COMMITTEE REPORT

SENATE

FURTHER: _____

_____

5/19/78

Date: 5/22/78

Mr. President:

The Committee on RESOURCES has had CSHB 854 (Fin)
leasing and exploration of state land for oil and gas development

under consideration and (a majority of the committee) (the committee reports it back as follows)

( ) recommends it do pass ( ) recommends it do not pass

( ) recommends it do pass with attached amendment(s)

(X) recommends it be replaced with CS for CSHB 854 (Fin)

and _____ ( ) new title (X) same title

( ) AND attaches a Letter of Intent ( ) New Fiscal Note

( ) reports it back without recommendation

( ) and recommends it be referred to the _____ Committee

MEMBERS SIGNING DO PASS:

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OTHER RECOMMENDATIONS:

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_____

Rodney Ps No Rec

Jan Faulkner NO Rec

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T. Poland
Chairman

Do Pass

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COMMENTS FROM AN ECONOMICS PERSPECTIVE ON HOUSE BILL NO. 854 IN THE LEGISLATURE IN THE STATE OF ALASKA TENTH LEGISLATURE -- SECOND SESSION

by

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May 15, 1978

This analysis will concentrate attention on major issues of House Bill No. 854 on which economic analysis can shed some light.

In general, it is clear that the Bill is patterned after proposed amendments to the Outer Continental Shelf Lands Act of 1953 now being considered by the U.S. Congress. There is an implied assumption that the State of Alaska can benefit by following Washington's legislative lead. Almost every Economist specialized in energy economics who has reviewed the record of federal energy legislation has concluded that a half-century of federal interference in the energy industry has been counterproductive. Such interference has not served the general welfare.

Enclosed as Appendix A is a reprint of my own analysis of President Carter's National Energy Program. This analysis includes an appraisal of past Federal energy policies. There is no evidence in the record to indicate that the State of Alaska will benefit in any way from following the lead of the Federal government in the energy policy area.

With respect to future joint state-federal leases in the Beaufort Sea, the State of Alaska is likely to commit a strategic error if it adopts leasing policies parallel to the revised OCS bill. If Alaska and the Federal government have nearly identical leasing provisions, then the Federal government is likely to determine lease policy for the joint sales. On the other hand, if the State of Alaska retains its present

bonus bidding system with the options currently provided, then Alaska is more likely to determine the outcome. As will be shown below, lease systems other than bonus biddings will yield less Economic Rents to government. This loss in income is of little concern to the Federal government, but is of great concern to the State of Alaska. If the arguments made below are acceptable, then the State of Alaska would be well advised to retain its present leasing system.

I. BIDDING ALTERNATIVES

House Bill No. 854 provides the Commissioner with a choice of several leasing methods. In order to simplify the analysis we will concentrate attention on four bid variables. (1) Bonus, (2) Royalty, (3) Profit-Share and, (4) Work-Commitment bidding. Each of these four bid variables is, in turn, paired with a variety of fixed payment requirements.

Before discussing each of these leasing alternatives, it would be useful to identify the basic economics involved. The oil and gas resources in the ground belong to the people of the State of Alaska. In turning over to lessees rights to explore for and produce any oil and gas found on leases, the people, through their government, are entitled to receive what economists call the "economic rent". This is the difference between the value of oil and gas produced, and the total necessary cost of exploration, development, and production, including in costs a competitive rate of return for the lessee. The important economic relationships are illustrated in Figure 1.

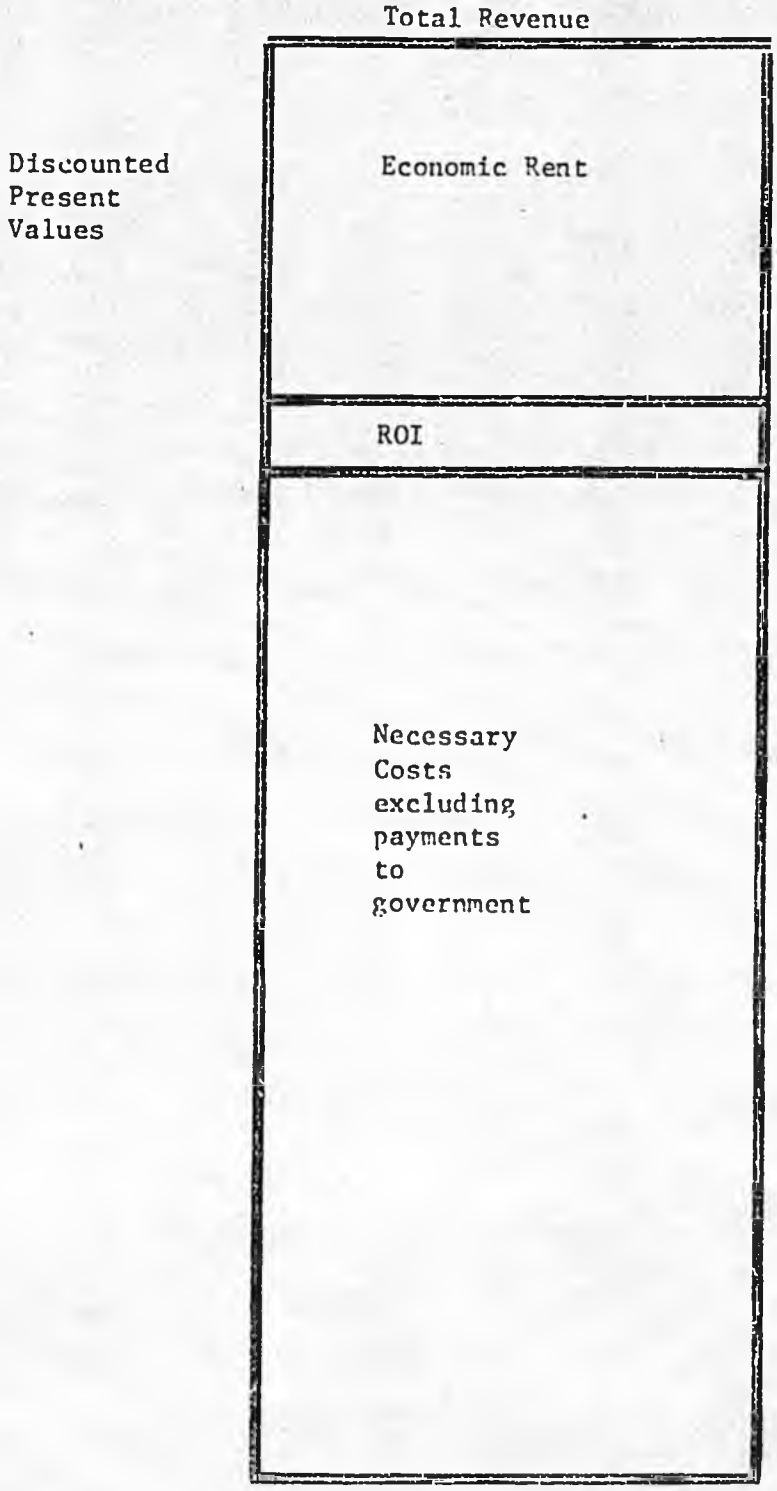
Because outlays and incomes flow at different points in time, it is necessary to use comparable values. This is done through the process of discounting future dollars to a common point in time. (Using a 10% discount rate, $1.10 next year is worth only $1.00 today.) In order to avoid the "apples and oranges" problem, all revenues and outlays represented in Figure 1 are shown as "Discounted Present Values."

The vertical distance in the diagram represents the discounted present value of total revenue obtainable from a given oil or gas lease. The middle segment of the figure represents the "necessary costs" of exploring for and producing oil and gas from a lease. However, payments to the government are not included in these costs.

The ROI segment of the figure represents the Return on the Investment for all capital costs incurred by the lessee. This ROI is assumed to be a necessary minimum as determined by competition.

The residual revenue, after all necessary costs including normal profit, is the Economic Rent collectible by the landowner.

Figure 1 is constructed on the assumption that maximum efficiency is obtained. If a leasing policy introduces inefficient operations, then costs will be higher than necessary and Economic Rent will be relatively low. It is important to realize that the total receipts of the government from an oil and gas lease do not necessarily correspond with the maximum obtainable Economic Rent. Rent is maximized only


Total Revenue
Discounted Present Values
Economic Rent
ROI
Necessary Costs excluding payments to government

under efficient conditions of production. A good leasing system then collects all of the economic rent.

(1) Bonus Bidding

Under bonus bidding a single lump sum is offered. The principal advantage of the bonus bid variable is that it is the most efficient system available. If the bonus payment is not accompanied by a fixed royalty payment, it does not impose on each barrel of oil (or gas) produced a charge which represents part of the economic rent payment. The only charges against each unit of output is the real economic cost (labor, electricity, maintenance) of producing another barrel of oil. This important fact leads to efficient business judgments concerning investments in secondary and tertiary recovery, and the optimum shut down point when a well approaches exhaustion.

Since only a lump sum payment to the government is required, this system is inexpensive to administer. The less the administration cost, the greater is the economic rent colletible by the government.

Finally, because the operator receives the residual value after the bonus payment and all economic costs of oil and gas production, the operator has the highest possible incentive to operate his lease efficiently.

Maximum efficiency should be of interest to all segments of society, and especially to the people of Alaska as the resource owners. Maximum efficiency means that resource (cost) input is minimized relative to product output. This is a goal of conservation. With maximum efficiency, the State

of Alaska will receive the highest possible payments. Maximum efficiency also produces lowest possible costs to consumers.

The above points can be illustrated by reference to Figure 1. The ROI is limited by competition in the long run. If inefficiency is built into the leasing system, them the "Necessary Costs" sector of Figure 1 will be large, reducing Economic Rent available to the state. Similarly, if the leasing system imposes unnecessary administrative costs on the lessee, then Economic Rents are again lowered. Any unnecessary administrative costs paid for by the state, come out of the Economic Rents directly.

The corresponding disadvantages of bonus bidding are two-fold.

First, bonus bidding requires "front end money." The lump sum bid must be paid before drilling has identified any reserves. There may be anti-competitive consequences arising from this "front end money" problem. Smaller, less well financed firms, may not be able to participate in bidding competition to the extent that they might wish. However, the severity of this problem may not be significant. Through widespread use of joint bidding, smaller firms, in fact, have been able to enter even the expensive OCS lease auctions through joining with other small firms and with large firms.

In order to reduce the "front end money" even further, the State might consider introducing a schedule of delayed payments. The only risk that the State would undertake through a delayed payment schedule is the risk that poorly financed

firms would "walk away" from part of their bonus payment obligation.

Oil exploration, development and production in a hostile environment requires a high degree of technological expertise as well as financial and operational integrity. The companies with this level of technological expertise are generally financially responsible firms.

Second, there is no one-to-one relationship between the bonus payment to government and the value of any oil and gas reserves ultimately found. In the extreme, this problem is illustrated by the Prudhoe Bay lease where probable value exceeds the bonus payment (and all future royalty and severance payments) by a large amount, and by the Destin Anticline offshore from Florida where the bonus payment was extremely large and revenues were zero. Even for productive wells there is usually not a perfect match between outlay and income. However, recent research on Federal OCS leases shows that, in the aggregate, under bonus bidding, with a fixed royalty, there is a very close match between costs plus payments to the government, on the one hand, and the discounted present value of oil and gas production from such leases, on the other hand.

Evidence from OCS Leasing. The record of production from all 839 leases issued by the Federal government in the Gulf of Mexico region of the Outer Continental Shelf between

the years 1954 and 1962 has been analyzed.[1] This record shows that of these 839 Federal leases, 522 (62%) produced only dry holes. Another 132 (16%) leases were productive but unprofitable. Only 185 (22%) were profitable. Effective competition requires that these profitable leases produce revenue flows sufficient to cover not only their own full costs but the bonus and exploration costs of all dry holes as well.

The rate of return that all lessees earned on their investment (bonus, exploration, development, etc.) in these leases has been estimated. Precise information on all leases is available showing bonus, rent, and royalty payments, together with oil and gas production by year through 1976. The value of such production is also known with precision. Estimates were made of pre-lease geological and geophysical exploration costs, post-lease exploration costs, development outlays, and production costs. Forecasts were made of oil and gas production from 1977 through projected closedown of each well. In addition, oil and gas prices and costs of production were forecast. With these outlays and income flows, the rate of return earned by lessees has been estimated. The results show that lessees earned a 9.5% rate of return before taxes on their investment. This ROI is low relative

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[1] R. O. Jones, W. J. Mead, and P. E. Sorensen, "Free Entry into Oil and Gas Production and Competition in the U.S. Oil Industry," Natural Resources Journal, July, 1978, forthcoming.

to competitive performance elsewhere in the U.S. economy. The interpretation of the results is as follows:

1. Competition for Federal leases from 1954 through 1962 was intense.

2. The federal government received more than a "Fair Market Value" for these leases. This does not mean that the Federal government received all of the Economic Rent which might be collected under most efficient conditions. As will be shown later, the fact that royalty payments were required introduces some economic inefficiency therby reducing the collectible Economic Rents.

3. The bonus bidding system, in the aggregate, is an effective method of collecting Economic Rent.

(2) Royalty Bidding.

Under royalty bidding, interested parties bid a percentage of gross wellhead value payable to the government for each and every barrel of oil or thousand cubic feet of gas produced from a lease. There are two advantages of royalty bidding:

First, payments to the government correspond with production. If a lease is found to be dry, then no payments are required. If a lease is highly productive, then payments correspond with the value of production. Royalty is calculated as some specified percent of production, or of the value of production at wellhead.

Second, in the absence of a fixed bonus, no "front-end" payment is required. This may stimulate additional competition. Firms are able to obtain leases with no payment being made to the government prior to production from such leases.

However, there are also substantial disadvantages arising out of a royalty bidding system.

First, royalty bidding is inefficient for three reasons. The royalty payment is a bid percentage of the gross (not net) wellhead value. It, therefore, requires a significant payment to the government in addition to the real cost of producing every barrel of oil or thousand cubic feet of gas. The first inefficiency is due to premature abandonment of leases. The problem is illustrated in Figure 2. The State of Alaska currently requires a 12.5% fixed royalty payment from oil and gas production. In addition, the State imposes a severance tax on production. This tax has the same effect as a royalty. The two payments together are shown in Figure 2 as a 20% royalty charge.

Costs of production are low in the initial phase of reservoir life. With the passage of time, reservoir pressure declines as economically recoverable output is produced. In the absence of any royalty charge, production would be carried to point Q_1. Beyond that point, the cost of producing an additional unit of output is higher than its value. At point Q_1, the value of the resources used up to produce the last barrel of oil is exactly equal to the value

Dollars per bbl.
$10.00
Royalty 40%
Royalty 20%
Real Economic Costs
Time
Q_3
Q_2
Q_1
Incremental Cost with 40% Royalty
Incremental Cost with 20% Royalty
Incremental Cost No Royalty

of the oil produced. Social waste would result from production beyond, or short of, this point.

Where a 20% combination royalty and severance tax is levied, production would be terminated at Q_2. If bidding takes place on the royalty, the royalty payments would rise to higher levels. Figure 2 illustrates a 40% combination royalty and severance tax. With this payment, the property illustrated in Figure 2, would be abandoned at Q_3. Thus a royalty leads to premature abandonment of valuable resources. It is correct to describe this as "premature abandonment" because the royalty payments are merely transfer payments from the operator to the government. They are not true economic costs in the sense that labor and materials are economic costs.

Returning to Figure 1, the effect of premature abandonment on Economic Rent can be shown. Because total revenue with a royalty payment is lower than it would be if no royalty were required, the Total Revenue column would be lower than shown in the diagram. But necessary costs and profits (ROI) would be reduced only slightly. Therefore, premature abandonment causes Economic Rents to be lower than their potential. This means that the people of the State of Alaska sacrifice money income due to a royalty payment requirement. Social costs are borne by all of the people. This is always the result when scarce resources are wasted. In the royalty case, the higher the royalty payment, the greater the loss in Economic Rent.

Where bidding takes place on the basis of a royalty payment, the loss to government in Economic Rent and to the people of a nation in lost resources can be substantial. An 80% royalty payment when oil is priced at $10.00 per barrel at wellhead requires a payment to the state of $8.00 per barrel. This means that when real economic costs reach $2.00 per barrel, this real cost together with the $8.00 transfer payment results in extremely early abandonment.

The second inefficiency in royalty payments arises from the fact that some smaller fields, which would be profitable to operate under low or zero royalty payments, become submarginal with higher royalty payments. In this case, a discovered field would be termed uneconomic to operate and would not be developed. This results in a monetary loss to the State of Alaska, and a social cost to the entire nation.

A third inefficiency arising out of royalty payments is that they reduce the incentive of operators to invest in more intensive management of their reserves. For example, secondary and tertiary recovery investments in some cases will not be undertaken. Without royalty payments, some of these investments might return an attractive rate of return, say 20% ROI; whereas with royalty payments the ROI might fall to the unattractive or negative category and investments would not be undertaken.

In terms of Figure 1, foregoing recovery investments reduce Total Revenue below the optimum level with the result that Economic Rents are less than what could be collected under efficient leasing terms.

Premature abandonment, however, can be avoided by successive reduction of royalty to zero. Everybody gains from reducing royalties to zero relative to fixed royalties. Profits to the operator would increase, additional royalties would accrue to the State, because premature abandonment would be avoided, employment would be higher, and the nation would receive additional oil production at social benefits which are greater than social costs.

A second disadvantage of the royalty system is that it may simply tie up leases without cost to the lessee. With no bonus payment, he may have no investment whatsoever in the lease. He has only a commitment to pay royalties in the event of production. This is a free option to buy. If other lessees are nearby who have invested bonuses in leases and are engaged in exploratory activity, the lessee with a royalty lease will probably choose to wait for the results of drilling by others. However, if a small fixed royalty is also required along with the contingent royalty payment, the royalty lessee has less of an incentive to do nothing. However, a pure bonus bid provides a maximum incentive to proceed quickly with exploration.

In an economic sense, any royalty should be reducible to zero prior to abandonment. The U.S. Interior Secretary has authority to do this, but has never exercised his authority possibly because of the administrative difficulty. There is no objective way to inexpensively determine when royalties should

be eliminated. If bidders, at the point of lease sale, understand that royalties will be reduced to zero to avoid premature abandonment, then they will place a higher value on the lease. Competition for the lease will force them to bid higher bonus payments. In this event, more oil is produced and the State would collect increased Economic Rents.

House Bill No. 854 also provides for a sliding royalty scale, "according to the volume of production." If a sliding scale is used, the inefficiencies and consequent losses in Economic Rent analyzed above would still appear. Any investment in secondary and tertiary recovery would still be retarded. Such investments cause output to increase, and therefore incur higher royalty obligations. The net effect would still reduce the ROI on the investment. In cases where the ROI is shifted from attractive to unattractive or negative levels, the state would suffer a loss of Economic Rents. Further, expensive administrative costs are incurred. There is no efficient and objective means of setting sliding scale royalty rates. If royalty rates are made purely a function of production, then the operator has an incentive to reduce production below the most efficient rate which would maximize the Economic Rent. Government administrators may try to avoid this problem with careful surveillance of the operator and careful, but subjective, determination of sliding scale royalty rates. But this requires expensive administration.

The cost of this bureaucracy may be shown in Figure 1 as a negative charge against Economic Rent. A relatively

high level of rent might be collected, but some of it will be dissipated in administrative costs and will not accrue to the people of Alaska. In addition, the lessees must also maintain staff personnel in order to develop and analyze data, and negotiate with their government counterparts. This raises costs to the lessee beyond those which are represented to be "necessary costs" in Figure 1. This means that Economic Rents are doubly reduced and payments available to the State decline even further.

In summary, royalty payments result in reduced efficiency and therefore in reduced Economic Rents. The larger the royalty payments, the greater the loss in Economic Rent. Sliding scale royalty rates will avoid premature abandonment if they are reduced to zero at appropriate points. However, sliding scale royalties artificially discourage investments in secondary and tertiary recovery, lead to abandonment of wells that are economically operable, and also result in wasteful administration costs, all of which lower Economic Rents available to the State.

(3) Profit-Share Bidding.

Under profit share bidding, each bidder offers a percent of the net profit for each lease to be paid to the State. There are four possible advantages of profit share bidding as follows:

First, it is an improvement over royalty bidding in that the profit share to be paid to the State is based on

net income (profit) rather than gross income. This means that as a field approaches exhaustion, its profit declines towards zero. Unless the profit share bidding system also requires a fixed royalty payment, the problem of premature abandonment is avoided.

Second, profit share bidding avoids the front end loading problem that is characteristic of bonus bidding, unless profit share bidding is paired with a fixed bonus requirement. No payments are due to the State until production appears and profits accrue to the operator. In the absence of front end payments, smaller less well financed operators may enter the bidding competition and possibly win leases. As indicated in the analysis above (page 8), this problem is of minor importance from a competitive performance viewpoint.

Third, payments correspond with benefits. Dry holes require no profit share payment. Conversely, the occasional rich discovery producing high profits results in larger payments to the State. This would avoid some of the political embarrassment associated with the Prudhoe Bay situation.

Fourth, hopefully, a pure profit share bidding arrangement may constrain over-zealous regulators and environmentalists from imposing uneconomic costs on oil exploration and production. Under the profit share system, any economic waste is clearly shared by the operator and the government.

Returning to Figure 1, when unnecessary costs are imposed on operators after a lease sale has taken place, both the ROI and the Econor ic Rent segments of the chart are reduced. It should be pointed out that when a government engages in such post-bidding practices, bidders will quickly learn to anticipate a repetition in subsequent sales. Such expectations will be factored into future bid calculations such that in subsequent leases the entire cost of uneconomic regulations is borne by the government in the form of reduced Economic Rent.

There are also substantial disadvantages involved in the profit share bidding system.

First, while the layman may consider computation of profit to be a simple and straight-forward calculation, in fact, a wide variety of accepted accounting procedures are used. There are two general concepts of profit which may be identified.

(1) Bidding may take place on an accounting concept of profit in which fixed costs and overhead costs, along with all operating costs, are deducted from gross revenue in order to obtain net profit.

(2) Net profit may be defined as operating profits in which fixed costs and overhead are not allowed as reportable expenses.

Within each general classification a multitude of problems immediately appear. For example: (1) The process of trading oil between separate companies is widespread in this industry, and an arm's length sale of oil may not take place.

Prices must be carefully analyzed. This requires unnecessary administrative expense by both lessee and lessor. (2) Where a company wishes to do some research and development concerned with oil exploration and production, it is likely to do so on leases involving profit share payments rather than on other company production. (3) Where a company has a mixture of highly efficient and less efficient drilling rigs or drill ships, it is likely to use the poor equipment on the profit share lease and reserve the best equipment for other company operations. (4) Where a company needs to train crews in drilling and reservoir development, it is likely to do its training on profit sharing leases. (5) "Gold-plating" is likely to occur on profit share leases where the share paid to government is high and the retained share is low. Evidence of this practice may be found in the Long Beach (Wilmington) field where profit shares paid to the government are extremely high. (6) In profit share leases, public relations expenditures are likely to be high. This will be particularly true when expenditures for P. R. produce benefits for the lessee company as a whole. (7) In the event of supply shortages such as occurred in 1973 and 1974, available supplies are likely to be allocated to non-profit share leases first.

Companies differ in their level of efficiency. In order for the State to select the highest bidder it should evaluate probable efficiency of each competing bidder. While

this is desirable, it is also expensive and probably impossible. But it means that the high profit share bidder is not necessarily the operator that will produce the most Economic Rent for the State.

In order to avoid the problems listed above, as well as others not listed, the State will probably determine that it must carefully police lessee operations. This, of course, requires additional administrative costs. Again in terms of Figure 1, one should expect not only the necessary cost of production to be incurred, but also unnecessary costs as well. But these costs reduce the Economic Rents available to the State. Also, the added policing function by the State involves additional administrative costs which must be paid for out of the State's Economic Rents. Further, because the interpretation of profit is difficult, one must expect litigation of disputes. This requires expensive attorney fees and court costs for both the operator and the government. All of these expenses further reduce available Economic Rents.

Second, in addition to the profit share bid, one must also consider the corporate income tax for it too is a profit share payment. With percentage depletion allowance totally phased out for all integrated oil companies and reduced for smaller non-integrated firms, the corporate income tax will approach a 48% effective rate at the federal level. Any state income taxes will increase this rate even further. Using a 48% corporate income tax paired with a 30% profit share

bid results in an effective profit share (or tax) rate of 63.6%. Thus, out of every additional dollar saved through efficiency, the company retains 36.4¢. Where an 80% profit share bid is paired with a 48% corporate income tax, the effective tax rate is 89.6%. This leaves only 10.4¢ on the dollar, as a reward for efficiency. This incentive is too small to produce maximum efficiency. In terms of Figure 1, expenses will be higher than necessary with the result that Economic Rents available to the State are sacrificed.

Third, as in the case of royalty payments, profit share payments discourage investments in intensive field management including well workovers, pressure maintenance projects, and secondary recovery investments. Some super-marginal investments will become submarginal and will be passed over. The lost net benefits are borne by the State in the form of reduced Economic Rents, and by all citizens in the form of resource waste.

Fourth, further experiment with profit share bidding is not needed. Instead of engaging in such wasteful bidding practices, researchers from the State of Alaska can easily examine the Long Beach record. In that case the profit share bid for the largest operating interest amounted to 94.56% of accounting profit being paid to the State. While this may sound good for the lessor, the profit share retained by the lessee (after profit share payment to the State, after management fee, and after income taxes) is only 0.75%. In effect, there is no efficiency incentive.

As a substitute, the Department of Oil Properties of the City of Long Beach has developed a 50 person permanent staff to supervise and police the operators. Administrative interference with the operation of the field becomes a necessity. The Long Beach-Wilmington contract provides that

> The City Manager... shall exercise supervision and control of all day-to-day unit operations... and... shall make determinations and grant approvals in writing as he may deem appropriate for the supervision and direction of day-to-day operations of the Field Contractor, and the Field Contractor shall be bound by and shall perform in accordance with such determination....

A spokesman for one operator has stated that "Hassle after hassle has developed regarding charges to the net profits account."[2] All of the problems outlined above can be verified in the Long Beach situation including the "gold-plating" problem.

In summary, while profit share bidding avoids some of the problems present in both bonus bidding and royalty bidding, it has its own set of serious problems. Economic analysis clearly indicates that Economic Rents received by the State would be substantially lower under profit share bidding than under bonus bidding.

(4) Work Commitment Bidding.

Under this system the bidder would specify in detail precisely the dollar amount of investments he would make in exchange for a lease. Presumably this means that the bidder

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[2] W. J. Mead, "Federal Public Lands Leasing Policies." Quarterly of Colorado School of Mines, October, 1969, p. 212.

would cost-out his entire exploration, development and production program.

The disadvantages of this system are overwhelming.

First, it is questionable whether the Commissioner and his staff will be in a position to determine the most efficient work program. If it selects any program other than the most efficient one, then Economic Rents are reduced as previously illustrated with reference to Figure 1.

Second, experience in North Sea work program bidding has shown that when it becomes known what type of work commitment is viewed with favor by the sale administrators, firms will concentrate their efforts and corresponding dollar amounts in that direction. In the early North Sea leases it became known that the bidder offering to drill the most holes would win the leases. The result was excessive drilling. But this practice reduced Economic Rents available to the British government.

There is no practical way the number of wells to be drilled can be specified in advance. The optimum number of wells to be drilled must be determined as experience in drilling a specific lease is gained. Similarly, other characteristics of a work program can best be determined after the presence or absence of reserves has been determined.

Third, if the winner is determined on the basis of the dollar amount of his work commitment, then the State sacrifices receipt of all or part of a cash bonus and receives in exchange only a work commitment. If bidder selection is

not based on the highest dollar amount of the work commitment, then there is no objective way in which the winner can be selected. This opens up a possibility of corruption of government officials.

Fourth, any work commitment must be policed. Administrators must carefully monitor all provisions of the work commitment to assure compliance. Consequently, adminstrative costs will be relatively high. Correspondingly, the lessee must maintain added staff in order to negotiate with government staff. Further, costing out the dollar value is an expensive process. If the State is to select the winner on the basis of the high dollar amount, then it must verify the costs claimed. All of this added administrative cost comes out of Economic Rents.

Fifth, a minor amount of specific work programs can be accomplished by a bonus bidding arrangement or other bid forms without resorting to a work commitment program. This may be accomplished by simply writing into the contract specific requirements. In any event, specific work requirements such as environmental safeguards should be justified by evidence that their benefits exceed their costs. Unless they are economically justified, they are not part of necessary costs as shown in Figure 1. Economically unjustified environmental or other work requirements, in the long run, simply reduce Economic Rents available to the State.

There is no need for the State of Alaska to experiment with the work commitment bidding form. There is abundant experience in both British and Norwegian North Sea experience. This experience has been evaluated by Kenneth Dam.[3] Dam reported that "the discretionary system turns out to be a most expensive subsidy."

While most of the British experience has been under a discretionary system in which a work program has been specified, the British leased 15 blocks by competitive bonus bidding in 1971. If these blocks had been leased by the discretionary system, the British would have failed to receive 37 million pounds ($90 million) the total amount of the bonus bids. The only offsetting gain to the government would be the incremental value of the work program. However, it is probable that the operators would have engaged in an optimal work program without bidding a specified work commitment.

The work commitment bidding system is probably the most expensive in terms of lost Economic Rents. While House Bill No. 854 provides for a fixed cash bonus, or fixed royalty, or fixed sliding scale royalty, or fixed net profits share in addition to the work commitment, it is highly unlikely that fixed payments would have a value to the people of Alaska equal to a bonus bid in the absence of the work commitment.

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[3] K. W. Dam, Oil Resources. Chicago: University of Chicago Press, 1976.

The work commitment option provision in the February 17, 1978 draft has been replaced by an exploration incentive credit system. This system has many of the same problems listed above. If 50% of the cost of drilling or exploratory work is to be deducted from payments to the State, then the after-payments and after-tax cost of drilling and exploratory work becomes cheap for the lessee. This leads to wasteful drilling and exploration. The people of Alaska pay the bill.

III. CONCLUSIONS

Economic analysis indicates that sealed bonus bidding without a fixed royalty is the most efficient system available and would, in the long run, maximize Economic Rents payable to Alaska.

Passage of House Bill No. 854 would appear to convert a reasonably effective bonus bidding system presently in use in Alaska, into a system which will virtually guarantee a loss of Economic Rents. This burden will be borne by the people in Alaska in terms of foregone money income, and by the entire nation in the form of inefficient use of scarce resources.

STATEMENT OF
SOUTHERN CALIFORNIA GAS COMPANY
PACIFIC GAS AND ELECTRIC COMPANY AND
PACIFIC ALASKA LNG ON HB 854

My name is Norman Gorsuch and I am the registered representative for Southern California Gas Company, Pacific Gas and Electric Company and Pacific Alaska LNG. We are very seriously concerned about paragraph Z on page 11 of the proposed legislation. That paragraph would grant the State the right to purchase as much as all of the volume of gas produced from a lease issued by the State for in state use. Arguably, because of a possible ambiguity in the language, this right can be exercised subsequent to the execution of the lease contract without notice having been given prior to the lease sale.

Affiliates of these companies are now actively engaged in financing drilling for gas reserves by oil companies holding leases located in the Cook Inlet area. In addition, Pacific Gas and Electric Company is a partner in a lease recently acquired at the Lower Cook Inlet sale held by the Federal Government. To date, these companies have expended $35,000,000 in payments to producers to fund the drilling of gas wells in the Cook Inlet area. In addition, these companies plan to expend another $35,000.000 over the next few years in similar ventures.

Pacific Gas and Electric and Southern California

Gas Companies are the largest public gas supply utilities in Calfiornia. Together they have delivered as much as 5 billion cubic feet of gas per day in California to residential and commercial customers. A recent staff report by the California Public Utilities Commission found that both utilities should expedite the acquisition of future gas supplies in Alaska. The Public Utilities Commission Staff most particularly urged rapid pursuit by these companies of their Cook Inlet Liquified Natural Gas project. This project consists of a proposed facility in Kenai to liquify and ship 400 million cubic feet of gas per day to these companies in California. The capital investment in 1977 dollars projected for this facility and related pipelines is $850,000,000. This project will not require any State financing nor does the project require the State royalty gas in Cook Inlet to make it economically feasible. At the present time, these companies have under committment approximately 800 billion cubic feet of gas in the Cook Inlet area. They will need approximately 1.3 trillion cubic feet for the first phase of the project which would be for 200 million cubic feet of LNG per day with a total of approximately 3.6 trillion cubic feet for a 400 million cubic feet per day throughput. It is contemplated by both companies that all of these gas reserves will be found by an agressive gas drilling program in the Cook Inlet area. These companies are also committed to invite the gas distribution public utilities in the Cook

Inlet area to participate in any of these ventures if those companies so desire. A subsidiary of Alaska Interstate Company is currently participating in a prospect being drilled at Stump Lake.

Southern California Gas Company and Pacific Gas and Electric have plans to continue to explore for gas reserves in southern Alaska. Long range plans contemplate the purchase of gas discovered in southcentral Alaska and a committment of the gas to this and future LNG projects.

Paragraph Z would effectively frustrate the plans of these companies in several ways and adversly affect gas exploration and development in Southcentral Alaska, First, these companies are financing this exploration program to obtain guaranteed gas supplies. They would not benefit from the receipt of money from the State for the acquisition of the gas supplied from State leases. Furthermore, under a ruling by the California Public Utilities Commission, the gas consumers of these two companies pay in their gas rates the carrying charges on the capital investment required to fund this drilling in expectation of the gas coming to California. Second, this provision in future gas leases would effectively deny financing for this Cook Inlet project and other LNG ventures should they materialize as no lender will advance capital if the project is not assured of a gas supply. Third, this provision would

effectively frustrate certification by the Federal Energy Regulatory Commission of this project and any future gas projects simply because the applicant seeking a certificate from the Federal Energy Regulatory Commission could not guarantee a supply of gas so long as the State arguably has an option to purchase as much as all of it in all future leases. Fourth, if a well prospect after being drilled shows a low potential for oil but a high potential for gas, it is uneconomic for the oil producer to develop that gas field unless a public utility funds development costs for the purpose of acquiring the gas from the producer. Fifth, there is no economic incentive for oil producers and drilling companies to drill for gas in the Cook Inlet area and in southcentral Alaska generally because there is no market for such gas at this time.

The Cook Inlet LNG project proposed by these companies when constructed and in operation, will provide a self sustaining market for this gas and future LNG projects when completed would provide markets for future gas discoveries.

Sixth, the existence of this provision effectively encumbers the ability of any lessee to sell gas to anyone if the state could arguably come in and execute its purchase right at any time during the gas production phase. The lessee would in no way be able to finalize a sale of the gas from the lease.

Obviously, the funding of exploration gas wells in Alaska by these utilities adds to the proven gas reserves under state lands and increases future state supplies of royalty gas. It also increases future income to the state from its severance taxes, ad valorem oil and gas property taxes and income taxes.

We urge the deletion of paragraph Z of the bill as it relates to the state's gas purchase option.

At a minimum we urge the inclusion of language in paragraph Z similar to that contained in the House Resources Committee version of the bill which places an absolute percentage limitation on the amount of gas which can be purchased by the state pursuant to this provision and makes it clear that this option must be exercised or made known to the lease bidders no later than the date of the announcement of the lease sale. These provisions would eliminate the ambiguity which does now exist in the section and avoid any possible interpretation that this right would be exercised after the lease was issued and accepted by the lessees. In addition by placing an absolute percentage limitation on this right to purchase, companies can plan to receive at least the balance of the gas from a lease for purposes of bidding, financing and operations planning.

Introduced: 2/17/78
Referred; Resources and Finance

IN THE HOUSE

BY THE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

HOUSE BILL NO. 854

IN THE LEGISLATURE OF THE STATE OF ALASKA

TENTH LEGISLATURE - SECOND SESSION

A BILL

For an Act entitled: "An Act relating to the leasing and exploration of state land for oil and gas development."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

Section 1. AS 38.05.180 is repealed and re-enacted to read:

Sec. 38.05.180. OIL AND GAS LEASING. (a) The legislature finds that

(1) the people of Alaska have an interest in the development of the state's oil and gas resources to

(A) maximize the economic recovery of the resources;

(B) minimize the exploitation of these natural resources in protection of the public interest;

(C) maximize competition among parties seeking to explore and develop the resources;

(D) maximize use of Alaska's human resources in the development of the resources;

AGO 546830

SUGGESTED REVISION OF HOUSE BILL NO. 854

NOTE: Suggestions to language are underlined in draft below, which also contains unchanged sections from original bill (at left). Although we reproduce many unchanged sections from the original bill below without specific suggestions, it should be understood that this does not constitute an endorsement of the language or the concepts involved, as we discuss many problems generally in the commentary preceding this addendum. We reproduce these sections only to facilitate reading of the language and comparing it to the original. In some cases we will note a specific deletion from the original bill, which is intended to draw the reader's attention to a specific problem with the original section.

Section 1. AS 38.05.180 is repealed and re-enacted to read:

Sec. 38.05.180. OIL AND GAS LEASING. (a) For the purpose of establishing the basic policy of the state for the development of its oil and gas resources the legislature finds that

(1) the people of Alaska have an interest in the development of the state's oil and gas resources to

(A) maximize the recovery of Alaska's resources consistent with the economic and energy needs of Alaska and the rest of the United States;

(B) encourage prompt exploration and competition among parties seeking to explore and develop the resources;

(C) maximize use of Alaska's human resources in the development of the resources;

(2) it is in the best interests of the state to encourage an assessment of its oil and gas resources and to allow the maximum flexibility in the methods of issuing leases to

(A) recognize the many varied geographical regions of the state and the different costs of exploring for oil and gas in these regions;

(B) recognize the need for stimulating development in particular regions of the state;

(C) minimize the adverse impact of exploration, development, production, and transportation activity on the environment of the state;

(D) maximize state revenue from profitable oil and gas production, while minimizing revenue from unsuccessful exploration and from marginal economic oil and gas production.

(b) The commissioner shall prepare, review, revise, and maintain an oil and gas leasing program as follows:

(2) it is in the best interests of the state to allow flexibility in the methods of issuing leases, where consistent with the findings stated in (1) above, and to encourage industry to assess, explore, develop and produce those areas of state lands which are likely to contain significant oil and gas resources and which are found to be compatible with such activity, in accordance with a publicly reviewed leasing program so structured as to permit all interested parties to rely on its consistent implementation once formulated and adopted. Such plan shall:

(A) recognize the many varied geographical regions of the state and the different potential in such areas with respect to environmental values, oil and gas potentials, exploration and development costs, and economic needs of these areas and balance these competing values as nearly as possible in the best interest of the state.

(B) maximize state revenue potential from areas which appear to offer the possibility of profitable oil and gas development.

(b) The commissioner shall prepare, review, revise, and maintain an oil and gas leasing program consistent with the above findings as follows:

AGO 546831

(1) The leasing program shall be submitted to the legislature for its information within 10 days after the convening of each regular session of the legislature. The leasing program must indicate as precisely as practicable the size, timing, and location of leasing activity which the commissioner determines will best meet state needs for the following five-year period. The commissioner shall establish the timing and location of leasing, tothe maximum extent practicable, so as to obtain a balance between the potential for environmental damage, the potential for the discovery of oil and gas and the potential for adverse impact on the local communities in the state.

(2) After the leasing program has been prepared by the commissioner, a lease shall be issued if it is for an area included in the leasing program; however, leasing may continue until January 1, 1980 or until a program is prepared, whichever is sooner, and leasing under (t) of this section may be excepted from the leasing program if the commissioner finds it to be in the best interest of the state.

(3) The commissioner shall review the leasing program at least once each year, at which time he may revise and reapprove the program.

(4) The commissioner shall, by regulation, establish procedures for

(1) The status of the current leasing program shall be reported to the to the legislature for its information within 10 days after the convening of each regular session of the legislature. The leasing program must indicate as precisely as practicable the size, timing, and location of leasing activity which the commissioner determines will best meet state needs for the following five-year period. The commissioner shall establish the timing and location of leasing, to the maximum extent practicable, so as to obtain a balance between the potential for environmental damage, the potential for the discovery of oil and gas and the potential for adverse impact on the local communities in the state.

(2) The commissioner may lease lands for oil and gas development until July 1, 1980 or until a program is prepared and adopted by him, whichever is sooner.

(3) The commissioner shall establish the conditions and stipulations under which each tract in a sale area may be leased and prepare sample lease documents as required. No lease stipulation or condition may be subsequently altered except upon a finding by the commissioner that the change is required for substantial and significant reasons and that without the change the state's interests would be materially and adversely affected. The commissioner shall. by regulation, establish procedures for

(A) receipt and consideration of nominations for any area to be offered for lease or to be excluded from leasing;

(B) public notice of and participation in development of the leasing program;

(C) review by federal and local government agencies which may be affected by the proposed leasing;

(D) consultation with local governments, oil and gas lesssees and permittees, and others engaged in activity on state land;

(E) coordination of the program with the management program developed under the Coastal Zone Management Act of 1972; and

(F) the use of the capabilities and resources of all state agencies in preparation of the leasing program, and for the provision by agencies to the commissioner of any nonproprietary information he requests.

(5) At the time the commissioner submits the leasing program to the legislature, as required by (1) of this subsection, he shall also submit to the legislature for its information, a report concerning the use of the various leasing methods provided for in (c) of this section. The report must include:

(A) receipt and consideration of nominations for any area to be offered for lease or to be excluded from leasing;

(B) public notice of and participation in development of the leasing program and the form of the lease for each sale.

(C) review by appropriate federal and local government agencies which may be affected by the proposed lease sale;

(D) consultation with affected local governments, oil and gas lessees and permittees, and others engaged in activity on state land;

(E) coordination of the program with the management program developed under the Coastal Zone Management Act of 1972; and

(F) the use of the capabilities and resources of all state agencies in preparation of the leasing program, and for the provision by agencies to the commissioner of any nonproprietary information he requests;

(G) any other matters required by law for the disposition of oil and gas rights on state lands.

(4) At the time the commissioner reports the status of the current leasing program to the legislature, as required by (1) of this subsection, he shall also report to the legislature the use of the various leasing methods provided for in (c) of this section. The report must include:

HOUSE BILL 854

(A) the schedule of all lease sales held during the preceeding calendar year and the bidding method or methods utilized;

(B) the schedule of all lease sales to be held the following year and the bidding method or methods to be used;

(C) the benefits and costs associated with conducting lease sales using the various bidding methods;

(D) the reasons why a particular bidding method was selected; and

(E) if applicable, the reason why more than 50 per cent of the area leased in the upcoming year was or is to be leased under one particular bidding method.

SUGGESTED REVISION OF HOUSE BILL 854

(A) the schedule of all lease sales held during the preceeding five calendar years and the bidding method or methods utilized;

(B) the schedule of all lease sales to be held during the balance of the current leasing program and the bidding method or methods to be used, if determined;

(C) the benefits and costs associated with conducting lease sales using the various bidding methods;

(D) the reasons why a particular bidding method was selected;

(E) deleted

AGO 546834

(c) The commissioner may issue oil and gas leases on state land to the highest responsible qualified bidder determined by competitive bidding under regulations adopted by the commissioner. Bidding may be by sealed bid or according to any other bidding procedure the commissioner determines is in the best interests of the state. Whenever, under any of the leasing methods listed in this subsection, a royalty share is reserved to the state, it is free of all lease or unit expenses, including but not limited to separation, cleaning, dehydration, gathering, salt water disposal, and preparation for transportation off the lease or unit area. Following a pre-sale analysis, the commissioner may choose at least one of the following leasing methods:

(c) The commissioner may issue oil and gas leases on state land to the highest responsible qualified bidder determined by competitive bidding under regulations adopted by the commissioner. Bidding may be by sealed bid or according to any other bidding procedure the commissioner determines is in the best interest of the state and insures fairness to all participants. Whenever, under any of the leasing methods listed in this subsection, a royalty share is reserved to the state, it is free of all lease or unit expenses, including but not limited to separation, cleaning, dehydration, gathering, salt water disposal, and preparation for transportation off the lease or unit area. Following a pre-sale analysis, conducted under regulations required by (3), the commissioner may choose one or more of the following leasing methods or adopt any other method consistent with the legislative findings in (a)(1) which insures basic fairness to all responsible qualified bidders, but if a system other than bonus bidding is to be used, the commissioner must find that (i) bonus bidding will not achieve the best interests of the state and (ii) his (her) selected method will.

(1) bonus bidding

(A) a cash bonus bid with a fixed royalty share reserved to the state of not less than 12 1/2 per cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease;

(B) a cash bonus bid with a fixed royalty share reserved to the state based on a sliding scale according to volume of production but in no event less than 12 1/2 per cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease;

(2) royalty bidding

(A) a fixed cash bonus with a royalty share reserved to the state as the bid variable but not less than 12 1/2 per cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease;

(B) a fixed cash bonus with a royalty share reserved to to the state based on a sliding scale according to the volume of production as the bid variable but not less than 12 1/2 per cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease;

(1) bonus bidding

(A) a cash bonus bid with a fixed royalty share reserved to the state of not less than 12 1/2 per cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease;

(B) a cash bonus bid with a fixed royalty share reserved to the state based on a sliding scale according to volume of production but in no event less than 12 1/2 per cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease;

(2) royalty bidding

(A) a fixed cash bonus with a royalty share reserved to the state as the bid variable but not less than 12 1/2 per cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease;

(B) a fixed cash bonus with a royalty share reserved to the state based on a sliding scale according to the volume of production as the bid variable but not less than 12 1/2 per cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease;

(3) net profit bidding

(A) a cash bonus bid with a fixed royalty share reserved to the state of not less than 12 1/2 per cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease and a fixed share or the net profit derived from the lease of not less than 30 per cent reserved to the state;

(B) a fixed cash bonus with the share of the net profit derived from the lease reserved to the state as the bid variable;

(C) a fixed cash bonus with a fixed royalty share reserved to the state of not less than 12 1/2 per cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease with the share of the net profit derived from the lease reserved to the state as the bid variable;

(D) the share of the net profit derived from a lease reserved to the state under this subsection is royalty sale proceeds for the purpose of the Alaska Permanent Fund under AS 37.10.065;

(4) a work commitment bid with a fixed cash bonus, or a fixed royalty or a fixed sliding scale royalty or a fixed net profits share reserved to the state, or any combination of these methods, at the discretion of the commissioner, with a work commitment stated in a dollar amount as the bid variable; however, in no event may a royalty share

(3) net profit bidding

(A) a cash bonus bid with a fixed royalty share reserved to the state of not less than 12 1/2 per cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease and a fixed share or the net profit derived from the lease of not less than 30 per cent reserved to the state;

(B) a fixed cash bonus with the share of the net profit derived from the lease reserved to the state as the bid variable;

(C) a fixed cash bonus with a fixed royalty share reserved to the state of not less than 12 1/2 per cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease with the share of the net profit derived from the lease reserved to the state as the bid variable;

(D) the share of the net profit derived from a lease reserved to the state under this subsection is royalty sale proceeds for the purpose of the Alaska Permanent Fund under AS 37.10.065;

(4) a work commitment bid with a fixed cash bonus, or a fixed royalty or a fixed sliding scale royalty or a fixed net profits share reserved to the state, or any combination of these methods, at the discretion of the commissioner, with a work commitment stated in a dollar amount as the bid variable; however, in no event may a royalty share

reserved to the state be less than 12 1/2 per cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease.

(d) To prolong the economical life of an oil and gas field, the commissioner shall adopt regulations for all bidding methods to allow reduction of royalty to compensate for increasing costs in the later stages of production decline. The commissioner may grant such a reduction of royalty so long as the reduced royalty begins nc sooner than two years after initial production from the lease.

(e) The commissioner may, in his discretion, defer any part of the payment of a cash bonus, under (c) of this section, according to a schedule announced at the time of the announcement of the lease sale, but such payment shall be made in total no later than five years from the date of the lease sale.

reserved to the state be less than 12 1/2 per cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease.

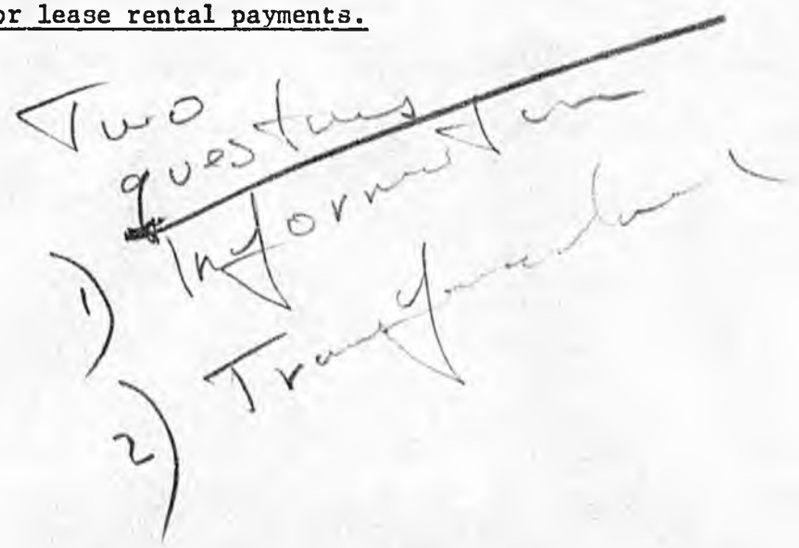
(d) To prolong the economic life of an oil and gas field, the commissioner shall adopt regulations for all bidding methods to allow reduction of royalty of leases within the field to compensate for increasing costs in the later stages of production decline. The commissioner may not grant such a reduction of royalty until two years' initial production from the field has occurred and each lessee requesting the reduction has made a clear showing that the revenue from all hydrocarbons produced from the field is insufficient to produce a reasonable rate of return with respect to that lessee's total investment therein.

(e) Deleted

(f) The commissioner may withhold acreage from leasing in a particular lease sale.

Deleted

(f) The commissioner may provide for the establishment of a drilling incentive credit system whereby all exploratory wells will earn credit based on the footage drilled and the region in which the well is sited. The credit formula used shall provide to the company drilling the well credits equal to no more than one half of the cost of the well. Such credits can be used for a bid in the state lease sale, or for royalty payments or lease rental payments.



HOUSE BILL 854

(g) The commissioner shall adopt regulations governing the calculation of net profits for lease sales under (c)(3) of this section. In the event of any dispute between the state and a lessee concerning the calculation of the net profits under the regulation adopted under this subsection, the burden of proof is on the lessee.

(h) The commissioner shall adopt regulations governing the exploration work commitment leasing method under (c)(4) of this section. The commissioner shall require either (i) a cash deposit for 20 per cent of the work commitment or, (ii) a performance bond, in form and substance and with a surety satisfactory to the commissioner, in the principal amount of 20 per cent of the exploration work commitment assuring the commissioner that the commitment will be faithfully discharged in accordance with this section, the regulations, and the lease. A lessee who fails to discharge a work commitment in its entirety is liable to the state for the undischarged portion of the commitment. At his discretion, the commissioner may terminate the work committment if he finds that the work would be unnecessary or cumulative.

SUGGESTED REVISION OF HOUSE BILL NO. 854

(g) The commissioner shall define all terms and adopt all regulations necessary for a reasonable understanding and evaluation of a particular bidding method prior to the public announcement of the terms of proposed sale employing that method.

(h) Deleted.

AGO 546840

(i) At his discretion, the commissioner may enter into an agreement whereby, with the consent of the lessee, the state's royalty share of oil and gas production may be stored or retained in storage by the lessee, or the commissioner may enter into an agreement with one or more of the affected field lease holders to trade current royalty production from a field for a like amount, kind, and quality of future production, on the condition that the state receives back its stored or traded royalty share during the first half of the estimated field life or no later than 15 years after start of production, whichever is sooner.

(i) At his discretion, the commissioner may enter into an agreement whereby, with the consent of the lessee, the state's royalty share of oil and gas production may be stored or retained in storage by the lessee, or the commissioner may enter into an agreement with one or more of the affected field lease holders to trade current royalty production from a field for a like amount, kind, and quality of future production, on the condition that the state receives back its stored or traded royalty share during the first half of the estimated field life or no later than 15 years after start of production, whichever is sooner.

HOUSE BILL 854

(j) An oil and gas lease must cover a reasonably compact area not exceeding 5,760 acres, and must be for a period of five years. The commissioner may grant a lease for a term greater than five years but not to exceed 10 years, where he finds that the longer period is necessary to encourage exploration and development in areas where environmental condiditons severly restrict operations. An oil and gas lease shall be automatically renewed if and for so long thereafter as oil or gas is produced in paying quantities from the lease or, if the lease is committed to a unit approved by the commissioner. A lease issued under this section covering land on which there is a well capable of producing oil or gas in paying quantities does not expire because the lessee fails to produce oil or gas unless the lessee is allowed reasonable time to place the well on a producing status. Upon renewal, the commissioner may increase lease rentals so long as the increased rental rate does not exceed 150 per cent of the rate of the preceding year. The commissioner may provide by regulation and in the lease that the lessee may earn production rights only to the depth drilled at the beginning of production from the lease. If drilling has commenced on the expiration date of the primary term of the lease and is continued with reasonable diligence, including such operations as redrilling, sidetracking, or other means necessary to reach the originally proposed bottom hole location, the lease continues in effect until 90 days after drilling has ceased and for so long thereafter as oil or gas is pro-

AGO 546842

SUGGESTED REVISION OF HOUSE BILL NO. 854

(h) An oil and gas lease must cover a reasonably compact area not exceeding 5,760 acres, unless tract size in adjacent lands, economic or geological factors relating to that locality require a larger area, and must have a term of ten years. The commissioner may grant a lease for a term less than ten years, but not less than five years, and only where the commissioner finds that environmental and economic conditions do not severely restrict operations. An oil and gas lease shall be automatically renewed if and for so long thereafter as oil or gas is produced in paying quantities from the lease or, if the lease is committed to a unit approved by the commissioner. A lease issued under this section covering land on which there is a well capable of producing oil or gas in paying quantities does not expire because the lessee fails to produce oil or gas unless the lessee is allowed reasonable time to place the well on a producing status. Upon renewal, the commissioner may increase lease rentals so long as the increased rental rate does not exceed 150 per cent of the rate for the preceding year. If drilling has commenced on the expiration date of the primary term of the lease and is continued with reasonable diligence, taking into account the limitations imposed on dirlling operations by Alaskan environmental conditions and including such operations as redrilling, 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 there is a well thereon capable of producing oil or gas in paying quantities.

HOUSE BILL 854

(k) The commissioner may establish by regulation that after a well has been plugged and abandoned, the rental rate which was in effect during the year of abandonment is maintained for the remainder of the term. Rental is payable in advance and continues until income to the state from royalty, net profit, or exploration work commitment exceeds rental income to the state for that year; after the rental income schedule has been exceeded for three consecutive years, the rental terminates. Oil and gas leases shall provide for payment to the state of rental on the following basis:

(1) for the first year, $1.00 per acre;

(2) for the second year, $1.50 per acre;

(3) for the third year, $2.00 per acre;

(4) for the fourth year, $2.50 per acre;

(5) for the fifth year, $3.00 per acre;

SUGGESTED REVISION OF HOUSE BILL NO. 854

(i) The commissioner may establish by regulation that after a well has been plugged and abandoned, the rental rate which was in effect during the year of abandonment is maintained for the remainder of the term. Rental is payable in advance and continues until income to the state from royalty, net profit, or exploration work commitment exceeds rental income to the state for that year; after the rental income schedule has been exceeded for three consecutive years, the rental terminates. Oil and gas leases shall provide for payment to the state of rental on the following basis:

(1) for the first year, $1.00 per acre;

(2) for the second year, $1.50 per acre;

(3) for the third year, $2.00 per acre;

(4) for the fourth year, $2.50 per acre;

(5) for the fifth year, $3.00 per acre;

AGO 546843

(l) Upon timely application as provided by regulation, the state may issue to the holder of a federal or private lease, a state shorelands lease covering land within the exterior boundaries of the federal or private lease which has been excluded on the basis of navigability or which is later administratively or judicially determined to be shoreland. The term of such a state shoreland lease shall be the same as the term of the federal or private lease, but may not exceed five years.

(j) Upon timely application as provided by regulation, the state may issue to the holder of a federal or private lease, a state shorelands lease covering land within the exterior boundaries of the federal or private lease which has been excluded on the basis of navigability or which is later administratively or judicially determined to be shoreland. The term of such a state shoreland lease shall be the same as the term of the federal or private lease.

HOUSE BILL 854

(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, when 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, change, or revoke drilling, producing, rental minimum royalty, and royalty requirements of the leases and adopt 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 require oil and gas leases issued under this section to 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 must operate. The plan must adequately protect all parties in interest, including the state.

SUGGESTED REVISION OF HOUSE BILL NO. 854

(k) To promote the most efficient development of the natural resources of all or 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, when 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, change, or revoke drilling, producing, rental minimum royalty, and royalty requirements of the leases and adopt 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 require oil and gas leases issued under this section to 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 must operate. The plan must adequately protect all parties in interest, including the state.

AGO 546845

(n) A plan authorized by (m) of this section, which includes land owned by the state, may contain a provision vesting the commissioner, or a person committee, or state agency with authority to 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 sec. 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 sec. 140 of this chapter.

(l) A plan authorized by (j) of this section, which includes land owned by the state, may contain a provision vesting the commissioner, or a person, committee, or state agency with authority to 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 sec. 140 of this chapter. The provisions of this section concerning cooperative or unit plans are in addition to, and are subject to the state's authority to prohibit waste of oil and gas in AS 31.05.

(m) 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 sec. 140 of this chapter.

HOUSE BILL 854

(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 land, 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 are 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, when, in his discretion, the conservation of natural resources 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 sec. 140 of this chapter. Drilling or development contracts may include, at the discretion of the commissioner, provisions authorizing the state to share in the costs of exploration.

AGO 546847

SUGGESTED REVISION OF HOUSE BILL NO. 854

(n) When separate tracts cannot be indivudually 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 land, whether or not owned by the state, under a communitization or drilling agreement providing for a 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 are considered as operations or production as to each lease committed to the agreement.

(o) 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, when, in his discretion, the conservation of natural resources 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 sec. 140 of this chapter. Drilling or development contracts may include, at the discretion of the commissioner, provisions authorizing the state to share in the costs of exploration.

HOUSE BILL 854

(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 land, in land 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 in paying quantities.

(s) Each oil or gas lease issued by the state must contain a provision requiring the lessee to furnish the Department of Labor a quarterly report regarding the employment of state residents on the leased property. The commissioner of labor shall adopt regulations necessary to implement this subsection. No lease issued under this chapter is valid unless it contains provisions requiring the employment of qualified Alaska residents in accordance with AS 38.40.030, and complies in all respects with the requirements of ch. 40 of this title.

SUGGESTED REVISION OF HOUSE BILL NO. 854

(p) To promote conservation of natural resources, the commissioner may authorize the subsurface storage of oil or gas whether or not produced from state land, in land 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 in paying quantities.

(q) Each oil or gas lease issued by the state must contain a provision requiring the lessee to furnish the Department of Labor a quarterly report regarding the employment of state residents on the leased property. The commissioner of labor shall adopt regulations necessary to implement this subsection. No lease issued under this chapter is valid unless it contains provisions requiring the employment of qualified Alaska residents in accordance with AS 38.40.030, and complies in all respects with the requirements of ch. 40 of this title.

AGO 546848

HOUSE BILL 854

(t) Notwithstanding any other provision of this section, land which has been offered for lease within the previous five years but which received no bids at competitive sale may be, at the discretion of the commissioner, immediately offered for lease, under regulations adopted by him, upon terms appearing most advantageous to the state, including leasing non-competitively. The commissioner shall use a sliding scale royalty based upon such formulae as he determines to be in the public interest but not less than 12 1/2 per cent at the beginning of production from the lease in amount or value of the production removed or sold from the lease or unit area encompassing the lease. A lease must provide for payment to the state of rental but need not adhere to the rental schedule in (k) of this section nor to the 5,760-acres-per-lease limitation in (j) of this section. The lease term may not exceed five years except as provided in (j) and (k).

AGO 546849

SUGGESTED REVISION OF HOUSE BILL NO. 854

(t) Notwithstanding any other provision of this section, land which has been offered for lease within the previous five years but which received no bids at competitive sale may be, at the discretion of the commissioner, immediately offered for lease, under regulations adopted by him, upon terms appearing most advantageous to the state, including leasing non-competitively. The commissioner shall use a sliding scale royalty based upon such formulae as he determines to be in the public interest but not less than 12 1/2 per cent at the beginning of production from the lease in amount or value of the production removed or sold from the lease or unit area encompassing the lease. A lease must provide for payment to the state of rental but need not adhere to the rental schedule in (k) of this section nor to the 5,760-acres-per-lease limitation in (j) of this section. The lease terms may not exceed five years except as provided in (j) and (k).

HOUSE BILL 854

*Sec. 2. AS 38.05.135(b) is repealed and re-enacted to read:

(b) When minerals are to be leased, in addition to any other notice given, notice must also be given as provided in secs. 305 and 345 of this chapter.

*Sec. 3. AS 38.05.140(c) is amended to read:

(c) No person may take or hold at one time phosphate leases on state lands exceeding the aggregate 10,240 acres. No person may 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 200,000 (500,000) acres granted on tide and submerged lands, and 400,000 acres on all land (LANDS) other than tide and submerged land (LANDS), including leases held both as lessee and under option or operating agreement from others. A person has five years from the effective date of this Act to conform to the 200,000-acre upland limitation. 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.

*Sec. 4. AS 38.05.145(b) is repealed.

SUGGESTED REVISION OF HOUSE BILL NO. 854

*Sec. 2. AS 38.05.135(b) is repealed and re-enacted to read:

(b) When minerals are to be leased, in addition to any other notice given, notice must also be given as provided in secs. 305 and 345 of this chapter.

*Sec. 3. AS 38.05.140(c) is amended to read:

(c) No person may take or hold at one time phosphate leases on state lands exceeding the aggregate 10,240 acres. No person may take or hold 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 400,000 acres on all land (LANDS) other than tide and submerged land (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.

*Sec. 4. AS 38.05.145(b) is repealed.

AGO 546850

(u) The commissioner may, by regulation, restrict joint bidding by major or multi-national oil and gas companies to encourage competition.

(v) The State has the right to purchase not more than 16 2/3 per cent of the volume of oil and up to 100 per cent of the volume of gas produced from a lease issued in accordance with this section, at the regulated price, or, if no regulated price applies, at the fair market value at the point of sale, except that any oil or gas obtained by the state as royalty or net profits shall be credited against the amount that may be purchased under this subsection. Oil and gas purchased under this section may be used by the state in the same manner as it uses its royalty oil and gas.

(w) A lessee or permittee conducting any exploration for, or development or production of, oil or gas on state land shall provide the commissioner access to all data obtained from that activity and shall provide copies of specific data, as the commissioner may request.

(delete)

(r) The commissioner may reserve the right to purchase not more than 16 2/3 per cent of the volume of oil and gas produced from a lease issued in accordance with this section, at the regulated price, or, if no regulated price applies, at the fair market value at the point of sale, except that any oil or gas obtained by the state as royalty or net profits shall be credited against the amount that may be purchased under this subsection. Oil and gas purchased under this section may be used by the state in the same manner as it uses its royalty oil and gas.

(s) A lessee or permittee conducting any exploration for, or development or production of, oil or gas on state leases shall provide the commissioner access to all <u>noninterpretive</u> data obtained from that activity and shall provide copies of specific <u>noninterpretive</u> data, as the commissioner may request. <u>Such data shall be held confidential by the commissioner upon request of the lessee or permittee as provided in AS 38.05.035. The commissioner shall, by regulation, establish procedures for each office where such data is filed governing access to and the safekeeping of the data.</u>

AGO 546851

How to Bid for Offshore Rights

Several systems have been proposed to replace the present "bonus-bid" method of assigning leases on offshore oil prospects to developers. Of these, Professor John W. Devanney III of M.I.T. opts for "percentage-of-excess-profits" bids (*see p. 42*). Other proposed arrangements include work obligation permits and various forms of royalty bidding.

The Work Obligation Permit Plan

Under the work obligation permit plan, developers would submit exploratory and provisional drilling plans for a given tract. The government would choose the developer with the most aggressive, best-considered plan, and the developer would then be responsible for agreed-upon amounts of royalties and/or lease rentals. Under this system, used currently by the Norwegians and the British in the North Sea, the great bulk of any economic rent would be transferred to the developer, and a portion of this rent would be returned to the public in the form of corporate income taxes. Of the possible methods reviewed here, this is clearly the most favorable to the developer.

Administering this method to maximize national income depends on the skill and honesty of administrators. There are temptations for prospective developers to submit work plans which represent over-development of the resource so they will be judged the most aggressive, and administrators will have to be wise enough to recognize such over-development and refuse it. The decisions to be made in choosing the "best" work plan are necessarily judgemental, and they are an open invitation to the influence of special interests and even to corruption.

But beyond the possibilities of incompetency or corruption which may result in loss of national income is the basic fact that most of the economic rent goes to the developer. Professor Devanney concludes that work obligation permitting is clearly not desirable, from a nondeveloper point of view. Indeed, as soon as it became clear that economic rent was associated with North Sea oil, the British and Norwegians moved away from this practice.

Royalty Bidding

Royalty bidding involves competitive bidding on a share of the actual gross revenues — generally a percentage of market value — associated with the resource. This method has long been used in state sales of rights, and the federal government experimented with it in the Gulf of Mexico in 1974.

Compared with bonus bidding, royalty bidding transfers some of the risk prior to exploratory drilling from the developer to the public. This helps maintain competition among bidders, for large amounts of up-front capital are not necessary, and the need for large bidding combines disappears.

However, there are other problems. While the method could theoretically give most of the revenues from offshore oil to the public, it could also reduce the total size of the offshore oil pie. This is because the royalty bid, unlike the bonus bid, affects the developer's marginal expenses. For instance, if a developer overestimates production from a certain tract, he will freeze himself into a royalty bid that makes it unprofitable for him to develop the smaller, and thus more expensive, oil find that is actually made. He will refuse to develop it, and the national income will suffer. This risk may especially affect secondary and tertiary production from a tract; such oil will be more expensive than primary oil but still less costly than foreign crude.

Proponents of royalty bidding offer two possible resolutions of this dilemma — re-leasing and renegotiation. The former proposes that if a developer decides not to produce a tract he must turn it back to the government, with all equipment intact, and the government may lease the tract anew, presumably to a different developer at a lower royalty. This would discourage expensive techniques to enhance oil recovery, because the original leaseholder may choose merely to take out the flush production before releasing a tract back to the government. This will be costly to the public, since processes for secondary and tertiary recovery of oil must begin early in a field's life to be most effective. There is also the possibility of excessive administrative costs associated with the negotiations necessary for re-leasing.

Advocates of renegotiation propose that if a developer feels he cannot develop a field at his bid royalty, he should be able to present his evidence to the regulatory body which should be empowered to grant him a decrease if it finds his presentation viable. The obvious problems here are in the regulatory body's verification of the developer's data. The capital-intensiveness of offshore oil makes any estimate extremely sensitive to the cost of capital, and that information is often confidential.

Other potential problems introduced by renegotiation include temptations for developers to "goldplate" a project since additional expenses could come off the royalty — i.e., out of the public's pocket. A developer might deliberately bid high initially in order to obtain a tract, anticipating that he will renegotiate later; and he might go through a whole series of renegotiations as his costs for enhanced recovery techniques begin to appear.

Some have suggested a compromise between bonus bidding and royalty bidding, in which developers would enter a "high" fixed royalty plus a bonus bid of up-front payments. This would decrease the size of bonus bids and aid competition, say its advocates. Unfortunately, this presents the same can of worms as straight royalty bidding.

Installment bonus bidding has also been suggested. This means a developer would pay his bonus in three installments — immediately, after three years, and after five years. He could surrender the lease before the last two payments if things failed to work out. But this presents the same pie-reducing problems as royalty bidding; if a developer originally bid $600 million and after exploratory drilling found oil worth only $350 million, he would abandon the tract rather than pay the final installments even though national income would be increased by $350 million if the find were developed.

There are advantages, however, in installment bonus bidding. There is an automatic re-leasing provision, which could assure that tracts were re-opened for development; and the marginal costs of the oil are not affected, which means that the developer has incentives to invest early in enhanced recovery.

However, the massive amounts of up-front money involved in even a one-third installment payment of a bonus bid will probably still frighten away many bidders. And many bidders would increase their total bonus bids considerably, knowing that they could thus avoid paying additional installments.

ALBERTA, CANADA

Exploratory Drilling Incentive System

A report from Alberta Energy and Natural Resources states the exploratory drilling incentive principles adopted for wells spudded between Jan. 1, 1978 and March 31, 1981 were announced by the government last fall and will be defined in detail in the Exploratory Drilling Incentive Regulation, 1978 when it is issued in the near future.

This regulation, however, may not be available to industry prior to the commencement of the drilling activity it affects. Accordingly, the essential details respecting the forthcoming program are described herewith.

The department expects that the principles and details outlined here will be incorporated, without a change in meaning, into the 1978 Regulation. If, however, such a change does occur, the 1978 Regulation would, of course, take precedence.

(1) Commencement Date of the Forthcoming Program

As previously indicated, an incentive exploratory well in good standing will be

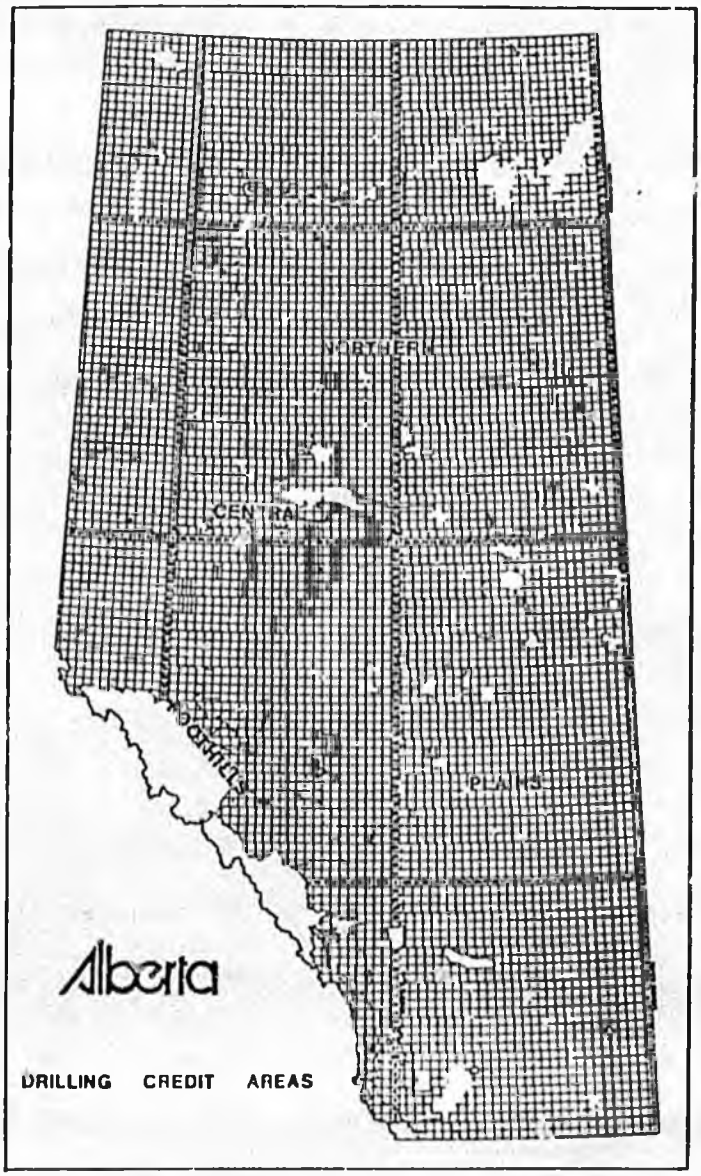


Figure 1

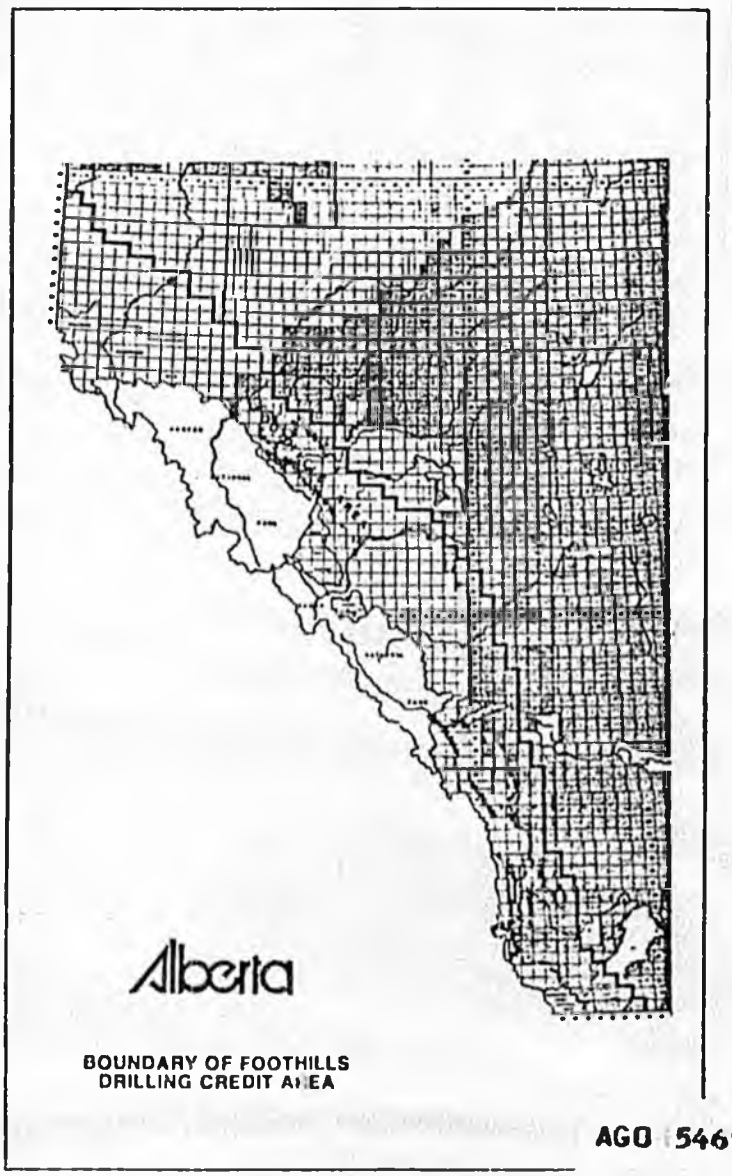


Figure 2

subject to the 1978 Regulation if it commences drilling on or after Jan. 1, 1978. This provision will not be affected if the licensing or certification date is before 1978.

(2) Drilling Credit Areas

Figure 1 shows the drilling credit areas as they will be defined under the 1978 Regulation. The Plains and Foothills Areas have not been changed. The subsisting Northern Area, however has been divided into the new Central and Northern Areas shown by the illustration. The boundary between the two new areas was defined by the Department on the basis of well cost data and topographic and access considerations.

Figure 2 is provided for the convenience of industry to depict the irregular eastern boundary of the Foothills Area. A similar map was issued by the Board in 1974.

(3) Drilling Credit Schedules

Drilling credits under the 1978 Regulation will be determined from Schedules F

SCHEDULE F

Applicable to the Class A Interval of an Incentive Exploratory Well that Commences Drilling on or after January 1, 1978

The Class A interval of an incentive exploratory well that commences drilling on or after January 1, 1978 shall be determined by the Board as the interval below the depth of 2,000 feet that

(i) has not been duplicated by a drilled and abandoned well within one and one-half miles.

(ii) occurs more than 500 feet below the base of the deepest accumulation of crude oil or natural gas that in the opinion of the Board has been penetrated by another well within three miles, and

(iii) occurs immediately below the base of the member or formation containing the deepest oil sands deposit that in the opinion of the Board may underlie the location of the said incentive exploratory well.

Where neither (ii) nor (iii) above applies, the Class A interval shall be determined from the depth of 2,000 feet to the total depth of the said incentive exploratory well.

	Basis for Credit Plains Area		Basis for Credit Central Area		Basis for Credit, Northern and Foothills Areas	
Depth, Feet	Cumulative Dollars	Incremental $/Foot	Cumulative Dollars	Incremental $/Foot	Cumulative Dollars	Incremental $/Foot
2,000	0	20	0	30	0	40
3,000	20,000	18	30,000	25	40,000	35
4,000	38,000	18	55,000	25	75,000	40
5,000	56,000	20	80,000	25	115,000	35
6,000	76,000	24	105,000	35	150,000	35
7,000	100,000	30	140,000	40	185,000	50
8,000	130,000	40	180,000	50	235,000	65
9,000	170,000	55	230,000	70	300,000	80
10,000	225,000	75	300,000	90	380,000	100
11,000	300,000	100	390,000	110	480,000	120
12,000	400,000	110	500,000	160	600,000	180
13,000	510,000	160	660,000	200	780,000	210
14,000	670,000	210	860,000	240	990,000	260
15,000	880,000	280	1,100,000	350	1,250,000	350
16,000	1,160,000	340	1,450,000	400	1,600,000	425
17,000	1,500,000	500	1,850,000	550	2,025,000	575
18,000	2,000,000	500	2,400,000	550	2,600,000	575

Figure 3

SCHEDULE G

Applicable to the Class B Interval of an Incentive Exploratory Well that Commences Drilling on or after January 1, 1978

The Class B interval of an incentive exploratory well that commences drilling on or after January 1, 1978 shall be determined by the Board as the interval below the depth of 2,000 feet that

(i) has been duplicated by a drilled and abandoned well within one and one-half miles.

(ii) occurs more than 500 feet below the base of the deepest accumulation of crude oil or natural gas that in the opinion of the Board has been penetrated by another well within three miles, and

(iii) occurs immediately below the base of the member or formation containing the deepest oil sands deposit that in the opinion of the Board may underlie the location of the said incentive exploratory well.

Where neither (ii) nor (iii) above applies, the Class B interval shall be determined from the depth of 2,000 feet to the total depth of the said incentive exploratory well.

	Basic for Credit Plains Area		Basic for Credit Central Area		Basis for Credit, Northern and Foothills Areas	
Depth, Feet	Cumulative Dollars	Incremental $/Foot	Cumulative Dollars	Incremental $/Foot	Cumulative Dollars	Incremental $/Foot
2,000	0	15	0	20	0	28
3,000	15,000	14	20,000	20	28,000	29
4,000	29,000	14	40,000	20	57,000	29
5,000	43,000	14	60,000	19	86,000	24
6,000	57,000	18	79,000	26	110,000	30
7,000	75,000	25	105,000	30	140,000	40
8,000	100,000	30	135,000	40	180,000	45
9,000	130,000	40	175,000	50	225,000	60
10,000	170,000	55	225,000	65	285,000	75
11,000	225,000	65	290,000	90	360,000	95
12,000	290,000	90	380,000	120	455,000	125
13,000	380,000	120	500,000	150	580,000	155
14,000	500,000	160	650,000	180	735,000	190
15,000	660,000	210	830,000	270	925,000	275
16,000	870,000	270	1,100,000	300	1,200,000	310
17,000	1,140,000	360	1,400,000	400	1,510,000	420
18,000	1,500,000	360	1,900,000	400	1,930,000	420

Figure 4

and G *(Figures 3 and 4)*. The schedules reflect the government's decision to exclude the upper 2,000 feet from the forthcoming program, and to increase the credits for qualifying wells deeper than about 3,500 feet. For wells greater than 5,000 feet in depth, the increase is between approximately 25 and 45 percent, the difference being justified by the Department's comprehensive well cost study. An exception applies to the new Northern Area, for which credit increases at certain depths exceed 45 percent to correspond with Foothills credits.

(4) Royalty Exemptions

(4.1) Eligibility

Crude oil or gas production must originate from a Class A or Class B interval to qualify for a royalty exemption. Production from any source shallower than 2,000 feet will thus not qualify for royalty exemption under the 1978 Regulation. An exception to the foregoing exclusion is found under the following circumstances: If conventional crude oil is produced from a source shallower than 2,000 feet in the new Northern Area, and if the 2,000-foot interval would have qualified as Class A or Class B footage pursuant to the 1974 Regulations, the crude oil production will be eligible for the normal royalty exemption applicable to deeper production.

(4.2) Duration

The royalty exemptions authorized under the 1978 Regulation will apply to the initial 60 crude oil-producing months or the initial 12 gas-producing months at the well, commencing with the first month in which the crude oil or gas would otherwise be subject to royalty payment.

Additional details concerning these and other principles relating to the forthcoming program will be specified in the 1978 Regulation. If any questions arise after the 1978 Regulation is studied, they may be referred to J. R. Pow or F. Phillips of the Energy Resources Conservation Board, if they pertain to the certification of a well or the determination of its Class A or Class B interval, or to C. R. Smith or E. Saldanha of the Department, if they are concerned with establishing credit or granting royalty exemption. □

Four Articles from Mineral Leasing as an Instrument of Public Policy, British Columbia Institute for Economic Policy Analysis, 1977.

1. Gregg K. Erickson, "Work Commitment Bidding"
2. Dale R. Jordan, "Petroleum Leasing in British Columbia"
3. Walter J. Mead, "Cash Bonus Bidding for Mineral Resources"
4. Arlon R. Tussing, "The Role of Public Enterprise"

Work Commitment Bidding

GREGG K. ERICKSON

One result of the growing concern in the United States over energy matters has been an increased attention to public policies governing the development of Outer Continental Shelf (OCS) oil and gas resources. The institutional structure under which all such development has thus far taken place was established in 1953 by the Outer Continental Shelf Lands Act.[1] This unamended statute provides the Secretary of the Interior with authority to sell oil and gas leases to the public on the basis of cash or royalty bids offered at sealed bid auctions.

The practice of the United States government since the first such sale in 1954 has been to offer relatively small quantities of offshore acreage on an irregular basis, soliciting always cash rather than royalty rate bids. In recent years, the rate at which acreage has moved to market has been accelerating. However, the average per acre bonus received by the government has also increased, partially reflecting worldwide supply conditions. The fact that bids are received in sealed envelopes has resulted in the winning bid being two, three, or several times the amount of the next highest bid.

Among criticisms of present policy is the assertion that this method of lease allocation diverts undesirably large amounts of *front-end money* into the coffers of the government landowner, money that could, would, and should otherwise be used for development of the resource itself.[2] One possible remedy would involve implementation of the existing statutory authority to substitute royalty rate bids, with fixed and presumably low cash bonuses. The problems created by royalty bidding, principally the premature shutdown effect and the potential for speculator induced misallocation of leases, have been well discussed in the literature. More importantly, they are well understood by persons influencing both public and private mineral resource management policies.[3]

An alternative proposed remedy to this same perceived problem is less well understood. Based in part on the method of lease allocation used in the offshore areas of the United Kingdom, it would allocate exploitation rights to the firm that would commit itself to spending the greatest sum in developing the resource. Sealed bids would be solicited as under the present system, but instead of cash the bid variable would be the *work commitment*. Proponents of this system claim that it will divert money the government

landowner would otherwise receive via bonuses into exploration and development expenditures.[4] These additional increments of expenditure, it is further suggested, will increase future production to such an extent that the government landowner will be able to recoup the foregone bonus income in the form of the consequentially increased royalty and tax revenue. Ancillary benefits in the form of employment, resource self-sufficiency, and improved trade balances are also sometimes claimed or alluded to.

To an economist these arguments may not seem too persuasive. Nevertheless, no one appears to have devoted much effort to analyzing the economic implications of such a system, and certainly not in a form that would be comprehensive to the noneconomist policy maker.[5] This is unfortunate not only because of the substantial public and private interests involved; the system has significant implications for minerals other than petroleum and in places other than the United States OCS. The purpose here is to provide such an analysis.

EVALUATION OF WORK COMMITMENT BIDDING

In evaluating something new the first step is usually to establish a standard against which it can be measured. In this context, the system of competitive cash bidding has long attracted economists concerned with the problem of natural resource allocation, not only as an ideal against which the performance of other systems might be measured, but as a practical and proven technique for bringing resources into productive employment.

Under an idealized competitive cash bidding arrangement, bidders determine the amount they can afford to offer for a mineral lease by a very simple process: they subtract their expected costs of extraction from their expected revenues. The resulting residual is the maximum the prospective bidder can offer for the tract without buying himself an expected loss. Competition, of course, implies that multiple firms will be preparing bids on each tract.

Assuming no uncertainty about the amount of oil to be found or the price that oil will eventually bring, and disregarding the time value of money, the firm with the lowest expected costs of extraction will be capable of submitting the highest, and thus the winning, bid. This is good from society's standpoint, since it means that the resource will be developed with the minimum expenditure of scarce goods and services. The resource's contribution to economic welfare will be greater than it would have been had the tract been awarded to any of the other, less efficient bidders.

Under a work commitment system each prospective bidder will be asking himself: What is the maximum amount I can promise to spend on the development of this tract and still expect to break even? Since any cash bonus

that would have been offered to acquire a tract under the traditional system is no longer necessary, the amount of that bonus may clearly be diverted to the work commitment without raising costs beyond the breakeven point. What is not quite so obvious, however, is that the amount a bidder will promise to spend under the commitment system will exceed the sum of the cash bonus and the amount that he would have allocated to development of the tract under the cash bonus system.

This follows from the fact that any additional increment of expenditure can almost always be spent in a way that will bring about some increase in output from the tract and a corresponding increase in revenue.

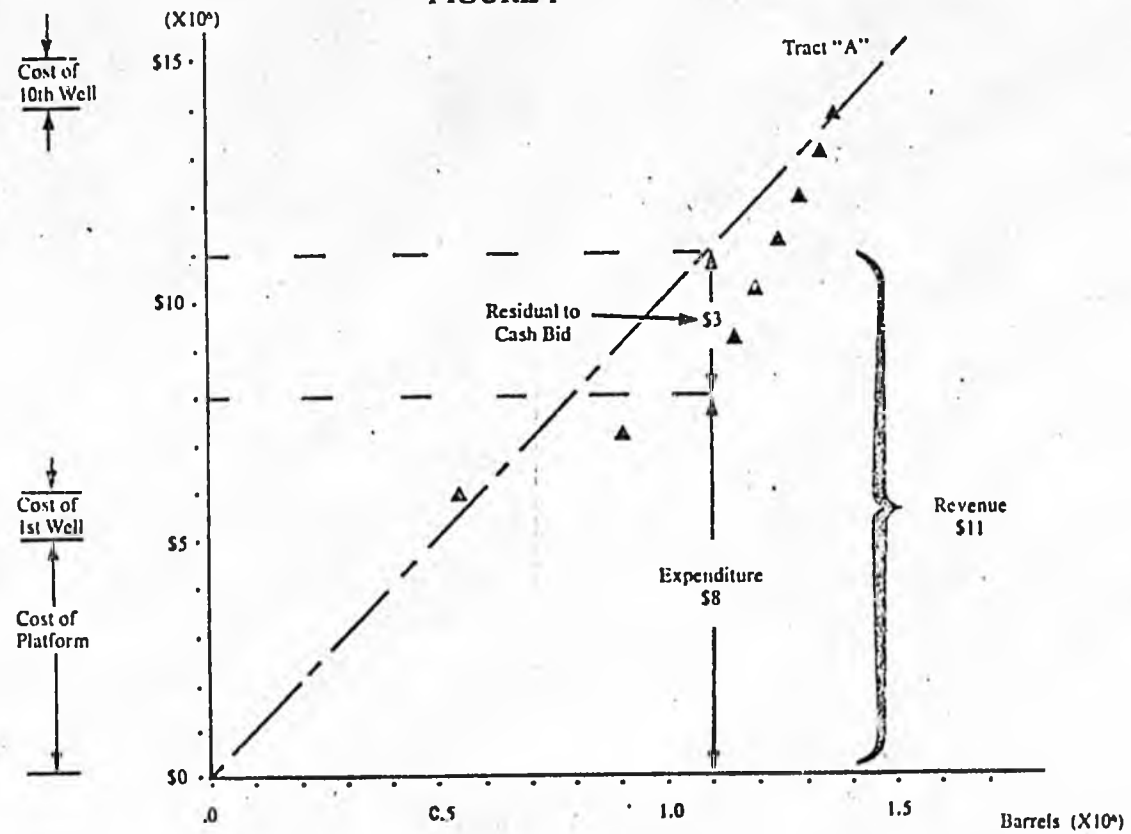
This is most easily demonstrated with a numerical example. Let us assume that a prospective bidder, in determining how much of a cash bonus he can offer for an oil and gas lease on a hypothetical tract A, has calculated the relationship between expenditures on development of the tract and expected production, and that the results of his calculations appear as plotted in Figure 1.

The vertical axis in this graph (and those that follow) measures dollars expended in the tract's development, dollars that we assume will be spent for construction of a platform and the drilling from it of wells. The horizontal scale measures the output that results from that expenditure, denominated in millions of barrels of oil. The relationship between those barrels of output and the revenue they bring their producer (at an assumed price of $10 per barrel) is shown, through appropriate choice of scales, by the dashed 45° straight line running upward to the right. By this means, the vertical scale can be used to show the value of output as well as the cost of production.

In Figure 1, the point closest to the origin indicates that with one platform and one well this operator would expend $6 million (vertical scale) producing an output of 550,000 barrels of oil, worth $5.5 million (determined by the intersection of the 45° line with a line drawn vertically from .55 million barrels). Moving upward and to the right, each subsequent point reflects seriatum the increases in expenditures and output resulting from the drilling of additional wells.

The general shape of the curve defined by these points is characteristic of situations where one major input to the productive process (in this case land) is held constant, while other inputs (in this case wells) are varied. The output curve originates at the lower left hand corner, but it rises vertically at first because the initial input of investment is unproductive: a platform and oil well costs a certain amount, and an expenditure of anything less than that threshold amount produces no oil. The cost of subsequent wells is assumed to be $1 million, no matter how many wells are drilled, creating a curve that looks like a staircase where each increment of cost (representing a new well) creates a new step. The fact that the staircase steepens as we move

FIGURE 1



to the right is a reflection of the diminishing returns, in terms of oil produced, to each additional well drilled into the fixed geographic area encompassed by the lease.

Naturally the prospective bidder will be looking for the point on this output curve that puts his costs as far below the 45° line (his output-revenue function) as possible. As shown in Figure 1, the maximum cash bid this operator could afford to make on tract A (and still expect to break even) is $3 million, which—if he is the winner—would require him to drill three wells.

Consider now the situation this bidder would face were a work commitment bidding system adopted. The question that now confronts him is: How much can I spend (or how many wells can I drill) on tract A and still break even? The answer is clearly $14 million (representing nine wells), indicated on the right side of Figure 2 by the output curve for tract A.

If the bidder wins tract A under a work commitment system, his oil output will be 1.4 million barrels (Figure 2) as compared to the 1.1 million barrels (Figure 1) that he would have produced had he won the tract in a cash bonus sale.

If the success of a mineral resource management policy is measured by the physical quantities of the mineral educed from the earth, the work commitment bidding is clearly superior. A resource's contribution to economic welfare, however, is not its total output (whether measured in dollars or physical quantities) but is the residual left over when the costs of all inputs to the productive process (other than the resource itself) are subtracted from the value of the outputs. In the case of tract A this residual is maximized at $3 million, when the value of the inputs is $8 million. As the input expenditure is increased above this optimum point, the residual—the resource's potential contribution to economic welfare—is gradually dissipated until, at the point where the value of inputs reaches $14 million, there is no more residual left to be dissipated.

In this particular example, the increase in output that would result from a switch to work commitment bidding ($3 million) happens to equal the amount of the residual. This coincides with the fact that the expenditure of each additional $1 million above $8 million (three wells) contributes exactly $500,000 to revenue. If the incremental contribution of the fourth and succeeding wells were greater, for example $750,000, the slope of the output curve traced by these points would be flatter, as shown by the squares in Figure 3, and the increase in production from a switch to commitment bidding would be much greater. To put it another way, it would take twice as large an increase in expenditure to dissipate the $3 million residual.

FIGURE 2

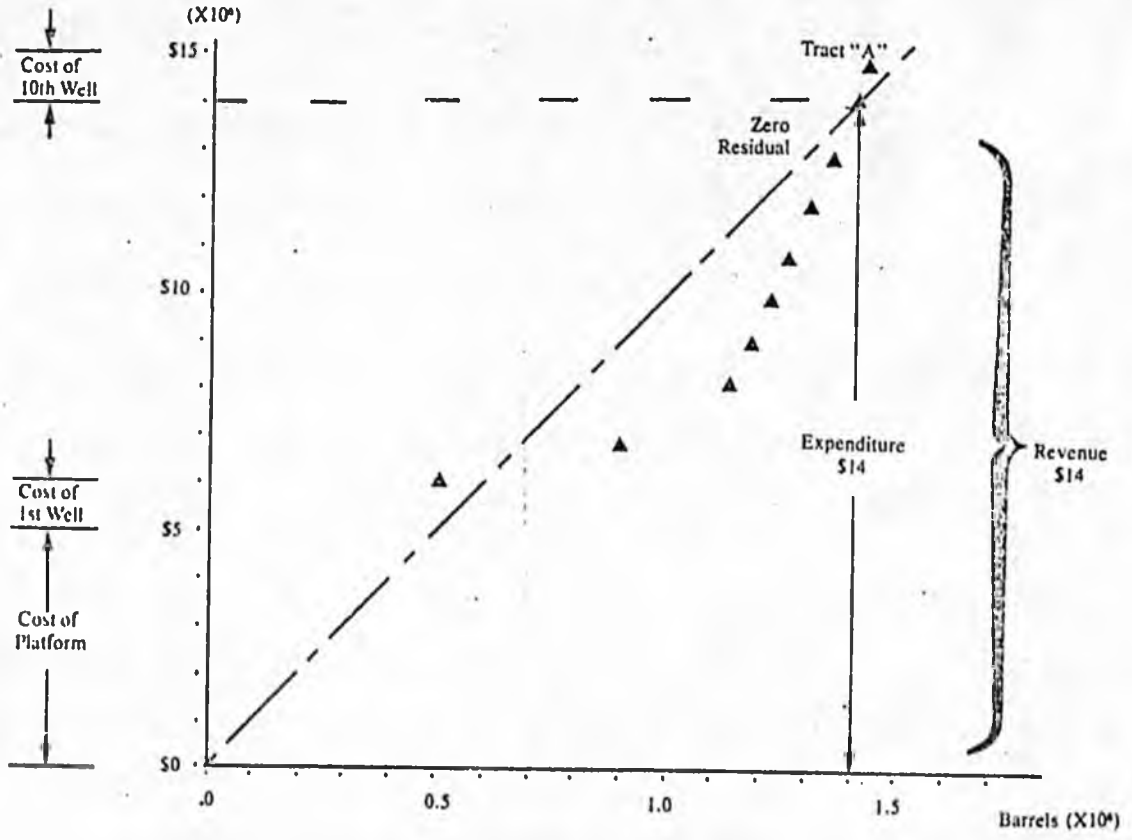
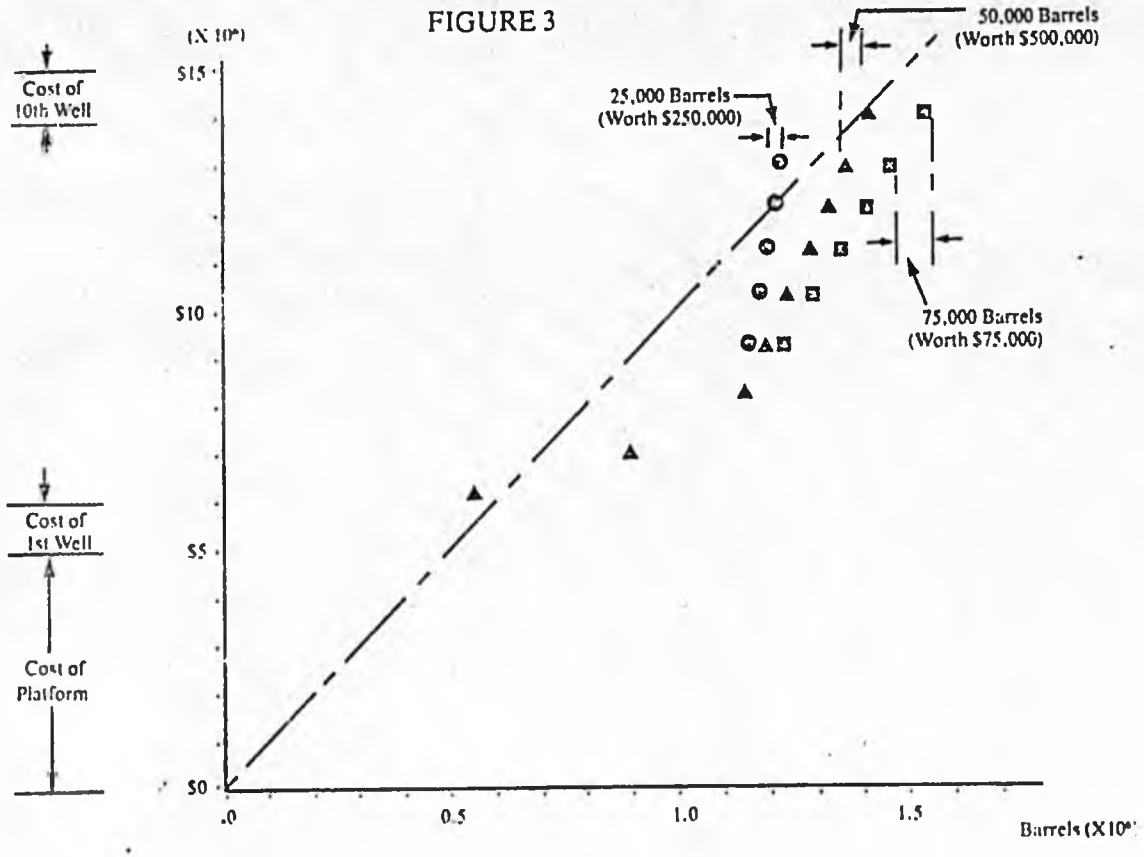


FIGURE 3



On the other hand, a smaller incremental contribution to output and revenue by the fourth and succeeding wells (for example, an increase of only $250,000 in revenue for each $1 million well) would trace a steeper curve such as the one defined by the circles in Figure 3. The addition to revenue would clearly be less than the $3 million residual sacrificed to obtain it, which is another way of saying that the increase in production would be worth less than the bonus bid sacrificed to obtain it.

TRANSFERABILITY OF COMMITMENTS

Clearly the previously discussed simple work commitment bidding system results in more intensive development of the tract to which it is applied. Clear also is the fact that this effect is dependent on the characteristics of the tract to which it is applied, and in particular on the efficiency with which the successive increments of additional expenditures required under the commitment can be put to work to increase output.

One way to increase this efficiency is to allow an operator who assumes a work commitment in the course of acquiring a particular tract to fulfil that commitment through expenditures on a different tract or tracts.

For example, assume that a bidder has acquired both tract A and tract B as shown in Figure 4. If the work commitment assumed in order to acquire a tract must be fulfilled on that same tract, then his maximum commitment on A (Figure 2) is $14 million; and on B (as indicated in Figure 4 by the dashed lines) it is $8 million. Total output from the two tracts will be 2.2 million barrels.

TABLE 1

WORK COMMITMENT BIDDING

	Output (bbl's)	Revenue ($)	Expenditure ($)	Residual ($)
Tract A	1.4	14	14	0
Tract B	0.8	8	8	0
	2.2	22	22	0

Note: All figures in millions

If the operator is allowed to bid on the two tracts jointly or is otherwise permitted to shift a commitment made to acquire one to the other, then his total work commitment will rise to $24 million, with a corresponding increase in output. As shown in Figure 4, this is possible by operating tract A at the point on the output curve which produces the greatest residual and by transfering that residual, as an internal subsidy, to tract B, where, as indicated by the flatter slope of the output curve, it can be utilized more efficiently. The numbers are summarized in Table 2.

FIGURE 4

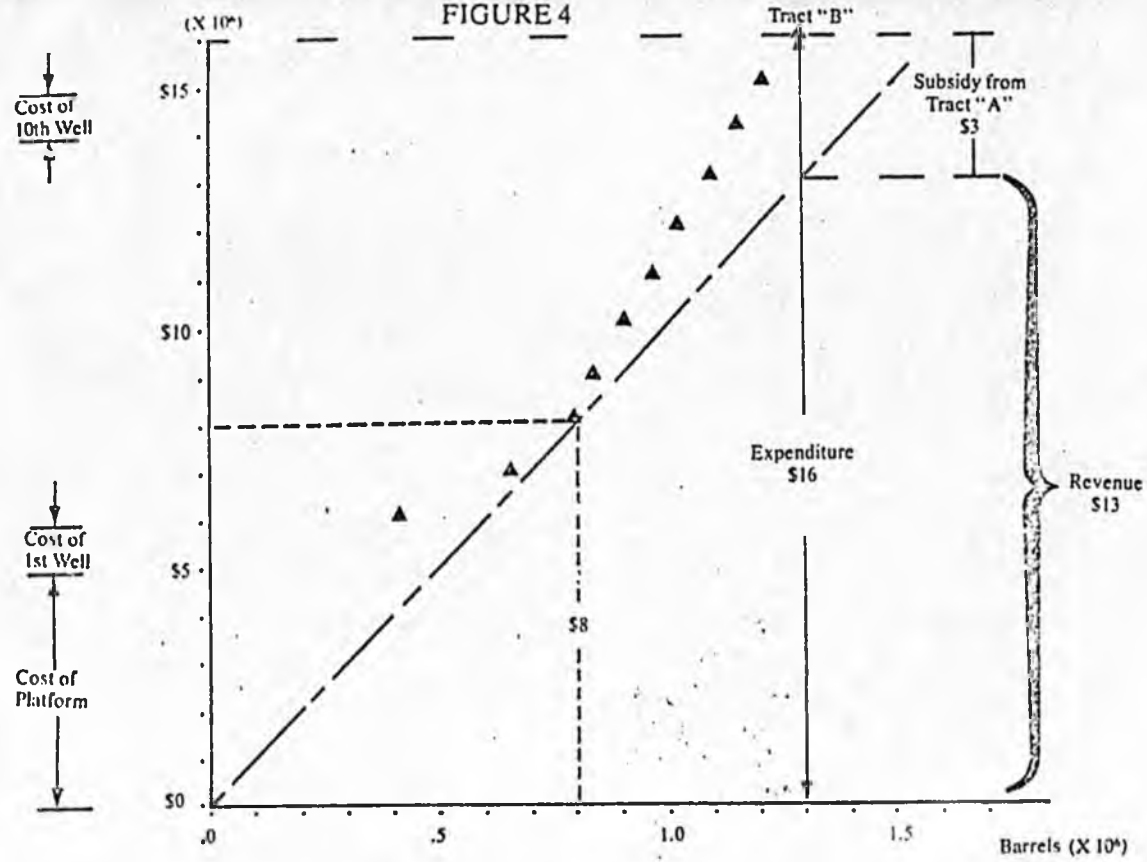


TABLE 2

WORK COMMITMENT BIDDING
(Internal Subsidy Allowed)

	Output (bbl's)	Revenue ($)	Expenditure ($)	Residual ($)
Tract A	1.1	11	8	3
Tract B	1.3	13	16	(3)
	2.4	24	24	0

Note: All figures in millions

EXTENT OF DEVELOPMENT

In the above examples work commitment bidding has been shown to result in a more intensive development of tracts than would be obtained under cash bidding arrangements. If commitment transfers are permitted among tracts, such a system will also bring about more extensive development.

Consider the output curve of tract C in Figure 5. Tract C is clearly something of a "dog," because there is no point at which the output function crosses the 45° "breakeven" line. Under cash bidding, tract C would elicit no interest at all; even if given away free, it would not be developed.

Under a work commitment system, however, tract C may very well be acquired and drilled. Assume that a firm has already acquired tracts A and B as a package with a work commitment of $24 million and that neither tract has yet been drilled. The firm is now offered tract C. How much of a work commitment can the firm offer for it?

The firm had previously planned to use the $3 million residual generated on tract A to internally subsidize tract B. If tract C is added to the inventory, the firm could apply to C $1.5 million of the internal subsidy that would have otherwise gone to tract B and thereby make the development of tract C a feasible proposition. The calculation is shown in Table 3.

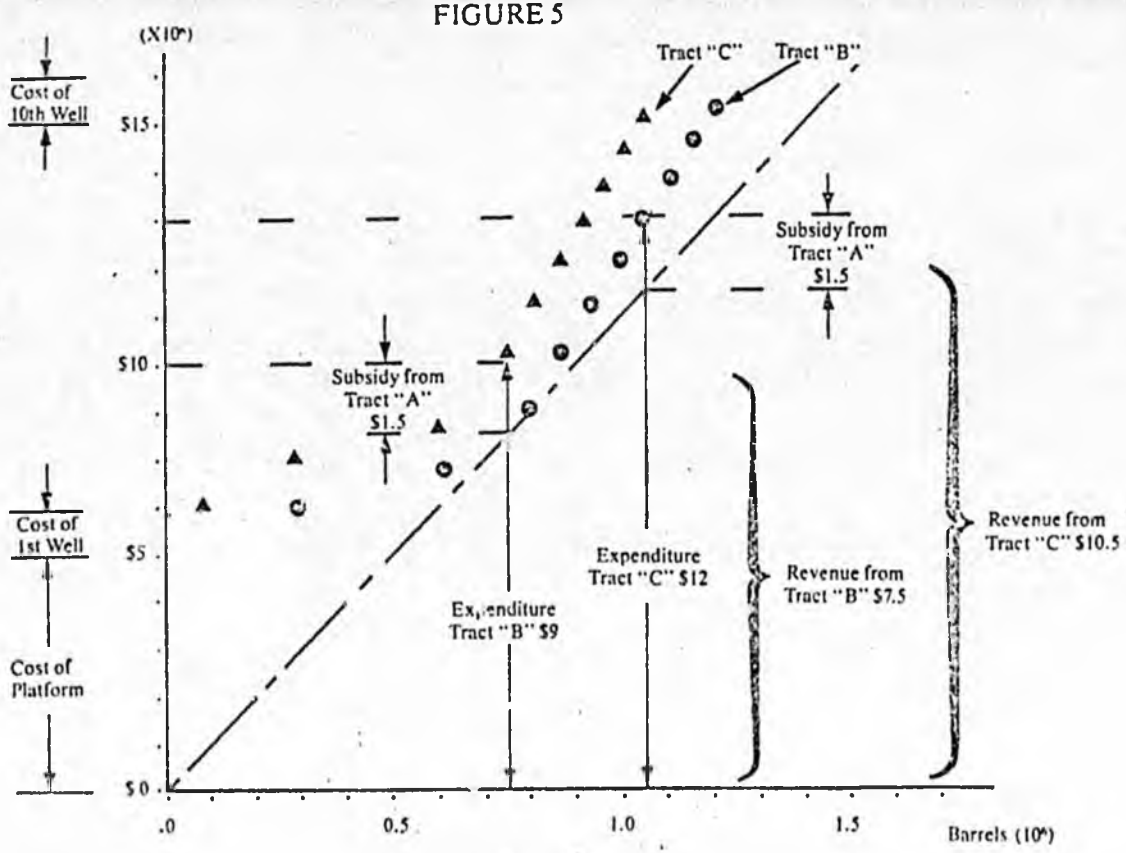
TABLE 3

WORK COMMITMENT BIDDING
(Internal Subsidy Allowed)

	Output (bbl's)	Revenue ($)	Expenditure ($)	Residual ($)
Tract A	1.10	11.0	8.0	3.0
Tract B	1.05	10.5	12.0	(1.5)
Tract C	0.75	7.5	9.0	(1.5)
	2.90	29.0	29.0	0

Note: All figures in millions

FIGURE 5



Development of the three-tract package under the work commitment system will be feasible with a total expenditure of $29 million. Since he has already been committed to spending $24 million of this, in the course of acquiring tracts A and B, the maximum commitment bid this operator can afford to make on tract C is $5 million.

Besides illustrating the mechanism through which commitment bidding induces more extensive resource development, the tract C example also indicates how the system (with internal subsidies allowed) may work to the advantage of the firms that can acquire the most tracts. Theoretically, a newcomer with no existing inventory of tracts would be unable to make any commitment bid on tract C.

A way of evading this problem would be to make the commitments transferable. This would allow operator Jones to legally assume the obligations to which operator Smith has committed himself in the course of acquiring tracts from the government. Presumably, operator Smith would pay Jones for the favour.

The prospective bidders in these examples have been endowed with the ability to foresee accurately and precisely the output curve associated with every tract. In practice this is not the case. If there is any characteristic that sets the exploration phase of the petroleum and mineral industries apart from other businesses, it is the everyday uncertainty with which its participants must learn to cope. It is perfectly possible, for example, that Smith might acquire tract C with a work commitment bid of $14 million on the mistaken belief that its output curve is that of tract A. After building a platform and drilling the first four wells, the true shape of the curve—and the firm's predicament—would reveal itself. The required $14 million expenditure applied to tract C would leave Smith with a net loss of about $4 million. If he could somehow shed $5 million of the $14 million commitment, Smith would be able to operate the tract with only four wells already drilled and thereby cut his losses to the more acceptable level of $1.5 million. Smith would be willing to pay up to $2.5 million in cash to unload the $6 million obligation, since that is the amount of his maximum additional loss if he can't get rid of it.

Any other operator who is facing or expects to face an output curve with a flatter slope than that faced by Smith will be able to make a mutually beneficial deal with him, since, for the other party, an additional expenditure of $5 million will bring in more than the maximum $2.5 million that Smith will be willing to pay.

Besides putting the small firm in a better position to compete and mitigating the problems of uncertainty for all firms, large and small, a system which allowed the free exchange of work commitments would have the further and more important advantage of maximizing the overall

efficiency with which work commitments are utilized. To the extent to which such a market was effective in bringing potential commitment offerers together with potential commitment takers, it would ensure that everyone would be operating at a point where a small increase in expenditure by one operator would produce no more and no less additional revenue than would the same increase applied to any other operator.

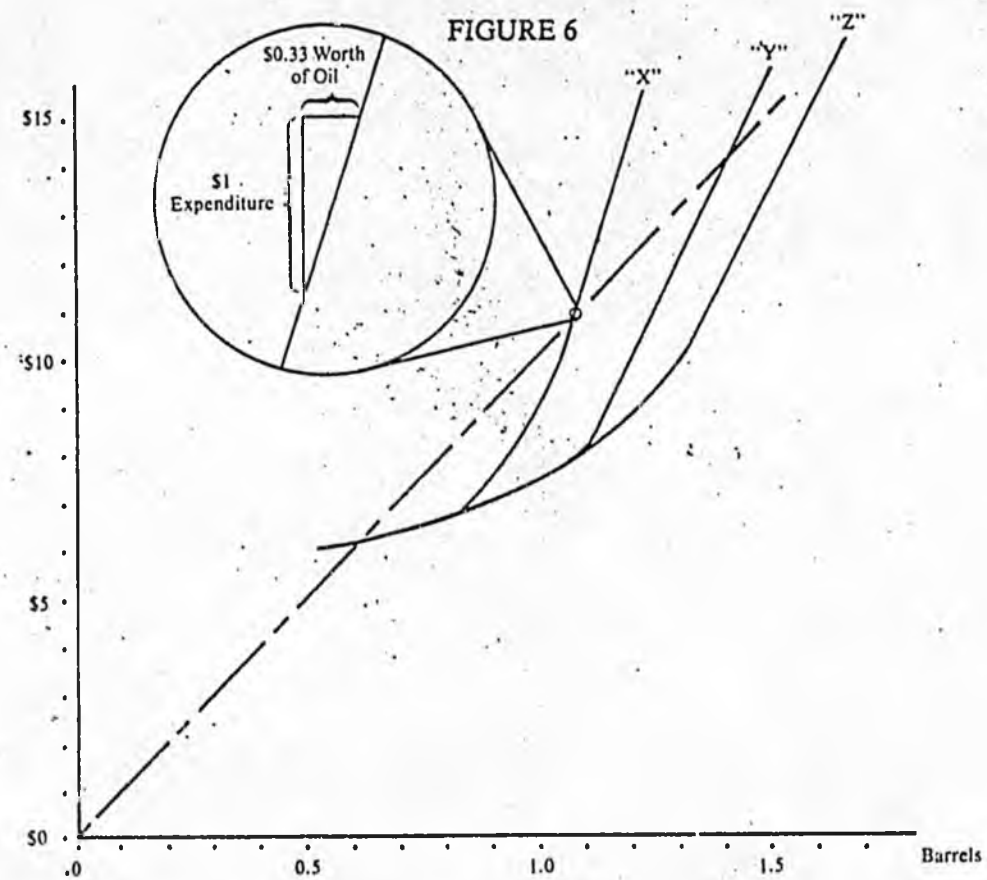
A minor but interesting benefit of a market in commitments would be the information it would provide concerning the efficiency with which the work commitment system is eliciting additional output.

This can be understood by applying the concept of the output curve (hitherto used in relation to individual tracts) to the entire universe of tracts being offered under the commitment bidding system. By combining all such tracts and treating them as a single entity, an overall output curve similar to Figure 6 can be drawn. Just as in the case of an individual tract, the point where the curve dips farthest below the 45° breakeven line will be the optimum operating point, the point which results in the resource's largest contribution to economic welfare. The distance between the breakeven line and the output curve at that point is the measure of that contribution, and it is equal to the income that would come to the government landowner were a competitive bidding system utilized. It is this residual—the difference between total revenues and total costs—that the public will be sacrificing to subsidize output.

The efficiency with which the subsidy provided by the work commitment system works to increase output will be a function of the output curve's shape to the right of the point where bonus income would be maximized. Three hypothetical configurations for this part of the curve are shown, and the difference this shape makes to the level of additional output educed by the sacrifice of the residual can be seen. The significance of the price at which commitments change hands will be determined by the slope of the output curve at the point where it intersects the 45° breakeven line. Curves Y and Z both cross at an angle which indicates that, at that point, $1 of expenditure produces $0.50 worth of additional output. In either situation the market price for assumption of a $1 million commitment would be $500,000. Curve X, however, crosses the line at a steeper slope (as shown in the inset), indicating that $1 of expenditure will produce $0.32 worth of additional output. If curve Z accurately represents the overall output curve, the market price for the assumption of a $1 million work commitment will be about $333,000.

From a policy standpoint these numbers, whatever they may be, have considerable significance since they can be used to compare the efficiency of the work commitment system in eliciting additional output with whatever other alternative policies may be available. For example, if the market for

FIGURE 6



commitments indicates that the last dollar of subsidy transferred is producing only 33 cents worth of additional oil, it may very well be that another source of oil development—for example, tar sand or oil shale—could be found that would give a better return.[6]

THE TIME FACTOR

To simplify the discussion of the work commitment system, the time dimension of both expenditures and income has thus far been ignored. Since a dollar in hand today is worth more than the promise of a dollar tomorrow, it has been assumed that all bidders have used a discounting mechanism to take account of the time value of money. Thus, they would reduce all amounts of both expenditure and income streams to their *present value*, that is, the lump sum that the bidder would be willing to receive or give in exchange for the specified income or expenditure stream.

If a work commitment system is to be implemented, it will be necessary to take careful account of the fact that a commitment fulfilled in the next year will have a very different impact on output from one of the same amount fulfilled ten years hence.

If the public is going to give up its bonus income to subsidize output, the time when that subsidy takes effect will presumably make some difference. Of course, some arbitrary time limit could be established for the fulfilment of commitments exactly as the United States government sets the five-year term on the OCS oil and gas leases it sells. If free exchanges of commitments are allowed, anyone who wished to distribute expenditures over a time frame incompatible with his commitments could simply enter the market and adjust his inventory of commitments accordingly.

Another way of handling the problem would be simply to apply some appropriate interest rate to every commitment assumed and specify that the amount of expenditure required under that commitment must increase by the amount of the compound interest accumulated in the period between the assumption of the commitment and its fulfilment.

CONCLUSION

The adoption of a work commitment bidding system implies a judgment that existing institutions for private exploitation of public resources result in a suboptimal rate of resource development.

Any argument for the adoption of such a system must first establish that this is in fact the case. Secondly, it must prove that the work commitment approach is the least costly method of achieving the desired higher rate of exploitation.

In comparing various alternative ways of achieving higher output against the work commitment system, some important features of that system are certain to stand out. First, and probably most significant, is the simple fact that the work commitment system results in a subsidy. As such, the criteria for its evaluation should be no less stringent than those applied to a direct appropriation of public funds or a tax concession adopted for the same purpose.

Secondly, the cost of the subsidy conferred under the work commitment approach is impossible to determine *a priori* and difficult of determination after the fact. If there exists a "right" level of subsidy it will be mostly a matter of luck if the foregone public revenue happens to equal that amount. For similar reasons, the benefits of the subsidy in terms of the total increase in output, development, or whatever, are not amenable to accurate quantification. As a consequence, it is doubly difficult to evaluate the system's relative efficiency.

Finally, a properly designed work commitment system allocates the uncertain amount of the subsidy in a fashion that tends to squeeze the maximum additional output from every dollar of subsidy. It does this more or less automatically. This characteristic means that the transfer of resources occasioned by the subsidy needs no affirmative action on the part of policy makers—as does a direct appropriation of public funds—in order to be continued. This fact, however, combined with the intrinsic uncertainty concerning the subsidy's magnitude makes it easier for vested interests to perpetuate such a subsidy long after any real justification for it has passed.

Notes

1. *U.S. Statutes at Large*, vol. 67, p.345. Public Law 212 (August 7, 1953).
2. For an exposition of the conventional industry wisdom on this point, see "Terms for North Sea Oil," in *Petroleum Press Service* 40 (1973): 122-24.
3. In recent testimony before the Senate Interior Committee, industry representatives were unanimous in their opposition to royalty rate bidding. *Outer Continental Shelf Oil and Gas Developments, Hearings Before the Subcommittee on Minerals, Materials, and Fuels of the Committee on Interior and Insular Affairs* (United States Senate, 93rd Congress, Second Session: May 6,7,8,10,1974).

4. Arguments for the work commitment system are expounded in detail in I. White, D. Kash et al., *North Sea Oil and Gas: Implications for Future United States Development* (Norman: University of Oklahoma Press, 1973).

5. Kenneth Dam has touched on some of these matters, however, in "Oil and Gas Licensing in the North Sea", *Journal of Law and Economics* 8(October 1965) and "Pricing of North Sea Gas in Britain," *Journal of Law and Economics* 13 (April 1970). Dam recognizes the subsidy for what it is and concludes that it is unjustified.

6. If it is determined that only a portion of the residual should be applied as a subsidy, this could be accomplished by offering only a portion of the tracts on the commitments bid basis, but allowing the fulfilment of a commitment on any tract acquired from the government. Since the reduction in the subsidy will move the operating point to the left on the output curve (Figure 5) to a point at which its slope is flatter, the result will be a higher assumption price for commitments. The commonsense explanation is that the optimum amount of total expenditure will be reduced only slightly; but that acreage over which commitments that can be fulfilled by that expenditure will be reduced relatively more. Another alternative would be to combine the work commitment system with a royalty, net profits share, or other form of deferred rent collection. This is in fact the arrangement pertaining in the North Sea sector. If the government takes a very high net profit share, the amount of the subsidy will be substantially reduced.

7. There are certain circumstances where a work commitment system could result in no more extensive or intensive development. This would be the case if the commitment were devoted to an activity not contributing to output. For example, if a government awarded a mineral concession to the operator who promised to build the largest smelter, no increase in mine output would result (unless the location of the smelter made lower grade ores profitable to mine).

Petroleum Leasing in British Columbia

DALE R. JORDAN

FACTORS AFFECTING THE LEVEL OF EXPLORATION

From data published by the provincial department of mines and petroleum resources, it would seem that exploratory drilling in British Columbia in 1974 was in a static position and may even have been declining. There was a 22 per cent drop in the number of exploratory wells drilled in 1973 compared with 1972, and a corresponding drop in the footage drilled. This decline in activity appeared to be continuing into 1974, with drilling down 10 per cent in the first seven months. This apparent decline in exploration for oil and gas in British Columbia came at a time when the demand for oil and gas was high. Prices for oil and gas had increased dramatically, and considerable concern was being expressed over national self-sufficiency in all forms of energy supplies. By comparison, exploration activity in Alberta showed the opposite pattern. In Alberta, exploratory drilling in 1973 increased 50 per cent over 1972. Statistics published by the Daily Oil Bulletin showed that during the first several months of 1974 there was a further increase over the same period in 1973.

What caused the static or possible decline of exploratory drilling in British Columbia at this particular period of strong demand and high price? There are several answers, and formulated theoretical solutions must be viewed in the light of political judgment where governments demand a greater share of resource revenues. Certainly, the federal budget proposals in the spring of 1974 discouraged exploration for oil and gas in Canada; however, it would seem that provincial government policies were largely responsible for any discouragement felt by the oil and gas explorer.

In this article I attempt to set out some of the basic causes that contributed to the 1974 situation in British Columbia. These causes are identified and any suggested solutions are offered in the realization that there is a danger of oversimplifying complex problems and the possible effects of implementing partial solutions.

For any analysis to be meaningful, a proper perspective must be maintained. One of the overriding factors influencing the oil and gas explorer's decision making is the number of geological prospects. In British Columbia, the potential hydrocarbon-bearing portion is thought to be

restricted to the northeast part of the province. The western boundary of this 51,000 square miles is the Rocky Mountains. In 1974, an estimated 37 per cent of the oil and 18 per cent of the gas in this area had been found, leaving an estimated 0.82 billion barrels of oil and 47.56 trillion cubic feet of gas still to be discovered. Although there was considerable potential still remaining for the oil and gas explorer, the area was small compared to Alberta and Saskatchewan, and it was much smaller than the vast geological potential north of the 60th parallel.

Another factor that depressed the enthusiasm of the explorer was the apparent lack of multizone prospects. Drilling a well to test only one potential horizon increases the risk factor significantly.

Before leaving the subject of the province's hydrocarbon potential, it should be remembered that several basins existed, both offshore and in the interior, containing substantial deposits of sedimentary rock that have not been explored to any great extent. Generally, the known geology in these basins discouraged any extensive exploration. Possibly, the very expensive exploration needed in the basins required special consideration before their potential could be fully realized. This special consideration might take the form of a reduced royalty on any hydrocarbon discovered, or of a joint participation scheme whereby the British Columbia government might share in the risks involved.

Another factor to be taken into account by the oil and gas explorer when selecting his areas of interest is the access to those tracts that he feels have hydrocarbon potential. Again, British Columbia was at a disadvantage in 1974 when compared with Alberta and Saskatchewan. Access to this already restricted basin area was affected by muskeg conditions over much of the plains and by deep river valleys in the foothills. These conditions involve greater expense in conducting exploratory work, and the oil and gas explorer would often be confined to only a four-month work year, because of such terrestrial conditions. The problem of limited access presents a very real constraint on attracting the oil and gas explorer and is relevant when considering any changes in land tenure and revenue sharing.

Another important parameter in any deliberation affecting oil and gas exploration is the availability of funds for exploration.

As a general rule, funds generated from production are used to finance exploration. It seems that the risk factor employed by financial institutions effectively discourages the use of debt capital as a source of exploration funds. It is not uncommon to read that an oil and gas producer has arranged for a substantial loan, but this will nearly always be for a specific purpose related to the development of a new reservoir of oil or gas. The discovery of this reservoir would have been funded out of the company's cash flow.

When an oil or gas explorer's cash flow comes from production outside any particular province, then for money for exploration to flow into that province, that jurisidiction must have a framework of leasing and revenue sharing that can favourably compete with other areas also requiring exploration.

It would seem that cash flows from Canadian production will continue to be a major source of exploration funds. In the case of the integrated companies (those having refinery capacity), this will be true under almost any condition short of expropriation.

However, within this framework these funds will generally gravitate to where they can expect the greatest return. It may not be enough for a province to show that it will ensure that the successful explorer will receive a reasonable rate of return. It may well be that the successful criterion for increasing the level of exploratory drilling will be a division of revenues such that the oil and gas explorer will have a sufficient cash flow for an active exploration programme, as compared with other jurisidictions. The explorers who have a cash flow generated from production and the flexibility to determine the best place to reinvest these funds have the responsibility of ensuring that they can go to where they can expect to return the greatest profit.

The ability of the producer to channel cash flow from one jurisdiction to another depends largely upon the particular laws in force where the oil or gas is being produced. The provinces of Alberta and Saskatchewan tend to attempt to discourage the outward flow of funds generated from production in their particular provinces. In both provinces, this discouragement took the form of a high royalty, coupled with a drilling incentive programme, designed to encourage continued exploration.

In Saskatchewan, the mineral tax and the royalty surcharge took away from the producer all of the recent price increases and, in fact, returned to the producer a smaller amount per barrel than he was receiving prior to the price increases. As an inducement to continued exploration in Saskatchewan, an incentive programme was developed, whereby the producer was allowed to retain an additional 30¢ for every barrel produced, providing this money was used for drilling wells, for waterflood projects, research, and other specified purposes in Saskatchewan. This incentive had not been in effect long enough in 1974 to permit a complete analysis of its performance; however, it was really restricted to only those companies that already had production in Saskatchewan. A review of these companies shows that the producers with the majority of the production were the so-called Majors, which raised the question as to whether or not these Majors were prepared to continue to explore in Saskatchewan under any conditions. It is more probable that the exploration philosophy of the

Majors directed that they use their exploration funds searching for high reserve reservoirs (which generally means exploring outside Saskatchewan).

To encourage explorers who do not have production in Saskatchewan, the government provided an incentive credit of about 30 per cent of the costs of drilling exploration wells. This credit could then be used to reduce any royalty or mineral tax obligations that may accrue.

In Alberta, in 1974, there was also an incentive programme for exploration drilling. This incentive took the form of a credit which could be subsequently used to satisfy most of the cash obligations that may arise by virtue of the royalty obligation, rental payments and mineral taxes, and could also be used to purchase oil and gas leases. Credits established in Saskatchewan could not be used to purchase leases. The formula which determined the amount of credit that could be established for any particular exploration well was predicated upon the area of the province in which the well was located and the depth of the well. This formula was expected to return to the explorer by way of credit approximately one-third of his drilling costs.

The principal producers of crude oil in Alberta were much the same as in Saskatchewan—they were the Majors in the oil and gas industry. Again, as in Saskatchewan, it would seem that the interest of the Majors in continuing to explore in Alberta had become blunted, not because of any particular rules, but more through the apparent lack of sufficient high reserve potential which this type of company must search for.

In Alberta, in 1974 the royalty was structured to increase not only when the production increased but also when the price increased. Alberta had also adopted a new oil/old oil concept, whereby royalties were considerably reduced on what was termed new oil, which, of course, had the affect of increasing the producer's cash flow and encouraging the development expenditures. This old/new concept applied as well in the case of natural gas. Saskatchewan also had provision for a reduction in its mineral tax and royalty surcharge for new oil. This reduction was gradually phased out after a few years. Alberta, in 1974, had the lowest rate of royalty on oil and gas, received the highest price for its natural gas and had a price for crude oil equivalent to the other provinces, all of which means that in Alberta the producer of oil and gas received a higher rate of return and, consequently, had more money available to him for exploration purposes than the producer in Saskatchewan or British Columbia.

While the incentive programme adopted in Alberta and Saskatchewan offered encouragement to drill exploration wells, any analysis of the performance of a similar programme which might be suggested for the province of British Columbia must be coupled with the consideration of a lower royalty and subsequent higher cash flows to the producer.

This type of incentive can only be effective if the producer is also offered a return on his development expenditures that is competitive with other jurisdictions into which the oil and gas explorer is free to go.

Another source of money for drilling exploratory wells previously used in North America has been the drilling fund. The drilling fund usually takes the form of buying a number of shares in a limited partnership. The attraction to the investor apart from the possibility of participating in oil and gas discoveries, is the income tax feature in the United States which permits all intangible drilling expenses to be written off in the year that expenditures were made. This can be done without qualifying under any principal business rules, as prevails in Canada. It is this principal business rule that has to the present time precluded the tapping of a similar source of exploration funds in Canada.

It is estimated that between 250 and 400 million dollars are generated annually through the sale of shares in drilling funds in the United States. The United States government, in an attempt to encourage further exploration within its own borders, has chosen to reduce the amount that can be written off against income for income tax purposes when the funds are spent outside the United States. This move precipitated the drying up of exploration funds in Canada which previously came from this source.

Over the past few years other extractive industries, particularly mining, have been channelling considerable amounts of their cash flows into oil and gas exploration. These endeavours have usually taken the form of funding a subsidiary company. The continuation of this type of fund for the purposes of exploring for oil and gas will depend upon the success of the subsidiary companies and also upon the influence that mining taxes will have upon the parent companies' cash flows.

A few years ago it was quite popular for large United States gas utility companies to provide exploration funds on the basis that they would have first call on any gas produced and exported for sale to the United States. This source of exploration funds has also dried up almost completely as a result of decisions by the National Energy Board concerning the exporting of gas and, as a result of rulings by the Federal Power Commission in the United States, which have not allowed these utility companies to include these expenditures in their rate base. The Federal Power Commission looks upon this type of exploratory funding as a mortgage loan, rather than as a prepayment for gas, as the utility companies would prefer.

THE LEASING SYSTEM

The 1974 system of leasing in British Columbia will now be reviewed, and I will attempt to analyse its effectiveness in relation to the relatively small

hydrocarbon potential area, lack of access, difficult terrain, and exploration funds generally coming from cash flows.

The system of granting oil and gas rights on crown lands in British Columbia invoved in 1974 an exploration grant called a "permit," a subsidiary exploration grant called a "drilling reservation," and a development grant called a "lease."

Permits, which can involve upwards of 100,000 acres, could only be acquired through a competitive cash bidding system at sales which were usually held four times a year.

The permits were classified from A to D, depending upon their accessibility and the terrain conditions. The class D permits were for offshore areas. One purpose for classifying permits was to allow them, where the working conditions were difficult, to have a longer life than was otherwise provided.

Permit classification also determined the minimum amount of work the permit owner was obligated to spend in any year. These minimum work obligations were more stringent for the Class A permit, where access and terrain problems were minimal. The significance of this particular requirement was lost because, in order to conduct an equivalent amount of exploration, particularly drilling, the costs involved in the offshore areas far exceed those which would be expended on a class A type permit. The sections of the Petroleum and Natural Gas Act that governed the permit work obligations did not specify any specific exploration programme, but only that a certain amount of money be spent during each term of the permit. This obligation to spend money in exploring on a permit could be satisfied by grouping several permits together, so that expenditures incurred in exploring on any one permit would satisfy the work obligation of the grouped permits. This grouping provision is important because it allowed an explorer to acquire large tracts of land for a short period in order to conduct extensive geophysical exploration.

This obligation to spend money on exploring on a permit could also be satisfied by paying the money to the British Columbia Crown. This would seem to be about as negative a provision as one could imagine, assuming, of course, that the government of British Columbia was interested in ensuring that the companies holding permits were the ones prepared to actively explore. If the removal of this system would give rise to problems, as in the case of an explorer unable to work a permit through no fault of his own, then a far better system would be to provide a means where work obligations could be accumulated and satisfied in the following year.

Permits were valid for one year and could be renewed annually, for a period ranging from five to eight years, providing the company was not in default.

When a permit holder had expended the minimum amount of money exploring on a permit or group of permits or had paid the money to the government, he was entitled to convert the permit into leases. To do this the permit holder had to relinquish 50 per cent of the land back to the Crown. Land selected for conversion into leases could not be in a consolidated block, but had to be in a number of leases, which had to corner one another, or be separated by at least two units—approximately one mile. The maximum size of the lease was six units—approximately three miles square.

This system of exploratory permit and subsequent conversion of half of the land to lease on a chequerboard fashion was similar to that used in Saskatchewan and part of Alberta. The system probably had its beginning in Alberta. It was designed to ensure that when crude oil was discovered, the Crown would be returned some prospective areas which were subsequently sold. This system worked reasonably well, particularly in Alberta, where some substantial discoveries of crude oil were made during the existence of the exploration agreement. Unfortunately, in the vast number of cases a discovery was not made, and the chequerboard pattern for leases led to fragmentation of rights throughout the area formerly comprising the permit. This effect tended to discourage other explorers from entering the area, and this system of selecting leases also prompted the need for the drilling reservation, which generally covered that 50 per cent of the land returned to the Crown.

Seemingly, in those parts of the province having relatively easy terrestrial access and where the potential hydrocarbon-bearing formations were not too deep, this system of chequerboard leasing may be satisfactory. However, in areas where access is a major cost and where deep expensive drilling is required, it tended to discourage anyone other than the holder of the 50 per cent leases from entering the area to explore. Certainly in offshore areas where seabed drilling cost is many times greater than land drilling, this system of lease selection is most unsatisfactory.

Leases granted on crown land in British Columbia in 1974 had a primary term of ten years, renewable for further ten-year periods if particular circumstances existed which generally related to production.

The acquisition of leases in British Columbia was handled in 1974 in two separate ways. First was the way previously mentioned, which was the result of having a permit and then earning the right to acquire leases of 50 per cent of the land. The second was through the competitive cash bidding at one of the quarterly sales held by the British Columbia Crown.

There was no obligation at that time on the part of the lessee to drill a well during the initial term of the lease. A 1974 amendment to the Petroleum and Natural Gas Act, however, permitted the minister to forward a notice to

drill when he considered that development of the lease was not active enough. This amendment seemed to suggest that before the minister would consider sending a notice, there would, in fact, have been a discovery made on the lease. Thus, in sending the notice, the minister was merely requiring development drilling. It seemed most unlikely that the wording of this section would be interpreted such that the minister could require exploratory drilling on existing leases.

There was an apparent trend to shorten the term of leases, with Saskatchewan granting only five-year primary terms. However, in British Columbia the term of 10 years was not excessive when one considers the short period of four to five months when work can be done in the area of hydrocarbon potential. This is quite different from most of the areas in Alberta and Saskatchewan, where drilling and other geophysical operations can be conducted all the year round.

The government of British Columbia appeared to feel that a large number of leases were held by companies not particularly active in exploring in the province and that something should be done to discourage these holdings, so that lands could be offered to others who were prepared to explore. These feelings may have promoted some of the 1974 changes in the Petroleum and Natural Gas Act, whereby the rental on leases was increased from one dollar an acre to two dollars an acre. The effect of this change seemed likely to be the return to the Crown of some acreage which, under the previous rental of one dollar an acre per year, would have been retained by the lessee. However, one must assume that for the most part relinquished leases would be the least attractive, and leases with potential, even though the lessee was not prepared to conduct any immediate exploration programme, would be retained, and the two dollars an acre would be paid. The greatest effect that this rental of two dollars an acre per year seemed likely to have was to deter other explorers from entering the province. It is one thing to create a system designed to discourage excess holdings by companies not prepared to explore immediately, and quite another thing to expect these same rules to promote the entry of new companies and increase exploration activities.

The royalties on crude oil in British Columbia were essentially the highest in Canada in 1974. The rate was 40 per cent for a well producing 1,000 barrels a month and further escalated to about 58 per cent when the monthly production reached 10,000 barrels. It would seem that this royalty level, which directly affected the producer's cash flow, could only act as a deterrent to increasing the level of exploration in British Columbia much beyond its historical pattern of about fifty to sixty exploration wells a year. Other changes that may be made in regulations designed to encourage greater exploration activity will never perform to their full potential until

the producer's return is comparable with what he can obtain in other jurisdictions.

GOVERNMENT OPTIONS

We can now examine the options available to the British Columbia government in 1974. First, the government could maintain the existing regulations without change; or they could have stricter enforcement of the rules, further reducing cash flows to the producer, making it more difficult to operate; and thirdly, they could make changes designed to encourage greater exploration activity in the province. In each of these options it is assumed that some accommodation could be made between the provincial and federal authorities with regard to the revenue-sharing aspect. If it could not, then it would seem almost certain that exploration activity would decline, not only in British Columbia but also in the rest of Canada, and that even significant changes in the regulations would fail to act as an effective inducement to continued exploration.

In the first instance, if the government were to resist changes to its rules and to continue the existing level of royalty, it could expect to receive about the same amount of exploratory drilling as there has been in the past. This is evident from the sale in August 1974, where some 7.2 million dollars was paid for the right to acquire oil and gas permits, drilling reservations, and leases. This was certainly an indication that the oil industry was not prepared to write British Columbia off because of its high royalties and rather stringent regulations. There are several reasons for this. Companies have enjoyed a general increase in their cash flow, and in 1974 enough cash flow was available to pursue exploration in a province where the rates of royalty would reduce their return on invested capital as compared to other jurisdictions—for example, Alberta or the United States. The intensive competitiveness in the oil and gas industry distinguishes it from all other industries. Companies that have invested a great deal of time and money developing the geological potential of a particular area and have found that it fits their exploration parameters are prepared to offer a good deal of bonus money when this land becomes available through a competitive sale. Also, because a number of years usually elapses between acquiring an exploration permit and the development of and production from any discoveries, the economic climate may change such that what at one time is not attractive may become economic at the time of production.

If the government of British Columbia wished to discourage continued exploration by the existing oil and gas explorers and to discourage entry by newcomers, they could most effectively do this by again raising the rates of royalty and making the tenure of agreements shorter than they were. This

type of action would cause the companies exploring in the province and those contemplating doing so to restrain their activities; exploration would then stagnate.

Presumably, such action by the British Columbia government would not occur without consideration of these consequences and the recognition that a different vehicle should enter the void left by the existing explorers. This could take the form of a public company, such as the British Columbia Petroleum Corporation; alternatively, the government might feel that, given time, the major oil and gas producers, the fully integrated companies, may finish their exploration for high-reserve reservoirs in other parts of Canada and be prepared to return to British Columbia to look for the remaining reserves which they may need to supply their refineries.

To give any support to this latter proposition, one would have to presuppose that the exploration presently being carried on by the Majors in Canada in the Northwest Territories, in the Arctic Islands, and in the offshore areas of eastern Canada will be unsuccessful and that they will have to lower their sights, accept a lesser prospect, and return. This is very difficult to support, considering the successes already achieved in the Northwest Territories, particularly in the Delta, and in the Arctic Islands. Also, there is a vast geological potential remaining as assessed against the very few wells that have been drilled...

The supposition that a provincial public corporation could enter the exploration field and its endeavours be more beneficial to the province than the present system raises many questions about the corporation's practical efficiency and about the possible political repercussions. This article's purpose is not to examine the political repercussions that might occur when dry holes are drilled with public funds; however, we should examine some of the practical considerations involved in the operation of a public company which has an almost exclusive area within which to explore as a result of discouraging the private sector. For the government to discourage both the existing explorer and the entry of any new ones and to expect the public corporation to be able to fill this void suggests that the government is saying, "If the private companies do it, so can we." Now remember that the private companies comprise all the oil and gas explorers working in the province and those contemplating doing so, given the right opportunities. All these companies have geological staffs, many of whom will be geologists who devote most of their time over a considerable number of years entirely to the study of British Columbia's geology. The public corporation could not expect to have such an extensive source of expertise as that available in the free enterprise system. And so the public corporation would suffer from a reduction in the number of ideas generated.

It is not unusual in oil and gas exploration, with its inherent problem of

scientific interpretation and evaluation of geological prospects, to find that one company will acquire a block of land, will explore it, and perhaps even drill on it before deciding the search is unsuccessful. The company will then return the land to its owner, the Crown. This does not mean that there are not any commercial hydrocarbons underlying this land; but rather that that particular company was unable to find them. To find these hydrocarbon deposits, a second, a third, or a fourth company should acquire this land, and, if this is done often enough, the hydrocarbon will be encountered, and production will follow. The problem with the public company being the only explorer in the province is that, unless it is fortunate enough to make the initial discovery, it is very doubtful whether there would be enough enthusiasm to have a second, third, or perhaps even a fourth try at that particular prospect, with the result that the discovery would not be made. This is surely the worst thing that could happen and is probably the most damning argument against a public corporation moving into an area with an almost exclusive right to explore.[1]

If the British Columbia government wishes to increase the level of exploration in the province and so lead, hopefully, to a greater number of discoveries and a better position of self-sufficiency in their own requirements, there are several measures which could be taken to promote such a situation.

The first step that can and must be taken is to increase the cash flow to the producer and to assure the newcomer that if he makes a commercial discovery, he will receive a sufficient return to expand his exploration endeavours in the province. This action should take the form of restructuring the royalty on oil and probably renegotiating the contracts on gas existing between the producer and British Columbia Petroleum Corporation. The 1974 royalty rate on oil was determined by production at the wellhead, with the price not being a factor at all. This means that if the price paid to the producer for a barrel of crude oil should decrease from the present level, then the producer will suffer a decrease in his cash flow, thus his future available financing to continue exploration endeavours in British Columbia will be diminished. A preferred structure on royalty would take into account the possibility of a rising and falling price for the product so that the producer, out of whose cash flows exploratory drilling is carried out, would be the last one to suffer in the case of a decrease in price for both oil or gas. Probably this might best be accomplished by the producer selling his crude oil to the British Columbia Petroleum Corporation in the way gas is sold, but with a better pricing adjustment mechanism than that which exists with the gas contracts.

Another measure that should be taken would be a redesigning of the exploration agreement. This could be done to ensure that the holder could

only earn leases after he had conducted actual work on the permit or in the area within reasonable proximity, and that his earnings would be restricted to a consolidated block rather than come from a sprinkling of leases throughout the permit area. This feature alone would help to ensure exploration, because the permit holder must be satisfied that he is getting, at least in his mind, the right half of the permit under lease.

The manner of acquiring oil and gas rights should be reviewed. As mentioned previously, the only method of acquiring an exploration permit under the present rule is through a competitive cash bidding system usually held on a quarterly basis. There are probably several instances where an oil and gas explorer would have been quite prepared to drill wells in British Columbia if he could have acquired the land for a minimal amount rather than having to use money he would put into exploration to purchase land through the cash bidding system. The rentals and fees charged should be the same as in Alberta, if only to appear competitive in this particular area.

CONCLUSION

The exploration for oil and gas in British Columbia cannot be considered in isolation. The proportion of the reserves of oil and gas remaining to be discovered will depend upon the number of exploration dollars allocated to the task. British Columbia's competitive position for these exploration dollars will depend in large measure on its royalty and land tenure policies.

Cash Bonus Bidding for Mineral Resources

WALTER J. MEAD

Mineral leasing policy alternatives arise out of the fact that governments own mineral resources but, in general, do not engage in mineral esource recovery and processing. Hence, a need arises to transfer publicly owned resources to private enterprise at a price which will reflect the "fair market value" of the resource. The following analysis will, first, explore the problems to be solved by a bidding policy and, second, evaluate the cash bonus method of bidding for mineral leases.

THE PROBLEMS TO BE SOLVED

There are three problems which must be solved by any leasing system. First, the leasing system must as objectively as possible determine who or what firm is to be given the right to exploit publicly owned mineral resources. Second, a price must be determined which the lessee is to pay to the government for the right to recover mineral resoures held in trust for its citizens. Third, assuming that a nation wishes to economize on the use of its scarce resources and to maximize the standard of living of its citizens over time, the leasing system must result in an efficient method of production.

As a prerequisite to a discussion of mineral leasing alternatives there should be a clear statement of the goal(s) to be achieved. It is probably true that economists as a group have a preference for a single goal, declaring it to be one of economic efficiency. Natural resources available to any economy are scarce by definition. Achieving the highest possible standard of living requires that scarce resources be utilized with a maximum of efficiency. If resources are sold at a price below their true value, then the products into which they are converted may also be underpriced. If demand elasticities are less than zero, then the flow of resources into products and the flow of products within the current period will be excessive. Present overconsumption of products and resources will be at the expense of future consumption.

One way of achieving maximum economic efficiency is to price all resources at their "fair market value." Such pricing allows a government the opportunity of capturing the economic rent. Resources should be sold

for the difference between future revenues and costs, appropriately discounted to their present value. The economic principle relating prices, costs, and money flows at different points in time in order to estimate present value (PV) is shown in the following formulation:

$$PV = \sum_{i=0}^{n} \frac{P_iQ_i - C_i}{(1+r)^i}$$

P_iQ_i is the value of the gross income flow at different points in time, C_i represents associated costs, and r represents the interest rate at which future money flows are discounted to the present. The formula clearly shows that higher future prices will increase present values while higher future costs will lower present values. Further, the greater the uncertainty and risk associated with production, the smaller will be present value. Firms utilize some variation of this present value formula in calculating their individual bids. Estimates of the quantity of minerals recoverable from a given tract will, of course, vary widely from firm to firm.

If mineral leases are sold for less than the fair market value as indicated in the above formula, then resources may be used at an excessively rapid rate, and the public, as owners of the resource, will fail to receive their full economic rent. On the other hand, if mineral resources are sold at prices in excess of the fair market value then, in the long run, some operators will be forced out of business. Use of such mineral resources in the present period will be at a suboptimal rate and the public owners will receive more than their normal economic rents.

In the past, Canada apparently has transferred some of its mineral and timber resources through various negotiated transactions rather than by utilizing the auction market approach. Similarly, other foreign governments have traditionally taken the negotiated sale approach in entering into long term oil concessions.

There are major problems involved in the negotiated approach. The correct present value of natural resources is extremely difficult to ascertain. There is no objective test in advance of ultimate production that can indicate the precise present value of mineral resources. By their nature they must first be discovered. Their presence, quantity, and quality are in doubt. With the government as the seller, negotiating with a single buyer, traditional problems of bilateral monopoly are encountered. The seller is interested in maximizing price, while the buyer is interested in minimizing price. Given this uncertainty plus opposing objectives, the civil servant is placed in a difficult position.

A visitor to Canada is reluctant to criticize Canadian experience which has circumvented the market place. Fortunately there is abundant experience within the United States to indicate the shortcomings of the negotiated approach to pricing. We may formulate two general laws which

seem to govern when prices are determined or may be influenced by administrative judgement. First, the buyer will always complain. If the buyer believes that market prices can be reduced by protesting that they are too high, then complaints based on the argument that the operator cannot make a "fair profit" because prices are set too high could be endless. In the timber context, there are two cases where elaborate reports have been written protesting the high price of timber. One, presented by the Simpson Timber Company, protested against the high price of stumpage set by the United States forest service for the Shelton Sustained Yield Unit Agreement. Timber, in this case, is not sold at auction; its price is determined by the United States forest service. In the second case, the Edward Hines Lumber Company protested against the high cost of timber for its southeastern Oregon lumber mill. The timber was sold at an auction where competition was so weak that, in effect, it was sold at the administratively determined minimum price. By protesting, the company apparently felt that minimum prices could be reduced. In this instance, local community help was solicited on the grounds that if the company failed to make a fair profit, it would be forced to curtail operations. Under auction market procedures the government is relatively free from constant complaint and protest, because it is the impersonal market that determines the price rather than a civil servant. Under auction bidding procedures the buyers themselves set the price in competition with one another.

A second general law is that, where prices are set through administration, the government will always set prices short of the fair market value. A bureaucracy will rarely choose the path that makes its position unpleasant. Low prices are believed to generate less criticism and complaint than high prices. Where there is no auction market to test administrative judgement concerning the fair market value, we have no means to prove the second law. Sales of timber in the United States offer an opportunity to test the administratively determined price. Timber is sold by the forest service on the basis of an appraised fair market value, which becomes the minimum price acceptable to the government. Auction bidding begins at this price. In the four years from 1959 through 1962, competitive bidding for timber in the United States Douglas fir region produced an average high bid price that exceeded the forest service statement of fair market value (the appraised price) by 46 per cent.[1] In this case, the interests of the public were protected, at least in part, by reasonably effective competition. In the absence of this competitive check it is quite likely that the appraised prices would have been even lower. The shortcomings of the negotiated approach should lead to auction bidding wherever competition is possible.

CASH BONUS BIDDING

Before bidding can take place, a decision must be made between oral and

sealed bidding. Bidding in either form may start with a stated or unstated minimum acceptable price. In the case of timber sales in the United States, the minimum acceptable price is given by the appraised price, and most timber auctions are conducted under oral auction procedures. On the other hand, in the case of oil and gas leases conducted by the federal government in the United States, the minimum acceptable price is not published, and bidding is normally by sealed bidding procedures. The government retains the right to "reject any and all bids." After bids have been received, it determines whether or not the high bid was adequate.

The factors important in choosing between oral and sealed bidding methods are as follows;

a. Of prime importance is the extent of competition. If competition is weak, then sealed bidding with its element of uncertainty makes collusive arrangements more difficult to enforce. Under sealed bidding rules there is no second chance to bid at any given sale. In contrast, under oral bidding procedures, a collusive arrangement can be policed by the participants during bidding. Further, there is always doubt about how many bidders may appear at a given sale. In oral bidding where only one bidder is present, he will bid the minimum; whereas, in sealed bidding a bidder would probably offer an amount which he believes will win the sale under conditions of more than one bidder.
b. In the timber industry where fixed investments in milling facilities normally exist prior to sales, the buyer needs a means of ensuring access to specific raw materials and specific locations. Oral auction procedures provide this means through the opportunity to cast reaction bids. In contrast, in oil and gas bidding fixed investments are made after winning a sale, hence there is less need to protect one's position through the opportunity to react to the bids of others.
c. Where the severed resource is relatively immobile, as in the case of timber, it is of greater importance that a specific nearby sale be obtained; therefore the oral auction procedures are more appropriate. In the case of oil and gas, the severed resource is highly mobile, so obtaining a specific sale is of less importance. In this case sealed bidding is not disadvantageous.
d. Where the resource to be auctioned is not homogeneous, it may be necessary for a firm to obtain a specific sale. Where this is true, the opportunity to make more than one bid to protect one's need for a specific type of resource may be of great importance. Only oral bidding facilitates this subsequent bidding opportunity.
e. Financial planning often requires that a firm carefully limit its financial exposure. Where this is necessary, oral bidding offers greater control over a total resource-financial commitment. In the case of sealed bidding,

firms may be unexpectedly successful and in the process win more sales than were desired or can be successfully financed. On the other hand, a firm's sealed bidding may be totally unsuccessful so that it becomes undercommitted. This shortcoming of sealed bidding may be corrected where resources may be freely transferred among interested buyers. This procedure is normally followed in the case of oil and gas leasing in the United States.

f. Oral bidding requires more on-the-spot decision making than does sealed bidding; therefore, oral bidding requires that a higher level of executive talent be present at the moment of the auction. In contrast, decisions made on the basis of a sealed bid offer no opportunity for subsequent action on the auction floor; therefore, the presence of expensive executive talent is not necessary.

g. The "free rider" is a problem for serious bidders under oral bidding conditions. A serious bidder will carefully examine the potential productivity of a proposed lease sale. This may, as in the case of minerals, require large investments. Under oral bidding conditions, a "free rider" can observe who is bidding, then, if he is confident that they have done their homework, he can continue to outbid them until they reach their maximum and he will win the sale. His purchase is therefore based on someone else's calculations and he, in turn, has saved the cost of the pre-exploration appraisal. Sealed bidding does not offer the free rider the same opportunity.

Once a decision has been made in favour of oral or sealed bidding, then a choice must be made on the object of bidding. A cash bonus bid is one alternative. Additional alternative bidding objects are shown in Table 1.[2]

Bonus bidding is the standard procedure used by the United States government in all of its Outer Continental Shelf (OCS) programmes. Using the present value formula given earlier, potential bidders presumably estimate the present value of the probable mineral recoverable from a tract of land. The formula provides for adequate recovery of capital and compensation for risk, uncertainty, and profit.

One strong advantage that can be claimed on behalf of a bonus system relative to royalty bidding is that it requires a lump sum payment and correspondingly modest royalty payments. Because royalty payments are due on each barrel of oil or unit of natural gas produced (or other mineral), such charges become part of the marginal cost. At the margin of production this is a transfer cost rather than a real social cost. Royalty bidding thus leads to premature abandonment of an oil or gas well. To the extent that royalty payments are required in addition to the cash bonus, there will be premature abandonment of the lease.

The disadvantages of bonus bidding are numerous. First, while the

technology for oil exploration prior to drilling has been advanced in the last century, exploration is still subject to extremely high risk. Drilling is the only definitive test to determine the presence of oil or gas. Thus, bonus bids must be submitted by bidders and accepted or rejected by the government when neither the buyer nor the seller knows whether and in what quantities oil is present. This places the seller in a position of accepting millions of dollars for nothing but the right to spend several more millions drilling potentially dry holes. In cases in which a rich oil field is found, returns to the lessee will be and must be very high.

Second, under current procedures a bonus must be paid when the bid is submitted. When the bonus bid is large, it will represent a very heavy cash drain to the bidder far in advance of any revenue which may be generated from the oil or gas produced from the lease. This significant *front-end loading* of capital costs effectively excludes a small operator from winning leases as a solo bidder, creating an additional barrier to entry into the oil and gas production market. To overcome this entry barrier, firms commonly form joint ventures and bid jointly for a lease.

Third, because the bonus is calculated on a present value basis, the government is forced to accept discount rates used by private enterprise. If private enterprise discount rates are unreasonably high from a social standpoint, then bonus payments to the government will be correspondingly low.

Possible variations of the bonus bidding form are shown in Table 1. The present United States system includes fixed royalty requirements (typically 12½ per cent or 16⅔ per cent of wellhead value). However, a bonus bid might be paired with a sliding scale royalty requirement, permitting the royalty rate to be reduced as a field declines in productivity. As the point of economic abandonment is approached, the royalty rate might be reduced substantially or even eliminated. This procedure would, in turn, eliminate a marginal cost of production that is not a real social cost, and it would permit continued production from a field until the real marginal costs equaled the marginal value of production. This is the optimum point for well abandonment from an economic point of view. If at the time that a bonus bid was submitted all bidders understood that the royalty rate would be reduced to zero under the conditions specified above, the present value of the lease would be increased by an amount equal to the present value of reduced future royalty payments. Thus a tradeoff would be effected from royalty payments to bonus payments. The principal impediment to a sliding scale lies in the difficulty of clearly identifying various points at which royalty rates would be reduced. The lessee would have an economic incentive to manage his production in such a way that minimization of royalty payments would be an operating objective, rather than economic efficiency.

TABLE 1

ALTERNATIVE BIDDING FORMS

Bonus Bidding
- a. with a fixed royalty requirement
- b. with a sliding scale royalty requirement
- c. without a royalty
- d. with or without a rental payment
- e. with a profit share
- f. with delayed bonus payments

Royalty Bidding
- a. flat (nonvariable) royalty
- b. sliding scale royalty
- c. with a fixed bonus requirement or no bonus

Profit Share Bidding
- a. net profit or gross profit
- b. with fixed bonus requirement or no bonus
- c. with a royalty requirement or no royalty

Combination of Bonus and Royalty Bidding

Bidding on the Work Programme

The royalty problem, together with the administrative problem of reducing royalty rates under a sliding scale, might be avoided entirely by using a bonus bid without a royalty payment. However, this procedure would simply magnify all three of the problems associated with bonus bidding listed above.

Present procedures in the United States include modest rental charges payable between the points of sale and production. When production begins, rental payments cease and royalty payments take over. Rental payments in OCS oil and gas lease income are insignificant. In 1972, they amounted to 0.3 per cent of total revenue from such leases.[3] The rental requirement apparently was introduced to motivate the lessees toward early production. If they were of significant size, this result would in fact occur, because rents cease when production begins.

To overcome the front-end-loading problem, provision might be made for delayed payment of the bonus. The problem that would follow from this procedure is that in some cases where no minerals were found, lessees would elect a bankruptcy route. In this event, an unfair bidding situation would be created. Responsible firms in business on a perpetual basis would not follow a bankruptcy procedure and would, therefore, be at a bidding disadvantage with respect to others that contemplated bankruptcy in the event of a "dry hole."

A bill currently pending before the United States Congress provides for a 55 per cent fixed share of net profits in lieu of the existing fixed royalty payment accompanying the bonus bid. The winner would still be

determined on the basis of a cash bonus. A profit share payment would avoid the above problems associated with royalty payments. As a given lease approaches exhaustion and its point of economic abandonment, profits would also approach zero and payments would decline proportionately to zero. If the profit share was calculated on the basis of net accounting profits including fixed costs, then the profit share payment would decline to zero prior to the point of economic abandonment. The latter point is reached only when marginal cost (not total costs) equals the marginal revenue. There is nothing wrong with this system providing both parties understand how it works and bidders understand it at the time they submit their bonus bids. The proposed 55 per cent profit share is high and is likely to lead to inefficient operations. A profit share payment is approximately the same as an income tax on each well and is additional to the existing income tax. When the profit share payment is added to the existing income tax, a large part of the penalty for wasteful operations will have been shifted from the operator to the government. While a bonus bid paired with a fixed profit share payment has merit, a 55 per cent profit share added to normal income taxes is inappropriately high from an economic point of view.[4]

Some data are available to permit a partial evaluation of the effectiveness of bonus bidding with a fixed royalty. The United States experience with OCS bidding provides a record of thirty-five oil and gas lease sales during the period November 1954 to 29 May 1974. In addition, three sulphur lease sales and two salt lease sales have been conducted on the OCS. The record may be evaluated in terms of the number of bidders competing for each sale, the conditions of entry of new firms, the record of joint bidding, the extent of concentration among winning firms, the trend in price bid per acre, the resale record of tracts where the initial bid was refused by the seller, and the rate of return earned by the winning bidders. Data pertaining to OCS bidding as follows:

a. For oil and gas lease sales there has been an average of 3.6 bidders competing for each tract receiving bids. The trend from 1954 to date has been one of increasing bidder activity. From 1954 to 1966 the average number of bidders per tract was 2.7. From 1967 to date the average increased to 3.9. From the seller's point of view, even more bidders would be preferred. Given the fact of relatively few bidders, sealed bidding procedures would appear to be more appropriate than oral auction.
b. Entry into the oil and gas auction markets appears to be relatively free. In the first 1954 federal lease offshore from Louisiana, 199 tracts were offered. Ninety-seven of these tracts received 327 bids from 22

different firms, some of which bid in joint bidding combinations. From 1954 to 28 March 1974, an additional 110 firms won tracts as solo bidders or joint bidders with 1 or more other firms. Thus, in addition to the unsuccessful bidders who also perform a competitive function in the bidding process, there were 132 separate firms participating as winning bidders in thirty-three OCS lease sales.[5]

c. Entry by relatively small firms into OCS lease sale bidding is facilitated through joint bidding. Joint bidding by two or more firms each unable to bid solo has the effect of increasing competition. On the other hand, when two or more large firms fully able to bid separately combine to submit a single bid, the effect may be to reduce the number of competitors. However, if through joint bidding, even among large firms, a combination of, say, four firms bids more than four times as frequently as the individuals would have bid solo, then the effect of joint bidding can again be procompetitive.

d. The record shows some tendency toward concentrating winning OCS bids in relatively few hands; however, the extent of concentration also appears to be declining over time. For the nineteen oil and gas OCS lease sales which took place from 1954 through 1966, the eight largest buyers, sale by sale, purchased 85.5 per cent of the tracts. In the fourteen sales from 1967 to 28 March 1974, the percentage of total tracts purchased by the eight largest buyers declined to 62.0.[6]

Using the 184 leases issued in the 1954 and 1955 Louisiana oil and gas lease sales, a multiple regression analysis tested the proposition that firm size was positively related to the high bid by tract as the dependent variable. If large firms are able to outbid smaller firms, then one would expect a positive relationship. The regression analysis revealed no significant relationship between size class of firm (the eight big firms versus all others) and the amount of the winning bid. The same regression equation revealed that the high bid was also independent of whether firms bid jointly or solo. Further, the most significant independent variable related to high bid was number of bidders; the greater the number of bidders competing for any given tract, the higher will be the resulting winning bid. The total value of oil and gas production accumulated through 1967 was also positively related to the high bid. As one would expect the number of acres in the tract leased is also related to the high bid. Estimated water depth as a proxy for development cost was not significantly related to the high bid.[7]

e. Data on the average price bid per acre indicates that with the passage of time the effective high bid per acre has increased substantially. For the entire period 1954 through to 28 March 1974, the average high bid per acre amounted to $1,257.50. For the 1954-1966 period the average was

$301.71 per acre. This increased more than sevenfold to $2,219.90 per acre for the period beginning in 1967. This increase is only partially accounted for by higher crude oil prices. The average price of crude oil increased from $2.89/bbl. in the earlier period, to $3.69/bbl. in the later period. Even this increase would be offset by an unknown decrease in the probability of finding oil, and by increased costs of exploration and production.

f. Lease sales through 1 October 1964 show that of the 1,377 tracts receiving bids, seventy-eight high bid offers were rejected by the government. Subsequently, 26 of these tracts were reoffered and leases awarded. For these 26 tracts, the initial rejected high bid average amounted to $42.41 per acre. The subsequently accepted high bid on resale averaged $411.38. Thus, where bids were found to be inadequate and subsequently reoffered, competition increased bonus payments on these rejected tracts nearly tenfold.

g. The most conclusive test of the workability of cash bonus bidding based on the United States record of OCS oil and gas lease sales is in terms of the rate of return on capital earned by the successful bidders. An analysis has been made of 184 offshore Louisiana oil and gas tracts leased in 1954 and 1955. Precise data are available on bonus payments, rental payments, oil and gas royalty payments, and production of oil and gas during the period from 1954 through 1967. Cost estimates were made for exploration, well drilling and equipment, and operation. Annual cost and annual wellhead values were discounted to obtain a net internal rate of return. The calculations indicate that these early OCS leases generated a 7.5 per cent before tax rate of return to the lessees.[8] Given the fact that oil companies pay relatively low U.S. income tax rates, the after tax rate of return would be only modestly lower than the 7.5 per cent before tax rate of return. This net yield clearly does not reflect monopoly power; it shows an excessive degree of competition.

On the basis of this evidence we conclude that competitive bidding for oil and gas leases is sufficiently strong to protect the public interest inobtaining competitive values for its oil and gas resources. This conclusion is further supported by evidence presented above indicating an increase in the average number of bidders and a substantial increase in the average price bid per acre for oil and gas leases.

CONCLUSIONS

This article has examined the problems to be solved by any leasing system used to transfer publicly owned mineral resources to private firms for processing. The cash bonus bidding system has been used extensively in

the United States, particularly in the leasing of OCS mineral resources. That record has been examined in some detail. While cash bonus bidding embodies problems which have been identified, it also appears to be an economically efficient method of resource conveyance. The United States record indicates that competition has been effective, if not overly effective, in permitting the government to capture the full economic rent. In addition, bonus bidding avoids a major problem of a popular alternative, that of royalty bidding. It appears to be far superior to a negotiated approach in solving the three critical problems of resource leasing: selecting the operator, determining a fair market value, and creating a climate for efficient mineral resource recovery.

Notes

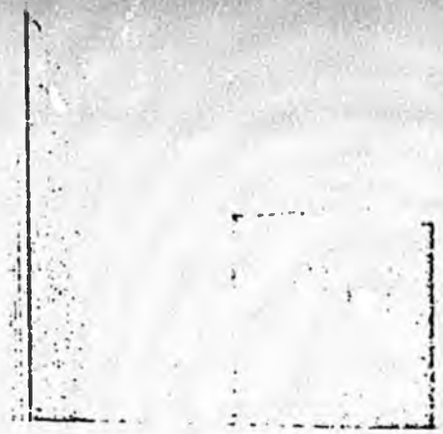
1. W. J. Mead and T.E. Hamilton, *Competition for Federal Timber in the Pacific Northwest—An Analysis of Forest Service and Bureau of Land Management Timber Sales* (U.S.D.A., Forest Service Research Paper PNW-64, 1968), p. 4.
2. For a more thorough discussion of the economic issues involved in oral auctions and sealed bidding, see W.J. Mead, "Natural Resource Disposal Policy-Oral Auctions versus Sealed Bids," *Natural Resources Journal* 7 (April 1967): 194-224.
3. U.S. Department of the Interior, Geological Survey, *Outer Continental Shelf Statistics* (June 1973), p. 43.
4. For a more thorough discussion of this point, see W.J. Mead, Testimony Presented before the United States Senate, Committee on Interior and Insular Affairs, Hearings 7 May 1974.
5. The data presented above from the OCS bidding record are from Susan M. Wilcox, "Entry and Joint Venture Bidding in the Offshore Petroleum Industry," (Ph.D. diss., University of California, Santa Barbara, 1975), p. 66.
6. Ibid.
7. The multiple regression equation is as follows:

$$Y = -9.5809 - \underset{(0.1513)}{0.2279X_1} + \underset{(0.0111)}{0.0229X_2} + \underset{(0.1701)}{0.1383X_3} + \underset{(0.0544)}{0.1235X_4} + \underset{(0.0253)}{0.408X_5} + \underset{(0.0235)}{0.0357X_6}$$

where Y is the high bid and the unit of measure is $100,000, X_1 is the size class of the high bidder coded as 10 for instances where the high bidder is one of the big firms and as zero for all other firms, X_2 is the total value of all oil and gas production accumulated up to the end of 1967 and the unit of measure is $100,000, X_3 is the corporate structure of the high bidder coded as 10 for a joint venture and zero for a single firms, X_4 is the number of acres with a unit of measure in 100 acres, X_5 is the number of bidders per sale multiplied by 10, and X_6 is the estimated water depth. This equation accounts for 62 per cent of the total

variability in the high bonus bid. The standard error of estimate is shown in parentheses: see Nossaman-Waters, *Study of the Outer Continental Shelf Lands of the United States*, vol. 1(1968), p. 553.

8. Ibid., p. 56.



The Role of Public Enterprise

ARLON R. TUSSING

My remarks are, firstly, about the role of governmental enterprise generally and, secondly, about some of the considerations involved in using governmental enterprise to foster greater control by the citizens of Canada and British Columbia over their own mineral industries. My view is that governmental ownership of producing operations is not generally the most effective way of accomplishing the social ends for which it is currently being advocated in these industries. Nevertheless, I have a few suggestions how some of the major disadvantages of public enterprise with respect to efficiency and responsibility might be overcome.

Government owned enterprises in the English-speaking countries have seldom owed their existence to an anticapitalist ideology. It is, in fact, hard to detect any systematic difference in motive, organization, or operation between the national, state and provincial, or municipal enterprises established during the incumbency of labour, socialist, and agrarian radical parties and those implemented by Tories of various names and complexions.

Despite the vast amount of existing governmental enterprise today in capitalist countries, and despite the importance of socialist movements and socialist thought in the history of modern civilization, the scholarly literature on public enterprise is remarkably skimpy. Rigorous comparisons —theoretical or empirical—of the economic performance of governmental and private enterprises in the same industry are, to the extent I can determine, nonexistent.

GOVERNMENT OWNERSHIP

The case for government ownership of undeveloped land and natural resource stocks rests on a broader base than that for government ownership of producing enterprises. The intrinsic value of any resource in its natural state is the difference between the value of goods that can be produced from it and the cost (in terms of labour, capital, materials, and organization) required to produce those goods. The size of this residual is not the product

of any person's labour or enterprise; most of the economic value of an *in situ* resource and its appreciation over time result from such diffuse causes as the increase in population, the general advance of technology, the decline in real transport costs, or directly from governmental outlays on roads or geological mapping. On these grounds, it has become almost an axiom of distributive justice (however commonly violated) that the intrinsic value of natural resources should not be privately appropriated.

Other classical grounds for government ownership of natural resources are the desire to control external costs or capture external benefits of their exploitation, and the expected divergence of private capital costs from the social rate of time preference, which is said to result in too rapid (or too slow) development of the resource. I am skeptical about the universal applicability of the last of these arguments; who, indeed, knows what society's true discount rate should be, and why are politicians and civil servants expected to be more sensitive to it than to entrepreneurs? This reservation notwithstanding, I believe that a presumption in favour of government ownership of undeveloped land and resources is generally justified.

Turning to productive enterprise, however, there are three main economic rationales for government ownership in a capitalist society. First is the use of the state to establish or maintain productive activity that would not be profitable as private enterprise, but whose external benefits are deemed to justify a subsidy out of the public exchequer. A subsidy does not, of course, require state ownership, because either private or governmental enterprise could enjoy that subsidy. In either case, support could take the direct form of providing capital or operating expenses from the Treasury or the indirect form of tax exemptions and the use of public resources at less than their cost of fair market value. State ownership, however, may well make a subsidy more palatable to the public, because it does not conspicuously enrich (or appear to enrich) a few private entrepreneurs.

Within the category of public ownership as a vehicle for subsidization are the numerous instances of private enterprise socialized because of chronic insolvency or imminent liquidation, including the Canadian National Railways, most of the British Labour Party's nationalizations after World War II, and the recent takeover of rail passenger transportation by the United States government.

In other cases, the motive for government ownership has been the creation of "public goods," products (or by products) of an enterprise whose value a private owner could not expect to recover by market pricing. Examples of such externalities are flood control by hydropower projects and the promotion of literacy and national unification by the postal system.

Military necessity has been another justification for producing goods in state enterprises which might not meet the test of the private market.

Nineteenth-century America had government lead mines and arsenals and plantations for naval stores; the processing of nuclear fuels now remains a governmental activity on security grounds. Many public transportation and communications ventures were begun as defence projects in Alaska, the Yukon, and British Columbia: examples are the ALCAN highway and the White Alice communications system.

Second among the rationales for public enterprise is the perceived inability of private business, because of the great size or risk of the venture in question, to assemble sufficient capital. This tradition in North America began with state ventures in canal and rail development in the early nineteenth century, then extended to river control and irrigation projects, and continues into the present in enterprises like COMSAT and Panarctic Oils. In many of these cases, the proposed activity was expected to be self-sufficient in the long run, on the basis of the revenues from its product or service, but state initiative was seen as necessary to take advantage of scale economies or to overcome high risk threshholds.

The third circumstance seen to justify government ownership is possession by an enterprise of monopoly power and/or exceptionally rich natural resources, either of which can produce substantial "unearned profits" or rents. Government ownership is one means either of preventing monopoly exploitation of consumers (or monopsony exploitation of workers and sellers) or of collecting for the public treasury monopoly profits or resource rents that would otherwise be captured by the private owners.

Government takeover of profitable businesses has been rare in the English-speaking world. There have been a few instances of ideologically motivated nationalization, but it is instructive to note that these have often been reversed, as in the cases of the iron and steel industry in Britain and, more recently, the grain trade in India. The remaining cases have principally been those of utilities—grain elevators, street railways, water, electrical or telephone systems—which had a monopoly ("natural" or otherwise) in a local service area. In the last category it is often hard to distinguish between the instances where government took over to prevent private exploitation of monopoly power and those in which government saw a monopoly as an opportunity to exploit an assured source of revenue for itself.

There are, of course, a variety of cases which overlap two or all three of these categories. Economic development of a poor or sparsely settled region is often advanced as a justification for public enterprise in transport, communications, or electrical power. In these instances the premise is often that the region lacks capital or capital markets and only the state can mobilize resources on the desired scale. At the same time, the project is seen to encourage growth by its ability to widen markets or otherwise cut costs for commodity producing sectors of the regional economy. Once estab-

lished, moreover, such an enterprise may have a monopoly status, with the power to abuse or exploit that status, and seem thereby to demand public control or ownership.

Many governmental enterprises (and regulated utilities, which they resemble in important respects) combine subsidies for some activities with appropriation of monopoly rents or resource rents from others. A common practice in both regulated private firms and government enterprise in transportation, communications, and utilities is *cross-subsidization*, in which monopoly profits earned from one area, line of business, or class of customers are dissipated in subsidizing others that are deemed to be socially meritorious. Thus, airline and railroad tariffs on heavily travelled route segments typically exceed cost (including a "fair" return), while service on lower density segments is provided at a loss. Hydroprojects in the Western United States typically subsidize users of irrigation water from revenues earned by water sales to municipalities and industry and by sales of electric power. In Alaska, revenues from both state and federal timber sales are sacrificed to support otherwise uneconomic lumber and pulp mills.

Turning to the mineral industries of Western Canada, there is little evidence that suggests they need to be subsidized by formation of a public corporation or otherwise. The province of British Columbia does not have, for example, a great but decaying industry upon which the community depends both for energy and employment, as the British had in the coal mines of the 1940's.

The British Columbia-Yukon Chamber of Mines may occasionally assert that each mining job generates seven additional jobs in supporting industries, but there is no respectable analytical foundation for such a claim. Even if the extractive industries had such an employment multiplier, it does not necessarily follow that job creation *per se* is a benefit that deserves subsidization from the public purse, much less the creation of a government enterprise. New employment opportunities are a *net* benefit to the existing community only to the extent that they are filled by residents who would otherwise be unemployed or working at more poorly paid jobs. In an "open economy" like that of British Columbia or Alaska, there is no predictable relationship between local job creation and local unemployment, because new employment opportunity attracts immigrants who tend to offset the employment gain. Even if the new jobs directly created were reserved for long-time residents, displacement of residents from old to new jobs and their replacement by nonresidents can be expected to make overall unemployment rates relatively unresponsive to employment growth.[1]

National self-sufficiency in minerals and the earning or retention of foreign exchange are sometimes claimed as external benefits of mining that justify preferential treatment. In Canada, paradoxically, some of those

(including the National Energy Board) who place the highest priority on national self-sufficiency in one or another mineral resource tend to advance policies that *deter* investment, on the grounds that the beneficiary of current development tends to be the export market, at the cost of future diminished Canadian self-reliance. In this country, moreover, balance of payment effects are often used as part of a case *against* mineral development for export rather than in favour of it. In a world of floating exchange rates, however, one might question whether there is any relevance at all to the balance of payments problem in its usual sense. Finally, the impacts upon environmental quality and the dispersion of population are more likely to be regarded as external *costs* of mining than as *benefits* that justify the government's promotion of mining ventures that otherwise would not be self-supporting.

It is hard to make a respectable case that mining (including oil and gas production) creates beneficial *externalities* for the surrounding community, as distinct from the net value of the minerals produced, or the factor payments (wages, profit, rents, and taxes) which make up that value. The current Canadian interest in state enterprise in the mineral industries does not seem, in summary, to be a result of the belief that they are inevitably unprofitable under private enterprise. On the contrary, it rests in part upon the notion that mineral extraction can indeed be very profitable, and that unearned profits (rents) ought to be controlled and disbursed in socially approved ways. This attitude is sometimes experienced as a concern whether the people of the nation or of the province, who are the nominal owners of its natural resources, are receiving as high a return for the products of their land as they might. One issue is, in short, whether the state is effectively maximizing its revenues from disposal of minerals.

Where effective capital markets exist together with a large enough number of potential operators to create workable competition for resource rights, the government (as landlord and/or sovereign) is more likely to maximize its revenues if it does *not* engage in production. This conclusion does not presume that particular government owned entities are necessarily less enterprising and less effective in cost control than profit motivated private corporations. There may well be a bias against efficiency in most forms of state enterprise, if only because their owners (the public) and managers do not have a clearly defined standard of performance as private managers have in the imperative to maximize the present worth of their firms. But more importantly, by operating a productive enterprise in the extractive industries, the government loses the ability it would otherwise have as landowner to exploit the competition among potential private operators.

At oil and gas lease auctions in the United States, for example, the bid prices on a single tract may vary by a factor of two, ten, or even one

hundred. These variations reflect widely differing geological evaluations of the tract, exploration strategies, and capital and other costs. Thus each tract tends to be won by the bidder with the *most favourable combination of capital cost and expectations* among all the bidders regarding future product prices, the particular tract's recoverable reserves, and their development and lifting costs. The landlord (state or private) who operates on his own land, however, would have only one management team, one exploration strategy, one team of geologists and engineers, and one supply function for capital. Only by rare accident would the landlord's *actual* performance over the average of all his properties tend to be better than the *expectations* of the most optimistic bidder. If, therefore, he were to lease each tract to the highest bidder among the competing operators, he might anticipate receiving a greater net revenue on each property than he could expect from developing the property himself.

The foregoing prediction is implicitly supported by empirical studies of United States Outer Continental Shelf leasing by Walter Mead and others, who show that successful bidders on the average earn a discounted cash flow rate of return on lease acquisition costs substantially less than the oil industry's average rate of return on capital (see Mead's article, "Cash Bonus Bidding for Mineral Resources," contained in this volume).

The effective use of competition to optimize revenues does not dictate the use of a cash bonus bidding system for *all* minerals or even for petroleum under every circumstance. The degree of knowledge or uncertainty regarding the volume and value of minerals present and their cost of extraction, the relative weight of fixed and variable costs in total extraction costs, the number of potential competitors, and the relative preferences of the government and private operators for certain present income versus uncertain future income are all appropriate considerations in the choice of leasing or disposal systems and taxes on the mineral industries. These questions have been discussed elsewhere,[1] and other articles in this volume give close attention to the relative merits of location, leasing, and sale as systems for disposing of minerals; to royalties and severance taxes, and whether they should be reckoned on gross value or net profits; to bidding on cash bonuses, deferred bonuses, gross or net royalty rates; to the use of acreage rentals; to the optimum size and configuration of tracts; to the amount of geological information the landlord ought to obtain and publish before opening land for lease or disposal; and to the duration of the primary term of a lease or permit, its terms for renewal, and so on.

In summary, state enterprise in the business of developing and producing minerals is surely *one* way to capture and redistribute resource rents, but it is unlikely to be as effective a device for maximizing those rents as the combination of a leasing system that takes full advantage of competition

among private firms (considering the technology and institutional characteristics of each branch of the mining industry) and an appropriate tax system.

The most powerful cases for public enterprise in developing regions (like much of Western Canada and the Territories) relate to transport facilities which create external economies for other economic sectors, including mining. In these instances, both the first motive for socialization (the desire to subsidize) and the second (the need to overcome barriers of scale and risk) may justify investment by the government on projects into which private enterprise will not venture. Neither of these motives, however, creates a case for state enterprise in mineral extraction. Capital and enterprise for mineral exploration and development are plentiful and mobile. Specialized technical inputs, such as geophysical surveys, drilling, and heavy construction can be purchased on contract in a highly competitive market (so that great petroleum and mining companies carry out very few of these activities themselves). Capital sums in the hundreds of millions, or even billions of dollars can be mobilized privately, even without government guarantees, for projects like the Trans-Alaska pipeline, in remote regions.

Development of minerals, like the collection of revenues from their development, is likely to be more rapid and more efficient if it utilizes the diversity of skills, techniques, enterprise, and access to capital in the private economy and the competition between firms differently endowed in these respects. Nationalization or municipalization of producing operations, in my view, has an inevitable price—both in state revenues and in social efficiency—the payment of which must be justified on other grounds.

The hard core of Canadian interest in public enterprise today seems to stem not from a perceived shortage of capital and entrepreneurship (much less an ideological opposition to capitalistic enterprise as such), but from a perceived surplus of foreign capital and entrepreneurship. The problem, it seems, is to assure that mineral development (and, presumptively, related activities like oil refining or oil and gas transportation) are under the control of Canadians or the people of British Columbia, rather than great multinational (read United States) corporations.

It is probably not politic of me as an American to ask what practical difference the nationality of a company's owners or management makes as long as it is subject to the same laws (and obeys them) and pays its proper share of taxes. Foreign companies in Canada have often been berated for not paying enough taxes, but it was after all a *Canadian* decision, reflecting a long-standing Canadian developmental philosophy that the extractive industries should remain largely untaxed. The satisfactions and grievances of Americans regarding the major oil companies apply in the same way to

Mobil and Texaco, which are domestically controlled, as they do to Shell and Sohio, which are foreign controlled. I am afraid I don't see how any more in the way of real resources for Canadians could be squeezed from a government owned business than could be squeezed from American or Canadian owned private enterprise under a well designed leasing and tax system. Nevertheless, one billion American dollars invested in Canada is more conspicuous than one billion Canadian dollars invested in the United States, and the nationality of your managers and stockholders obviously does make a difference to many Canadians. (I must confess, also, that some Americans become hysterical about the very idea of the Arabs or Persians taking over United States businesses.)

Government enterprise is one way to "nationalize" the mineral industries, but it is not, of course, the *only* possible way to foster Canadian equity and enterprise. Stricter nationality criteria could well be applied to holders of claims and leases or of permits to build pipelines, concentrating plants, and refineries. Such policies raise the further question, however, whether there is in fact enough private equity capital and enterprise in Canada to effectively take the place of foreign equity and enterprise. This is an empirical question to which I do not have an answer. If the answer is negative, consideration must be given to the fact that establishing a government enterprise does not *create* any new Canadian resources. It only uses tax money or potential resource revenues to bid capital and talent away from some other employment in Canada. The cost of Canadianization (either by restrictive licensing of private industry or by government enterprise) may be minimal, however, if preferences for nationals result in bidding home significant amounts of Canadian capital and Canadian talent which would otherwise be employed in other countries. (Presumably, the net effects of even these moves would have to take into consideration remittances that would otherwise flow back to Canada from investments abroad.)

Government capital need not be regarded strictly as a *substitute* for private capital, Canadian or foreign. In North America during the first half of the nineteenth century, and in almost every country at one time or another, state companies were used as a vehicle to *attract* foreign debt or equity capital, usually British, to ventures they would not otherwise consider. A government owned (or guaranteed) railroad company was often naively regarded by Lombard Street as a safe investment, while the promotions of unknown overseas entrepreneurs were viewed with little regard in the world's principal money market.

The use of government participation is still a major instrument for encouraging foreign investment in developing areas. Joint ventures between American, European, or Japanese private companies and governmental entities of the host country are common in almost all the extractive

industries and in many countries at different levels of economic development. Canada has at least one government enterprise created largely with this function in mind, Quebec's SOQUEM, whose activity consists mainly of joint ventures in mineral exploration with private companies. Petro Canada also *seems* to be interested in this kind of approach.

In addition to being a means by which domestic enterprise becomes a trustworthy borrower (or partner) of foreign capital, state enterprise can also be a means of offsetting a shortage of domestic equity and entrepreneurship. In this role, it has one advantage over promotion of domestic private enterprise through nationality restrictions on investment, management or licences: it avoids the spectre of open discrimination, which could lead to retaliation and might otherwise undermine trade and investment relationships that are beneficial to Canada. The nearly open border allows this country to draw on a much larger pool of capital, technology, and talent than it would with policies fostering autarky. Although this openness is a major element in the ambiguity and insecurity of Canada's national identity, its economic benefits to Canada are relatively greater than they are to the United States. (That is, its impact on the size of the resource pool available to Canada is greater than on the size of the pool available to the United States.) It is therefore a circumstance to be modified only carefully and selectively. Establishing a provincial oil company is one way of containing the side effects of a move in the direction of autarky in a single industry. Such a move might, in fact, limit these side effects even in the industry in question. Suppose the best candidate for executive officer for a British Columbia based oil company were a Texan; there might well be fewer misgivings about hiring him to work for the province than about his heading a subsidiary of an American private firm.

I will conclude this article with some suggestions for the structure and policy of public corporations in the mineral industry, suggestions aimed at combining some of the best features of government and private enterprise, rather than their worst.

First, before establishing a governmental enterprise, be clear what its purpose is to be, what the incentive for the management to accomplish that purpose will be, and, quite rigorously, what will be the measure of the enterprise's success. (I owe this first and most vital point to Milton Moore's critique of the draft of this article.)

Second, do not set up a monopoly. There is no surer formula for inefficiency and social irresponsibility. Economies of scale do exist in mining and petroleum exploration, but they are very small when compared to some other industries or relative to the opportunities for development in an area the size of British Columbia. In petroleum refining, the minimum efficient size of a refinery is probably about the size of the British Columbia

market for petroleum products, but if a new government owned refinery needs a monopoly or protectionist legislation to be profitable, it will almost certainly be a serious burden on consumers. Industries in which scale economies are narrow and where ingenuity and intuition are still crucial, as in mineral exploration or onshore oil and gas production, are probably not the most appropriate candidates for nationalization; but where it is determined to establish a state enterprise, consideration might be given to the establishment of more than one competing public enterprise.

Third, do not clothe the corporation in sovereign immunities. Such immunity can be, and often is, a cover for inefficiency, irresponsibility, and even lawlessness. The corporation should be suable; it should pay taxes or their equivalent (federal, provincial, and local); and it should be subject to environmental and safety laws and regulations and, above all, subject to the bankruptcy laws. Its operations should not be protected by any version of an official secrets act. There is no good reason why the directors, officers, and employees should be excused from the same civil and criminal liability for their actions to which their counterparts in private enterprise are subject.

I would urge hesitation even in providing guarantees for the corporation's debt. A public mining or oil corporation will be pursuing a line of business in which private enterprise regularly borrows money without such guarantees. The more intense scrutiny of bankers and underwriters toward a corporation whose debt must stand on its own merit might well save the corporation's owners—the public—more money than the small interest differential associated with government guarantees.

Fourth, give the public and the corporation's officers and staff a material interest in its success and its efficiency. The government need not hold all the shares but only a controlling interest, not necessarily even a majority. One block of shares (enough to elect at least one director) can be held in trust for the company's employees and voted by them. The remainder of the shares would be offered to the public; they would be voted by their owners and publicly traded. Not only would this provision broaden interest and participation in management, but the market price of publicly traded shares would be a continuing indicator of management performance and of the value of the government's equity. I see no compelling reason to restrict share ownership to residents; it might in fact be useful to encourage minority participation by major oil companies or mining companies. A residence requirement for shareholders, however, would reinforce symbolically the corporation's identity as a national or provincial instrument, and would, of course, limit remittance of dividends abroad.

Fifth, the corporation's policies should be responsive to public policy but not bend to every political wind. I would suggest that only a minority of the

government directors serve at the pleasure of the Cabinet and be regarded as spokesmen for its policies. The remaining directors representing the government's equity would be chosen indirectly for long and staggered terms.

Sixth, the corporation should be under pressure to pay dividends. A majority of the shares (and directors) should represent parties who have a material interest that the corporation *not* retain, reinvest, or dissipate all its earnings: private shareholders, the employees, and the members who serve at the pleasure of the Cabinet (who would presumably be responsive to the fiscal interest of the government). The influence of this group will be a constant corrective to tendencies of management, inside directors, and permanent directors toward complacency, empire building, pyramid building, or gold plating.

Seventh, maintain a clear distinction between the corporation and the government as landowner. The public enterprise should obtain resource rights on crown lands only in competition with other prospective operators. The corporation should not receive a concealed (and indeterminate) subsidy by access to resources at no charge or at a lower price than a competitor might offer. If it must have a preferent right, let it be at most a right to match the highest bidder.

A preferent right on the best offshore leases is a feature of the federal oil and gas corporation (FOGCO), proposed recently in the United States Congress. In view of the prices oil companies have been recently willing to spend in these lease sales, such a preference would guarantee that FOGCO would appear profitable, however incompetent its management, and that the federal treasury would lose billions of dollars in lease revenues.

Eighth, take advantage of the division of labour and competition. The corporation should not attempt to do for itself the things that even the greatest oil and mining companies contract out to others, such as seismic surveying, core drilling, well drilling, well logging, and construction. There is virtually no chance that a state corporation could improve on the performance of private firms in these exceedingly competitive areas.

In summary, I am generally skeptical of the case for public enterprise in the minerals industry but hopeful that such enterprises could be established free of many of their usual shortcomings, providing some thought is given to their purpose, organization, and standards of performance.

Notes

1. In a study aimed at projecting the employment impact of the Trans-Alaska pipeline, we found that *unemployment* in individual labour market areas was almost totally insensitive to the level of *employment*; that is, on a *net* basis, at least, new jobs in Alaska's petroleum and wood products industries and government were entirely filled by immigrants. [Arlon R. Tussing; George W. Rogers; and Victor Fischer; with Richard Norgaard, and Gregg Erickson, *The Alaska Pipeline Report: Alaska's Economy and Gas Industry Development and Impact of Building and Operating the Trans-Alaska Pipeline*, Institute of Social, Economic and Government Research Report no. 31 (Fairbanks: University of Alaska, 1971)].
2. Arlon R. Tussing and Gregg K. Erickson, *Mining and Public Policy in Alaska* (Fairbanks: Institute of Social, Economic and Government Research, University of Alaska, 1969).

EXPERIMENTATION IN ALASKA'S OIL AND GAS LEASING PROGRAM

AN ANALYSIS OF LEASING POLICY ISSUES RAISED IN H.B. 854

Sohio Petroleum Company
Division of Sohio Natural Resources Company
SOHIO-BP ALASKA PRODUCTION DIVISION
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EXPERIMENTATION IN ALASKA'S OIL AND GAS LEASING PROGRAM

-An Analysis of Leasing Policy Issues Raised in H.B. 854-

ATTACHMENTS

1. Suggested Amendments to H.B. 854.

2. M.I.T. Professor John W. Devanney III, "How to Bid for Offshore Rights," Technology Review, February 1976, p. 44.

3. "Alberta, Canada: Exploratory Drilling Incentive System," The Landman, March 1978, pp. 18-20.

4. Articles from Mineral Leasing as an Instrument of Public Policy, British Columbia Institute for Economic Policy Analysis, 1977:

   - Gregg K. Erickson, "Work Commitment Bidding"

   - Dale R. Jordan, "Petroleum Leasing in British Columbia"

   - Walter J. Mead, "Cash Bonus Bidding for Mineral Resources"

   - Arlon R. Tussing, "The Role of Public Enterprise"

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March 28, 1978

Rep. Al Osterback
Chairman
House Natural Resources Committee
Alaska State House of Representatives
Juneau, Alaska

Dear Rep. Osterback:

When I testified before your committee two weeks ago on H.B. 854, I indicated then that Sohio Petroleum Company would be willing to submit additional information in written form to the committee, in further consideration of changes in Alaska's oil and gas leasing policies.

In this regard, attached is a memorandum, "Experimentation in Alaska's Oil and Gas Leasing Program: An Analysis of Leasing Policy Issues Raised in H.B. 854," prepared by our staff in Anchorage. An addendum presents suggestions for new language in certain sections of H.B. 854 that in our opinion would improve the bill from the State's standpoint as well as that of industry's. We hope you will consider our suggestions as constructive, if critical.

In general, we feel that H.B. 854 as it is now written would create a bias in the State's leasing system toward experimentation with procedures that are unusual and new in Alaska. Our suggested language changes would essentially create a bill that would give the Commissioner of Natural Resources the flexibility that he desires, but with a bias instead toward relying on well-known and proven leasing systems, unless special circumstances would call for the use of an alternative bidding system.

We are also concerned over the extent to which the Administration, in proposing H.B. 854, has simply tracked many concepts (and copied specific language in many cases) from OCS bills now in Congress, without an apparent close examination as to whether these specific provisions proposed for federal OCS sales are really appropriate for the State of Alaska.

We hope you will find this information useful in your consideration of H.B. 854.

With regards,

D.S. Mace
Assistant General Manager

PART I: AT THE CROSSROADS

I. THE IMPORTANCE OF OIL AND GAS POLICY DECISIONS

A. Global Prospects

The Workshop on Alternative Energy Strategies (WAES), a two-year international energy and economic project, directed by the Massachusetts Institute of Technology, recently released their final report which indicated that:

(1) All energy resources and conservation measures must be developed vigorously to meet total projected demand in the period 1985 - 2000; and

(2) Energy policy decisions made now will be the critical determinants as to whether or not sufficient incremental supplies will be available to meet demand in the years ahead.

In other words; according to the WAES Report:

> The years up to 1985 are critical ones...We are...on the threshhold of a critical decision period. We cannot afford to waste the years immediately ahead if we are to have any large-scale energy options available before the end of the century. The time for decisive action is now. 1/

In this environment, the importance of H.B. 854, the Administration's proposed oil and gas leasing bill, cannot and must not be underestimated, as Alaska's oil and gas resources can and will play an important role in determining the future global energy, economic and political balance. The critical nature of energy decision-making at this time is further underscored by the following conclusions stated in the WAES Report:

1/ ENERGY:GLOBAL PROSPECTS, 1985-2000, Report of the Workshop on Alternative Energy Strategies, M.I.T. Professor Carroll L. Wilson, Project Director McGraw-Hill Book Company, San Francisco, 1977.

(1) The supply of oil will fail to meet increasing demand before the year 2000, most probably between 1985 and 1995...(p.3)

(2) Demand for energy will continue to grow even if governments adopt vigorous policies to conserve energy...(p. 4)

(3) The continued growth of energy demand requires that energy resources be developed with the utmost vigor...(p.4)

(4) Even if there are no governmental constraints on oil production, oil supply will meet demand only under the most optimistic assumptions about gross additions to reserves...(p.145)

(5) Possible constraints on oil production by members of OPEC are likely to cause oil supply to peak at the latest some-time around 1990 although lower production limits could bring this date forward into the early 1980's...(p.145)

(6) All the effort put into oil exploration around the world over the past one hundred years has only yielded 240 large oil fields...(p.123)

(7) With only a small chance of either discovering a new Middle East or discoveries in the Middle East as large as in the past, the past rate of genuine new discoveries can only be achieved if a large number of smaller producing areas are found. (p.122)

(8) Given lead times of 5-10 years or more for many projects, failure to make necessary near-term commitments or to resolve a variety of current restraints on production, or to develop future supplies may foreclose some options for 1985. (p.265)

(9) Failure to recognize the importance and validity of these findings and to take appropriate and timely action will almost certainly result in a world different from the one on which these projections have been based. (p.5)

(10) Failure to act could lead to substantially higher energy prices as the supply/demand imbalance becomes more apparent with the consequent frustration of the aspirations of the less developed countries. The major political and social difficulties that might arise could cause energy to become a focus for confrontation and conflict. (p.5)

(11) The longer the world delays facing this issue the more serious the outcome will be. Even with prompt action the margin between success and failure in the 1985-2000 period is slim. Time has become one of the most precious of our resources. (p.5) 2/ (Emphasis added)

2/ Ibid., pages as indicated above.

Another important point in the Report relates to the size of future oil fields. Worldwide, over 30,000 oil fields have been discovered, but about 75 percent of the oil lies within 240 large fields, each with over 500 million barrels of recoverable reserves. 3/

Out of the tens of thousands of producing oil fields in North America, there are only five fields that have recoverable reserves of more than 500 million barrels (Prudhoe Bay, which is new; and Elk Hills and Wilmington in California, and East Texas and Yates in Texas, all of which are old fields). Despite a great deal of exploration in North America, there has been no recent discoveries of fields more than 500 million barrels, except Prudhoe Bay. In other words, the probabilities of finding large new fields on the order of Prudhoe Bay has significantly diminished, not only globally, but also in the United States.

The WAES Report also makes clear that in certain environments, such as the North Sea, a 500 million barrel field is at the economic margin. 4/ Because of the particularly harsh environment in Alaska's North Slope, and elsewhere in the unexplored part of the State, a field that may contain even more than 500 million barrels of oil could be right on the edge of economic viability in Alaska, given the uniquely high costs and transportation difficulties.

While all of the above has critical implications both for the United States and Alaska, there are yet another set of reasons why we believe that the designing of the future oil and gas leasing program in Alaska deserves serious and careful consideration.

3/ Ibid., p.123

4/ Ibid.

B. Alaskan Outlook

In a sense, the State of Alaska is facing on a smaller scale some of the same problems described earlier on a global scale. Whereas world oil production may begin to decline in about seven years, so also will Prudhoe Bay. This fact has important implications to all Alaskans and, in view of the revenue needs of the State, it would appear to be in the State's interest to encourage a steady, ongoing oil and gas development program in parts of the State with petroleum potential. But the historic rate of genuine new discoveries can only be achieved worldwide if a large number of small producing areas are found. Likewise the future of petroleum discoveries in Alaska will most probably involve smaller fields which will be more costly to develop.

Actually, the possibility of finding another Prudhoe Bay-sized field in Alaska is extremely remote. Further, because of the very high costs of operating in much of Alaska, the size of a discovery must be larger in Alaska than it would in other states to make the project economic. Even the Lisburne and Kuparuk oil pools, which according to State estimates range in potential from one to two billion barrels, are marginally economic and may be typical, in terms of economics, of many future oil and/or gas finds in Alaska. All this tends to suggest that Alaska is special and needs to pay closer attention to the development of her resource policy than a State like Louisiana, for example.

Some have argued that Alaska might be better off 'sitting on' her potential oil and gas resources and waiting for the world oil price to rise even further. Dr. Arlon Tussing, an Alaskan economist and advisor to the Senate Energy Committee, considers this attitude, "simplistic" and "naive."

In real terms, world oil prices may stabilize as a result of a prolonged period of relatively low economic growth which would result in lower growth rates for energy consumption than is generally projected. Additionally, as global attention is increasingly focused on energy, the drive to conserve energy and to develop heavier oils, such as Athabascan tar sands, Rocky Mountain oil shale and Orinoco tar belt; and substitutes for conventional oil and gas will increase. Again, to quote Dr. Tussing, "if you choose to 'sit on' your oil and the decision was wrong, the resultant imbalances could be serious."

A final serious consideration for Alaska relates to a realistic assessment of the growth of State spending. While this subject cannot be addressed in the analysis, there is reason to believe that Alaska's revenue needs in future years requires continuous exploration and development of her oil and gas resources so that new revenues will be coming in as Prudhoe Bay starts to decline. This is especially true when one considers the long lead times involved in exploration and production in the frontier areas of Alaska, where a decade may be needed to find, prove up and begin to develop a field, and where transportation problems can be enormously complex.

C. Implications

Being at the economic/energy crossroads globally -- and in Alaska -- would seem to suggest that it is of critcal importance to the State to (1) carefully delineate its goals with respect to a new oil and gas leasing bill and (2) ensure that the proposed legislation, in its implementation, will achieve the desired goals outlined in the legislation. With this in mind, it would appear appropriate both to review the goals outlined for H.B. 854 and to analyze some of the broad issues raised by the draft legislation.

II. OBJECTIVES FOR ALASKA'S OIL AND GAS LEASING PROGRAM

> "As a prerequisite to a discussion of mineral leasing alternatives there should be a clear statement of the goal (s) to be achieved." 5/

A. Objectives Outlined for H.B. 854

To analyze the objectives outlined for H.B. 854, there are two relevant source documents: the Governor's letter of transmittal and the language contained in the "findings" section of H.B. 854. Both contain ambiguities and sources of conflict that deserve serious attention.

This is important in that the goals and objectives outlined in the legislation reflect the intent of the Legislature, in offering guidance to the Commissioner of Natural Resources.

As described in the bill [Sec. 38.05.180(a)(1)(A-D)] the State's goals are to:

(A) maximize the economic recovery of these natural reosurces in protection of the public interest;

(B) minimize the exploitation of these natural resources in protection of the public interest;

(C) maximize competition among parties seeking to explore and develop the resources;

(D) maximize use of Alaska's human resources;

While (D) is clearly in the State's interest, (B) appears to be in direct conflict with (A) and, in and of itself, could certainly be interpreted to mean more than one thing, e.g., 'sit on' the oil until later or 'protect the environment' or 'don't develop at all,' depending on one's definition of the "the public interest." One might also raise the question as to

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5/ Walter J. Mead, "Cash Bonus Bidding for Mineral Resources," Mineral Leasing as an Instrument of Public Policy, ed. M. Crommelin and A. Thompson, British Columbia Institute for Economic Policy Analysis Series, 1977, p.46

whether (C) could conflict with (A) or is even a necessary goal for the State of Alaska's leasing program or whether the goal to "maximize competition" means having more companies bidding or more competition among current bidders. In short, while goals (A) and (D) appear well-defined, there are important questions that could be raised with respect to the other goals as stated.

If one looks to the Governor's letter of transmittal for guidance on the matter, one becomes more confused. Some of what is presented as broad goals are in fact provisions of the bill related to goals which may in actuality work against the achievement of the overall broad objectives. What appear to be the three major goals of the legislation are presented in paragraph 3 of the Governor's February 17 letter of transmittal on H.B 854:

> "The proposed changes will update the leasing law to provide increased public control over exploration, development, and production from state land, obtain a fair return from our non-renewable resources, and, at the same time, provide land from which explorers may find new energy supplies."

Yet the letter lists six "important state objectives," which include items such as reducing "the length of the term of a lease from ten years to five years..." The reduction of a lease term should not be listed as an "important state objective," it would seem, in that it is not an objective but rather a provision designed to achieve the State objective of assuring "that exploration begins promptly once State land is leased." Whether or not reducing lease terms is the best means to assure prompt exploration or not is not the issue here, but rather the importance of clearly delineating goals (prompt exploration) as opposed to suggested means of implementation (reduce length of term of lease).

While clarifying what are the State's goals may seem academic, the exercise would seem worthwhile, particularly since what are described as "important State objectives" in the Governor's letter appear to conflict with the goals stated in H.B. 854. If it is a State goal in H.B. 854 to maximize competition, for example, then increasing rentals on fields may not be in the State's interest at all and should certainly not be listed as one of the "important State objectives" in the Governor's transmittal letters.

Thus, it would appear to be in the State's interest to set out more clearly, and in some order of priority, what the State is really seeking to do in this legislation. The Commissioner of Natural Resources, who would be designing the leasing program today, and future Commissioners who will be administering the program in future years, need to know what the State really intends and what is most important, given the energy and economic environment today and the future needs of Alaskans. If the Commissioner is given clear guidance by the Legislature as to the overall goals, then the State should be able to rely on the Commissioner to use his judgment and discretion in designing a program that is the best interests of the State.

In addition to the ambiguity relating to the State's most important objectives related to H.B. 854, we are also concerned that the overall legislation would actually deny the Commissioner the very object the bill's proponents suggest they are seeking to guarantee, i.e., flexibility so that the Commissioner may design a program best suited to achieving the State's broad goals. Instead of really allowing flexibility, this bill appears to put stress on the Commissioner by (1) requiring him (her) in many instances to adopt changes; and (2) setting limits on those changes;

and (3) forcing him (her) to account for why this or that was not done, for example, as opposed to merely requesting information as to why what is planned or was done is planned or was done.

Based on studies we have analyzed, we would also suggest that "maximum" experimentation in bidding at this time may not be in the State's interest any more than it is the Federal Government's interest. While we will go into this subject in some detail in Section III, we think it important to highlight here that the Alaska Legislature should be aware that, in many respects, H.B. 854 appears to copy the Federal draft legislation. A brief review of the goals related to the Federal bills would thus appear to be in order.

B. Objectives Related to Federal Legislation

It is noteworthy that the Governor's letter of transmittal states that the "proposed changes will update the leasing law to provide increased public control over exploration, development and production from State land..." (emphasis added). Many in Washington D. C. have been working for years to amend the laws affecting OCS oil and gas exploration and development so as to be able to establish a Federal oil and gas corporation (popularly known by the opponents of the concept as "FOGCO").

While we do not mean to suggest here that the drafters of H.B. 854 are aiming to establish an Alaskan State drilling corporation, we do think it pertinent for the State to analyze the goals and provisions of H.B. 854 in terms of where it would take Alaska, if enacted as presently conceived. Would the result be more exploration and development by private companies, or would the result be added complications in petroleum development and the eventual need for Alaska to establish its own "FOGCO?" We would offer two cautionary notes.

First, Dr. Arlon Tussing has pointed out that "the scholarly literature on public enterprise is remarkably skimpy. Rigorous comparisons - theoretical or empircal - of the economic performance of governmental and private enterprises in the same industry are, to the extent I can determine, nonexistent." 6/

Second, from our own limited experience of government drilling corporations, we would tend to concur with Dr. Tussing's conclusion that a State FOGCO is, as Dr. Tussing says, "unlikely to be as effective a device for maximizing [resource] rents as the combination of a leasing system that takes full advantage of competition among private firms (considering the technology and institutional characteristics of each branch of the ...industry) and an appropriate tax system." 7/

There are a host of reasons given by economists why government drilling corporations (would not) do not serve the public interest, 8/ but the point here is that certainly many companies and analysts view the Federal draft legislation - upon which Alaska's H.B. 854 appears to be patterned - as the first step towards the creation of a FOGCO, especially in that this type of legislation greatly increases the amount of uncertainty and risk related to what is already an uncertain and risky business, that of exploring for oil and gas.

6/ Arlon R. Tussing, "The Role of Public Enterprise," Mineral Leasing as an Instrument of Public Policy, British Columbia Institute for Economic Policy Analysis, 1977, p.163.

7/ Ibid., pp. 168-169

8/ See also "Natural Gas Policy Issues and Options," Prepared at the Request of Henry M. Jackson, Pursuant to R. Res. 45, A National Fuels and Energy Policy Study, Serial No. 93-20 (92-55), 1973, pp. 108-109.

C. Alaska's Leasing Objectives: Problems and Priorities

As the discussion above indicates, we see a host of problems both with the explicit and implicit objectives for H.B. 854. To summarize, we are concerned with:

(1) The Governor's Letter of Transmittal - As this letter is part of the legislative package, it will be used as a reference when, assuming H.B. 854 is passed, a future Commissioner seeks guidance in decision-making. The fact that it confuses objectives and provisions is of concern, especially where some of the provisions that are listed as "important objectives" may be counter-productive to the goals of the legislation.

(2) The Goals Listed in H.B. 854 - At least one goal (B) could be interpreted in drastically different ways, and it is unclear what goals really are most important nor how several of the goals interrelate.

(3) Implicit Goals - While the bill's supporters contend that an important purpose of H.B. 854 is to provide the Commissioner of Natural Resources with flexibility in administering the leasing program, several provisions would not only deny real flexibility but also would require justifications for non-experimentation, in effect putting political pressure on the Commissioner to experiment in bidding practices, for example, even though such experimentation may not be, in the Commissioner's judgment, in the best interests of the State of Alaska.

(4) Following the Federal Trend - We are concerned that H.B. 854, in many ways, parallels many of the provisions in the bills passed by the U. S. House and Senate. Whereas the ultimate goal (implicit or explicit) of many supporters of the Federal legislation may be the establishment of a federal drilling corporation, we would question whether or not it is in

Alaska's best interest to so closely follow the Federal lead in this area at this time...or any time. We would also caution the State, particularly about (1) the reasons why data gathering is viewed as the first step in establishing government drilling corporations; (2) the lack of hard evidence and the experimental nature of using different bidding methods; and (3) the issues related to competition and joint bidding.

To take care of the above-described problems relating to objectives, we would like to suggest some new language in the opening section of the bill (see Attachment I). We have sought, through the proposed changes, to highlight the fact that prompt exploration is an important goal which should be stated in the legislation and that this goal is inextricably related to the overall State goal of maximizing State revenue. We have sought also to provide flexibility for the Commissioner without forcing him (implicitly or explicitly) into experimentation. These and other proposed amendments are further explained in the following two sections.

III. BROAD ISSUES AND OBJECTIVES

A. Data Acquisition: How Useful?

While we understand the State's desire to know more about the potential oil and gas resources underlying State lands, we would reiterate what we and other companies have previously stated: obtaining more data from the companies does not necessarily put the State in a better position to evaluate potential resources. In fact the opposite could be true; government officials, looking at company data, might well understate the potential value of proposed lease acreage because of the general conservative nature of a government compared with, for example, the daringness of one Company geologist willing to stake a professional career on an interpretation of exploratory data. It could also be argued that the very nature of a large government agency makes it easier to hide errors of judgment whereas the company which decides to "go" on a project can hold specific employees more accountable for errors of judgment. But the most important fact to remember is that regardless of how much data the State may obtain, the State will never know what it does or does not have unless the State drills.

Since you may not wish to simply take a company's word for it, the following quotation is presented to underscore the importance of drilling as a means of obtaining useful information and to highlight the relative lack of usefulness of data without drilling. This excerpt is from the writings of an acknowledged expert in leasing policy, Professor Walter Mead, University of Southern California at Santa Barbara:

> "...while the technology for oil exploration prior to the drilling has been advanced in the last century, exploration is still subject to extemely high risk. Drilling is the only definitive test to determine the presence of oil or gas. Thus, bonus bids must be

> submitted by bidders and accepted or rejected by the government when neither the buyer nor the seller knows whether and in what quantities oil is present..." 9/ (Emphasis added)

It would seem obvious, therefore, that if the companies -- with all their data and experience -- don't know at the time of a lease sale whether they've just spent millions for the right to put millions more into drilling potentially dry holes, then the government, with the same data, could hardly be better off. And having all the data of all the companies doesn't necessarily lower the risk of error for the government in that the view supported by most of the data of most of the companies (data that might suggest that "Tract 20" is worthless, for example) could be wrong.

Because more is not necessarily better in the exploration data game, many companies do in fact view data acquisition by the government as the first step which will inevitably lead -- and naturally extend to -- the establishment of government drilling corporations. And, as previously noted, Dr. Arlon Tussing does not view "governmental ownership of producing operations" as "the most effective way of accomplishing the social ends for which it is currently being advocated..." 10/

Additionally, Dale R. Jordan details some of the more severe problems of esblishing government drilling corporations:

> "...This article's purpose is not to examine the political repercussions that might occur when dry holes are drilled with public funds; however, we should examine some of the practical considerations involved in the operation of a public company which has an almost exclusive area within which to explore as a result of discouraging the private sector. For the government to discourage both the existing explorer and the entry of any new ones and to expect the public corporation to be able to fill this void suggests that the government is saying, "if the private companies do it, so can we."

9/ Mead, op. cit., p.51.

10/ M. Crommelin and A. Thompson, "Introduction," Mineral Leasing as an Instrument of Public Policy, British Columbia Institute for Economic Policy Analysis, 1977, p.xvi.

Now remember that the private companies comprise all the oil and gas explorers working in the province and those contemplating doing so, given the right opportunities. All these companies have geological staffs, many of who will be geologists who devote most of their time over a considerable number of years entirely to the study of British Columbia's geology. The public corporation could not expect to have such an extensive source of expertise as that available in the free enterprise system. And so the public corporation would suffer from a reduction in the number of ideas generated.

It is not unusual in oil and gas exploration, with its inherent problem of scientific interpretation and evaluation of geological prospects, to find that one company will acquire a block of land, will explore it, and perhaps even drill on it before deciding the search is unsuccessful. The company will then return the land to its owner, the Crown. This does not mean that there are not any commercial hydrocarbons underlying this land; but rather that that particular company was unable to find them. To find these hydrocarbon deposits, a second, a third, or a fourth company should acquire this land, and, if this is done often enough, the hydrocarbon will be encountered, and production will follow. The problem with the public company being the only explorer in the province is that, unless it is fortunate enough to make the initial discovery, it is very doubtful whether there would be enough enthusiasm to have a second, third or perhaps even a fourth try at that particular prospect, with the result that the discovery would not be made. This is surely the worst thing that could happen and is probably the most damning argument against a public corporation moving into an area with an almost exclusive right to explore. 11/

B. Experimentation in Leasing: How Successful?

The simple answer to the above question is "No one knows." The U. S. Government tried royalty bidding on eight tracts in an October 1974 lease sale with questionable results. It appears that neither the industry participants nor government officials found the experiment to be particularly successful.

According to The Oil and Gas Journal, "operators say they doubt royalty bidding will ever surface again except in areas where production is almost certain or possibly in drainage-tract sales. Development of wildcat acreage

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11/ Dale R. Jordan, "Petroleum Leasing in British Columbia," Ibid., pp. 252-253.

can prove too costly on a royalty bid basis, despite the absence of high front-end expenditures normally budgeted under the traditional bonus-bid system." 12/

Similarly, Energy Secretary Schlesinger appeared to be disenchanted with the royalty bidding experience in Louisiana in that, in a letter to Interior Department Secretary Andrus, Schlesinger apparently stated that the Department of Energy has reservations about the effectiveness of the royalty method based on past experience in the Gulf of Mexico. It appears in fact that Schlesinger raised the same objections to the royalty system as had been raised by industry and formerly by officials in the Department of Interior, i.e., that royalty bidding leads to early abandonment of leases because declining production eventually makes the lease unprofitable under a high royalty arrangement.

Significantly, the Department of Energy and the Interior Department are considering the formation of a task force of experts to help analyze pros and cons of the various systems being proposed in the Federal legislation (which were largely copied in H.B. 854). A key problem seems to be a dearth of experts, however, in that few governments have undertaken experiments in bidding practices long enough or in a manner similar enough as that envisioned in the proposed Federal and State legislation, and to paraphrase Dr. Arlon Tussing's comments: scholarly, empirical analysis of the different bidding systems appears to be 'remarkably skimpy.'

One source document, from which we have already quoted, appears to be quite useful, however. Published by the British Columbia Institute for Economic Policy Analysis, Mineral Leasing as an Instrument of Public Policy,

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12/ Mike Long, "Royalty-bidding experiment turns sour," Oil and Gas Journal, May 2, 1977, p.32.

contains articles by an international and interdisciplinary group of economists, mining engineers, businessmen and industry consultants. In an introductory section, Dr. Mason Gaffney describes the report as "an outstanding contribution to a rapidly growing field of study."

Our greatest concern with the proposed legislation is reflected in many of the articles in the British Columbia Institute's report. The publication cites significant problems with many of the bidding systems proposed in H.B. 854. Since each new system is so experimental, moreover, the likelihood of the Alaska's experiments not succeeding is high. An additional concern is that it would be years before the success or lack of success with a given system can be determined.

An example of our concern relates to the use of royalty bidding. Dr. Arlon Tussing, Dr. Walter Mead and others (including now Energy Secretary Schlesinger) have raised objections to royalty bidding for a variety of reasons. In the Report, Professor Hayne E. Leland, University of California at Berkeley, echoes some of their concerns and ours:

> "Competitive bidding theory makes clear that undesirable consequences may follow from royalty or profit share bidding. If there are no bonus payments required, speculative bidding may lead to extremely high royalties or profit shares being bid, with development occuring only in the most favorable circumstances. This happens because firms have little or nothing to lose by bidding high and then failing to explore or develop..." 13/ (Emphasis added)

Gregg Erickson, a well-known Alaskan economist, in his article on "Work Commitment Bidding," suggests that the problems associated with royalty bidding are well known:

> "The problems created by royalty bidding, principally the premature shutdown effect and the potential for speculator induced misallocation of leases, have been well discussed in the literature. More importantly, they are well understood by persons influencing both public and private mineral resource policies." 14/ (Emphasis added)

13/ Hayne Leland, "Comment," British Columbia Institute Report, p.60.

14/ Gregg Erickson, "Work Commitment Bidding," Ibid., p.61.

Yet, it is not clear to us that royalty bidding problems are well understood by the officials who will guide the Department of Natural Resources in leasing decisions in the next few critical years or in the future.

A specific example of why we are concerned relates to the material prepared by the Department of Natural Resources to accompany H.B. 854, entitled "Two Views on Bidding Strategies." Not only are the numerous problems and dangers of royalty bidding (cited by Meade, Erickson and others in the University of British Columbia Report) not even mentioned, but also, after three short descriptive phrases under the heading "Royalty Bid-Fixed Bonus," the Department of Natural Resources, with no further comment, analysis, or explanation, simply states: "The Beaufort Sale is an ideal candidate for a royalty bidding scheme." (Emphasis added)

We view such remarks by the State Administration with concern. As indicated previously, many who have taken the time to study the various proposed bidding methods in depth list extensive problems with various schemes for royalty bidding (see also Attachment 2) and, would hesitate to use royalty bidding schemes of any sort except in drainage sales or where there are known, proven reserves (as mentioned above in the Leland citation). The Beaufort Sea is believed to have a high potential for discovery, but, as in the Gulf of Alaska, the drilling of wells may result in no discoveries, or discoveries of marginal fields. No discoveries - with royalty bidding - means no income for the State of Alaska. And, as royalty bidding adds risk for the State, another quote from Leland is perhaps appropriate here:

> "Note that if the lessor is such that leasing forms a substantial fraction of its revenue (for example the State of Alaska), it may not be optimal to transfer risk from firms to the lessor. Thus, lease contracts which might be appropriate to the federal government may not be appropriate for regional governments". 15/ (Emphasis added)

15/ Leland, op cit., p.60.

In view of the Department of Natural Resources' apparent current ease of decision-making with regard to where and how the current competitive-bid lease system should be abandoned, we feel it important to stress that we concur both with Mason Gaffney and Gregg Erickson as to where the burden of proof should lie, i.e., with those who would change the current system--not, as is implied and indirectly stated in H.B. 854, upon the Commissioner who would be cautious about a great deal of experimentation. In this regard, we believe we are safe in assuming that Gregg Erickson's statement below with respect to the work commitment bidding system would apply to any new proposed bidding system:

> "The adoption of a work commitment bidding system implies a judgment that existing institutions for private exploration of public resources result in a suboptimal rate of resource development.
>
> Any argument for the adoption of such a system must first establish that this is in fact the case..." 16/

Similarly, though in a more general way, Mason Gaffney warns:

> "To serve his citizens best, the statesman should...resist the temptation to use his power to manipulate and control...on the too easy presumption that the market has no rationale or normative value of its own. Generations of economists have established that it has, and governments seeking to improve on it need face a certain burden of proof." 17/

One final point: The effects of the cash bonus bidding method, though not perfect, have been rigorously scrutinized, with over 20 years of experience as a basis for analysis. And, according to Professor Mead's extensive studies related to the results of 35 oil and gas lease sales during the period November 1954 to May 29, 1974, bonus bidding with a fixed royalty is effective:

16/ Erickson, op cit., p.75.

17/ Gaffney, op cit., p.3.

> "On the basis of this evidence, we conclude that competitive bidding for oil and gas leases is sufficiently strong to protect the public interest in obtaining competitive values for its oil and gas resources. This conclusion is further supported by evidence presented above indicating an increase in the average number of bidders and a substantial increase in the average price bid per acre for oil and gas leases". 18/

Thus, it is our judgment that, although in certain, special circumstances, changes in the bidding approach may be advantagous to the State, several factors should be remembered. First, the State currently depends on the petroleum production for some 70 percent of its revenue, most of which is from a field that will begin to decline in about seven years. New exploration in Alaska is vitally needed.

Second, although oil companies by the nature of their business deal daily in risk and uncertainty, there is no question but that, to the extent the State can reduce uncertainty and foster confidence with regard to the use of new bidding systems, oil and gas exploration will be encouraged.

Third, because the new systems are experimental, we would suggest that the burden of proof for adopting a new system for any lease sale be placed on the Department of Natural Resources because the use of any new system involves greater risks and uncertainty not only for the companies but also for the State. The proposed amendments contained in Attachment 1 reflect this analysis and these conclusions.

18/ Mead, op cit., p.55.

C. Oil and Gas Leasing: How Competitive?

Much has been said in recent years about the competitiveness or lack of competition in oil and gas exploration and development. Concern has risen particularly with respect to joint ventures in general and joint bidding in particular. Although the formation of joint venture groups for lease sale bidding facilitates ease of entry in high-risk ventures, and allows producers to spread their financial investments in an effort to minimize overall risks, the sheer numbers of joint ventures have been interpreted by some as 'fostering something other than competition.'

The two theories about the nature of joint bidding in Federal lease sales (collusive vs. risk-sharing purposes) have been tested by University of North Carolina Professor Edward Erickson and M.I.T. Professor Robert Spann. As they reported in testimony before the U.S. Senate Commerce Committee, the observed patterns of bidding partnerships are most consistent with the hypothesis that joint bidding is a means of risk-sharing, not collusion. 19/ Among the ways in which competition might be fostered rather than reduced by joint arrangements are the following:

Because risks are shared, the cost of capital per unit of supply increment is less, so that entry barriers are lowered in high risk ventures;

Because of joint agreements, smaller independents can and do form independent and successful groups for bidding purposes in Federal lease sales, as evidenced by data on successful bidders in the June 1973 Federal lease sale;

19/ In their study of the 1972 and 1973 Federal offshore lease sales, Erickson and Spann found that membership of bidding groups varies from year to year; market shares for members fluctuate from one year to the next; the most frequent bidding group is a combination of majors and smaller firms, but majors bid alone, as do smaller firms; single firm bids are frequently made by the largest firms, but other firms are also successful single firm bidders, and bidding groups which contain a large number of firms are predominantly composed of smaller firms. They also concluded that the incidence of joint bidding increased as the size of the firm decreased; there was a heavy incidence of joint bidding partnerships between unlike firms; smaller firms use joint bidding ventures as a vehicle for entry into offshore activity. "Competition in the Field Markets for New Natural Gas Supplies," Statement before Senate Commerce Committee, November 8, 1973.

Because of the number of large and small producer combinations and the frequency with which new groups are formed with different members, producers are able to become involved in many projects so that competition is spread through many projects.

Since joint operating agreements also expressly provide for separate marketing of production from joint ventures, it would appear safe to conclude that risk-sharing through joint ventures need not make competition less intense. By facilitating ease of entry, joint ventures by domestic petroleum companies may indeed make competition more intense. 20/

The work of Professor Mead tends to underscore the findings of Erickson and Spann:

> "The most conclusive test of the workability of cash bonus bidding based on the United States record of OCS oil and gas lease sales is in terms of the rate of return on capital earned by the successful bidders. An analysis has been made on 184 offshore Louisiana oil and gas tracts leased in 1954 and 1955. Precise data are available on bonus payments, rental payments, oil and gas royalty payments, and production of oil and gas during the period from 1954 through 1967. Cost estimates were made for exploration, well drilling and equipment, and operation. Annual cost and annual wellhead values were discounted to obtain a net internal rate of return. The calculations indicate that these early OCS leases generated a 7.5 per cent before tax rate of return to the lessees. Given the fact that oil companies pay relative low U.S. income tax rates, the after tax rate of return would be only modestly lower than the 7.5 per cent before tax rate of return. This net yield clearly does not reflect monopoly power; it shows an excessive degree of competition". 21/ (Emphasis added).

In fact, two studies conducted under the auspices of the United States Geological Survey (both authored jointly by Dougherty of the University of Southern California and Lorenz of the U.S.G.S.) have indicated that the restriction of joint-bidding has failed to achieve its objectives in Federal OCS lease sales.

20/ In the last analysis, if the formation of such groups constituted monopoly power, one would expect to see some results where such groups are formed, e.g., a non-random bid price pattern in Federal lease sales.

21/ Mead, op. cit., p.55.

Major conclusions were:

1. The ban of joint-bidding by major oil companies may in fact have acted to broaden the overall influence of major companies in a given sale. The percentage of all bids and the number of bids per lease in which a major oil company was involved actually increased, which in turn may have increased the total amount of acreage in which major companies participated during this period.

2. When the U.S.G.S studies compared solo bids to joint-bids on given tracts, it was concluded that the joint-bidders tended to go after more highly sought-after leases and that they tended to bid higher on the average than sole-bidding competitors.

From a practical standpoint, allowing joint-bidding has important advantages to the State as well as to the industry, in terms of overall economic efficiency, environmental effects of exploration activity, and flexibility.

For example: Often, a given company may have a great deal of geologic and geophysical data in an area, but for one reason or another does not have the cash on hand to fully utilize its data in a competitive-bonus sale. In this kind of situation, it would make sense to join with another company that has the necessary investment capital and does not have the data.

If the two were unable to combine in partnership, a situation could develop where one company had to duplicate seismic and geologic information already held by the other company. Ironically, a situation would then develop where overall competition in the sale would be reduced, because one company with cash reserves would have expended part of its funds in gaining data, while the other company with information would be limited in participation

because of its cash limitations. Also, there would be the obvious environmental effect of the increased seismic and other activity, including, possibly, the drilling of wells, that would go along with the need to gain additional data.

In view of all of the above, we wonder why the State Administration proposes to ban joint bidding among "major and multinational oil and gas companies" (terms which are not defined in H.B. 854). Again, is the State simply following the Federal government's lead? If so, we would repeat Leland's cautionary note that it may not be in the State of Alaska's best interest so to do.

NOTE: The fact that Sohio/BP has proposed amendments to some sections of H.B. 854 does not mean that the Company endorses the bill in its entirety with the proposed amendments nor that we endorse the provisions to which we did not offer amendments. Part I of this paper is meant to clarify many of the concerns we have with H.B. 854 conceptually as well as in detail, concerns which, as shown in Part I, have been expressed in the analytical literature on the subject of the bill.

PART II: H.B. 854: PROBLEMS AND SUGGESTED AMENDMENTS

I. PROPOSED AMENDMENTS TO MAJOR PROVISIONS

A. Objectives (findings):

As explained in Part I above, we feel strongly that the language pertaining to the State's objectives as contained in the "findings" section of H.B. 854, should be amended to clarify the State's major goals in its leasing program. This section will and should be used by the Commissioner of Natural Resources in carrying out the Department's responsibilities under the proposed act in the "best interests" of the State.

These suggested amendments to H.B. 854 are particularly important in that, as explained before, some of the "important goals" outlined in the Governor's letter of transmittal appear to conflict with the apparent goals expressed in H.B. 854.

Suggestions: (Refer to attached draft language, Attachment 1, Page 1 and 2).

We suggest amending (A) to reflect the global and Alaskan energy/economic outlook. We also substituted the goal of encouraging prompt exploration and competition, in place of the ambiguous language of the original (B).

On Page 2, under (2), our amending language was designed to reduce uncertainty with regard to the implementation of the program. The language would allow flexibility, but only where consistent with the findings in (1).

Changes in (A) and (B) on Page 2 simplify the language in the original bill to reach the same goals, listed in (A) through (D) in H.B. 854.

B. Procedures

On Page 2, in (B), we suggest that the Commissioner be required to make his lease sale program consistent with the objectives in the bill.

Under (1), on Page 3 of the draft, we suggest that the status of the current leasing program shall be reported to the legislature, rather than, "submitted."

Section (2) clarifies ambiguous language in the same section of the original bill.

Section (3), also on Page 3, provides more certainty in lease stipulations and conditions by adopting language already contained in proposed state pre-leasing regulations.

On Page 4, under (B) in the suggested language, we suggest permitting the public to comment on the form of the lease sale as well as the leasing program itself.

Changes in (C) and (D) are being suggested to make the language more specific to reduce unnecessary delays and the potential for litigation, by adding "appropriate" federal agencies, "affected" local governments, etc...

Section (G) was added to clarify that (A) through (F) do not supercede Section 305 and 345 of the Alaska Lands Act, which provide for extensive review by affected municipalities and Alaska Native groups.

On Page 5 of the draft language, in (A), we would suggest that the Commissioner review bidding methods and leasing procedures used in the previous five years, rather than one year.

We suggest deleting (E) in the original H.B. 854 because we feel that such a requirement would put the Commissioner under undue pressure to experiment. It would tend to undercut the overall goal of flexibility for the Commissioner.

C. Lease Methods

We suggest new language in (C) on Page 6 of the draft, to provide more flexibility to the Commissioner, to insure fairness to all participants, to insure that the program is consistent with legislative findings of H.B. 854, and to place the burden of proof for the need of change to an alternative bidding system on the Commissioner.

D. Reduction of Royalty

On Page 9 of the draft language, the purpose of our amending language is to make it more difficult for speculation in the bidding of royalties. Under the proposed language, the lessee would have to clearly show that a reduction in royalty is required. These amendments should help in avoiding the problem of irresponsible bidding during a royalty-bid sale.

E. Bonus Bid Deferral

We would propose deleting this language (E) in original bill, Page 9, because we think that the option to defer payment of bonuses would encourage speculation and could lead to charges of unfairness if lessees have the option to "renegotiate" bonuses.

F. Withholding Acreage

For a variety of reasons, we would propose deleting Section (F) in the original bill, page 10. This is similar to powers held by the Commissioner under existing statutes and, as such, is not objectionable.

However, the problem with withholding acreage is illustrated by the description of it as "the fifth bidding system" by the Department of Natural Resources. This is further amplified by written comments by DNR personnel, in Report 2-77, where the withholding of acreage was specifically recommended as a means of significantly increasing state income on the assumption that the withheld acreage would cover half a known geological structure.

In the example discussed in Report 2-77 under the title of "Percentage of Acreage Withheld Leasing," it is assumed that 60% of a structure is leased initially at odds of 1 success in 10 which, after exploration, improve to 9 in 10. The fallacy of the argument is that the authors, (and subsequent proponents of the idea), neglected to take into account the other nine instances where exploration shows the acreage to be more or less worthless. Although 4% (10% of the withheld 40%) would attract high bids, the average overall income should be no different than if the whole acreage had been leased initially.

The assumption that all closed geological structures contain hydrocarbons is attractive, but untrue. The ability to close the rare structures which are filled with hydrocarbons is not vested in the State's geologists or those of a single oil company. Consequently the chances of the State losing income by deliberately withholding leases over a structure far exceed the chances of it making a windfall profit from the procedure.

What is often forgotten in the use of the example of Prudhoe Bay to show how not to lease, is the fact that at the time of the geophysical recognition of the Prudhoe structure, a bigger and geologically more attractive structure was found a short distance away. This was known as

the "Colville High". The Colville structure was drilled in 1966 with disastrous results because it was discovered to be dry and devoid of prospects. Those results seriously downgraded the Prudhoe structure, in the following year. It is highly unlikely that even if the Commissioner has the choice of multiple bidding methods he would have leased the Prudhoe acreage by anything other than cash bonus bids. If he had guessed, the same way that industry did, that the Colville High was the better of the two structures and had deliberately withheld half of it from leasing, would he have dared, in the light of the drilling failures, to do the same for Prudhoe? Obviously he would not have risked a second debacle. It is annoying in the light of this history to read that DNR authors, in, "Two Views on Bidding Strategies", 1978, persist in misusing the Prudhoe Bay example to reach the incorrect conclusion that "Bonus bidding should not have been used in that instance."

G. Exploration Work Credit Program

This is a suggestion made before the House Resources Committee by Sohio in early hearings on H.B. 854, involving credits for exploration as an incentive.

A major objective of H.B. 854 is to maximize revenues to Alaska, but to do this it is essential that the State adopt policies which encourage a steady, ongoing exploration program on State lands. Many sections in H.B. 854, if enacted, could actually serve to dampen exploration, but one option the State Legislature could consider to add an incentive for exploration is a program similar to Albert'a Exploratory Drilling Incentive System. This kind of program has proven to be successful as a way of encouraging high levels of exploratory activity, and in Alberta has been largely responsible for the record-breaking levels of drilling

activity in recent years, and subsequent high rates of discoveries since it was introduced in 1974. This year, the program was extended, until 1981.

The system is simple and is based on a drilling credit which can be earned by all exploratory wells and which varies according to the footage drilled and the region drilled in. For example, under the Alberta system, a well drilled to 8,000 feet on the North Slope could earn a credit of, for example, $2 million, where a similar well on the Kenai Peninsula might qualify for a $1.5 million credit. Deeper wells could earn proportionately more, as would offshore wells. These credits could be scheduled to equal approximately one-third to one-half of the cost of a well in each region, and they could be used by the earning company against bonus bids in a State sale, or against lease rental payments of royalty payments. The result could be an influx of capital into Alaska, similar to what has taken place in Alberta. But since the Commissioner would control the incentive program by regulation, it would be capital that would be directed by the State to areas in which the State wished exploration to occur.

To allow the Commissioner the discretion to introduce such a drilling credit system, we have taken the liberty of proposing general language in section (f) that could be translated into detailed regulations for a successful incentive program (see Page 10).

The system would require control by the Department of Natural Resources, but it could operate with less manpower than is needed for the policing of net profit bidding or royalty-bidding systems. The benefits would be tangible and immediate, and would probably exceed, in terms of new revenues to Alaska, the theoretical and untried potential of royalty or net-profits bidding.

H. Terms and Regulations

On Page 11 of the draft, our proposed language in (G) would replace (G) and (H) in the original bill. Our language would be simpler and would accomplish the same purpose, we think.

I. Lease Terms

On Page 13 of the draft language, our new language in (H) would give the Commissioner the option to have five-year lease terms, but only where the Commissioner finds that environmental and economic conditions would not severely restrict operations. The original language in the bill requires a five-year lease unless severe environmental conditions require a longer period.

In most parts of Alaska, severe environmental conditions and remote exploration locations dictate that drilling and other exploration activity be done only on a seasonal basis. A five-year lease term would therefore place great strain on the operator in all parts of the State except for Cook Inlet or Southern Alaska locations where work can proceed year-round. Our proposed language would leave the 10-year lease term intact, although the Commissioner would have the option for shorter terms where environmental conditions permit.

Our proposed language would also give the Commissioner authority to go to larger lease tracts if circumstances require, if, for example, a work-commitment system is used.

J. 90-Day Provision

Also on Page 13 of the draft language, we also amend section (H) in language dealing with expiration of leases, to reflect unique Alaskan environmental problems in the term "reasonable diligence." This language

deals with activities that an operator may have underway at the time of the expiration of a lease. We would like to see environmental conditions taken into consideration by the Commissioner in delays that might affect an operator.

Also in section (H) on Page 13, we would suggest amending the language to reflect that a lease will be extended if there is a well capable of producing oil and gas, rather than a well producing oil and gas, as in the original language. Our reasoning is that there could be situations where a productive well has been drilled, but there are delays in building transportion systems to actually take the oil away.

K. Commissioner's Role in Conservation

On Page 17 of the draft, we propose new language that would clarify an apparent ambiguity in the original language regarding the Commissioner's conservation regulatory authority under Title 31 over pools unitized under this chapter. Our suggested language would reinforce the Commissioner's conservation authority, and would clarify this language.

L. Noncompetitive Leasing

Sohio-BP has no corporate position on noncompetitive leasing, but while some companies would like to have the option of noncompetitive leasing available, there may be situations where the State's broader public interest might not be served. Noncompetitive leasing can invite speculation in leases and in certain circumstances, there could be adverse environmental effects.

M. Joint Bidding Prohibitions

On Page 21 of the draft, the original language in the bill allows the Commissioner to restrict joint bidding by "major and multinational oil and gas companies" (these terms are nowhere defined). There are many serious problems that are discussed extensively in Part I, Section III C with respect to this provision. Based on the conclusions of the studies cited in this section ("Oil and Gas Leasing: How Competitive?"), we would suggest that it is neither necessary nor in the State's interest ot restrict joint bidding in any way. Such prohibitions not only restrict entry into Alaska leasing, but also could reduce potential revenues from lease sales. We would suggest deletion of this section from the bill.

N. State's Right to Purchase Oil and Gas

Section (v) on page 21 in H.B. 854 would include in leases a provision whereby the State would be allowed to puchase up to 100 percent of any gas discovered on State lands. This could be very harmful to the State in the long run, as it could effectively eliminate the financing of exploration programs by means of gas sale contracts. These contracts have been normal in Alaska, and in the past few years have contributed many millions of dollars to oil and gas drilling. This source of investment would be cut off and the proposed provision would only discourage exploration and the purposeful search for gas.

Under the terms of this section, contractual commitments would be impossible to make because the lessee would have no certainty of ownership of gas and would lose the right to dispose of his share of production to his best advantage, which could also be to the State's advantage. The result could be an increase in the risks and costs of exploration.

O. Data

In accordance with statements made by Administration officials with respect to the intent of the langugage in H.B. 854 relating to data acquisition and confidentiality, we have amended (w) of H.B. 854 on Page 21. Under our amended language in (s) on the same page, therefore, the Commissioner is given access only to noninterpretative data which shall be held confidential upon the request of the lessee or permittee as provided in AS 38.05.035. Additionally, in our (s) section, we have added that the Commissioner shall, by regulation establish procedures to govern access to and the safekeeping of such data.

As to the usefulness of such data acquisition, we would refer you to the analysis contained in PART I, Section III A above ("Data Acquisition: How Useful?"). This section additionally attempts to explain why data acquisition by the government is frequently viewed as the first step that inevitably leads to government drilling corporations.

P. Acreage Limitations

Section 3 AS 38.05.140(c) in H.B. 854 would limit any one company's onshore lease holdings to a limit of 200,000 acres. We would suggest that this limitation may be unnecessary in reaching the objective of encouraging competition and may, in fact, undercut the goal of maximizing competition on State lands simply because some companies are now near or at the proposed limit in terms of onshore acreage holdings. They would not be able to participate in future state sales for at least five years if this provision were enacted.

The limitation also seems to work against other objectives of H.B. 854. For instance, the Department of Natural Resources, in its comments on the proposed work commitment bidding method, acknowledges that large areas on the order of 100,000 acres are needed to make the type of bidding practical. Such acreage would be low potential, high risk land which would not normally be seriously considered for exploration. If the 200,000 acre maximum is retained, no responsible company could even bid on large work commitment parcels of this kind. Consequently, retention of this stipulation would narrow the leasing options available to the State and would be detrimental to the responsible assessment of State land.

II. SUMMARY AND CONCLUSIONS

In summary, we would offer these observations and conclusions:

1. H.B. 854 as currently drafted would create a State leasing system biased towards experimentation with procedures that are new and untried in Alaska. This may not be in the State's interest, because unusual leasing systems could lead to delays in petroleum development that could have serious consequences on future State revenues and Alaska's contribution toward U.S. energy needs.

2. The United States faces a critical energy-import problem that may have serious consequences for the Nation's economy. Alaska can contribute to the lessening of U.S. dependence on imported oil, but long lead times and large investments are needed to develop new petroleum discoveries in remote Alaskan locations. By enacting new leasing legislation that could lead to unusual and untried lease systems, the State could inadvertently delay exploration and development in remote Alaskan areas with resulting consequences in the global energy/economic sphere.

3. The State of Alaska faces a potentially serious revenue situation in the late 1980's as annual State expenditures increase and oil production from the Prudhoe Bay field begins to decline. Again, the long lead-times needed to find and develop new Alaskan oil discoveries would indicate that exploration must proceed soon on State lands to provide needed petroleum revenues.

4. Alternative bidding systems proposed in H.B. 854, although also proposed in OCS legislation now pending in Congress, have not had extensive use in the U.S., nor in very many other places in the world. Experience with royalty bidding in federal OCS sales has been dissappointing, and the federal government may now be reconsidering the use of alternate bidding systems other than the competitive bonus-bid procedures.

5. The majority of academic literature that we have been able to find supports the thesis that the traditional bidding methods have worked well in the leasing of public lands for petroleum development. Academic experts also seem to agree that alternative bidding systems present serious problems, except when used in certain special situations.

6. We have offered in Attachment 1 suggested language that would, we believe, improve many sections of H.B. 854, and give the Commissioner the flexibility he desires while at the same time encouraging the use of proven leasing systems unless special circumstances dictate the need for an alternate situation. Royalty-bidding in a drainage sale would be an example.

7. We have suggested an exploration work-credit program similar to a successful system used in Alberta that we believe would offer substantial incentives for increased Alaska oil and gas exploration.

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.

Fax to: Bob Walker, Juneau May 26, 1978

From: Bleu Beathard, Anchorage

Proposed Amendments to HB 854
(In order of importance)

1. Section N, page 6, lines 20-25.

Delete first two sentences, replace with following:

An oil and gas lease must cover a reasonably compact area not exceeding 5,760 acres and must be for a period of ten years. The Commissioner may grant a lease for a term less than ten years but not less than five years if he finds that environmental conditions do not severely restrict operations.

2. Section 3 AS 38.05.140(c), page 12, lines 5-15.

Delete remainder of this section starting with sentence that begins No persons may take or hold, and replace with the following:

No persons 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.

3. Section O, page 7, line 29.

Amend as follows:

for the fifth year and subsequent years, $3.00 per acre.

4. Section C, page 2.

Line 10 delete words third and fourth, change years to year.

Line 12 delete fourth.

Line 13 delete after the year.

AGO 546855 +

THE LEGISLATURE OF THE STATE OF ALASKA
TENTH LEGISLATURE

FISCAL NOTE

I. REQUEST
Bill/Resolution No. HOUSE BILL NO. 354
Title Leasing and exploration of state land for oil and gas development
Requested by Governor Date

II. FISCAL DETAIL
Agency Affected Department of Natural Resources
Program Category Affected
Budget Request Unit(s) Affected

EXPENDITURES (Thousands of Dollars)

		FY 78	FY 79	FY 80	FY 81	FY 82	FY 83
100	PERSONAL SERVICES						
200	TRAVEL						
300	CONTRACTUAL						
400	COMMODITIES						
500	EQUIPMENT						
600	LAND & STRUCTURES						
700	GRANTS, CLAIMS, ETC.						
	TOTAL						

FUNDING (Thousands of Dollars)

GENERAL FUND	0	0	0	0	0	0
FEDERAL FUNDS						
OTHER (Specify)						

POSITIONS

FULL TIME	0	0	0	0	0	0
PART TIME						
TEMPORARY						

III. ANALYSIS (See Fiscal Note Preparation Instructions, Section III)
Existing administrative staff are capable of evaluating and carrying out lease sales under any of the proposed leasing methods within the reporting period unless the number and volume of sales in significantly larger than expected. Should net profits or a post-discovery type leasing method be used by the State, prior to production some auditing and/or assessing functions will have to be increased. However, some of these services are now being performed by Department of Revenue personnel in reserves tax assessing, and by 1983, or thereabouts and beyond, when the impact of production is felt, may be interchangeable with Natural Resources personnel.

Jack Roderick

IV. DATE February 6, 1978 PREPARED BY Jack Roderick
AGENCY Commissioner's Office, Dept. of Nat. Resources
PHONE 279-5577

Original: Legislative Finance
cc: Budget and Management
Prime Sponsor (First Legislator Named)

AGO 546856

33-001 (Rev. 12/77)

AMENDMENT

OFFERED IN THE ~~HOUSE:~~ Senate Resources BY: Chatterton

To: Senator Poland HOUSE BILL No. CSHB 815 (Finance)

SENATE BILL No. .

PAGE: 7 and 9 LINE: Pg. 7 - Lines 20 & 23
Pg. 9 - Lines 3,4 & 6

Page 7, Line 20

(a) Delete - (the unit) immediately preceding the word Production.

(b) Add - or lease immediately following the word tract.

Page 7, Line 23

Add - or lease immediately following the word unit.

Page 9, Line 3 & 4

(a) Delete - (the unit) immediately preceding the word Production.

(b) Line 4 - Add - or lease immediately following the word tract.

Page 9, Line 6

Add - or lease immediately following the word unit.

AGO 546857

R F

IN THE FREE CONFERENCE COMMITTEE ON HB 854
MOVED BY SENATOR CROFT:

Add the following subsection to SCS CSHB 854 (Resources), renumber the succeeding subsections accordingly, and adopt the thus amended version as the Free Conference Committee Substitute for SCS CSHB 854.

(x) The commissioner may include in any oil and gas lease provisions giving the state the right to purchase at the prevailing price an amount of oil and an amount of gas equal to the percentage amounts reserved in the lease to the state as royalty. The provisions shall provide that the lessee shall be given the same notice of the exercise of the option to purchase as is required for the state's exercise of its option to take royalty in kind. The commissioner may not include these provisions in any lease unless the intention to include it in the lease is stated in the final notice of sale issued not less than 30 days before the date of the sale.

prior knowledge –
Know ahead →

No Market for Gas →

Your Project needs gas on land yet to be leased.

1. WITHIN 60 DAYS OF RECEIPT OF "LEASING PROGRAM" LEGISLATURE, BY CONCURRENT RESOLUTION, MAY DISAPPROVE "ALL OR ANY PART" OF PROGRAM. P. 2	1. ADMINISTRATION SUBMITS PROGRAM — NO "LEGISLATIVE VETO"
2. SLIDING SCALE ROYALTY BIDDING — EITHER FIXED OR BID — AND ALSO MANDATORY WHEN OFFERED FOR BID A SECOND TIME. P. 3 P. 12	2. SLIDING SCALE ROYALTY — DELETED
3. ROYALTY BIDDING — (4) (5) AS VARIABLE. P. 4	3. ROYALTY BIDDING ONLY WHEN "UNLEASED ACREAGE SUBJECT TO DRAINAGE BY OFFSETTING WELLS."
4. COMMISSIONER MAY DEFER CASH BONUS UP TO 5 YEARS. P. 6	4. DELETED
5. LEASE TERM — 5 YEARS, BUT "GREATER THAN 5 YRS. BUT NOT TO EXCEED 10 YEARS WHEN — — ENVIRONMENTAL CONDITIONS SECURELY RESTRICT OPERATIONS." P. 6	5. LEASE TERM — 5 YEARS, OR "10 YEARS WHEN — — — ENVIRONMENTAL CONDITIONS — — — —"
6. RENTAL CONTINUES UNTIL ROYALTY OR NET PROFIT EXCEEDS RENTAL FOR 3 YEARS. P. 7	6. DELETED
7. RESTRICTION ON JOINT BIDDING P. 10	7. DELETED
8. RIGHT TO PURCHASE FOR IN-STATE USE P. 11	8. DELETED
9. UPLANDS ACREAGE MAXIMUM 300,000 ACRES — 10 YEARS TO CONFORM. P. 12	9. RAISED TO 5,760,000 ACRES (EXISTING LAW)

THE LEGISLATURE OF THE STATE OF ALASKA
TENTH LEGISLATURE

FISCAL NOTE

I. REQUEST
Bill/Resolution No. HOUSE BILL NO. 854
Title leasing and exploration of state land for oil and gas development
Requested by Governor Date

II. FISCAL DETAIL
Agency Affected Department of Natural Resources
Program Category Affected
Budget Request Unit(s) Affected

EXPENDITURES (Thousands of Dollars)

		FY 78	FY 79	FY 80	FY 81	FY 82	FY 83
100	PERSONAL SERVICES						
200	TRAVEL						
300	CONTRACTUAL						
400	COMMODITIES						
500	EQUIPMENT						
600	LAND & STRUCTURES						
700	GRANTS, CLAIMS, ETC.						
	TOTAL						

FUNDING (Thousands of Dollars)

GENERAL FUND	0	0	0	0	0	0
FEDERAL FUNDS						
OTHER (Specify)						

POSITIONS

FULL TIME	0	0	0	0	0	0
PART TIME						
TEMPORARY						

III. ANALYSIS (See Fiscal Note Preparation Instructions, Section III)
Existing administrative staff are capable of evaluating and carrying out lease sales under any of the proposed leasing methods within the reporting period unless the number and volume of sales in significantly larger than expected. Should net profits or a post-discovery type leasing method be used by the State, prior to production some auditing and/or assessing functions will have to be increased. However, some of these services are now being performed by Department of Revenue personnel in reserves tax assessing, and by 1983, or thereabouts and beyond, when the impact of production is felt, may be interchangeable with Natural Resources personnel.

Jack Roderick

IV. DATE February 6, 1978 PREPARED BY Jack Roderick
AGENCY Commissioner's Office, Dept. of Nat. Resources
PHONE 279-5577

Original: Legislative Finance
cc: Budget and Management
Prime Sponsor (First Legislator Named)

AGO 546860

33-001 (Rev. 12/77)

HOUSE JOURNAL

LETTER OF INTENT

CSHB 854 (RESOURCES)

The Honorable Hugh Malone
Speaker of the House
Alaska State Legislature

Dear Mr. Speaker:

The Resources Committee substitute for House Bill 854 makes numerous changes in the legislation as proposed by the Governor. Two of these changes involve the deletion of the following language:

1. Subsection (f) on page 6.

2. In subsection (j) the following sentence (at the top of page 8 in the original bill) - "The commissioner may provide by regulation and in the lease that the lessee may earn production rights only to the depth drilled at the beginning of production from the lease."

The record should show that the committee's intent in deleting these two items was not to limit the discretion of the Commissioner of Natural Resources in these areas, but simply the result of its determination that the authority in both of these areas is implied, and does not require special authorizing language in the bill.

Alvin Osterback

Alvin Osterback, Chairman
House Resources Committee

Date: 4/14/78

AGO 546861

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.

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 $1 Million
(Values in 10°$)

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 on 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 unwarrented 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)

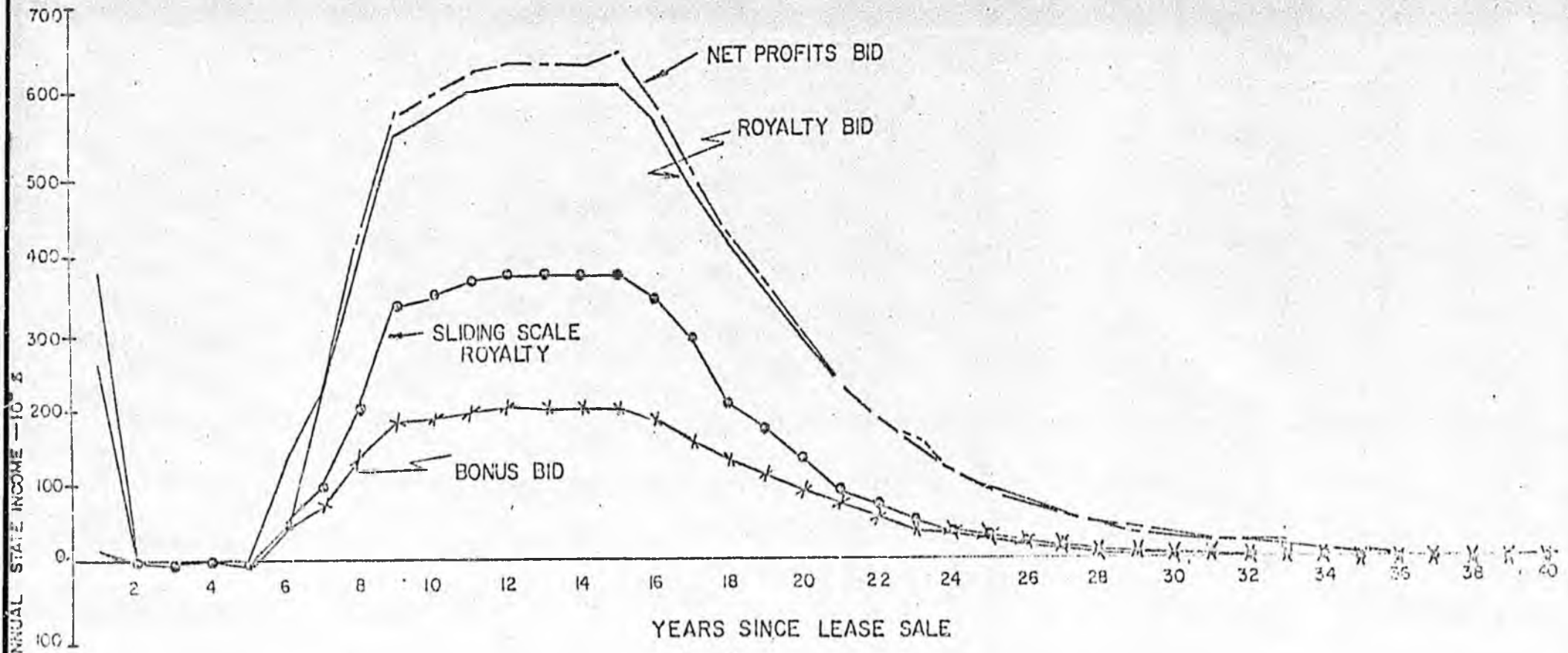
On the basis of exploration knowledge, lack of interest by industry and reasonable analysis, the department may determine that lands have very low potential for oil and gas.

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 similtaneous 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.



COMPARISON OF STATE INCOME
FOR VARIOUS LEASING METHODS
AT 90% CHANCE SUCCESS

BEW 1-30-78

Alaska State Legislature

Senate

Committee on Resources

AGENDA 5-28-78

Official Business

Pouch V
State Capitol
Juneau, Alaska 99811

CSHB 898 am	ALLOCATION TO AK FISHERIES DEVELOPMENT CORPORATION
CSHB 815 (Fin)	OIL AND GAS CONSERVATION
	THOMAS KRUEGER - EXXON
CSHB 854 (Fin)	LEASING AND EXPLORATION OF STATE LAND FOR OIL AND GAS DEVELOPMENT
	JACK RODERICK
	JOHN CARSON - CHEVRON
	DAVID MACE - SOHIO ROGER HERRARA - SOHIO
	ROD BOANE - EXXON

Alaska State Legislature

Senate

Committee on Resources

AGENDA

Official Business

Pouch V
State Capitol
Juneau, Alaska 99811

CSHB 854 - AN ACT RELATING TO THE LEASING AND EXPLORATION OF STATE LAND FOR OIL AND GAS DEVELOPMENT.

GEORGE FULFORD - DEPT. OF ENERGY & NATURAL RESOURCES
EDMONTON, ALBERTA

MARC SINGLETARY - ARCO

LARRY VAVRA - UNION

NORM GORSUCH - ATTORNEY

KEITH ARNOLD - AK OIL AND GAS

CLAUDE BROWN - TEXACO

Alaska State Legislature

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TEL. 212-586-5263-4
CABLE "WALTLEVY"

MAY 10 1978

May 5, 1978

The Honorable Steve Cowper
Chairman
House Finance Committee
Alaska State Legislature
Pouch V - State Capitol
Juneau, AK 99811

Dear Steve:

I'd like to review and expand a bit on my discussion last week before your House Finance Committee with respect to CS for House Bill No. 854 -- specifically the proposed exploration incentive credit system.

You will recall that we had suggested the possibility that a minimum work obligation be set out by the Commissioner on every lease offered for competitive bidding. The purpose would be to discourage speculative lease holding and to ensure that the State will get the benefit of actual exploratory activity by each successful bidder. Competing companies would, of course, reckon on the minimum work obligations when they calculate their bids.

We further suggested before your Committee that the exploration incentive credit system (pp. 4-5) may not be an essential incentive, particularly if there are work obligations and especially where prospects are attractive. In any event, the specific provisions of the bill look to be extremely awkward.

If the Legislature feels they should provide the Commissioner with authority for an exploration incentive system, we think you might alternatively consider something along the following

. . . /

AGO 546828

lines. First, expenditures up to minimum work obligations would not qualify. Second, beyond that minimum, additional expenditures on drilling exploratory wells could qualify for incentive credits. Credits could be related to footage and region; credits should never exceed a specified percentage of well cost -- as provided in the bill. Third, such credits could be applied against lease rentals -- not only on the lease where the well is drilled, but on any rentals accruing on State leases. To the extent that exploratory drilling credits exceed a company's accrued rentals, they might perhaps be carried forward. This could be a somewhat simpler approach to an exploration incentive credit system. It would apparently obviate the provision now in the bill whereby the Legislature has to appropriate offsetting funds to reimburse the Alaska permanent fund and the Alaska renewable resources development fund.

The proposed credits for geophysical work on State land within two seasons of an announced lease sale look to be even less necessary. We can appreciate a company's concern that costly exploration outlays designed to provide information to that company in advance of a scheduled lease sale may lose its proprietary value if a lease sale is deferred and the period of confidentiality expires. You may want to consider, therefore, that the period of confidentiality shall be extended by the Commissioner for work done on or proximate to areas scheduled for leasing if the lease sale is deferred beyond its announced date -- but not beyond some limited extension, say, 12 to 18 months.

I hope these thoughts may be of interest. Don't hesitate to call if we can be of any help.

Best regards.

Cordially,

Milton Lipton

/pt

cc: The Hon. Hugh Malone
The Hon. John Rader
The Hon. Kay Poland
Mr. Gregg Erickson

10-J3LH

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

MINERALS AND ENERGY MANAGEMENT / 323 E. 4TH AVENUE – ANCHORAGE 99501

July 1, 1977

To The Honorable Hugh Malone
Speaker of the House of Representatives
Box 9
Kenai, AK 99611

Dear Mr. Malone:

The Division of Minerals and Energy Management has been appointed the lead agency in developing the Alaskan Petroleum Leasing System. A major portion of the Leasing System is the development of policies and goals which the System will be expected to satisfy.

The staff of the division has prepared a preliminary list of possible leasing policies and criteria for evaluation leasing methods (see attachments). We are asking that all appropriate State and Federal agencies, legislative committees, and private parties provide input to the Alaskan Leasing System by reviewing the attached list, commenting on them, and adding policies and criteria that may have been ommitted.

Because of the necessity of arriving at the final leasing system as rapidly as possible, the time schedule for initial input into the policy segment is very tight. Please send your comments to the Division of Minerals and Energy Management at the letterhead address to the attention of Kristina O'Connor by July 15.

Thank you for your prompt attention to this very timely and important matter.

Sincerely,

Joseph P. Green KMO

Joseph P. Green
Director

AGO 547096

OIL AND GAS LEASING PROGRAM

POLICY AND GOAL ANALYSIS

EXHIBIT I.

PROPOSED POLICY AND GOALS FOR THE ALASKA LEASING SYSTEM

Nonrenewable resources should be developed when a net benefit accrues to the State of Alaska, or as may become necessary from a national need.

I. ECONOMIC Leasing of state lands should provide economic benefit to the state by providing direct revenue and by contributing to the development of a broader business and industrial base.

A. The value of resource revenue to the state should exceed the appreciation of the resource if left undeveloped unless it becomes expedient to develop from an overriding need.

B. The state should receive true value from its resources.

C. Resultant development should contribute to development of other related resources, industries and associated businesses.

D. The state should encourage the reinvestment within Alaska of revenues derived from leasing and associated development.

E. One of the benefits of the leasing program should be the improvement and/or establishment of transportation, communication and related facilities

F. The leasing program must be stable and predictable for the benefit of the state and industry.

CRITERIA FOR EVALUATION OF LEASING METHODS

1. Encourage active exploration and development.
2. Receive equitable compensation for the State's resources.
3. Maximize production from existing fields, encourage development of marginal fields, and use of enhanced recovery projects, and discouraging premature shut down of marginal production.
4. Encourage appropriate capitalization.
5. Encourage the State and Industry to maximize discounted cash flow.
6. Encourage preleasing exploration but discourage duplication.
7. Promote bidding competition and increase numbers of bidders.
8. Allow the State to share good fortune of increased reserves and value of crude oil.
9. State should realize only minimal income from dry structures.
10. State and industry to maximize advantages in Federal income tax laws.
11. State to stabilize petroleum exploitation so that prospective lesees can be sure "ground-rules" won't be subject to frequent change.
12. Leasing system to reduce industry risk by small front end filter.
13. Discourage speculation and over bidding.
14. State equity to be based on value of reserves discovered.
15. Maximize State control over amount of State's revenue.
16. Minimize State control over industry
17. State to maintain right to take royalty oil and gas in kind.
18. Effeciency of administration and operation.
19. Criteria for selection of successful bidders.

OIL AND GAS LEASING PROGRAM

POLICY AND GOAL ANALYSIS

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D. The state should encourage the reinvestment within Alaska of revenues derived from leasing and associated development.

E. One of the benefits of the leasing program should be the improvement and/or establishment of transportation, communication and related facilities

F. The leasing program must be stable and predictable for the benefit of the state and industry.

G. The system should attempt to maximize ultimate oil and gas recovery consistant with sound economic practices and increase State employment.

II. POLITICAL: The leasing program should result in improved political harmony between local communities, state and federal government.

A. The leasing program should be compatible with development plans prepared by community, federal and other management groups such as native corporations and beneficial special interest associations.

B. Industrial resources needed for development in Alaska and distribution of the products should be planned to minimize adverse impact on other states or regions.

III. SOCIAL: Leasing should serve to improve the social well-being of Alaskan citizens.

A. The leasing policy should consider the effect a particular resource development would have upon the desired lifestyle of the majority of Alaskan people as well as upon local and statewide historical and cultural values.

B. A demographic study to minimize or determine cost effectiveness of the negative effects of resource development should be made a part of the leasing study.

C. The leasing program should encourage such social benefits as cultural and recreational activities; and improved medical, communication, transportation facilities, and general life style.

CRITERIA FOR EVALUATION OF LEASING METHODS

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18. Effeciency of administration and operation.
19. Criteria for selection of successful bidders.

IV. ENVIRONMENTAL: Leasing and development should be conducted with minimal environmental damage and should occur only where benefits exceeds losses.

A. The leasing program must minimize the adverse environmental effects on subsistence and recreational hunting and fishing, water and air pollution, and on asthetic values.

B. Industry is to be encouraged to use methods and technology to minimize environmental problems and reduce need for scarce or limited resources such as water and gravel.

C. Hydrocarbon development when possible should utilize those renewable resources which are available so as to conserve and delay the exhaustion of non-replaceable resources.

V. RESOURCE MANAGEMENT: Alaska's resources should be developed only if there is a need for the resource and only if the state receives true value in return.

A. Lease planning should consider the timing and maximum efficient use of associated renewable and nonrenewable resources. (e.g. fresh water and gravel on the North Slope, excess hydroelectric power, etc.)

B. The Alaska Leasing System must be consistant with national and State goals in the area of energy conservation and development of alternate energy resources.

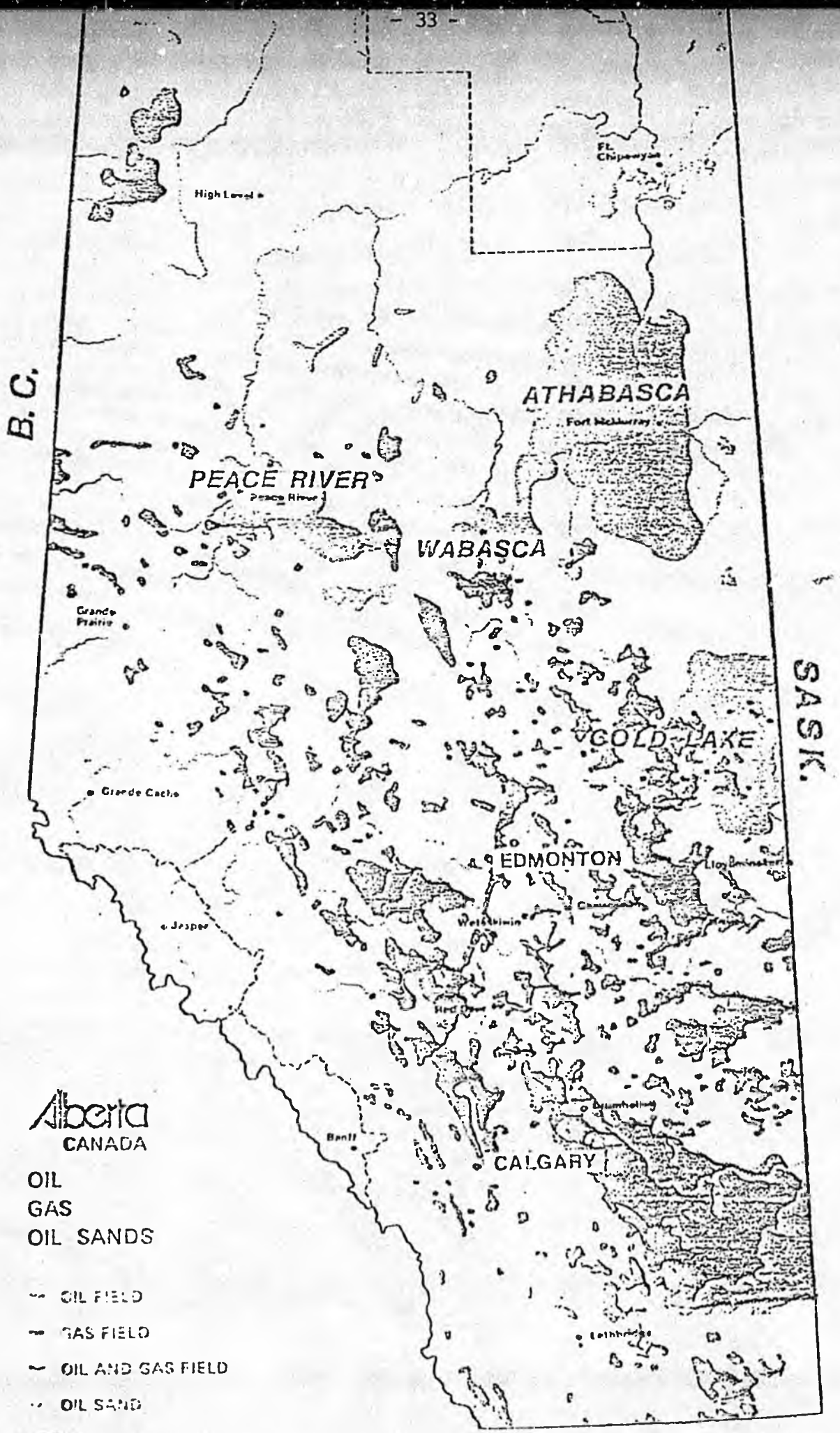

Fig 1

U.S.A. AGO 546761 +

GOVERNMENT INCENTIVES TO EXPLORATION

FIGURE 1

Alberta's oil and gas resources extend over most of the province and constitute a major source of energy. To expedite the location of such resources, the Government of Alberta on July 28, 1972, approved the Natural Resource Revenue Plan. A main feature of this plan was an increase in annual revenues to the Government of about 70 million dollars commencing in 1973. The Alberta government felt this to be a fair and reasonable additional return to the citizens of Alberta for their ownership of a depleting and non-renewable resource. This dollar figure has increased since the initiation of the program due to the escalating price of crude oil.

To offset this increase in revenues from industry and to stimulate increased exploratory activity in Alberta, the Government implemented the Exploratory Drilling Incentive System. The program has undergone several modifications since it was introduced, but essentially consists of a monetary credit for an exploratory well drilled for oil or gas. The credit may be applied against taxes payable under The Freehold Mineral Taxation Act,

.....2

royalties, rentals, fees and bonuses on petroleum and natural gas Crown minerals rights. A producing incentive exploratory well may also qualify for royalty or mineral taxation exemptions.

The Exploratory Drilling Incentive System is administered jointly by the Alberta Department of Energy and Natural Resources and the Alberta Energy Resources Conservation Board. Determination of qualifying footage upon completion or abandonment of the incentive exploratory well is made by the Board. Determination of the credit to be established is made by the Department.

Due to the close relationship between geophysical and drilling activity, it is found desirable to provide incentives for geophysical exploration. It is considered vital to maintain a high level of geophysical work to ensure the continuity of the search for new oil or gas reserves.

Therefore, the Alberta Government, in taking a second step toward maintaining the necessary level of petroleum activity in the province, implemented on January 1, 1975, the Geophysical Incentive Program.

The credit for a geophysical incentive program is determined from a

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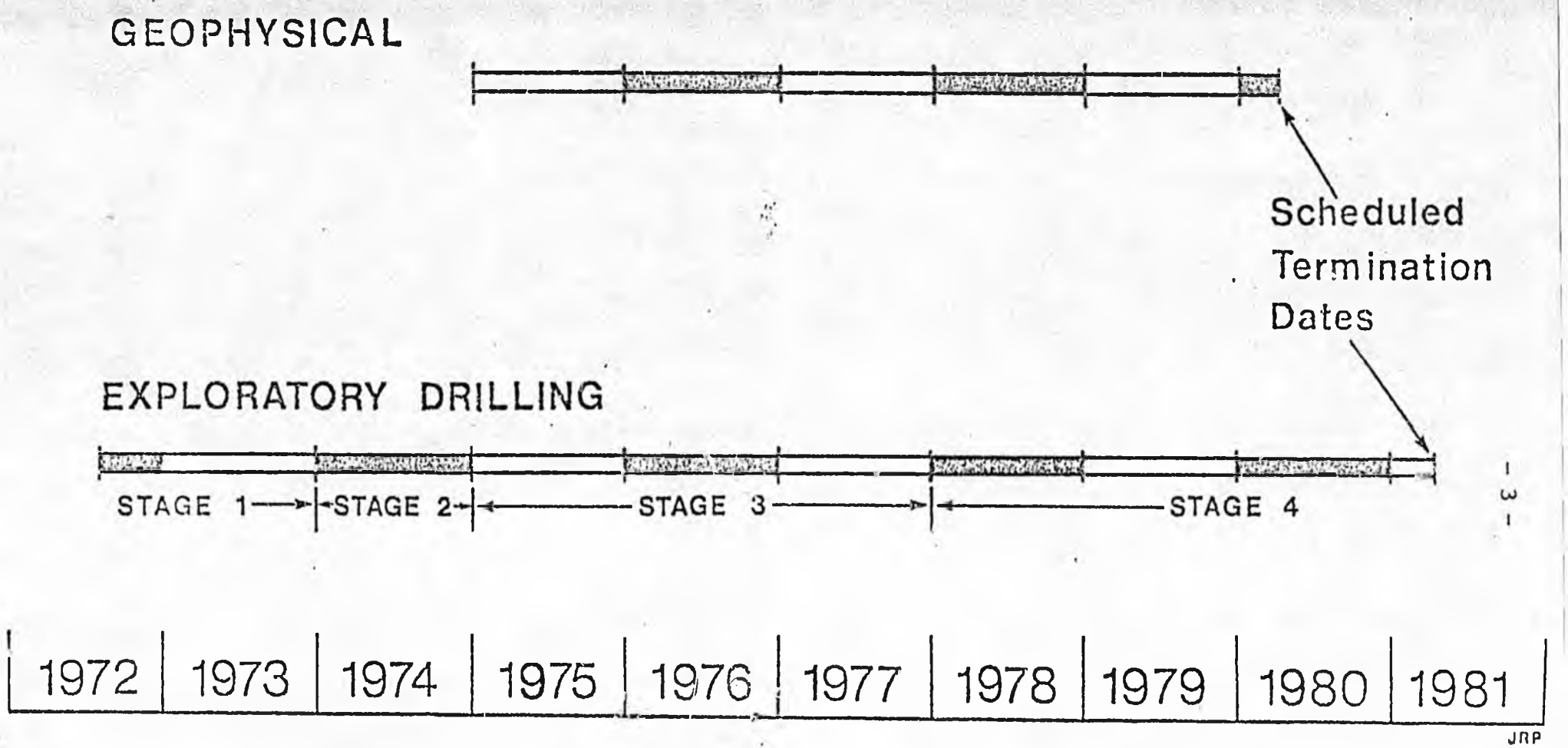

DURATION OF INCENTIVE PROGRAMS

A60 546764

Source: ERCB

FIGURE 2

formula based on the number of miles of subsurface coverage recorded and the geographical area in which the survey was conducted. The incentive credits maybe applied against revenues owing to the Crown, for bonuses on petroleum and natural gas, Crown mineral rights, fees, rentals, royalties and freehold mineral taxes.

FIGURE 2

The Exploratory Drilling Incentive System was implemented on August 1, 1972, and was scheduled to be in existence for a period of five years terminating on December 31, 1977.

After an extensive government task force study, an amendment was introduced extending the Exploratory Drilling Incentive System to March 31, 1981.

At the time the Drilling Incentive program was implemented, it was estimated that only 50% of ultimate oil and gas reserves in Alberta had been discovered. Exploratory activity had declined and many companies with substantial land holdings were apparently shifting their exploratory activity to the frontier areas. For this reason, the Government tried to "tie-in" the Natural Resource Revenue Plan with the Exploratory Drilling Incentive System to benefit those

.....4

operators who undertook exploration in Alberta.

Between 1964 and 1969, the number of new field wildcat wells drilled in Alberta maintained fairly high levels - about 500 wells per year. In 1971, this number dropped to about 300 wells per year.

A further indication of both the decline and shift in exploratory activity was indicated by seismic crew activity in Canada. Seismic activity dropped from a peak of 972 crew months in 1967 to a 1970 low of 724 crew months.

The shift of activity away from Alberta during 1970 and 1971 was of greater significance. From 1961 to 1967, close to 70% of Canada's geophysical activity occurred in Alberta. In 1968 and 1969, Alberta accounted for just over 60% of the total. In 1970, more Canadian seismic activity occurred outside Alberta than in Alberta.

There was a substantial drop in bonuses from the sale of Crown mineral rights. During the period 1965 to 1969, these revenues averaged $100 million per year. In 1970 and 1971, these revenues dropped to about $25 million per year.

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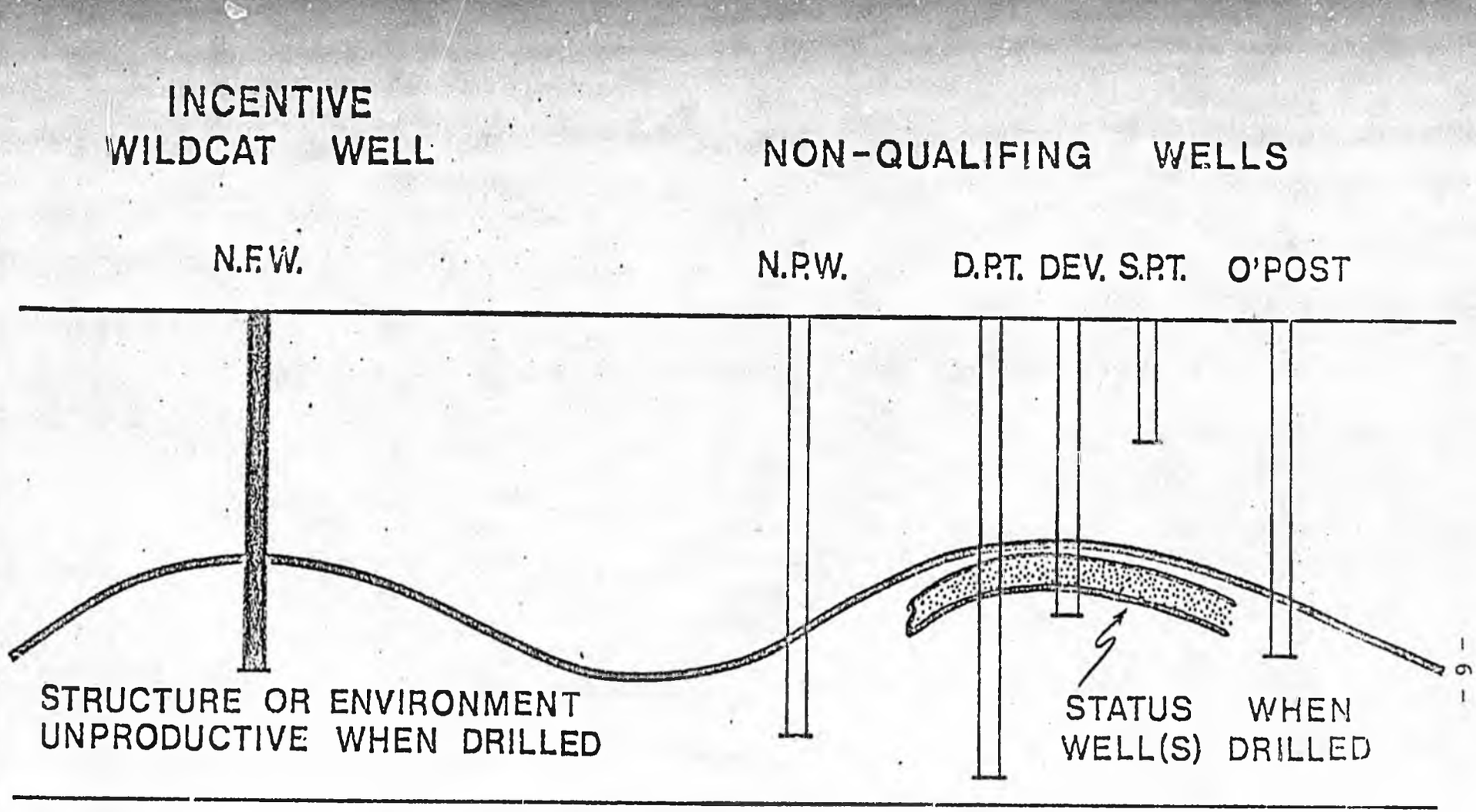

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INCENTIVE WILDCAT WELL

AUGUST 1, 1972 TO DECEMBER 31, 1973

FIGURE 3

AGO 546197

The Exploratory Drilling Incentive System, within the Natural Resource Revenue Plan, was designed to stimulate the discovery of crude oil reserves and shift exploratory activity back to the province by providing substantial rewards to the wildcat entrepreneur.

The objective of the Exploratory Drilling Incentive System was to encourage high risk exploratory drilling and increase the drilling activity in remote locations at a time when this type of drilling was declining in the province. The tendency in Alberta was to explore in known and reasonably accessible regions rather than stepping out in the search for new fields.

The Exploratory Drilling Incentive System has had several amendments since its original inception.

FIGURE 3

From August 1, 1972 to December 31, 1973, the program related to wells that were classified by the Energy Resources Conservation Board as "New Field Wildcats" under the "Lahee" classification system. A formula was derived which enabled the establishment of a credit equalling approximately 30% of the cost

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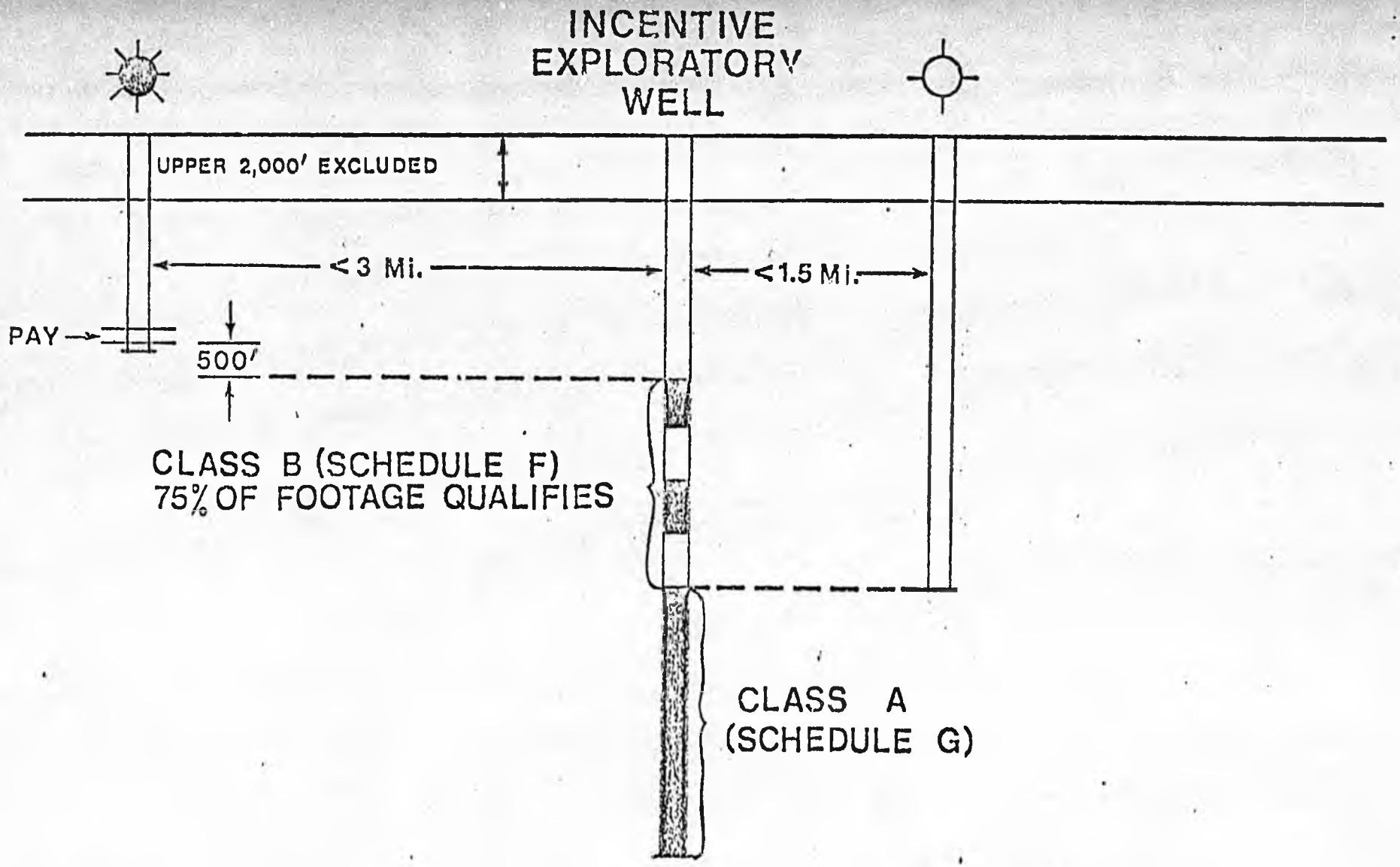

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AGO 546769

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TWO CLASSES OF QUALIFYING FOOTAGE

(EXCLUDING UPPER 2,000 FEET)

FIGURE 4

Energy Resources Conservation Board

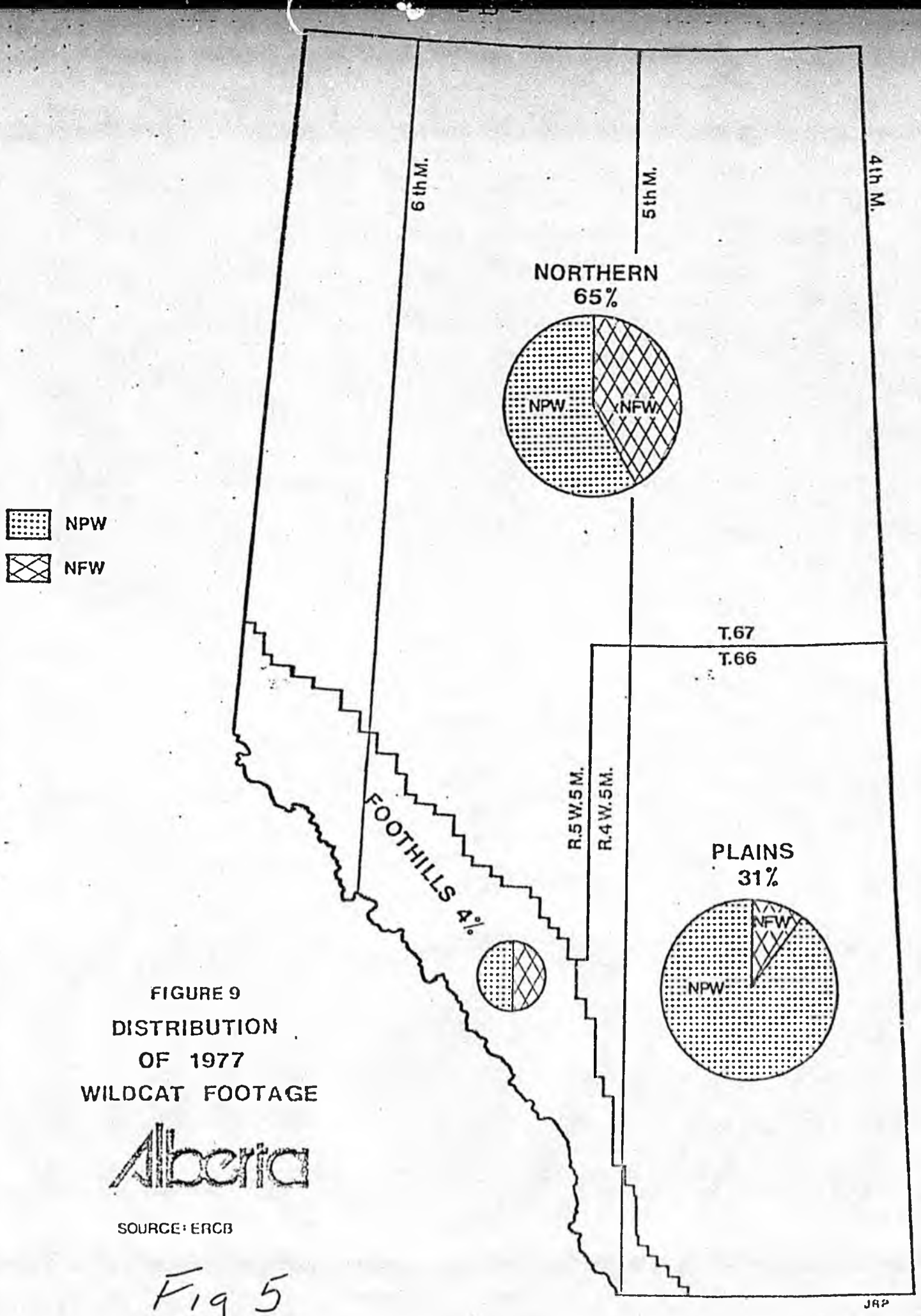

FIGURE 9

DISTRIBUTION
OF 1977
WILDCAT FOOTAGE

Alberta

SOURCE: ERCB

Fig 5

AGO 546770

of the well. The total footage of a new field wildcat qualified for incentive credit. A five-year crude oil royalty "holiday" was granted.

During this 17 month period, $16 million in drilling credits were earned by industry.

FIGURE 4

From January 1, 1974 to December 31, 1974 the program was expanded to include, along with the new field wildcats, about one-quarter of the more remote new pool wildcats and deeper pool footage. Figure 4 shows the principles that were adopted on January 1, 1974. The footage shown in white is known as Class "A" footage and it earned as credits, approximately 40% of the total recognized cost of the well. The Class "B" footage is applicable where a dry hole is within one and one half miles of the well. Class "B" footage earned about 30% support.

FIGURE 5

During this period, drilling costs were increased and a cost distinction was made for wells located in the Foothills, Northern and Plains regions.

.....7

These areas, as modified on February 26, 1975, are shown on Figure 5. Added features included a two-year natural gas royalty "holiday" and authorization for credits to be used to defray bonus payments tendered for Crown oil and gas mineral rights. The credits could continue to be used to offset payments due for royalty, rental or freehold mineral tax.

On January 15, 1974, the Alberta Petroleum Marketing Commission was created. Prior to its creation incentive credits established could be used by the holder to satisfy oil Crown royalty payments. This was discontinued on January 15, 1974 by the Commission.

During this 12 month period, the credits amounted to roughly $20 million and involved almost 600 wells.

From January 1, 1975 to December 31, 1977, the Government increased the benefits of the Exploratory Drilling Incentive System by expanding recognized well costs and by increasing the credit support for Class "A" and "B" footage to approximately 50% and 37½% respectively.

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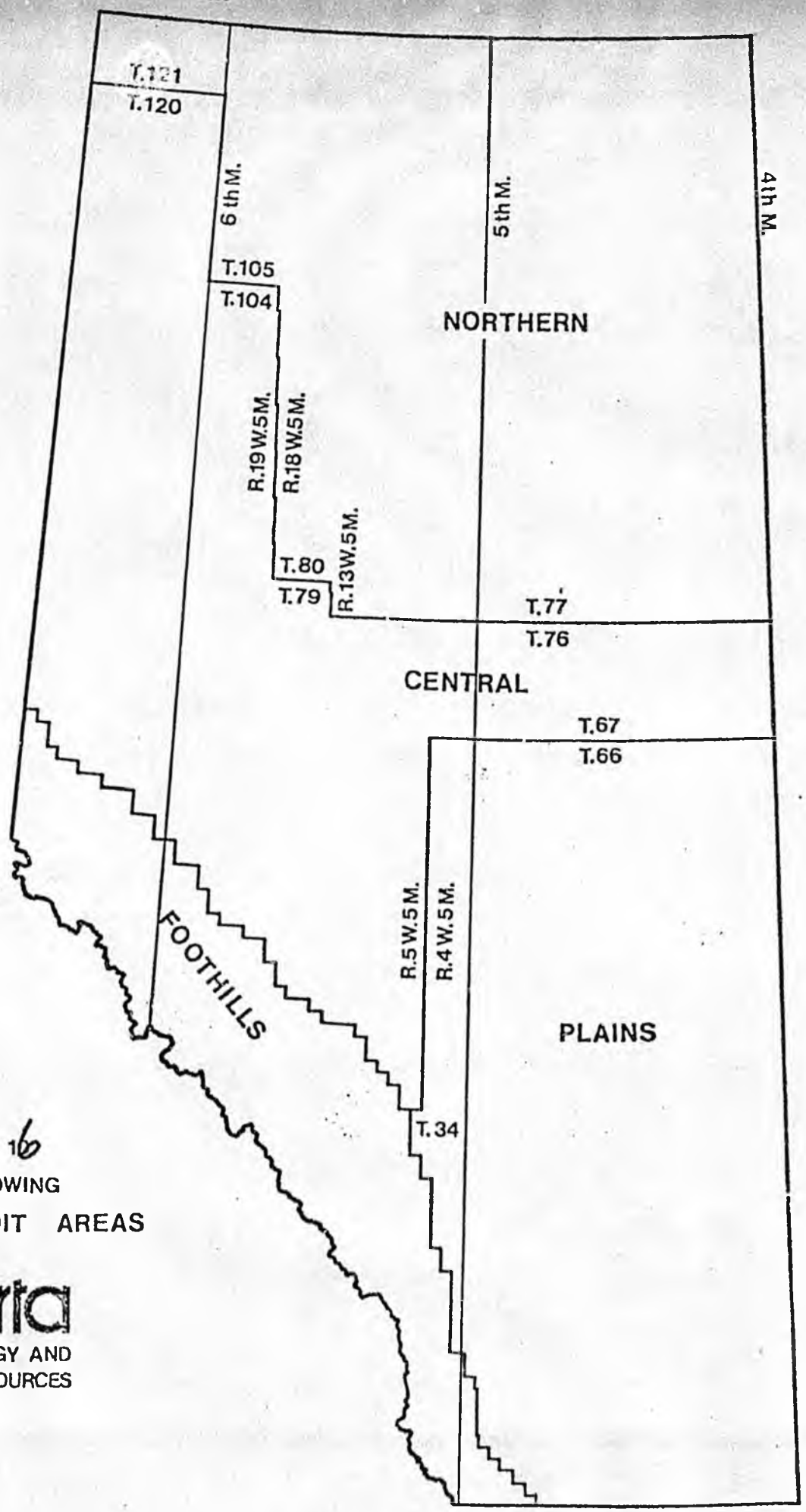


FIGURE 16

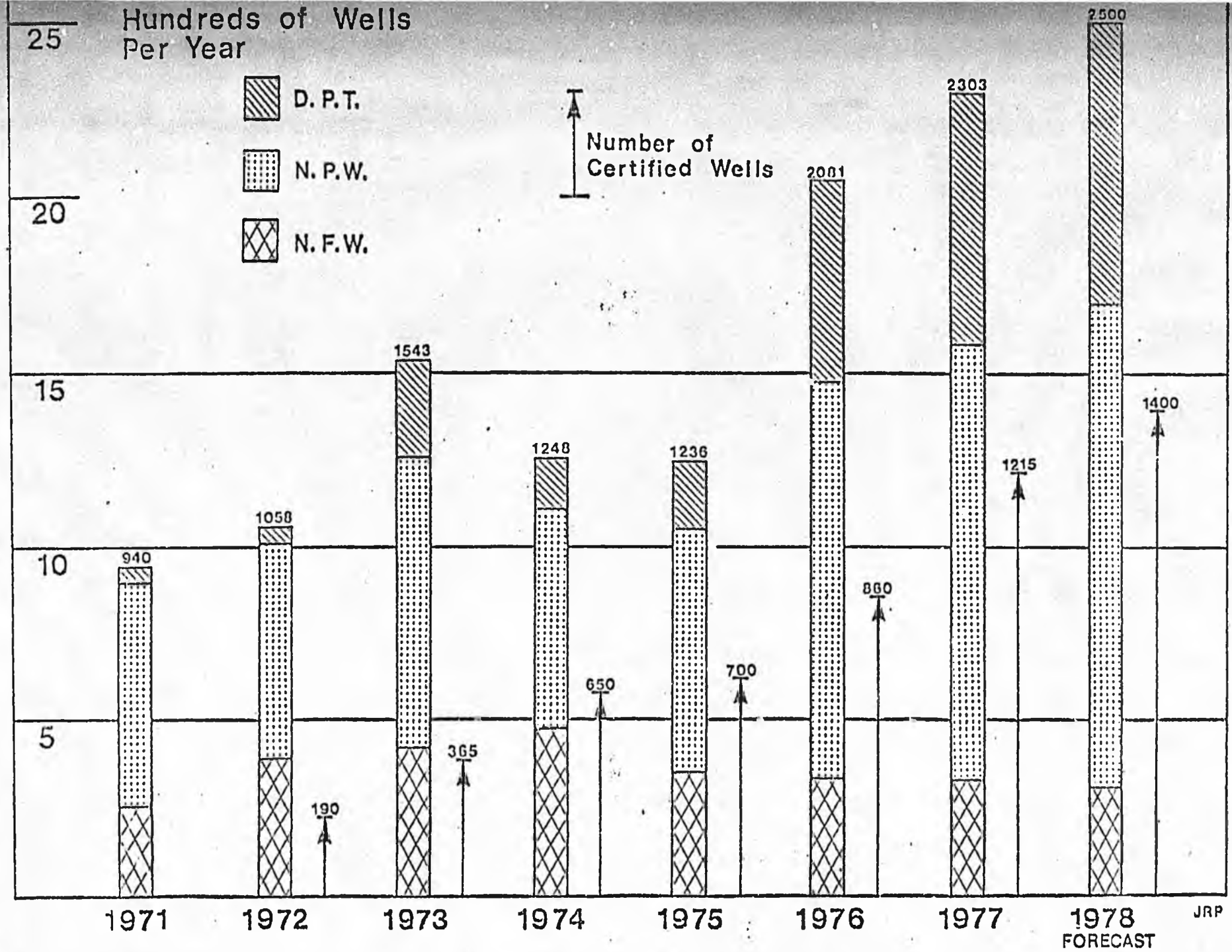
MAP SHOWING

DRILLING CREDIT AREAS

Alberta

ENERGY AND
NATURAL RESOURCES

AGO 546773



EXPLORATORY AND CERTIFIED WELLS, ALBERTA

Source: ERCB

FIGURE 6

AGD 546774

FIGURE 6

Commencing January 1, 1978 the drilling credit areas have been redefined. The Plains and Foothills Areas are unchanged, but the former Northern Area was divided into a Central and Northern Area. The boundary between the two new areas was defined on the bais on well costs, topographic and access considerations. The amendments also include the upper 2,000 feet of sediments from receiving any incentive credit and increase the credits for qualifying wells deeper than 3,500 feet.

For wells greater than 5,000 feet in depth, the incentive is increased by 25% to 45% depending on the location of the well.

FIGURE 7

There has been a considerable increase in the number of exploratory wells drilled in Alberta since inception of the incentive program in 1972. There were 1,058 exploratory wells drilled in 1972 compared with 2,303 drilled in 1977. The number of wells qualifying for incentive footage in 1972 was 190 compared to 1,215 in 1977. An increase is expected in 1978. The number of new pool

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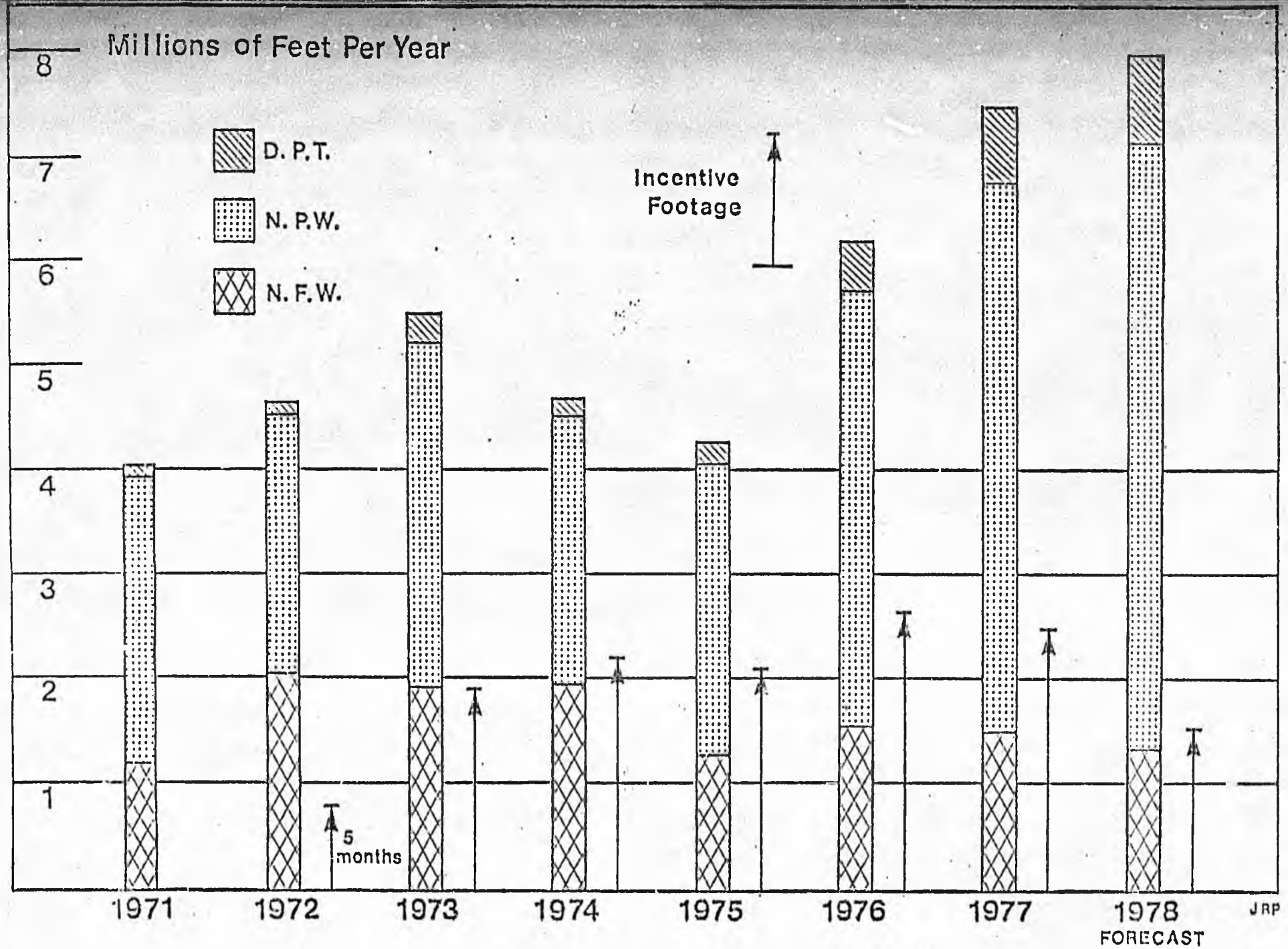
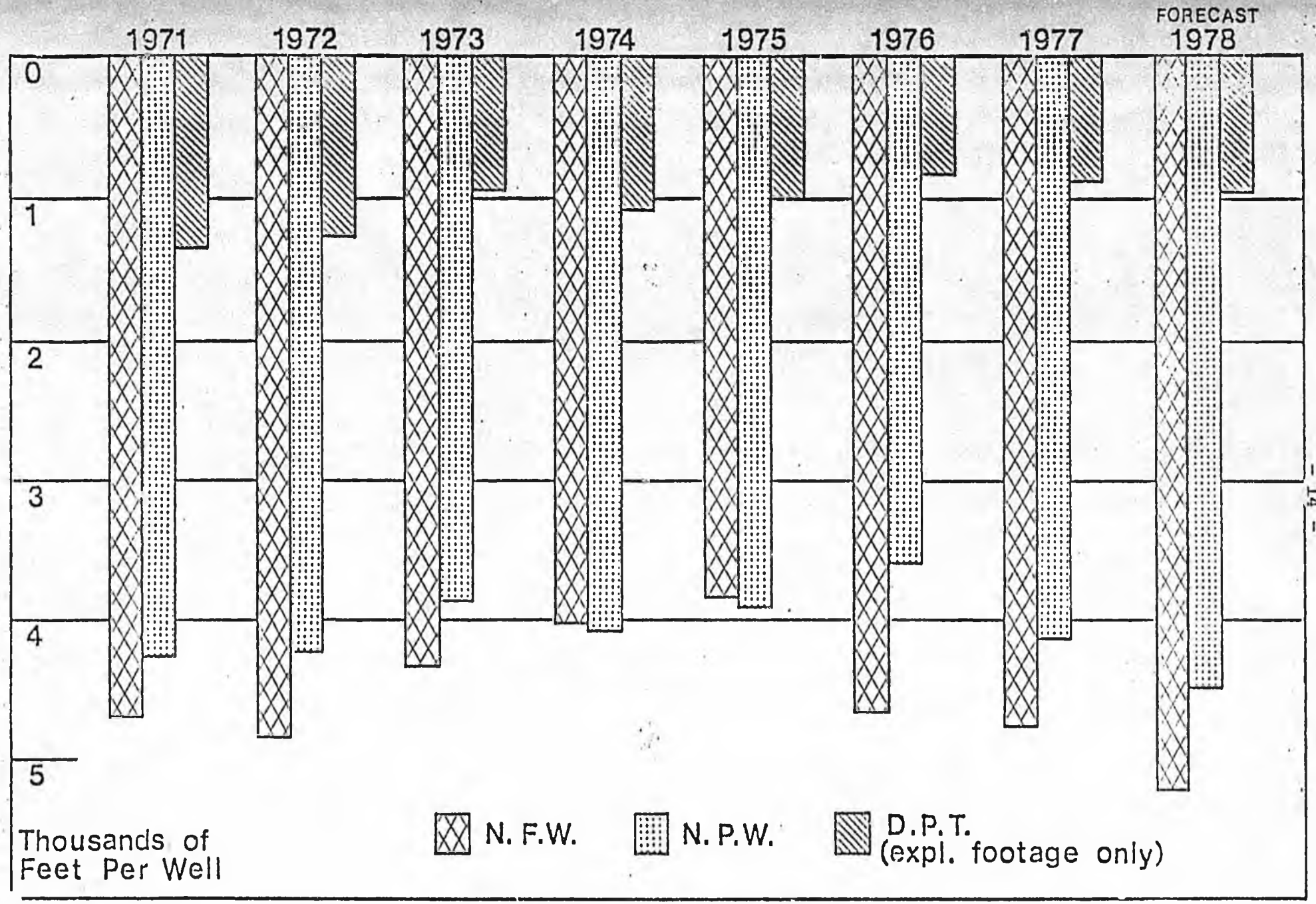


EXPLORATORY AND INCENTIVE FOOTAGE

Source: E&NR, ERCB

FIGURE 8

AGD 546776



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AVERAGE WELL DEPTH

Source: ERCB

FIGURE 9

AGO 546777

wildcats and deeper pool tests have increased since the program began, but the number of new field wildcats have declined.

FIGURE 8

The amount of exploratory footage drilled in 1977 exceeded all previous years. Footage for new field wildcats remained similar to 1976 at 1½ million feet, new pool wildcats increased to 5¼ million from 4¼ million feet in 1976, and deeper pool tests increased to 3/4 million feet from 1/2 million feet. The amount of footage certified under the program has increased since inception, equally divided between New Pool Wildcats and New Field Wildcats. In 1977 a total of 2½ million feet were certified to receive incentive footage. This figure shows an increase of 32% from the first full year the program was in operation.

Normally, 100% of the new field wildcat footage, 20% of the new pool wildcat footage, and 80% of the deeper pool test footage qualified for incentive benefits.

FIGURE 9

The average well depths per year has shown a gradual decrease from the period 1971 to 1976, but a slight upswing occurred in 1977. New field wildcats

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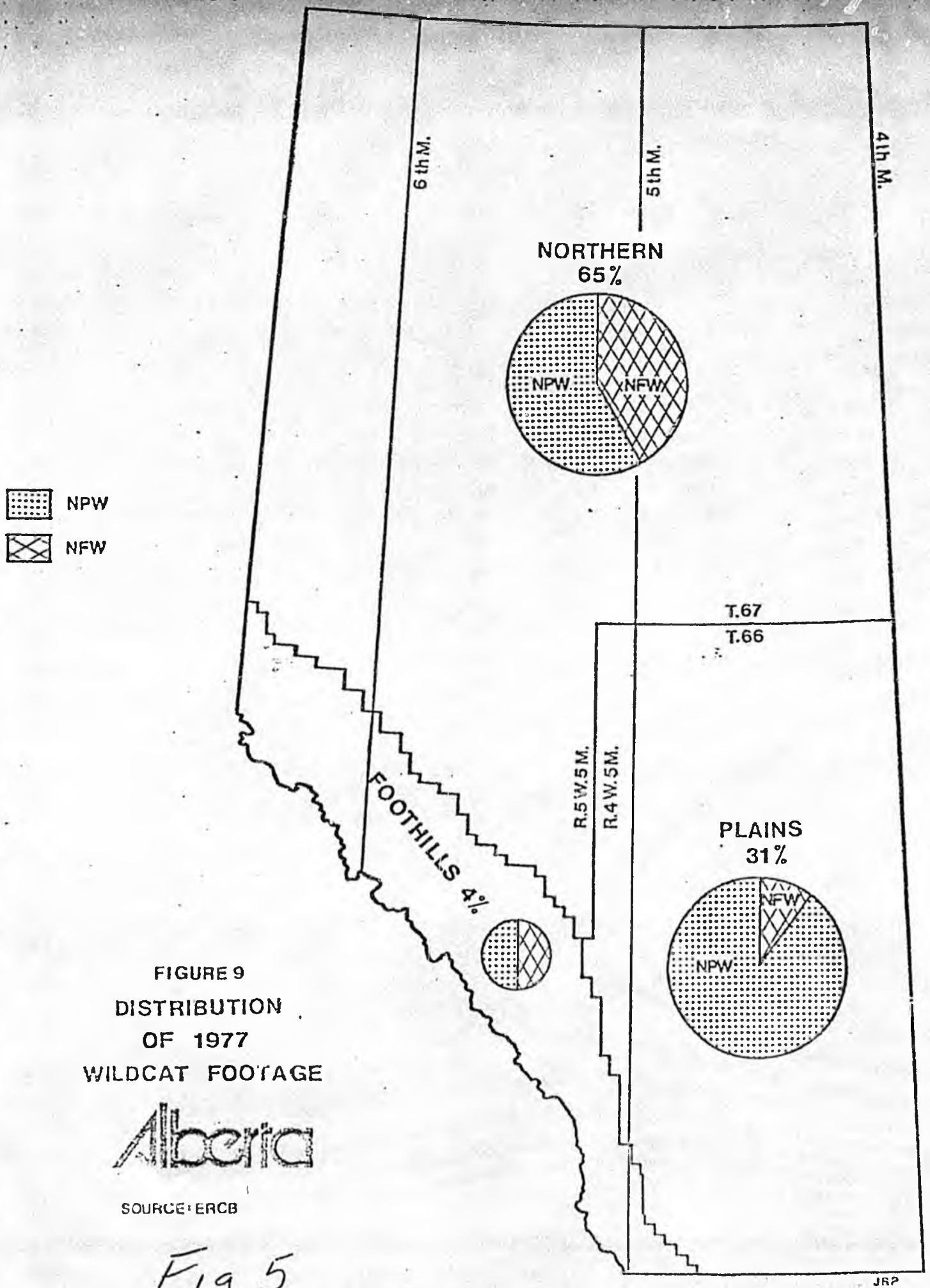

FIGURE 9

DISTRIBUTION OF 1977 WILDCAT FOOTAGE

Alberta

SOURCE: ERCB

Fig 5

AGO 546779

averaged 4,800 feet in 1977, new pool wildcats averaged 4,100 feet, and deeper pool tests averaged 1,000 feet.

FIGURE 5

The majority of the exploratory footage drilled in 1977 was in the Northern Areas. The total footage drilled here was 65% of the total exploratory footage. Of this 65%, new pool wildcats constituted 65% and new field wildcats 36%.

Exploratory drilling in the Plains Area accounted for 31% of the total, with new pool wildcats forming 90% of the figure, and new field wildcats about 10%. Drilling footage in the Foothills Area constituted 4% of the total. Of this 4%, half were classed as new pool wildcats and half as new field wildcats. Deeper pool tests formed less than 10% of the total exploratory footage for the province in 1977.

These figures indicate a shift of emphasis since 1976 from the Plains Area to the more remote Northern Area. In both areas, the total footage of new field wildcats has taken a considerable drop from the 1976 figures. New field wildcat footage in the Foothills Area has increased.

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Geophysical Incentive Program

On January 1, 1975, the Alberta Government implemented the Geophysical Incentive Program to stimulate the level of seismic exploratory activty in Alberta. The program was scheduled to terminate on March 31, 1978. This program has been extended to March 31, 1980 through a recent amendment to the Regulations. The Government recognizes the positive effects improved geophysical techniques have on drilling success rates and feels geophysical work must be encouraged to search for the less obvious hydrocarbon accumulations.

The Geophysical Incentive Program is administered by the Department of Energy and Natural Resources.

Geophysical activities, primarily in the form of reflection surveys, provide the initial technical basis on which many exploration "plays" for new oil and gas deposits are planned. Such surveys have performed a key role in finding many of the prolific reef accumulations of hydrocarbons in the Alberta plains. Geophysical data is essential to interpreting the complex rock structures of the foothills which are expected to contain major new deposits of hydrocarbons.

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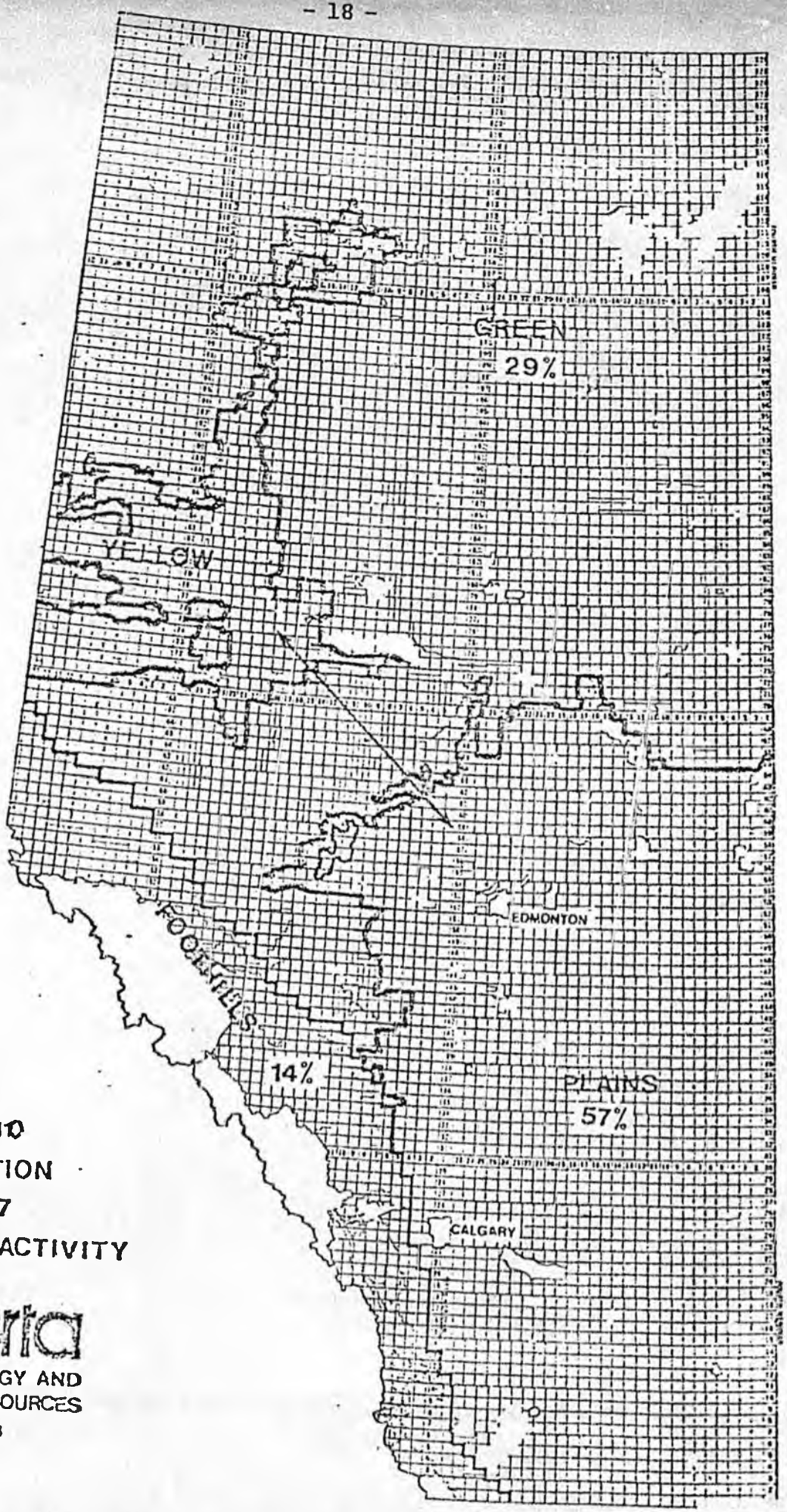

FIGURE 10
DISTRIBUTION
OF 1977
GEOPHYSICAL ACTIVITY

Alberta
ENERGY AND
NATURAL RESOURCES
JUNE, 1978

AGO 546782

The main features of the Geophysical Incentive Program are:

(a) The incentive will apply to seismic surveys certified after January 1, 1975.

(b) Incentive credits are established in the name of the licensee however, these credits may be allocated to partners sharing in the cost of the seismic program.

FIGURE 10

The incentive credits are determined from a formula based on the number of miles of subsurface coverage and the area in which the survey is conducted. Surveys carried out in difficult terrain in the Foothills and Green Areas receive a larger incentive credit than surveys carried out in the Plains region.

The determination of credit for a certified geophysical incentive program was calculated on the number of miles of minimum (400%) subsurface coverage by the following equation:

Credit (dollars) = 500 K M

Where K is the incentive factor for different geographic areas in Alberta where the program was conduted M is the number of miles of minimum subsurface

.....13

coverage.

The incentive credits may be applied in the same manner as the exploratory drilling incentive credits. A licensee may apply for the monetary equivalent of the credit where he is not the owner of a mineral agreement or a freehold mineral right.

Any geophysical information and data obtained pursuant to a geophysical incentive program must be made available by the licensee to any person for a period of not less than five years

(a) three years after the date the program was certified.

(b) at a cost to that person of 60% of the credit determined for each mile of minimum subsurface coverage.

Amendments to the Geophysical Incentive Program effective April 1, 1978, reducing credit by 50% will result in a phase down of the program.

Credit (dollars) = 250 K M

The minimum subsurface requirements have been increased requiring 600% in the white and yellow area and 1200% in Foothills and Northern Areas.

AGO 546784

The total number of miles of subsurface coverage in 1977 that qualified for incentive credit was 28,000 miles. This figure reflects an increase of

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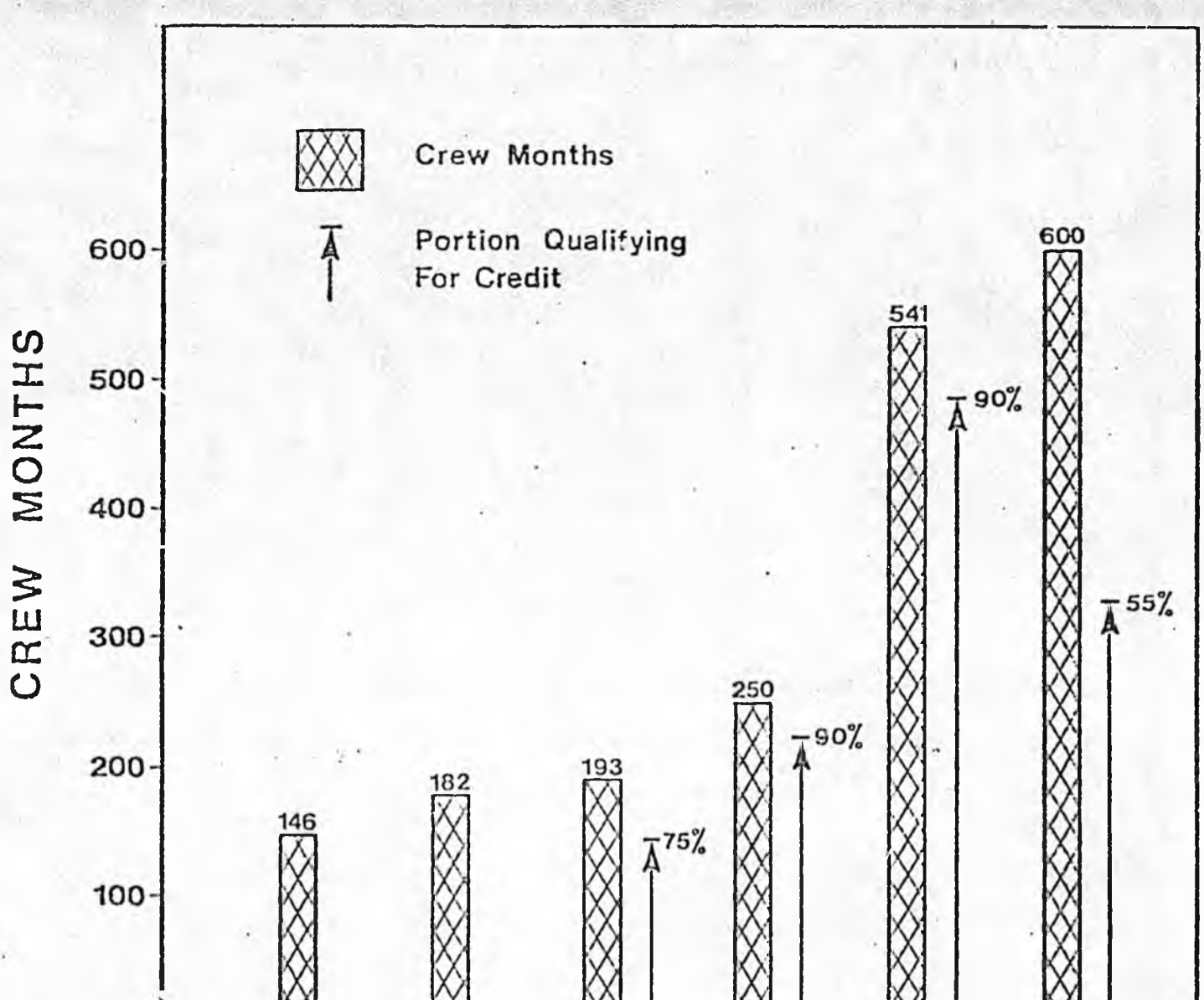

SEISMIC ACTIVITY & PORTION QUALIFYING FOR INCENTIVE CREDIT

FIGURE 12

AGO 546785

82% over the 1976 figure of 15,400 miles. Of this total, 16,105 miles was in the Yellow-Plains Area, 7,994 miles was in the Green Area and 3,921 miles was in the Foothills Area. These figures show an increase in activity in the Yellow-Plains Area, a decrease in the Foothills Area and unchanged activity in the Green Area.

FIGURE 12

This figure shows the crew activity from 1973 to 1978. In 1977 there were 541 crew months of activity, compared with 193 crew months in 1975 the first year the incentive program was in operation. The forecast is that the number of crew months will continue to increase.

In 1976 and 1977, 90% of the programs conducted in the province were certified under the Geophysical Incentive Program Regulations compared with 75% in 1975. The amendments effective April 1, 1978 are expected to reduce the number of programs submitted to the Department for credit. It is estimated that 55% of the programs shot in Alberta will receive incentive credits.

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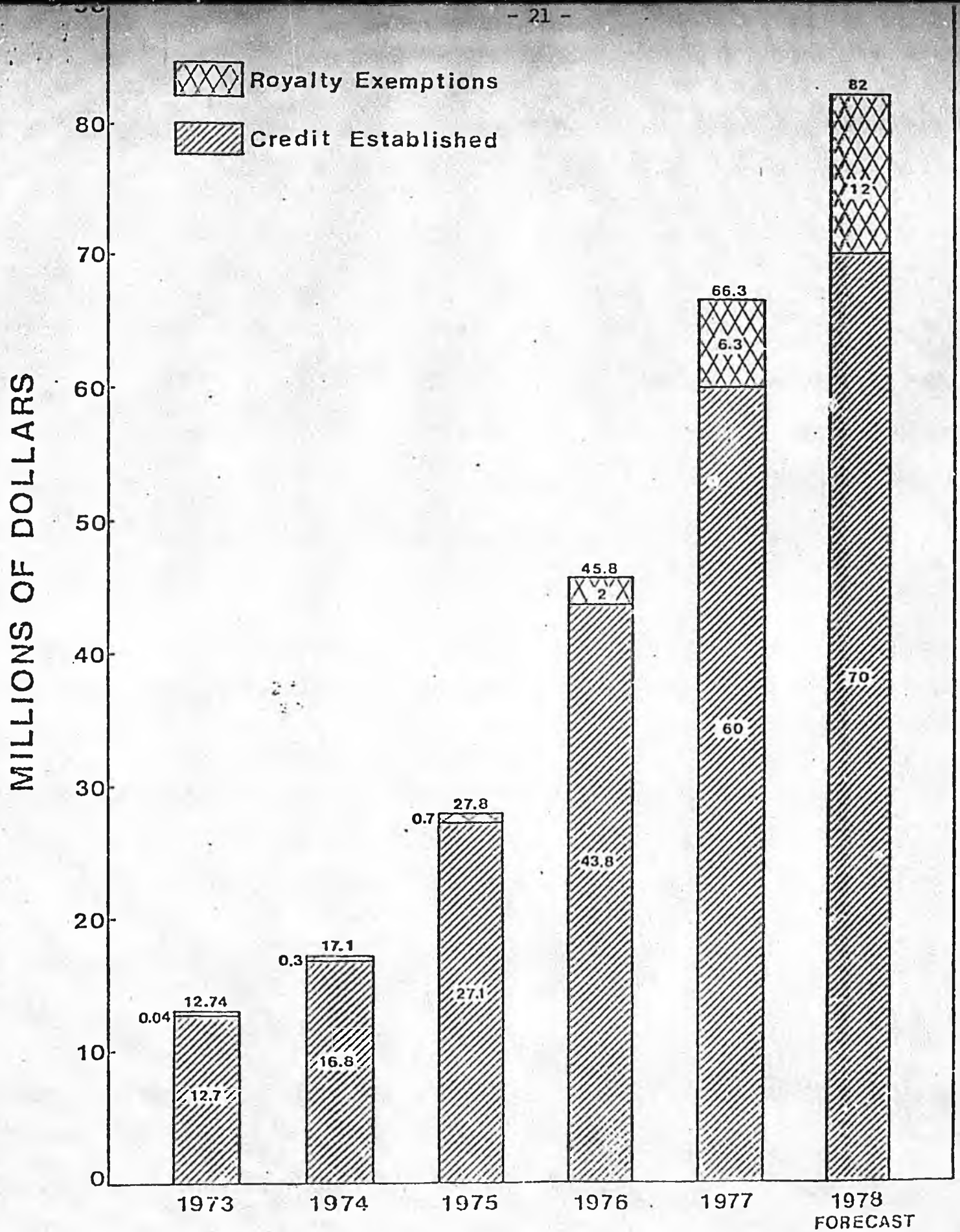

INCENTIVE COSTS ASSOCIATED WITH DRILLING ACTIVITY

AGO 546787

FIGURE 13

Energy & Natural Resources, June 1978

FIGURE 13

The Exploratory Drilling Incentive System and the Geophysical Incentive Program were initially devised to reduce the burden placed on industry when the Natural Resource Revenue Plan was initiated. The incentive programs were meant to reduce the increased royalties owed on Crown oil and gas mineral rights by financing a portion of the exploration costs. These incentive costs have escalated considerably in the years since the inception of the programs from a few million dollars to tens of millions of dollars per year.

The total costs to the Alberta Government for credit, royalty exemptions, cash refunds and administration of the programs amounted to over $90 million in 1977.

The cost for the Exploratory Drilling Incentive System in 1977 was 66.3 million dollars. This figure shows an increase over the 1973 costs of 12.7 million dollars. The credit established in 1978 is forecast to be $82 million. During the same period royalty exemptions have increased from $0.04 million to $6.3 million. It is forecast that royalty exemptions will reach $12 million in 1978.

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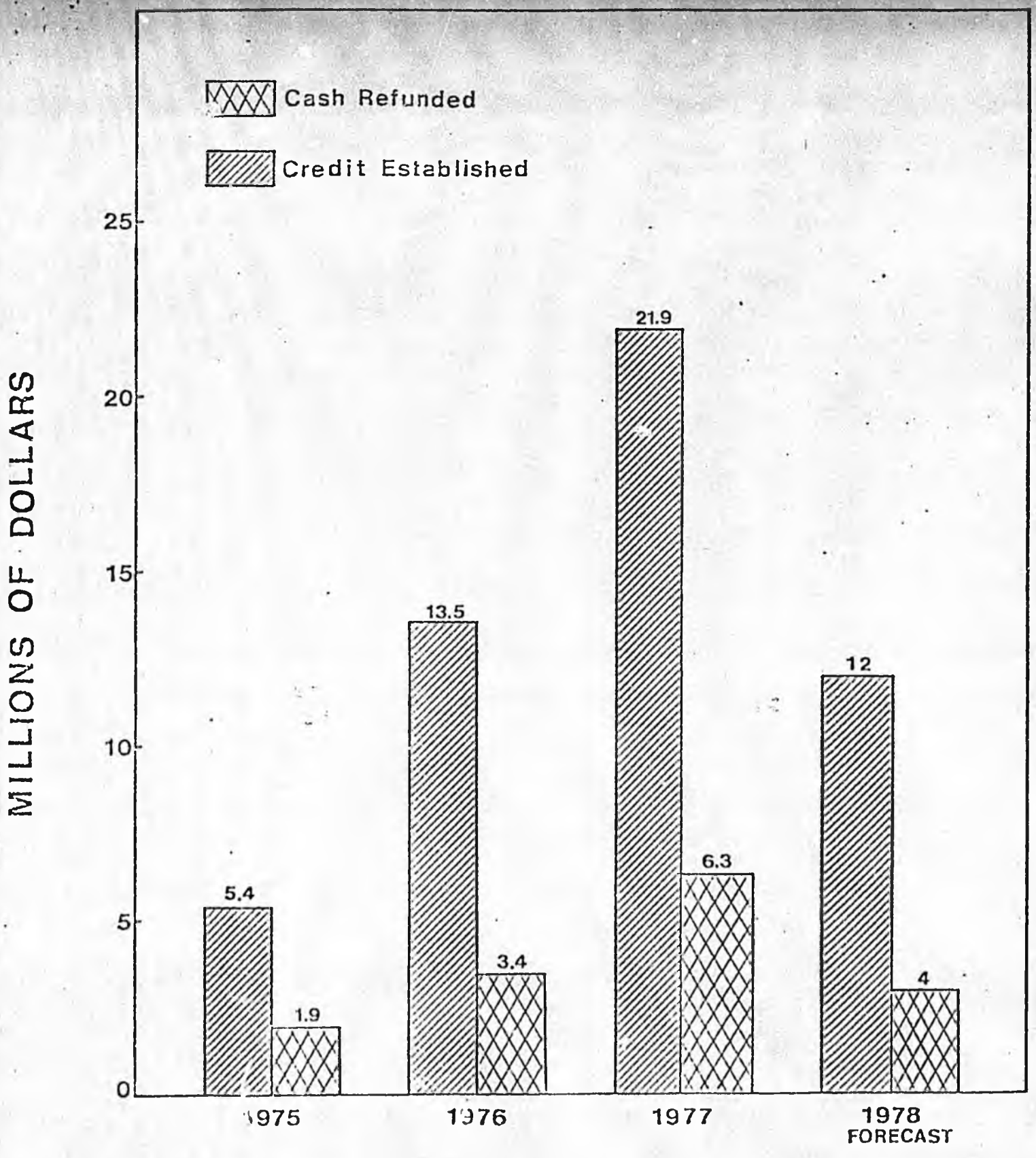
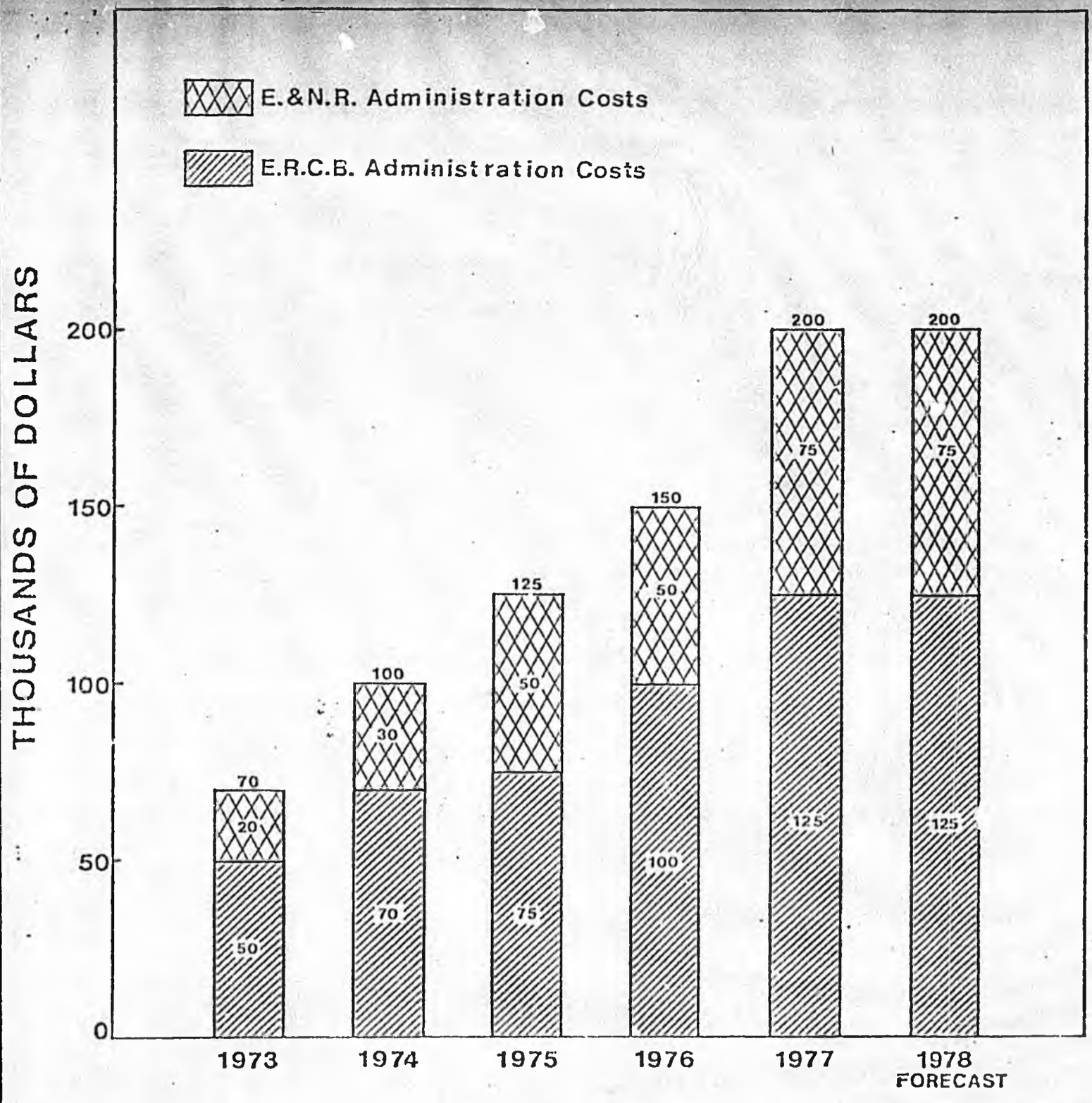


INCENTIVE COST ASSOCIATED WITH SEISMIC ACTIVITY AND CASH REFUNDED

AGO 546789

FIGURE 14

Energy & Natural Resources, June 1978

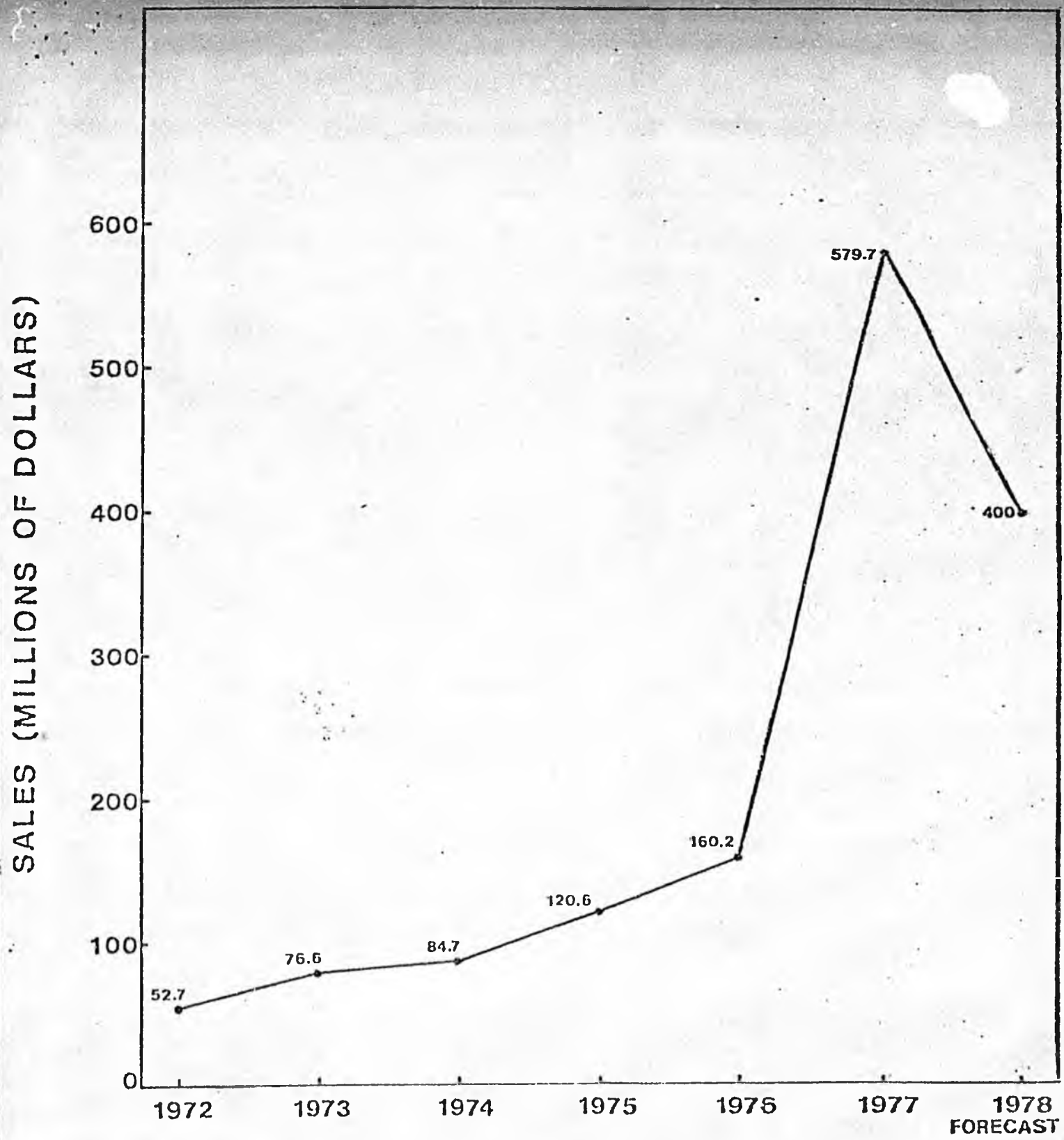


GOVERNMENT ADMINISTRATION COSTS ASSOCIATED WITH THE DRILLING AND GEOPHYSICAL INCENTIVE PROGRAMS

AGO 546790

FIGURE 15

Energy & Natural Resources, June 1976



SALES OF CROWN OIL AND GAS MINERAL RIGHTS

FIGURE 16

Energy & Natural Resources, June 1978

AGO 546791

FIGURE 14

$21.9 million was established as credit in 1977 for the Geophysical Incentive Program. This is an increase of more than 300% over the credit established in the first year the of the program. It is estimated that $12 million will be established as credit in 1978.

The cash refunded has increased from $1.9 million in 1975 to $6.3 million in 1977. We believed that in 1978 cash refunds will total $4 million.

FIGURE 15

In 1973, total administration costs were $70,000 roughly $50,000 for the ERCB and $20,000 for the Department. In 1977, these figures had risen to about $200,000 - $125,000 for the ERCB and $75,000 for the Department. It is expected that these figures will remain constant in 1978.

FIGURE 16

The revenue generated through sales of Crown oil and gas mineral rights has tripled from 1972 to 1976. During 1977 sales increased from $160 million to $579.7 million. The forecast for 1978 is 400 million.

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We recognize three factors which may exist when exploration is supported by an incentive program.

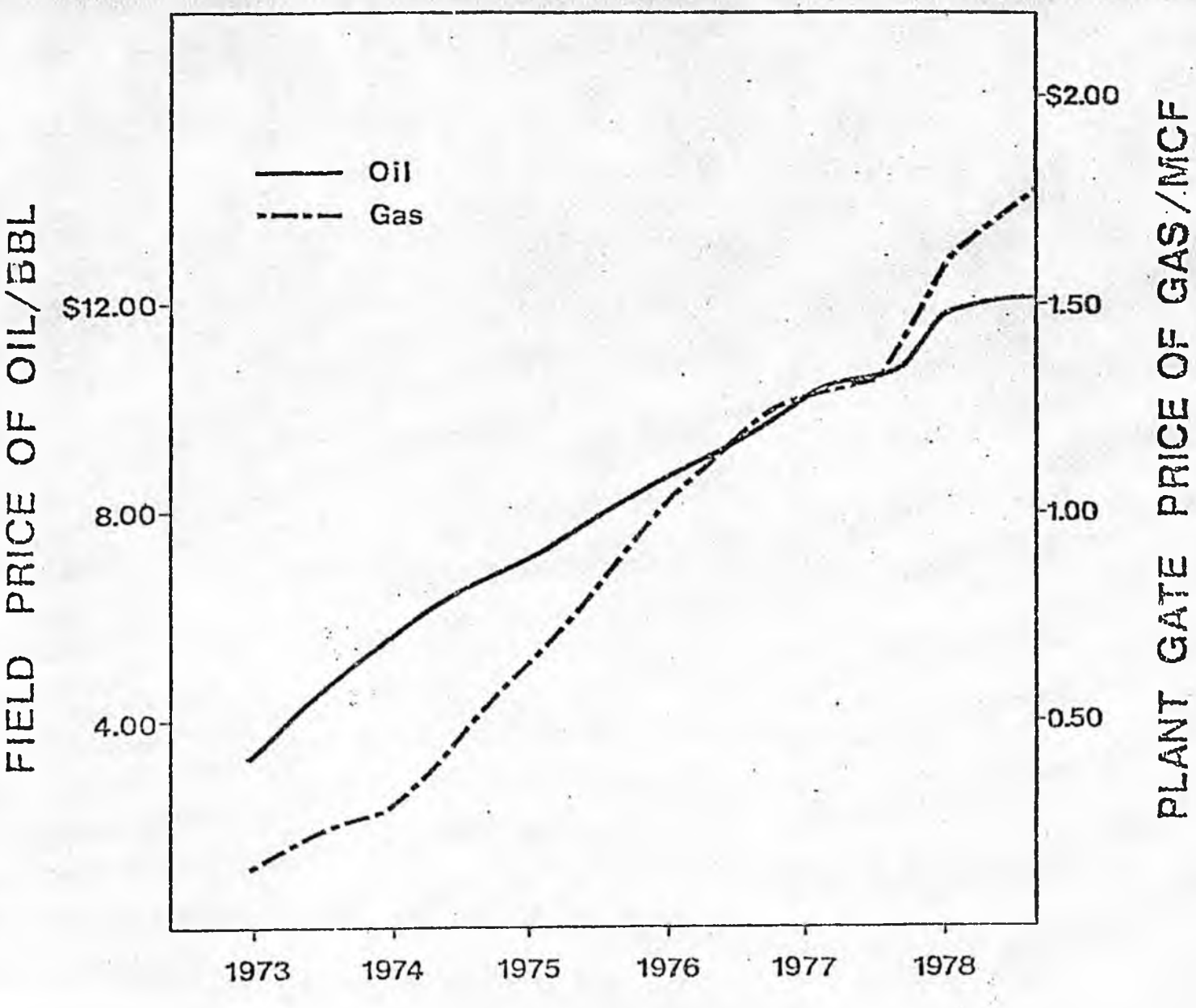
(a) The activity may have occurred even if it had not been supported by an incentive program.

(b) The exploration activity was advanced to take advantage of the programs before their scheduled termination dates.

(c) The activity may not be performed in the forseeable future without incentive support.

The second and third considerations appear in the present situation to be applicable. The programs have been directly responsible for the discovery of large additional reserves and have encouraged high risk deep drilling in the foothills region.

Although the definite effects of the programs on exploration activity cannot be quantitatively assessed, the general trend has shown a considerable increase in exploration activity since inception of the programs.



PRICE OF CRUDE OIL & NATURAL GAS

1973 - 1978

FIGURE 17

Energy & Natural Resources, June 1978

AGO 546794

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.

TESTIMONY ON H.B. 854

Mr. Chairman, members of the committee, my name is John Carson, and I appreciate the opportunity to comment on House Bill 854.

I've been a petroleum geologist for 22 years, and I'm presently Division Geologist in Alaska for Chevron U.S.A., the principal domestic oil and gas subsidiary of the Standard Oil Company of California. I've lived and worked in this state, and since 1965, I've been actively involved in all state lease sales and the two OCS sales in the Gulf of Alaska and the Lower Cook Inlet.

Chevron is aware of the amount of preliminary work done by the state administration and the Department of Natural Resources in researching and drafting this legislation.

We commend efforts in drafting legislation that proposes a five-year leasing program for Alaska. We believe the state should be encouraged in its effort to establish and maintain such a long-term program, with appropriate industry participation.

Members of the committee, the petroleum industry--as indicated by its response to your solicitations--clearly desires a realistic plan that can serve as the basis for an effective working relationship between the industry and the state.

Frankly, we believe the proposed legislation will inhibit or prevent orderly development of oil and gas resources in Alaska--to the detriment of the state government, its taxpayers and my own industry.

I will say candidly that this legislation is untenable from our point of view. If enacted into law, H.B. 854 would have a serious and far-reaching impact on my own company, and would give us serious cause to reconsider our exploration activities in the high-cost, high-risk frontier state lands of Alaska.

The situation we face today reminds me of a quote I heard the other day attributed to an executive of Walt Disney Productions, which recently announced that it was abondoning its latest recreation complex because of excessive and oppressive regulation.

The Walt Disney executive blamed the end of the project on, and I quote: "An irresponsible proliferation of delays, the never-ending requests for more irrelevant information and studies, and bureaucratic sidetracking and meanderings into unreasonable alternatives."

I realize this is the first of many hearings on this legislation, but H.B. 854, as now written, would be counter-productive. It actually would be a step backward at the very time our nation desperately needs an effective oil and gas exploration program.

Generally stated, we object to provisions covering: (1) the wide variety of bidding methods to be employed; (2) the Commissioner's access to all the lessee's data, including proprietary data; (3) the state's call on production; (4) short and restrictive lease term and conditions; (5) the need for the Commissioner to submit and defend his lease plan before the legislature; (6) the Commissioner's right to ban joint bidding by major companies; and (7) reduced acreage chargeability on state uplands.

Time does not permit me to discuss in detail each of the provisions, but I will attempt to outline our most significant objections:

First, the wide variety of bidding methods:

In advocating numerous bidding schemes--actually a shift from only cash bonus bidding, a system that has worked well--the administration hopes to maximize its financial return from state lands.

But Chevron believes a move away from the cash bonus method means the perilous abandonment of a proven concept that has brought stability to the state's leasing program. The bonus system would be replaced by an array of untested leasing methods, particularly in the frontier areas.

We believe this provision, if enacted, will transform Alaska into a trial-and-error laboratory in oil and gas leasing. It means replacing orderly development with uncertainty and the unknown. It's not a gamble Chevron feels is worth taking.

Before discussing each bidding system, all concerned parties should be aware that a move away from cash bonus bidding will result in three key developments:

First, it will shift a substantial part of the burden of risk from industry to the taxpayer.

Second, it will serve as a substantial deterrent to exploration and development, and

Third, it will cause the rapid and constant growth of state agencies to administer, evaluate and audit the leases and subsequent production. This places increasing demands on taxpayers to support this bureaucracy.

Chevron believes these are unacceptable consequences which would be intolerable to the taxpayers and leaders of this state.

As you know, cash bonus bidding provides that leases be awarded to the highest cash bonus bidder. This bonus is paid before the lessee can proceed with exploratory drilling on the lease.

The other bid methods provide for bid variables such as royalty, net profit, or work commitment. In these cases, the state receives nothing other than perhaps a small fixed bonus at the time of leasing. Other revenue is not forthcoming under the royalty and net profit schemes unless there is production. Simply stated: No production, no revenue.

In our opinion, cash bonus bidding is the only method that will strongly encourage the petroleum industry to lease and explore the state land.

We further believe that this method will result in the production of the most oil and gas and consequently will provide the most revenue, both to the state and the petroleum industry.

The other methods, employing biddable royalties and net profits, reduce the incentive to explore and produce. These alternatives, particularly in the case of biddable royalties, serve to shorten the economic life of the fields--resulting in less production and, therefore, less revenue.

Cash bonus bidding is particularly advantageous to the lessor in frontier areas of high risk. Most of Alaska's lands are in this category.

Now let's compare other proposed bidding methods with traditional cash bonus bidding. Because of time limitations, I can only touch briefly on these, but I am prepared to go into more detail if questions arise.

The royalty bidding method, although it allows oil and gas companies to acquire land with little cash, is a strong deterrent to early drilling. Very simply, it is easier and cheaper to wait on others to bear the risk and expense of exploratory drilling.

Having spent little capital to acquire the lease, an operator is tempted not to spend a dime to evaluate the lease, hoping an adjacent leaseholder may do it for him. Carried to the extreme, the effect of this would be that no wells would be drilled to evaluate the leases. This same problem is inherent in the net profits system, which I'll talk about shortly. On the other hand, when cash bonus is involved, the winning bidder has a strong incentive for early drilling because his bonus investment is earning him nothing.

In cash bonus bidding the state assumes none of the risk but still receives revenue from leases, whether or not they are productive.

The advantages of this system were clearly demonstrated a few years ago in the sale of federal leases off the coasts to Mississippi, Florida and Louisiana. Successful bidders paid $743 million for several tracts on one structure, the Destin Anticline, and spent over 10 million dollars drilling seven dry holes on the structure--all at no cost to the taxpayer. Under royalty or net profit bidding, the government would have received nothing.

What would government have received if it had sold the Gulf of Alaska on a royalty bid basis? As in the Gulf of Mexico case I previously cited, nothing. Should the taxpayer and the government be forced to suffer the loss of more than one-half billion dollars--when to date, no royalty appears forthcoming?

The NPRA comes to mind as another example of an area adjudged to possess high potential, but which so far is a disappointment. Again, if sold on a royalty bidding method, the lessors would have received nothing to date.

Let me emphasize that in all these cases, the areas were considered extremely attractive to both the industry and government. These are precisely the types of areas in which the state might be enticed to use a royalty or net profit bidding method. Yet none of these has led to any discovery or government revenue.

Proponents of royalty bidding believe it encourages competition among bidders and allows the small company and the independent improved entry into oil and gas lease bidding. Cash bonus bidding usually is blamed for tending to discourage small companies from bidding.

This is not supported by the facts. Small companies gain entry into the sale by joining with a larger company or with several other smaller companies. In the recent Lower Cook Inlet sale, independents and smaller companies bid on royalty and cash bonus tracts with about the same frequency as the majors. Of the 34 companies which bid in the sale, 18 were smaller companies. These 18 made successful cash bonus bids on 26 tracts, of which 13 were sold for more than one million dollars. Moreover, the small companies are represented in half of the top tracts of the sale.

The second proposed bidding method we are concerned about is net profit bidding. This system has most of the disadvantages of royalty bidding plus two more: It requires a huge staff to administer and audit.

For example, each property would require a battery of accountants to audit the companies' production and costs. Just as in the case of royalty bidding, the risks are passed on to the government. Furthermore, net profit bidding discourages cost-effective, efficient development practices.

Work commitment bidding is the least onerous alternative to cash bonus bidding methods and would be beneficial, provided that it is enforceable. We view this method with some caution because of the uncertainty of the conditions under which it might be imposed.

At this point, I would like to summarize why we believe a majority of the industry prefers cash bonus as the best method for both the state and the energy explorers.

First, we believe it is the foundation for all free enterprise contract arrangements;

Second, it is the simplest and easiest to determine and administer by all parties;

Third, it is fair and equitable; by this I mean that all parties travel at their own risk, and finally,

The right to explore is paid for in advance.

In 1977 the Department of Natural Resources completed a report entitled, "A Study of Petroleum Leasing Methods and Possible Alternatives." H.B. 854 apparently is based on this study and its conclusions.

In this study, a great deal of attention is given to the "percentage of acreage option." We assume this is the reason for granting the Commissioner authority to withhold acreage from any sale areas under Section 180 (c) (4) (f). Under this scheme, certain amounts of acreage would be withheld from a sale so that following a discovery the state could collect a windfall on drainage acreage sales. This is a workable approach only if you know which acreage to withhold and on which structures. This is rarely the case, as we saw in the MAFLA, Gulf of Alaska and NPRA. Furthermore, industry cannot bid or drill on only portions of prospects in high risk or high cost areas which predominate in Alaska.

I would like to make a few more comments about the Department of Natural Resources' report. The one overriding conclusion of that study was that a variety of bidding methods, widely employed, would increase the state's return from its commitment of oil and gas properties.

Chevron believes this conclusion is biased against cash bonus bidding, and we feel that the odds are against anyone knowing all they need to know to use the right method at the right time. The state, even if armed with a skilled staff and large amounts of data, can hope to do no better than an individual company in evaluating potential and risks, and these companies are more often wrong than right in their appraisals.

We believe the state's report, and particularly its main bias against cash bonus bidding, is based on a few but major faulty economic assumptions.

First, the authors of the report assume that the industry will make an 18 percent rate of return. Although this is very desirable, and would not be out of line considering the high risk involved, past experience shows that the industry has averaged no more than seven to eight percent from OCS ventures which approximates Alaska lands, according to several exhaustive studies. For example, in May 1977 Prof. Walter J. Mead of U.C. Santa Barbara testified before a U.S. House of Representatives Committee that weighted average rate of return from 184 leases issued in the Gulf of Mexico in 1954-55 amounted to only 7½ percent before taxes. This sale period was selected because these leases have a 20-year production history which provides a comprehensive data base.

Second, no reduction of state income was assumed in royalty cases, but it almost certainly will occur. The economic limit of a field is going to be greatly influenced by the amount of royalty. The higher the royalty, the earlier the economic limit is reached. When an operator can no longer produce oil or gas profitably the result will be oil and gas left in the ground and neither industry, nor the state, will make any money on it.

* * *

Next, I would like to turn to the provision of the bill that would require the lessee or permittee to make available to the Commissioner all data obtained from exploration and production activities on the lease or permit. We believe this provision raises fundamental questions about the appropriateness of the state's entry into the exploration business, and secondly, points to grave problems--from our point of view--about the preservation of confidentiality.

should but
The language in the proposed legislation does not distinguish between, "raw", "processed" and "interpretative" data. We are unalterably opposed to providing the state with the results of the efforts of our interpretative staff. Industry cannot operate under this law. We urge the committee to delete this section.

We are also opposed to giving the state our basic geophysical data. We are not convinced that the state can hold this data confidential because of its large staff and turnover rate. Any leak of this sensitive information to our competitors definitely will have an immediate and adverse impact on our exploration program in this state.

The third provision we object to (Sec. 38.05.180(v)) gives the state the right to purchase up to 16 and two-thirds percent of the lessee's share of the oil and up to 100 percent of the lessee's gas.

We are not opposed to the state's right to take its royalty share of oil or gas in kind, but we oppose any provisions which empowers the state to take any portion of the lessee's share.

In order to justify the risk and expense of exploration and development, and be able to satisfy its contractual commitments, the lessee must retain the right to dispose of all of its share of production. Without this right, the state of Alaska lands become less desirable to explore and develop. We believe this is another step toward the state's entry into the oil and gas business, which should stay with private industry.

It seems inconceivable to Chevron that the state would take a portion of the lessee's share when that is the very incentive for industry to explore in the state initially.

Another provision we oppose is Paragraph Q. Paragraph Q refers to drilling and development contracts and to the authority of the state to share in the cost of exploration.

We're not clear on the meaning and intent of this paragraph. If it means the state intends to become a working interest participant in leases, then we strongly object.

Our next objection concerns the terms and conditions of the lease itself. Because of the remoteness of most of Alaska's land and the seasonal restriction on operations, Chevron prefers a ten-year primary lease term. We feel this length of time is necessary to adequately evaluate a lease under Alaskan conditions.

There is one provision which would allow the Commissioner to grant rights on leases only to the depth drilled at the time production begins. Chevron is at a total loss to see how this provision can benefit the state in any way. It will certainly cause waste in time and money for the industry because wells will be drilled far beyond primary objectives--just to ensure earning the rights of a normal lease. In effect, this will delay production and thereby delay revenue to the state.

Considering the geological, legal and practical ramifications of this provision, one must conclude that it is totally unacceptable to the industry and can do the state no good. It should be stricken from the bill.

Our next objection is to any effort to restrict joint bidding between majors or multinational companies. In Alaska, particularly, with its accompanying expensive costs of exploration and production, it is essential for large and small companies to be able to join together to share the risk.

A ban on joint bidding by majors does not necessarily increase state income. In fact, a recent study by the Department of Interior showed that joint bidders tend to bid higher, on the average, than solo bidding competitors. (November 1976 issue of the Journal of Petroleum Technology.)

The next provision we wish to discuss deals with the need for the Commissioner to submit and defend his leasing program to the legislature. We prefer that the various reporting methods set out in this section not be prescribed in law. We believe this review is an administrative function and that public hearings are an adequate and effective vehicle for gathering comments and reactions to the proposed action. Neither the timber leases nor any other types of state lease are submitted to the legislature, and to require this approach in law for the petroleum industry will lead to further delays in development of the state's natural resources. Particularly objectionable to us is the requirement that the Commissioner must defend his previous year's program and explain why he used certain methods. This is certain to toss the entire leasing program into an interminable bureaucratic morass.

And finally we oppose the provision which deals with acreage chargeability. We believe the reduction to 200,000 acre limitation on uplands is arbitrary and unjustified. The 500,000 acre limitation in this state, where there are large areas of state lands potentially available for bid, is not unreasonable. A large acreage position is necessary as an incentive for an operator to explore frontier areas.

In closing, Mr. Chairman, Chevron believes H.B. 854 is an unreasonable, unwise and unworkable piece of legislation that simply is not in the best interest of the citizens of Alaska.

As I said at the outset of my remarks, my own company would be faced with the prospect of seriously reassessing its current and future exploration activities on Alaska state lands if this bill is enacted.

It is our opinion that this legislation will only serve to inhibit or prevent the orderly exploration and development of Alaska's oil and gas properties.

We oppose a shift away from the successful cash bonus bidding system because we believe that the cash bonus ensures a fair and equitable return to the state, as well as ensuring the fair share of any revenue resulting from production.

It is conceivable that Prudhoe Bay may not have been found if royalty or net profits bidding or percentage acreage option had been employed.

Mr. Chairman, members of the committee, we have serious concern that if this legislation becomes law, the ultimate losers will be the citizens of this state, as well as the consumers of oil and gas.

Thank you for giving Chevron this opportunity to comment on this proposed legislation.

* * *

TESTIMONY ON COMMITTEE SUBSTITUTE FOR HOUSE BILL 854 (FINANCE)

PRESENTED BEFORE THE

SENATE RESOURCES COMMITTEE

BY

J. R CARSON

CHEVRON, USA, INC.

May 22, 1978

Juneau, Alaska

TESTIMONY ON H.B. 854

Madam Chairman, members of the committee, my name is John Carson, and I appreciate the opportunity to comment on Committee Substitute for House Bill 854. (Finance)

I am a petroleum geologist and I'm presently Division Geologist in Alaska for Chevron U.S.A., the principal domestic oil and gas subsidiary of the Standard Oil Company of California. Since 1965, I've been actively involved in all state lease sales and the two OCS sales in the Gulf of Alaska and the Lower Cook Inlet.

Chevron is aware of the amount of preliminary work done by the state administration and the Department of Natural Resources in researching and drafting this legislation.

We commend efforts in drafting legislation that proposes a long term leasing program for Alaska. We believe the state should be encouraged in its effort to establish and maintain such a program, with appropriate industry participation.

Members of the committee, the petroleum industry--as indicated by its response to the State's solicitations--clearly desires a realistic plan that can serve as the basis for an effective working relationship between the industry and the state.

Frankly, we believe the proposed legislation will inhibit or prevent orderly development of oil and gas resources in Alaska--to the detriment of the state government, its taxpayers and my own industry.

I will say candidly that this legislation is untenable from our point of view. If enacted into law, Committee Substitute for House Bill 854 would have a serious and far-reaching impact on my own company, and would give us serious cause to reconsider our exploration activities in the high-cost, high-risk frontier state lands of Alaska.

854 as now written would be counter-productive. It actually would be a step backward at the very time our nation desperately needs an effective oil and gas exploration program.

Generally stated, we object to provisions covering: 1) the wide variety of bidding methods to be employed; 2) the Commissioner's access to all the lessee's data, including proprietary data; 3) the state's call on production; 4) short and restrictive lease term and conditions; 5) the need for the Commissioner to submit and defend his lease plan to the legislature, and 6) the Commissioner's right to ban joint bidding for approval.

Time does not permit me to discuss in detail each of the provisions, but I will attempt to outline our most significant objections:

First, the wide variety of bidding methods, starting on page 3, section (f):

In advocating numerous bidding schemes--actually a shift from only cash bonus bidding, a system that has worked well--the administration hopes to maximize its financial return from state lands.

But Chevron believes a move away from the cash bonus method means the perilous abandonment of a proven concept that has brought stability to the state's leasing program. The bonus system would be replaced by an array of untested leasing methods, particularly in the frontier areas.

We believe this provision, if enacted, will transform Alaska into a trial-and-error laboratory in oil and gas leasing. It means replacing orderly development with uncertainty and the unknown. It's not a gamble Chevron feels is worth taking.

Before discussing each bidding system, all concerned parties should be aware that a move away from cash bonus bidding will result in three key developments:

First, it will shift a substantial part of the burden of risk from industry to the taxpayer.

Second, it will serve as a substantial deterrent to exploration and development, and

Third, it will cause the rapid and constant growth of state agencies to administer, evaluate and audit the leases and subsequent production. This places increasing demands on taxpayers to support this bureaucracy.

Chevron believes these are unacceptable consequences which would be intolerable to the taxpayers and leaders of this state.

As you know, cash bonus bidding provides that leases be awarded to the highest cash bonus bidder. This bonus is paid before the lessee can proceed with exploratory drilling on the lease.

The other bid methods provide for bid variables such as royalty, net profit, or work commitment. In these cases, the state receives nothing other than perhaps a small fixed bonus at the time of leasing. Other revenue is not forthcoming under the royalty and net profit schemes unless there is production. Simply stated: No production, no revenue.

In our opinion, cash bonus bidding is the only method that will strongly encourage the petroleum industry to lease and explore the state land.

We further believe that this method will result in the production of the most oil and gas and consequently will provide the most revenue, both to the state and the petroleum industry.

The other methods, employing biddable royalties and net profits, reduce the incentive to explore and produce. These alternatives, particularly in the case of biddable royalties, serve to shorten the economic life of the fields--resulting in less production and, therefore, less revenue.

Cash bonus bidding is particularly advantageous to the state in frontier areas of high risk. Most of Alaska's lands are in this category.

Now let's compare other proposed bidding methods with traditional cash bonus bidding. Because of time limitations, I can only touch briefly on these, but I am prepared to go into more detail if questions arise.

The royalty bidding method, although it allows oil and gas companies to acquire land with little cash, is a strong deterrent to early drilling. Very simply, it is easier and cheaper to wait on others to bear the risk and expense of exploratory drilling.

Having spent little capital to acquire the lease, an operator is tempted not to spend a dime to evaluate the lease, hoping an adjacent leaseholder may do it for him. Carried to the extreme, the effect of this would be that no wells would be drilled to evaluate the leases. This same problem is inherent in the net profits system, which I'll talk about shortly. On the other hand, when cash bonus is involved, the winning bidder has a strong incentive for early drilling because his bonus investment is earning him nothing.

In cash bonus bidding the state assumes none of the risk but still receives revenue from leases, whether or not they are productive.

The advantages of this system were clearly demonstrated a few years ago in the sale of federal leases off the coasts of Mississippi, Alabama, Florida and Louisiana. Successful bidders paid $743 million for several tracts on one structure, the Destin Anticline, and spent over 10 million dollars drilling seven dry holes on the structure--all at no cost to the taxpayer. Under royalty or net profit bidding, the government would have received nothing.

What would government have received if it had sold the Gulf of Alaska on a royalty bid basis? As in the Gulf of Mexico case I previously cited, nothing. Should the taxpayer and the government be forced to suffer the loss of more than one-half billion dollars--when to date, no royalty appears forthcoming?

The NPRA comes to mind as another example of an area adjudged to possess high potential, but which so far is a disappointment. Again, if sold on a royalty bidding method, the lessors would have received nothing to date.

Let me emphasize that in all these cases, the areas were considered extremely attractive to both the industry and government. These are precisely the types of areas in which the state might be enticed to use a royalty or net profit bidding method. Yet none of these has led to any discovery or government revenue.

Proponents of royalty bidding believe it encourages competition among bidders and allows the small company and the independent improved entry into oil and gas lease bidding. Cash bonus bidding usually is blamed for tending to discourage small companies from bidding.

This is not supported by the facts. Small companies gain entry into the sale by joining with a larger company or with several other smaller companies. In the recent Lower Cook Inlet sale, independents and smaller companies bid on royalty and cash bonus tracts with about the same frequency as the

majors. Of the 34 companies which bid in the sale, 18 were smaller companies. These 18 made successful cash bonus bids on 26 tracts, of which 13 were sold for more than one million dollars. Moreover, the small companies are represented in half of the top bonus tracts of the sale.

Provisions are made for reducing the royalty in the event the lessee cannot operate profitably. While we agree that such a provision may be necessary, we think this only serves to point up a major weakness of royalty bidding. Due to the highly competitive nature of the business, industry is encouraged to bid and agree to terms that may be truly ridiculous. Another commission will almost certainly be necessary to review and rule on the long list of plaintiffs for reduced royalties.

The second proposed bidding method we are concerned about is net profit bidding. This system has most of the disadvantages of royalty bidding plus one more: It requires a huge staff to administer and audit. For example, each property would require a battery of accountants to audit the companies' production and costs. Just as in the case of royalty bidding, the risks are passed on to the government. Furthermore, net profit bidding discourages cost-effective, efficient development practices.

At this point, I would like to summarize why we believe a majority of the industry prefers cash bonus as the best method for both the state and the energy explorers.

First, we believe it is the foundation for all free enterprise contract arrangements;

Second, it is the simplest and eas_ st to determine and administer by all parties;

Third, it is fair and equitable; by this I mean that all parties travel at their own risk, and finally,

The right to explore is paid for in advance.

In 1977 the Department of Natural Resources completed a report entitled, "A Study of Petroleum Leasing Methods and Possible Alternatives." H.B. 854 apparently is based on this study and its conclusions.

I would like to make a few comments about the Department of Natural Resources' report. The one overriding conclusion of that study was that a variety of bidding methods, wisely employed, would increase the state's return from its commitment of oil and gas properties.

Chevron believes this conclusion is biased against cash bonus bidding, and we feel that the odds are against anyone knowing all they need to know to use the right method at the right time. The state, even if armed with a skilled staff and large amounts of data, can hope to do no better than an individual company in evaluating potential and risks, and these companies are more often wrong than right in their appraisals.

We believe the state's report, and particularly its main bias against cash bonus bidding, is based on a few but major faulty economic assumptions.

First, the authors of the report assume that the industry will make an 18 percent rate of return. Although this is very desirable, and would not be out of line considering the high risk invclved, past experience shows that the industry has averaged no more than seven to eight percent from OCS ventures which approximates Alaska lands, according to several exhaustive studies. For example, in May 1977 Prof. Walter J. Mead of U.C. Santa Barbara testified before a U.S. House of Representatives Committee that weighted average rate of return from 184 leases issued in the Gulf of Mexico in 1954-55 amounted to only 7½ percent before taxes. This sale period was selected because these leases have a 20-year production history which provides a comprehensive data base.

Second, no reduction of state income was assumed in royalty cases, but it almost certainly will occur. The economic limit of a field is going to be greatly influenced by the amount of royalty. The higher the royalty, the earlier the economic limit is reached. When an operator can no longer produce oil or gas profitably the result will be oil and gas left in the ground and neither industry, nor the state, will make any money on it.

Next, I would like to turn to the provision of the bill that would require the lessee or permittee to make available to the Commissioner all data obtained from exploration and production activities on the lease or permit. Found on p. 11 - section (aa). We believe this provision raises fundamental

questions about the appropriateness of the state's entry into the exploration business, and secondly, points to grave problems--from our point of view--about the preservation of confidentiality.

The language in the proposed legislation is not clear as to what non-interpretive data will be required. If the intent is to provide access to data existing prior to the lease, we are unalterably opposed. "Non-interpretive" is a loaded word which needs strict definition.

We are also opposed to giving the state our basic geophysical data. We are not convinced that the state can hold this data confidential because of its large staff and turnover rate. Any leak of this sensitive information to our competitors definitely will have an immediate and adverse impact on our exploration program in this state.

The third provision we object to gives the state the right to purchase a specified volume of the lessee's oil or gas. This is found on p. 11, section (Z).

We are not opposed to the state's right to take its royalty share of oil or gas in kind, but we oppose any provisions which empowers the state to take any portion of the lessee's share.

In order to justify the risk and expense of exploration and development, and be able to satisfy its contractual commitments, the lessee must retain the right to dispose of all of its share of production. Without this right, the state of

Alaska lands become less desirable to explore and develop. We believe this is another step toward the state's entry into the oil and gas business, which should stay with private industry.

It seems inconceivable to Chevron that the state would take a portion of the lessee's share when that is the very incentive for industry to explore in the state initially.

If such a clause remains in the bill, Chevron feels it is mandatory that the state make its intention known on this matter prior to the lease sale. Otherwise, it will be totally inoperable. The industry, without contractual commitments for its product, cannot bid on oil and gas leases.

Our next objection concerns the terms and conditions of the lease itself. I refer to p. 6, section (n). Because of the remoteness of most of Alaska's land and the seasonal restriction on operations, Chevron prefers a ten-year primary lease term. We feel this length of time is necessary to adequately evaluate a lease under Alaskan conditions. We appreciate that the proposed legislation gives the Commissioner the right to grant a ten-year lease under certain conditions. However, it should be stated that this decision will be made and announced prior to this sale.

Our next objection is to any effort to restrict joint bidding, found on p. 10, section (y). In Alaska, particularly, with its accompanying expensive costs of exploration and production, it is essential for large and small companies to be able to join together to share the risk.

A ban on joint bidding does not necessarily increase state income. In fact, a recent study by the Department of Interior showed that joint bidders tend to bid higher, on the average, than solo bidding competitors. (November 1976 issue of the Journal of Petroleum Technology.)

The final provision we wish to discuss deals with the need for the Commissioner to submit and defend his leasing program to the legislature. See p. 1, section (b). We prefer that the various reporting methods set out in this section not be prescribed in law. We believe this review is an administrative function and that public hearings are an adequate and effective vehicle for gathering comments and reactions to the proposed action. Neither the timber leases nor any other types of state leases are submitted to the legislature, and to require this approach in law for the petroleum industry will lead to further delays in development of the state's natural resources. Particularly objectionable to us is the requirement that the Commissioner must defend his previous year's program and explain why he used certain methods. This is certain to toss the entire leasing program into an interminable bureaucratic morass.

In closing, Madam Chairman, Chevron believes CS for H.B. 854 is an unreasonable, unwise and unworkable piece of legislation that simply is not in the best interest of the citizens of Alaska.

As I said at the outset of my remarks, my own company would be faced with the prospect of seriously reassessing its current and future exploration activities on Alaska state lands if this bill is enacted.

It is our opinion that this legislation will only serve to inhibit or prevent the orderly exploration and development of Alaska's oil and gas properties.

We oppose a shift away from the successful cash bonus bidding system because we believe that the cash bonus ensures a fair and equitable return to the state, as well as ensuring the fair share of any revenue resulting from production.

It is conceivable that Prudhoe Bay may not have been found if royalty or net profits bidding or percentage acreage option had been employed. Our sincere suggestion is to retain the leasing statute now in effect and supplement it with provisions for a long term leasing program.

Madam Chairman, members of the committee, we have serious concern that if this legislation becomes law, the ultimate losers will be the citizens of this state, as well as the consumers of oil and gas.

Thank you for giving Chevron this opportunity to comment on this proposed legislation.

* * *

H.B. 854
Gov's. Bill

TESTIMONY ON

ALASKA LEASING POLICY BILL

(H.B. 854)

By
Rod L. Boane
Alaska District Manager
Exxon Company, U.S.A.

Before The
State of Alaska
House Resources Committee

Juneau, Alaska

March 17, 1978

Mr. Chairman and Members of the Committee --

I am Rod L. Boane, District Manager for the Alaska Exploration District of Exxon Company, U.S.A. I appreciate the opportunity to be here today and present the views of my Company concerning the proposed Leasing Policy Bill.

First, let me say that Exxon believes the existing provisions of Section 38.05.180 of the Alaska Statutes are quite satisfactory in administering adequate control over exploratory and development activities on State leases. Therefore, we do not believe these new amendments to the Statutes are needed to protect the public interest. On the contrary, we think the proposed amendments would create unnecessarily involved and cumbersome procedures that will neither foster needed exploration nor benefit the State of Alaska. Although we take exception to almost all features of the proposed amendments, in the interest of time, I intend to discuss only the more troublesome provisions, with particular emphasis on the proposed bidding methods.

Exxon believes that the best method for awarding leases is on a cash bonus basis. This system has several advantages which I would like to review.

- First, the successful bidder sees very strong incentives to explore and develop rapidly and to recover the maximum economic volume of hydrocarbons at the lowest possible cost. This is necessary in order for him to maximize the return on the cash bonus invested.

- Second, under the cash bonus system, the State bears none of the risk that commercial reserves will not be found. This risk is placed directly on industry where it belongs. This is a particularly critical concept in Alaska which is still essentially a frontier province where very little exploratory drilling has occurred and thus very little is known about the oil and gas potential of most of the State. When one further takes into account the fact that Alaska is a very high cost area due to its remoteness and harsh operating environment, it should be easy to see that the exploration risks and costs are indeed great. The Gulf of Alaska history should prove this point as, thus far, no commercial discovery has been made.

- Third, under the cash bonus system there is no possible way that the awards will be made in an arbitrary manner since the highest bid is obvious.

- Finally, the system is simple and inexpensive to administer, and its integrity is unaffected by future events. The State would not have to expand its staff to implement this system.

Now I would like to compare the alternate bidding methods proposed in this legislation to conventional cash bonus bidding with fixed royalty. Basically, the proposed alternative bidding methods fall into one of three categories. The first category involves some form of royalty bidding. The second category uses

some form of net-profit bidding. The third category uses some form of work commitment. All three categories require a cash bonus, either as a bid variable or a fixed amount. Let's first examine the royalty bidding systems.

(1) It is not uncommon for operators to discover reserves of lesser magnitude than anticipated. With high fixed royalty, some of these discoveries could not be developed profitably unless the State agreed to accept a lower royalty than originally bid. Downward adjustment in royalty rate prior to any development would be difficult to administer and could undermine the integrity of this bidding system.

(2) With royalty bidding, the successful bidder does not have a strong incentive for rapid exploration and development since front-end cash investment is small. Speculators could therefore see incentives to acquire leasehold interest, and then wait in hopes that they will be able to cash in on the discoveries made by others. This situation would obviously result in delayed exploration and development activities.

(3) With exclusive royal bidding, the public bears the major portion of the exploration risk because if the tract doesn't contain commercial hydrocarbon reserves, as the majority will not, the public receives no compensation whatever. As an example, the State received $900 million in bonus for acreage on the North Slope in the September 1969 sale. Under a royalty bidding system the State would have received little income to date. We strongly believe that risk-taking and its associated rewards or losses are more properly the province of private enterprise.

The second royalty bidding system involves a sliding scale royalty system which would be difficult to monitor and, practically speaking, would make it impossible to compare bids unless you know the total reserves, the price at which production would be sold, and the rate of production. Sliding royalty could result in widely differing positions on prudent development. Also, unitization of tracts would be a very complex and difficult job.

With these comments in mind, let's review recent experience with royalty bidding in the Federal sector. A program of experimentation began with the recent sale in the Lower Cook Inlet. Thirty-four percent of the tracts were put up for royalty bidding. Selection of these tracts was in such a manner that they were scattered over the entire sale area. When this type of tract distribution is coupled with a forced unitization lease stipulation, it is not difficult to conclude that the owners of the royalty tracts have no incentive for rapid evaluation. They can just sit back and wait for the owners of cash bonus tracts to do the initial drilling. They can then join the units covering any reservoirs that extend under their tract.

After the Cook Inlet sale, this problem apparently became obvious to the Department of Interior. For the North Atlantic Sale (Sale #42), they attempted to "fix" this problem by grouping the royalty tracts together and having them removed from the cash bonus tracts. They further expanded the experiment by having a group of cash bonus tracts that had a fixed royalty of 40 percent.

Industry comments relating to royalty bidding have apparently begun to create some concerns about this system. In the upcoming South Atlantic Sale (Sale #43), we see another attempt to "fix" difficulties in the previous system. Tracts are being offered by cash bonus bidding with a sliding scale royalty. They have attempted to "fix" the unitization problem by again grouping the sliding scale royalty tracts together. However, they did not address how a group of sliding scale royalty tracts or sliding scale royalty and cash bonus tracts would be unitized.

Now that this experimentation process has begun, we see the continuing creation of new difficulties and complexities as attempts are made to correct previous difficulties and problems. It appears that this process is going to have a "snow-balling" effect and may eventually reduce competition. In this situation, only the companies that can afford to dedicate a large professional staff to the long unitization negotiations and wait long periods for initial production will servive. This certainly does not promote increased competition.

Now let's look at the second bidding category a profit-sharing system, which has most of the same adverse characteristics as royalty bidding, but with four added complications and disadvantages.

(1) Using net profits will be much like selecting a contractor to perform a job. The operating efficiency of the bidder could become an important consideration in determining which of

several bidders had submitted the high bid inasmuch as the gross proceeds to be received by the public would be a direct function of the efficiency of the operator. Thus, the successful bidder would no longer be obvious. Since the relative operating efficiency of companies cannot be determined quantitatively, the Commissioner would be vulnerable to charges that bid awards were being made in an arbitrary or discriminatory manner.

(2) A profit-sharing system would be difficult and costly to administer. A large administrative organization would likely be established to audit and monitor the continuing activities of lessees. Discretionary judgments would be required by the State with regard to what costs were to be included or rejected in the profit base. This system could lead to State control of expenditures.

(3) A profit-sharing system would significantly reduce the incentive for a successful bidder to operate at maximum efficiency. Any prudent operator utilizes a priority system when restraints of either manpower or materials create limitations. When these restraints exist, net-profit tracts will have low priority. The result - reduction of efficiency. It would also reduce the timing and incentive for development of advanced technology currently in progress by industry.

(4) Most important, sharing in net profits would signal the State's entry into the production phase of the oil business. It might be politically and economically difficult for the State not

to be deeply involved in decisions about day-to-day operations and thereby become an operating partner. This step would not be consistent with the maintenance of a strong private enterprise system either within the oil industry or within the State itself.

The third category of bidding system is work commitment which can be combined with any of the other methods. A work commitment bid becomes a form of cash bonus bidding. If an operator has a high interest in a tract, he will bid a work commitment which is equivalent to what he would bid in a cash bonus system. In many instances, this committment would be much larger than required for evaluation. If early exploration results are negative, the operator remains committed to drill more wells than would normally be prudent or necessary.

The provision that the Commissioner can terminate a work commitment further complicates the issue. Termination of a work commitment for one operator would undoubtedly result in inequities because he has received an unfair competitive advantage. Continuation of this practice could result in extremely high work commitments in anticipation of cancellation after performing only a portion of the work.

A work commitment bid will be nothing more than a form of cash bonus. The same result can be accomplished more easily and efficiently with a cash bonus bid.

Now I would like to discuss a few other provisions which give us concern.

(1) AS38.05.180(v) Right to Purchase - The provision gives the State the right to purchase not more than 16 2/3 percent of the oil and 100 percent of the gas. The most onerous portion of this provision is the right of the State to purchase 100 percent of the gas.

The present and potential supplies of gas within Alaska far exceed reasonably anticipated demands by the State residents. Therefore, to find a market, this gas will have to move into interstate commerce. This requirement, that the State could remove the gas from the market, could severely hamper a producer's ability to market the reserves. Without a reasonable expectation that the developed gas can be marketed, there is greatly reduced incentive to explore.

It would also retard development of natural gas for State residents. The risk that the gas could be diverted would have significant impact on ventures to install gas transportation systems.

In addition to these concerns, it raises other questions such as:

1. Determination of fair market value
2. Use of gas for lease fuel
3. Timing and rate of production - could the State control these to satisfy their own requirements or desires?

(2) AS380.05.180(w) - Exxon is strongly opposed to this proposed section which requires any lessee or permittee conducting exploration for, or development or production of, oil or gas on State land, to provide the Commissioner access to all data obtained from such activity and to provide copies of such specified data, as the Commissioner may request. Access to all data could potentially permit endless intrusions into private business. Much of this data is very costly. In a competitive industry such as ours, a considerable amount of data is proprietary. Disclosure of this type of data could result in the loss of a competitive edge. In none of the other producing states are operators required to provide access to all data. In addition, we feel that any such requirement would, in effect constitute a "taking" for which compensation by the State would be required. We believe this proposed amendment is unnecessary and should be deleted because the existing regulations provide the State with adequate control over exploration and development activities.

(3) AS38.05.100(1) - We are strongly opposed to the concept of earning production rights only to the depth drilled at the beginning of production from a lease. We are not aware of this language in lease forms for any other producing state.

This language is somewhat similar to that commonly used by a lessee in "farming out" acreage for the purpose of evaluating specific geologic objectives by a third party. In a frontier

province like Alaska it doesn't make any sense to place such restrictions in the lease form. The idea should be to give the lessee maximum flexibility in evaluating his acreage - not to curtail or to require unreasonable and costly actions on his part. We, therefore, strongly suggest that this language be deleted.

We also recommend that reworking be added to the list of actions which will hold a lease in force. In fact, a grace period of 60 days should be allowed between cessation of production and initiation of drilling or reworking operations. This useful and desirable feature is in the present law.

(4) AS38.05.180(j) Lease Term - A five-year primary lease term is very restrictive in Alaska. The remote location of most prospects, rugged terrain, short construction season, and reduced drilling season, either necessary or imposed, make completion of the exploration cycle a difficult and time-consuming process. Once a discovery is made, additional drilling is required before an estimate of the field size can be made. All of the previously mentioned factors affect this drilling too. Once the lengthy process of discovering a field and establishing its commerciality is complete, the long development phase must begin. We strongly recommend that the 10-year lease term be retained.

(5) AS38.05.180(c) Uplands Acreage Limitation - The proposed 200,000-acre limitation on all lands other than tide and submerged lands is very restrictive compared with the current 500,000-acre limitation in a State like Alaska which has so many frontier

interior basins to explore. In a hostile high cost environment such as Alaska, a large block of acreage may be necessary in order to justify exploration. We believe the proposed 200,000-acre limitation would be a strong disincentive of an operator to explore these frontier interior basins and strongly recommend maintenance of the current 500,000-acre limitation.

(6) AS38.05.180(u) Joint Bidding - The provision allowing the Commissioner to restrict joint bidding, if he so desires, could prohibit the involvement of some companies most capable of operating in the Alaskan environment.

A study was performed by the University of Southern California and the USGS to determine the effects of restricting majors from bidding jointly in the OCS. They concluded that on the average, this restriction resulted in more bids per lease by the major oil companies.

(7) Legislative Review - We object to the requirement for submission of the leasing program for annual review by the Legislature because we believe it will result in unnecessary delays in implementing leasing programs.

(8) AS38.05.180(q) Drilling and Development Contracts - The proposed amendment which would allow the State to share in exploration costs is inconsistent with the provisions of the lease agreement, as the State's royalty interest is free of all exploration

and development costs. If this is intended to allow the State to share in working interest, we are opposed since it would signal entrance of State Government into the oil and gas business.

In closing, I would like to reiterate that Exxon believes the current leasing statutes and the implementing and regulations have served the State and industry well and do not need to be changed.

Passage of this bill will require the State to embark into an experimental program. Because these systems are unknown, many mistakes will be made. New "wrinkles" will be tried in order to correct these mistakes. In fact, the State of Alaska will find itself taking a course which is identical to the course presently being followed by the Federal Government. The end result will be an extremely complex system which may allow only a few companies to survive.

This concludes my prepared testimony, and I will be happy to answer any questions which you may have.

* * * * *

Anchorage Division
Production Exploration, U.S. & Canada

Marathon Oil Company

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May 22, 1978

Ms. Kay Poland, Chairman
Senate Resources Committee
Pouch V
Juneau, AK 98911

Dear Ms. Poland:

We wish to submit herein Marathon's thoughts, concerns and suggestions regarding the proposed legislation entitled "An Act relating to the leasing and exploration of state land for oil and gas development".

First and most important, the present statues and regulations have worked well for the State and they have a background for proper legal interpretation and understanding. The State has under the existing laws authority to protect itself and to judge whether it is receiving fair value for leases sold at that time with the then known information. Hind sight makes instant experts of persons unknowledgeable in a given field of endeavor. Oil and Gas exploration is a risk business and it deals with many unknowns until it has the opportunity to prove or disprove a theory or imagitative interpretation by drilling a test well. Therefore it is our

feeling that the proposed legislation being considered here today is unnecessary.

Specific comments to provision of HR 854 are as follows: 38.05.180(b) requires the commissioner to annually submit a proposed leasing schedule, wherein the legislature has the opportunity to disapprove all or part of it. It has long been the theory that the legislature makes the law and the Administration implements them. This proposed procedure gets the legislature involved with implementation of the laws. We feel there is much more important work for the legislature than looking at a specific leasing schedule, unless of course, there has been some impropriety.

38.05.180(f) provides for numerous bidding methods the commissioner may use to issue oil and gas leases. Other than the cash bonus bid and a fixed royalty reserved to the state, we believe the systems would not be in the best interest of the State of Alaska. When royalty bidding and net profits bidding methods are used the citizens of the state are then assuming a portion of the risk. Also, these methods will require additional personnel to administer and could result in less net return to the citizens. The small population of the State of Alaska does not need laws that would enlarge the bureaucratic organization.

When leases in a given area have various royalty provisions it would be difficult if not impossible for the individual companies to agree on a unit operation. With

differing royalty provisions the companies would have different economic incentives and philosophies which would be impossible to overcome.

In Section 38.05.180(n), we encourage its modification to provide for ten (10) year term leases as provided for in existing statues. The short operating seasons and continuing environmental concerns and lengthy process to obtain permits to drill are reasons to justify a ten (10) year term lease.

In line 11 on page 7 of this same section, it is recommended that the words "or is capable of" be added following the word "produced". This would in our opinion clarify the intent. Also we recommend the following sentence be added to this section "No lease issued under this section expires because operation or production is suspended under an order, or with the consent of the commissioner".

In Section 38.05.180(o), we recommend that a fixed rental be established for a lease and that it continue for the life of the lease or until production commences. That a minimum royalty be established and it be payable at the expiration of each lease year beginning on or after a discovery of oil and gas in paying quantities on the lands leased. Also that there be no dual payment of rental and royalties as presently provided for in the proposed leasing bill.

In Section 38.05.180(z), we feel the provision for the

state to take or purchase any volumes of discovered hydrocarbons over and above the reserved royalty share would be counter productive. Such provisions could eliminate or impair the ability of lessees to utilize gas sale contracts or production payments as a method of financing, likewise discourage exploration.

In 38.05.180(aa), we have strong misgivings about furnishing data as provided for therein. Information garnered from ones own initiative and imagination is valuable and proprietary and should be retained by ones own self. These provisions will certainly be counter productive.

In our statement, we have voiced some of our concerns and objections as well as some suggested modifications to HR 854, however, it is our hope that this proposed legislation will languish in committee without further action. We feel the existing law is satisfactory and workable. HR 854 will create confusion and misunderstanding in its implementation and will unnecessarily enlarge the bureaucratic organization and we recommend its rejection.

Very truly yours,

Morris L. Lowman
Senior Landman
MLL/pr

cc: Resource Committee Members

AOGA COMMENTS -- HOUSE BILL NO. 854

Comments on Section 1:

Sec. 38.05.180(a)(1)(B)

In the description of the legislative purposes of this bill, there is a negative connotation given the word "exploitation" in Sec. 38.05.180(a)(1)(B). This section in general suggests sinister motives to the oil and gas industry which need to be "minimized." A possible modification should read, "regulate the development of these natural resources in protection of the public interest."

Sec. 38.05.180(a)(2)

Underlying this section is the notion that it is in the State's best interest to maximize the leasing methods available to the State. However, it is our view that the new leasing methods proposed are largely untested and may result in reduced revenues to the State. Further, it is not at all clear how a unit agreement could ever be formulated for a group of lessees who had obtained their leases under a combination of the proposed bidding methods.

Sec. 38.05.180(b)

This section deals with the Commissioner's obligations to prepare a leasing program for the following 5 year period and his obligation to keep the legislature informed. We are in favor of such a long-range leasing program and support the State's acknowledged

goal of "stability and predictability" in a petroleum leasing program. However, the long-range benefits intended and the State's goal are frustrated by the ability, and, indeed requirement, that the Commissioner review and possibly revise the leasing program at least annually. Perhaps the possibility of revision could be limited to the last two years of the ongoing five year programs so that industry could expend exploration dollars with some certainty that a sale will be held. Alternatively, Sec. 38.05.180(b)(3) should be deleted.

The annual submission to the legislature of the leasing program, although for "its information," would seem to presuppose further modification of the leasing program. Again, opportunity for yearly modification of the leasing program abrogates the State's goal of a stable and predictable petroleum leasing system. As an alternative to reporting to the legislature, the Commissioner could be required to make an annual public report of the leasing program.

Additionally, in Sec. 38.05.180(b)(5)(E), the Commissioner is required to justify in his report to the legislature why more than 50 percent of an area is leased under any one method of leasing. This requirement of justification seems to be an incentive, if not explicit direction, to utilize the full array of leasing alternatives for any one sale and to, in effect, "experiment".

The language in Sec. 38.05.180(b)(2) is extremely confusing and should be clarified. Further, it is not clear whether or not this section is directed to or will have any effect, intended or otherwise, on the Beaufort Sea sale.

Sec. 38.05.180(c)

This section authorizes four generic categories or methods of leasing: (1) "Bonus bidding," (2) "Royalty bidding," (3) "Net profit bidding," and (4) a "Work commitment bid." Several combinations or variations of methods are authorized under each of the generic headings.

The first method of conventional bonus bidding has the best overall record from the lessor's standpoint. A study of federal OCS sales through 1975 showed that industry had invested $35 billion in bonuses, exploration and development on OCS leases while receiving $22 billion in revenue.

Net profit bidding opens up a multitude of problems as to the definition of "net profit." This method would allow many companies to get into a land position for speculative purposes. It is a

fierce deterrent to early drilling as it is far easier and cheaper to wait out the competition. It is extremely cumbersome to administer and audit, and is even more costly to operate than royalty bidding methods.

The last method of bidding, a work commitment for a lease which cannot, by definition, exceed 5,760 acres, seems completely unworkable as such an area is much too small. This method is usually used in European and mid-east concessions or Canadian permits or reservations which share a common characteristic of being very large geographic areas.

In each of the four leasing methods, the language describing the State's royalty is troublesome. Each description of the State's royalty provides, "... royalty share reserved to the state of not less than 12 1/2 cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease ...." (emphasis added) This language would preclude anything but 100 percent state units. Unitization of lands involving federal or native lands and state lands would be impossible because of the inability of the participants to give the state at least 12-1/2 percent of the production from the "unit area encompassing the [state] lease."

Further, it should be noted that all of the methods and components of the alternate leasing methods will necessitate substantial increases in the budgets and personnel of the agencies involved.

Finally, if some minimum flexibility in leasing methods is desired, the same could be accomplished with minor changes in the existing law.

Sec. 38.05.180(d)

This section allows the Commissioner to reduce royalty when production becomes uneconomical, but only after two years of production. The most recent federal leases require only one year of production, which would be more in line with the stated goal of the bill to minimize revenue from marginal production. Given the explicit description of the royalty in Sec. 38.05.180(c) as "not less than 12 1/2 percent ...," it is not clear whether the Commissioner could ever reduce royalty to any figure below 12 1/2 percent.

Sec. 38.05.180(e)

This section purportedly authorizes the Commissioner to defer payment of any part of a cash bonus bid, provided the bonus is paid within five years. This authority is in direct conflict with AS 38.05.335(c), neither referenced nor repealed by the bill, which requires a deposit of 20 percent, in cash, of the bid.

Sec. 38.05.180(f)

This section authorizes the Commissioner to withhold acreage from leasing in a particular sale. It is assumed that the motive of

this provision is a desire to increase the state's income from leasing by leasing, for example, only part of a structure, and then, once proven productive, leasing the remainder for higher amounts. However, this authority to withhold acreage can just as easily decrease the state's income, in the event the first acreage leased is found non-productive.-- which is usually the case. In essence, this section is authorization for the Commissioner to "gamble" on the productivity of state lands.

This section also seems unfair to the first lessees, who, if the first tracts leased prove productive, are faced with the prospect of having to buy themselves back into the fruits of their own risk at a higher rate.

Sec.'s 38.05.180(g) and (h)

These sections relate net profits and work commitment leasing which, as previously discussed, are ill-advised.

Sec. 38.05.180(i)

There are no objections to this section so long as the trading or storage of royalty oil remains and is clearly the subject of mutual agreement.

Sec. 38.05.180(j)

This section concerns several of the provisions to be included in state oil and gas leases:

First, this section reduces the primary term of state leases from 10 to 5 years. It should be understood that in most areas of Alaska the ability to carry out exploration work is limited to a four month period per year, consequently a five year lease allows only 1-2/3 years of exploratory work. This is clearly insufficient in such a high cost, high risk area.

Second, this section provides that a state lease will be "renewed", if and for so long thereafter as oil and gas is produced in paying quantities or if the lease is committed to a unit. The term "renewed" should be replaced with the term "extended" as this is the long-understood and recognized effect of production or commitment to a unit.

Third, the section's provision concerning shut-in wells should be clarified, since, in its present form, it appears as though the shut-in well must be located on the land prior to the issuance of a lease.

Fourth, this section authorizes the Commissioner to increase rentals up to 150 percent of the preceding year's rate and to provide that a lessee earns production rights only to the depth drilled at the beginning of production. Both of these provisions should be deleted as unnecessary and unworkable.

As to rental increases, as noted, Alaska is already a high cost, high risk area. The prospect of substantial rental increases

during the primary term of a lease will serve only to curb exploration not encourage it.

The provision concerning production rights only as to the depth drilled is unnecessary and unfair. Aside from an obvious example of the lessee drilling into the top of a reservoir and being mechanically unable to go deeper and thereby losing the main body of the reservoir, it also could result in split ownership of a lease with one party having to drill through another's rights to reach his own with possible damage to the upper reservoir resulting.

Finally, the means of extending a lease by drilling are set forth in this section. Given the seasonal nature of drilling in Alaska, the 90 day grace period after drilling has ceased should be expanded if further drilling is prevented by environmental considerations or other circumstances imposed by the State.

Sec. 38.05.180(k)

The increased rentals proposed in this section will discourage exploration and will not increase income to the State because the extra expense will be compensated by lower bid totals. The present $1.00 per acre per year rental should be retained.

Further, this section alters substantially the nature of the ordinary rental provisions in oil and gas leases. The rental to be paid under these provisions is no longer a delay rental. This

section provides, "Rental is payable in advance and continues until income to the state from royalty, net profit, or exploration work commitment exceeds rental income to the state ... for three consecutive years ...." There is no provision for credit or set-off of rental paid during those three years against the state's income from production. Consequently, for the first three years of production, the state would receive both rental income and production income.

Sec. 38.05.180(l)

This section should be modified to provide that the state shall issue a State shorelands lease, as AS 38.05.180 presently reads. Also, the Commissioner should be given the discretion to grant a shorelands lease in excess of five years.

Sec.'s 38.05.180(m) and (n)

These two sections concern the unitization of state leases and are re-enactments of present law. However, given the alternate leasing methods of the bill, and the previously discussed, implicit direction to the Commissioner to "experiment" with these methods, unitization of state leases will be extremely difficult, if not impossible.

It is entirely reasonable to assume that under this bill, a proposed unit will be composed of leases involving highly disparate royalty percentages and one net profits or other kind

of lease. The extreme difficulty of applying these completely different lease burdens to the production allocated to each lease under a proposed unit are obvious. These difficulties constitute a disincentive to unitization and therefore nullify the conservation benefits of unitization.

Sec. 38.05.180(o)

This section concerns the acreage chargeability of KGS leases and is unobjectionable.

Sec. 38.05.180(p)

This section is a re-enactment of the present authorization for the pooling of state leases. Like the provisions concerning unitization, the problems inherent in alternate leasing methods will make pooling more difficult, to the detriment of the conservation objectives of pooling.

Sec. 38.05.180(q)

This section authorizes the State to share in the costs of exploration under a drilling or development contract. Oil and gas exploration is extremely risky and historically the province of private enterprise. Financial participation by the state in an exploration venture raises fundamental questions as to the appropriate role of state government. Given the fact that most wells drilled are unsuccessful, and the substantial sums involved in drilling in Alaska, additional challenges may be anticipated as to the authority or wisdom of the State to participate in a particular drilling project.

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Sec. 38.05.180(r)

This section is a re-enactment of present law concerning the subsurface storage of oil or gas on state leases. However, the present law's provision concerning the extension of the lease used for storage for the period of storage and so long thereafter as oil and gas are produced was deleted. This extension provision should be retained.

Sec. 38.05.180(s)

This section concerns the employment of state residents on state leases is substantially the same as the existing law.

Sec. 38.05.180(t)

This section is an attempt by the state to encourage exploration on lands on which no bids have been tendered. This philosophy is laudable. However, the Commissioner should not be restricted by the leasing details of this section.

Sec. 38.05.180(u)

This section would restrict joint bidding and should be deleted. Joint bidding can very well be to the advantage of the state as it tends to increase the size of the bids submitted and facilitates the exploration process. See, for example, the paper in the November 1976 issue of "Journal of Petroleum Technology" in which the authors conclude that "joint bidders tend to bid on more sought-after (and apparently more valuable) leases and that they tend to bid higher, on the average, than solo-bidding

competitors". Industry testimony before the U.S. Senate has indicated that since the first OCS sale in 1954, 172 companies have purchased OCS leases. 42% of these leases were not purchased by the major companies, and in recent years the smaller companies have increased their share of OCS production at the expense of the major oil companies.)

Depending on the content of the regulations adopted, this section may violate Article 8, §17 of the Alaska Constitution. This Constitutional provision requires that laws and regulations governing the use or disposal of natural resources must apply equally to all persons "similarly situated".

Sec. 38.05.180(v)

This section grants the state an unfettered option to purchase 16-2/3 percent of oil and up to 100 percent of gas produced from a state lease. This section will in effect eliminate the lessee's ability to use the gas sales contract as a method of financing. Consequently, gas exploration in Alaska will be discouraged if not precluded. Similarly, if the state should wait several years before deciding to take up to 100 percent of the gas, the discoveror of a gas field would be deprived of all income from his legally obtained gas, because he could not enter into a contract with any other user. This section would also eliminate or impair the ability of lessees to utilize the production payment as a method of financing, likewise discouraging exploration.

Sec. 38.05.180(w) This section requires state access to all of a permittee or lessee's exploration data and should be eliminated from the bill. This section is, in essence, a confiscation of valuable proprietary data, for the sole purpose of deciding whether the explorer has found anything or not. If the state decides he has, the area could then be thrown open to all other competitors, thereby removing any incentive for an aggressive company to be a leader or employ innovative ideas to discover new resources. This section completely removes that incentive, and thereby will cause significant state natural resources to remain unsought.

In addition, grave problems as to the preservation of the confidential nature of the data are inherent in this section. It is common knowledge that such information is extremely confidential and closely guarded by the individual members of the industry.

The existing law upon which the oil and gas industry has relied for the confidentiality of information is contained in AS 38.05.035(a)(9)(C). This existing provision requires the director to keep geological, geophysical and engineering data confidential "upon request of the persons supplying the information." As the Bill's provision requires disclosure of information to the Commissioner, not the director, and since it requires also access, as distinct from supplying copies, are the confidentiality provisions incumbent upon the director not

applicable to the information required to be disclosed to the Commissioner?

If this section is to be applicable to existing exploration data, then the Commissioner's access and utilization of such existing data is almost certainly an unconstitutional taking of this valuable and expensive property. If the Commissioner is to be allowed access at all to such data, such access should be limited to future data only. Further, there should be a requirement of the adoption of regulations prescribing the confidentiality of this data and the addition of statutory criminal penalties for intentional disclosure of such data.

Section 2

There are no objections to this section concerning notice of mineral leasing.

Section 3

This section would amend AS 38.05.140(c) to reduce the upland acreage limitation from 500,000 acres to 200,000 acres. In Alaska, where there are large areas of state lands which are potentially eligible for bid, a 500,000 acre limitation, which the present statute contemplates, is not unreasonable. The effect of a 200,000 acre limitation would clearly be to limit the participation of those individuals who are most active in exploration business in Alaska, i.e., those individuals who have

historically submitted the highest bids to the state. It is not at all clear why the state would seek to discourage, rather than to encourage, the continued involvement of those individuals in Alaska. Further, this section's applicability to the holding of existing lessee's -- requiring them to reduce their holdings within 5 years -- is an unconstitutional taking of leasehold estates.

Alaska State Legislature

Senate

Committee on Resources

Official Business

Pouch V
State Capitol
Juneau, Alaska 99811

LIPTON on LEASING

The following notes summarize Lipton's major points on proposed leasing legislation in his testimony before the Senate Resources Committee on 1/28, 3/15, and 4/28. The initial two testimonies relate to HB 854, while the latter refers to changes later incorporated into CS HB 854 (Finance).

.2 line 3
B 854

Subsection (d) of the initial findings contains an unusual but exemplary approach to leasing - that is to "maximize state revenue from profitable oil and gas production, while minimizing revenue from unsuccessful exploration and from marginal economic oil and gas production." (Deleted in present version)

With respect to the eight leasing methods proposed, his specific comments were confined to:

Royalty Bidding - a method not preferable except when the lease is on a known structure with known risks. There is a potential problem if royalty bidding is permitted as an option and if the commissioner is also given discretion to abate royalties where there is an insufficient rate of return. The successful bidder may overbid a royalty with the expectation of a future royalty reduction. The section on abatement (page 5, line 18 CS HB 854) is still present, but modified from original bill.

Net Profit Bidding - this method may be attractive to both the state and the industry under certain circumstances. Allows the oil company to keep more front-end captial for exploration. (Retained in CS HB 854)

Work Commitment Bidding - not a particularly useful method. May cause company to over-commit itself in relationship to actual profitability of the lease, resulting in premature abandonment. (Deleted in CS HB 854)

Lipton's general comment on the leasing methods is that it may not be desirable to itemize 7 or 8 options with minimum fixed commitments on each variable. The commissioner should have greater flexibility to design the lease sale to conform to the structures to be leased.

.6 line 15 HB 854 "The commissioner may withhold acreage from leasing in a particular lease sale." This is an important section as it may often be in the state's best interest to do so. Suggested a more positive statement to encourage utilization of this authority. (Deleted in CS HB 854)

.7 line 15 HB 854 There should be a provision for reasonable extension of exploration deadline beyond 5 years under certain circumstances. The bill allows for leases up to 10 years - but does not specifically address extensions of 5 year leases. (Same in both versions)

11 line 13 HB 854 This section authorizes the award of non-competitive leases when no bids have been received at a sale. Lipton advises against this because changing circumstances may result in a favorable lease agreement later if the state is not too hasty. (Modified in CS to prohibit non-competitive leasing)

p.12 line 1 HB 854 Gives the state the right to purchase up to 16 2/3% of oil and 100% of gas from a lease at fair market value. Lipton cautions state to use this judiciously as it may hurt the leaseholders under some conditions. CS HB 854 was rewritten to delete specific percentages, but still allows the state to buy "specified volumes" cited in the lease.

.6 line 22 B 854

Work Obligations - should be made a part of every lease agreement - This section is modified but still present in CS HB 854 (Finance). The committee might consider changing may to shall on page 4, line 26 in the CS.

.5 line 2 S HB 854 Finance)

Exploration Credits - See attached letter from Lipton to Cowper dated May 5, 1978.

.11 line 7 S HB 854 Finance)

Confidentiality of Exploration Data - there should be a provision to extend the period of confidentiality beyond two years if a scheduled lease sale is postponed.

CHAPTER 81: OIL AND GAS PRELEASING PROCEDURES

ARTICLES

1. (GENERAL PROVISIONS) AFFECTED LANDS AND EXCEPTIONS
2. PRELEASING PROCEDURES
3. SOCIAL, ECONOMIC, AND ENVIRONMENTAL ANALYSIS
4. ALASKAN ADVISORY COMMITTEE ON LEASING
5. NOTICE AND REVIEW
6. DEFINITIONS

ARTICLE 1: AFFECTED LANDS

SECTION

10. General Provision
20. Joint Federal-State Beaufort Sea Lease Sale
30. Limited Acreage Provision
40. Drainage Situation Provision

11 AAC 81.110. General Provision. (a) These regulations apply only to competitive leasing as specified in AS 38.05.020, 38.05.135, 38.05.145, 38.05.180.

11 AAC 81.120. Joint Federal-State Beaufort Sea Lease Sale (a) The proposed joint Federal-State Beaufort Sea Lease Sale is exemted from the requirements of these regulations.

11 AAC 81.130. Limited Acreage Provision (a) Should an area of up to but not greater than one township in area be deemed leasable, the Commissioner may at his discretion, offer the area for lease under the following method.

1) The Commissioner will publish a notice of intent to lease and a notice of public hearing.

2) The Commissioner will hold the public hearing in the affected area to guage public opinion to the proposed lease sale.

3) Upon completion of subsection two the Commissioner will publish a notice of a lease sale and a chart delineating the tracts to be offered.

11 AAC 81.140 Drainage Situation Provision (a) Should a situation arise whereby the leasing of land by another party adjacent to State owned lands, threaten the mineral interest of the State lands through possible drainage situations, the

Commissioner may, at his discretion, offer that threatened land for leasing under the following methods:

1) The Commissioner will publish a notice of intent to lease and a call for public reaction and nomination.

2) Upon completion of subsection 1 and receipt of nominations, the Division will prepare an economic analysis on the sale area.

3) The Commissioner will then call for and hold a public hearing within the affected area to gauge public sentiment to the proposed lease sale.

4) The Commissioner, taking into account information gathered at the public hearing, will issue a list of the tracts proposed to be leased and a notice of a lease sale.

5) Lands offered for lease under this section may total no more than 100,000 acres.

ARTICLE 2: PRE-LEASING PROCEDURES

SECTION

10. Notice and Publication
20. Soliciation of Comments
30. Initial Tract Selection
40. Social, Economic and Environmental Analysis
50. Public hearings on Social, Economic, and Environmental Analysis
60. Final Social, Economic, and Environmental Analysis and Final Tract Selection
70. Preparation of Leasing Conditions
80. Public Hearings on Lease Conditions
90. Final Lease Conditions Set and Notice of Lease Sale

11 AAC 81.210 Notice and Publication. (a) The commissioner, at a date no greater than 24 months prior to any proposed lease sale, will publish a set of charts with accompanying written descriptions adequately locating the general geographic area in which the proposed lease sale will be.

(b) The commissioner will, concurrent with provision (a) cause to be published a notice for the Solicitation of Comments.

Chapter 81: Oil and Gas Pre-Leasing Procedures.

Due to a new article one being inserted into this chapter, articles 1 - 5 of the previous draft are now 2 - 6 with article six being re-titled to read "Definitions." Within article six, sections 520 and 530 have been deleted.

Article 2: Pre-Leasing Procedures

1) 11 AAC 81.210 Notice and Publication (a) The phrase ...date no less than 18 months prior..., has been amended to read...date no greater than 24 months.... The phrase...any lease sale, will cause to be published...has been amended to read ...any proposed lease sale, will publish.

2) 11 AAC 81.230 Initial Tract Selection (a) The phrase...date no less than 16 months prior to any lease sale..., has been amended to read...date no greater than two months after the first notice date of the Solicitation of Comments period,.... The phrase "utilizing industry and public comments" has been added to the end of the sentence.

3) 11 AAC 81.240 Social, Economic, and Environmental
a) the phrase "each tract, group of tracts, and/or," has been deleted.
b) the phrase "all or part of" has been deleted.
e) New Paragraph
From the date of notification by the commissioner of his decision under section 230 of this article, the concerned state agencies will have a maximum of four months in which to prepare their components of the SEEA.

4) 11 AAC 81.250 Public Hearings on Social, Economic, and Environmental Analysis.
c) ...date no less than nine months prior to the lease sale, has been amended to read...date no greater than three months after the completion of the SEEA.

5) 11 AAC 81.260 Final SEEA and Specific Tract Selection
c) ...date no less than six months prior to the lease sale, has been amended to read"...a date no greater than 12 months from the date of notice of Solicitation of Comments under section 10 of this article.
c) The commissioner will, upon completion of paragraph (c) of this section, announce to the public a date by which, barring unforeseen circumstances, the proposed lease sale will be held.

6) 11 AAC 81.280. Public Hearings on Lease Stipulations
c) ...date no less than four months prior to the lease sale has been amended to read...date no greater than three months from the date of completion of paragraph (c) section 60 of this article.

7) 11 AAC 81.290 Final Lease Stipulations Set and Notice of Lease Sale (a)
(a) a) ...date no less than three months prior to the lease sale, has been amended to read...date no greater than four months from the date of completion of paragraph (c section 60 of this article.

8) 11 AAC 81.320 Economic Component (c)...committee not less than 14 months prior to the lease sale, has been amended to read...committee not greater than one month after completion of section 40 article two of this chapter.

9) 11 AAC 81.420 Composition of Committee (a) the phrase "the Division of

Minerals and Energy Management will be represented on this committee by both its leasing and petroleum managers."

b) the phrase "leasing manager of the" has been inserted between the words "by the"...and;;;"Division of....

c) A new paragraph has been added - "For each lease sale, a delegate from the borough government affected by the sale, will be invited to participate on the committee.

STATE OF ALASKA
THE LEGISLATURE

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

LEGISLATIVE AFFAIRS AGENCY

MEMORANDUM May 30, 1978

SUBJECT: CSHB 854 and the Effects of Using Multiple Oil and Gas Leasing Methods on Unitization

TO: The Honorable Kay Poland

FROM: Gregg K. Erickson
Director of Research

Summary

At the Senate Resources Committee meeting on Friday you received testimony to the effect that the use of differing leasing methods on adjacent tracts, as would be permitted under HB 854, would make it difficult to establish unitized development and production of the pools over which those tracts lie. Generally, our studies of this question, which we have conducted since the matter was first raised several months ago, do not support this conclusion. On the contrary, they show that the incentives to unitize will not be seriously reduced by diverse lease arrangements, and that the difficulties of reaching unit agreements will not be increased as a result of this diversity.

The Incentive To Unitize

Unit arrangements exist and are encouraged by state policy because centralized, unitized operation of an oil or gas field can and usually will result in substantial reduction in the expenses of extracting the resource, and in absolute gains in the total amount of oil and gas recovered. That the potential for these gains exists is, under the circumstances we have had in Alaska, almost never a matter of contention among the leaseholders who would be a party to a unit.[1] The most

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[1] See Bradner, Tim, "Oil and Gas Regulation in Alaska," *Alaska Review of Business and Economic Conditions*, 1971.

important question here is therefore: Will the use of differing leasing systems as contemplated in HB 854 significantly reduce the incentive to unitize that is provided currently by the very real benefits of joint, unitized field development and operations?

We think not. At a high royalty rate, as might be encountered under straight royalty bidding, the benefits in the form of increased production are, of course, shared with the landowner on the basis of the royalty percentage. But all the benefits in the form of reduced costs remain with the lessee. In a net profits arrangement the benefits of increased production and reduced expense are both shared with the lessor, but still leave the lessee with substantial incentive to partake of the advantages of unitization. Naturally, if the royalty or net profits rates were set at or close to 100 percent these incentives would disappear, but so would the incentive to develop the tract at all.

Difficulties in Unitization

Despite the retention of a clear incentive to unitize under a mixture of leasing methods as in HB 854, it is possible that a mixture of systems might create a practical barrier to unitization. This might occur, for example, if the differing lease terms made it impossible for the lessees to agree on the proper apportionment of the unit's expenses and produced oil and gas.

Current Alaska law provides only general guidance as to how this allocation is to be made.[2] The usual practice has been to allocate the costs and production generally on the basis of the costs and production that would accrue to an individual leaseholder were he to operate the tract on an individual, non-unitized basis. Another method less frequently employed, but used, at least partly, in the formation of the Prudhoe Bay unit, is to allocate expenses and actual production on the basis of the original petroleum in place underneath each lease. Other factors, or combinations of these factors, may also be considered, and one study has distinguished examples of 42 different methods of apportioning participation.[3]

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[2] AS 31.05.110(c) provides that "each plan of unitization shall contain fair, reasonable and equitable provisions for...the division of interest or formula for the apportionment and allocation of the unit production, among and to the several separately owned tracts within the unit area such as will reasonably permit persons otherwise entitled to share in or benefit by the production from such separately owned tracts to produce and receive, instead thereof, their fair, equitable and reasonable share of the unit production or other benefits of it; a separately owned tract's equitable, and reasonable share of the unit production shall be measured by the value of each such tract for oil and gas purposes and its contributing value to the unit in relation to like values of other tracts in the unit, taking into account [1] *acreage*, [2] *the quantity of oil and gas recoverable from it*, [3] *location on the structure*, [4] *its probable productivity of oil and gas in the absence of unit operations*, [5] *the burden of operations to which the tract will or is likely to be subjected*, or so many of these factors, or such [6] *other pertinent engineering*, [7] *geological* or [8] *operating factors* as may be reasonably susceptible of determination...." (emphasis and numbers added)

[3] A. A. Khan and H. H. Power, "An Analysis and Comparison of Engineering Bases of Participation in Unit Agreements," *IOCC Committee Bulletin*, December 1960, p. 101.

Reaching an agreement on the theoretical basis for allocating participation and resolving all the associated technical issues can be a complex, difficult and protracted process. Although all parties usually have a clear view of the overall benefits to be gained from unitization, some may "hold out" in hopes that by doing so they may be able to extract a better deal from their fellow lessees concerning the allocation of the benefits of unitization.[4]

The question here, though, is whether differing lease arrangements will make reaching an agreement *more* difficult. In our view, the question answers itself when considered in the context of Alaska's unitization law and the permissible bases for apportionment of participating unit interests enumerated therein.[5] For example, is the "acreage" in a lease altered by the fact the lease contains profit sharing arrangements? Is the "location or the structure" affected by the royalty arrangements? Or are the "engineering, geologic or operating factors" influenced by either? We believe it is obvious that they are not.

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[4] For a listing of the problems that can arise in unitization negotiations see Stephen McDonald, *Petroleum Conservation in the United States: An Economic Analysis* (Resources for the Future, Washington: 1971), pp. 198-201.

[5] AS 31.05.110(c). See note 2, *supra*.

A Final Point

As a final point, we note that tracts bearing differing royalty burdens have already been included in units, in Alaska and elsewhere, wherever individual holders of federal and state noncompetitive leases have sold those leases while retaining overriding royalties. Moreover, differing lease arrangements are likely to exist in the future side by side wherever Native corporation or federal and state oil and gas lands are contiguous. It is possible, of course, that if the legislature gives the commissioner of Natural Resources authority to use alternative leasing methods that these differences may be reduced or eliminated.

GKE:jm

cc: Members, Senate Resources Committee
The Honorable Chat Chatterton
The Honorable Hugh Malone
Mr. Phil Holdsworth

STATE of ALASKA

MEMORANDUM

TO: Jack Roderick
Joe Green, Director, DNEM

Thru: Pat Dobey, Petroleum Manager

FROM: Blair Wondzell
Petroleum Engineer

DATE: March 3, 1978

FILE NO.

TELEPHONE NO.

SUBJECT: Sliding Scale Royalty Considerations, Examples, Bidding Methods

Our proposed legislation, House Bill No. 854, contains provisions for utilizing sliding scale royalties as the fixed parameter in some bidding methods and as the bid parameter in others. Since there have been several questions on how we would set up a sliding scale royalty schedule for use as the fixed parameter and how we would request and evaluate sliding scale royalty bids, I have prepared this discussion and some examples.

The basic elements of my recommendations are that production steps will be in multiples of the approximate economic limit (1000 B/D, 2000 B/D, 3000 B/D, etc.). The percent royalty to be applied to each production step is based on increasing by equal increments (x+y, x+2y, etc.), the royalty percentage applied to the base (economic limit) production step. This criteria will make it easy to definitely determine the top bid when industry is asked to bid the sliding scale royalty reserved to the state. For example: The production rate steps are fixed (1000 B/D, 2000 B/D, etc.) as is 12.5% royalty at 1000 B/D, industry then bids on the equal incremental royalty percent increases to be applied to the higher steps.

I noticed that in Jack Roderick's letter to the commissioner, he is also looking at sliding scale royalty schedules. His schedules and discussion should be compared to my data as set out in this memo.

AGO 546740

TO: Joe Green
FROM: Blair Wondzell
RE: Sliding Scale Royalty Schedules

TYPICAL SLIDING SCALE ROYALTY SCHEDULES

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)	Equivalent 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

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)	Equivalent 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

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.

TO: Joe Green
FROM: Blair Wondzell
RE: Sliding Scale Royalty Schedules

SLIDING SCALE ROYALTY
Considerations, Example Schedules, Bidding Methods

CONSIDERATIONS:

1. Sliding scale royalty use is based on the intent that the ownership royalty share be small from economically marginal production and be large from very profitable production.

2. Ideally, at production rates below the economic limit there should be no royalty. ("EL" is herein defined as the production rate necessary to pay direct operating costs; overhead and amortization are not included). Immediately above the EL level or rate of production, industry's share should include an amount for pay back of investment - beyond this pay-back production rate, the State and industry should share the profits which are represented by production. Based on royalty rates actually bid, at very high well rates the State's royalty share should exceed 50%. As the field declines, individual well rates would decline with a corresponding decrease in average or equivalent royalty; therefore, if the State is to obtain a field life average royalty in the 50% range, royalty rates during the peak production years must be higher than the intended overall average equivalent royalty rates.

3. Computer programs for the determination of the correct slide/percent royalty do not, to my knowledge, exist. Because of the many estimated factors which would go into such a program (normal capital, operating cost, production rates, and number of wells producing), the results would be somewhat unreliable.

4. The problem of setting the slide steps and royalty rates can be solved from another direction, however. A good schedule can be obtained based on logical reasoning consistent with the guidelines stated in paragraph #2 above.

5. Since State statutes require a minimum royalty of 12.5%, the "ideal" situation is not obtainable. However, it can be approximated by gradually increasing State royalty - above the EL production rates - to a partial sharing and then to a full sharing of the production. Following are typical sliding scale royalty schedules for the North Slope Area and for the South Central Area.

6. Sliding scale royalty bidding may be a future bidding method. This can be handled in at least 2 ways.

Method #1: Industry can be requested to furnish a sliding scale royalty bid with the only provision being that the minimum royalty be 12.5%. The determination of the winning bid would require multiple economic computer analyses. These analyses would be based on a multitude of estimates and would therefore vary depending on estimates of the input parameters. Industry would most likely, and justifiably, contest the awarding of bids by this method.

Method #2: Industry can be requested to bid royalty percentages having equal incremental increases which will be applied to preset production steps: or industry can be requested to bid the equal increment production steps for preset royalty percentages. Bids based on either of these alternates (preset production steps or preset royalty percentages) can be precisely compared to one another and the winning bidder can easily and definitely be determined.

Method #2 types of a sliding scale royalty bid is shown in the following examples:

EXAMPLE

LEASE AWARDS

A lease will be awarded on each tract to the responsible qualified bidder offering the highest percentage royalty for the production steps as specified below under Bid Method . . . . .

ALTERNATE I

Royalty percentages bid, preset production steps.

BID METHOD

All bidders must designate the percentage royalty reserved to the State for each of the below listed production steps which are average daily production rates based on monthly production volumes for each well as defined in regulations _____. Minimum royalty percentage as required by State Statutes is 12.5%. A royalty percentage of 12.5% is specified for the base production step which is 0 to 1000 B/D and will be

TO: Joe Green
FROM: Blair Wondzell
RE: Sliding Scale Royalty Schedules

increased in equal increments for each subsequent production step. The following production steps will be utilized:

Average Daily Production Rate (Bbls./day)	Incremental Royalty Rate (%)
0-1000	x (must be 12.5%)
1001-2000	x+y
2001-3000	x+2y
3001-4000	x+3y
4001 and above	x+4y

ALTERNATE 2

Production steps bid, preset royalty percentages.

BID METHOD

All bidders must designate the daily average per well production steps for the royalty percentages reserved to the State which are listed below. The daily average production steps are based on the monthly production volumes from each well as defined in regulation _____. The production steps above the base step will be increased by equal increments. The following royalty percentages reserved to the State will be utilized.

Incremental Royalty Rate (%)	Average Daily Production Rate (Bbls./day)
12.5	x
25.0	x+y
37.5	x+2y
50.0	x+3y
62.5	x+4y and above

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 least 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 ~~risk~~ Degree of potential Target.

(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. Ingeneral, 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 prices~~ ~~[illegible] the advantages of the royalty~~ ~~bid would be used in the opposite location.~~ 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 (2)).

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 encourages exploration by making it the bid variable.

This method would be used in remote low potential high risk areas. Some of the states 3 mile limit lands such as Area M might be ~~used applicable~~ applicable to this method.

Low Potential & High Risk and Previously Leased Section (c)

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 a 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 similtaneous 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.

STATE of ALASKA

MEMORANDUM

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINERALS AND ENERGY MANAGEMENT

TO: Robert E. LeResche
Commissioner Natural Resources

DATE: February 28, 1978

FILE NO:

TELEPHONE NO:

FROM: [redacted]

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,

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 that 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 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

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

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 agressive operator.

   The time between Cook Inlet lease sales in 1962 and 1965 until first production was begun from Middle Ground,

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 develope 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

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 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.

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.

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 alot 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 Acreage Holdings

COMPANY	ACRES
Amoco	126, 134.64
ARCO	411, 482.68
BP Alaska	103, 218.99
Beard Oil	71, 260.49
Chevron	126, 493.55
Elias Sousa	140, 071.58
Exxon	158, 627.73
Marathon Oil	71, 538.36
Mobil	120, 375.19
Phillips Pet.	250, 748.38
Sohio Pet.	135, 588.28
Texaco	156, 027.63
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

HB 441
approved March 9, 1973

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 procedures 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.

TESTIMONY ON
ALASKA LEASING POLICY BILL
(H.B. 854)

BY

ROD L. BOANE

ALASKA DISTRICT MANAGER

EXXON COMPANY, U.S.A.

BEFORE THE

STATE OF ALASKA

SENATE RESOURCES COMMITTEE

JUNEAU, ALASKA

MAY 22, 1978

MADAM CHAIRMAN AND MEMBERS OF THE COMMITTEE --

I AM ROD L. BOANE, DISTRICT MANAGER FOR THE ALASKA EXPLORATION DISTRICT OF EXXON COMPANY, U.S.A. I APPRECIATE THE OPPORTUNITY TO BE HERE TODAY AND PRESENT THE VIEWS OF MY COMPANY CONCERNING THE PROPOSED LEASING POLICY BILL.

FIRST, LET ME SAY THAT EXXON BELIEVES THE EXISTING PROVISIONS OF SECTION 38.05.180 OF THE ALASKA STATUTES ARE QUITE SATISFACTORY IN ADMINISTERING ADEQUATE CONTROL OVER EXPLORATORY AND DEVELOPMENT ACTIVITIES ON STATE LEASES. FURTHERMORE, THE EXISTING LEASING PROVISIONS HAVE BEEN VERY SUCCESSFUL IN PROVIDING THE INCENTIVE FOR THE PETROLEUM INDUSTRY TO DISCOVER PRUDHOE BAY, THE LARGEST OIL FIELD IN NORTH AMERICA, PLUS FOUR OTHER MAJOR OIL FIELDS INCLUDED IN THE TOP 100 OIL FIELDS IN THE U.S. IN OTHER WORDS, THE SUCCESS OF THE CURRENT SYSTEM IS AN ESTABLISHED FACT, AND IS A TRIBUTE TO THE FORESIGHT OF THE FIRST LEGISLATURE WHICH ENACTED THE PRESENT LEASING ACT SOME EIGHTEEN YEARS AGO. INSTEAD OF REPEALING THE PRESENT LEASING SYSTEM, WHAT IS NEEDED TO REJUVENATE EXPLORATION ACTIVITY IN ALASKA IS A RESTORATION OF COMPETITIVE LEASE SALES UNDER THE CURRENT PROVISIONS OF AS 38.05.180. THEREFORE, WE DO NOT BELIEVE THESE NEW AMENDMENTS TO THE STATUTES ARE NEEDED TO PROTECT THE PUBLIC INTEREST. ON THE CONTRARY, WE THINK THE PROPOSED AMENDMENTS WOULD CREATE UNNECESSARILY INVOLVED AND CUMBERSOME PROCEDURES THAT WILL NEITHER FOSTER NEEDED EXPLORATION NOR BENEFIT THE STATE OF ALASKA. ALTHOUGH WE TAKE EXCEPTION TO MANY OF THE FEATURES OF THE PROPOSED

AMENDMENTS, IN THE INTEREST OF TIME, I INTEND TO DISCUSS ONLY THE MORE TROUBLESOME PROVISIONS, WITH PARTICULAR EMPHASIS ON THE PROPOSED BIDDING METHODS.

EXXON BELIEVES THAT THE BEST METHOD FOR AWARDING LEASES IS ON A CASH BONUS BASIS WITH A FIXED ROYALTY WHICH IS IN THE CURRENT LAW. THIS SYSTEM HAS SEVERAL ADVANTAGES WHICH I WOULD LIKE TO REVIEW.

FIRST, THE SUCCESSFUL BIDDER SEES VERY STRONG INCENTIVES TO EXPLORE AND DEVELOP RAPIDLY AND TO RECOVER THE MAXIMUM ECONOMIC VOLUME OF HYDROCARBONS. THIS IS NECESSARY IN ORDER FOR HIM TO MAXIMIZE THE RETURN ON THE CASH BONUS INVESTED.

SECOND, UNDER THE CASH BONUS SYSTEM, THE STATE BEARS NONE OF THE RISK THAT COMMERCIAL RESERVES WILL NOT BE FOUND. THIS RISK IS PLACED DIRECTLY ON INDUSTRY WHERE IT BELONGS. THIS IS A PARTICULARLY CRITICAL CONCEPT IN A FRONTIER PROVINCE SUCH AS ALASKA WHERE VERY LITTLE EXPLORATORY DRILLING HAS OCCURRED AND THUS VERY LITTLE IS KNOWN ABOUT THE OIL AND GAS POTENTIAL OF MOST OF THE STATE. THE GULF OF ALASKA HISTORY SHOULD PROVE THIS POINT AS, THUS FAR, NO COMMERCIAL DISCOVERY HAS BEEN MADE. ANOTHER EXAMPLE OF THIS POINT IS THE NORTH SLOPE SALE OF 1969.

THIRD, UNDER THE CASH BONUS SYSTEM THERE IS NO POSSIBLE WAY THAT THE AWARDS WILL BE MADE IN AN ARBITRARY MANNER SINCE THE HIGHEST BID IS OBVIOUS. THIS IS NOT THE CASE FOR OTHER SYSTEMS WHICH WE WILL DISCUSS LATER.

FINALLY, THE SYSTEM IS SIMPLE AND INEXPENSIVE TO ADMINISTER. THE STATE WOULD NOT HAVE TO EXPAND ITS STAFF TO CONTINUE THE CASH BONUS SYSTEM, WHEREAS OTHER SYSTEMS WILL REQUIRE A LARGER STAFF. THE INTEGRITY OF THE SYSTEM WOULD NOT BE AFFECTED BY FUTURE EVENTS SUCH AS REDUCTION OF ROYALTY OR DETERMINATION OF OPERATORY EFFICIENCY. THESE PROBLEMS WILL BE DISCUSSED LATER.

PROPONENTS OF ALTERNATE BIDDING HAVE STATED THAT CASH BONUS BIDDING DOES NOT ENSURE THE PUBLIC A FAIR RETURN ON ACREAGE LEASED. THEY ALSO ARGUE THAT CASH BONUS BIDDING REDUCES COMPETITION. WE DISAGREE WITH THESE STATEMENTS, AND I'LL DISCUSS GULF OF MEXICO EXPERIENCE WHICH IS THE BASIS FOR OUR CONCLUSIONS. IT SHOULD BE NOTED THAT IN A HIGH COST, HIGH RISK ENVIRONMENT, COMPETITION WILL REMAIN HIGH ONLY IF THE POTENTIAL FOR HIGH REWARD EXISTS. THIS ALLOWS THE FEW SUCCESSES TO COVER THE COSTS OF THE MANY FAILURES.

THE GULF OF MEXICO IS ONE AREA THAT HAS HAD ENOUGH SALES, DISCOVERIES, AND PRODUCTION TO ALLOW AN EVALUATION OF THE CASH BONUS SYSTEM. DATA PUBLISHED BY THE U.S.G.S. SHOWS THAT THE GOVERNMENT HAS RECEIVED AN EXCELLENT RETURN. FROM 1953 THROUGH 1976, BONUSES, RENT, AND ROYALTY PAID TO THE U.S. GOVERNMENT HAVE AMOUNTED TO 83% OF THE TOTAL OCS REVENUE. NUMEROUS STUDIES HAVE BEEN CONDUCTED THAT INDICATE THAT INDUSTRY RETURN ON OCS OPERATIONS IS ABOUT 7%.

Source	Date Issued	Period Covered	DCF - % BFIT	DCF - % AFIT
Barrow, T.D.	1967	1951-65		7.0
DOE Tech. Bull. 5	1970	1965-67	5.6	
Nanz, R. H.	1975	1964-73		5.0
Nanz, R. H.	1976	1945-73		7.0
Mead, W. J.	1977	1954-55	7.5	
DOI	1975	1954-68	9.0	
Bybee, R. W.	1970	1954-69		6.0

These studies indicate that industry has not earned an excessive return.

For this same time period, new bidders have been successful in purchasing acreage in all but 3 of the 24 general sales. A total of 172 companies have been successful in purchasing acreage in the OCS (as of 1/1/77). This does not support the claim that cash bonus bidding restricts competition. It is also difficult to conclude that an industry which is earning a 7% rate of return is non-competitive. In fact, this would lead one to draw the conclusion that competition for OCS leases under the cash bonus system has been intense.

Now I would like to compare the alternate bidding methods proposed in this legislation to the current system of cash bonus bidding with fixed royalty. Basically, the proposed alternative bidding methods fall into two categories. The first category involved some form of royalty bidding. The second category uses some

FORM OF NET-PROFIT BIDDING. BOTH CATEGORIES REQUIRE A CASH BONUS, EITHER AS A BID VARIABLE OR A FIXED AMOUNT. LET'S FIRST EXAMINE THE ROYALTY BIDDING SYSTEMS.

(1) IT IS NOT UNCOMMON FOR OPERATORS TO DISCOVER RESERVES OF LESSER MAGNITUDE THAN ANTICIPATED. WITH HIGHER ROYALTY, WHICH WOULD BE EXPECTED UNDER A ROYALTY BID SYSTEM, SOME OF THESE DISCOVERIES COULD NOT BE DEVELOPED PROFITABLY UNLESS THE STATE AGREED TO ACCEPT A LOWER ROYALTY THAN ORIGINALLY BID. DOWNWARD ADJUSTMENT IN ROYALTY RATE PRIOR TO ANY DEVELOPMENT WOULD BE DIFFICULT TO ADMINISTER AND COULD UNDERMINE THE INTEGRITY OF THIS BIDDING SYSTEM. SECTION 38.05.180(J) ALLOWS THE COMMISSIONER TO ADOPT REGULATIONS FOR REDUCTION OF ROYALTY AFTER TWO YEARS OF PRODUCTION. THIS WILL NOT ALLOW DEVELOPMENT OF MARGINAL RESERVES SINCE NO PRUDENT OPERATOR WILL DEVELOP A PROPERTY KNOWING THAT IT WILL BE UNECONOMICAL, BUT IN HOPES OF OBTAINING A LOWER ROYALTY AFTER TWO YEARS.

(2) WITH ROYALTY BIDDING, THE SUCCESSFUL BIDDER DOES NOT HAVE A STRONG INCENTIVE FOR RAPID EXPLORATION AND DEVELOPMENT SINCE FRONT-END CASH INVESTMENT IS SMALL. SPECULATORS COULD THEREFORE SEE INCENTIVES TO ACQUIRE LEASEHOLD INTEREST, AND THEN DELAY EXPLORATORY DRILLING IN HOPES THAT OTHER NEARBY OPERATORS WILL CONDUCT EXPLORATION. IF THESE OPERATORS ARE SUCCESSFUL, THE SPECULATORS CAN CASH IN WITH MINIMAL RISK. THIS SITUATION WOULD OBVIOUSLY RESULT IN DELAYED EXPLORATION AND DEVELOPMENT ACTIVITIES.

(3) WITH EXCLUSIVE ROYALTY BIDDING, THE PUBLIC BEARS THE MAJOR PORTION OF THE EXPLORATION RISK BECAUSE IF THE TRACT DOESN'T CONTAIN COMMERCIAL HYDROCARBON RESERVES, AS THE MAJORITY WILL NOT, THE PUBLIC RECEIVES NO COMPENSATION WHATEVER. WE STRONGLY BELIEVE THAT RISK-TAKING AND ITS ASSOCIATED REWARDS OR LOSSES ARE MORE PROPERLY THE PROVINCE OF PRIVATE ENTERPRISE.

ANOTHER ROYALTY BIDDING SYSTEM INVOLVES SLIDING SCALE ROYALTY WHICH CAN EITHER BE THE BID VARIABLE OR USED IN COMBINATION WITH A CASH BONUS BID. IN THE CASE WHERE THE SLIDING SCALE ROYALTY IS THE BID VARIABLE, IT WILL BE EXTREMELY DIFFICULT TO COMPARE BIDS UNLESS YOU KNOW THE TOTAL RESERVES, THE PRICE AT WHICH PRODUCTION WOULD BE SOLD, AND THE RATE OF PRODUCTION. SHOULD PRODUCTION BE ESTABLISHED, SLIDING ROYALTY COULD CAUSE WIDELY DIFFERING POSITIONS TO DEVELOP BETWEEN OPERATORS AND THE STATE. IN AN EFFORT TO MAXIMIZE ITS INCOME, THE STATE COULD REQUIRE OPERATORS TO MAKE INVESTMENTS FOR PRODUCTION INCREASES WHICH WOULD EARN A MARGINAL OR SUBMARGINAL RETURN. THIS COULD RESULT IN PREMATURE ABANDONMENT OF THE PROPERTY. ALSO, UNITIZATION OF TRACTS WITH DIFFERENT ROYALTY BASES OR SLIDING SCALE TRACTS WITH CASH BONUS TRACTS WOULD BE A VERY COMPLEX AND DIFFICULT JOB AND COULD DELAY DEVELOPMENT OF A DISCOVERY.

NOW LET'S LOOK AT THE SECOND BIDDING CATEGORY, A PROFIT-SHARING SYSTEM, WHICH HAS MOST OF THE SAME ADVERSE CHARACTERISTICS AS ROYALTY BIDDING, BUT WITH FOUR ADDED COMPLICATIONS AND DISADVANTAGES.

(1) USING NET PROFITS WILL BE MUCH LIKE SELECTING A CONTRACTOR TO PERFORM A JOB ON A COST-PLUS BASIS. THE OPERATING EFFICIENCY OF THE BIDDER COULD BECOME AN IMPORTANT CONSIDERATION IN DETERMINING WHICH OF SEVERAL BIDDERS HAD SUBMITTED THE HIGH BID INASMUCH AS THE PROCEEDS TO BE RECEIVED BY THE PUBLIC WOULD BE A DIRECT FUNCTION OF THE EFFICIENCY OF THE OPERATOR. THUS, THE SUCCESSFUL BIDDER WOULD NO LONGER BE OBVIOUS. SINCE THE RELATIVE OPERATING EFFICIENCY OF COMPANIES CANNOT BE DETERMINED QUANTITATIVELY, THE COMMISSIONER COULD BE VULNERABLE TO CHARGES THAT BID AWARDS WERE BEING MADE IN AN ARBITRARY OR DISCRIMINATORY MANNER. THIS WOULD AFFECT THE INTEGRITY OF THE SYSTEM AS WAS PREVIOUSLY MENTIONED.

(2) A PROFIT-SHARING SYSTEM WOULD BE DIFFICULT AND COSTLY TO ADMINISTER. A LARGE ADMINISTRATIVE ORGANIZATION WOULD LIKELY BE ESTABLISHED TO AUDIT AND MONITOR THE CONTINUING ACTIVITIES OF LESSEES. DISCRETIONARY JUDGMENTS WOULD BE REQUIRED BY THE STATE WITH REGARD TO WHAT COSTS WERE TO BE INCLUDED OR REJECTED IN THE PROFIT BASE.

(3) A PROFIT-SHARING SYSTEM WOULD SIGNIFICANTLY REDUCE THE INCENTIVE FOR A SUCCESSFUL BIDDER TO OPERATE AT MAXIMUM EFFICIENCY. ANY PRUDENT OPERATOR UTILIZES A PRIORITY SYSTEM WHEN RESTRAINTS OF EITHER MANPOWER OR MATERIALS CREATE LIMITATIONS. WHEN THESE RESTRAINTS EXIST, NET-PROFIT TRACTS WILL HAVE LOW PRIORITY. THE RESULT - REDUCTION OF EFFICIENCY. IT WOULD REDUCE THE INCENTIVE FOR EARLY DEVELOPMENT OF TECHNOLOGY BY INDUSTRY. UNDER A PROFIT-

SHARING SYSTEM, TECHNOLOGY WILL ONLY BE DEVELOPED WHEN IT IS NEEDED AND THE COSTS OF THIS DEVELOPMENT WOULD BE SHARED WITH THE STATE. THIS WOULD LEAD TO DELAYS IN DEVELOPMENT OF NEEDED RESERVES.

(4) MOST IMPORTANT, SHARING IN NET PROFITS WOULD SIGNAL THE STATE'S ENTRY INTO THE PRODUCTION PHASE OF THE OIL BUSINESS. IT MIGHT BE POLITICALLY AND ECONOMICALLY DIFFICULT FOR THE STATE NOT TO BE DEEPLY INVOLVED IN DECISIONS ABOUT DAY TO DAY OPERATIONS AND THEREBY BECOME AN OPERATING PARTNER. THIS TYPE OF INVOLVEMENT WOULD REQUIRE A LARGE TECHNICAL STAFF TO BE EMPLOYED BY THE STATE. THIS STEP BY THE STATE WOULD WEAKEN THE PRIVATE ENTERPRISE SYSTEM WITHIN THE OIL INDUSTRY AND DIMINISH FREE ENTERPRISE IN THE STATE OVERALL.

NOW I WOULD LIKE TO DISCUSS A FEW OTHER PROVISIONS WHICH GIVE US CONCERN.

(1) AS38.05.180(z) RIGHT TO PURCHASE - THE PROVISION GIVES THE STATE THE RIGHT TO PURCHASE A SPECIFIED VOLUME OF OIL AND GAS. THE VAGUENESS OF THIS PROVISION MAKES IT VERY ONEROUS TO THE INDUSTRY. THE PROVISION DOES NOT SPECIFY WHEN THE ACTUAL QUANTITY WILL BE SPECIFIED. WILL IT BE PUBLISHED AT THE TIME THE LEASE SALE SCHEDULE IS PUBLISHED? IF IT IS NOT, AN OPERATOR MAY RUN THE RISK OF OBTAINING GEOPHYSICAL DATA IN PREPARATION FOR THE SALE AND THEN FINDING HE'S NOT INTERESTED WHEN THE STATE THROUGH ITS OPTION TO PURCHASE PRODUCTION, DEPRIVES HIM THE FREEDOM TO MARKET AND/OR USE THE PRODUCTION HE HOPES TO DEVELOP.

IT WOULD APPEAR THAT A SPECIFIED VOLUME COULD RANGE FROM THE STATE'S ROYALTY SHARE UP TO A MAXIMUM OF 100%. BASED ON PRIOR VERSIONS OF THE BILL, IT SEEMS REASONABLE TO ASSUME THAT THE STATE'S PRIMARY INTEREST IS IN PURCHASING A LARGE PORTION OF THE GAS.

HOWEVER, THE PRESENT AND POTENTIAL SUPPLIES OF GAS WITHIN ALASKA FAR EXCEED REASONABLY ANTICIPATED DEMANDS BY THE STATE RESIDENTS. THEREFORE, TO FIND A MARKET, THIS GAS WILL HAVE TO MOVE INTO INTERSTATE COMMERCE. THIS REQUIREMENT, THAT THE STATE COULD REMOVE THE GAS FROM THE MARKET, COULD SEVERELY HAMPER A PRODUCER'S ABILITY TO MARKET THE RESERVES. WITHOUT A REASONABLE EXPECTATION THAT GAS CAN BE MARKETED, THERE IS GREATLY REDUCED INCENTIVE TO EXPLORE.

IT WOULD ALSO RETARD DEVELOPMENT OF NATURAL GAS FOR STATE RESIDENTS. THE RISK THAT THE GAS COULD BE DIVERTED WOULD HAVE SIGNIFICANT IMPACT ON VENTURES TO INSTALL GAS TRANSPORTATION SYSTEMS.

IN ADDITION TO THESE CONCERNS, IT RAISES OTHER QUESTIONS SUCH AS:

1. DETERMINATION OF FAIR MARKET VALUE
2. TIMING AND RATE OF PRODUCTION - COULD THE STATE CONTROL THESE TO SATISFY THEIR OWN REQUIREMENTS OR DESIRES?

(2) <u>AS38.05.180(N) LEASE TERM</u> - A FIVE-YEAR PRIMARY LEASE TERM IS VERY RESTRICTIVE IN ALASKA. THE REMOTE LOCATION OF MOST

PROSPECTS, RUGGED TERRAIN, SHORT CONSTRUCTION SEASON, AND REDUCED DRILLING SEASON, EITHER NECESSARY OR IMPOSED, MAKE COMPLETION OF THE EXPLORATION CYCLE A DIFFICULT AND TIME-CONSUMING PROCESS. ONCE A DISCOVERY IS MADE, ADDITIONAL DRILLING IS REQUIRED BEFORE AN ESTIMATE OF THE FIELD SIZE CAN BE MADE. ALL OF THE PREVIOUSLY MENTIONED FACTORS AFFECT THIS DRILLING TOO. ONCE THE LENGTHY PROCESS OF DISCOVERING A FIELD AND ESTABLISHING ITS COMMERCIALITY IS COMPLETE, THE LONG DEVELOPMENT PHASE MUST BEGIN. WE STRONGLY RECOMMEND THAT THE 10-YEAR LEASE TERM BE RETAINED.

(3) AS38.05.140(c) UPLANDS ACREAGE LIMITATION - THE PROPOSED 300,000-ACRE LIMITATION ON ALL LANDS OTHER THAN TIDE AND SUBMERGED LANDS IS RESTRICTIVE COMPARED WITH THE CURRENT 500,000-ACRE LIMITATION IN A STATE LIKE ALASKA WHICH HAS SO MANY FRONTIER INTERIOR BASINS TO EXPLORE. IN A HOSTILE HIGH COST ENVIRONMENT SUCH AS ALASKA, A LARGE BLOCK OF ACREAGE MAY BE NECESSARY IN ORDER TO JUSTIFY EXPLORATION. WE BELIEVE THE PROPOSED 300,000-ACRE LIMITATION WOULD REDUCE THE INCENTIVE OF AN OPERATOR TO EXPLORE THESE FRONTIER INTERIOR BASINS AND STRONGLY RECOMMEND MAINTENANCE OF THE CURRENT 500,000-ACRE LIMITATION.

(4) AS38.05.180(y) JOINT BIDDING - THE PROVISION ALLOWING THE COMMISSIONER TO RESTRICT JOINT BIDDING, IF HE SO DESIRES, COULD PROHIBIT THE INVOLVEMENT OF SOME COMPANIES MOST CAPABLE OF OPERATING IN THE ALASKAN ENVIRONMENT.

A STUDY WAS PERFORMED BY THE UNIVERSITY OF SOUTHERN CALIFORNIA AND THE USGS TO DETERMINE THE EFFECTS OF RESTRICTING MAJORS

FROM BIDDING JOINTLY IN THE OCS. THEY CONCLUDED THAT ON THE AVERAGE, THIS RESTRICTION RESULTED IN MORE BIDS PER LEASE BY THE MAJORS. THE STUDY ALSO SHOWED THAT THE NUMBER OF BIDS BY NON-MAJORS EITHER BIDDING ALONE OR IN COMBINES NOT INCLUDING A MAJOR, DECREASED SHARPLY. ("STATISTICAL ANALYSIS OF SOLO AND JOINT BIDS FOR FEDERAL OFFSHORE OIL AND GAS LEASES", SPE #6517 BY ELMER L. DOUGHERTY AND JOHN LOHRENZ.) FROM THIS DATA, IT DOES NOT APPEAR THAT THE RESTRICTION OF JOINT BIDDING BY MAJORS HAS RESULTED IN ANY INCREASED COMPETITION BY THE NON-MAJORS.

(5) AS38.05.180(i) INCENTIVE CREDIT - THIS PROVISION ALLOWS THE COMMISSIONER TO ESTABLISH AN EXPLORATION INCENTIVE CREDIT SYSTEM. IN ORDER TO OBTAIN CREDIT FOR GEOPHYSICAL WORK, THE OPERATOR MUST RELEASE THE INFORMATION TO THE PUBLIC FOLLOWING THE SALE. WE OBJECT TO THE REQUIREMENT FOR RELEASE OF THIS DATA.

THE PROVISION DOES NOT ESTABLISH A TIME REQUIREMENT FOR THE RELEASE OF THIS DATA. I ASSUME THE RELEASE WOULD BE REQUIRED BEFORE ANY CREDIT COULD BE RECEIVED. RELEASE OF THIS DATA COULD COST AN OPERATOR ANY COMPETITIVE EDGE WHICH HE MIGHT HAVE ON LEASING ACREAGE THAT IS RELEASED BY A LESSEE AND RENOMINATED. IN ADDITION, RELEASE OF THIS DATA TO THE PUBLIC COULD RESULT IN THE DISCLOSURE OF PROPRIETARY RECORDING TECHNIQUES AND THEREFORE RESULT IN THE POSSIBLE LOSS OF A TECHNOLOGICAL ADVANTAGE.

IN CLOSING, I WOULD LIKE TO REITERATE THAT EXXON BELIEVES THE CURRENT LEASING STATUTES AND THE IMPLEMENTING REGULATIONS

HAVE SERVED THE STATE AND INDUSTRY WELL AND DO NOT NEED TO BE CHANGED.

THIS CONCLUDES MY PREPARED TESTIMONY, AND I WILL BE HAPPY TO ANSWER ANY QUESTIONS WHICH YOU MAY HAVE.

* * * * *

ALASKA OIL AND GAS ASSOCIATION TESTIMONY on CSHB 854
Senate Resources Committee
May 24, 1978

I am KEITH ARNOLD, Public Affairs Manager for the Alaska Oil and Gas Association, a trade association whose 25 member companies are engaged in or have an interest in oil and gas activities in Alaska, including exploration, production, transmission, refining and marketing.

The basic position of our Association is that because Alaska's present leasing system has worked well for the state, major changes--such as those proposed in the bill before you--should be subjected to the most careful, deliberate study possible. We believe this has not yet been accomplished The current law is sufficient. It has encouraged industry to lease, explore, discover and develop oil and gas resources with confidence, and sometimes success.

Our remarks will attempt to highlight provisions of the bill we consider particularly counterproductive. We understand several companies will comment individually on the bill and that specific suggestions reflecting individual views may be offered.

We have several areas of particular concern to call to your attention and we will try to identify them as briefly as possible:

The item on page one, line 27, paragraph (b), calls for annual legislative review of the Commissioner's leasing program. Traditionally it has been the function of the Administrative branch of state governments to administer the use of state lands. The annual submission of the leasing program to the legislature would seem to presuppose

further modification of the leasing program. We believe that the program should be administered totally on the basis of its merits and it should remain out of the political arena.

Next please refer to page 3, paragraph (f). We favor the traditional method of wellhead pricing and are opposed in principle to the state receving a free ride on the gathering systems and high grading of the oil or gas. The very essence of a reserved royalty share is that the mineral estate owner keeps a portion of whatever is found and produced from the leased land. Such reserved shares become possessory immediately at the point shares can be reduced to physical possession, i.e., at the wellhead. Whatever the quality of the production, the royalty share is the property of the royalty owner to be disposed of in accordance with the terms of the lease contract. A shifting of the royalty owner's share of costs to the lessee of the expense of processing for market, and preparation for transportation off the lease will necessitate an attendant reduction in the bid to cover the greatest potential cost which could occur in the event of production.

Various leasing methods are also proposed in paragraph (f). In advocating a move away from bonus bidding one should consider that the risk burden is being shifted from the oil industry to the public, that the rate of exploration and development is being impeded, and that the growth of state agencies to administer and audit such systems is inevitable.

Our member companies prefer the cash bonus bid and fixed royalty arrangement. This method historically has generated the greatest dollar value to the state. Tracts receiving abnormally high royalty bids are not the first to be explored or developed and are held, in many instances, for speculation. This same premise also applies to "net profits."

Regarding Section 38.05.180 (j), we concur with the ability (authority) of the Commissioner to reduce the royalty in the interest of conservation and to encourage the greatest ultimate recovery of oil or gas. However, we believe a requirement that the Commissioner find a need for such reduction, based on two years of uneconomic production, is wasteful. Two years is too long.

Section (k), on page 6, gives the Commissioner authority to defer payment of any part of a cash bonus bid for a period of five years. Such a provision would encourage speculation with the state's assets by parties who have no intention of conducting expensive exploration programs but rather, hope to capitalize on any enhancement in value caused by the work of others in the vicinity of their lease. This is not in the best interest of the state.

It is common knowledge that Alaska is a high-cost, high-risk area for our industry. Exploration and drilling seasons are short. For these reasons, we respectfully request that you give favorable attention to the retention of the ten-year primary term for leases.

If cash bonus/fixed royalty is adopted as the bidding method and the 10 year term remains in the Law, the benefits to the state will be greater, in the long-run, than the experimentation proposed in CSHB 854.

Sections (n) and (o), dealing with rentals, are both counter productive and regressive. Alaska is already a high-cost, high-risk area. The prospect of substantial rental increases during the primary term of the lease can only discourage exploration interest in Alaska--not encourage it. The extra expense for rentals will have to be compensated for by lower bid totals. Further, these high fixed costs will lessen the amount of cash flow dollars that otherwise would be available for exploration work. Subsection (o) alters substantially the nature of the ordinary rental provisions in oil and gas leases. The rental to be paid under these provisions is no longer a delay rental. Also, there is no provision for credit or set-off of "rental" paid during those three years against the state's income from production. Consequently, we find ourselves in the absurd situation during the first three years of production, paying the state both a rental and royalty payment at the same time. This means, we are paying for the privilege of deferred drilling, after drilling operations have been completed and in addition, paying production income during this same period of time.

Section 38.05.180(y) would restrict joint bidding and should be deleted. Joint bidding can very well be to the advantage of the

state as it tends to increase the size of the bids submitted and facilitates the exploration process. See, for example, the paper in the November 1976 issue of "Journal of Petroleum Technology" in which the authors conclude that "joint bidders tend to bid on more sought-after (and apparently more valuable) leases and that they tend to bid higher, on the average, than solo-bidding 'competitors.' Industry testimony before the U.S. Senate has indicated that since the first OCS sale in 1954, 172 companies have purchased OCS leases. Forty-two percent of these leases were not purchased by the major companies.

Depending on the content of the regulations adopted, this section may violate Article 8, Section 17, of the Alaska Constitution. This Constitutional provision requires that laws and regulations governing the use or disposal of natural resources must apply equally to all persons "similarly situated."

A provision giving the state the right to purchase a specified volume of oil and gas (Section 38.05.180(z)) would, in our opinion, be considered objectionable to any potential participant at a state lease sale whether a major oil company or the smallest independent. It virtually eliminates the lessee's ability to use a gas sales contract as a method of financing. A discoverer of a gas field could find it impossible to market the discovered reserves. This would inevitably result in a disincentive to explore with adverse results for both the state, as owner of the resource, and for its residents whose needs for fuel could be drastically affected.

As our Association has previously testified at public hearings dealing with similar provisions in proposed amendments to the Alaska Administrative Code, we believe that a provision in paragraph (aa) for state access to a lessee's exploration data constitutes an invasion of industry's proprietary property for the sole purpose of enabling the state to decide whether the area in which the exploring party is working should or should not be thrown open to his competition. It should be obvious that this can only result in a substantial reduction in incentive to undertake exploration work in the future, the performance of which is significantly in the state's best interest.

If the section is to be considered applicable to existing exploration data, then the Commissioner's access, and utilization thereof, is almost certainly an unconstitutional taking of a valuable private property.

The proposed bill also would amend Section 38.05.140(c) to reduce the upland acreage limitation from 500,000 to 300,000 acres. In Alaska, where there are large areas of state lands which are potentially eligible for bid, a 500,000 acre limitation, which the present statute contemplates, is not unreasonable. The effect of a 300,000 acre limitation would clearly be to limit the participation of those individuals who are most active in exploration business in Alaska, i.e., those individuals who have historically submitted the highest bids to the state. It is not at all clear why the state would seek to discourage, rather than to encourage, the continued

involveme of those individuals in Alaska. Further, this section's applicability to the holding of existing lessees--requiring them to reduce their holding within 10 years--is an unconstitutional taking of leasehold estates.

In summary we offer the following:

We believe the existing law has worked very well over the last 18 years to protect the interests of all the citizens of the State of Alaska. The present law provides important public benefits that are seriously lacking in the proposed bill, such as:

(a) protection to the state from having to take "exploration risk" when selling leases;

(b) assurance the state will get the fair market value of what the state offers for sale by utilizing a proven unhampered competitive, free-enterprise open market system;

(c) ease of administration minimizing the number of state employees and overhead expense;

(d) assurance that all citizens, bot individual and corporate, are treated equally under the law;

(e) legislative and judicial history that gives relative stability in interpretation and operation;

(f) allowance of latitude to lease lands in low interest or high-risk areas non-competitively to avoid the bureaucratic expense of competitive sales;

(g) and recognition that the geological and geophysical data gleaned from an exploration operation is the 'stock-in-trade' of the explorationist and is proprietary in a competitive industry. The present law also recognizes that forced disclosure of proprietary data will discourage exploration. Research and development to find better methods of obtaining usable data will also suffer.

In conclusion, we strongly urge retention of leasing procedures that exist under present regulations. The effect of the sweeping provisions of CSHB 854 should be studied carefully before further consideration is given to the measure. We urge that you do not adopt CSHB 854.

It is our belief that the current method is not only fair to industry but also is in the best interest of the people of the State of Alaska.

Thank you.

THE MINES AND MINERALS ACT

GEOPHYSICAL INCENTIVE PROGRAM REGULATION, 1978

(filed April 26, 1978)

1 In this regulation

(a) "certificate" means a certificate issued for a program under this regulation;

(b) "Department" means the Department of Energy and Natural Resources;

(c) "foothills area", "green area", "yellow area" and "plains area" mean the respective areas of Alberta described in Schedule C to this regulation;

(d) "geophysical incentive program" means a program certified by the Minister as an incentive program under this regulation;

(e) "geophysical information and data" means all field data, field reports and the standard processed sections that are stacked after filtering and correction for statics and normal moveout;

(f) "Geophysical Regulations" means the Geophysical Regulations filed as Alberta Regulation 26/59, as amended;

(g) "licence" means a licence issued pursuant to Part 9 of The Mines and Minerals Act;

(h) "licensee" means the holder of a licence under which a program is conducted;

(i) "line" means a portion of a program;

(j) "minimum subsurface coverage" means the coverage obtained when seismic pulses generated from not less than 6 different energy source positions in the yellow area and plains area or 12 different energy source positions in the green area and foothills area are reflected from a subsurface point;

(k) "Minister" means the Minister of Energy and Natural Resources;

(l) "permit" means a permit to operate geophysical equipment issued pursuant to the Geophysical Regulations;

(m) "program" means a survey conducted by the use of the geophysical prospecting technique known as the seismic reflection method for the purpose of exploring for petroleum or natural gas or both.

2 This regulation applies to a program for which an application for a certificate is received by the Minister before April 1, 1980.

3 (1) A licensee may, in accordance with this regulation, apply to the Minister to have a program certified as a geophysical incentive program.

(2) The application shall be submitted by the licensee and shall be in Form of Schedule A to this regulation.

(3) Where a program qualifies as a geophysical incentive program, the Minister shall issue a certificate for the program in Form 2 of Schedule A to this regulation.

(4) A copy of the certificate shall be sent to the licensee.

4 A certificate is subject to the following conditions:

(a) that the licensee shall allow the Minister, or any person authorized by the Minister for the purpose, to have access to any field data or field reports obtained by the licensee or his representatives during the course of conducting the program, and

(b) that the licensee and his representatives shall render to the Minister or the person authorized by him under clause (a) such assistance as may be necessary for the purposes of enabling the Minister or that person to inspect the field data or field reports.

5 (1) Within 120 days of completing a geophysical incentive program, or on or before August 1, 1980, whichever is earlier, the licensee shall submit to the Minister a final report on the program in Form 3 of Schedule A to this regulation.

(2) A final report submitted by the licensee under subsection (1) shall be accompanied by a copy of the computer stacking diagram for each line in the program.

(3) The final report on a geophysical incentive program shall be made on behalf of the licensee by a professional geophysicist within the meaning of The Engineering and Related Professions Act.

(4) At any time following submission to the Minister of the final report on a geophysical incentive program, the licensee shall make available to the Department upon request all geophysical information and data obtained from the program.

6 Subject to subsection (3), where a geophysical incentive program

(a) is conducted under a certificate for which an application is received by the Minister after March 31, 1978, and before April 1, 1980,

(b) is completed to the satisfaction of the Minister, and

(c) is reported on within the time and in the manner prescribed by section 5,

the Minister shall

(d) determine a credit for the program in accordance with Schedule B to this regulation, and

(e) notify the licensee of the credit as determined.

(2) The mileage upon which a determination of credit for a geophysical incentive program is based shall never exceed the number of miles of minimum subsurface coverage approved for the program, but where the number of miles of minimum subsurface coverage in a geophysical incentive program as determined from the final report and computer stacking diagrams is less than the mileage approved for the program, the Minister shall base his determination of credit for the program upon the size of the program as ascertained from the computer stacking diagrams.

(3) The Minister shall not determine a credit for a program under subsection (1) where he is satisfied that

(a) the program fails to meet minimum subsurface coverage,

(b) the program is not conducted in accordance with generally accepted standards of geophysical practice, or

(c) the recording of the program has commenced before a certificate for the program is issued under section 3.

(4) Subsection 3(c) does not apply to a geophysical incentive program for which an application for certification is received by the Minister during April, 1978.

(5) When submitting a final report on a program under section 5, the licensee shall inform the Minister in writing as to the manner of allocation of the credit among the persons specified by the licensee as being participants who have contributed to the actual cost of conducting the program and, subject to subsection (6) and section 7, the credit shall be allocated and established in the records of the Department accordingly.

(6) If the licensee fails to comply with subsection (5), the credit shall be established in the records of the Department in the name of the licensee.

7 Notwithstanding sections 6 and 9, the Minister may withhold from establishment in the records of the Department or from utilization, 25% of the credit determined by the Minister for a geophysical incentive program until the Minister receives evidence satisfactory to him that the program was conducted in accordance with the Geophysical Regulations, and that the surface of the land on which the program was conducted has been adequately reclaimed.

8 (1) Subject to subsection (2), credit established in the records of the Department under section 6 is not transferable.

(2) Any credit held in the records of the Department in the name of a licensee or of a party to whom credit has been allocated under section 6 may be transferred to any other person where that person provides evidence satisfactory to the Minister

(a) that he has acquired the assets and liabilities of the licensee or party in whose name the credit is being held, and

(b) that the licensee or party in whose name the credit is being held has ceased to carry on business in Alberta, or, being a corporation, is dissolved or is struck off the register pursuant to The Companies Act.

9 (1) Credit established in the records of the Department pursuant to section 6 may, upon the written request of the holder thereof, and subject to procedures established by the Department, be applied in satisfaction of

(a) money payable by him with respect to any applications made and agreements made or entered into under Part 5 of The Mines and Minerals Act,

(b) royalty payable on petroleum and natural gas obtained pursuant to an agreement made or entered into under Part 5 of The Mines and Minerals Act,

(c) interest on money payable under any agreement made or entered into under Part 5 of The Mines and Minerals Act, or

(d) taxes levied under The Freehold Mineral Taxation Act on petroleum or natural gas rights,

and becoming due and payable on or before December 31, 1987.

(2) Where a licensee submits a request to the Minister for the monetary equivalent of the credit being held in the name of the licensee in the records of the Department and provides evidence satisfactory to the Minister that he is neither the registered owner under The Land Titles Act of a petroleum or natural gas right as defined in The Freehold Mineral Taxation Act nor the holder of an agreement under Part 5 of The Mines and Minerals Act, the Minister may pay to the licensee upon submission of the request the monetary equivalent of the credit.

10 (1) It is a condition of every certificate that geophysical information and data obtained pursuant to the geophysical incentive program for which the certificate is issued shall be made available by the licensee under whose licence the program was conducted 3 years after the date upon which the geophysical incentive program is certified

(a) to any person requesting the data in writing within 20 days after receipt by the licensee of the written request for the data and thereafter for a period of not less than 5 years, and

(b) at a cost to that person of

(i) $300.00 for each mile of minimum subsurface coverage in the yellow area or plains area to which the geophysical information and data to be acquired relates,

(ii) $600.00 for each mile of minimum subsurface coverage in the green area to which the geophysical information and data to be acquired relates, and

(iii) $900.00 for each mile of minimum subsurface coverage in the foothills area to which the geophysical information and data to be acquired relates,

and of the expense of reproducing the geophysical information and data requested.

(2) The minimum amount of geophysical information and data which may be purchased pursuant to a written request under subsection (1) shall be the lesser of the geophysical information and data relating to

(a) 5 miles of minimum subsurface coverage, or

(b) the minimum subsurface coverage in a line.

(3) If a licensee, within the 3-year period referred to in subsection (1),

(a) withdraws from Alberta and ceases carrying on business in Alberta, or

(b) being a corporation, is dissolved or is struck off the register pursuant to The Companies Act,

he shall place in trust with a person approved by the Minister all the geophysical information and data obtained pursuant to geophysical incentive programs that were conducted under his licence until the 3-year period has expired, and thereafter for an additional period of 5 years, and any credit held in the name of the licensee in the records of the Department shall be cancelled.

11 (1) Where geophysical information and data obtained from a geophysical incentive program for which no credit is determined by the Minister under this regulation is not made available in accordance with section 10 by the licensee, the Minister may cancel

(a) his licence,

(b) his permit, and

(c) any credit held in his name in the records of the Department.

(2) Where geophysical information and data obtained from a geophysical incentive program for which credit is established in the records of the Department is not made available in accordance with section 10 by the licensee, the Minister may cancel

(a) his licence,

(b) his permit,

(c) any credit established for the program in the records of the Department, and

(d) any credit held in the records of the Department in the name of the licensee.

12 Any of the powers of the Minister under this regulation may be exercised by any employee of the Department authorized in writing by the Minister for that purpose.

Form 1
(Section 3)

APPLICATION FOR CERTIFICATION OF A PROGRAM AS A
GEOPHYSICAL INCENTIVE PROGRAM

DATE:

NAME OF LICENSEE: _____

ADDRESS: _____

LICENCE NO. _____

LICENSEE REPRESENTATIVE: _____

TELEPHONE NO. _____

NAME OF PERMITTEE: _____

ADDRESS: _____

PERMIT NO. _____ PARTY NO. _____

PROGRAM NO. _____

PROGRAM RECORDING TO COMMENCE: _____

ANTICIPATED PROGRAM RECORDING COMPLETION DATE: _____

ENERGY SOURCE: _____

SOURCE SPACING (FEET): _____

RECEIVER SPACING (FEET): _____

NUMBER OF TRACES: _____

	yellow-plains	green	foothills
MILES PLANNED (APPROX.):	_____	_____	_____
INCENTIVE ANTICIPATED (APPROX.):	_____	_____	_____
TOTAL INCENTIVE ANTICIPATED:	_____	_____	_____

_____
Licensee

(Note: Application must be accompanied by a map or maps on a scale of not less than 1" = 1 mile.)

AGO 546637

Form 2

(Section 3)

CERTIFICATE NUMBER _____

DATE: _____

NAME OF LICENSEE: _____

ADDRESS: _____

LICENCE NO. _____ PERMIT NO. _____

PROGRAM NO. _____

MAXIMUM MILEAGE APPROVED _____

_____

for MINISTER OF ENERGY AND NATURAL RESOURCES

SCHEDULE A

Form 3
(Section 5)

FINAL REPORT

LICENSEE: _____

LICENCE NO. _____

ADDRESS: _____

PROGRAM CERTIFICATE NO. _____ PROGRAM CERTIFICATE DATE _____

RECORDING COMMENCEMENT DATE _____ RECORDING COMPLETION DATE _____

PERMITTEE: _____

PERMIT NO: _____

ADDRESS: _____ PARTY NO: _____

RECORDING COMMENCEMENT DATE _____ RECORDING COMPLETION DATE _____

AMPLIFIER MAKE _____ MODEL _____ NO. OF TRACES _____ (24) _____ (48) _____ (Other)

SOURCE INTERVAL _____ RECEIVER INTERVAL _____ SOURCE TYPE _____

	yellow-plains	green	foothills
No. of miles of minimum subsurface coverage.	$250 x 1 x	$250 x 2 x	$250 x 3 x
(Accurate to two significant decimals)			
Credit (in dollars) applied for	= $	= $	= $

Total $_____

I, the undersigned, certify that I am qualified to report on this program and have personal knowledge of and attest to the accuracy of the above report.

_____ _____

Signature and Seal of Professional Geophysicist *A.P.E.G.G.A. Class*

(Note: Must be accompanied by a map or maps on a scale of not less than 1" = 1 mile showing location of data recorded. A final report must be completed for each program.)

AGO 546639

SCHEDULE B

DETERMINATION OF CREDIT

The credit in dollars for a geophysical incentive program, shall be calculated in accordance with the following equation:

$$\text{Credit (In dollars)} = 250 KM$$

where K is the incentive factor for the area of Alberta described in Schedule C in which the geophysical incentive program was conducted,

and

M is the number of miles of minimum subsurface coverage in the area.

Incentive Factors

For the purposes of section 6 and this Schedule, the incentive factors established for the areas of Alberta described in Schedule C are as follows:

(a) 1 for the yellow area and the plains area,

(b) 2 for the green area, and

(c) 3 for the foothills area.

FOOTHILLS AREA

The Foothills Area consists of the lands in Alberta listed below and those lands within Alberta located south and west of the listed lands:

Township 1, Range 24; Township 2, Range 25; Township 3, Range 26; Township 4, Range 27; Township 5, Range 28; and Townships 6 to 11 inclusive, Range 29, all west of the 4th Meridian;

and

Townships 12 and 13, Range 1; Townships 14 to 20 inclusive, Range 2; Townships 21 and 22, Range 3; Townships 23 to 28 inclusive, Range 4; Townships 29 and 30, Range 5; Townships 31 to 34 inclusive, Range 6; Townships 35 and 36, Range 7; Township 37, Range 8; Township 38, Range 9; Townships 39 and 40, Range 10; Township 41, Range 11, 12 and 13 inclusive; Township 42, Range 14; Township 43, Ranges 15 and 16; Township 44, Range 17; Townships 45 and 46, Range 18; Townships 47 and 48, Range 19; Township 48, Range 20; Township 49, Ranges 21 and 22; Township 50, Range 23; Townships 51 and 52, Range 24; Townships 53 and 54, Range 25, Township 54, Range 26; Townships 55 and 56, Range 27, all west of the 5th meridian;

and

Township 56, Range 1; Townships 57 and 58, Range 2; Township 58, Range 3; Townships 59 and 60, Range 4; Township 60, Ranges 5 and 6; Township 61, Ranges 7 and 8; Township 62, Ranges 9 and 10; Township 63, Range 11; Townships 64 and 65, Range 12;and Township 66, Ranges 13 and 14, all west of the 6th meridian.

GREEN AREA

The green area consists of that part of Alberta in which public lands are classified as forest land not available for agricultural development other than grazing by an order of the Minister pursuant to Section 12 of The Public Lands Act effective to November 30, 1974, but does not include those lands described in this Schedule as the Foothills Area.

YELLOW AREA

The yellow area consists of that part of Alberta in which public lands are classified as being adaptable to any kind of disposition by an order of the Minister pursuant to Section 12 of The Public Lands Act effective to November 30, 1974.

PLAINS AREA

The plains area consists of the remaining lands in Alberta not described in the Foothills Area, the Green Area or the Yellow Area.

HOUSE JOURNAL

LETTER OF INTENT

CSHB 854 (RESOURCES)

The Honorable Hugh Malone
Speaker of the House
Alaska State Legislature

Dear Mr. Speaker:

The Resources Committee substitute for House Bill 854 makes numerous changes in the legislation as proposed by the Governor. Two of these changes involve the deletion of the following language:

1. Subsection (f) on page 6.

2. In subsection (j) the following sentence (at the top of page 8 in the original bill) - "The commissioner may provide by regulation and in the lease that the lessee may earn production rights only to the depth drilled at the beginning of production from the lease."

The record should show that the committee's intent in deleting these two items was not to limit the discretion of the Commissioner of Natural Resources in these areas, but simply the result of its determination that the authority in both of these areas is implied, and does not require special authorizing language in the bill.

Alvin Osterback

Alvin Osterback, Chairman
House Resources Committee

Date: 4/14/78

AGO 546642

STATE OF ALASKA
THE LEGISLATURE

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

LEGISLATIVE AFFAIRS AGENCY

MEMORANDUM

June 16, 1978

SUBJECT: Suggested Technical Amendments to HB 854

TO: The Free Conference Committee on HB 854

FROM: Gregg K. Erickson
Director of Research

We suggest that you may wish to consider the following technical amendments to the oil and gas leasing bill. Page and line numbers referred to SCS CS HB 854 (2nd Rules).

P.#- SIDE
By SIDE ANALYSIS

p. 2

1. Page 2, lines 9-13: Delete the word "and" on Line 9 and substitute the word "or". Insert a period after the word "issued" on line 10, and delete all remaining material on lines 10-13.

The change suggested above is unnecessary if the House's position on legislative review is accepted by the Free Conference Committee. However, if the provision for legislative review is deleted, as was the case in the Senate bill, the change suggested here would appear to eliminate possible confusion over the legislature's roll, and would eliminate any doubt concerning whether an area proposed in the third (but not the fourth) year preceding leasing, could be leased.

p. 6

2. Page 4, lines 23 and 25: Delete the last sentence in subsection (h) and substitute the following material, "The Commissioner may waive a work commitment, or portion of it if, based on the results of exploration in the area surrounding lease, a lease holder demonstrates that there is a substantial probability that the lease is incapable of producing oil or gas."

We believe this language to be a clearer expression of what we understand to be the intent of this sentence.

p. 17

3. Page 12, line 19; Delete the word "this" and substitute "the leasing program submitted to the first session of the 11th Legislature."

Administration officials have suggested that restatement rather than the use of the pronoun would eliminate any possible confusion on this subsection.

GKE:fc

AGO 546629+