almost without exception opt for the cash bonus bid with a fixed royalty as the preferred leasing method. They want the simplest and most predictable method.

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I believe Alaska needs a flexible leasing law so that it may adjust to changes as they occur. The world, national and Alaska energy and oil and gas future is in a state of flux and will remain so for the two decades for which this bill is designed to accomodate. No one can be sure what future developments in energy will be and particularly in Alaska where exploration condition are so diverse.

Alaska is now one of the largest oil owning entities in the world. It will be dealing with petroleum matters, directly, for at least the next two decades, probably much longer. It's immediate future depends in large part on how it deals with petroleum matters. As such, it should become familiar with most of the alternative methods it can use to control petroleum exploration. HB 854, we believe, once it is enacted and in operation will provide the industry the certainty it requires. Admittedly, it calls for State land to be offered by methods including but also other than bonus bid where feasible. The bill introduces more alternatives than now exist, but once these methods are in place and have been used, we believe, most uncertainty will disappear.

One last word on flexibility. In addition to the State, the Federal government and Native Regional Corporations will be leasing land for oil and gas exploration for the next several decades. Terms and conditions under which leases are issued by these entities will include all the variables addressed in HB 854, and, undoubtedly, more. To protect its interest and to operate effectively in this constantly changing exploration picture, the State needs a flexible leasing law by which to respond.

Following, are an itemized list of the objections which I anticipate will be made to HB 854.

1. Term of 5 years. All operators want a lease term as long as possible. In HB 854, Commissioner can go up to 10 years if "extreme conditions, etc." exist. The majors usually know what they intend doing when they bid and lease. The smaller companies will argue that they need more time to put drilling blocks together. The State's interest is to have leases explored and it is not in having leased acreage on the books paying rentals only. Deals can be made in five years. Drilling should proceed as soon as possible, or the land should be offered again to a more aggressive operator.

The time between Cook Inlet lease sales in 1962 and 1965 until first production was begun from Middle Ground,

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McArthur, Trading Bay and Granite Point averages under 4 years. Note this is production, not beginning drilling date. Average time from sale to drilling in New Mexico is 6 years.

As I have indicated before, I believe this is the most important term in the lease. The ideal would be for the commissioner to have discretion to set the length of the lease, but I do not believe the legislature or the industry would accept such discretionary authority.

2. Methods of leasing

- a. Royalty bidding creates no incentive to develop leases (Chevron). This is particularly true if "surrounding leasehold were such that early evaluation was likely" - (Champlin Petroleum). Same lack of incentive argument is said to apply to high net profits and/or work commitment.

Loss of revenue to state, too risky and premature shutdown problem - (SE Alaska Empire editorial; a reprint of Fairbanks News-Miner editorial, 1977-no date) Rumor has it the USGS in Anchorage (Jones, et al) don't like royalty bidding and DOI forced it on So. Cook Inlet sale. But ARCO's first location appears to be on a royalty tract.

- b. Work commitment is faulted for several reasons. Economists, including Gregg Erickson, see it as stimulating activity which the marketplace would not otherwise require. In fact, it can be used to stimulate exploration and, specifically, to acquire exploration information in areas which otherwise might not be explored. There can be an element of incentive in this method.

Tom Kelly sees the use of work commitments as pre-empting small companies. (It is interesting to note that Chevron favored the work commitment so long as the bonus or royalty was fixed and the work commitment was the sole biddable factor). Kelly sees it discouraging the promoting of participations (partners?) in drilling deals because the amount of dollars bid has been fixed. Frankly, I don't quite understand his argument, and contrary to hurting the small companies, I believe it could be used to encourage them to explore. Kelly believes a work commitment works best when it is negotiated and I agree with

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him, but we agree that it is unlikely that the Alaskan legislature and public would condone negotiated lease terms by public officials. (unlike royalty sales.)

- c. No mention is made of sliding scale royalty by any of the AOGA participants or companies who replied to your letter. All in the department, including Easy Gilbreth and Pedro Denton (from past memorandum in file), feel this is a most satisfactory answer. We are preparing several sliding scale examples for the Cook Inlet and the North Slope so as to focus on the factors which must be taken into consideration in setting the appropriate scale for an area.
- d. Net profit will be objected to because it gets the government into the oil company's books and it will be more costly to administer. Economists Lipton, Erickson, et al will argue it returns the most to the state.

Most economists will agree, I believe, it is the best way if "gold plating" can be controlled, but there seems to be disagreement as to whether it is best used where risks are high or low. Government encroachment will underlie the opponent's arguments.

- 3. The acreage limitation of 200,000 acres on state uplands (rather than present 500,000) has been objected to thus far only by a few majors. The reduction in the maximum is obviously aimed at the larger companies, and we should so state directly. (A list of state leaseholdings as of 2/10/78 is attached).

Some background may be helpful. No other state that I am aware of, has an acreage limitation. But no other state is Alaska's size nor has any state tens of millions of acres available to lease.

The Federal government has an acreage maximum for its land within each state. During Alaska's territorial days the Federal oil and gas acreage limitation in Alaska was 100,000 acres. In other states it was 46,080.

After 1961, Alaska's rose to 300,000 in the Northern district (approximately north of the Yukon River) and 300,000 in the Southern district. These apply today. Presently the acreage limitation is 246,080 acres of Federal leases per state, other than Alaska.

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Finally, note that in HB 854 companies are given five years from the effective date of the act to comply with the 200,000 acre maximum.

Hopefully, a lesser upland acreage maximum in Alaska will act as, albeit a small, incentive for companies other than the majors now here to explore in Alaska.

4. The state's right to purchase up to 16 2/3% of the oil and 100% of the gas will be opposed on the grounds that it is a negative incentive for integrated companies who wish to find and use the oil and gas. We should be careful of this one, but suffice to say that in 1972 New Mexico passed a similar law (N. Mexico can purchase 100% of gas and oil), which though never exercised or tested in court, remains on the books. (a copy attached).
5. Rentals may be opposed as being too high. The authority of the commissioner to up the rental at least 150% each year on shut-in leases may begin to bind the operator without a market, but there is no easy answer to the shut-in field unless we investigate something like the reserves tax concept, which I don't believe will solve the problem.
6. Leases offered noncompetitively after receiving no bids appear to be favored by the industry. Tom Kelly comments that such leases should be offered immediately (automatically?) after the competitive sale.

Please note that HB 854(t), as written, allows the commissioner three options. He can offer tracts immediately, at any time up to 5 years after receiving no bids, or not at all. If he intended to offer tracts noncompetitively immediately after a competitive sale he would so announce in the notice of the competitive sale.

The problem inherent in giving the administrator this many options, it will be argued, is that unpredictability will occur. Unless the operator knows before hand that he can fill out his block of acreage, he is at a distinct disadvantage. The administrator should take these matters into consideration before he notices a sale.

Milton Lipton, Gregg Erickson and others may oppose this open-ended authority to lease noncompetitively following an unsuccessful competitive sale on the grounds that an administrator might rig a competitive sale so that it will not elicit bids so that an immediate noncompetitive lease can be awarded. I don't think such a hit-and-run transaction can exist these days, particularly with HB 854's public disclosure procedures, but, perhaps, I'm too naive.

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7. Sealed bids or oral auction or sliding sealed bids (like Alberta). HB 854 permits the commissioner to use any or all of these. Sealed bids will be most commonly used. They are easy to administer. Oral bidding is used in New Mexico and Colorado. Champlin recommends oral bidding on "low potential" land so as to avoid preparing bid forms and "leaving money on the table." New Mexico, on the contrary, uses oral bidding about 50% of the time when it perceives that there will be a lot of competition in a sale. About 50% of the time New Mexico offers tracts by sealed bid.

Alberta allows bidders to slide bids from one tract to another in a sale. Thus, if bidder A's sealed bid fails to win on tract 1, he can direct his bonus be slid to tract 2, and so on.

Tom Kelly, when commissioner, had his staff investigate this sliding bid method in Alberta in hopes that it might be used for the 1969 Prudhoe Bay \$900 million sale. The idea was rejected because the industry objected on the grounds that it would cause too much uncertainty so close to the time of sale. Score one for certainty. Obviously, the advantage to the state would be that more money would be paid at the sale if bids were allowed to slide. Before actually using this system, Alberta's procedures should be studied again.

8. By regulation, the lessee may earn only to the depth drilled(j). I envision that the state would not invoke this right until it felt deeper horizons contained oil, and then would give the lessee a reasonable time to explore deeper. If the lessee failed to drill deeper, the deeper horizons would be offered at a competitive lease sale. Alberta woke up to this problem late and solved it by changing terms of existing lease contracts with all that political controversy.

I will ask Peter Froehlich to research whether this issue of drilling deeper might not be solved by tightening-up terms of the lease form to require due diligence by the operator at the request of the state.

2-10-78

Alaska - O+G Average Holdings

<u>COMPANY</u>	<u>ACRES</u>
Amoco	126, 134.64
ARCO	411, 482.68
BP Alaska	103, 218.99
Beard Oil	71, 260.49
Chevron	126, 493.55
Exxon Service	140, 071.58
Exxon	158, 627.73
Marathon Oil	71, 538.36
Mobil	120, 375.19
Phillips Pet.	250, 748.38
So. Pet.	135, 588.28
Texaco	156, 027.03
Union	293, 712.05
Getty	29, 857.30
Shell Oil	40, 603.10
Sun Oil	27, 453.87

CHAPTER 26

AN ACT

RELATING TO STATE LANDS; REQUIRING THE COMMISSIONER OF PUBLIC LANDS TO RESERVE CERTAIN RIGHTS TO THE STATE IN LEASES OR OTHER CONVEYANCES OF STATE LANDS GRANTING ANY INTEREST IN OR RIGHTS TO MINERALS OF WHATSOEVER KIND, INCLUDING OIL AND GAS; PROVIDING FOR A WAIVER OF THE REQUIRED RESERVATION; PROVIDING FOR DISPOSAL OF RESERVED MINERALS.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF NEW MEXICO:

Section 1. COMMISSIONER OF PUBLIC LANDS TO RESERVE CERTAIN RIGHTS TO THE STATE IN LEASES OR OTHER CONVEYANCES OF ANY MINERAL INTERESTS OR RIGHTS TO MINERALS IN STATE LANDS.--In any lease or other conveyance of state lands granting any interest in or rights to minerals of whatsoever kind, including oil and gas, in those lands executed by the commissioner of public lands after the effective date of this section, the following reservation of rights to the state shall be made: "The state has a continuing option to purchase at any time and from time to time, at the market price prevailing in the area on the date of purchase, all or part of any minerals (specify the minerals) that may be produced from the lands covered by this lease (or other conveyance).".

Section 2. WAIVER OF REQUIREMENTS FOR RESERVATION OF RIGHTS IN LEASES OR CONVEYANCE FOR SPECIFIC MINERALS--PROCEDURES FOR WAIVER.--

A. The commissioner of public lands may waive by written order the reservation of rights required under Section 1 of this act in respect to any specific mineral, other than fossil fuels, for which

there is no significant consumptive use within the state, but such order may be made only:

(1) after written notice is mailed by certified mail at least twenty days before the hearing required by Paragraph (3) of this subsection to the governor;

(2) after notice of the hearing required by Paragraph (3) of this subsection is posted in the same manner as notice of public sale of mineral leases is required to be posted under Section 7-9-34 NMSA 1953;

(3) after a public hearing on the issue of waiver under this subsection has been held by the commissioner of public lands or his designated representative in accordance with procedure adopted by the commissioner of public lands; and

(4) if the commissioner of public lands finds after considering the evidence produced at the hearing that a waiver of the provision would be in the best interests of the trust beneficiaries considering long-range and short-range benefits.

B. A waiver granted under Subsection A of this section shall be limited to a definite period of time not to exceed five years. Waivers may be renewed by the commissioner but only after following the procedure required under Subsection A of this section.

Section 3. DISPOSAL OF MINERALS BY COMMISSIONER OF PUBLIC LANDS.--The commissioner of public lands shall dispose of any minerals reserved under this act at the best price available in order to gain the maximum benefit for the trust beneficiaries.

STATE'S RIGHT TO PURCHASE
OIL & GAS IN HB 854

The State has the right in HB 854(v) to purchase not more than 16 2/3% of the oil and up to 100% of the gas at the regulated price or fair market value at the point of sale. The right to purchase is needed to protect the "in kind" taking of its royalty by Alaska, a sale of said royalty, and a subsequent reduction of the royalty in the later stages of production (d).

New Mexico, 1973, enacted a law which gives it the right to reserve an option to purchase at any time at the prevailing market price any or all minerals, including oil and gas, produced from State land. Thus, New Mexico may purchase 100% of the oil and gas found on State land.

Whereas the New Mexico Commissioner is authorized to waive the reservation option with respect to any specific mineral, he may not do so for oil or gas.

The Act, Chapter 26 of the Session Laws of 1973, has never been exercised by New Mexico; thus no opportunity has been given to test its constitutionality.

If Alaska were to reserve an option to purchase up to the amount of the royalty, fixed or bid, an equivalent net profit share would have to be determined.

LEASING METHODS EXAMINED

BUT NOT INCLUDED IN HB 854

1. The so-called "dual leasing" system which would authorize the State to issue separate exploration and production leases. Senator Ted Steven's amendment to S-9 would permit the exploratory lessee to share with the government (Federal) the costs of the exploratory drilling program, which would be managed by the lessee, in exchange for a share of the revenues received by the government from a subsequently issued production lease.

The Administration believes that the State can know before it offers its land for drilling what development and production activities it expects to take place.

2. Dr. Mason Gaffney's ad valorem charge, or a "post" royalty system versus the "ante" systems in HB 854. In other words, the state determines its take before discovery, not after. Other governments, like the Canadian national, are going to the "post" systems, i.e. "progressive incremental royalty."
3. Incentives. There are no direct incentives to lessees contemplated in HB 854, except that "work commitment" would allow cash bonuses not to go to the government but instead used by industry for exploration.
4. Government equities in leases or state-owned and operated exploration companies are not envisioned in HB 854.
5. Oil Payment Bidding - shift royalty to rental.
6. Performance System which provides government with the authority to specify the exact rate and extent of resource development.
7. Share Bidding or Phillips Plan. Bonus bids are entered for the entire structure 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 percentage participation by any one company.
8. Alberta's so-called "checkerboard" leasing system wherein a reservation holder may apply for leases over not more than 50% of the area in the reservation in a checker-board pattern. These leases convey the right to produce and sell the Crown's oil and gas, and the government retains the right to alter unilaterally the terms and conditions of the arrangement.

SUMMARY OF ACREAGE LIMITATION
CHANGE IN HB 854

The acreage any one State lessee may hold is 500,000 acres upland and 500,000 acres offshore. HB 854 reduces the uplands to 200,000 acres. This is to help increase the number of upland lessees by limiting the holdings of the larger major oil companies. Offshore holdings will be unaffected.

No other state that we are aware of has an acreage limitation. But no other state is Alaska's size nor has any state tens of millions of acres available to lease.

The Federal government has an acreage maximum for its uplands within each state. During Alaska's territorial days the Federal oil and gas acreage limitation in Alaska was 100,000 acres. In other states it was 46,080 acres.

After 1961 the Federal maximum for Alaska rose to 300,000 acres in the Northern district (approximately north of the Yukon River) and 300,000 in the Southern district. These apply today. There is no Federal acreage limitation on the Outer Continental Shelf. Presently, the acreage limitation is 246,080 uplands acres of Federal leases per state, other than Alaska.

HB 854 grants companies five years from the effective date of the act to comply with the 200,000 upland acre maximum.

A list of major leaseholdings as of February, 1978, (showing uplands and offshore holdings of those companies which now exceed 200,000 acres) follows:

ALASKA OIL AND GAS ACREAGE HOLDINGS
(as of March 13, 1978)

<u>COMPANY</u>	<u>ACRES</u>		
ARCO	408,151.21	356,882.86	acres of uplands
		<u>51,268.35</u>	offshore
		408,151.21	total
UNION	287,032.83	233,138.75	uplands
		<u>53,894.08</u>	offshore
		287,032.83	total
PHILLIPS PETROLEUM	243,227.94	80,332.74	uplands
		<u>162,895.20</u>	offshore
		243,227.94	total
EXXON	158,627.73		
TEXACO	156,027.03		
SOHIO PETROLEUM	135,588.28		
BP ALASKA	103,218.99		
CITIES SERVICE	140,071.58		
CHEVRON	126,493.55		
AMOCO	126,134.64		
MOBIL	120,375.19		
MARATHON OIL	71,538.36		
BEARD OIL	71,260.49		
SHELL OIL	40,603.10		
GETTY	29,857.30		
SUN OIL	27,453.87		

DESCRIPTION OF LEASING METHODS IN HB854

Currently, the State of Alaska's leasing system is a cash bonus bid with a minimum fixed royalty of 12.5 percent. The methods outlined below include the present system with different fixed royalties, sliding scale royalty with bonus bid, sliding scale royalty bid with fixed bonus, net profit share bid with fixed bonus, royalty bid with fixed bonus and exploration work commitment. The basic elements of these methods are summarized below.

(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 or auctioned 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. To avoid early termination of production, royalties need to be flexible during a field's declining years.

(2) Sliding Scale Royalty With Bonus Bid (or Sliding Scale Bid with Fixed Bonus)

Under this system, the government receives a cash bonus bid and a sliding scale royalty. We used 12.5 percent as a minimum figure and 62.5 percent as a ceiling wherein the rate in any period is dependent upon the production of that period.

The royalty rate is graduated in much the same manner as the federal personal income tax. Table I gives two examples of a sliding scale royalty schedule. The royalty is progressive, that is, the royalty on additional production increases. For example, in the South Central Area, the initial 500 barrels pay a royalty of 12.5 percent, the next 500 barrels pay 25 percent. The royalty rate increases by 12.5 percentage points per 500 barrels until 2000 barrels of output are achieved. All production beyond 2000 barrels pays a royalty of 62.5 percent. Thus, if production reaches 5000 barrels, the average royalty rate is 50 percent. In the limit, the average rate would converge towards 62.5 percent as daily production continues to increase.

As field productivity declines and well production falls, the producer backs down the schedule and royalties decline. In order to optimally exploit the field, the royalties should decline to zero near the end of field life. Actually, final rates of five or six percent would result in minimal early shut down.

TABLE I
TYPICAL SLIDING SCALE ROYALTY SCHEDULES

SOUTH CENTRAL AREA

Daily Average Prod. Rate (Bbls./day)	Incremental Royalty Rate (%)	Royalty For Specific Producing Rates		
		Producing Rate (Bbls./day)	Royalty Production (Bbls./day)	Average Royalty Rate (%)
-500	12.5	500	62.5	12.50
501-1000	25.0	1000	187.5	18.75
1001-1500	37.5	1500	375.0	25.00
1501-2000	50.0	2000	625.0	31.25
2001-2500	62.5	2500	937.5	37.50
		3500	1562.5	44.64
		4500	2187.5	48.61
		5000	2500.0	50.00

NORTH SLOPE AREA

Daily Average Prod. Rate (Bbls./day)	Incremental Royalty Rate (%)	Royalty For Specific Producing Rates		
		Producing Rate (Bbls./day)	Royalty Production (Bbls./day)	Average Royalty Rate (%)
-1000	12.5	1000	125	12.50
1001-2000	25.0	2000	375	18.75
2001-3000	37.5	3000	750	25.00
3001-4000	50.0	4000	1250	31.25
4001 and above	62.5	5000	1875	37.50
		7000	3125	44.64
		9000	4375	48.61
		10000	5000	50.00

Note: The Sliding Scale Royalty Schedule for the North Slope area is significantly higher than for the South Central area because the higher North Slope operating costs result in a much higher economic limit.

Hopefully, this illustration clarifies the relationship between production rates and royalty rates.

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

A 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.

(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 could encourage speculation causing an overbid. Royalty bidding should encourage more competition among bidders and may allow the smaller companies a better chance of winning the tract.

(5) Work Commitment With Fixed Bonus, Royalty or Net Profit Share

The government itemizes the performance criteria such as the rate and amount of work to be performed on each tract. The total bid specified in dollar terms and a portion of the bid used for exploration and development activities. This system gives the government some control over the rate and extent of resource development.

TWO VIEWS ON BIDDING STRATEGIES

WEALTH MAXIMIZING STRATEGIES FROM THE STATE'S VIEWPOINT

The choice of bidding method cannot be made on the basis of any single criteria but is the result of evaluating a number of factors including but not limited to the potential economic payoff and physical characteristics of the lease area. HB854 offers essentially four leasing schemes: (1) Bonus Bid - Fixed Royalty, (2) Royalty Bid - Fixed Bonus, (3) Net Profit Bidding with Fixed Bonus, (4) Work Commitment with Bonus Bidding. These options will be briefly evaluated.

Bonus Bid - Fixed Royalty

If the royalty is fixed at 12-½%, there is no reason to use this option. It is of historical value only. At higher fixed royalties, it has some merit, but the higher fixed royalty means a lower bonus bid which is supposedly the advantage of the system. Private discount rates are too high for bonus bidding to be advantageous to the State. For example, a brief examination of an annuity table suggests that increases in the discount rate rapidly diminish the present value of a future income stream. This income stream can be interpreted as the discounted net revenues resulting from the potential discovery and development of an oil field. Table II illustrates the discount rate effect.

Table II
Present Value of an Annuity of \$1 Million
(Values in 10⁶\$)

Number of Years	Discount Rates					
	6%	10%	14%	16%	18%	20%
20	\$11.470	\$ 8.514	\$6.623	\$5.929	\$5.353	\$4.870
30	13.765	9.427	7.003	6.177	5.517	4.979
N	16.67	10.00	7.14	6.25	5.56	5.00

From the State's viewpoint, a 6% discount rate may properly reflect the present value of the income generated by the potential oil discovery. The industry, on the other hand, is likely to discount the future net income stream at much higher rates, say 20%. Thus, the maximum bid under ideal circumstances would be \$5 million for an income stream that would yield net revenues of one million per year in perpetuity. Perpetuity is longer than the life of Prudhoe Bay.

Royalty Bid - Fixed Bonus

Relatively easy to administer - reduces risk and front end filter to the private sector. With sliding scale, most early shut down problems are avoided. The fact

that the State receives a revenue stream over a 20⁺ year time horizon also is an attractive feature. The Beaufort Sale is an ideal candidate for a royalty bidding scheme.

Net Profit Bidding

This is very attractive from a risk sharing point of view. All risks (geologic, exploration, development, and production costs as well as product price) are shared with the industry. Would increase exploration and development in remote high risk areas. May be useful where there is low probability of bid find. Under ideal circumstances (political) is the best of all possible options but does have serious administrative problems.

Work Commitment

Cases where State wants information and is willing to specify type of information desired. Good for high risk areas in remote locations. May also be used where the State wants more information before putting structures up for competitive bidding scheme.

On balance, the royalty bidding schemes represent a substantial improvement over bonus bidding and are administratively tractable. Given the time to build the expertise, it may be advisable to shift to profit sharing or ad valorem schemes.

MULTIPURPOSE STRATEGIES

Bonus Bids

Bonus bidding should be applied in cases where the State has either:

- (a) A very great amount of knowledge about the resource, or
- (b) The prospect is of extremely high risk, the lessor has little knowledge of the resource and expected value revenues would be marginal.

The first case (a) where tracts might be offered for Bonus Bidding could be that of a drainage or near drainage situation where the State wished to maximize its near term discounted revenues. It would be advisable to not offer all of the tracts for bonus bidding, but to withhold a percent of acreage to be sold at a later date, (Report 2-77). Also, since royalty and other bidding methods have shown to offer higher expected value revenues for lower risk cases it could be advisable to mix royalty bidding with the bonus bidding, a practice followed by the Federal Government in the recent Cook Inlet OCS sale.

In the second case (b), that of extreme high risk, bonus bidding can be used as a filter to determine the value of marginal tracts. This is discussed under the section on (t) low potential, high risk and previously leased.

Report 2-77 indicates that for very high risk cases all bidding methods approach the same level of expected value income for the State. In cases of small and marginal potential reservoirs the bonus bid method with its ease of administration might afford optimum State revenues. Report 2-77 also indicates that in probability of success percents of 1 percent or less bonus bids could afford higher revenues, but the State should ensure that leasing under such high risk cases only occurs when sufficient knowledge is gained to indicate that the land to be leased is of such a low potential. For example, a geologic structure as large as the Prudhoe Bay anticline may have had a high degree of risk before it was drilled but its potential to hold enormous reserves was there. Bonus bidding should not have been used in that instance.

In summary, bonus bidding can be used when:

- (1) Very small potential reservoirs are expected;
- (2) Extreme risk is expected and the gaining of sufficient knowledge to determine the presence of reservoirs is unwarranted because of marginal to low potential indications.
- (3) A sliding royalty should be considered in all bonus bid cases;
- (4) This method could be used in a mixture with other methods such as royalty bidding;
- (5) Also, in general, this method should only be considered when leasing in the less desirable state areas, i.e. those below the top 10 rank.

Royalty Bidding - Fixed Bonus

Report 2-77 indicates that royalty bidding and profit sharing deliver the highest expected value revenues to the State of all bidding methods. It is particularly effective where the probability of occurrence is high (i.e. low risk) and especially when the expected reservoirs are large. A sliding scale should be added in the declining production years to eliminate the problem of premature shut down. Cases for royalty bidding would be when:

- (1) The State has enough knowledge to assess the size of potential traps.
- (2) Potential reservoirs are not extremely small or of extreme risk.

The Beaufort Sea sale is a good example of a case for using Royalty bidding on tracts. In general, this method should be considered when leasing in the top 10 leasing areas on the desirability scale.

Net Profit Bidding

Net profit bidding would be most advantageous when costs and oil prices are in a state of extreme fluctuations making economic predictions unreliable. In remote high risk areas, this method might attract stronger bids than the royalty

or the bonus bid method.

Of the 35 potential State leasing areas, this method might be used to advantage on those areas below the top 10 in desirability.

Work Commitment

(See section (t)).

This bidding method can be best used where the State has a large (i.e. 100,000⁺ acres) area of probable low potential where industry has shown a general lack of interest in exploration and leasing. By offering a large area for lease to one lease owner, the State provides an extra incentive to undertake exploration and the State ensures the exploration by making the bid variable.

This method would be used in remote low potential high risk areas. Some of the State's 3 mile limit lands such as Area IX might be applicable to this method.

Low Potential & High Risk and Previously Leased Section (t)

On the basis of exploration knowledge, lack of interest by industry and reasonable analysis, the department may determine that lands have very low potential for oil and gas.

As a means of encouraging the evaluation and possible development of these low potential lands, the department could:

- (1) Offer the lands for competitive lease using a bonus bid with sliding royalty. A minimum bid equal to the first year's rentals could be used to filter the bids. This should give a check on the potential of the lands. The sliding royalty would act as a safeguard for very low value bonus bid tracts if a discovery is made later on the lands.
- (2) On tracts that receive no acceptable bids, the commissioner could hold a non-competitive simultaneous drawing after proper notice (30 days). Tracts not receiving applications for the drawing could then be opened for over the counter applications. Tracts could be offered at fixed 50¢/year rentals, 5 year terms. A sliding scale royalty would be used in all cases to provide a revenue safeguard against future potential discoveries.
- (3) In some cases, all tracts not receiving acceptable bids could be aggregated into large blocks (100,000 acres or more) and offered for work commitment bidding or development contracts.

RESULTS OF LEASING MODEL SIMULATION @ 10% RISK AND LOW COST REGION

EXPECTED VALUE STATE INCOME

Leasing Method	Oil Rec MM/Bbls.	OIL CO. PROFIT		STATE INCOME				
		*Total	*PW @ 10%	*Bonus	Royalty	*Total	BONUS, ROYALTY & TAXES	
							*PW @ 6%	*PW @ 10%
BONUS 12-1/2%								
I.	137.6	72.6	14.7	.5	27.6	61.2	24.9	14.6
II.	633.8	376.3	93.2	48.1	127.0	338.9	171.6	118.7
III.	5238.1	3189.1	697.2	385.3	1048.1	2807.0	1347.8	917.1
BONUS 12-1/2% Acreage Withheld (initial sale)								
II.	633.8	1524.8	289.9	179.9	533.5	1408.3	711.0	490.4
III.	5238.1	17905.3	2950.6	1780.0	6079.1	15900.8	7510.1	5035.4
BONUS 25%								
I.	uneconomic							
II.	633.6	316.9	77.9	38.5	292.5	445.1	214.3	141.8
III.	5236.9	2698.2	582.8	316.3	2095.7	3693.4	1681.2	1091.1
SLIDING ROYALTY								
I.	137.6	71.1	14.2	.1	31.0	63.9	26.2	15.4
II.	633.9	274.6	64.7	30.0	344.8	519.8	249.0	161.3
III.	5238.5	1388.6	265.1	117.1	4891.8	6046.5	2591.7	1563.3
ROYALTY								
I.	137.5	70.0	14.1	0.0	33.1	65.7	26.6	15.5
II.	632.6	178.9	42.4	15.0	547.9	688.9	311.4	193.4
III.	5230.1	1400.5	281.0	125.0	4861.2	6024.1	2555.6	1544.1
NET PROFITS								
II.	634.0	169.8	40.4	15.0	567.0	706.6	318.6	197.1

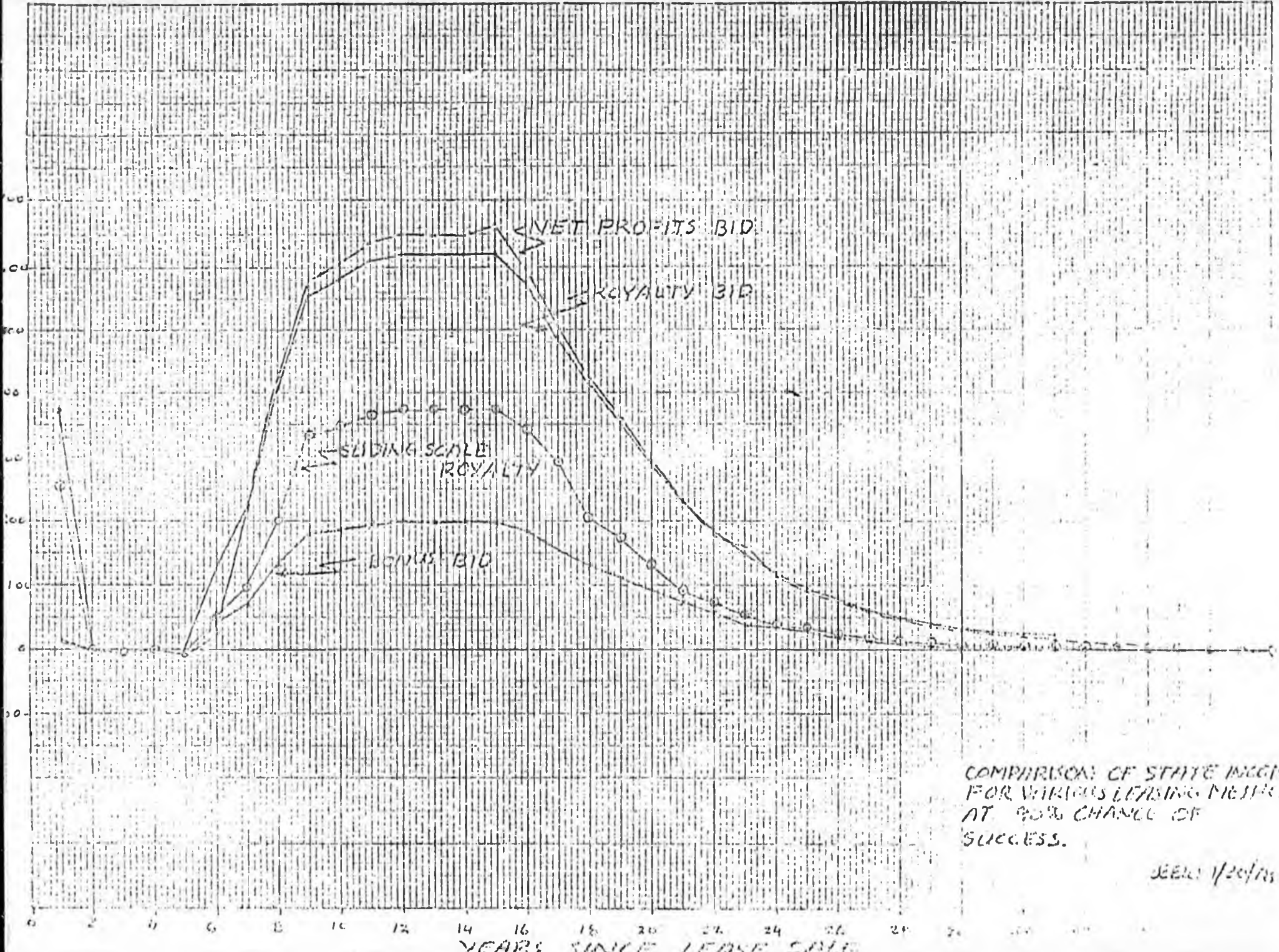
RESULTS OF LEASING MODEL SIMULATIONS @ 90% RISK AND LOW COST REGION

EXPECTED VALUE STATE INCOME

Leasing Method	Oil Rec MM/Bbls.	OIL CO. PROFIT		STATE INCOME				
		*Total	*PW @ 10%	*Bonus	Royalty	BONUS, ROYALTY & TAXES		
						*Total	*PW @ 6%	*PW @ 10%
BONUS 12 1/2%								
I.	137.6	635.0	98.6	44.5	24.9	603.4	275.2	180.8
II.	633.8	3247.7	585.0	377.5	1143.3	3012.2	1520.2	1048.0
III.	5238.1	27716.2	4452.9	2709.9	9433.1	24630.1	11618.3	7780.9
BONUS 25%								
I.	137.4	523.1	79.2	30.6	49.7	815.5	358.0	226.8
II.	633.6	2737.5	492.6	308.9	2285.9	3984.8	1917.6	1267.6
III.	5236.9	23473.1	3746.7	2228.6	18861.8	32734.2	14723.2	9443.5
SLIDING ROYALTY								
I.	137.6	622.1	95.5	42.1	279.0	628.4	287.2	188.1
II.	633.9	2376.0	407.6	256.1	3103.4	4678.2	2249.0	1461.2
III.	5238.5	12200.0	1832.0	820.6	44026.2	54260.4	23201.8	14001.0
ROYALTY								
I.	136.8	308.4	42.9	2.5	972.7	1219.5	516.4	314.2
II.	629.2	495.3	80.5	15.0	7261.1	8216.0	3665.7	2238.2
III.	5216.7	5666.5	836.4	125.0	58312.9	66525.9	27704.6	16370.0
NET PROFITS								
I.	137.7	271.6	38.6	2.5	1054.8	1295.5	538.8	323.7
II.	634.0	433.8	71.6	15.0	7419.0	8369.7	3712.6	2255.9

RESULTS OF LEASING MODEL SIMULATION @ 100% RISK (PERFECT CERTAINTY) & LOW COST REGION

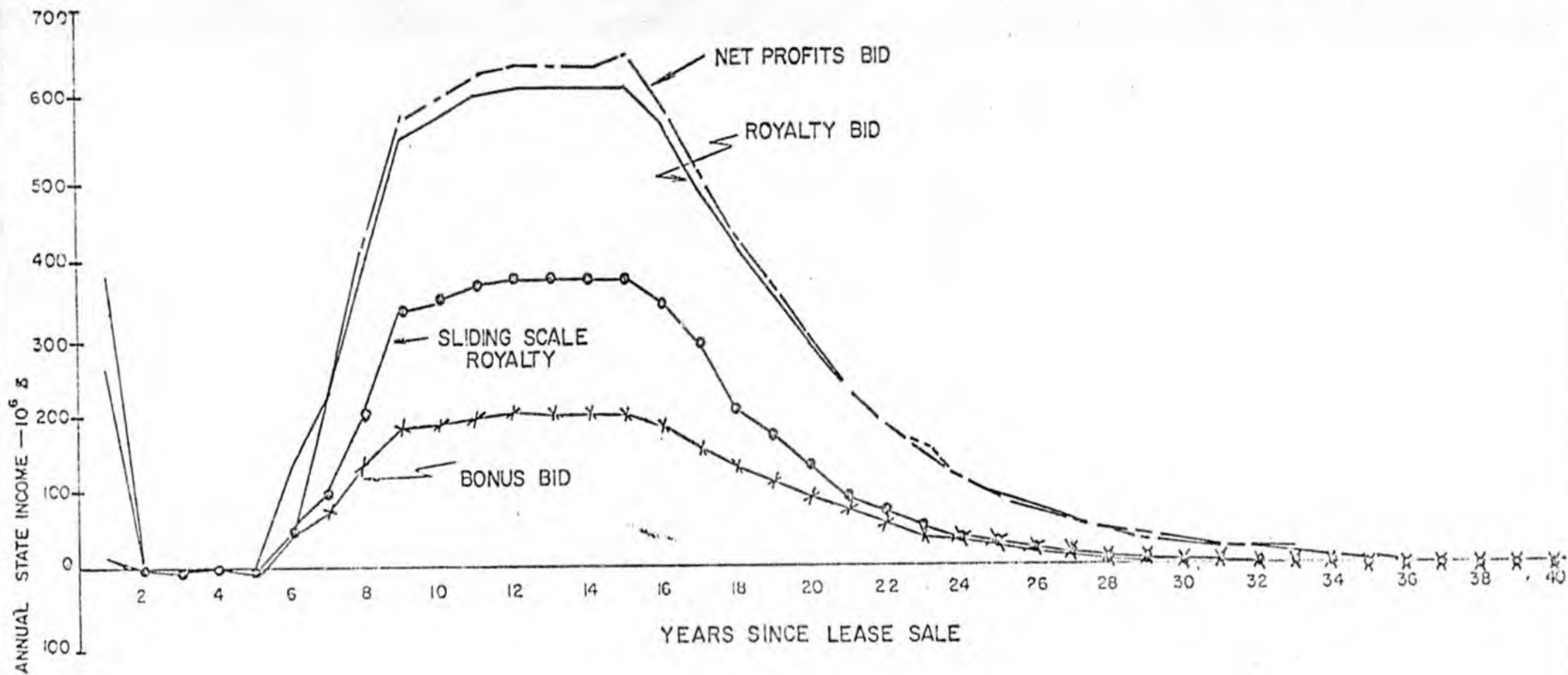
Leasing Method	Oil Rec MM/Bbls.	OIL CO. PROFIT		EXPECTED VALUE STATE INCOME				
		*Total	*PW @ 10%	*Bonus	Royalty	*Total	*PW @ 6%	*PW @ 10%
BONUS + 12-1/2% ROYALTY								
I.	137.6	705.6	109.6	49.4	27.7	670.4	305.8	200.9
II.	633.8	3608.6	650.0	419.4	1270.3	3346.9	1689.1	1164.4
III.	5238.1	30795.8	4947.7	3011	10481.2	27366.8	12909.2	8644.4
BONUS + 25% ROYALTY								
I.	137.4	581.2	88	34	55.2	906.1	397	251
II.	633.6	3041.7	547.3	343.2	2539.9	4427.6	2130.7	1408.4
III.	5236.9	26081.2	4163	2476.2	20957.6	36371.1	16359.1	10492.8
SLIDING ROYALTY								
I.	137.6	691.2	106.1	46.8	310	698.2	318.9	209
II.	633.9	2640	452.9	284.6	3448.2	5198	2498.9	1624.4
III.	5238.5	13555	2035.6	911.8	489.8	60289.3	25778.9	1556.7
ROYALTY BIDDING								
I.	136.8	342.7	47.7	2.8	1080.8	1355	573.8	349.1
II.	629.2	550.3	89.4	16.7	8017.8	9128.9	4073	2486.9
III.	5216.7	6296.1	929.3	138.9	64792.9	73917.7	30782.2	18188.9
NET PROFITS								
I.	137.1	301.8	42.9	2.8	1172	1439.4	598.7	359.7
II.	634.0	482	79.6	16.7	8243.4	9299.7	4125.1	2506.6



COMPARISON OF STATE INCOME FOR VARIOUS LEASING METHODS AT 90% CHANCE OF SUCCESS.

SEE 1/20/75

YEARS SINCE LEASE SOLD



COMPARISON OF STATE INCOME
FOR VARIOUS LEASING METHODS
AT 90% CHANCE SUCCESS

BEW 1-30-78

SEC. C

construct, maintain, and use all such buildings, machinery, roads, pipelines, powerlines, and railroads, sink such shafts, drill such wells, remove such soil, and to remain on said lands or any part thereof for the foregoing purposes and to occupy as much of said lands as may be necessary or convenient for such purposes hereby expressly reserving to itself, its lessees, successors, and assigns, as aforesaid, generally all rights and power in, to, and over said land, whether herein expressed or not, reasonably necessary or convenient to render beneficial and efficient the complete enjoyment of the property and rights hereby expressly reserved." (§ 1 art VII ch 169 SLA 1959; am § 14 ch 61 SLA 1960; am § 1 ch 42 SLA 1966; am § 3 ch 240 SLA 1976)

Effect of amendment. — The 1976 amendment substituted "§§ 315 — 325 of this chapter, §§ 45 — 120 of this chapter, or ch. 50 of this title except as provided in AS 38.50.050 is" for "§§ 315 — 325 of this chapter or §§ 45 — 120 of this chapter, except for those lands originally acquired by purchase, exchange, condemnation, gift, escheat or foreclosure are" near the beginning of the section.

Legislative committee report. — For report on ch. 2, SLA 1966 (HB 387 am), see 1966 House Journal, p. 492.

Chapter 19, SLA 1977 held not invalid. — Chapter 19, SLA 1976, authorizing a three-way exchange of land between the state of Alaska, the United States government and a regional corporation of Alaska Natives, was not invalid on the ground that it waived the provisions of this section restricting the state's right to alienate minerals and former AS 38.95.060 authorizing exchanges of land with native corporations on the basis of equal value. *State v. Lewis*, Sup. Ct. Op. No. 1364 (File No. 3039), 559 P.2d 630 (1977).

Sec. 38.05.127. Access to navigable or public waters. (a) Before the sale, lease, grant, or other disposal of any interest in state land adjacent to a body of water or waterway, the Department of Natural Resources shall,

(1) under regulations, determine if the body of water or waterway is navigable water, public water, or neither;

(2) upon finding that the body of water or waterway is navigable or public water, provide for the specific easements or rights-of-way, or both, reasonably necessary to insure free access to and along the body of water, unless the department finds that regulating or limiting access is necessary for other beneficial uses or public purposes.

(b) The Department of Natural Resources shall adopt regulations implementing this section.

(c) Nothing in this section affects valid existing rights. (§ 2 ch 117 SLA 1976)

Editor's note. — Section 1, ch. 117, SLA 1976, provides: "Intent. It is the intent of this Act to implement the provisions of art. VIII, sec. 14, Alaska State Constitution, relating to access to the navigable or public waters of the state."

Legislative committee report. — For report on ch. 117, SLA 1976 (HCS 2d CSSB 215), see 1976 Senate Journal, p. 452; 1976 House Journal, p. 1296.

Sec. 38.05.130. Damages and posting of bond. No rights shall be exercised by the state, its lessees, successors or assigns under the

reservation as set out in § 125 of this chapter or until the state, its lessee, successors, or assigns make provisions to pay the owner of the land full payment for all damages sustained by the owner, by reason of entering upon the land. If the owner for any cause refuses or neglects to settle the damages, the state, its lessees, successors, assigns, or an applicant for a lease or contract from the state for the purpose of prospecting for valuable minerals, or option contract or lease for mining coal or lease for extracting petroleum or natural gas, may enter upon the land in the exercise of the reserved rights after posting a surety bond determined by the director, after notice and an opportunity to be heard, to be sufficient as to form, amount, and security to secure to the owner payment for damages, and may institute legal proceedings in a court where the land is located, as may be necessary to determine the damages which the owner may suffer. (§ 2 art VII ch 169 SLA 1959; am § 15 ch 61 SLA 1960)

Article 6. Leasing of Mineral Lands.

Section

- 135. Generally
- 137. Leasing agreements
- 140. Limitations
- 145. Leasing procedure
- 150. Coal
- 155. Phosphates
- 160. Oil shale
- 165. Sodium
- 170. Sulphur

Section

- 175. Potassium
- 180. Oil and gas
- 181. Geothermal resources
- 182. Royalty on natural resources
- 183. Sale of royalty
- 184. Limitation on oil and gas leases in certain areas, and reacquisition of leases

Sec. 38.05.135. Generally. (a) Except as otherwise provided, valuable minerals deposits in lands belonging to the state shall be open to exploration, development, and the extraction of minerals. All lands, together with tide, submerged, or shorelands, to which the state holds title to or to which the state may become entitled, may be obtained by permit or lease for the purpose of exploration, development, and the extraction of minerals. Except as specifically limited by §§ 135 — 181 of this chapter, lands may be withheld from lease application on a first-come, first-served basis, and offered only on a competitive bid basis when determined by the commissioner to be in the best interests of the state. In unproven areas the commissioner may offer additional incentives, including a reduction of royalty to a minimum of five per cent in the case of oil and gas, and other terms in and granting permit or lease for exploration and development whenever it appears to be in the best interests of the state to do so.

(b) When minerals are to be leased on a competitive basis, in addition to any other notice given, notice shall also be given as provided in §§ 305 and 345 of this chapter. If land is to be made available for noncompetitive mineral leasing, notice of the proposed action shall also be given as provided in §§ 305 and 345 of this chapter. After the notice of

noncompetitive leasing has been made as required in this subsection, notice of the subsequent issuance of a noncompetitive lease for the land involved shall be made by mail not less than 30 days before the issuance of the lease only to those who have requested the notice. (§ 1 art VIII ch 169 SLA 1959; am § 1 ch 30 SLA 1964; am § 1 ch 91 SLA 1967; am § 2 ch 71 SLA 1971; am § 10 ch 257 SLA 1976)

Effect of amendment. — The 1976 amendment added present subsection (b).

Cited in Kirkpatrick v. Commissioner, Dep't of Natural Resources, Sup. Ct. Op. No. 201 (File No. 388), 391 P.2d 7 (1964); Moore v. State, Sup. Ct. Op. No. 1284 (File Nos. 2551, 2587), 553 P.2d 8 (1976).

Am. Jur., ALR and C.J.S. references. — 24 Am. Jur., Gas and Oil, §§ 32 to 102; 36 Am. Jur., Mines and Minerals, §§ 11 to 22,

39 to 62, 65 to 98, 139 to 142; 42 Am. Jur., Public Administrative Law, § 111; 4th Am. Jur., States, Territories and Dependencies, §§ 57 to 61.

Validity of prohibition or regulations of removal or exploitation of oil, minerals, soil, sand, gravel, stone or natural products within municipal limits, 168 ALR 1188.

73 C.J.S. Public Lands § 259.

Sec. 38.05.137. Leasing agreements. The commissioner is authorized to enter into cooperative mineral leasing agreements with the United States regarding lands which are the subject of a title dispute between federal and state authorities. Any such lease need not conform to the provisions of state law applicable to state leases issued under the authority of this chapter. (§ 2 ch 30 SLA 1964)

Sec. 38.05.140. Limitations. (a) No person may take or hold coal leases or permits during the life of coal leases on state lands exceeding an aggregate of 46,080 acres, except that a person may apply for coal leases or permits for acreage in addition to 46,080 acres, not exceeding a total of 5,120 additional acres of state land. The additional area applied for shall be in multiples of 40 acres and the application shall contain a statement that the granting of a lease for additional lands is necessary for the person to carry on business economically and is in the public interest. On the filing of the application, the coal deposits in the lands covered by the application shall be temporarily set aside and withdrawn from all other forms of disposal provided under §§ 135 — 181 of this chapter.

(b) The commissioner shall, after posting notice of the pending application in the local land office, conduct public hearings on the application for additional acreage. After public hearings, to the extent he finds to be in the public interest and necessary for the applicant in order to carry on business economically, the commissioner may, under regulations he prescribes, permit the person to take or hold coal leases or permits for an additional aggregate acreage of not more than 5,120 acres.

(c) No person may take or hold at one time phosphate leases on state lands exceeding in the aggregate 10,240 acres. No person may take or hold sodium leases or permits during the life of sodium leases on state lands, exceeding in the aggregate acreage 5,120 acres except that the

commissioner may, where it is necessary in order to secure the economic mining of sodium compounds, permit a person to take or hold sodium leases or permits for up to 15,360 acres. No person may take or hold at any one time oil or gas leases exceeding in the aggregate 500,000 acres granted on tide and submerged lands, and 500,000 acres on all lands other than tide and submerged lands, including leases held both as lessee and under option or operating agreement from others. Where more than a single person holds an interest in an oil or gas lease, each person shall be charged only with that percentage of the total acreage which corresponds to its percentage share of the total beneficial interest in the lease.

(d) The commissioner, for the purpose of encouraging the greatest ultimate recovery of coal, oil, gas, oil shale, phosphate, sodium, potassium, sulphur, and geothermal resources and in the interest of conservation of natural resources, after public hearing, or, when the state's title to land beneath navigable waters has been legally challenged by the United States and litigation initiated, may waive, suspend, refund, or reduce the rental, or minimum royalty, or reduce the royalty on an entire leasehold, or on any tract or portion of a leasehold segregated for royalty purposes, whenever in his judgment it is necessary to do so in order to promote development, or whenever in his judgment the lease cannot be successfully operated under its terms. If the commissioner, in the interest of conservation, directs or assents to the suspension of operations and production under a lease granted, the payment of acreage rental or of minimum royalty prescribed by the lease may be suspended during the period of suspension of operations and production. The term of the lease shall be extended by adding the period of suspension to the lease.

(e) The provisions of (d) of this section that apply to waiver, suspension, refund or reduction of rental of minimum royalty apply to rental or minimum royalty paid before or after June 19, 1970 on any lease covering land beneath navigable waters which, according to the records of the division of lands, is in effect on June 19, 1970.

(f) The submerged and shorelands lying north of 57°, 30 minutes north latitude and east of 159°, 49 minutes west longitude within the Bristol Bay drainage are designated as the Bristol Bay Fisheries Reserve. Within the Bristol Bay Fisheries Reserve no surface entry permit to develop an oil or gas lease may be issued on state owned or controlled land until the legislature by appropriate resolution specifically finds that the entry will not constitute danger to the fishery. (§ 2 art VIII ch 169 SLA 1959; am § 1 ch 68 SLA 1969; am §§ 1, 2 ch 208 SLA 1970; am §§ 3, 4 ch 71 SLA 1971; am § 1 ch 102 SLA 1972)

Legislative committee report. — For report on ch. 68, SLA 1969 (HB 3030), see 1969 House Journal, p. 572.

Sec. 38.05.145. **Leasing procedure.** (a) Deposits of coal, phosphates, oil shale, sodium, potassium, oil, gas, geothermal resources and state lands containing these deposits are subject to disposition under rules and regulations, recommended by the director and adopted by the commissioner, and the provision of §§ 145 — 181 of this chapter. In applying the acreage limitations the commissioner may apply the rule of approximation. The uses of the rule of approximation made before March 31, 1960, by the commissioner are ratified.

(b) If the state selects or otherwise acquires land other than shorelands, title to which was in the federal government and which, at the effective date of the selection or acquisition, is subject to a valid existing offer for a noncompetitive United States oil and gas lease, or application for a prospecting permit or noncompetitive mining lease, for coal, phosphates, sulphur, oil shale, sodium, or potassium under the federal Act of February 25, 1920 (41 Stat. 437 as amended), or for a noncompetitive United States geothermal lease, or application for a prospecting permit or noncompetitive lease under the federal Act of December 24, 1970 (84 Stat. 1566), the offeror or applicant for the federal permit or lease, if a qualified applicant hereunder, shall be considered the first qualified applicant for a state noncompetitive oil and gas lease, noncompetitive geothermal lease, prospecting permit, or noncompetitive mining lease and is entitled to a state noncompetitive lease or permit upon compliance with the provisions of the regulations covering applications within 60 days after receipt of written notice from the commissioner of selection or acquisition. These priorities are not effective if the land covered by the federal offers or applications is classified by the commissioner as competitive land within 90 days after the selection of the land is finally approved by the Secretary of the Interior or the land is otherwise acquired. (§ 3 art VIII ch 169 SLA 1959; am § 16 ch 61 SLA 1960; am § 3 ch 30 SLA 1964; am §§ 5, 6 ch 71 SLA 1971; am § 33 ch 71 SLA 1972)

Revisor's note (1971). — In § 6, ch. 71, SLA 1971, the first sentence of AS 38.05.145(b) was split into two sentences. Since that would leave the first sentence incomplete and meaningless, and appears to have been a manifest clerical error, the two have been rejoined. Also, the missing "or" has been inserted before "for a noncompetitive United States geothermal lease" in that sentence. The federal Act of

February 25, 1920, referred to is PL 66-146; the federal Act of December 24, 1970, referred to is PL 91-581 (the Geothermal Steam Act of 1970).

Legislative committee report. — For report on ch. 71, SLA 1972 (HCSSB 383 am H), see 1972 House Journal, p. 898.

Applied in *Moore v. State*, Sup. Ct. Op. No. 1284 (File Nos. 2551, 2587), 553 P.2d 8 (1976).

Sec. 38.05.150. **Coal.** (a) The commissioner may, and upon the petition of a qualified applicant, shall divide coal lands or the deposits of coal owned by the state into leasing tracts of 40 acres each, or multiples of 40 acres, and in the form which will permit the economical mining of the coal in the tract.

(b) Thereafter the commissioner may, upon the request of a qualified applicant or on his own motion, from time to time, offer the lands or

deposits of coal for leasing. Each lease shall be awarded to a qualified applicant by competitive bidding or by the method which the commissioner adopts by general regulation.

(c) Where prospecting or exploration work is necessary to determine the existence or workability of coal deposits in an unclaimed and undeveloped area, the commissioner may issue to qualified applicants prospecting permits for a term of two years, not exceeding 5,120 acres. If within the period of two years the permittee shows to the commissioner that the land contains coal in commercial quantities and submits a satisfactory mining plan for the coal's recovery, the permittee shall be entitled to a lease for all or part of the land in his permit. A coal prospecting permit may be extended by the commissioner for a period of two years, if he finds that the permittee has been unable, with the exercise of reasonable diligence, to determine the existence or workability of coal deposits in the area covered by the permit and desires to prosecute further prospecting or exploration, or for other reasons in the opinion of the commissioner warranting extension.

(d) For the privilege of mining or extracting the coal in the lands covered by the lease, the lessee shall pay to the state the royalties specified in the lease. The royalties shall be fixed before offering the lease, and shall be effective for a period of not more than 20 years. The royalties shall be not less than five cents a ton of 2,000 pounds. The lessee shall also pay an annual rental payable at the date of the lease and annually thereafter, on the land or coal deposits covered by the lease, at a rate fixed by the commissioner before offering the lease. The annual rental shall be effective for a period of not more than 20 years. The annual rental shall be not less than 25 cents an acre for the first year of the lease, not less than 50 cents an acre for the second year, third year, fourth year and fifth year, and not less than \$1 an acre for each year thereafter during the continuance of the lease. The rental for each year shall be credited against the royalties as they accrue for that year. Each lease shall provide that the annual rental payment is subject to adjustment at intervals of no more than 20 years and adjustments shall be based on the current rates for properties similarly situated.

(e) Each lease shall be for an indeterminate period upon condition of diligent development and continued operation of the mine, except when operation is interrupted by strikes, the elements, or casualties not attributed to the lessee. (§ 3(1) art VIII ch 169 SLA 1959; am § 17 ch 61 SLA 1960; am § 1 ch 71 SLA 1966; am §§ 2, 3 ch 88 SLA 1969)

Legislative committee reports. — For 1969 (HB 303), see 1969 House Journal, p. report on ch. 71, SLA 1966, see 1966 House 572.
Journal, p. 491. For report on ch. 68, SLA

Sec. 38.05.155. Phosphates. (a) The commissioner may lease to qualified applicants lands belonging to the state which contain deposits of phosphates and associated and related minerals, when in his judgment it is in the public interest to do so. The commissioner may lease land

included in a permit may not exceed 2,560 acres of land in reasonably compact form. Upon showing to the satisfaction of the commissioner that valuable deposits of potassium compounds have been discovered by the permittee within the area covered by his permit, and that the land is chiefly valuable for these deposits, the permittee is entitled to a lease for all or a part of the land embraced in the prospecting permit, at a royalty of not less than two per cent of the quantity or gross value of the output of potassium compounds and other related products, except sodium, at the point of shipment to market. The commissioner may lease lands known to contain valuable deposits of potassium compounds which are not covered by permits or leases through advertisement, competitive bidding, or other methods as he adopts by general regulation. The area covered by the lease may not exceed 2,560 acres.

(b) Each lease shall be conditioned upon payment by the lessee of a royalty of not less than two per cent of the quantity or gross value of the output of potassium compounds and other related products, except sodium, at the point of shipment to market, and the payment in advance of a rental of 25 cents an acre for the first calendar year or fraction of it, 50 cents an acre for the second calendar year, third calendar year, fourth calendar year, and fifth calendar year, and \$1 an acre a year thereafter during the continuance of the lease. The rental for any one year shall be credited against royalties accruing for that year.

(c) Each lease shall be for a term of 20 years and so long thereafter as the lessee complies with the terms and conditions of the lease. (§ 3(6) art VIII ch 169 SLA 1959)

Sec. 38.05.180. Oil and gas. (a) All tide and submerged lands, mental health lands, school lands, and university lands shall be leased by competitive bidding, and whenever oil or gas is discovered in commercial quantities, the commissioner shall determine the extent of the area of lands in addition to tide, submerged, mental health lands, school, or university lands in the same general area of the discovery well which, by reason of the discovery, the commissioner reasonably believes to be capable of producing oil or gas, and the additional lands shall be leased to the highest responsible qualified bidder by competitive bidding under general regulations, in units of not exceeding 2,560 acres (except that tide and submerged lands shall be leased in units of not exceeding 5,760 acres), which shall be as nearly compact in form as possible, upon the payment by the lessee of such bonus as may be accepted by the commissioner and of such royalty as may be fixed in the lease which shall not be less than 12½ per cent in amount or value of the production removed or sold from the lease. All lands other than those above provided to be leased by competitive bidding may be leased competitively or noncompetitively as determined by the commissioner to be in the best interests of the state. Noncompetitive leases shall be issued in units of not exceeding 2,560 acres in any one lease. Noncompetitive leases shall be conditioned upon the payment by the lessee of a royalty of 12½ per

cent in amount or value of the production removed or sold from the lease. Competitive leases issued under this subsection shall be for 10 years except that in the Cook Inlet sedimentary basin, leases shall be for a primary term of not more than 10 years and not less than five years at the discretion of the commissioner, and shall continue so long thereafter as oil or gas is produced in paying quantities. Noncompetitive leases issued under this subsection shall be for a primary term of five years and shall continue so long thereafter as oil or gas is produced in paying quantities. If drilling has commenced on the expiration date of the primary term of the lease and is continued with reasonable diligence, such operations to include re-drilling, sidetracking or other means necessary to reach the originally proposed bottom hole location, the lease shall continue in effect until 90 days after drilling has ceased and for so long thereafter as oil or gas is produced in paying quantities. If all or part of the lands covered by the lease are lands that have been selected by the state under laws of the United States granting lands to the state and a patent has not been issued on them, a conditional lease may be issued. However, no term extension may be granted for the period during which the lease was conditional.

(b) An oil or gas lease issued under this section which is subject to termination by reason of cessation of production does not terminate if, within 60 days after production ceases, reworking or drilling operations are commenced on the land under lease and are thereafter conducted with reasonable diligence during the period of nonproduction. No lease issued under this section expires because operation or production is suspended under an order, or with the consent of the commissioner. No lease issued under this section covering lands on which there is a well capable of producing oil or gas in paying quantities expires because the lessee fails to produce oil or gas, unless the licensee is allowed a reasonable time within which to place the well on a producing status. After producing status is established, production shall continue on the leased premises until suspension of production is allowed by the commissioner.

(c) Upon the expiration of the initial five-year term of a noncompetitive lease maintained in accordance with applicable requirements and regulations, the record title holder is entitled to a single extension of the lease, unless otherwise provided by law. A noncompetitive lease on lands not determined to be competitive lands shall be extended for a period of five years and so long thereafter as oil or gas is produced in paying quantities. A noncompetitive lease on lands determined to be competitive lands shall be extended for a period of two years and so long thereafter as oil or gas is produced in paying quantities. A noncompetitive lease extended under this paragraph is subject to the rules and regulations in force at the expiration of the initial five-year term of the lease. No extension may be granted, however, unless within a period of 90 days before the expiration date

an application for extension is filed by the record title holder or an assignee whose assignment has been filed for approval, or an operator whose operating agreement has been filed for approval.

(d) The commissioner may provide for extension of the term of a lease whether competitive or noncompetitive, if all or part of the lease is included in an approved unit plan or program of secondary recovery operation to bring about or restore production.

(e) All noncompetitive oil or gas leases issued under this section shall be conditioned upon the payment by the lessee in advance of an annual rental of 50 cents an acre or fraction of an acre. All competitive oil and gas leases issued under this section shall be conditioned upon the payment of an annual rental, before discovery on the leased lands, of \$1 an acre or fraction of an acre. A minimum royalty of \$1 an acre instead of rental is payable at the expiration of each lease year beginning on or after a discovery of oil or gas in paying quantities on the lands leased.

(f) Repealed by § 7 ch 30 SLA 1964.

(g) An offeror for a federal oil and gas lease whose lease was issued after January 2, 1959, or a qualified applicant for a preference right under the Act of July 3, 1958, (72 Stat. 322) whose application for a preference right was filed before January 3, 1959, has a preference right to a state lease on the shorelands included within the exterior boundaries of the federal lease.

(h) If lands described in the offer for a federal lease are covered by nontidal water and are excluded from the federal lease on the basis of navigability, the state shall, upon application within 60 days after notice of the exclusion, if not previously filed, grant a preference lease for the areas excluded, carrying the same provisions as an ordinary state lease on the same lands, except that the term of the state lease shall conform in all respects to that of the adjoining federal lease including extended terms. The state shall issue a shorelands preference lease where a federal lease has been issued before March 31, 1960, and application is made to the state before July 1, 1960. Where a federal lessee or offeror failed before January 3, 1959, to file a proper application for a preference right under the Act of July 3, 1958, he may apply for a state preference lease under this section, subject to the rights of intervening applicants.

(i) Where the lands are classified as competitive, they shall be leased by competitive bidding. The holder of the preference right has 10 days after receipt of notice in which to submit an amount equal to the highest bid plus the rental for the first year.

(j) Upon timely application as provided by regulation, the state shall issue to the holder of a federal lease a state shorelands lease covering land within the exterior boundaries of the federal lease which has been excluded on the basis of navigability or which are later administratively or judicially determined to be "shorelands." The term of every shoreland lease shall conform to that of the adjacent federal lease including

extended terms. The authority of the state to classify the lands as competitive or noncompetitive shall not be impaired.

(k) Instead of the foregoing procedure, the federal lessee or his assignee may, at his option, exercise his preference right for a state lease on the shorelands included within the exterior boundaries of his federal lease by applying to the division of lands, Department of Natural Resources. If, at the time of applying, the lands are classified as noncompetitive, the state shall, upon application, issue a lease covering whatever shorelands are included within the exterior boundaries of the federal lease. If, at the time of applying, the shorelands included in the federal lease are classified as competitive lands, the lands shall be leased by competitive bidding. The competitive lease shall be issued to the federal lessee or his assignee upon payment to the state of an amount equal to the highest bid for the lease, plus the rental for the first year, payment to be made within 10 days after the lessee's or assignee's receipt of written notice from the director of the division of lands of the amount of the highest bid. These leases, whether competitive or noncompetitive, shall carry the same conditions as an ordinary state lease on the same lands, except that the term of the state lease shall conform to that of the adjoining federal lease, including extended terms, and shall terminate if the federal lease is terminated for any reason. The lease shall provide for annual rental at the rate of \$100 a unit of 640 acres or part thereof of the lands included within the federal lease until agreement is reached between the state and the Secretary of the Interior of the United States, or his authorized representative, as to the actual area of the shorelands included in the federal lease, and as to the apportionment between the state and federal government of the rental theretofore paid under the federal lease.

(l) The lease of a record lessee of a federal oil and gas lease who filed, or whose predecessor in interest filed, between July 3, 1958, and January 3, 1959, a proper preference right application under the Act of July 3, 1958, (72 Stat. 322) to have included in the lease the shorelands within the exterior boundaries of the lease and which lease or any part of it has terminated or failed as to the shorelands due to mispayment of or failure to pay the required rental as to the shorelands in advance of the anniversary date of the federal lease, shall be revived and reinstated as to the shorelands upon payment to the Bureau of Land Management of the United States Department of the Interior or to the state of all rental payable as to the shorelands under the lease since January 3, 1959. The rights under this section terminate 60 days after receipt of notice from the director, but not later than March 31, 1961. Nothing herein operates to extend a lease beyond its stated term.

(m) To conserve the natural resources of all or a part of an oil or gas pool, field, or like area, (whether or not the part is then subject to a cooperative or unit plan of development or operation), lessees and their representatives may unite with each other, or jointly or separately with

others, in collectively adopting or operating under a cooperative or a unit plan of development or operation of the pool, field, or like area, or a part of it, whenever determined and certified by the commissioner to be necessary or advisable in the public interest. The commissioner may, with the consent of the holders of leases involved, establish, alter, change, or revoke drilling, producing, rental minimum royalty, and royalty requirements of the leases and make regulations with reference to the leases, with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan as he determines necessary or proper to secure the proper protection of the public interest. The commissioner may provide that oil and gas leases issued under this section shall contain a provision requiring the lessee to operate under a reasonable cooperative or unit plan, and he may prescribe a plan under which the lessee shall operate. The plan shall adequately protect all parties in interest, including the state.

(n) A plan authorized by (m) of this section, which includes lands owned by the state, may contain a provision vesting the commissioner, or a person, committee, or state agency with authority to alter or modify from time to time the rate of prospecting and development and the quantity and rate of production under the plan. All leases operated under a plan approved or prescribed by the commissioner are excepted in determining holdings or control under § 140 of this chapter. The provisions of this section concerning cooperative or unit plans are in addition to, and do not affect AS 31.05.

(o) Producing acreage on a known geologic structure of a producing oil or gas field is excluded from chargeability as against the acreage limitation provisions of § 140 of this chapter.

(p) When separate tracts cannot be individually developed and operated in conformity with an established well-spacing or development program, a lease, or a portion of a lease, may be pooled with other lands, whether or not owned by the state, under a communitization or drilling agreement providing for an apportionment of production or royalties among the separate tracts of land comprising the drilling or spacing unit when determined by the commissioner to be in the public interest. Operations or production under the agreement shall be considered as operations or production as to each lease committed to the agreement.

(q) The commissioner may, on conditions which he prescribes, approve drilling, or development contracts made by one or more lessees of oil or gas leases, with one or more persons, whenever, in his discretion, the conservation of natural products or the public convenience or necessity requires it or the interests of the state are best served. All leases operated under approved drilling, or development contracts, and interests under them are excepted in determining holding or control under § 140 of this chapter.

(r) To avoid waste or to promote conservation of natural resources, the commissioner may authorize the subsurface storage of oil or gas

whether or not produced from state lands, in lands leased or subject to lease under this section. This authorization may provide for the payment of a storage fee or rental on the stored oil or gas, or, instead of the fee or rental, for a royalty other than that prescribed in the lease when the stored oil or gas is produced in conjunction with oil or gas not previously produced. A lease on which storage is so authorized shall be extended at least for the period of storage and so long thereafter as oil or gas not previously produced is produced in paying quantities.

(s) Each oil or gas lease issued by the state shall contain a provision requiring the lessee to furnish the Department of Labor a quarterly report regarding the employment on the leased property of state residents. The commissioner of labor shall promulgate regulations necessary to carry out the provisions of this subsection. (§ 3(7) art VIII ch 169 SLA 1959; am § 18 ch 61 SLA 1960; am § 1 ch 124 SLA 1962; am §§ 4—7 ch 30 SLA 1964; am § 20 ch 70 SLA 1964; am § 2 ch 91 SLA 1967; am § 1 ch 65 SLA 1969; am § 1 ch 86 SLA 1970)

Revisor's note (1970). — In ch. 86, SLA 1970, subsection (s) of AS 38.05.180 was incorrectly designated (t).

Cross references. — See note to AS 38.05.020. As to establishment of drilling units for pools, see AS 31.05.100. As to gross production tax, see AS 43.55.010.

Purpose of subsection (a). — The provisions of subsection (a) of this section were intended to insure that leases on valuable oil and gas producing state lands will be made available to the public on a fair and equitable basis, that the state will be adequately compensated for its natural resources, and that the state's resources are developed in an orderly fashion. For the commissioner to decide that these purposes are furthered by providing for bidding by cash bonus cannot be said to be unreasonable. *Kelly v. Zamarello*, Sup. Ct. Op. No. 705 (File Nos. 1255, 1256), 486 P.2d 906 (1971).

And construction thereof. — The only reasonable construction that can be placed on subsection (a) of this section is that the legislature intended to give the commissioner broad authority to determine the kind of bonus he will accept. The legislature at the time it passed subsection (a) was undoubtedly aware that under competitive bidding procedures different forms of bonuses might be offered. It did not itself prescribe a particular form, but instead provided that competitive bidding shall be "under general regulations," and that lands shall be leased upon the payment of "such bonus as may be accepted by the commissioner." The plain language of the statute shows that royalties were to be

fixed independently of the acceptance of the highest bonus. *Kelly v. Zamarello*, Sup. Ct. Op. No. 705 (File Nos. 1255, 1256), 486 P.2d 906 (1971).

Power to change law respecting lease extensions is vested in state. — The governmental power to change the law respecting the granting of lease extensions, vested in Congress prior to statehood and preserved by § 6(k) of the Alaska Statehood Act, became vested in the state when the lands subject to the lease were granted to the state as its property. *Kirkpatrick v. Commissioner, Dep't of Natural Resources*, Sup. Ct. Op. No. 201 (File No. 388), 391 P.2d 7 (1964).

And has been exercised by the Alaska Land Act. — The state has exercised its power to change the law respecting lease extensions by the Alaska Land Act and by regulations adopted under its authority. *Kirkpatrick v. Commissioner, Dep't of Natural Resources*, Sup. Ct. Op. No. 201 (File No. 388), 391 P.2d 7 (1964).

Subsection (c) has no application to pre-statehood federal leases. — Read in the context of article 6 of this chapter, it becomes apparent that subsection (c) of this section, as to extensions, relates only to leases issued by the state under the authority of the Alaska Land Act, and is not pertinent with respect to pre-statehood federal leases. *Kirkpatrick v. Commissioner, Dep't of Natural Resources*, Sup. Ct. Op. No. 201 (File No. 388), 391 P.2d 7 (1964).

Subsection (c) of this section, relating to extensions of state oil and gas leases, has no application to federal leases of lands

granted to the state by the Alaska Statehood Act. Hence, appellant had no right to an extension of its federal lease, but only a right, which it was granted under the commissioner's regulations, to a state lease for a period of two years following expiration of the original five-year term of its federal lease. *Kirkpatrick v. Commissioner, Dep't of Natural Resources, Sup. Ct. Op. No. 201 (File No. 388), 391 P.2d 7 (1964).*

Nor to lands classified by Statehood Act as competitive. — The language of this section is not directed to a situation where lands have been classified as competitive by the Alaska Land Act itself, and where there is no room for the exercise of the commissioner's authority to make classifications. *Kirkpatrick v. Commissioner, Dep't of Natural Resources, Sup. Ct. Op. No. 201 (File No. 388), 391 P.2d 7 (1964).*

Effect of Alaska Statehood Act and statutes on pre-statehood federal leases. — For effect of the Alaska Statehood Act and statutes enacted by the Alaska State Legislature on oil and gas leases of Alaska lands issued by the United States Department of the Interior while Alaska was a territory of the United States, see *Kirkpatrick v. Commissioner, Dep't of Natural Resources, Sup. Ct. Op. No. 201 (File No. 388), 391 P.2d 7 (1964).*

Land classification orders of the commissioner are not within the meaning of "regulation" under the Administrative Procedure Act (AS 44.62.180 — 44.62.250) and are thus not subject to it. *Bradley v. State, 2 Alas. L.J. No. 6, p. 88 (June-July, 1964).*

State's reclassification of lands in the Cook Inlet Basin for competitive oil and gas leasing under subsection (a) of this section upheld in *Bradley v. State, 2 Alas. L.J. No. 6, p. 88 (June-July, 1964).*

For full treatment and explanation of oil and gas leasing procedures under Alaska law, see *Bradley v. State, 2 Alas. L.J. No. 6, p. 88 (June-July, 1964).*

"Commercial quantities" construed. — See *Pan American Petroleum Corp. v. Shell Oil Co., Sup. Ct. Op. No. 553 (File No. 918), 455 P.2d 12 (1969).*

The words "bonus" and "royalty" in their broadest concepts and meanings are conflicting and overlapping. On the other hand, when it is necessary that they be distinguished, there is a narrower concept of the two terms as they are ordinarily and commonly used and understood in the oil and gas industry in which they do not conflict but are harmonious. In this

narrower sense, a reservation or a payment of a part or percentage of production under a lease which is to continue throughout the life of the lease is regarded as "royalty," and a sum certain to be paid in cash or out of production is regarded as "bonus." *Kelly v. Zamarello, Sup. Ct. Op. No. 705 (File Nos. 1255, 1256), 486 P.2d 906 (1971).*

In its broadest sense, "bonus" is any consideration given for a lease over and beyond the usual $\frac{1}{4}$ th royalty, whether the additional consideration be paid or payable and whether paid in cash or payable out of production. *Kelly v. Zamarello, Sup. Ct. Op. No. 705 (File Nos. 1255, 1256), 486 P.2d 906 (1971).*

In its broadest aspect, "royalty" is a share of the product or profit reserved by the owner for permitting another to use the property. In this broad sense, a sum certain to be paid out of production, although "bonus" in that it is consideration in addition to the usual $\frac{1}{4}$ th royalty, would also be "royalty." *Kelly v. Zamarello, Sup. Ct. Op. No. 705 (File Nos. 1255, 1256), 486 P.2d 906 (1971).*

Choosing concept of "bonus" most commonly encountered. — In choosing the concept of "bonus" most commonly encountered in the oil and gas industry, defendants acted neither unreasonably nor arbitrarily. *Kelly v. Zamarello, Sup. Ct. Op. No. 705 (File Nos. 1255, 1256), 486 P.2d 906 (1971).*

Requiring compensation for lease immediately upon award of lease. — It is not unreasonable for the commissioner to determine that it is in the state's best interest to receive compensation for the leases immediately upon the award of the lease, rather than to wait for uncertain sums to arrive in the form of premium royalties. *Kelly v. Zamarello, Sup. Ct. Op. No. 705 (File Nos. 1255, 1256), 486 P.2d 906 (1971).*

Considering only cash portions of bids. — In considering only the cash portion of plaintiffs' 33 bids, defendants acted pursuant to valid regulations which provided that a lease would be awarded to the bidder offering the highest cash bonus. Since other bids on the 33 tracts contained higher cash offerings than plaintiffs' bids, the defendants acted properly in determining that the high cash bids on those 33 tracts were the apparent high bids, not plaintiffs' bids. *Kelly v. Zamarello, Sup. Ct. Op. No. 705 (File Nos. 1255, 1256), 486 P.2d 906 (1971).*

Royalty legislation on state oil and gas leases is a matter within the paramount jurisdiction of the state. The conservation