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.

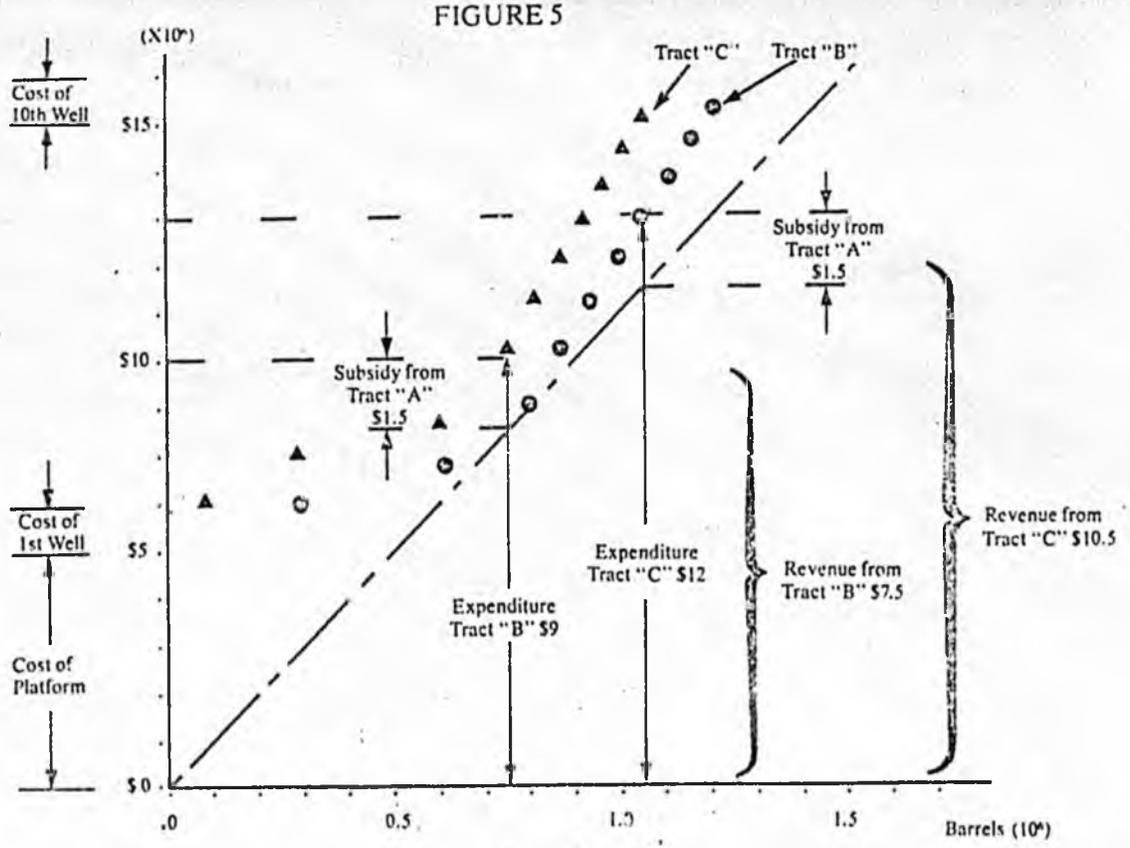
TABLE 3

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.

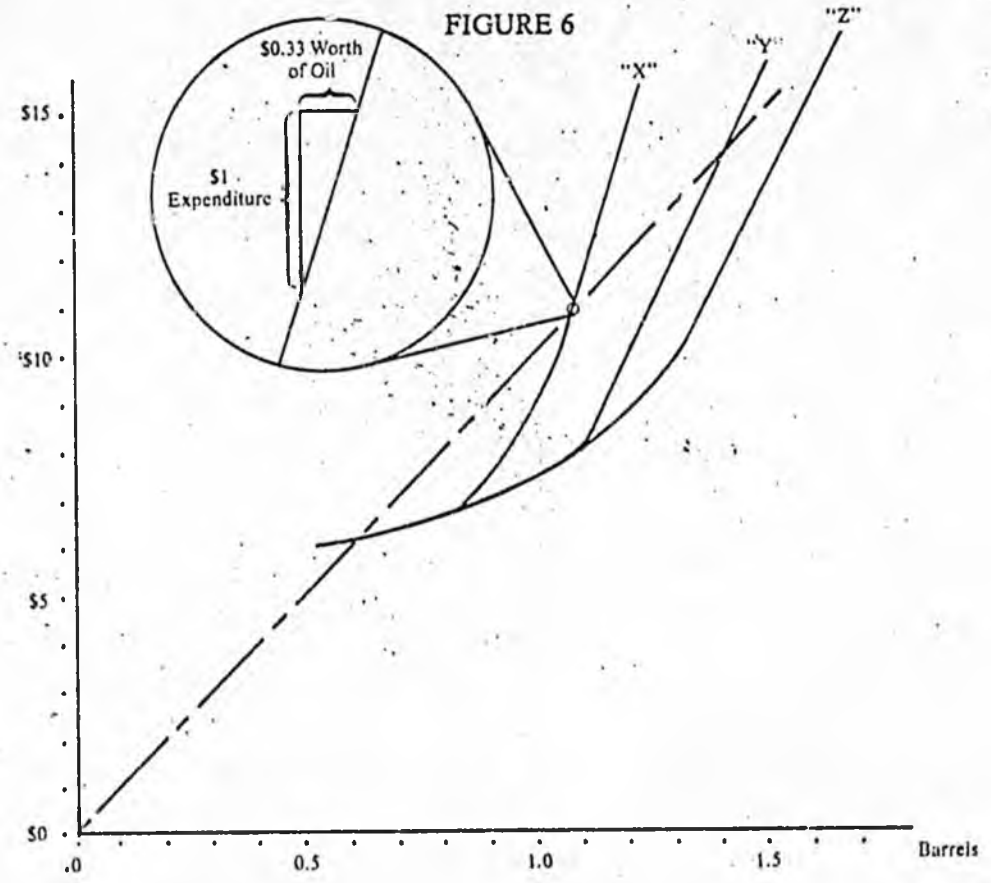
A minor but interesting benefit of a market in commitments would be the information it would provide concerning the efficiency with which the work commitment system is eliciting additional output.

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 $0.33 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.[7]

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 Development 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 32 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.

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 resource 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 I

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.[1] 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 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 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.

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).

(10/1/77) Draft subject to significant and/or substantial changes at any time.)(Draft 5)

REVISED DRAFT

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) Purpose. The legislature finds and declares that

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

(A) maximize the economic recovery of this important natural resource;

(B) control the exploitation of this natural resource so as to protect the public interest;

(C) maximize the competition among parties seeking to obtain the the right to explore and develop the state's oil and gas resources.

(2) the interest of the state is to encourage an assessment of its oil and gas resources and that will allow the maximum flexibility in the methods of awarding the leases to

(A) recognize the many and 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 the state's share from profitable oil and gas production, while minimizing revenue from unsuccessful exploration wells and from marginal economic oil and gas production.

ROUGH DRAFT

(b) Leasing Program.

(1) The commissioner shall prepare and periodically revise, and maintain an oil and gas leasing program. This leasing program shall be submitted to the legislature for its information within 10 days of the convening of a regular session of the legislature. The leasing program shall 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 elect the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper 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 approved by the commissioner, no lease shall be issued unless it is for an area included in the approved leasing program and unless it contains provisions consistent with the approved leasing program, except that leasing shall be permitted to continue until such program is approved and for so long thereafter as such program is under judicial or administrative review. Leasing under paragraph (t) of this Act may be excepted from the leasing program if in the judgment of the commissioner it appears most advantageous to the state. written

(3) The commissioner shall review the leasing program approved under this section at least once each year, and he may revise and reapprove such program, at any time, in the same manner as originally developed.

(4) 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 the Federal and local governments which may be impacted by the proposed leasing;

(D) periodic consultation with the Federal and local governments, oil and gas lessees and permittees, and representatives of other individuals or organizations engaged in activity in or on state land; and

(E) coordination of the program with the management program developed by the state under the Coastal Zone Management Act of 1972.

(F) the commissioner shall utilize the existing capabilities and resources of all state agencies in preparing the leasing program, and such agencies shall provide the commissioner with any nonproprietary information he requests.

(5) Within 10 days of the convening of a regular session of the lesiglature, the commissioner shall report to the legislature with respect to the use of the various bidding methods provided for in this Act. Such report shall include:

(A) The schedule of all lease sales held during the preceding 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 utilized;

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

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

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

ROUGH DRAFT

(c) The commissioner is authorized to grant to the highest responsible qualified bidder, by competitive bidding under regulations promulgated in advance, oil and gas leases on state land. The bidding shall be by sealed bid, and at the discretion of the commissioner, shall be on the basis of

(1) Royalty

(A) cash bonus bid with a royalty at not less than a 12½ percent reserved to the state which may be taken in kind or in value;

(B) a cash bonus bid with a royalty based on a sliding scale reserved to the state but not less than 12½ percent at the beginning of the lease period which may be taken in kind or in value;

(C) a fixed cash bonus with a royalty based on a sliding scale reserved to the state as the bid variable but not less than 12½ per cent at the beginning of the lease period which may be taken in kind or in value;

(2) Net profit

(A) cash bonus bid with a royalty at not less than 12½ percent which may be taken in kind or in value and a fixed share of the net profit of not less than 30 percent reserved to the state;

(B) fixed cash bonus with the net profit share reserved as the bid variable;

(C) fixed cash bonus bid with a royalty at not less than 12½ percent which may be taken in kind or in value and a percent of the net profit share reserved to the state as the bid variable.

(3) Work commitment bid based on a dollar amount for exploration with a fixed cash bonus and a fixed royalty, but not less than 12½ percent at the beginning of the lease period which may be taken in kind or in value.

(d) The commissioner may, in his decretion, defer any part of the payment of the cash bonus, as authorized in paragraph c of this Act, 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.

(e) The commissioner is authorized to withhold acreage from leasing in a particular lease sale.

(f) The commissioner may utilize other leasing methods after public hearings, unless the legislature by joint resolution disapproves within thirty days after receipt of notice of the proposed bidding method.

(g) At least ninety days prior to notice of any lease sale under paragraph (c) (2), the commissioner shall by regulation establish rules to govern the calculation of net profits. In the event of any dispute between the state and a lessee concerning the calculation of the net profits under the regulation issued pursuant to this paragraph, the burden of proof shall be on the lessee. In determining the attribution of profits between oil and gas, costs, other than those directly attributable to the production of either oil or gas, shall be allocated proportionately based on the Btu equivalent values of the respective amounts of oil and gas produced.

(h) At least ninety days prior to notice of any lease sale under paragraph (c)(3), the commissioner shall by regulation establish rules to govern the work committment option. The commissioner shall require either (i) cash deposit for the full amount 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 such exploration work commitment assuring the commissioner that such commitment shall be faithfully discharged in accordance with this section, the regulation and the lease. As provided in the regulation, the principal amount of such

cash deposit or bond may be periodically reduced upon proof, satisfactory to the commissioner, that a portion of the exploration work commitment has been satisfied.

(i) At the discretion of the commissioner, he may enter into an agreement or may initiate a request whereby with the consent of the majority of the effected field lease holders, the state's royalty oil and gas production may be stored or retained in storage, or the commissioner may enter into an agreement with one or more of the effected field lease holders to trade current royalty production from a field for a like amount, kind andquality of future production, provided the state receives back its stored or traded royalty oil and gas during the first half of the field life or no later than 15 years after start of production.

(j) An oil and gas lease shall cover a reasonably compact area not exceeding 5,760 acres, and be for a period of five years. An oil and gas lease may be extended for an additional five years if the commissioner determines the extension is in the best interest of the state and he bases his decision on a showing by the lessee of due exploration diligence as defined by regulation; however, rental rates will continue to increase as if the lease had originally been made for the extended period. An expiring 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 temporary cessation of production approved by the commissioner does not constitute grounds for nonrenewal or cancellation of the lease. If drilling has commenced on the expiration date of the primary term of the lease and is continued with reasonable diligence, such operations to include 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 oil or gas is produced in paying quantities.

(k) Oil and gas leases shall provide for payment to the state of rental on the following basis:

(1) for the first through third years, $1.00 per acre annually

(2) for the fourth and fifth years, $2.00 per acre annually

(3) for the sixth year, $4.00 per acre

(4) for the seventh year, $8.00 per acre

(5) for the eighth year, $12.00 per acre

(6) for the ninth year, $24.00 per acre

(7) for the tenth year, $36.00 per acre

(8) for the eleventh year and beyond, rental rate is 150% of the preceding year.

The commissioner may establish by regulation, that after a discovery has been made which is capable of producing in paying quantities, the rental rate which was in effect during the year of discovery is maintained for the following 5 years. Rental is payable in advance and continues until income to the state from royalty, net profit or the base parameter of other leasing methods exceeds rental income to the state for that year; after the rental income schedule has been exceeded for three consecutive years, the rental shall terminate.

(l) Upon timely application as provided by regulation, the state may issue to the holder of a federal lease a state shorelands lease covering land within the exterior boundaries of the federal lease which has been excluded on the basis of navigability or which are later administratively or judicially determined to be "shorelands."

(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, alter, change, or revoke drilling, producing, rental, minimum royalty, and royalty requirements of the leases and make regulations with reference to the leases, with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan as he determines necessary or proper to secure the proper protection of the public interest. The commissioner may provide that oil and gas leases issued under this section shall contain a provision requiring the lessee to operate under a reasonable cooperative or unit plan, and he may prescribe a plan under which the lessee shall operate. The plan shall adequately protect all parties in interest, including the state.

(n) A plan authorized by (m) of this section, which includes land owned by the state, may contain a provision vesting the commissioner, or a person, committee, or state agency with authority to alter or modify from time to time the rate of prospecting and development and the quantity and rate of production under the plan. All leases operated under a plan approved or prescribed by the commissioner are excepted in determining holdings or control under section 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 section 140 of this chapter.

(p) When separate tracts cannot be individually developed and operated in conformity with an established well-spacing or development program, a lease, or a portion of a lease, may be pooled with other 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 shall be considered as operations or production as to each lease committed to the agreement.

(q) The commissioner may, on conditions which he prescribes, approve drilling, or development contracts made by one or more lessees of oil or gas leases, with one or more persons, 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 section 140 of this chapter. Drilling or development contracts may include, if in the judgment of the commissioner it appears most advantageous to the state, provisions for the state to share in the costs of exploration.

(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 shall 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 promulgate regulations necessary to carry out the provisions of this subsection.

(t) Lands which have been offered for lease within the previous five years but which received no bids at public auction may, at the discretion of the commissioner, be immediately offered for lease under regulations promulgated in advance upon terms appearing most advantageous to the state. The commissioner shall utilize a sliding scale royalty based upon such formulae as he determines to be equitable. In establishing sliding scale royalty formulae the commissioner shall take into consideration operating, secondary and enhanced recovery costs.

(u) The commissioner may, by regulation, restrict joint bidding.

(v) The state shall have the right to purchase not to exceed 16 2/3% by volume of the oil and gas produced pursuant to a lease issued in accordance with this Act, at the regulated price, or, if no regulated price applies, at the fair market value at the well-head of the oil and gas saved, removed or sold, except that any oil or gas obtained by the state as royalty, net profits, or other leasing method shall be credited

against the amount that may be purchased under this subsection. Oil and gas purchased under provisions of this section may be utilized by the state in the same manner as it utilizes its royalty oil and gas.

(w) Any lessee or permittee conducting any exploration for, or development or production of, oil or gas pursuant to this Act shall provide the Commissioner access to all data obtained from such activity and shall provide copies of such specific data, as the commissioner may request.

Section 2. AS 38.05.13 is deleted.

Section 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 in the aggregate 10,240 acres. No person may take or hold sodium leases or permits during the life of sodium leases on state lands, exceeding in the aggregate acreage 5,120 acres, except that the commissioner may, where it is necessary in order to secure the economic mining of sodium compounds, permit a person to take or hold sodium leases or permits for up to 15,360 acres. No person may take or hold at any one time oil or gas leases exceeding in the aggregate 500,000 acres granted on tide and submerged lands, and (500,000) 200,000 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."

Section 4. AS 38.05145(b) is deleted.

Section 5. AS 38.05.335(c) is deleted.

(10/1/77) Draft subject to significant and/or substantial changes at any time.)(raft 6)

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) Purpose. The legislature finds and declares that

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

(A) maximize the economic recovery of this important natural resource;

(B) control the exploitation of this natural resource so as to protect the public interest;

(C) maximize the competition among parties seeking to obtain the right to explore and develop the state's oil and gas resources.

(2) the interest of the state is to encourage an assessment of its oil and gas resources and that will allow the maximum flexibility in the methods of awarding the leases to

(A) recognize the many and 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 the state's share from profitable oil and gas production, while minimizing revenue from unsuccessful exploration wells and from marginal economic oil and gas production.

(b) Leasing Program.

(1) The commissioner shall prepare and periodically revise, and maintain an oil and gas leasing program. This leasing program shall be submitted to the legislature for its information within 10 days of the convening of a regular session of the legislature. The leasing program shall 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 elect the timing and location of leasing, to the maximum extent practicable, so as to obtain a proper 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 approved by the commissioner, no lease shall be issued unless it is for an area included in the approved leasing program and unless it contains provisions consistent with the approved leasing program, except that leasing shall be permitted to continue until such program is approved and for so long thereafter as such program is under judicial or administrative review. Leasing under paragraph (t) of this Act may be excepted from the leasing program if in the judgment of the commissioner it appears most advantageous to the state.

(3) The commissioner shall review the leasing program approved under this section at least once each year, and he may revise and reapprove such program, at any time, in the same manner as originally developed.

(4) 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 the Federal and local governments which may be impacted by the proposed leasing;

(D) periodic consultation with the Federal and local governments, oil and gas lessees and permittees, and representatives of other individuals or organizations engaged in activity in or on State land;

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

(F) the commissioner shall utilize the existing capabilities and resources of all state agencies in preparing the leasing program, and such agencies shall provide the commissioner with any nonproprietary information he requests.

(5) Within 10 days of the convening of a regular session of the legislature, the commissioner shall report to the legislature with respect to the use of the various bidding methods provided for in this Act. Such report shall include:

(A) the schedule of all lease sales held during the preceding 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 utilized;

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

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

(E) if applicable, the reason why more than 50% of the area

leased in the upcoming year, was or is to be leased under one particular bidding method.

(c) The commissioner is authorized to grant to the highest responsible qualified bidder, by competitive bidding under regulations promulgated in advance, oil and gas leases on state land. The bidding shall be by sealed bid, and at the discretion of the commissioner, based on a pre-sale analysis, of at least one of the following:

(1) Royalty

(A) cash bonus bid with a royalty at not less than 12½ percent reserved to the state which may be taken in kind or in value;

(B) a cash bonus bid with a royalty based on a sliding scale reserved to the state but not less than 12½ percent at the beginning of the lease period which may be taken in kind or in value;

(C) a fixed cash bonus with a royalty based on a sliding scale reserved to the state as the bid variable but not less than 12½ percent at the beginning of the lease period which may be taken in kind or in value;

(D) a fixed cash bonus with a royalty bid less than 12½ percent, to be taken in kind or in value.

(2) Net profit

(A) cash bonus bid with a royalty at not less than 12½ percent which may be taken in kind or in value and a fixed share of the net profit of not less than 30 percent reserved to the state;

(B) fixed cash bonus with the net profit share reserved as the bid variable;

(C) fixed cash bonus bid with a royalty at not less than 12½ percent which may be taken in kind or in value and a percent of the net profit share reserved to the state as the bid variable.

(3) Work commitment bid based on a dollar amount for exploration with a fixed cash bonus and a step royalty, but not less than 12½ percent at the beginning of the lease period which may be taken in kind or in value.

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(d) Regulations shall be established for all bidding methods to allow reduction of royalty to compensate for ~~their~~ those increasing costs in the later ~~states~~ stages of production decline, to prolong the economic life of the field.

(e) The commissioner may, in his discretion, defer any part of the payment of the cash bonus, as authorized in paragraph (c) of this Act, 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.

(f) The commissioner is authorized to withold acreage from leasing in a particular lease sale.

(g) The commissioner may utilize other leasing methods after public hearings, unless the legislature by joint resolution disapproves within thirty days after receipt of notice of the proposed bidding method.

(h) At least ninety days prior to notice of any lease sale under paragraph (c) (2), the commissioner shall by regulation establish rules to govern the calculation of net profits. In the event of any dispute between the state and a lessee concerning the calculation of the net profits under the regulation issued pursuant to this paragraph, the burden of proof shall be on the lessee. In determining the attribution of profits between oil and gas, costs, other than those directly attributable to the production of either oil or gas, shall be allocated proportionately based on the Btu equivalent values of the respective amounts of oil and gas produced.

(i) At least ninety days prior to notice of any lease sale under paragraph (c)(3), the commissioner shall by regulation establish rules to govern the work commitment option. The commissioner shall require either (i) cash deposit for the full amount 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 such exploration work commitment assuring the commissioner that such commitment shall be faithfully discharged in accordance with this section, the regulation and the lease. As provided in the regulation, the principal amount of

such cash deposit or bond may be periodically reduced upon proof, satisfactory to the commissioner, that a portion of the expioration work commitment has been satisfied.

(j) At the discretion of the commissioner, he may enter into an agreement or may initiate a request whereby with the consent of the majority of the effected field lease holders, the state's royalty oil and gas production may be stored or retained in storage, or the commissioner may enter into an agreement with one or more of the effected field lease holders to trade current royalty production from a field for a like amount, kind and quality of future production, provided the state receives back its stored or traded royalty oil and gas during the first half of the field life or no later than 15 years after start of production.

(k) An oil and gas lease shall cover a reasonably compact area not exceeding 5,760 acres, and be for a period of five years. An oil and gas lease may be extended for an additional five years if the commissioner determines the extension is in the best interest of the state and he bases his decision on a showing by the lessee of due exploration diligence as defined by regulation; however, rental rates will continue to increase as if the lease had originally been made for the extended period. An expiring 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 temporary cessation of production approved by the commissioner does not constitute grounds for nonrenewal or cancellation of the lease. If drilling has commenced on the expiration date of the primary term of the lease and is continued with reasonable diligence, such operations to include drilling, sidetracking or other means necessary to reach the originally proposed bottom hole location, the lease shall continue in effect until 90 days after drilling has ceased and for so long thereafter as oil or gas is produced in paying quantities.

(l) 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

(6) for the sixth year, $4.00 per acre

(7) for the seventh year, $8.00 per acre

(8) for the eighth year, $12.00 per acre

(9) for the ninth year, $24.00 per acre

(10) for the tenth year, $36.00 per acre

(11) for the eleventh year and beyond, rental rate is 150% of the preceding year.

The commissioner may establish by regulation, that after a discovery has been made which is capable of producing in paying quantities, the rental rate which was in effect during the year of discovery is maintained for the following 5 years. Rental is payable in advance and continues until income to the state from royalty, net profit or the base parameter of other leasing methods exceeds rental income to the state for that year; after the rental income schedule has been exceeded for three consecutive years, the rental shall terminate.

(m) Upon timely application as provided by regulation, the state may issue to the holder of a federal lease a state shorelands lease covering land within the exterior boundaries of the federal lease which has been excluded on the basis of navigability or which are later administratively or judicially determined to be "shorelands."

(n) 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, alter, change, or revoke drilling, producing, rental, and royalty requirements of the leases and make regulations with reference to the leases, with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan as he determines necessary or proper to secure the proper protection of the public interest. The commissioner may provide that oil and gas leases issued under this section shall contain a provision requiring the lessee to operate under a reasonable cooperative or unit plan, and he may prescribe a plan under which the lessee shall operate. The plan shall adequately protect all parties in interest, including the state.

(o) 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 alter or modify from time to time the rate of prospecting and development and the quantity and rate of production under the plan. All leases operated under a plan approved or prescribed by the commissioner are excepted in determining holdings or control under section 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.

(p) 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 section 140 of this chapter.

(q) 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 shall be considered as operations or production as to each lease committed to the agreement.

(r) 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 section 140 of this chapter. Drilling or development contracts may include, if in the judgment of the commissioner it appears most advantageous to the state, provisions for the state to share in the costs of exploration.

(s) 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.

(t) Each oil or gas lease issued by the state shall contain a provision requiring the lessee to furnish the Department of Labor a quarterly report regarding the employment of state residents on the leased property. The commissioner of labor shall promulgate regulations necessary to carry out the provisions of this subsection.

(u) Lands which have been offered for lease within the previous five years but which received no bids at public auction may, at the discretion of the commissioner, be immediately offered for lease under regulations promulgated in advance upon terms appearing most advantageous to the state. The commissioner shall utilize a sliding scale royalty based upon such formulae as he determines to be equitable and may exclude rental schedule in subsection (l) of this act. In establishing sliding scale royalty formulae the commissioner shall take into

consideration operating, secondary and enhanced recovery costs.

(v) The commissioner may, by regulation, restrict joint bidding.

(w) The state shall have the right to purchase not to exceed 16 2/3% by volume of the oil and gas produced pursuant to a lease issued in accordance with this Act, at the regulated price, or, if no regulated price applies, at the fair market value at the well-head of the oil and gas saved, removed or sold, except that any oil or gas obtained by the state as royalty, net profits, or other leasing method shall be credited against the amount that may be purchased under this subsection. Oil and gas purchased under provisions of this section may be utilized by the state in the same manner as it utilizes its royalty oil and gas.

(x) Any 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 such activity and shall provide copies of such specific data, as the commissioner may request.

Section 2. AS 38.05.135(b) is deleted.

Section 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 in the aggregate 10,240 acres. No person may take or hold sodium leases or permits during the life of sodium leases on state lands, exceeding in the aggregate acreage 5,120 acres, except that the commissioner may, where it is necessary in order to secure the economic mining of sodium compounds, permit a person to take or hold sodium leases or permits for up to 15,360 acres. No person may take or hold at any one time oil or gas leases exceeding in the aggregate 500,000 acres granted on tide and submerged lands, and (500,000) 200,000 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."

Section 4. AS 38.05.145(b) is deleted.

Section 5. AS 38.05.335(c) is deleted.

← LOCAL HIRE →

(12/22/77) Draft subject to significant and/or substantial changes at any time.)(Draft 8)

full leasing of

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) Purpose. The legislature finds and declares that

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

(A) maximize the economic recovery of this important natural resource;

(B) control the exploitation of this natural resource so as to protect the public interest;

(C) maximize the competition among parties seeking to obtain the right to explore and develop the state's oil and gas resources.

(2) the interest of the state is to encourage an assessment of its oil and gas resources and that will allow the maximum flexibility in the methods of awarding the leases to

(A) recognize the many and 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 the state's share from profitable oil and gas production, while minimizing revenue from unsuccessful exploration wells and from marginal economic oil and gas production.

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(b) Leasing Program.

(1) The commissioner shall prepare and periodically revise, and maintain an oil and gas leasing program. This leasing program shall be submitted to the legislature for its information within 10 days of the convening of a regular session of the legislature. The leasing program shall 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 elect 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) After the leasing program has been approved by the commissioner, a lease shall be issued if it is for an area included in the approved leasing program and if it contains provisions consistent with the approved leasing program, except that leasing shall be permitted to continue until such program is approved and for so long thereafter as such program is under judicial or administrative review. Leasing under paragraph (t) of this Act may be excepted from the leasing program if in the finding of the commissioner it appears most advantageous to the state.

(3) The commissioner shall review the leasing program approved under this section at least once each year, and he may revise and reapprove such program, at any time, in the same manner as originally developed.

(4) 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;

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

(D) periodic consultation with local governments, oil and gas lessees and permittees, and representatives of other individuals or organizations engaged in activity in or on State land;

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

(F) the commissioner shall utilize the existing capabilities and resources of all state agencies in preparing the leasing program, and such agencies shall provide the commissioner with any nonproprietary information he requests.

(5) Within 10 days of the convening of a regular session of the legislature, the commissioner shall report to the legislature with respect to the use of the various bidding methods provided for in this Act. Such report shall include:

(A) the schedule of all lease sales held during the preceding 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 utilized;

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

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

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

(c) The commissioner is authorized to grant to the highest responsible qualified bidder, by competitive bidding under regulations promulgated in advance, oil and gas leases on state land. The bidding shall be by sealed bid, and at the

discretion of the commissioner, based on a pre-sale analysis, of at least one of the following:

(1) Royalty

(A) cash bonus bid with a royalty at not less than 12½ percent reserved to the state which may be taken in kind or in value;

(B) a cash bonus bid with a royalty based on a sliding scale reserved to the state but not less than 12½ percent at the beginning of production from the lease which may be taken in kind or in value;

(C) a fixed cash bonus with a royalty based on a sliding scale reserved to the state as the bid variable but not less than 12½ percent at the beginning of production from the lease which may be taken in kind or in value;

(D) a fixed cash bonus with a royalty bid not less than 12½ percent, to be taken in kind or in value.

(2) Net profit

(A) cash bonus bid with a royalty at not less than 12½ percent which may be taken in kind or in value and a fixed share of the net profit of not less than 30 percent reserved to the state;

(B) fixed cash bonus with the net profit share reserved as the bid variable;

(C) fixed cash bonus bid with a royalty at not less than 12½ percent which may be taken in kind or in value and a percent of the net profit share reserved to the state as the bid variable.

(3) Work commitment bid based on a dollar amount for exploration with a fixed cash bonus and a sliding scale royalty, but not less than 12½ percent at the beginning of production from the lease which may be taken in kind or in value.

(d) Regulations shall be established for all bidding methods to allow reduction of royalty to compensate for these increasing costs in the later stages of production decline, to prolong the economic life of the field. The commissioner

may grant such reduction so long as it takes affect no sooner than 2 years after beginning of production from the lease.

(e) The commissioner may, in his discretion, defer any part of the payment of the cash bonus, as authorized in paragraph (c) of this Act, 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.

(f) The commissioner is authorized to withold acreage from leasing in a particular lease sale.

(g) At least ninety days prior to notice of any lease sale under paragraph (c) (2), the commissioner shall by regulation establish rules to govern the calculation of net profits. In the event of any dispute between the state and a lessee concerning the calculation of the ret profits under the regulation issued pursuant to this paragraph, the burden of proof shall be on the lessee.

(h) At least ninety days prior to notice of any lease sale under paragraph (c)(3), the commissioner shall by regulation establish rules to govern the work commitment bidding method. The commissioner shall require either (i) cash deposit for 20% 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% of such exploration work commitment assuring the commissioner that such commitment shall be faithfully discharged in accordance with this section, the regulation and the lease. As provided in the regulation, the amount of such cash deposit or the principal amount of the bond may be periodically reduced upon proof, satisfactory to the commissioner, that a portion of the exploration work commitment has been satisfied.

(i) At the discretion of the commissioner, he may enter into an agreement or may initiate a request whereby with the consent of the majority of the affected field lease holders, the state's royalty oil and gas production may be stored or retained in storage, or the commissioner may enter into an agreement with one or

more of the effected field lease holders to trade current royalty production from a field for a like amount, kind and quality of future production, provided the state receives back its stored or traded royalty oil and gas during the first half of the field life or no later than 15 years after start of production.

(j) An oil and gas lease shall cover a reasonably compact area not exceeding 5,760 acres, and be for a period of five years. An expiring 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 temporary cessation of production approved by the commissioner does not constitute grounds for nonrenewal or cancellation of the lease. A lease issued under this section covering lands on which there is a well capable of producing oil or gas in paying quantities shall not expire because the lessee fails to produce oil or gas unless the lessee is allowed reasonable time within which to place the well on a producing status. The commissioner may impose lease rentals past the original term of the lease so long as the rental rate does not exceed 150% of the preceding year. If drilling has commenced on the expiration date of the primary term of the lease and is continued with reasonable diligence, such operations to include drilling, sidetracking or other means necessary to reach the originally proposed bottom hole location, the lease shall continue in effect until 90 days after drilling has ceased and for so long thereafter as oil or gas is produced in paying quantities.

(k) 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

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 the base parameter of other leasing methods exceeds rental income to the state for that year; after the rental income schedule has been exceeded for three consecutive years, the rental shall terminate.

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

(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, alter, change, or revoke drilling, producing, rental, and royalty requirements of the leases and make regulations with reference to the leases, with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan as he determines necessary or proper to secure the proper protection of the public interest. The commissioner may provide that oil and gas leases issued under this section shall contain a provision requiring the lessee to operate under a reasonable cooperative or unit plan, and he may prescribe a plan

under which the lessee shall operate. The plan shall adequately protect all parties in interest, including the state.

(n) A plan authorized by (m) of this section, which includes land owned by the state, may contain a provision vesting the commissioner, or a person, committee, or state agency with authority to alter or modify from time to time the rate of prospecting and development and the quantity and rate of production under the plan. All leases operated under a plan approved or prescribed by the commissioner are excepted in determining holdings or control under section 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 provision of section 140 of this chapter.

(p) When separate tracts cannot be individually developed and operated in conformity with an established well-spacing or development program, a lease, or a portion of a lease, may be pooled with other 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 shall be considered as operations or production as to each lease committed to the agreement.

(q) The commissioner may, on conditions which he prescribes, approve drilling or development contracts made by one or more lessees of oil or gas leases, with one or more persons, when, in his discretion, the conservation of natural resources or the public convenience or necessity require it or the interests of the tate are best served. All leases operated under approved drilling, or development contracts, and interests under them are excepted in determining holding or control under section 140 of this chapter. Drilling or development contracts may include, if in the judgment of the commissioner it appears most advantageous to the state,

to share in the costs of exploration.

(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 secti 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 shall contain a provision requiring the lessee to furnish the Department of Labor a quarterly report regardi the employment of state residents on the leased property. The commissioner of lab shall promulgate regulations necessary to carry out the provisions of this subsect

(t) Lands which have been offered for lease within the previous five years but which received no bids at public auction may, at the discretion of the commissioner, be immediately offered for lease under regulations promulgated in advance upon terms appearing most advantageous to the state, including leasing noncompetitively. The commissioner shall utilize a sliding scale royalty based upon such formulae as he determines to be equitable but need not adhere to the rental schedule in subsection (k) of this act nor to 5,760 acres per lease. Lease term may not exceed five years except for the renewal provisions of subsecti (k) of this act.

(u) The commissioner may, by regulation, restrict joint bidding.

(v) The state shall have the right to purchase not to exceed 16 2/3% by volume of the oil and gas produced pursuant to a lease issued in accordance with this Act, at the regulated price, or, if no regulated price applies, at the fair market value at the well-head of the oil and gas saved, removed or sold, except that any oil or gas obtained by the state as royalty, net profits, or other leasi method shall be credited against the amount that may be purchased under this sub-section. Oil and gas purchased under provisions of this section may be utilized

by the state in the same manner as it utilizes its royalty oil and gas.

(w) Any 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 such activity and shall provide copies of such specific data, as the commissioner may request.

Section 2. AS 38.05.135(b) is amended to read:

"(b) When minerals are to be leased on a competitive basis, in addition to any other notice given, notice shall also be given as provided in Section 305 and 345 of this chapter."

Section 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 in the aggregate 10,240 acres. No person may take or hold sodium leases or permits during the life of sodium leases on state lands, exceeding in the aggregate acreage 5,120 acres, except that the commissioner may, where it is necessary in order to secure the economic mining of sodium compounds, permit a person to take or hold sodium leases or permits for up to 15,360 acres. No person may take or hold at any one time oil or gas leases exceeding in the aggregate 500,000 acres granted on tide and submerged lands, and (500,000) 200,000 acres on all lands other than tide and submerged lands, including leases held both as lessee and under option or operating agreement from others. A person shall have five years from the effective date of this Act to conform to the 200,000 acre uplands 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."

Section 4. AS 38.05.145(b) is deleted.

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April 21, 1978

Honorable D. R. Getty, Minister
Alberta Energy and Natural Resources
319 Legislative Building
Edmonton, Alberta, Canada
T5K, 2B6

Dear Mr. Getty:

Governor Hammond's recently introduced oil and gas leasing legislation for Alaska has now had incorporated into it by the legislature a drilling and geophysical incentive credit system similar to Alberta's. We have looked at the concept and, based on what we know, believe that the system could become useful in Alaska. However, we do need help in understanding how it has actually worked in your province.

Could we ask your assistance in explaining the operations of the system, both conceptually and technically, to some members of our legislature. The bill, HB 854, a copy of which is enclosed, is expected to begin Senate committee hearings sometime in May.

It would be of particular help to us if someone from your department could come to Anchorage to brief my staff and to Juneau to testify before the Senate Natural Resources Committee. We would, of course, cover all expenses. The exact dates of the visit would have to wait on the progress of the bill, but it is likely to be in mid or late May, 1978.

Over the past several years, Jack Roderick, my Special Projects Coordinator, who has been in charge of this particular legislation, has kept in contact with Michael J. Day, and others, in your minerals disposition division, on land tenure matters and he, or someone of your choice, would be most welcome. I will have Mr. Roderick arrange for the visit, subject to your authorization.

AGO 547289

Thank you for your assistance in this matter. We believe Alaska can benefit from Alberta's experience with the exploration incentive credit system.

Sincerely yours,

Robert LeResche
Commissioner

cc: Dr. G. B. Mellon, Deputy Minister
Michael J. Day, Asst. Deputy Minister
Petroleum Plaza, South Tower
9915-108 Street
Edmonton, Alberta T5K 2C9

Jack Roderick

bc: House Speaker Hugh Malone
Senate President John Rader