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Statement of David S. Mace
Sohio Petroleum Company
before the
Senate Resources Committee
Alaska State Legislature
May 22, 1978

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As Assistant General Manager, I am pleased to have the opportunity to present the views of Sohio Petroleum Company, a Division of Sohio Natural Resources Company, with respect to the House-passed version of H.B. 854.

We strongly feel that the oil and gas leasing bill merits thoughtful study, as its implementation will determine the State's ability to conduct an effective leasing program in the future. Since the industry's ability and willingness to participate in future lease sales will be determined by the manner in which future administrations administer the State's leasing bill, it is vitally important that the provisions contained therein give clear guidance to the Department of Natural Resources (DNR).

Although the House has significantly improved the bill as originally introduced, we feel that there are key provisions that should be further amended. Additionally, we strongly believe that further consideration should be given to the ~~ex~~clusion of several of the proposed bidding methods and to the general concept of experimentation in Alaska's leasing program.

Prior to describing the specific problems we see in H.B. 854, I should like to outline for you why we feel that Alaska should, particularly at this time, pay close attention to energy policy development in general and its leasing program in particular. To put it in a nutshell, world supplies of conventional oil and gas have shrunk and are narrowing rather quickly; the chances of finding another Prudhoe Bay-sized field--anywhere^{in the U.S.}--are next to zero. Thus policy decisions affecting oil and gas are crucial if Alaska is to find and develop her remaining petroleum resources, thereby strengthening the future economic outlook for all Alaskans and the political/economic outlook for the United States.

PART I: AT THE CROSSROADS

THE IMPORTANCE OF OIL AND GAS POLICY DECISIONS

Global Prospects

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

- (1) All energy resources and conservation measures must be developed vigorously to meet total projected demand in the period 1985 - 2000; and
- (2) Energy policy decisions made now will be the critical determinants as to whether or not sufficient incremental supplies will be available to meet demand in the years ahead.

In other words; according to the WAES Report:

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

In this environment, the importance of the Federal and State petroleum leasing programs affecting Alaska cannot and must not be underestimated. Whether or not Alaska's oil and gas resources can and will be developed will be an important factor not only for Alaska but also for the United States as a determinant in the future global energy, economic and political balance. The critical nature of energy decision-making at this time is further underscored by the following conclusions stated in the WAES Report:

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

- (1) The supply of oil will fail to meet increasing demand before the year 2000, most probably between 1985 and 1995... (p.3)
- (2) Demand for energy will continue to grow even if governments adopt vigorous policies to conserve energy... (p. 4)
- (3) The continued growth of energy demand requires that energy resources be developed with the utmost vigor... (p.4)
- (4) Even if there are no governmental constraints on oil production, oil supply will meet demand only under the most optimistic assumptions about gross additions to reserves... (p.145)
- (5) Possible constraints on oil production by members of OPEC are likely to cause oil supply to peak at the latest some-time around 1990 although lower production limits could bring this date forward into the early 1980's... (p.145)
- (6) All the effort put into oil exploration around the world over the past one hundred years has only yielded 240 large oil fields... (p.123)
- (7) With only a small chance of either discovering a new Middle East or discoveries in the Middle East as large as in the past, the past rate of genuine new discoveries can only be achieved if a large number of smaller producing areas are found. (p.122)
- (8) Given lead times of 5-10 years or more for many projects, failure to make necessary near-term commitments or to resolve a variety of current restraints on production, or to develop future supplies may foreclose some options for 1985. (p.265)
- (9) Failure to recognize the importance and validity of these findings and to take appropriate and timely action will almost certainly result in a world different from the one on which these projections have been based. (p.5)
- (10) Failure to act could lead to substantially higher energy prices as the supply/demand imbalance becomes more apparent with the consequent frustration of the aspirations of the less developed countries. The major political and social difficulties that might arise could cause energy to become a focus for confrontation and conflict. (p.5)
- (11) The longer the world delays facing this issue the more serious the outcome will be. Even with prompt action the margin between success and failure in the 1985-2000 period is slim. Time has become one of the most precious of our resources. (p.5) 2/ (Emphasis added)

2/ Ibid., pages as indicated above.

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

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

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

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

3/ Ibid., p. 123

4/ Ibid.

Alaskan Petroleum Outlook

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

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

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

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

A final serious consideration for Alaska relates to a realistic assessment of the future revenue needs of the State. Projections indicate that Alaska's revenue problems in future years require a significant expansion of petroleum exploration and development activity now so that new sources of revenue will be available as Prudhoe Bay declines. This is an especially critical consideration in view of the long lead times involved in exploration and production in the frontier areas of Alaska. In some areas, it can take a decade to find, prove up and begin to develop a field, and transportation problems can be enormously complex, causing further delays.

Implications

Being at the economic/energy crossroads globally -- and in Alaska -- would seem to suggest that it is of vital importance to the State to (1) carefully delineate its goals with respect to a new oil and gas leasing bill and (2) ensure that the proposed legislation, in its implementation, will achieve the desired goals outlined in the legislation. With this in mind, I would like to address some of the specific, critical problems we foresee if H.B. 854 were to be implemented in its current version. Additionally, I would like to present some of the experts' views with respect to several broad issues raised by the draft legislation.

PART II: CRITICAL CONCERNS WITH H.B. 854

Bidding Methods - Experimentation

No one knows how beneficial experimentation in bidding methods will be. The U. S. Government tried royalty bidding on ten tracts in an October 1974 lease sale with questionable results. It appears that neither the industry participants nor government officials found the experiment to be particularly successful.

According to The Oil and Gas Journal, "operators say they doubt royalty bidding will ever surface again except in areas where production is almost certain or possibly in drainage-tract sales. Development of wildcat acreage can prove too costly on a royalty bid basis, despite the absence of high front-end expenditures normally budgeted under the traditional bonus-bid system." 5/

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

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

Significantly, the Department of Energy and the Interior Department are considering the formation of a task force of experts to help analyze pros and cons of the various systems being proposed in the Federal legislation (which were largely copied in H.B. 854). Apparently, there is considerable disagreement between the two agencies as to the merit of the sliding scale royalty systems used in the last two lease sales, as well as to the efficacy of using other bidding methods. A key problem in forming a task force seems to be a dearth of real experts, however, in that few governments have undertaken experiments in bidding practices long enough or in a manner similar enough as that envisioned in the proposed Federal and State legislation, and to paraphrase Dr. Arlon Tussing's comments: scholarly, empirical analysis of the different bidding systems appears to be 'remarkably skimpy.'

One source document appears to be quite useful, however. Published by the British Columbia Institute for Economic Policy Analysis, Mineral Leasing as an Instrument of Public Policy, contains articles by an international and interdisciplinary group of economists, mining engineers, businessmen and industry consultants. In an introductory section, Dr. Mason Gaffney describes the report as "an outstanding contribution to a rapidly growing field of study."

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

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

"Competitive bidding theory makes clear that undesirable consequences may follow from royalty or profit share bidding. If there are no bonus payments required, speculative bidding may lead to extremely high royalties or profit shares being bid, with development occurring only in the most favorable circumstances. This happens because firms have little or nothing to lose by bidding high and then failing to explore or develop..." 6/ (Emphasis added)

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

"The problems created by royalty bidding, principally the premature shutdown effect and the potential for speculator induced misallocation of leases, have been well discussed in the literature. More importantly, they are well understood by persons influencing both public and private mineral resource policies". 7/ (Emphasis added)

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

A specific example of why we are concerned relates to the material prepared by the Department of Natural Resources to accompany H.B. 854, entitled "Two Views on Bidding Strategies." Not only are the numerous problems and dangers of royalty bidding (cited by Meade, Erickson and others in the University of British Columbia Report) not even mentioned,

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

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

but also, after three short descriptive phrases under the heading "Royalty Bid-Fixed Bonus," the Department of Natural Resources, with no further comment, analysis, or explanation, simply states: "The Beaufort Sale is an ideal candidate for royalty bidding scheme." (Emphasis added)

We view such remarks by the State Administration with concern. As indicated previously, many who have taken the time to study the various proposed bidding methods in depth list extensive problems with various schemes for royalty bidding (see also Part 3) and, would hesitate to use royalty bidding schemes of any sort except in drainage sales or where there are known, proven reserves (as mentioned above in the Leland citation). The Beaufort Sea is believed to have a high potential for discovery, but, as in the Gulf of Alaska, the drilling of wells may result in no discoveries, or discoveries of marginal fields. No discoveries - with royalty bidding - means no income for the State of Alaska. And, as royalty bidding adds risk for the State, another quote from Leland is perhaps appropriate here:

"Note that if the lessor is such that leasing forms a substantial fraction of its revenue (for example the State of Alaska), it may not be optimal to transfer risk from firms to the lessor. Thus, lease contracts which might be appropriate to the federal government may not be appropriate for regional governments". 8/ (Emphasis added)

Future administrations working with the proposed leasing statutes may have multiple choices of bidding methods available to them. We feel it important to stress that we concur both with Mason Gaffney and Gregg Erickson as to where the burden of justification of such decisions should lie, i.e., with those who would change the current system of cash bonus bidding. In this regard, we believe we are safe in assuming that Gregg Erickson's

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

statement below with respect to the work commitment bidding system would apply to any new proposed bidding system:

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

Any argument for the adoption of such a system must first establish that this is in fact the case..." 9/

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

"To serve his citizens best, the statesman should...resist the temptation to use his power to manipulate and control...on the too easy presumption that the market has no rationale or normative value of its own. Generations of economists have established that it has, and governments seeking to improve on it need face a certain burden of proof." 10/

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

"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".
11/

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

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

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

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

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

Third, because the new systems are experimental, we would suggest that the burden of proof for adopting a new system for any lease sale be placed on the Department of Natural Resources because the use of any new system involves greater risks and uncertainty not only for the companies but also for the State.

Lease Terms (b) and (z)

As currently proposed in H.B. 854 the lease stipulations include a normal lease life of five years duration; leases can only be prolonged to ten years in areas where environmental conditions severely restrict operations. It is our understanding from testimony given to the House Resources Committee by personnel of DNR that severely restrictive environmental conditions are interpreted to include moving ice zones in the Beaufort Sea, but not onshore conditions on the North Slope. As this latter area can only be explored by winter operations, a five year lease would only allow 1-2/3 years of exploration time. From a practical standpoint this is not sufficient, and such a restriction would make it physically impossible for an operator to explore a reasonable number of leases.

The cost of exploratory wells in environmentally difficult areas of Alaska, both onshore and offshore, can now be expected to exceed 10 million dollars and sometimes reach 20 million dollars per well. With such large amounts of money involved, exploratory wells are high risk ventures which must be very carefully planned to obtain the greatest return, not only in oil and gas discovered, but also in geological data obtained. Consequently, a company's exploratory program on Alaskan leases must be systematic and careful and can no longer follow the philosophy of "wildcatting." Such a logical approach cannot be rushed in its implementation, and the restriction of leases to a five year term would inevitably result in many leases not receiving the exploratory attention they might deserve. They would be relinquished without having been drilled, and would therefore diminish in value due to their apparent unimportance to the lessee with consequent loss to the State.

To counteract this situation, and allow operators to assess the true value of their landholdings, we are proposing that the normal term of a lease should be ten years, except in those areas where the Commissioner determines that environmental and economic restrictions on operations are not a factor. Since many of the future lease sales will be in hostile environmental areas, it is in the State's interest, we feel, to ensure that sufficient time is permitted for a proper evaluation of the lease areas.

Furthermore, we feel that the bill should specify that, prior to the lease sale, in the tract terms, the State will provide specific information related to provision (z), i.e., the percentages of oil and gas that the State intends to require for in-state use. Otherwise, it becomes impossible realistically to bid on the proposed tracts.

Joint Bidding - Its Effect on Competition (y)

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

The two theories about the nature of joint bidding in Federal lease sales (collusive vs. risk-sharing purposes) have been tested by University of North Carolina Professor Edward Erickson and M.I.T. Professor Robert Spann. As they reported in testimony before the U.S. Senate Commerce Committee, the observed patterns of bidding partnerships are most consistent with the hypothesis that joint bidding is a means of risk-sharing, not collusion.^{12/} Among the ways in which competition might be fostered rather than reduced by joint arrangements are the following:

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

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

^{12/} In their study of the 1972 and 1973 Federal offshore lease sales, Erickson and Spann found that membership of bidding groups varies from year to year; market shares for members fluctuate from one year to the next; the most frequent bidding group is a combination of majors and smaller firms, but majors bid alone, as do smaller firms; single firm bids are frequently made by the largest firms, but other firms are also successful single firm bidders, and bidding groups which contain a large number of firms are predominantly composed of smaller firms. They also conclude that the incidence of joint bidding increased as the size of the firm decreased; there was a heavy incidence of joint bidding partnerships between unlike firms; smaller firms use joint bidding ventures as a vehicle for entry into offshore activity. "Competition in the Field Markets for New Natural Gas Supplies," Statement before the Senate Commerce Committee, November 8, 1973.

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

Since joint operating agreements also expressly provide for separate marketing of production from joint ventures, it would appear safe to conclude that risk-sharing through joint ventures need not make competition less intense. By facilitating ease of entry, joint ventures by domestic petroleum companies may indeed make competition more intense. ^{13/}

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

"The most conclusive test of the workability of cash bonus bidding based on the United States record of OCS oil and gas lease sales is in terms of the rate of return on capital earned by the successful bidders. An analysis has been made on 184 offshore Louisiana oil and gas tracts leased in 1954 and 1955. Precise data are available on bonus payments, rental payments, oil and gas royalty payments, and production of oil and gas during the period from 1954 through 1967. Cost estimates were made for exploration, well drilling and equipment, and operation. Annual cost and annual wellhead values were discounted to obtain a net internal rate of return. The calculations indicate that these early OCS leases generated a 7.5 per cent before tax rate of return to the lessees. Given the fact that oil companies pay relative low U.S. income tax rates, the after tax rate of return would be only modestly lower than the 7.5 per cent before tax rate of return. This net yield clearly does not reflect monopoly power; it shows an excessive degree of competition". ^{14/} (Emphasis added).

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

^{13/} In the last analysis, if the formation of such groups constituted monopoly power, one would expect to see some results where such groups are formed, e.g., a non-random bid price pattern in Federal lease sales.

^{14/} Mead, op. cit., p.55.

Major conclusions were:

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

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

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

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

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

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

In view of all of the above, it is very doubtful that joint bidding will adversely affect competition, and it is more likely to enhance competition and result in financial advantages to the State as well as oil companies. In this instance, the Federal Government's stance on restricting joint bidding appears to be counter-productive, and it is not in the State of Alaska's best interest to follow that lead.

Minimum Work Commitments (h)

The current language of H.B. 854 permits the Commissioner to impose a minimum work commitment on a lessee. The only reasons we can deduce for including the provision is to overcome the problems inherent in royalty and net profit bidding procedures. Both these methods inadvertently encourage a lessee to sit on a lease as long as possible without carrying out any work, because the lessee has no meaningful financial involvement in the lease. Consequently, under royalty or net profit bidding, the leaseholder will tend to prefer to 'sit on' the lease in the hope that neighboring leaseholders will, by their efforts, help indicate the true potential of the lease. Conversely, minimum work commitments are not necessary on leases won with a cash bonus bid because the lessee has an obvious financial incentive to produce a profit from his cash investment in the lease as soon as possible.

No responsible bidding company will bid on a lease which it thinks is devoid of prospects unless the bidding method imposes no appreciable risk or financial outlay to the company. Under these circumstances, i.e., when royalty or net profit bidding are used, the company has an inducement to try to obtain the acreage because of the slim chance that its assessment of the poor potential of the land is wrong. To prevent the company from doing nothing with this lease, the Commissioner has to impose a work commitment on it. But if the lessee views the lease prospects as negligible, the lessee will expend money for exploration only up to the amount equal to the work commitment imposed by the State.

The question arises: is this result in the State's best interest? Instead of obtaining maximum exploration on tracts with maximum potential,

the State, under royalty and net profits bidding, will encourage, through work commitments, capital outlays on tracts with minimum potential. And the capital outlays will most likely be a waste of dollars, producing no ultimate gain for the State.

If the cash bonus bidding system is not utilized on a particular lease, however, the level of fixed cash bonus imposed with the bidding system chosen can be ~~made~~ sufficiently large to ensure adequate and prompt exploration. Thus, we recommend that (h) be deleted from H.B. 854.

Data Acquisition by the State

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

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

"...while the technology for oil exploration prior to the drilling has been advanced in the last century, exploration is still subject to 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..." ^{15/} (Emphasis added)

^{15/} Mead, op. cit., p.51.

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

Because more is not necessarily better in the exploration data game, many companies do in fact view data acquisition by the government as the first step which will inevitably lead -- and naturally extend to -- the establishment of government drilling corporations. And, as previously noted, Dr. Arlon Tussing does not view "governmental ownership of producing operations" as "the most effective way of accomplishing the social ends for which it is currently being advocated..." 16/

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

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

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

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

It is not unusual in oil and gas exploration, with its inherent problem of scientific interpretation and evaluation of geological prospects, to find that one company will acquire a block of land, will explore it, and perhaps even drill on it before deciding the search is unsuccessful. The company will then return the land to its owner, the Crown. This does not mean that there are not any commercial hydrocarbons underlying this land; but rather that that particular company was unable to find them. To find these hydrocarbon deposits, a second, a third, or a fourth company should acquire this land, and, if this is done often enough, the hydrocarbon will be encountered, and production will follow. The problem with the public company being the only explorer in the province is that, unless it is fortunate enough to make the initial discovery, it is very doubtful whether there would be enough enthusiasm to have a second, third or perhaps even a fourth try at that particular prospect, with the result that the discovery would not be made. This is surely the worst thing that could happen and is probably the most damning argument against a public corporation moving into an area with an almost exclusive right to explore. 17/

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

SUMMARY AND CONCLUSIONS

In summary, we would offer these observations and conclusions:

1. H.B. 854, as currently drafted, would create a State leasing system containing many experimental procedures that are new and untried in Alaska. This may not be in the State's interest, because unusual leasing systems could lead to delays in petroleum development that could have serious consequences on future State revenues and Alaska's contribution toward U.S. energy needs.
2. The State's future revenue problems should not be underestimated. The State of Alaska may face an extremely serious revenue situation in the late 1980's as oil production from the Prudhoe Bay field begins to decline. The long lead-times needed to find and develop new Alaskan oil discoveries would indicate that exploration must expand rapidly on State lands to provide needed petroleum revenues for the future.
3. Alternative bidding systems proposed in H.B. 854, although also proposed in OCS legislation now pending in Congress, have not had extensive use in the U.S., nor in very many other places in the world. Experience with royalty bidding in Federal OCS sales has apparently been disappointing, and the Federal government is giving serious attention to the use of alternate bidding systems.
4. The majority of academic literature that we have been able to find supports the thesis that the traditional bidding methods have worked well in the leasing of public lands for petroleum development. Academic experts also seem to agree that alternative bidding systems present serious problems, except when used in certain special situations.

5. The bill must be clarified where judgmental factors in its administration are critical to the success of the leasing program. The life span of a lease in years must be compatible with the extreme environmental and economic constraints placed on exploration activity in Alaska. To underestimate those constraints will result in unacceptably short lease terms, with a consequent reduction in exploratory work carried out on the leases. A decrease in exploration leads directly to a reduction in discoveries, production and State revenues.
6. Section (2) needs to be clarified in that, as currently drafted, the financing of exploration ventures based on a commitment of future production, would be impossible.
7. Work commitments are not as effective as higher bonus bids in encouraging prompt exploration of worthwhile leases, as work commitments, particularly in conjunction with royalty bidding schemes, work against the State's best interests in developing promising acreage.

PART III: ARTICLES ON LEASING

1. M.I.T. Professor John W. Devanney III, "How to Bid for Offshore Rights," Technology Review, February 1976, p. 44.
2. "Alberta, Canada: Exploratory Drilling Incentive System," The Landman, March 1978, pp. 18-20.
3. Articles from Mineral Leasing as an Instrument of Public Policy, British Columbia Institute for Economic Policy Analysis, 1977:
 - Gregg K. Erickson, "Work Commitment Bidding"
 - Dale R. Jordan, "Petroleum Leasing in British Columbia"
 - Walter J. Mead, "Cash Bonus Bidding for Mineral Resources"
 - Arlon R. Tussing, "The Role of Public Enterprise"

How to Bid for Offshore Rights

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

The Work Obligation Permit Plan

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

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

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

Royalty Bidding

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

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

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

tract; such oil will be more expensive than primary oil but still less costly than foreign crude.

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

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

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

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

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

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

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

Exploratory Drilling Incentive System

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

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

The department expects that the principles and details outlined here will be incorporated, without a change in mean-

ing, into the 1978 Regulation. If, however, such a change does occur, the 1978 Regulation would, of course, take precedence.

(1) Commencement Date of the Forthcoming Program

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

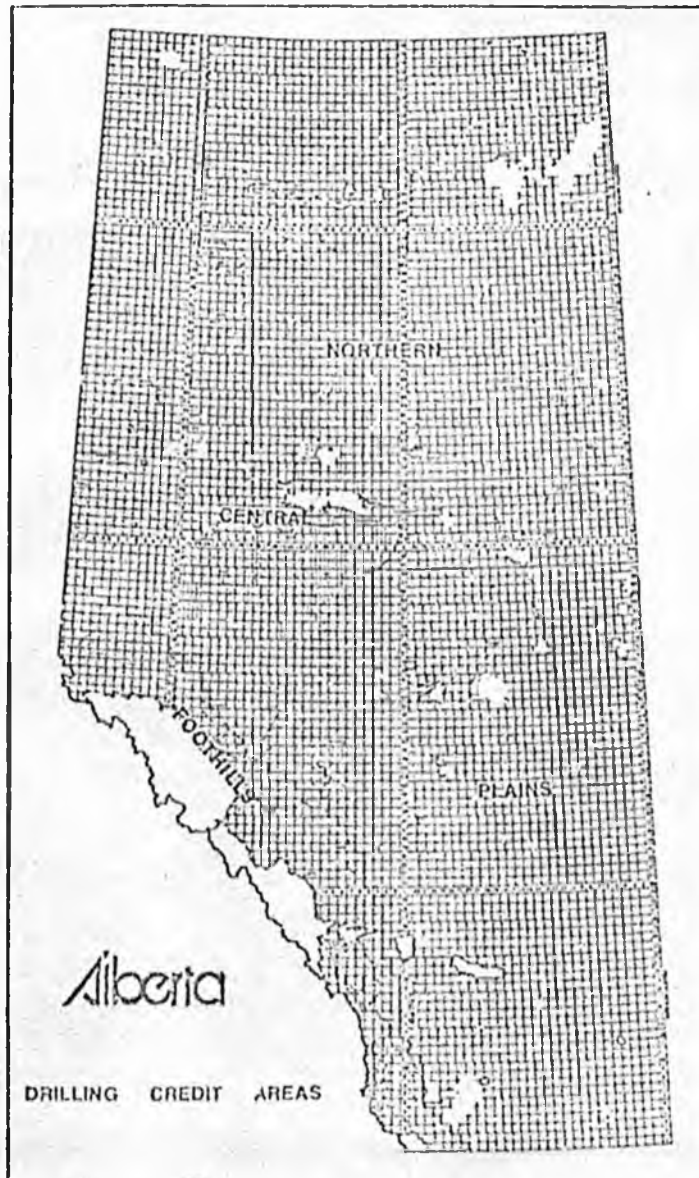
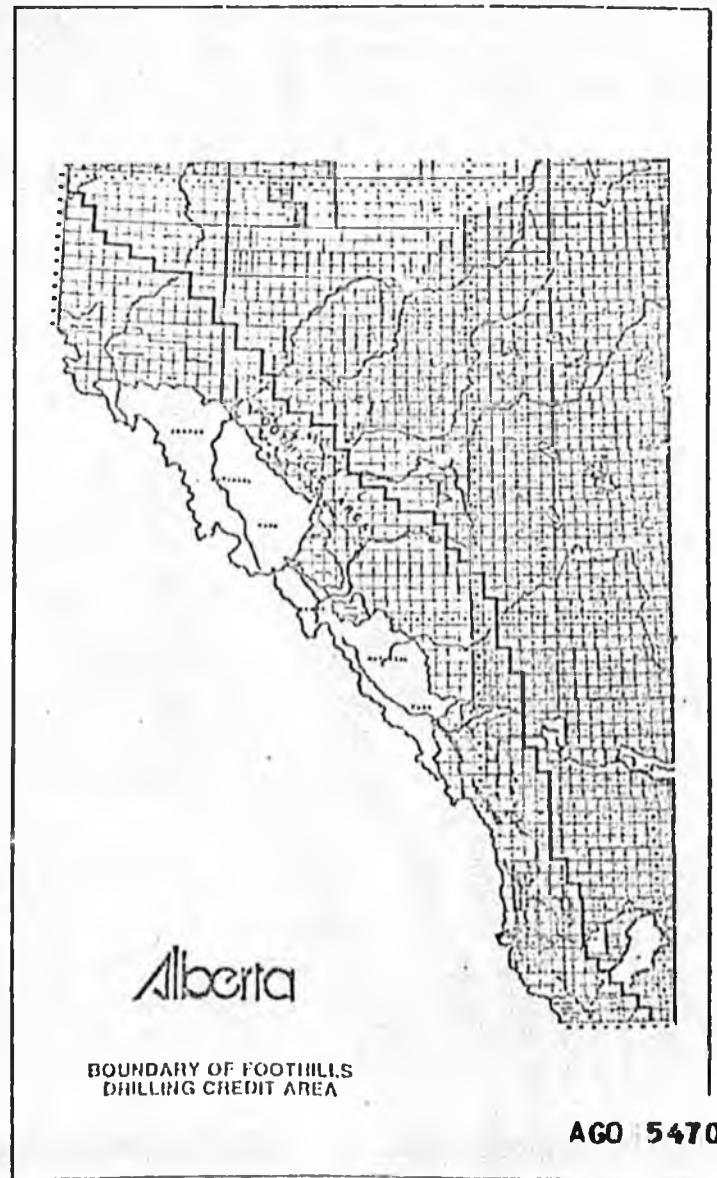


Figure 1



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Figure 2

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

(2) Drilling Credit Areas

Figure 1 shows the drilling credit areas as they will be defined under the 1978

Regulation. The Plains and Foothills Areas have not been changed. The subsisting Northern Area, however has been divided into the new Central and Northern Areas shown by the illustration. The boundary between the two new areas was defined by the Department on the basis of well cost data and topographic and access considerations.

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

(3) Drilling Credit Schedules

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

SCHEDULE F						
Applicable to the Class A Interval of an Incentive Exploratory Well that Commences Drilling on or after January 1, 1978						
The Class A interval of an incentive exploratory well that commences drilling on or after January 1, 1978 shall be determined by the Board as the interval below the depth of 2,000 feet that:						
(i) has not been duplicated by a drilled and abandoned well within one and one-half miles.						
(ii) occurs more than 500 feet below the base of the deepest accumulation of crude oil or natural gas that in the opinion of the Board has been penetrated by another well within three miles, and						
(iii) occurs immediately below the base of the member or formation containing the deepest oil sands deposit that in the opinion of the Board may underlie the location of the said incentive exploratory well.						
Where neither (ii) nor (iii) above applies, the Class A interval shall be determined from the depth of 2,000 feet to the total depth of the said incentive exploratory well.						
Depth, Feet	Basis for Credit Plains Area		Basis for Credit Central Area		Basis for Credit Northern and Foothills Areas	
	Cumulative Dollars	Incremental \$/Foot	Cumulative Dollars	Incremental \$/Foot	Cumulative Dollars	Incremental \$/Foot
2,000	0	20	0	30	0	40
3,000	20,000	18	30,000	25	40,000	35
4,000	38,000	18	55,000	25	75,000	40
5,000	56,000	20	80,000	25	115,000	35
6,000	76,000	24	105,000	35	150,000	35
7,000	100,000	30	140,000	40	185,000	50
8,000	130,000	40	180,000	50	235,000	65
9,000	170,000	55	230,000	70	300,000	80
10,000	225,000	75	300,000	90	380,000	100
11,000	300,000	100	390,000	110	480,000	120
12,000	400,000	110	500,000	160	600,000	180
13,000	510,000	160	660,000	200	780,000	210
14,000	670,000	210	860,000	240	990,000	260
15,000	880,000	280	1,100,000	350	1,250,000	350
16,000	1,160,000	340	1,450,000	400	1,600,000	425
17,000	1,500,000	500	1,850,000	550	2,025,000	575
18,000	2,000,000	500	2,400,000	550	2,600,000	575

Figure 3

SCHEDULE G						
Applicable to the Class B Interval of an Incentive Exploratory Well that Commences Drilling on or after January 1, 1978						
The Class B interval of an incentive exploratory well that commences drilling on or after January 1, 1978 shall be determined by the Board as the interval below the depth of 2,000 feet that:						
(i) has been duplicated by a drilled and abandoned well within one and one-half miles.						
(ii) occurs more than 500 feet below the base of the deepest accumulation of crude oil or natural gas that in the opinion of the Board has been penetrated by another well within three miles, and						
(iii) occurs immediately below the base of the member or formation containing the deepest oil sands deposit that in the opinion of the Board may underlie the location of the said incentive exploratory well.						
Where neither (ii) nor (iii) above applies, the Class B interval shall be determined from the depth of 2,000 feet to the total depth of the said incentive exploratory well.						
Depth, Feet	Basis for Credit Plains Area		Basis for Credit Central Area		Basis for Credit Northern and Foothills Areas	
	Cumulative Dollars	Incremental \$/Foot	Cumulative Dollars	Incremental \$/Foot	Cumulative Dollars	Incremental \$/Foot
2,000	0	15	0	20	0	28
3,000	15,000	14	20,000	20	28,000	29
4,000	29,000	14	40,000	20	57,000	29
5,000	43,000	14	60,000	19	86,000	24
6,000	57,000	18	70,000	26	110,000	30
7,000	75,000	25	105,000	30	140,000	40
8,000	100,000	30	135,000	40	180,000	45
9,000	130,000	40	175,000	50	225,000	60
10,000	170,000	55	225,000	65	285,000	75
11,000	225,000	65	290,000	90	360,000	95
12,000	290,000	90	300,000	120	455,000	125
13,000	380,000	120	500,000	150	580,000	155
14,000	500,000	160	650,000	180	735,000	190
15,000	660,000	210	830,000	270	925,000	275
16,000	870,000	270	1,100,000	300	1,200,000	310
17,000	1,140,000	360	1,400,000	400	1,510,000	420
18,000	1,500,000	360	1,800,000	400	1,930,000	420

Figure 4

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

(4) Royalty Exemptions

(4.1) Eligibility

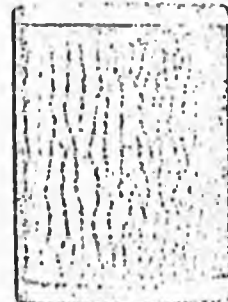
Crude oil or gas production must originate from a Class A or Class B interval to qualify for a royalty exemption. Production from any source shallower than 2,000 feet will thus not qualify for royalty exemption under the 1978 Regulation. An exception to the foregoing exclusion is found under the following circumstances: If conventional crude oil is produced from a source shallower than

2,000 feet in the new Northern Area, and if the 2,000-foot interval would have qualified as Class A or Class B footage pursuant to the 1974 Regulations, the crude oil production will be eligible for the normal royalty exemption applicable to deeper production.

(4.2) Duration

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

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



Work Commitment Bidding

GREGG K. ERICKSON

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

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

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

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

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

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

EVALUATION OF WORK COMMITMENT BIDDING

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

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

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

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

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

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

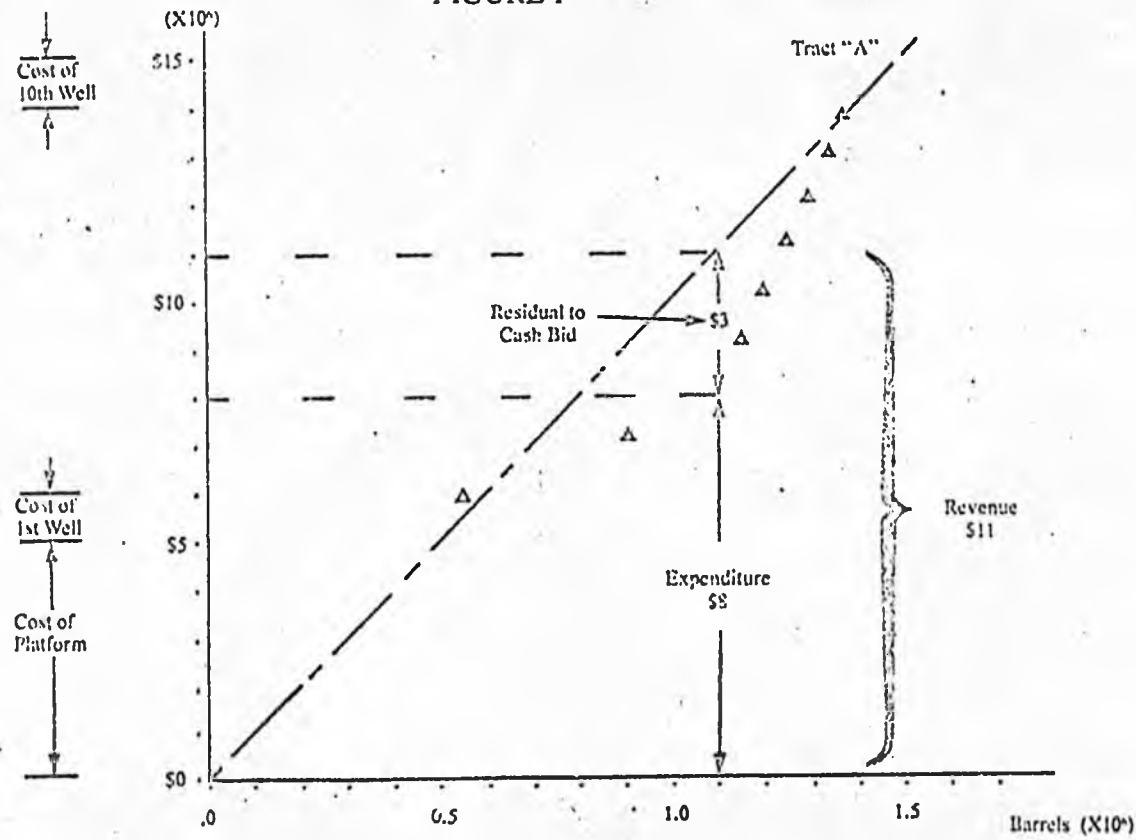
This is most easily demonstrated with a numerical example. Let us assume that a prospective bidder, in determining how much of a cash bonus he can offer for an oil and gas lease on a hypothetical tract A, has calculated the relationship between expenditures on development of the tract and expected production,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

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

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

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

FIGURE I



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

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

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

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

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

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

FIGURE 2

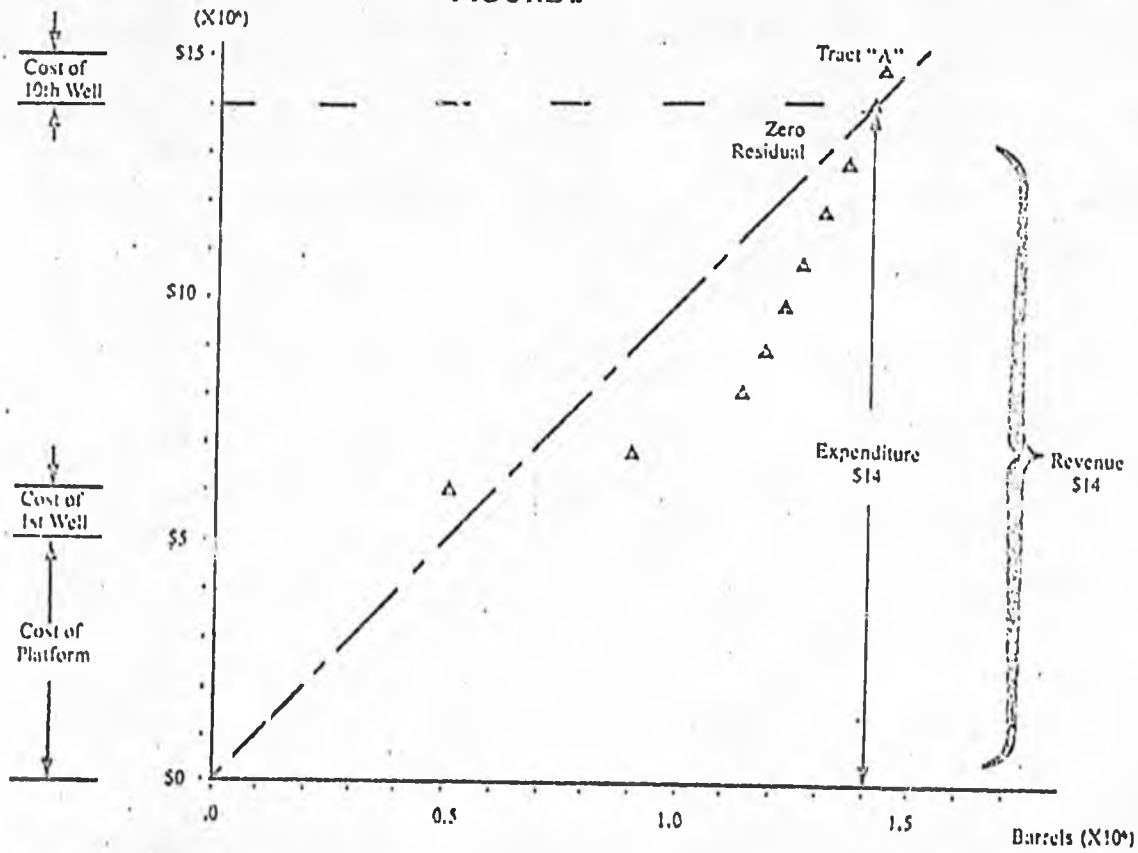
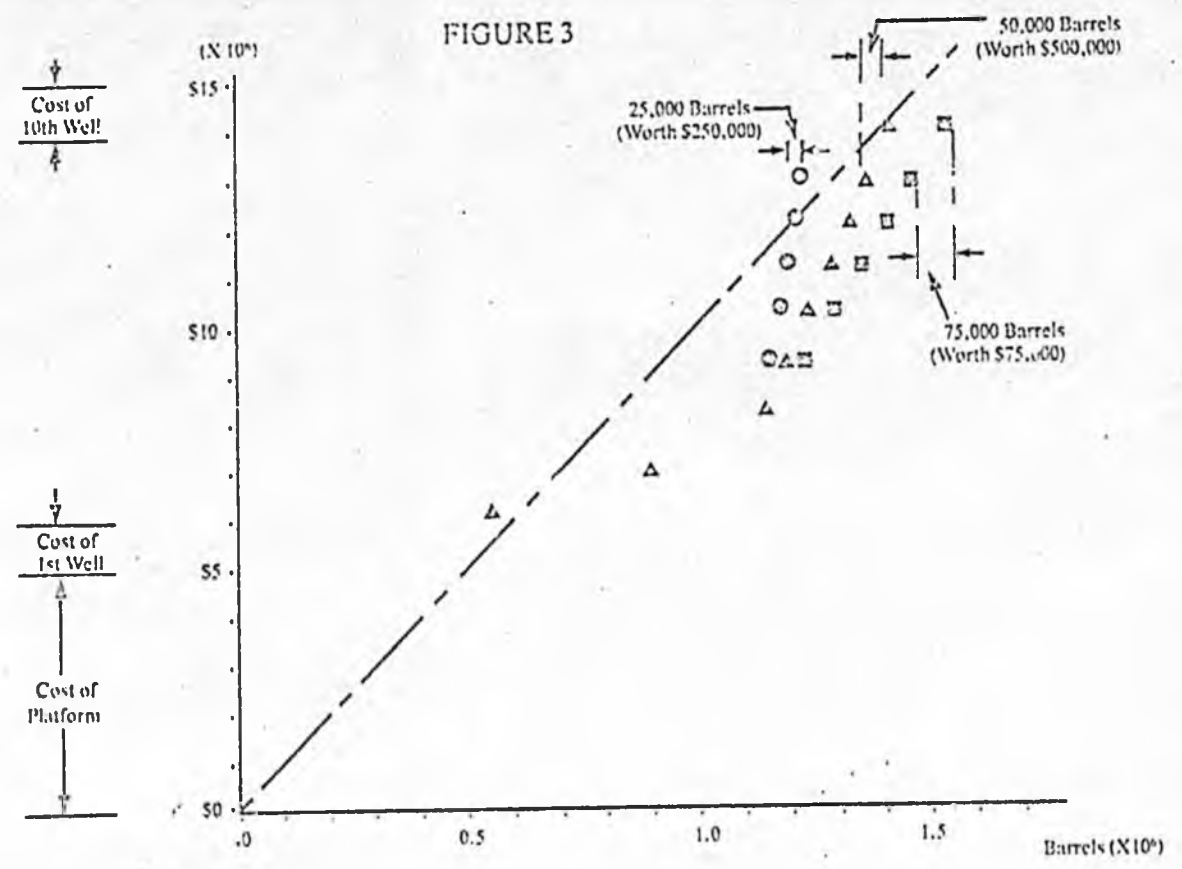


FIGURE 3



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

TRANSFERABILITY OF COMMITMENTS

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

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

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

TABLE 1

WORK COMMITMENT BIDDING

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

Note: All figures in millions

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

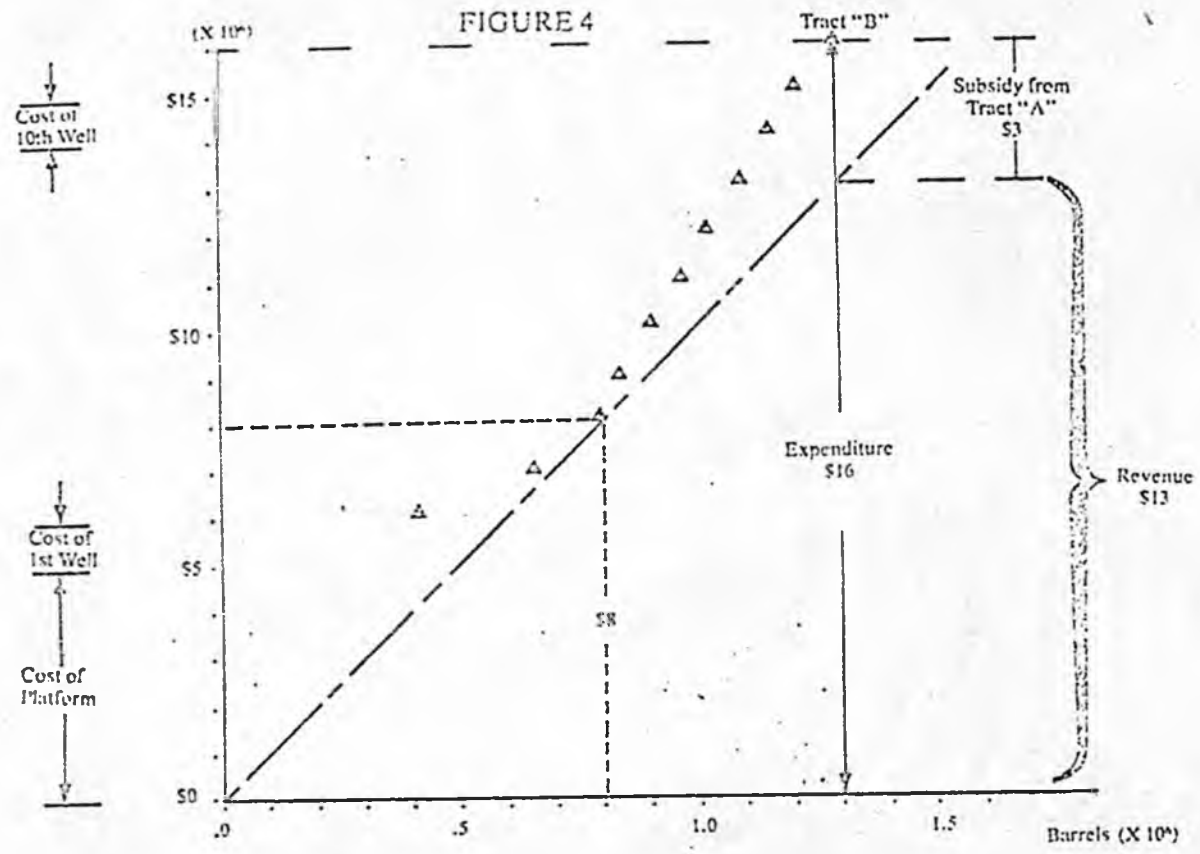
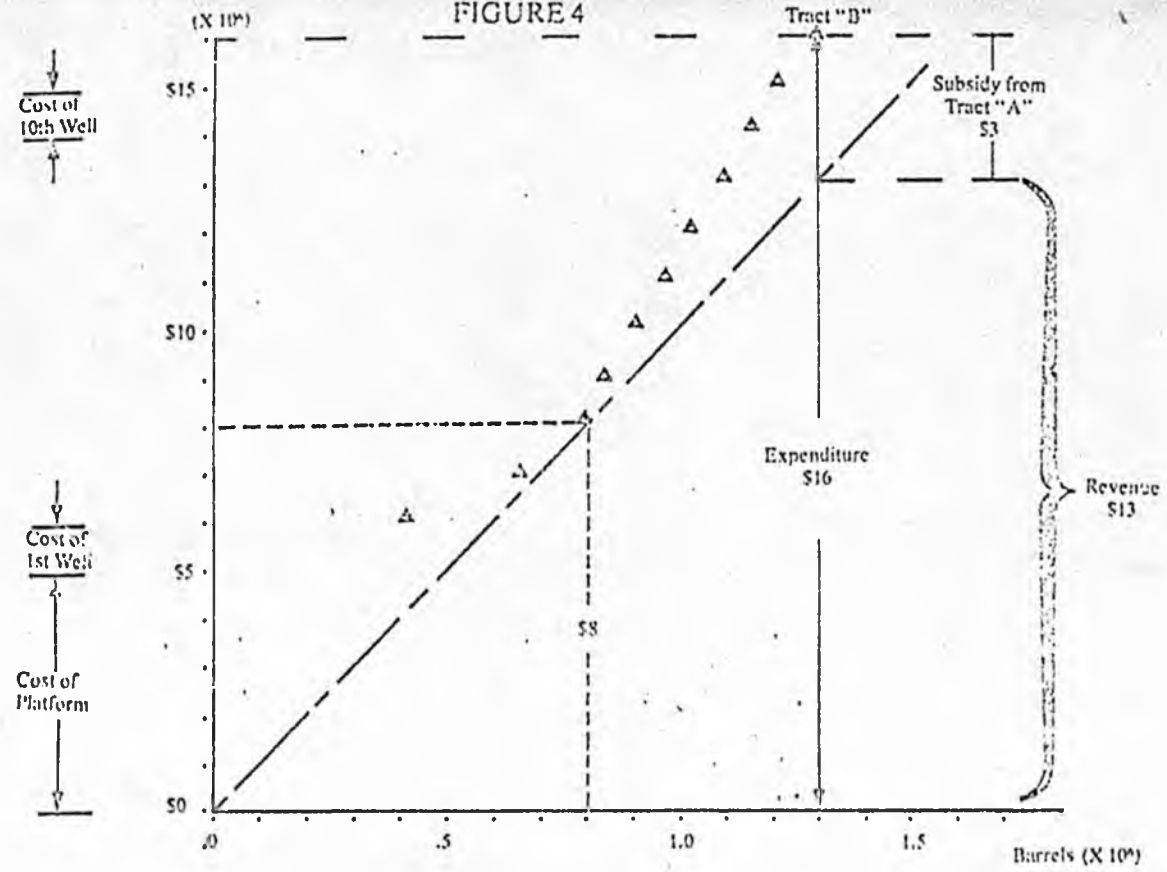


FIGURE 4



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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)
	<u>2.4</u>	<u>24</u>	<u>24</u>	<u>0</u>

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)
	<u>2.90</u>	<u>29.0</u>	<u>29.0</u>	<u>0</u>

Note: All figures in millions

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 fulfillment 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 fulfillment.

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

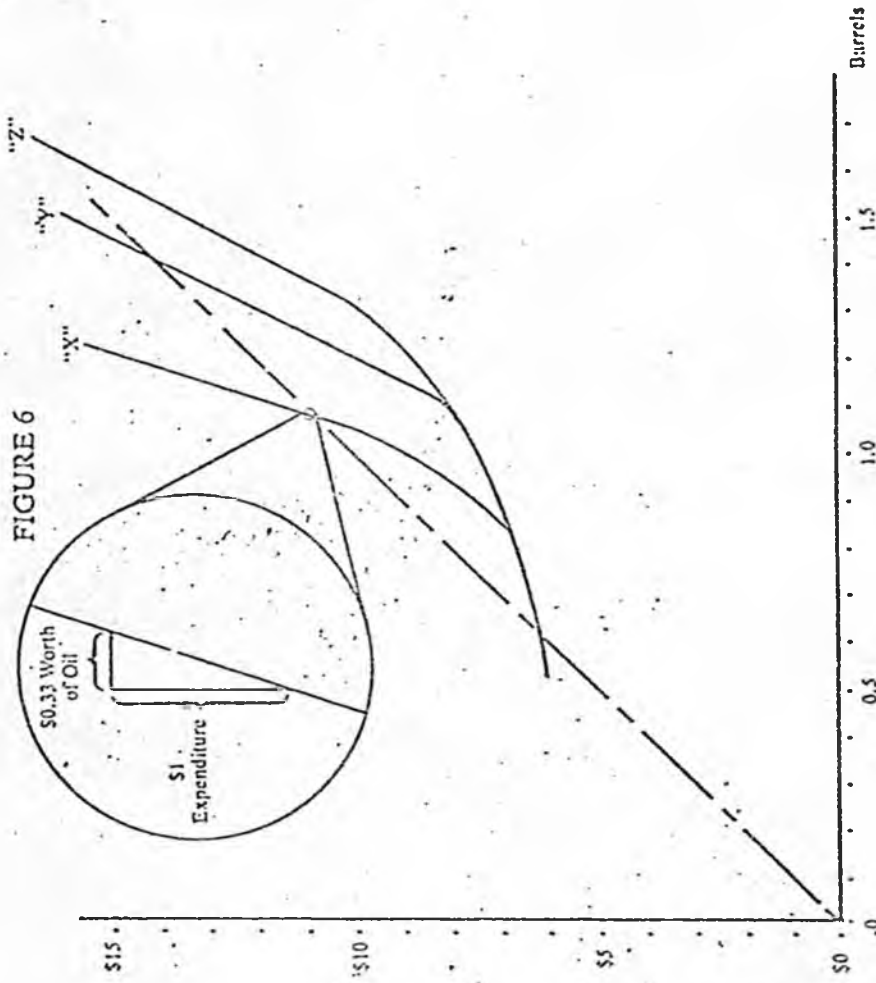
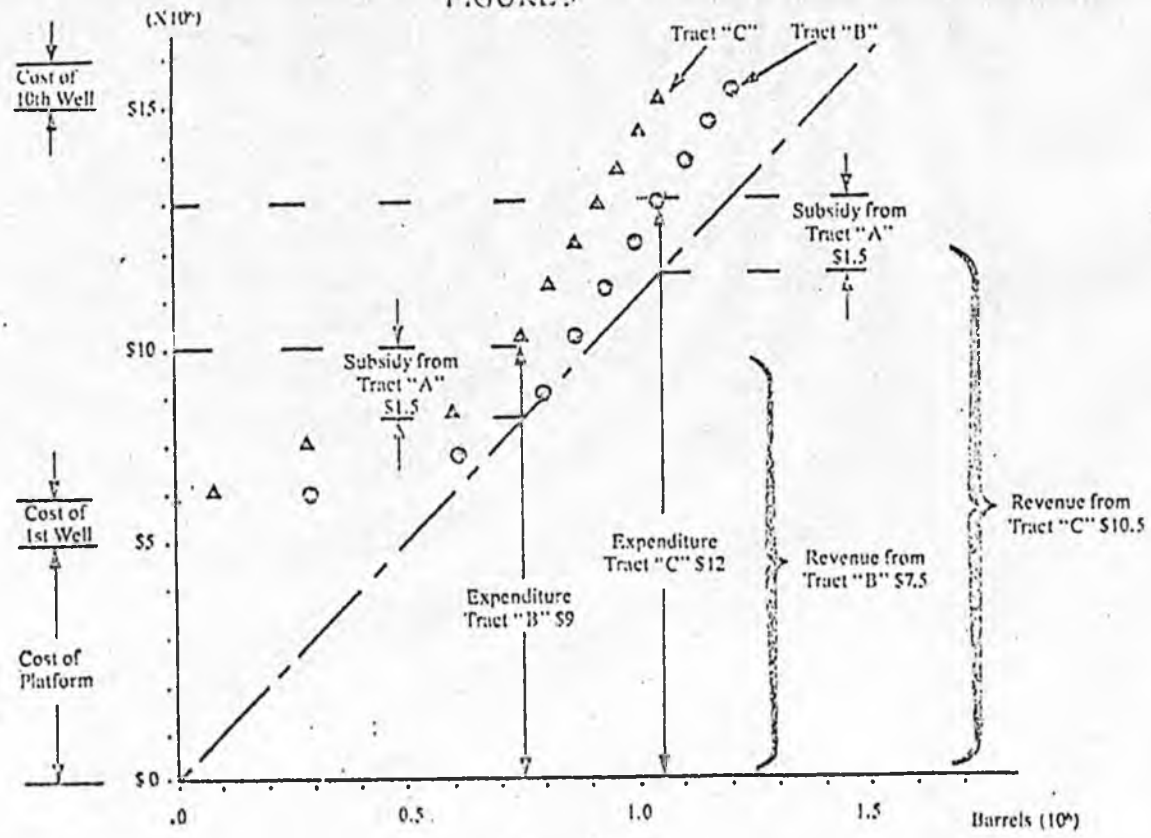


FIGURE 5



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 deduced 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

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

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

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

Notes

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

4. Arguments for the work commitment system are expounded in detail in I. White, D. Kash et al., *North Sea Oil and Gas: Implications for Future United States Development* (Norman: University of Oklahoma Press, 1973).
5. Kenneth Dam has touched on some of these matters, however, in "Oil and Gas Licensing in the North Sea" *Journal of Law and Economics* 8 (October 1965) and "Pricing of North Sea Gas in Britain," *Journal of Law and Economics* 13 (April 1970). Dam recognizes the subsidy for what it is and concludes that it is unjustified.
6. If it is determined that only a portion of the residual should be applied as a subsidy, this could be accomplished by offering only a portion of the tracts on the commitments bid basis, but allowing the fulfillment of a commitment on any tract acquired from the government. Since the reduction in the subsidy will move the operating point to the left on the output curve (Figure 5) to a point at which its slope is flatter, the result will be a higher assumption price for commitments. The commonsense explanation is that the optimum amount of total expenditure will be reduced only slightly; but that acreage over which commitments that can be fulfilled by that expenditure will be reduced relatively more. Another alternative would be to combine the work commitment system with a royalty, net profits share, or other form of deferred rent collection. This is in fact the arrangement pertaining in the North Sea sector. If the government takes a very high net profit share, the amount of the subsidy will be substantially reduced.
7. There are certain circumstances where a work commitment system could result in no more extensive or intensive development. This would be the case if the commitment were devoted to an activity not contributing to output. For example, if a government awarded a mineral concession to the operator who promised to build the largest smelter, no increase in mine output would result (unless the location of the smelter made lower grade ores profitable to mine).

Petroleum Leasing in British Columbia

DALE R. JORDAN

FACTORS AFFECTING THE LEVEL OF EXPLORATION

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

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

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

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

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

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

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

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

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

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

When an oil or gas explorer's cash flow comes from production outside any particular province, then for money for exploration to flow into that province, that jurisdiction 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 jurisdictions. 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 involved 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 enterpris 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 resources 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:

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

$P_i Q_i$ 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 16½ 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.* Given the fact that oil companies pay relatively low U.S. income tax rates, the after tax rate of return would be only modestly lower than the 7.5 per cent before tax rate of return. This net yield clearly does not reflect monopoly power; it shows an excessive degree of competition.

On the basis of this evidence we conclude that competitive bidding for oil and gas leases is sufficiently strong to protect the public interest 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:

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

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 firm, 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 thresholds.

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 dispersed 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,² 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 Norgard, 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).

TEXACO'S TESTIMONY CONCERNING CS FOR HOUSE BILL NO. 854
PRESENTED TO THE STATE OF ALASKA SENATE RESOURCES COMMITTEE
ON MAY 22, 1978

Texaco is opposed to CSHB 854, the State Leasing and Exploration Bill, in its entirety for reasons which we will enumerate in our following comments.

It is our firm belief that the present Statute AS 38.05.180, in effect since 1959, has proven equitable to both the State and the oil industry and has served to maximize economic benefits to the State. We firmly believe that industry competition has flourished under the present regulations, to the State's benefit.

In reviewing the proposed bill, #854, we would like to point out some of the areas that we believe are not in the best interest of the State and do not follow the goals stated in (a) (2) (A) and (B) (Page 1).

Legislative Review of Leasing Programs-Section (b) (Page 1)

We completely concur with proposed long range leasing programs giving industry sufficient lead time to acquire subsurface information and to budget costs of lease acquisitions and subsequent exploratory drilling. However, should annual reviews result in major revisions or reductions in areas to be leased, or complete elimination of sale areas, substantial

human and monetary efforts by both State and industry personnel will have been wasted. We believe this would be contrary to: 1) the State's goal of a stable and predictable petroleum leasing program, and 2) the State's interest in maximizing the economic recovery of its resources.

Leasing Methods-Section (f) (1) through (7) (Pages 3 & 4)

Paragraph (1) providing for bonus bidding with a fixed royalty is the most desirable and will have the greatest economic benefit to the State. Experimenting with other types of bidding, i.e., royalty, sliding scale royalty and net profits variables, places a greater risk on the State of the loss of revenue. As an example, let's use the Gulf of Alaska OCS sale. To date, 8 wildcat wells have been drilled without a single commercial hydrocarbon discovery; a very discouraging situation. Had the Federal Government resorted to bidding methods other than the conventional bonus bid, the result would have been a loss of \$400 million+ in needed revenue. Although State lands have great potential for discovery of hydrocarbon reserves, it must be clearly realized that these lands have thus far been virtually unexplored. Undesirable consequences may result from royalty or net profits bidding. These bidding methods which allow many companies to establish a land position with very little cash outlay is a deterrent to early drilling. These companies would probably drill only

under the most favorable conditions as it would be much easier and cheaper to await the results of exploration in the same general area by competitive lease holders. In view of these conditions, the State can ill afford to assume the risk of experimenting with alternate types of bidding.

Minimum Work Commitment-Section (h) (Pages 4 & 5)

This section enables the Commissioner to impose a minimum work commitment on any oil and gas lease, with penalties for noncompliance. That is a very poor provision, for these reasons: A work commitment is sensible only when applied to entire concessions or other large geographical areas. Applied to individual leases, it is unworkable. If a dry well is drilled on an adjacent lease, and if it proves that there is no hope for oil or gas on the subject lease, then it would be senseless waste of exploration dollars to carry out the work commitment. It would serve the State much more effectively if that lease were surrendered, with the money saved to explore elsewhere, where there is a more reasonable chance for a discovery.

Defferal of Cash Bonus-Section (k) (Page 6)

This section allows the Commissioner to defer any part of a cash bonus payment, allowing up to 5 years for full payment.

This is in direct conflict with AS 38.05.335(c), which requires a deposit of 20 percent of the bid in cash. Moreover, it opens the possibility for a bidder to deposit a small fraction of the cash bonus, and then to default on the balance no oil or gas is indicated by his neighbors' drilling programs. It also appears to conflict with section (a) (1) (A), to "maximize the economic recovery of the resources."

Lease Term-Section (n) (Pages 6 & 7)

This section mandates a 5-year term for oil and gas leases, with a possible extension to 10 years where operations are restricted by the environment. As the great majority of the State is subject to environmental conditions which limit an exploration season to about 4 winter months, a 5-year lease allows only 1 and 2/3 years of exploratory work. This is quite insufficient in such high-risk, high-cost areas of Alaska. We therefore would urge that the present statute be maintained whereby leases contain a 10-year primary term.

Non-Competitive Leasing-Section (x) (Page 10)

The proposed bill requires competitive leasing for all State lands. This basis may be good for many areas within the State having a high prospective value; however, this system is not suitable for low prospective areas, many of which would

attract little or no bids at a competitive sale. In line with the objective to maximize the economic recovery, the State should provide for non-competitive leasing in certain areas of low prospectiveness and in instances where tracts received no bids in an earlier competitive lease sale. This procedure is comparable to that used very successfully by the Federal Government and would provide additional revenue to the State.

Joint Bidding Restriction-Section (y) (Pages 10 & 11)

Texaco believes that the State would lose revenue by adopting a policy of restricting joint bidding. The theory of the author of the bill was that one must restrict joint bidding in order to promote competition. This, however, may have the opposite effect since many small companies, or large companies with limited budgets, may be precluded from participating in a competitive sale if joint bidding is not permitted. Joint bidding combinations may be the only means of acquiring lease acreage for these companies. In addition, the federal experiment in joint bidding restrictions on the OCS has not demonstrated that any additional revenue has been received by the government as a result of higher bids. On the contrary, a recent study indicated that higher bonus bids were received in joint bidding rather than by sole company bidding.

State's Call on Oil and Gas Production-Section (z) (Page 11)

Texaco objects to the State having a call on production for the reason that it will discourage oil and gas exploration within the State. An increasing number of wells are being drilled within the State as a result of financing from various utility companies interested primarily in the production to serve their customers. If the State were to include a call on production in excess of its royalty share, this will effectively preclude the utility form of financing from future exploration, reduce industry exploration on State lands, and, therefore, not be in the State's best interest.

State Access to Exploratory Data-Section (aa) (Page 11)

Texaco is particularly opposed to supplying any of its valuable proprietary seismic data to the State.

This section would remove the incentive for an aggressive company to be a leader in initiating new or innovative ideas in an effort to discover new resources. It is common knowledge that geophysical data, in particular, is extremely confidential and closely guarded by the individual members of the industry. Leakage of this information, whether by accident or other means, could cost an individual company its competitive advantage in a given area, especially an area which has

heretofore been relatively unexplored. We believe such a requirement would discourage rather than promote exploration of the State's lands.

Acreage Limitations-Section 3(c) (Page 11)

The acreage limitations should apply only to non-competitive leases. To limit the amount of competitive acreage a company holds effectively precludes that company from participating in some future leases sales at such time as its lease holdings approach the limitation figure. This reduces the competition by lowering the number of companies bidding for the leases, which will most likely reduce the revenue to the State.

In the event the State insists on limiting oil and gas lease holdings by an individual or company, Texaco requests that the present statute providing for the holding of leases on 500,000 acres of tide and submerged lands, and 500,000 acres of all lands other than tide and submerged lands be maintained in effect.

Summary

There are numerous other conflicts and ambiguities contained in this bill which we are sure your Committee will detect in

your review of the various sections. After a thorough review of CSHB No. 854, taking into account the testimony and comments presented by various individuals, we sincerely trust that your Committee will determine that: 1) such legislation will not fully accomplish the intent set forth in Section (a) (1) and (2); 2) that such legislation may in fact seriously discourage and delay an assessment of the State's oil and gas resources; and 3) that your deliberations will result in your finding the existing leasing statute AS 38.05.180 to be in the best interests of the State and the most equitable for the State and industry to work in concert in accomplishing the desired goals.

Claude H. Brown

STATE OF ALASKA
THE LEGISLATURE

POUCH Y - STATE CAPITOL
JUNEAU, ALASKA 99811
907-465-3800

LEGISLATIVE AFFAIRS AGENCY

MEMORANDUM

April 4, 1978

SUBJECT: Oil and Gas Leasing Bill: Major Issues in Drafting CS for
HB 854

TO: The Honorable Hugh Malone
The Honorable Merle Snider

FROM: Gregg K. Erickson
Director of Research

Here, as you requested, is our list of some major issues the committee will probably want to address in drafting a committee substitute for this bill. They are listed in no particular order.

1. DEGREE OF LEGISLATIVE INVOLVEMENT IN THE LEASING PROCESS. As currently written, the legislature would not be involved in any formal way in the leasing process, except as a recipient of information from the department. We discuss this issue in more detail in an accompanying memorandum.
2. WORK COMMITMENT BIDDING. Work commitment bidding, including the system of drilling incentives proposed by BP/Sohio, implies a subsidy from the state in favor of oil exploration and/or development. If the committee decides that such a subsidy is desirable, then the question of whether or not this is the most appropriate method of providing it should be addressed. Finally, the committee may wish to put some limitation on the extent of the subsidy, and consider the specific terms under which it is offered. For example, the period of time over which the commitment can be worked off, and its transferability among lessees and between tracts are all issues which you might wish to consider.
3. NON-COMPETITIVE LEASING. HB 854 would allow non-competitive leasing where tracts have been offered under competitive conditions but where no bids have been received. Theoretically, tracts could be offered with very high minimum bids, or with other terms which make them very unattractive. This would ensure a lack of competitive interest, and make it possible for the lands to be reclassified as non-competitive, and essentially given away. If noncompetitive leasing is to be retained, the committee should probably review the question of whether these arrangements are appropriate.

AGD 547072 +

4. REDUCTION OF ROYALTY. This provision has been fairly widely criticized by the various witnesses before the committee, particularly in combination with the royalty bidding arrangements.
5. NET PROFITS BIDDING. The bill has been criticized for being insufficiently precise about how the net profits would be calculated. The department has indicated that this can and would be taken care of in regulations. The committee could attempt to provide a general description of this calculation in the bill.
6. ROYALTY BIDDING WITHOUT THE SLIDING SCALE. Almost all economists who've looked closely at this method have been critical of it.
7. PUBLIC OUTCRY BIDDING. HB 854 allows this method of bidding; a number of scholarly studies have indicated a tendency toward collusive and non-competitive behavior in situations where natural resources are disposed of by this method.
8. ONE HUNDRED PERCENT GAS ROYALTY RESERVATION TO THE STATE. It has been asserted fairly convincingly that this provision will reduce gas company interest in exploration. On the other hand, particularly in the Cook Inlet Basin, the utility of having large gas reserves controlled by the state may be very high.
9. FIVE YEAR LEASE TERM. Most economists and the Department of Natural Resources would argue for the shorter term. Most industry representatives believe longer terms are necessary in many circumstances.
10. MINIMUM LEASE SIZE. Under the bill before you, individual leases are limited to 5,760 acres except under non-competitive leasing. It is clear from testimony of the department that it is contemplated that larger tracts should be made available in cases of low potential lands. Most economists and industry representatives would agree. The department seems to believe that it could amalgamate tracts, in which case the acreage limitation would be of no effect. The committee may want to retain the existing acreage limitation, but provide that the commissioner may lease much larger tracts when he makes specified findings.
11. ACREAGE LIMITATIONS. The maximum acreage that can be held by any one lessee is reduced in this bill over present law. Apparently, two companies would be affected by this reduction. The provision has been criticized by the industry. It becomes more significant as the term of lease is increased, so this provision should probably be considered together with number 9, above.

12. STATUS OF EXISTING OFFERS FOR NON-COMPETITIVE OIL AND GAS LEASES. No non-competitive oil and gas leases have been issued during the past two years, although many offers have been made for such leases under the existing law. Options for dealing with these "prior rights" will be discussed in a later memorandum.
13. RESTRICTION OF JOINT BIDDING. The committee may want to require such restrictions, or it may want to eliminate the provision entirely. Federal regulations currently limit joint bidding between the twelve largest oil companies. A similar provision is in pending federal legislation.
14. ACCESS TO AND CONFIDENTIALITY OF EXPLORATION DATA. The industry seems to generally oppose this provision. The department believes it is very important but would be willing to specify that the confidentiality of this information would be as established in current law.

GKE:jm

File
HB854

NOTE: Professor Norgaard in his study which accompanied Dr. Mason Gaffney's leasing policy study recommends a "more sophisticated analysis" of the affect of bonus bidding in Cook Inlet. See Recommendation III. B. 1 on page 25, attached. A comparison of other bidding methods could be done, also.

UNCERTAINTY, COMPETITION, AND LEASING POLICY

by

Richard B. Norgaard*

B. Bonus Bids and Rent Collected by the State

It is now well known to Alaskans that approximately 90 percent of the Prudhoe Bay field was acquired by ARCO and British Petroleum in mid-1960's sales which, along with considerable other Arctic Slope acreage, brought \$10,500,000 in bonus bids. After oil was discovered, the small amount of remaining Prudhoe Bay acreage brought \$900 million in bonus bids. Clearly, had the state known

*Associate Professor of Agricultural and Resource Economics and a member of Energy and Resources Group, University of California, Berkeley.

25.

about the Prudhoe Bay field in advance, between \$5 billion and \$10 billion more would have been collected in bonus bids. Several years after the sale, petroleum prices tripled. Presuming that industry had not predicted this increase at the time of the sale, then the state probably "lost out" on perhaps an additional \$15 billion to \$30 billion. Prudhoe Bay is clearly a "tough luck" story for the state, and industry is quick to point out that at other times and places they have bid large bonuses and lost. Offshore Cook Inlet is undoubtedly more representative than Prudhoe Bay due to the larger number of sales and smaller size of fields discovered.

The discounted value of oil produced and estimated to be produced from Lease Sales 7 and 9 is \$1.3 billion (Table 3, column 7). Ideally, we would like to determine what portions of this value have gone to cover production costs, what portion has been collected in royalties and similar per barrel taxes, and what portions of the remaining amount were paid in lease bonuses and retained by the industry. The following discussion will be complicated by (1) imprecise measures of the value of future natural gas production; (2) imprecise estimates of production costs; (3) uncertain shares of rent collected or to be collected by royalties, severance taxes, and other taxes; (4) the value of oil and gas in fields which are under lease but have not yet produced; and (5) the number of lease sales to be included in the analysis. The effect of alternative assumptions for items 1 through 5 could be incorporated a computer-modeled sensitivity analysis. For the purposes of this report assumptions will be made which are biased in favor of the effectiveness of the bonus bid as an instrument for collecting rent. If the bonus bid appears to be ineffective under these favorable assumptions, then we can be reasonably confident that it, in fact, has been ineffective.

Natural gas sales from Cook Inlet fields are now approximately 11 percent of the value of oil sales. This percentage, however, has been increasing historically and is expected to continue to increase significantly in the future. Nevertheless, the discounted value of oil will only be increased by 13 percent to \$1.5 billion to account for gas sales. Production costs (exclusive of interest charges since petroleum flows have been discounted to the present) in 1975 dollars are assumed to be \$1.25 per barrel, which may be somewhat low, or \$2.50 per barrel which is definitely high. The average wellhead price of crude oil in 1975 dollars reached a high in 1965 of \$5.66 a barrel, declined to \$4.26 in 1973, rose dramatically to \$5.38 in 1974, and is likely to increase gradually in the future. Nevertheless, for this analysis, we assume a constant price of \$5.00 per barrel. The state collects a 12.5 percent royalty, a severance tax of 3 percent to 8 percent depending on the rate of production, and has occasionally levied other smaller production taxes as well as occasionally granted discovery credits. For the purposes of this analysis, we assume these payments average 20 percent of the value of petroleum produced which is undoubtedly somewhat higher than actually the case. Lastly, we assume that all the oil and gas fields that will ever be produced up to Lease Sale 16 are now producing, and we assume that these 11 sales constitute a meaningfully large sample.

Given the above assumptions, production costs plus royalties and related payments come to 0.45 to 0.70 of the discounted value of the petroleum. The 0.30 to 0.55 remaining share has a discounted value of \$450 million to \$825 million. What proportion of this amount was collected in lease bonus payments? The value of the lease bonus payments discounted to 1961, roughly the year of the sales for the tracts in which oil was discovered, equals \$74 million. Thus, assuming the high production cost estimate, bonus bids transferred 16 percent

of the remaining rent, after royalties, etc., to the state. With the low production cost estimate, this percentage diminishes to 9 percent. Even given the favorable assumptions, the effectiveness of the bonus bid as a method for transferring rent to the state appears to be very low.

RECOMMENDATION III.B.1. The Department of Natural Resources should conduct a more sophisticated analysis along the above lines, with attention given to the sensitivity of the conclusions to alternative assumptions.

One might still argue that offshore Cook Inlet is another bad-luck example for the state of Alaska but that, with a large number of sales, the state will earn a fair return over the long run. This may be true in theory. But given the tremendous variations around the mean which are possible due to the great uncertainties involved, the state should (1) consider whether it has enough petroleum lands to lease to be reasonably certain that the law of large numbers is relevant and (2) whether it has sufficient planning expertise and access to capital to cope with the variations in bonus bid flows over time.

RECOMMENDATION III.B.2. The Department of Natural Resources should employ a statistician to assess alternative confidence limits about the mean for bonus bid revenues in 2-year, 5-year, and 10-year intervals given the projected pace of acreage to be leased in the future.

IV. Conclusions

The lease bonus bid appears to have been between 5 and 20 percent effective as a means of collecting rent over and above that collected through royalties. Its historic ineffectiveness may be due to extensive risk discounting on the part of industry, low levels of competition and the use of game theory by industry in determining bids, simply bad luck, or a combination of all of these. Regardless of the reason, both the theory and evidence brought out in this report suggest the state of Alaska should seriously consider alternative leasing systems, initiating or participating in presale exploration, acquiring the expertise to establish competitive bid rejection values for each tract, or a combination of all three of these.

This portion of the overall study does not address alternative lease terms or procedures for determining lease winners. If the state retains the lease bonus bid approach, especially with current royalty levels, its effectiveness can be increased in two interrelated ways. First, the state could contract or provide incentives for limited exploratory drilling with public dissemination of information prior to lease sales. This information could reduce uncertainty substantially and thereby increase the level of competition. Second, the state could, itself, behave as a bidder by establishing competitive bid rejection criteria for each tract. Such an approach at least would increase the level of competition substantially, for example, from 2.2 to 3.2 serious bidders on likely tracts in Lease Sale 9. But more importantly, the state's bid could reduce the effectiveness of game theoretic strategies significantly, thereby having a bigger impact than merely increasing the number of bidders. Each of these approaches can be developed over time with increasing intensity or sophistication. Their effectiveness and cost can be monitored and optimal levels roughly

27.
determined. These proposals cannot be rejected on the grounds that staffing and expenditures comparable to Exxon's exploration division would be required.

Even if the lease bonus bid approach is abandoned, some changes along the above lines would probably be desirable. First, there is no known perfect set of lease terms or procedures of determining lease winners under conditions of uncertainty and limited competition. While other leasing strategies may be better, there will probably still be advantages to reducing uncertainty and increasing competition. Second, the state could better plan sales over time and predict revenue flows if it had information on areas to be leased. Again, such information might be gathered by initiating or providing incentives to industry to drill. Or it may be sufficient for the state to participate in industry-initiated seismic exploration and to employ several seismologists or contract for the analysis of seismic data.

In summary, the Department of Natural Resources should seriously consider increasing its level of expertise and role in exploration, incrementally over time but substantially during the next 5 to 10 years.

Page 24
Hennings

1. 5-year leasing program submitted to each regular Legislature specifying land to be leased in the 3rd and 4th years after the year in which leasing program is submitted. The 1979 through 1983 leasing program will be submitted to next year's Legislature.

THIS WILL PERMIT THE LEGISLATURE, THE PUBLIC AND THE OIL & GAS COMPANIES TO KNOW LONG-RANGE LEASING PLANS OF ANY PARTICULAR GOVERNOR OR COMMISSIONER OF NATURAL RESOURCES.

2. Commissioner would also submit an annual report to the Legislature on the bidding methods used, or proposed to be used, and why.

THIS WILL HELP ALL ALASKANS TO UNDERSTAND BETTER THE ECONOMICS OF OIL EXPLORATION.

3. Methods include:

- a. Cash bonus with a fixed royalty of not less than 12½% (present method);

- b. not profit bidding, and

- c. royalty bidding, but only where "unleased acreage is subject to drainage by offsetting wells."

4. A "minimum work commitment" may be included in a lease. (to be amended?)

5. Exploration incentive credits -- based on footage drilled and geophysical work done -- can be made part of the lease and may be taken against royalties; rentals and taxes, but may not exceed 50% of the payment toward which it is being applied.

THE CREDIT SYSTEMS WILL PROBABLY NOT BE NEEDED AT THIS TIME, BUT SHOULD BE IN THE LAW TO PERMIT THEIR USE IN THE FUTURE, IF NECESSARY.

6. The Commissioner may reduce royalty but only when a clear showing is made by the lessee that in the later stages of production his rate of return, based on his total investment in the field, is insufficient.

ANOTHER SECTION OF THE LAW IS AMENDED TO DELETE COMMISSIONER'S EXISTING POWER TO REDUCE ROYALTY AT ANY TIME.

7. The lease term is reduced from 10 years to 5 years, except when "environmental conditions severely restrict operations", the term can then be 10 years.

IT IS IN THE STATE'S INTEREST TO HAVE THE LESSEE EXPLORE AS QUICKLY AS POSSIBLE AFTER HAVING BEEN AWARDED A LEASE OR RETURN IT TO THE STATE FOR RE-LEASING.

8. Rentals have been increased from \$1.00 per acre to \$1.00 - 1st year; \$1.50 - 2nd year; \$2.00 - 3rd year; \$2.50 - 4th year and \$3.00 for the 5th and following years. "Shut-in" field rentals may be increased but not to exceed 150% of the rate for the preceding year.
9. The existing law concerning unitization has been left as is. (See HB 815)
10. Leases which draw no bids may be offered by another competitive method but the rental may be less and the lease size greater.
11. All non-interpretive data obtained from activity on the lease may be made available to the State by the lessee, but the information shall be controlled by the existing law on confidentiality.



Oil, Gas & Mineral Properties

LUM LOVELY, Geologist

P.O. Box 99
Anchorage, Alaska 99510

Offices located at
1016 W. 6th Ave., Suite 440
Anchorage, Alaska 99501
Phone (907) 277-1551

March 31, 1978

Dr. Robert E. LeResche, Commissioner
Alaska Department of Natural Resources
Pouch M
Juneau, Alaska 99811

Re: Issuance of non-competitive oil and
gas leases in Susitna Basin

Dear Dr. LeResche:

It has just come to my attention that you or Governor Hammond will be announcing within the next few days that a relatively small area near Flaxman Island on the North Slope will soon be opened for competitive oil and gas leasing, and that many non-competitive oil and gas (and coal?) leases will finally be issued by the State pursuant to applications filed by numerous individuals as long as 2½ years ago. It is also my understanding that you will be announcing your intention to reject all currently pending non-competitive lease applications filed by oil and gas companies in Susitna Basin (many were filed nearly 2 years ago), in order that the land now covered by those applications might be reclassified for competitive oil and gas leasing only.

Your proposed North Slope competitive lease sale will surely generate spirited bidding because of Exxon's recent nearby oil discovery. And, you are certainly to be commended for acting affirmatively at long last on those non-competitive oil and gas lease applications which so many individuals filed in good faith so many years ago. If you have been advised that competitive interest will be high in those areas which are now covered by oil company applications for non-competitive leases in Susitna Basin, however, then your advisors are sadly out of touch with reality.

As an independent geologist who makes his living principally from oil and gas leasing activities, and as the one person who has more leasing experience in Susitna Basin than any other individual, I can assure you on the basis of real world experience that interest in Susitna Basin is extremely low at this time despite Union Oil Company's current reconnaissance seismic activities in the southwestern corner of the basin.

Rejection of oil company applications in Susitna Basin at this time will serve only to dampen what little interest there is in Susitna Basin already. Even if competitive interest were eventually to develop in the basin, however, required cumbersome and time consuming pre-leasing and leasing procedures would necessarily result in undue delays in exploration and development activities. If it is your intention to encourage early exploration for natural gas and/or oil in Susitna Basin, therefore, you will approve, rather than reject, all oil company non-competitive oil and gas

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lease applications in the Basin, forthwith, just as you contemplate doing for those non-competitive lease applications which were filed by individuals in the area.

Please bear in mind that Susitna Basin is an extremely low-priority geologic province where oil possibilities are believed to be nil and possibilities for natural gas are marginal at best. The sedimentary section is thin in Susitna Basin, and structural information there is extremely scarce.

Moreover, hundreds of thousands of acres remain unleased (or even applied for) in the basin, despite the fact that this land has been available for non-competitive oil and gas leasing for many years now. I also wish to stress that Texaco dropped its oil and gas leases on over 150,000 acres in Susitna Basin after first conducting an extensive seismic program there some eight years ago. Furthermore, to my knowledge Texaco has no plans to drill its remaining 70,000 acres of leases in the basin before they expire next December.

I also think you should know that oil companies haven't exactly been stumbling all over themselves trying to buy my leases in Susitna Basin, either. It took me 7½ years to sell my 40,000-acre Yentna River lease block (to Union Oil Company and Pacific Lighting) in the southwest part of the basin, for example, and, after nearly eight years, I still haven't found any takers for my 47,000-acre Highway Bridge lease block in the east-central part of the basin despite the fact that Union Oil Company is now conduct seismic operations only 25 miles away. As a matter of fact, I still own leases in the immediate vicinity of Union's current shooting area which I haven't yet been able to sell or farm out!

I caution you not to interpret as an indication of high general interest the over-the-counter non-competitive oil and gas lease applications which Amarex Inc. and Gas Supply Corporation of Alaska (GASCOA, a subsidiary of Anchorage Natural Gas) filed jointly on 40,000 acres in the southeastern part of the basin, and on 36,000 acres in the north-central part of the basin nearly two years ago. These companies are so cautious about Susitna Basin, in fact, that, prior to filing the aforementioned applications, they were unwilling to purchase either my Yentna River lease block (which Union Oil and Pacific Lighting now own) or my Highway Bridge lease block, even for as little as \$3.00 per acre (my rental investment at that time). In their view, there were (and still are) simply too many geological unknowns in Susitna Basin to justify spending more than a state filing fee of \$20.00 per application plus the required annual rental of 50¢ per acre for leases there. Inasmuch as Amarex and GASCOA filed their applications with my help, I can also attest to the fact that their applications cover prospects which are inferred, only, on the basis of best-guess extrapolations from old, incomplete, and now publicly available seismic data which Pure Oil Company filed with the U.S.G.S. over 14 years ago.

Neither should you misconstrue Union Oil Company's recent over-the-counter filings for oil and gas leases in Susitna Basin as an indication that an abundance of favorable geological data is available in that area.

As a matter of fact, in filing its recent applications for non-competitive oil and gas leases on approximately 100,000 acres west of Mt. Yenlo, Union Oil Company had even less geological information to go on than Amarex and GASCOA had when they filed their aforementioned applications elsewhere in Susitna Basin. No outcrops are present where Union filed, for example, and neither has any seismic exploration ever been conducted in the area. Moreover, it should be obvious from the simple rectangular pattern of Union's filings west of Mt. Yenlo that the company hasn't the foggiest notion of what to expect geologically in the area. It would therefore be unrealistic, indeed, to expect Union (or anyone else, for that matter) to pay any more for leases in the area than the small filing fees and rentals which are presently required for state non-competitive leases.

Amarex, GASCOA (now McAlester Fuel Company), and Union Oil Company obviously filed their respective non-competitive oil and gas lease applications in Susitna Basin with the intention of eventually exploring large areas where geologic information is currently sparse or non-existent. In data deficient areas such as these, however, history shows that 90% or more of the land will be condemned geologically by future exploration. These companies are therefore faced with the unpleasant task of condemning most is not all of their respective areas of interest as cheaply as possible!

In these circumstances, of course, it would be totally unrealistic to expect that any of the aforementioned companies (or any others) would suddenly become spirited bidders for competitive leases in any of the geologically questionable areas mentioned above. In fact, it is safe to say that no exploration whatsoever will be initiated in the aforementioned areas by either Amerex, McAlester, or Union Oil unless inexpensive non-competitive leases are first issued to them by the State pursuant to their currently pending applications

The facts make it clear that reclassification of the aforementioned areas for competitive leasing, only, would result in postponement, if not total abandonment, of new exploration and development efforts in Susitna Basin. The question is, however, "Can the State afford to block exploration in Susitna Basin at this time in hopes that competitive interest in the area may pick up at some indefinite time in the future?" I don't believe it can. Here's why.

As you know, Mr. Pat Dobey of the Division of Minerals and Energy Management here in Anchorage has warned the Administration and the public that the Anchorage Bowl area will be faced with ^acritical shortage of natural gas by 1985 (just seven years from now), unless more discoveries are made in south-central Alaska soon, or, in the alternative, unless a state-built-or-subsidized gas pipeline is laid from Prudhoe Bay to Anchorage.

It would of course be unwise for the State to spend taxpayers' money on a gas pipeline from Prudhoe Bay to Anchorage, when oil companies such as those who have filed for non-competitive leases in Susitna Basin appear ready, willing, and able to spend money from the private sector to explore for and develop natural gas reserves right here in Anchorage's own back yard.

It therefore behooves the State to approve the aforementioned oil companies' non-competitive oil and gas lease applications, forthwith, in order to clear the way for new exploration in Susitna Basin as soon as possible. Remember, Anchorage is rapidly running out of gas, and new discoveries of oil and gas generally require lead times ranging from five to ten years. The State simply cannot afford to hold up development in Susitna Basin any longer. To do so would be totally irresponsible.

While new exploration in Susitna Basin could be highly beneficial to the State of Alaska in general, and to Anchorage natural gas consumers in particular, it could also result in a significantly broadened tax base for the Matanuska-Susitna Borough in which Susitna Basin is situated. Obviously, any further impediments to early leasing, exploration, and development in the aforementioned areas will definitely not be in the best interests of the Matanuska-Susitna Borough. It is therefore to be expected that your proposal to reclassify lands for competitive leasing in Susitna Basin will be denounced by the Matanuska-Susitna Borough Assembly and Planning Department when your competitive reclassification proposal comes up for notice and review pursuant to Section 38.05.305 of the Alaska Statutes. Undue delay in broadening the borough's tax base could be avoided, of course, if you would simply approve all currently pending oil-company (and individually-filed) applications for non-competitive oil and gas leases in Susitna Basin forthwith.

While I believe you can justify immediate approval of all pending non-competitive oil and gas lease applications in Susitna Basin on the basis of the foregoing reasons alone, you must of course also consider the moral and legal aspects of your forthcoming proposal to reject all lease applications filed by oil companies while approving similar applications filed by individuals.

First of all, it must be remembered that all of the now-pending applications were filed in good faith pursuant to laws and regulations which were in effect when the applications were filed (and still are in effect). Moreover, it clear that most of these applications would have been approved already, were it not for the current land freeze.

The land freeze, of course, was originally designed to protect certain aggrieved parties until such time that their grievances could be reconciled by the courts and/or the Legislature (these grievances have since been reconciled). It was not intended to be used as a means of cheating oil companies out of non-competitive oil and gas leases when it was first instituted, and it should not be used as a weapon to be turned against oil companies now.

The oil companies which are involved here (and individuals, too, for that matter) have filed their lease applications pursuant to laws and regulations which are supposed to protect their first-priority rights to the lands in which they have revealed their interest to the world in good faith (their areas of interest are described in their applications, of course, and their applications are on public file for all to see). Accordingly, use of the land freeze as a means of selectively blocking the issuance of leases to

March 31, 1978

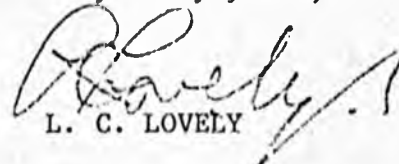
oil companies, while allowing the issuance of such leases to individuals, not only would constitute a reprehensible breach of trust on the part of the administration but also would serve double duty as an arbitrary and capricious abuse of administrative power which probably could be challenged successfully in court.

While oil and gas possibilities in Susitna Basin are generally considered to be marginal (even by those oil companies now holding oil and gas leases and lease applications in the area), the element of surprise in oil and gas exploration is such that significant reserves of oil and gas could nevertheless be discovered there. For a low-priority area such as Susitna Basin, however, economic incentives for exploration must be unusually attractive. You can provide this needed incentive, of course, simply by making it easy for everyone (including oil companies) to assemble large blocks of inexpensive non-competitive oil and gas leases in the area.

An early increase in the rate of exploration and development in Susitna Basin will clearly bring economic benefits not only to the State but to the Matanuska-Susitna Borough as well. It will also provide new jobs for oil workers, and it will stimulate new business for the service companies. Moreover, by making it known that you are clearing the way for possible early discoveries which could prevent the occurrence of an impending natural gas crisis in the Anchorage area, you could make considerable political hay in this important election year.

The foregoing observations make it obvious that competitive leasing will not stimulate urgently needed new exploration for oil and gas in Susitna Basin, whereas non-competitive oil and gas leasing will. I therefore urge you to reconsider your present plans to reclassify lands in Susitna Basin for competitive leasing only, and, instead, to approve all presently pending applications which oil companies and individuals alike have filed for non-competitive oil and gas leases in the area to date. I also urge you to lift the current land freeze in order to clear the way for future non-competitive oil and gas leasing in Susitna Basin. The sooner you take these important steps, of course, the sooner exploration can get under way, and the better it will be for all parties concerned.

Very truly yours,



L. C. LOVELY

Copies to: Jay S. Hammond, Governor, Juneau
Joseph P. Green, Director, DMEM, Anchorage
Patrick Dobey, Petroleum Manager, DMEM, Anchorage
Jack Roderick, Special Projects, DMEM, Anchorage
Gregg K. Erickson, Director, Div. of Research, Juneau
Lance Garola, Mat-Su Borough Planning Department, Palmer
Rep. C. V. "Chat" Chatterton, Juneau

(continued)

AGO 547087

(continued)

Copies to: Senator Joseph L. Orsini, Juneau
Dale Teel, President, Alaska Gas & Service Co., Anchorage
R. L. Rich, Manager of Land, Amarex Inc., Oklahoma City
W. B. "Buzz" Sawyer, V. P., McAlester Fuel Co., Magnolia, Ark.
Wayne Rodges, Land Manager, Union Oil Co., Anchorage
Wm W. Hopkins, Executive Director, AOGA, Anchorage
Don Hartmen, Exploration Representative, Texaco Inc., Anchorage

10-002
(12-23-70)

DEPARTMENT OF NATURAL RESOURCES
INTRA-DEPARTMENT ROUTE SLIP

TO: _____ LOCATION: _____
DIV/SEC: _____

ATTN: Hugh Malone

- | | |
|--|--|
| <input type="checkbox"/> Approval | <input type="checkbox"/> Note & Return |
| <input type="checkbox"/> Signature | <input type="checkbox"/> Initial & Return |
| <input type="checkbox"/> Comment | <input type="checkbox"/> Return As Requested |
| <input type="checkbox"/> Contact Me | <input type="checkbox"/> Return For Approval |
| <input type="checkbox"/> Prepare Reply | <input type="checkbox"/> Necessary Action |
| <input type="checkbox"/> For Your File | <input checked="" type="checkbox"/> Your Information |

REMARKS:

APR 26 1978

AGO 547089 +

FROM: _____ DATE: 4/24/78
 BY: [Signature]
 DIV/SEC: Special Projects LOCATION: [Signature]

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

Hugh Malone
JAY S. HAMMOND, GOVERNOR

*file
HB 854*

11TH FLOOR, STATE OFFICE BLDG.
POUCH # - JUNEAU 99811

April 21, 1978

RECEIVED

APR 24 1978

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

Div. of Minerals & Energy Mgt.
Anchorage, Ak.

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.

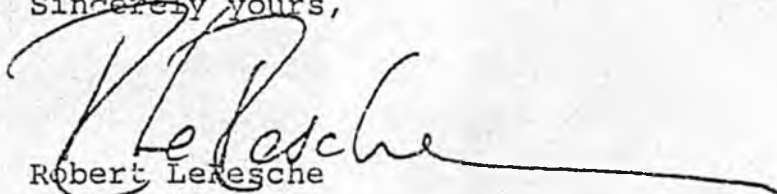
It would be of particular help to us if someone from your department could come to Anchorage to brief my staff and to Juneau to testify before the Senate Natural Resources Committee. We would, of course, cover all expenses. The exact dates of the visit would have to wait on the progress of the bill, 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 547090

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 2C0

Jack Roderick

file copy
*odg leasing*TO:

DATE: December 22, 1977

Robert E. LeResche, Commissioner
Department of Natural Resources

FILE NO:

TELEPHONE NO:

FROM: Jack Roderick *JR*
Special CoordinatorSUBJECT: Meeting with AOGA landmen
Juneau, 12/15/77
Proposed Leasing Legislation

Presented copies of draft oil and gas legislation to oil company representatives (Alaskan Oil and Gas Association land and legal committee) at a meeting in Baranof Hotel, Juneau on December 15, 1977. This is the same proposed legislation which was presented to Speaker Hugh Malone's ad hoc leasing committee on December 9th in Anchorage. A 3-hour give-and-take discussion was had. Representing the State in addition to Roderick were Joe Green and Pat Dobe. Carl Smith took notes.

In the order of discussion the oil company representatives felt:

- 1) No need to change existing laws, leasing or other.
- 2) Opposed to Commissioner having to "report" to legislature, either 5-year leasing program, or annual leasing methods. Feel executive should maintain complete control over leasing i.e. "keep politics out", perhaps a Leasing Board, like Louisiana, Colorado, etc., (a) and (b).
- 3) Opposed to requirement that federal agencies must be consulted prior to leasing. Failure to consult might result in law suit, (b) (4) (C).
- 4) Opposed to restricting any one leasing method to no more than 50% of area, (5) (E).
- 5) Opposed to royalty, net profits and work commitment type bidding (c) (but see Chevron's position, attached.) BP thought that allowing the Commissioner to postpone any part of the payment of the cash bonus would result in the state being "ripped off" by the irresponsible operator.
- 6) Opposed to permitting legislature by joint legislation to disapprove new leasing method, (g). Stated that State Attorney General believes this kind of attempted delegation is unconstitutional.
- 7) Questioned whether State should have the right to store or trade its royalty even with "consent of the majority" of the effected field lease holders". (j) Phillips (Swetnam)
- 8) Pointed out that (k) as written would allow State to terminate a 5-year lease which was capable of production in paying quantities but had no market available. Recognized State's need not to allow fields to remain "shut-in".
- 9) Opposed to accelerating rentals of this magnitude. (Roger Herrera, BP, suggested "freezing" rentals after a dry-hole, thereby giving incentive to drill quickly and yet continue to explore.) (l).

TO: R. E. LeResche
FROM: J. Roderick
DATE: 12/22/77
SUBJ: Meeting with AOGA landmen, Juneau, 12/15/77 - Proposed Leasing Legislation

- 10) Suggested that a State "shorelands" preference lease, due to a determination of navigability, be given on fee (Native) acreage, also, (m).
- 11) Didn't believe development contracts are workable and certainly opposed to State sharing in "the costs of exploration." (r)
- 12) Favored lands being offered non-competitively if no bids received at first sale. (u) Stressed the need for lands to be made available on a regular, continuous basis.
- 13) Opposed to restriction on joint bidding.(v)
- 14) Opposed to State's right to "purchase not to exceed 16 2/3% by volume of the oil and gas produced". Might accept an amount equal to original royalty in lease.(w)
- 15) Opposed to State's right to "all data". (x)
- 16) Opposed to lowering acreage limitation on uplands to 200,000 acres. Pointed out that there would have to be a "phase-in" period during which companies now at the maximum would be allowed to continue to lease. Otherwise, those companies who have acted aggressively in the past would be penalized. Sec. 3 (c).

Summary: AOGA Land and Legal Committee believes that the Legislature asked the Administration to review not revise oil and gas leasing law. Present bonus bid system is sufficient. Federal OCS law still not passed by Congress. Royalty bids on OCS will result in "less money to U.S. government." State administration should maintain complete and strict control over leasing; legislature should be informed only as they are presently.

Proposed law will hinder, not help, exploration in Alaska. "This will kill exploration in Alaska. We are categorically opposed to it." Herrera, BP. The methods, other than bonus bid, will not work. Work commitments will be impossible to administer.

Cash or performance bond requirement will discourage exploration even if commissioner can credit work against cash deposit. Perhaps statewide performance bond based on a percentage of amount bid would satisfy.

Reaction was as I expected. Despite the overwhelming negativism, some constructive ideas came from the exchange.

Recommendations:

- 1) Redraft legislation taking into account some of AOGA's suggestions. This has been done (see attached draft #8, in which I have made the changes noted below.)

Key issues still appear to be:

TO: R. E. LeResche
FROM: J. Roderick
DATE: 12/22/77
SUBJ: Meeting with AOGA landmen, Juneau, 12/15/77 - Proposed Leasing Legislation

- a. executive-legislature relationship (have retained the "reports" to legislature).
 - b. number and kind of leasing alternatives (have retained net profits and work commitments).
 - c. escalating rentals and lease term (have shortened to 5 years).
 - d. "shut-in" status of fields (have added "reasonable" time in which to produce).
 - e. state's right to purchase oil and gas (have retained 16 2/3%).
 - f. acreage limitation reduction on uplands (have included a "phase-in period).
 - g. restriction on joint bidding (have retained).
 - h. maintenance of non-competitive leasing in some form (have specified "noncompetitive" as option).
 - i. state's right to store or trade (have retained).
- 2) Contact Hugh Malone to see how extensive a leasing law change is possible in the upcoming legislative session. If taken at their word, AOGA is prepared to fight "any change" in the oil and gas leasing statute.
 - 3) I believe AOGA realizes that Alaska will eventually demand to have at least as much flexibility in leasing as the Federal government. I believe our fortunes ride to some extent on the OCS legislation now pending in the U.S. House and for that reason I feel we should follow the OCS Legislation closely and time our legislative effort accordingly.
 - 4) Contact independent oil operators who will support methods of leasing which the major oil companies may oppose. (See enclosed sample letter for you to send to attached list of "independents" and others, including the AFN.)
 - 5) It appears as if the high tax, low development profile of the State government over the past few years have the major oil companies in a fighting mood. The "tax ads" are the leading edge of the attack. Any leasing changes will be caught in the 1978 "political" year. Thus, consultations with key legislators is doubly important. The key policy decision remains: what changes are essential to proceed at this time toward the Beaufort lease sale in 1979 and beyond?
 - 6) You will need to consider the disposition of the noncompetitive offers which were chosen in simultaneous drawings several years back, and over-the-counter offers. Also, the question of pending Federal oil and gas offers which appear to have a State preference right at the time

MEMORANDUM - page 4

TO: R. E. LeResche
FROM: J. Roderick
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of TA under existing law. The draft legislation no longer grants an automatic preference right to these Federal oil and gas offerors, so the status of these pending offers will come into question.

I will be willing to meet with you at any time to decide what course of action should be taken on these matters.

AGO 547095

COPY (MEMO ONLY)
TO SNIDER

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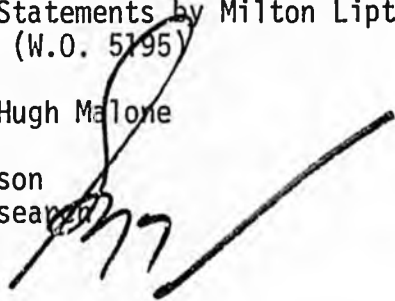
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JUNEAU, ALASKA 99801
907-465-3800

HAVE ENTIRE THING
PUT IN MY HBB54
FILE

MEMORANDUM

March 28, 1978

SUBJECT: Comparison of Statements by Milton Lipton on Oil and Gas
Leasing Policy (W.O. 5195)
TO: The Honorable Hugh Malone
FROM: Gregg K. Erickson
Director of Research



As you requested, we have analyzed recent statements by Mr. Milton Lipton concerning oil and gas leasing policy, and compared these with the positions taken in late 1969 and early 1970 by Mr. Lipton (Economic Considerations for Alaska's Future Oil and Gas Leasing Policy, W. J. Levy Consultants Corporation, N. Y., 1970). Although a number of the points discussed in the 1970 memorandum were not the subject of more recent comments, and vice-versa, we generally find the Lipton positions to have been consistent. We have summarized some of the high points and are attaching a copy of the 1970 memorandum.

In general, the 1970 memorandum made its strongest recommendation with respect to the rate at which lands are made available for exploration. It was suggested that a continuous and steady supply of exploration acreage would be appropriate, but that the state should feel no compunction about withholding acreage for future lease sales adjacent to lands being currently disposed of. With respect to leasing systems, the memorandum expressed general approval of the competitive leasing system currently in place, a somewhat qualified disapproval of royalty bidding, and a strong disapproval (with only minor exceptions) to the use of non-competitive leasing systems.

In 1970, as this year, Lipton argued for the establishment of work obligations in leases, but did not consider their use as a bid variable. The sliding scale royalty device, though not considered as a bid variable, was given a qualified endorsement as a lease term. However, from the context, it appears that Lipton's 1970 discussion contemplated that the highest royalty rate in the sliding scale would be 25 percent, substantially lower than the percentages presented in the hypothetical calculations made by the Department of Natural Resources.

All of the foregoing positions are consistent with Lipton's most recent testimony. In one minor change of emphasis, Mr. Lipton now seems to have some question about the desirability of acreage limitations. In the 1970 memorandum, these were explicitly endorsed.

AGO 547101 +

March 28, 1978

Net profits leasing and work commitment bidding were not discussed at all in the 1970 memorandum.

Please let us know if you need a more detailed analysis of any of these points.

GKE:jm
Attachment

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907-465-3800

LEGISLATIVE AFFAIRS AGENCY

April 4, 1978

M E M O R A N D U M

SUBJECT: Legislative Role in Leasing of Oil and Gas Land - HB 854

TO: The Honorable Hugh Malone
The Honorable Merle Snider

FROM: Gregg K. Erickson
Director of Research

In testimony and private conversations concerning HB 584, administration representatives have strongly argued against any direct legislative involvement in the oil and gas leasing process. This opposition creates an important political dimension to the decision as to how (or whether) the legislature should be involved in this process. The purpose of this memorandum, however, is to explore other aspects of this issue, and to present some options for your consideration.

As currently structured, HB 854 would place the legislature in an almost totally passive position with respect to leasing. The administration would be required to make certain reports to the legislature, but any other direct influence would have to be through enactment of future legislation (including appropriations). Two major areas where some legislators might desire a more active involvement are in the choice of leasing systems, and in the selection and scheduling of acreage to be offered for lease. In each of these cases, legislative involvement could take the form of:

AGO 547103 +

1. A requirement that the leasing program (bidding systems) be approved in advance by joint resolution, or
2. A stipulation that the leasing program (bidding systems chosen) would be subject to a legislative veto, by joint resolution or by simple resolution of either house.

If you desire to include either of these methods (with respect to the choice of acreage, the choice of systems, or both), we would suggest that the formal document to be acted on by the legislature be a two or three year "program" and that the commissioner be required to update this each year. A legislative veto could stop all leasing, or it could simply mean that the program would go forward under the previously approved plan.

While we have not secured a formal legal opinion on the requirement for legislative approval, or legislative veto, informal consultation indicates that both systems have been used in the past in other instances, and that both would be constitutionally sustainable.

In a sense, a committee decision to advocate legislative approval of individual leasing decisions, implies that the committee cannot or is unwilling to deal in a comprehensive way with the various issues that will arise in the course of the life of this act. In any event, if the

legislature decides not to formally inject itself into the leasing process, it is likely to want a much more tightly drawn and carefully conceived piece of legislation. On the other hand, a bill which includes a provision for legislative veto could probably be written allowing much more latitude for the commissioner in his conduct of leasing policy.

Finally, it should be noted that legislature could specify more formal oversight of the leasing function without intruding directly into the leasing process. For example, the bill could require that a standing or special committee of the legislature, or a legislative staff agency submit formal reports to the legislature each year on the manner which the legislative policy is being carried out.

GKE:ftc

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LEGISLATIVE AFFAIRS AGENCY

March 15, 1978

MEMORANDUM

SUBJECT: Leasing of State Land for Oil and Gas Development - HB 854
(W.O. #11/R)

TO: The Honorable Alvin Osterback

FROM: Gregg K. Erickson
Director of Research *GKE*

You requested that we provide an analysis of this bill. We have done this below in a cursory manner, and have attached additional material provided by the Department of Natural Resources (DNR). We have also noted some areas where we see potential problems. You will undoubtedly be taking a great deal of testimony on this bill from DNR, the legislature's consultants (Milton Lipton and Mason Gaffney), and the industry. After you have heard the testimony we would be pleased to address any points that you may at that time wish to have analyzed in depth.

Under current law the state is restricted to leasing oil and gas lands under the bonus bid system, or by the non-competitive system, which is essentially a lottery. However, the use of the non-competitive system has been of little importance during the past fifteen years, since all lands of medium or high potential have been classified so as to make them only eligible for bonus bidding.

In recent years other jurisdictions, most notably the federal government, have been moving towards expanding the number of bidding systems that could be used in leasing oil and gas lands. The U.S. Senate and House of Representatives have passed different versions of a bill that would accomplish this, and are about to enter conference on this legislation.

The legislation before your committee, HB 854, resembles this federal legislation in a number of important ways. The major thrusts of both the Alaska bill and the federal legislation are directed at expanding a number of leasing systems that may be used by the government in disposing of its land, increasing the opportunities for smaller firms to participate in development of oil and gas resources, and at insuring that the government achieves an appropriate return for the leasing of its oil and gas lands. In addition, the federal legislation establishes

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March 15, 1978

procedures for coordination and review of federal leasing plans by adjacent states, and establishes institutional arrangements for protection of the environment.

The attached material headed "Description of Leasing Methods in HB 854" sets out in summary form the systems that would be allowable under the Alaska legislation as it now stands. Also attached is a memorandum from Mr. Jack Roderick to Commissioner LeResche which describes the rationale which went into choosing these systems. This particular memorandum has been released by the Department with the request that its circulation be restricted to legislators and legislative staff. All the other attached material may be released to the public, if you so choose.

Some points which you may particularly wish to look into in your consideration of HB 854 are noted below:

1. Legislative Review. The legislation calls for submission by the commissioner to the legislature of an annual "leasing program". The administration apparently intends that no lease would be issued unless "it is for an area included in" the program (page 2, line 19). If this is indeed the intent, it perhaps could be clarified by amending language at this point. In any case, you should note that the bill has been carefully drafted to avoid any active involvement in leasing policy by the legislature. This, of course, is no change from the current policy, but under HB 854 the latitude of the commissioner, in choosing leasing systems and in other matters, has been substantially increased, and the legislature may wish to be more involved.
2. Expenses Charged Against Royalty Oil. The bill contains language (subsection (c), on page 4) which would insure that future leases are not subject to the same sort of dispute over the cleaning and dehydration costs as the state is now litigating with the Prudhoe Bay producers.
3. Choice of Leasing Systems by the Commissioner. Nowhere in the bill does the legislature give the Commissioner of Natural Resources any guidance as to when he should or should not use a particular leasing system. The commissioner is required, in his annual "leasing program" submission, to explain to the legislature why he believes a particular system should be used in a particular area. However, the choice and the adequacy of the justification remain beyond legislative review. In the attached material DNR has provided some explanation as to the conditions that would call for the use of one system or another. The legislature may wish to consider these explanations, and - if it agrees with them - may wish to include language within the law to give the commissioner (and future commissioners) guidance along these lines.

4. Work Commitment Bidding. Paragraph (4) (on page 5) would establish work commitment bidding as a leasing alternative. Under this system the bid variable would be the amount of effort the lessee agrees to expend in exploring the land. Use of this alternative will, on the average, result in less revenue to the state, with the revenue that is foregone by the state being expended in developing resources that would otherwise be uneconomic. This is a clear instance of economic subsidy. The legislature may wish to consider whether this subsidy is desirable, and if so, whether this is the most efficient way to provide it.
5. Commissioner's Discretionary Authority to Reduce Royalty. The commissioner now has authority to reduce the royalty rate on tracts having marginal production. So far as we know this authority has never been utilized. Subsection (d) of the proposed law (page 6) retains this authority to lower royalties. It becomes much more significant in the context of this bill, however, because of its use of royalty bid and sliding scale royalty leasing systems. Particularly in the case of the royalty bid arrangement, a lessee may, with a very high royalty bid, acquire a tract on the assumption that the commissioner will reduce that royalty if and when production is developed. The legislature may wish to consider the possibly of limiting this authority to only to royalties paid ^{the} ~~the~~ ^{WHEN} production level is within the lowest block of the royalty schedule, i.e., at the bottom of the "sliding scale".
6. Non-competitive Bidding. HB 854 would allow the commissioner, at his discretion, to offer acreage on a lottery system if the acreage had not received a bid in an earlier competitive sale. The legislature should be aware that this system, in combination with initial offerings at unrealistically high minimum bids, could be used to give away the state's oil and gas resources to private individuals or firms.

We will be pleased to examine these or other questions in more detail. We are confident that Mr. Lipton, Professor Gaffney, and the industry will raise additional questions that the legislature may also wish to examine.

GKE:dh
Attachments

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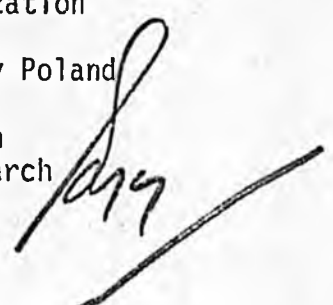
MEMORANDUM

May 30, 1978

SUBJECT: CSHB 854 and the Effects of Using Multiple Oil and Gas Leasing Methods on Unitization

TO: The Honorable Kay Poland

FROM: Gregg K. Erickson
Director of Research



Summary

At the Senate Resources Committee meeting on Friday you received testimony to the effect that the use of differing leasing methods on adjacent tracts, as would be permitted under HB 854, would make it difficult to establish unitized development and production of the pools over which those tracts lie. Generally, our studies of this question, which we have conducted since the matter was first raised several months ago, do not support this conclusion. On the contrary, they show that the incentives to unitize will not be seriously reduced by diverse lease arrangements, and that the difficulties of reaching unit agreements will not be increased as a result of this diversity.

The Incentive To Unitize

Unit arrangements exist and are encouraged by state policy because centralized, unitized operation of an oil or gas field can and usually will result in substantial reduction in the expenses of extracting the resource, and in absolute gains in the total amount of oil and gas recovered. That the potential for these gains exists is, under the circumstances we have had in Alaska, almost never a matter of contention among the leaseholders who would be a party to a unit.¹ The most

¹ See Bradner, Tim, "Oil and Gas Regulation in Alaska," *Alaska Review of Business and Economic Conditions*, 1971.

AGO 547109 +

important question here is therefore: Will the use of differing leasing systems as contemplated in HB 854 significantly reduce the incentive to unitize that is provided currently by the very real benefits of joint, unitized field development and operations?

We think not. At a high royalty rate, as might be encountered under straight royalty bidding, the benefits in the form of increased production are, of course, shared with the landowner on the basis of the royalty percentage. But all the benefits in the form of reduced costs remain with the lessee. In a net profits arrangement the benefits of increased production and reduced expense are both shared with the lessor, but still leave the lessee with substantial incentive to partake of the advantages of unitization. Naturally, if the royalty or net profits rates were set at or close to 100 percent these incentives would disappear, but so would the incentive to develop the tract at all.

Difficulties in Unitization

Despite the retention of a clear incentive to unitize under a mixture of leasing methods as in HB 854, it is possible that a mixture of systems might create a practical barrier to unitization. This might occur, for example, if the differing lease terms made it impossible for the lessees to agree on the proper apportionment of the unit's expenses and produced oil and gas.

Current Alaska law provides only general guidance as to how this allocation is to be made.² The usual practice has been to allocate the costs and production generally on the basis of the costs and production that would accrue to an individual leaseholder were he to operate the tract on an individual, non-unitized basis. Another method less frequently employed, but used, at least partly, in the formation of the Prudhoe Bay unit, is to allocate expenses and actual production on the basis of the original petroleum in place underneath each lease. Other factors, or combinations of these factors, may also be considered, and one study has distinguished examples of 42 different methods of apportioning participation.³

² AS 31.05.110(c) provides that "each plan of unitization shall contain fair, reasonable and equitable provisions for...the division of interest or formula for the apportionment and allocation of the unit production, among and to the several separately owned tracts within the unit area such as will reasonably permit persons otherwise entitled to share in or benefit by the production from such separately owned tracts to produce and receive, instead thereof, their fair, equitable and reasonable share of the unit production or other benefits of it; a separately owned tract's equitable, and reasonable share of the unit production shall be measured by the value of each such tract for oil and gas purposes and its contributing value to the unit in relation to like values of other tracts in the unit, taking into account [1] acreage, [2] the quantity of oil and gas recoverable from it, [3] location on the structure, [4] its probable productivity of oil and gas in the absence of unit operations, [5] the burden of operations to which the tract will or is likely to be subjected, or so many of these factors, or such [6] other pertinent engineering, [7] geological or [8] operating factors as may be reasonably susceptible of determination...." (emphasis and numbers added)

³ A. A. Khan and H. H. Power, "An Analysis and Comparison of Engineering Bases of Participation in Unit Agreements," *IOCC Committee Bulletin*, December 1960, p. 101.

Reaching an agreement on the theoretical basis for allocating participation and resolving all the associated technical issues can be a complex, difficult and protracted process. Although all parties usually have a clear view of the overall benefits to be gained from unitization, some may "hold out" in hopes that by doing so they may be able to extract a better deal from their fellow lessees concerning the allocation of the benefits of unitization.⁴

The question here, though, is whether differing lease arrangements will make reaching an agreement *more* difficult. In our view, the question answers itself when considered in the context of Alaska's unitization law and the permissible bases for apportionment of participating unit interests enumerated therein.⁵ For example, is the "acreage" in a lease altered by the fact the lease contains profit sharing arrangements? Is the "location or the structure" affected by the royalty arrangements? Or are the "engineering, geologic or operating factors" influenced by either? We believe it is obvious that they are not.

⁴ For a listing of the problems that can arise in unitization negotiations see Stephen McDonald, *Petroleum Conservation in the United States: An Economic Analysis* (Resources for the Future, Washington: 1971), pp. 198-201.

⁵ AS 31.05.110(c). See note 2, *supra*.

A Final Point

As a final point, we note that tracts bearing differing royalty burdens have already been included in units, in Alaska and elsewhere, wherever individual holders of federal and state noncompetitive leases have sold those leases while retaining overriding royalties. Moreover, differing lease arrangements are likely to exist in the future side by side wherever Native corporation or federal and state oil and gas lands are contiguous. It is possible, of course, that if the legislature gives the commissioner of Natural Resources authority to use alternative leasing methods that these differences may be reduced or eliminated.

GKE:jm

cc: Members, Senate Resources Committee
The Honorable Chat Chatterton
The Honorable Hugh Malone
Mr. Phil Holdsworth

file
HB 854
odg leasing

March 8, 1973

Robert LeResche
Commissioner

Position Paper on HB 854
Oil and Gas Leasing

~~_____~~
~~_____~~

✓ Here is a clause-by-clause analysis of HB 854. Coupled with my memo to you of February 28, 1973, you should have much of the information needed for the hearings scheduled before the House Resources Committee on March 16 and 17. Note that I am already recommending amendments. Perhaps we should offer them on the 16th. Milton Lipton is to testify after us on the 16th; Mason Gaffney will testify on the 17th.

Section 1

(a) Purpose clauses - self explanatory

Choice of the phrase ".....minimize the exploitation of these natural resources...."

(1)(B) meaning to reduce uneconomic exploration, may be unfortunate. These words do not mean that leasing is opposed. Likewise the phrase "...while minimizing revenue from unsuccessful exploration" (1)(D) which means the state's desire to share less in bonuses and more royalties, etc.

- (b) Five year leasing program. As precisely as practicable, the commissioner determines the size, timing and location of leasing which he expects to take place during the following five-year period. He "approves" the program and must review "at least once each year." We may wish to change this to "no more than once each year" if more stability is desired. He may "revise" and "reapprove" the leasing program.

The leasing program is submitted to the legislature "for its information" (not approval) within 10 days after the convening of each regular session. The first leasing program is due on or before January 1, 1980.

(4) Leasing program procedures. An AMENDMENT deleting "by regulation" will be necessary. We believe it will be sufficient for the commissioner to establish procedures for the formulation review and revisions to the leasing program. Pre-leasing regulations, which apply to the sales, will be in addition to these leasing program procedures. Should regulations be required for the leasing program, any revisions by the commissioner would probably require a formal hearing or hearings. We feel this would not be necessary.

Included in the procedures will be nominations of areas to be included or excluded from the leasing program, and notice to the federal and local governments and to the public who wish to participate in the development of a leasing program are called for, as well as coordination with the CZM program.

Perhaps an AMENDMENT specifying which federal (Dept. of Interior?) and local (boroughs?) agencies should review.

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PAGE 2

TO: LeResche
FROM: RODERICK

(5) Annual bidding method report is submitted to legislature within 10 days of the convening of each regular session. The report includes:

- (A) A schedule of all lease sales held during preceding year and bidding method or methods used;
- (B) Schedule of all lease sales to be held the next year and bidding method or methods proposed to be used;
- (C) Cost-benefit analysis associated with each method;
- (D) Reasons why a bidding method was selected;
- (E) The reasons why more than 50% of the area leased in the upcoming year is to be leased under one particular bidding method;

(HR 1614, the House OCS bill, requires that sliding scale royalty, net profits and work commitment bidding methods be used not less than 20% nor more than 50% of the time.

This provision applies for 5 years, but can be waived by the Secretary. S9 requires, for five years, that bonus bidding not be used more than 50% of the time in areas where there has been "no development" prior to October 1, 1975. The Secretary determines these areas.)

- (c) HB 854 requires that all lands will be first offered competitively. Only one bid variable will be used in any bidding method. Bids will be sealed, or other methods can be used. The state's royalty share will be free of all lease or unit expenses, including separation, cleaning, etc. costs.

Following a pre-sale analysis, the commissioner may choose at least one of the following leasing methods (which are all included in HR 1614 or S9):

- (1) Bonus bidding
 - (A) Cash bonus bid with a fixed royalty - this is the present competitive method
 - (B) Cash bonus bid with a sliding scale royalty (see B. Mondzell's Memo dated 3/1/73 attached)
- (2) Royalty bidding
 - (A) Fixed bonus with royalty as the bid variable
 - (B) Fixed bonus with sliding royalty as the bid variable
- (3) Net profit bidding
 - (A) Cash bonus bid, fixed royalty, not less than 30% net profit (in OCS legislation 30% net profits equates to 12% royalty)

AGO 547059

PAGE 2
TO: ICK
FROM: LeRESCHE
RODERICK

(B) Fixed bonus, bid net profit--this is the only bidding method that does not require of royalty of not less than 12½%. "In kind" taking is protected by the state's right to purchase (v).

(C) Fixed bonus, fixed royalty, bid net profit

(D) Net profit share is "royalty" for Permanent Fund

(4) Work commitment bidding

Fixed bonus, or fixed royalty, or fixed sliding scale royalty, or fixed net profit, or any combination. Work commitment bid in dollars. 20% of the dollar amount bid in cash or performance bond required at the time of bid.

State may recover unperformed amount. Commissioner may terminate if work is unnecessary or cumulative. Regulations will permit the inclusion of all costs, except lessee's general overhead, toward work commitment. (S-9 requires 100% cash or performance bond. HR 1614 fixes a bonus at not less than \$62 per hectare (\$25/acre) and fixes the royalty at 12½% or 30% net profits.)

- (d) Regulations allowing reduction of royalty during declining production, beginning two years after initial production. (HR 1614 allows the Secretary to eliminate any royalty at any time.)
- (e) Commissioner may defer any part of the payment of the cash bonus up to five years.
(HR 1614 - same)
- (f) Commissioner may withhold acreage from particular sale - this provision may be unnecessary unless legislature feels authority should be specified in order to withhold a tract from leasing block.
- (g)(h) Regulations governing net profits and work commitments will be adopted. (Question: Should definition of allowable costs in net profits and work commitment be in the bill? Ad hoc leasing committee thought not.)
- (i) With consent of the leaseholder, state may store or trade its royalty. (HR 815 addresses this matter and appears to prohibit all storing; i.e. underlifting or overlifting.)
- (j) Maximum size of lease is 5,760 acres, except subsec.(t). Presently, uplands 2,560 acres, offshore 5,760 (same as OCS).

Lease term 5 years, (except up to 10 years if environmental conditions severely restrict operations) or so long as produced in paying quantities (same as OCS). Unit or drilling will hold a lease. Commissioner must give

PAGE 4

TO: LeRESCHÉ
FROM: RODERICK

reasonable time to place a shut-in well on producing status (same as existing law). Rental may be increased not to exceed 150% of the rental the preceding year for a lease held past the primary 5-year term. (Presently a minimum royalty of \$1/acre is charged on shut-in leases). By regulation, commissioner may require the lessee to drill deeper or the deeper horizons revert to state for resale. (Perhaps this requirement to drill deeper can be accomplished by inserting stronger due diligence language in lease contract.)

- (k) Freeze rental at abandonment or until royalty, net profit or work commitment exceeds rental for 3 consecutive years.

Rentals are:

Year 1 =	\$1.00/acre
Year 2 =	\$1.50/acre
Year 3 =	\$2.00/acre
Year 4 =	\$2.50/acre
Year 5 =	\$3.00/acre

(present rentals - competitive \$1/acre; noncompetitive .50¢/acre)

- (l) May issue holder of a federal or private lease or state shorelands lease within its boundaries. Term may not exceed 5 years. (These are lands determined to be "navigable" during lease term.)
- (m)(n) Unitization (existing law). No changes.
- (p) Pooling for well spacing (existing law). No changes.
- (q) Development or drilling contracts (existing law). State may share in the costs of exploration (new). These contracts have been authorized for years, but never used. We did not delete from HB 854 in order to allow the legislature to decide to eliminate or to keep. Work commitment and subsection(t) could replace these contracts. (S9, OCS, Federal government can share in exploration costs.)
- (r) Subsurface storage (existing law). AMENDMENT. By error last line in existing law was not included. Should be added.
- (s) Lessee's report on "local hire" (existing law). Provision required in lease (new).
- (t) Tracts receiving no bids may be offered on flexible terms including noncompetitive. Must include a sliding scale royalty. Rentals may be less than in subsec(k) and tracts may exceed 5,760 acres in size.
- (u) Authority to restrict joint bidding by major or multi-national oil and gas companies to encourage competition.
- (HR) (HR 1614 restricts joint bidding to companies who have 1.6 million barrels or more per day production. Also, anti-trust review by the Attorney General and the Federal Trade Commission is required.)

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TO: LeRESCHE
FROM: RODERICK

- (v) State may purchase up to 16.66% of oil and 100% of gas production at the regulated price or fair market value. Purchased petroleum may be used as "in-kind" royalty.
- (w) The commissioner is given the right to obtain "all data" obtained from exploration, development or production from the lease. This is simply the lessor's recognized right to have what information it deems necessary to intelligently manage its land. (Title 30, Section 251.12, Code of Federal Regulations gives the Secretary the right to inspect and select for at least one year any or all geological or geophysical data collected by the lessee. This includes geophysical data, processed geophysical information and reprocessed information. It does not include interpreted geological or geophysical information. Data must be kept confidential for ten years after the issuance of the permit, and, then, processed, reprocessed and interpreted geophysical information is released to the public. Geological data and analyzed and interpreted geological information obtained from deep stratigraphic tests are released five years after completion of the test well or 60 calendar days after the issuance of the first Federal lease within 50 geographic miles of the test site, whichever is earlier.)

POSSIBLE AMENDMENT TO INCLUDE CONFIDENTIAL STATUTE AS 33.05.035

Section 2

Notice requirements of AS 33.05.135(b) retained for competitive sales; deleted for noncompetitive

Section 3

Upland acreage limitation reduced from 500,000 acres to 200,000 acres. Offshore maximum acreage remains at 500,000 acres.
AS 33.05.140(c)

Section 4

The priority given a Federal oil and gas offer to a state noncompetitive lease is extinguished. AS 33.05.145(b) This provision now provides that if lands on which a federal oil and gas noncompetitive lease offer exists is classified as competitive by the state within 90 days of receipt of tentative approval from Interior, the priority given the Federal offeror to a state noncompetitive lease is extinguished. I believe an AMENDMENT to HB 254 will be necessary to specify that as of the effective date of the Act all state lands will be classified as competitive. Thus, any lands which subsequently are tentatively approved will not grant a priority to a noncompetitive offer. Approximately 30 Federal offers have earned a preference right and will be awarded state noncompetitive leases under the existing law. The amendment will need to protect these existing rights.

HB 654 will also need an AMENDMENT to AS 33.05.100 which will specify the extension rights of existing state noncompetitive leaseholders. Under AS 33.05.130(c) upon expiration of the initial five-year term of a noncompetitive lease the lessee is entitled to a five-year extension unless the lands are determined to be competitive in which case the lease is extended for only two years.

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TO:

FROM:

LeRESCHÉ

RODERICK

The AMENDMENT should read:

"A noncompetitive lease existing at the affective date of this Act shall be extended for a period of two years and so long thereafter as oil and gas is produced in paying quantities. A noncompetitive lease extended under this paragraph is subject to the rules and regulations in force at the expiration of the initial five-year term of the lease. No extension may be granted, however, unless within a period of 90 days before the expiration date an application for extension is filed by the record title holder or an assignee whose assignment has been filed for approval, or an operator whose operating agreement has been filed for approval."

cc: J. P. Green

AGO 547063

TESTIMONY ON
ALASKA LEASING POLICY BILL
(H.B. 854)

By
Rod L. Boane
Alaska District Manager
Exxon Company, U.S.A.

Before The
State of Alaska
House Resources Committee

Juneau, Alaska

March 17, 1978

Mr. Chairman and Members of the Committee --

I am Rod L. Boane, District Manager for the Alaska Exploration District of Exxon Company, U.S.A. I appreciate the opportunity to be here today and present the views of my Company concerning the proposed Leasing Policy Bill.

First, let me say that Exxon believes the existing provisions of Section 38.05.180 of the Alaska Statutes are quite satisfactory in administering adequate control over exploratory and development activities on State leases. Therefore, we do not believe these new amendments to the Statutes are needed to protect the public interest. On the contrary, we think the proposed amendments would create unnecessarily involved and cumbersome procedures that will neither foster needed exploration nor benefit the State of Alaska. Although we take exception to almost all features of the proposed amendments, in the interest of time, I intend to discuss only the more troublesome provisions, with particular emphasis on the proposed bidding methods.

Exxon believes that the best method for awarding leases is on a cash bonus basis. This system has several advantages which I would like to review.

- o First, the successful bidder sees very strong incentives to explore and develop rapidly and to recover the maximum economic volume of hydrocarbons at the lowest possible cost. This is necessary in order for him to maximize the return on the cash bonus invested.

AGO 547115

- o Second, under the cash bonus system, the State bears none of the risk that commercial reserves will not be found. This risk is placed directly on industry where it belongs. This is a particularly critical concept in Alaska which is still essentially a frontier province where very little exploratory drilling has occurred and thus very little is known about the oil and gas potential of most of the State. When one further takes into account the fact that Alaska is a very high cost area due to its remoteness and harsh operating environment, it should be easy to see that the exploration risks and costs are indeed great. The Gulf of Alaska history should prove this point as, thus far, no commercial discovery has been made.

- o Third, under the cash bonus system there is no possible way that the awards will be made in an arbitrary manner since the highest bid is obvious.

- o Finally, the system is simple and inexpensive to administer, and its integrity is unaffected by future events. The State would not have to expand its staff to implement this system.

Now I would like to compare the alternate bidding methods proposed in this legislation to conventional cash bonus bidding with fixed royalty. Basically, the proposed alternative bidding methods fall into one of three categories. The first category involves some form of royalty bidding. The second category uses

some form of net-profit bidding. The third category uses some form of work commitment. All three categories require a cash bonus, either as a bid variable or a fixed amount. Let's first examine the royalty bidding systems.

(1) It is not uncommon for operators to discover reserves of lesser magnitude than anticipated. With high fixed royalty, some of these discoveries could not be developed profitably unless the State agreed to accept a lower royalty than originally bid. Downward adjustment in royalty rate prior to any development would be difficult to administer and could undermine the integrity of this bidding system.

(2) With royalty bidding, the successful bidder does not have a strong incentive for rapid exploration and development since front-end cash investment is small. Speculators could therefore see incentives to acquire leasehold interest, and then wait in hopes that they will be able to cash in on the discoveries made by others. This situation would obviously result in delayed exploration and development activities.

(3) With exclusive royalty bidding, the public bears the major portion of the exploration risk because if the tract doesn't contain commercial hydrocarbon reserves, as the majority will not, the public receives no compensation whatever. As an example, the State received \$900 million in bonus for acreage on the North Slope in the September 1969 sale. Under a royalty bidding system the State would have received little income to date. We strongly believe that risk-taking and its associated rewards or losses are more properly the province of private enterprise.

The second royalty bidding system involves a sliding scale royalty system which would be difficult to monitor and, practically speaking, would make it impossible to compare bids unless you know the total reserves, the price at which production would be sold, and the rate of production. Sliding royalty could result in widely differing positions on prudent development. Also, unitization of tracts would be a very complex and difficult job.

With these comments in mind, let's review recent experience with royalty bidding in the Federal sector. A program of experimentation began with the recent sale in the Lower Cook Inlet. Thirty-four percent of the tracts were put up for royalty bidding. Selection of these tracts was in such a manner that they were scattered over the entire sale area. When this type of tract distribution is coupled with a forced unitization lease stipulation, it is not difficult to conclude that the owners of the royalty tracts have no incentive for rapid evaluation. They can just sit back and wait for the owners of cash bonus tracts to do the initial drilling. They can then join the units covering any reservoirs that extend under their tract.

After the Cook Inlet sale, this problem apparently became obvious to the Department of Interior. For the North Atlantic Sale (Sale #42), they attempted to "fix" this problem by grouping the royalty tracts together and having them removed from the cash bonus tracts. They further expanded the experiment by having a group of cash bonus tracts that had a fixed royalty of 40 percent.

Industry comments relating to royalty bidding have apparently begun to create some concerns about this system. In the upcoming South Atlantic Sale (Sale #43), we see another attempt to "fix" difficulties in the previous system. Tracts are being offered by cash bonus bidding with a sliding scale royalty. They have attempted to "fix" the unitization problem by again grouping the sliding scale royalty tracts together. However, they did not address how a group of sliding scale royalty tracts or sliding scale royalty and cash bonus tracts would be unitized.

Now that this experimentation process has begun, we see the continuing creation of new difficulties and complexities as attempts are made to correct previous difficulties and problems. It appears that this process is going to have a "snow-balling" effect and may eventually reduce competition. In this situation, only the companies that can afford to dedicate a large professional staff to the long unitization negotiations and wait long periods for initial production will survive. This certainly does not promote increased competition.

Now let's look at the second bidding category a profit-sharing system, which has most of the same adverse characteristics as royalty bidding, but with four added complications and disadvantages.

(1) Using net profits will be much like selecting a contractor to perform a job. The operating efficiency of the bidder could become an important consideration in determining which of

several bidders had submitted the high bid inasmuch as the gross proceeds to be received by the public would be a direct function of the efficiency of the operator. Thus, the successful bidder would no longer be obvious. Since the relative operating efficiency of companies cannot be determined quantitatively, the Commissioner would be vulnerable to charges that bid awards were being made in an arbitrary or discriminatory manner.

(2) A profit-sharing system would be difficult and costly to administer. A large administrative organization would likely be established to audit and monitor the continuing activities of lessees. Discretionary judgments would be required by the State with regard to what costs were to be included or rejected in the profit base. This system could lead to State control of expenditures.

(3) A profit-sharing system would significantly reduce the incentive for a successful bidder to operate at maximum efficiency. Any prudent operator utilizes a priority system when restraints of either manpower or materials create limitations. When these restraints exist, net-profit tracts will have low priority. The result - reduction of efficiency. It would also reduce the timing and incentive for development of advanced technology currently in progress by industry.

(4) Most important, sharing in net profits would signal the State's entry into the production phase of the oil business. It might be politically and economically difficult for the State not

to be deeply involved in decisions about day-to-day operations and thereby become an operating partner. This step would not be consistent with the maintenance of a strong private enterprise system either within the oil industry or within the State itself.

The third category of bidding system is work commitment which can be combined with any of the other methods. A work commitment bid becomes a form of cash bonus bidding. If an operator has a high interest in a tract, he will bid a work commitment which is equivalent to what he would bid in a cash bonus system. In many instances, this commitment would be much larger than required for evaluation. If early exploration results are negative, the operator remains committed to drill more wells than would normally be prudent or necessary.

The provision that the Commissioner can terminate a work commitment further complicates the issue. Termination of a work commitment for one operator would undoubtedly result in inequities because he has received an unfair competitive advantage. Continuation of this practice could result in extremely high work commitments in anticipation of cancellation after performing only a portion of the work.

A work commitment bid will be nothing more than a form of cash bonus. The same result can be accomplished more easily and efficiently with a cash bonus bid.

Now I would like to discuss a few other provisions which give us concern.

(1) AS38.05.180(v) Right to Purchase - The provision gives the State the right to purchase not more than 16 2/3 percent of the oil and 100 percent of the gas. The most onerous portion of this provision is the right of the State to purchase 100 percent of the gas.

The present and potential supplies of gas within Alaska far exceed reasonably anticipated demands by the State residents. Therefore, to find a market, this gas will have to move into interstate commerce. This requirement, that the State could remove the gas from the market, could severely hamper a producer's ability to market the reserves. Without a reasonable expectation that the developed gas can be marketed, there is greatly reduced incentive to explore.

It would also retard development of natural gas for State residents. The risk that the gas could be diverted would have significant impact on ventures to install gas transportation systems.

In addition to these concerns, it raises other questions such as:

1. Determination of fair market value
2. Use of gas for lease fuel
3. Timing and rate of production - could the State control these to satisfy their own requirements or desires?

(2) AS380.05.180(w) - Exxon is strongly opposed to this proposed section which requires any lessee or permittee conducting exploration for, or development or production of, oil or gas on State land, to provide the Commissioner access to all data obtained from such activity and to provide copies of such specified data, as the Commissioner may request. Access to all data could potentially permit endless intrusions into private business. Much of this data is very costly. In a competitive industry such as ours, a considerable amount of data is proprietary. Disclosure of this type of data could result in the loss of a competitive edge. In none of the other producing states are operators required to provide access to all data. In addition, we feel that any such requirement would, in effect, constitute a "taking" for which compensation by the State would be required. We believe this proposed amendment is unnecessary and should be deleted because the existing regulations provide the State with adequate control over exploration and development activities.

(3) AS38.05.100(1) - We are strongly opposed to the concept of earning production rights only to the depth drilled at the beginning of production from a lease. We are not aware of this language in lease forms for any other producing state.

This language is somewhat similar to that commonly used by a lessee in "farming out" acreage for the purpose of evaluating specific geologic objectives by a third party. In a frontier

province like Alaska it doesn't make any sense to place such restrictions in the lease form. The idea should be to give the lessee maximum flexibility in evaluating his acreage - not to curtail or to require unreasonable and costly actions on his part. We, therefore, strongly suggest that this language be deleted.

We also recommend that reworking be added to the list of actions which will hold a lease in force. In fact, a grace period of 60 days should be allowed between cessation of production and initiation of drilling or reworking operations. This useful and desirable feature is in the present law.

(4) AS38.05.180(j) Lease Term - A five-year primary lease term is very restrictive in Alaska. The remote location of most prospects, rugged terrain, short construction season, and reduced drilling season, either necessary or imposed, make completion of the exploration cycle a difficult and time-consuming process. Once a discovery is made, additional drilling is required before an estimate of the field size can be made. All of the previously mentioned factors affect this drilling too. Once the lengthy process of discovering a field and establishing its commerciality is complete, the long development phase must begin. We strongly recommend that the 10-year lease term be retained.

(5) AS38.05.180(c) Uplands Acreage Limitation - The proposed 200,000-acre limitation on all lands other than tide and submerged lands is very restrictive compared with the current 500,000-acre limitation in a State like Alaska which has so many frontier

interior basins to explore. In a hostile high cost environment such as Alaska, a large block of acreage may be necessary in order to justify exploration. We believe the proposed 200,000-acre limitation would be a strong disincentive of an operator to explore these frontier interior basins and strongly recommend maintenance of the current 500,000-acre limitation.

(6) AS38.05.180(u) Joint Bidding - The provision allowing the Commissioner to restrict joint bidding, if he so desires, could prohibit the involvement of some companies most capable of operating in the Alaskan environment.

A study was performed by the University of Southern California and the USGS to determine the effects of restricting majors from bidding jointly in the OCS. They concluded that on the average, this restriction resulted in more bids per lease by the major oil companies.

(7) Legislative Review - We object to the requirement for submission of the leasing program for annual review by the Legislature because we believe it will result in unnecessary delays in implementing leasing programs.

(8) AS38.05.180(q) Drilling and Development Contracts - The proposed amendment which would allow the State to share in exploration costs is inconsistent with the provisions of the lease agreement, as the State's royalty interest is free of all exploration

and development costs. If this is intended to allow the State to share in working interest, we are opposed since it would signal entrance of State Government into the oil and gas business.

In closing, I would like to reiterate that Exxon believes the current leasing statutes and the implementing and regulations have served the State and industry well and do not need to be changed.

Passage of this bill will require the State to embark into an experimental program. Because these systems are unknown, many mistakes will be made. New "wrinkles" will be tried in order to correct these mistakes. In fact, the State of Alaska will find itself taking a course which is identical to the course presently being followed by the Federal Government. The end result will be an extremely complex system which may allow only a few companies to survive.

This concludes my prepared testimony, and I will be happy to answer any questions which you may have.

* * * * *

TESTIMONY ON H.B. 854

Mr. Chairman, members of the committee, my name is John Carson, and I appreciate the opportunity to comment on House Bill 854.

I've been a petroleum geologist for 22 years, and I'm presently Division Geologist in Alaska for Chevron U.S.A., the principal domestic oil and gas subsidiary of the Standard Oil Company of California. I've lived and worked in this state, and since 1965, I've been actively involved in all state lease sales and the two OCS sales in the Gulf of Alaska and the Lower Cook Inlet.

Chevron is aware of the amount of preliminary work done by the state administration and the Department of Natural Resources in researching and drafting this legislation.

We commend efforts in drafting legislation that proposes a five-year leasing program for Alaska. We believe the state should be encouraged in its effort to establish and maintain such a long-term program, with appropriate industry participation.

Members of the committee, the petroleum industry--as indicated by its response to your solicitations--clearly desires a realistic plan that can serve as the basis for an effective working relationship between the industry and the state.

Frankly, we believe the proposed legislation will inhibit or prevent orderly development of oil and gas resources in Alaska--to the detriment of the state government, its taxpayers and my own industry.

I will say candidly that this legislation is untenable from our point of view. If enacted into law, H.B. 854 would have a serious and far-reaching impact on my own company, and would give us serious cause to reconsider our exploration activities in the high-cost, high-risk frontier state lands of Alaska.

The situation we face today reminds me of a quote I heard the other day attributed to an executive of Walt Disney Productions, which recently announced that it was abandoning its latest recreation complex because of excessive and oppressive regulation.

The Walt Disney executive blamed the end of the project on, and I quote: "An irresponsible proliferation of delays, the never-ending requests for more irrelevant information and studies, and bureaucratic sidetracking and meanderings into unreasonable alternatives."

I realize this is the first of many hearings on this legislation, but H.B. 854, as now written, would be counter-productive. It actually would be a step backward at the very time our nation desperately needs an effective oil and gas exploration program.

Generally stated, we object to provisions covering: 1) the wide variety of bidding methods to be employed; 2) the Commissioner's access to all the lessee's data, including proprietary data; 3) the state's call on production; 4) short and restrictive lease term and conditions; 5) the need for the Commissioner to submit and defend his lease plan before the legislature; 6) the Commissioner's right to ban joint bidding by major companies; and 7) reduced acreage chargeability on state uplands.

Time does not permit me to discuss in detail each of the provisions, but I will attempt to outline our most significant objections:

First, the wide variety of bidding methods:

In advocating numerous bidding schemes--actually a shift from only cash bonus bidding, a system that has worked well--the administration hopes to maximize its financial return from state lands.

But Chevron believes a move away from the cash bonus method means the perilous abandonment of a proven concept that has brought stability to the state's leasing program. The bonus system would be replaced by an array of untested leasing methods, particularly in the frontier areas.

We believe this provision, if enacted, will transform Alaska into a trial-and-error laboratory in oil and gas leasing. It means replacing orderly development with uncertainty and the unknown. It's not a gamble Chevron feels is worth taking.

Before discussing each bidding system, all concerned parties should be aware that a move away from cash bonus bidding will result in three key developments:

First, it will shift a substantial part of the burden of risk from industry to the taxpayer.

Second, it will serve as a substantial deterrent to exploration and development, and

Third, it will cause the rapid and constant growth of state agencies to administer, evaluate and audit the leases and subsequent production. This places increasing demands on taxpayers to support this bureaucracy.

Chevron believes these are unacceptable consequences which would be intolerable to the taxpayers and leaders of this state.

As you know, cash bonus bidding provides that leases be awarded to the highest cash bonus bidder. This bonus is paid before the lessee can proceed with exploratory drilling on the lease.

The other bid methods provide for bid variables such as royalty, net profit, or work commitment. In these cases, the state receives nothing other than perhaps a small fixed bonus at the time of leasing. Other revenue is not forthcoming under the royalty and net profit schemes unless there is production. Simply stated: No production, no revenue.

In our opinion, cash bonus bidding is the only method that will strongly encourage the petroleum industry to lease and explore the state land.

We further believe that this method will result in the production of the most oil and gas and consequently will provide the most revenue, both to the state and the petroleum industry.

The other methods, employing biddable royalties and net profits, reduce the incentive to explore and produce. These alternatives, particularly in the case of biddable royalties, serve to shorten the economic life of the fields--resulting in less production and, therefore, less revenue.

Cash bonus bidding is particularly advantageous to the lessor in frontier areas of high risk. Most of Alaska's lands are in this category.

Now let's compare other proposed bidding methods with traditional cash bonus bidding. Because of time limitations, I can only touch briefly on these, but I am prepared to go into more detail if questions arise.

The royalty bidding method, although it allows oil and gas companies to acquire land with little cash, is a strong deterrent to early drilling. Very simply, it is easier and cheaper to wait on others to bear the risk and expense of exploratory drilling.

Having spent little capital to acquire the lease, an operator is tempted not to spend a dime to evaluate the lease, hoping an adjacent leaseholder may do it for him. Carried to the extreme, the effect of this would be that no wells would be drilled to evaluate the leases. This same problem is inherent in the net profits system, which I'll talk about shortly. On the other hand, when cash bonus is involved, the winning bidder has a strong incentive for early drilling because his bonus investment is earning him nothing.

In cash bonus bidding the state assumes none of the risk but still receives revenue from leases, whether or not they are productive.

The advantages of this system were clearly demonstrated a few years ago in the sale of federal leases off the coasts to Mississippi, Florida and Louisiana. Successful bidders paid \$743 million for several tracts on one structure, the Destin Anticline, and spent over 10 million dollars drilling seven dry holes on the structure--all at no cost to the taxpayer. Under royalty or net profit bidding, the government would have received nothing.

What would government have received if it had sold the Gulf of Alaska on a royalty bid basis? As in the Gulf of Mexico case I previously cited, nothing. Should the taxpayer and the government be forced to suffer the loss of more than one-half billion dollars--when to date, no royalty appears forthcoming?

The NPRA comes to mind as another example of an area adjudged to possess high potential, but which so far is a disappointment. Again, if sold on a royalty bidding method, the lessors would have received nothing to date.

Let me emphasize that in all these cases, the areas were considered extremely attractive to both the industry and government. These are precisely the types of areas in which the state might be enticed to use a royalty or net profit bidding method. Yet none of these has led to any discovery or government revenue.

Proponents of royalty bidding believe it encourages competition among bidders and allows the small company and the independent improved entry into oil and gas lease bidding. Cash bonus bidding usually is blamed for tending to discourage small companies from bidding.

This is not supported by the facts. Small companies gain entry into the sale by joining with a larger company or with several other smaller companies. In the recent Lower Cook Inlet sale, independents and smaller companies bid on royalty and cash bonus tracts with about the same frequency as the majors. Of the 34 companies which bid in the sale, 18 were smaller companies. These 18 made successful cash bonus bids on 26 tracts, of which 13 were sold for more than one million dollars. Moreover, the small companies are represented in half of the top tracts of the sale.

The second proposed bidding method we are concerned about is net profit bidding. This system has most of the disadvantages of royalty bidding plus two more: It requires a huge staff to administer and audit.

For example, each property would require a battery of accountants to audit the companies' production and costs. Just as in the case of royalty bidding, the risks are passed on to the government. Furthermore, net profit bidding discourages cost-effective, efficient development practices.

We. Commitment bidding is the least onerous alternative to cash bonus bidding methods and would be beneficial, provided that it is enforceable. We view this method with some caution because of the uncertainty of the conditions under which it might be imposed.

At this point, I would like to summarize why we believe a majority of the industry prefers cash bonus as the best method for both the state and the energy explorers.

First, we believe it is the foundation for all free enterprise contract arrangements;

Second, it is the simplest and easiest to determine and administer by all parties;

Third, it is fair and equitable; by this I mean that all parties travel at their own risk, and finally,

The right to explore is paid for in advance.

In 1977 the Department of Natural Resources completed a report entitled, "A Study of Petroleum Leasing Methods and Possible Alternatives." H.B. 854 apparently is based on this study and its conclusions.

In this study, a great deal of attention is given to the "percentage of acreage option." We assume this is the reason for granting the Commissioner authority to withhold acreage from any sale areas under Section 180 (c) (4) (f). Under this scheme, certain amounts of acreage would be withheld from a sale so that following a discovery the state could collect a windfall on drainage acreage sales. This is a workable approach only if you know which acreage to withhold and on which structures. This is rarely the case, as we saw in the MAFLA, Gulf of Alaska and NPRA. Furthermore, industry cannot bid or drill on only portions of prospects in high risk or high cost areas which predominate in Alaska.

I would like to make a few more comments about the Department of Natural Resources' report. The one overriding conclusion of that study was that a variety of bidding methods, widely employed, would increase the state's return from its commitment of oil and gas properties.

Chevron believes this conclusion is biased against cash bonus bidding, and we feel that the odds are against anyone knowing all they need to know to use the right method at the right time. The state, even if armed with a skilled staff and large amounts of data, can hope to do no better than an individual company in evaluating potential and risks, and these companies are more often wrong than right in their appraisals.

We believe the state's report, and particularly its main bias against cash bonus bidding, is based on a few but major faulty economic assumptions.

First, the authors of the report assume that the industry will make an 18 percent rate of return. Although this is very desirable, and would not be out of line considering the high risk involved, past experience shows that the industry has averaged no more than seven to eight percent from OCS ventures which approximates Alaska lands, according to several exhaustive studies. For example, in May 1977 Prof. Walter J. Mead of U.C. Santa Barbara testified before a U.S. House of Representatives Committee that weighted average rate of return from 184 leases issued in the Gulf of Mexico in 1954-55 amounted to only 7½ percent before taxes. This sale period was selected because these leases have a 20-year production history which provides a comprehensive data base.

Second, no reduction of state income was assumed in royalty cases, but it almost certainly will occur. The economic limit of a field is going to be greatly influenced by the amount of royalty. The higher the royalty, the earlier the economic limit is reached. When an operator can no longer produce oil or gas profitably the result will be oil and gas left in the ground and neither industry, nor the state, will make any money on it.

* * *

Next, I would like to turn to the provision of the bill that would require the lessee or permittee to make available to the Commissioner all data obtained from exploration and production activities on the lease or permit. We believe this provision raises fundamental questions about the appropriateness of the state's entry into the exploration business, and secondly, points to grave problems—from our point of view—about the preservation of confidentiality.

(subsection (aa))

should but

The language in the proposed legislation does not distinguish between, "raw", "processed" and "interpretative" data. We are unalterably opposed to providing the state with the results of the efforts of our interpretative staff. Industry cannot operate under this law. We urge the committee to delete this section.

We are also opposed to giving the state our basic geophysical data. We are not convinced that the state can hold this data confidential because of its large staff and turnover rate. Any leak of this sensitive information to our competitors definitely will have an immediate and adverse impact on our exploration program in this state.

The third provision we object to (Sec. 38.05.180(v)) gives the state the right to purchase up to 16 and two-thirds percent of the lessee's share of the oil and up to 100 percent of the lessee's gas.

We are not opposed to the state's right to take its royalty share of oil or gas in kind, but we oppose any provisions which empowers the state to take any portion of the lessee's share.

In order to justify the risk and expense of exploration and development, and be able to satisfy its contractual commitments, the lessee must retain the right to dispose of all of its share of production. Without this right, the state of Alaska lands become less desirable to explore and develop. We believe this is another step toward the state's entry into the oil and gas business, which should stay with private industry.

It seems inconceivable to Chevron that the state would take a portion of the lessee's share when that is the very incentive for industry to explore in the state initially.

Another provision we oppose is Paragraph Q. Paragraph Q refers to drilling and development contracts and to the authority of the state to share in the cost of exploration.

We're not clear on the meaning and intent of this paragraph. If it means the state intends to become a working interest participant in leases, then we strongly object.

Our next objection concerns the terms and conditions of the lease itself. Because of the remoteness of most of Alaska's land and the seasonal restriction on operations, Chevron prefers a ten-year primary lease term. We feel this length of time is necessary to adequately evaluate a lease under Alaskan conditions.

There is one provision which would allow the Commissioner to grant rights on leases only to the depth drilled at the time production begins. Chevron is at a total loss to see how this provision can benefit the state in any way. It will certainly cause waste in time and money for the industry because wells will be drilled far beyond primary objectives-- just to ensure earning the rights of a normal lease. In effect, this will delay production and thereby delay revenue to the state.

Considering the geological, legal and practical ramifications of this provision, one must conclude that it is totally unacceptable to the industry and can do the state no good. It should be stricken from the bill.

Our next objection is to any effort to restrict joint bidding between majors or multinational companies. In Alaska, particularly, with its accompanying expensive costs of exploration and production, it is essential for large and small companies to be able to join together to share the risk.

A ban on joint bidding by majors does not necessarily increase state income. In fact, a recent study by the Department of Interior showed that joint bidders tend to bid higher, on the average, than solo bidding competitors. (November 1976 issue of the Journal of Petroleum Technology.)

The next provision we wish to discuss deals with the need for the Commissioner to submit and defend his leasing program to the legislature. We prefer that the various reporting methods set out in this section not be prescribed in law. We believe this review is an administrative function and that public hearings are an adequate and effective vehicle for gathering comments and reactions to the proposed action. Neither the timber leases nor any other types of state lease are submitted to the legislature, and to require this approach in law for the petroleum industry will lead to further delays in development of the state's natural resources. Particularly objectionable to us is the requirement that the Commissioner must defend his previous year's program and explain why he used certain methods. This is certain to toss the entire leasing program into an interminable bureaucratic morass.

And finally we oppose the provision which deals with acreage chargeability. We believe the reduction to 200,000 acre limitation on uplands is arbitrary and unjustified. The 500,000 acre limitation in this state, where there are large areas of state lands potentially available for bid, is not unreasonable. A large acreage position is necessary as an incentive for an operator to explore frontier areas.

In closing, Mr. Chairman, Chevron believes H.B. 854 is an unreasonable, unwise and unworkable piece of legislation that simply is not in the best interest of the citizens of Alaska.

As I said at the outset of my remarks, my own company would be faced with the prospect of seriously reassessing its current and future exploration activities on Alaska state lands if this bill is enacted.

It is our opinion that this legislation will only serve to inhibit or prevent the orderly exploration and development of Alaska's oil and gas properties.

We oppose a shift away from the successful cash bonus bidding system because we believe that the cash bonus ensures a fair and equitable return to the state, as well as ensuring the fair share of any revenue resulting from production.

It is conceivable that Prudhoe Bay may not have been found if royalty or net profits bidding or percentage acreage option had been employed.

Mr. Chairman, members of the committee, we have serious concern that if this legislation becomes law, the ultimate losers will be the citizens of this state, as well as the consumers of oil and gas.

Thank you for giving Chevron this opportunity to comment on this proposed legislation.

* * *

Rep. Malone
File, HB
854.

EXPERIMENTATION IN ALASKA'S OIL AND GAS LEASING PROGRAM

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

Sohio Petroleum Company
Division of Sohio Natural Resources Company
SOHIO-BP ALASKA PRODUCTION DIVISION
3111 "C" Street
Anchorage, Alaska 99509

AGO 547140 +

EXPERIMENTATION IN ALASKA'S OIL AND GAS LEASING PROGRAM

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

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1. Suggested Amendments to H.B. 854.
2. M.I.T. Professor John W. Devarney III, "How to Bid for Offshore Rights," Technology Review, February 1976, p. 44.
3. "Alberta, Canada: Exploratory Drilling Incentive System," The Landman, March 1978, pp. 18-20.
4. Articles from Mineral Leasing as an Instrument of Public Policy, British Columbia Institute for Economic Policy Analysis, 1977:
 - Gregg K. Erickson, "Work Commitment Bidding"
 - Dale R. Jordan, "Petroleum Leasing in British Columbia"
 - Walter J. Mead, "Cash Bonus Bidding for Mineral Resources"
 - Arlon R. Tussing, "The Role of Public Enterprise"



SOHIO PETROLEUM COMPANY
Division of Sohio Natural Resources Company

3111 "C" STREET
ANCHORAGE, ALASKA

TELEPHONE (907)265-0000

MAIL: P. O. BOX 4-1379
ANCHORAGE, ALASKA 99509

SOHIO-BP ALASKA PRODUCTION DIVISION

March 28, 1978

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

Dear Rep. Osterback:

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

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

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

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

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

With regards,

AGO 547143

D.S. Mace
Assistant General Manager

PART I: AT THE CROSSROADS

I. THE IMPORTANCE OF OIL AND GAS POLICY DECISIONS

A. Global Prospects

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

- (1) All energy resources and conservation measures must be developed vigorously to meet total projected demand in the period 1985 - 2000; and
- (2) Energy policy decisions made now will be the critical determinants as to whether or not sufficient incremental supplies will be available to meet demand in the years ahead.

In other words; according to the WAES Report:

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

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

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

- (1) The supply of oil will fail to meet increasing demand before the year 2000, most probably between 1985 and 1995... (p.3)
- (2) Demand for energy will continue to grow even if governments adopt vigorous policies to conserve energy... (p. 4)
- (3) The continued growth of energy demand requires that energy resources be developed with the utmost vigor... (p.4)
- (4) Even if there are no governmental constraints on oil production, oil supply will meet demand only under the most optimistic assumptions about gross additions to reserves... (p.145)
- (5) Possible constraints on oil production by members of OPEC are likely to cause oil supply to peak at the latest some-time around 1990 although lower production limits could bring this date forward into the early 1980's... (p.145)
- (6) All the effort put into oil exploration around the world over the past one hundred years has only yielded 240 large oil fields... (p.123)
- (7) With only a small chance of either discovering a new Middle East or discoveries in the Middle East as large as in the past, the past rate of genuine new discoveries can only be achieved if a large number of smaller producing areas are found. (p.122)
- (8) Given lead times of 5-10 years or more for many projects, failure to make necessary near-term commitments or to resolve a variety of current restraints on production, or to develop future supplies may foreclose some options for 1985. (p.265)
- (9) Failure to recognize the importance and validity of these findings and to take appropriate and timely action will almost certainly result in a world different from the one on which these projections have been based. (p.5)
- (10) Failure to act could lead to substantially higher energy prices as the supply/demand imbalance becomes more apparent with the consequent frustration of the aspirations of the less developed countries. The major political and social difficulties that might arise could cause energy to become a focus for confrontation and conflict. (p.5)
- (11) The longer the world delays facing this issue the more serious the outcome will be. Even with prompt action the margin between success and failure in the 1985-2000 period is slim. Time has become one of the most precious of our resources. (p.5) 2/ (Emphasis added)

2/ Ibid., pages as indicated above.

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

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

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

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

3/ Ibid., p.123

4/ Ibid.

B. Alaskan Outlook

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

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

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

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

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

C. Implications

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

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

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

A. Objectives Outlined for H.B. 854

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

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

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

- (A) maximize the economic recovery of these natural resources in protection of the public interest;
- (B) minimize the exploitation of these natural resources in protection of the public interest;
- (C) maximize competition among parties seeking to explore and develop the resources;
- (D) maximize use of Alaska's human resources;

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

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

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

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

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

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

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

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

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

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

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

B. Objectives Related to Federal Legislation

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

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

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

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

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

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

7/ Ibid., pp. 168-169

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

C. Alaska's Leasing Objectives: Problems and Priorities

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

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

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

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

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

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

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

III. BROAD ISSUES AND OBJECTIVES

A. Data Acquisition: How Useful?

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

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

"...while the technology for oil exploration prior to the drilling has been advanced in the last century, exploration is still subject to 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..." 9/ (Emphasis added)

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

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

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

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

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

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

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

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

B. Experimentation in Leasing: How Successful?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Any argument for the adoption of such a system must first establish that this is in fact the case..." 16/

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

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

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

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

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

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

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

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

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

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

C. Oil and Gas Leasing: How Competitive?

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

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

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

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

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

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

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

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

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

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

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

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

Major conclusions were:

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

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

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

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

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

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

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

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

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

I. PROPOSED AMENDMENTS TO MAJOR PROVISIONS

A. Objectives (findings):

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

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

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

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

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

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

B. Procedures

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

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

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

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

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

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

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

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

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

C. Lease Methods

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

D. Reduction of Royalty

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

E. Bonus Bid Deferral

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

F. Withholding Acreage

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

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

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

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

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

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

G. Exploration Work Credit Program

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

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

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

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

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

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

H. Terms and Regulations

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

I. Lease Terms

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

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

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

J. 90-Day Provision

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

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

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

K. Commissioner's Role in Conservation

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

L. Noncompetitive Leasing

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

M. Joint Bidding Prohibitions

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

N. State's Right to Purchase Oil and Gas

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

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

O. Data

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

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

P. Acreage Limitations

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

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

AGO 547178

II. SUMMARY AND CONCLUSIONS

In summary, we would offer these observations and conclusions:

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

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

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

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

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

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

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



April 6, 1978

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

Dear Chairman Osterback:

Recently, Mr. Mark Singletary provided the Resources Committee with verbal testimony reflecting Atlantic Richfield Company's reaction to proposals contained in HB 854.

Attached is written commentary on HB 854 which I would respectfully request that the Committee consider and include in the official record of these proceedings.

Sincerely,

Dave Harbour
Director
Alaska State and Local
Government Relations

ATLANTIC RICHFIELD COMPANY COMMENTS ON
HOUSE BILL 854

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

April 6, 1978

Comments on Section 1:

Sec. 38.05.180(a)(1)(B)

In the description of the legislative purposes of this bill, there is a negative connotation given the word "exploitation" in Sec. 38.05.180(a)(1)(B). This section in general suggests sinister motives to the oil and gas industry which need to be "minimized." A possible modification should read, "regulate the development of these natural resources in protection of the public interest."

Sec. 38.05.180(a)(2)

Underlying this section is the notion that it is in the State's best interest to maximize the leasing methods available to the State. However, it is our view that the new leasing methods proposed are largely untested and may result in reduced revenues to the State. Further, it is not at all clear how a unit agreement could ever be formulated for a group of lessees who had obtained their leases under a combination of the proposed bidding methods.

Sec. 38.05.180(b)

AGO 547182

This section deals with the Commissioner's obligations to prepare a leasing program for the following 5 year period and his obligation to keep the legislature informed. We are in favor of such a long-range leasing program and support the State's acknowledged

goal of "stability and predictability" in a petroleum leasing program. However, the long-range benefits intended and the State's goal are frustrated by the ability, and, indeed requirement, that the Commissioner review and possibly revise the leasing program at least annually. Perhaps the possibility of revision could be limited to the last two years of the ongoing five year programs so that industry could expend exploration dollars with some certainty that a sale will be held. Alternatively, Sec. 38.05.180(b)(3) should be deleted.

The annual submission to the legislature of the leasing program, although for "its information," would seem to presuppose further modification of the leasing program. Again, opportunity for yearly modification of the leasing program abrogates the State's goal of a stable and predictable petroleum leasing system. As an alternative to reporting to the legislature, the Commissioner could be required to make an annual public report of the leasing program.

Additionally, in Sec. 38.05.180(b)(5)(E), the Commissioner is required to justify in his report to the legislature why more than 50 percent of an area is leased under any one method of leasing. This requirement of justification seems to be an incentive, if not explicit direction, to utilize the full array of leasing alternatives for any one sale and to, in effect, "experiment".

The language in Sec. 38.05.180(b)(2) is extremely confusing and should be clarified. Further, it is not clear whether or not this section is directed to or will have any effect, intended or otherwise, on the Beaufort Sea sale.

Sec. 38.05.180(c)

This section authorizes four generic categories or methods of leasing: (1) "Bonus bidding," (2) "Royalty bidding," (3) "Net profit bidding," and (4) a "Work commitment bid." Several combinations or variations of methods are authorized under each of the generic headings.

The first method of conventional bonus bidding has the best overall record from the lessor's standpoint. A study of federal OCS sales through 1975 showed that industry had invested \$35 billion in bonuses, exploration and development on OCS leases while receiving \$22 billion in revenue. |

Net profit bidding opens up a multitude of problems as to the definition of "net profit." This method would allow many companies to get into a land position for speculative purposes. It is a

fierce deterrent to early drilling as it is far easier and cheaper to wait out the competition. It is extremely cumbersome to administer and audit, and is even more costly to operate than royalty bidding methods.

The last method of bidding, a work commitment for a lease which cannot, by definition, exceed 5,760 acres, seems completely unworkable as such an area is much too small. This method is usually used in European and mid-east concessions or Canadian permits or reservations which share a common characteristic of being very large geographic areas.

In each of the four leasing methods, the language describing the State's royalty is troublesome. Each description of the State's royalty provides, "... royalty share reserved to the state of not less than 12 1/2 cent in amount or value of the production removed or sold from the lease or unit area encompassing the lease" (emphasis added) This language would preclude anything but 100 percent state units. Unitization of lands involving federal or native lands and state lands would be impossible because of the inability of the participants to give the state at least 12-1/2 percent of the production from the "unit area encompassing the [state] lease."

Further, it should be noted that all of the methods and components of the alternate leasing methods will necessitate substantial increases in the budgets and personnel of the agencies involved.

Finally, if some minimum flexibility in leasing methods is desired, the same could be accomplished with minor changes in the existing law.

Sec. 38.05.180(d)

This section allows the Commissioner to reduce royalty when production becomes uneconomical, but only after two years of production. The most recent federal leases require only one year of production, which would be more in line with the stated goal of the bill to minimize revenue from marginal production. Given the explicit description of the royalty in Sec. 38.05.180(c) as "not less than 12 1/2 percent ...," it is not clear whether the Commissioner could ever reduce royalty to any figure below 12 1/2 percent.

Sec. 38.05.180(e)

This section purportedly authorizes the Commissioner to defer payment of any part of a cash bonus bid, provided the bonus is paid within five years. This authority is in direct conflict with AS 38.05.335(c), neither referenced nor repealed by the bill, which requires a deposit of 20 percent, in cash, of the bid.

Sec. 38.05.180(f)

This section authorizes the Commissioner to withhold acreage from leasing in a particular sale. It is assumed that the motive of

this provision is a desire to increase the state's income from leasing by leasing, for example, only part of a structure, and then, once proven productive, leasing the remainder for higher amounts. However, this authority to withhold acreage can just as easily decrease the state's income, in the event the first acreage leased is found non-productive.-- which is usually the case. In essence, this section is authorization for the Commissioner to "gamble" on the productivity of state lands.

This section also seems unfair to the first lessees, who, if the first tracts leased prove productive, are faced with the prospect of having to buy themselves back into the fruits of their own risk at a higher rate.

Sec.'s 38.05.180(g) and (h)

These sections relate net profits and work commitment leasing which, as previously discussed, are ill-advised.

Sec. 38.05.180(i)

There are no objections to this section so long as the trading or storage of royalty oil remains and is clearly the subject of mutual agreement.

Sec. 38.05.180(j)

This section concerns several of the provisions to be included in state oil and gas leases:

First, this section reduces the primary term of state leases from 10 to 5 years. It should be understood that in most areas of Alaska the ability to carry out exploration work is limited to a four month period per year, consequently a five year lease allows only 1-2/3 years of exploratory work. This is clearly insufficient in such a high cost, high risk area.

Second, this section provides that a state lease will be "renewed", if and for so long thereafter as oil and gas is produced in paying quantities or if the lease is committed to a unit. The term "renewed" should be replaced with the term "extended" as this is the long-understood and recognized effect of production or commitment to a unit.

Third, the section's provision concerning shut-in wells should be clarified, since, in its present form, it appears as though the shut-in well must be located on the land prior to the issuance of a lease.

Fourth, this section authorizes the Commissioner to increase rentals up to 150 percent of the preceding year's rate and to provide that a lessee earns production rights only to the depth drilled at the beginning of production. Both of these provisions should be deleted as unnecessary and unworkable.

As to rental increases, as noted, Alaska is already a high cost, high risk area. The prospect of substantial rental increases

during the primary term of a lease will serve only to curb exploration not encourage it.

The provision concerning production rights only as to the depth drilled is unnecessary and unfair. Aside from an obvious example of the lessee drilling into the top of a reservoir and being mechanically unable to go deeper and thereby losing the main body of the reservoir, it also could result in split ownership of a lease with one party having to drill through another's rights to reach his own with possible damage to the upper reservoir resulting.

Finally, the means of extending a lease by drilling are set forth in this section. Given the seasonal nature of drilling in Alaska, the 90 day grace period after drilling has ceased should be expanded if further drilling is prevented by environmental considerations or other circumstances imposed by the State.

Sec. 38.05.180(k)

The increased rentals proposed in this section will discourage exploration and will not increase income to the State because the extra expense will be compensated by lower bid totals. The present \$1.00 per acre per year rental should be retained.

Further, this section alters substantially the nature of the ordinary rental provisions in oil and gas leases. The rental to be paid under these provisions is no longer a delay rental. This

section provides, "Rental is payable in advance and continues until income to the state from royalty, net profit, or exploration work commitment exceeds rental income to the state ... for three consecutive years" There is no provision for credit or set-off of rental paid during those three years against the state's income from production. Consequently, for the first three years of production, the state would receive both rental income and production income.

Sec. 38.05.180(1)

This section should be modified to provide that the state shall issue a State shorelands lease, as AS 38.05.180 presently reads. Also, the Commissioner should be given the discretion to grant a shorelands lease in excess of five years.

Sec.'s 38.05.180(m) and (n)

These two sections concern the unitization of state leases and are re-enactments of present law. However, given the alternate leasing methods of the bill, and the previously discussed, implicit direction to the Commissioner to "experiment" with these methods, unitization of state leases will be extremely difficult, if not impossible.

It is entirely reasonable to assume that under this bill, a proposed unit will be composed of leases involving highly disparate royalty percentages and one net profits or other kind

of lease. The extreme difficulty of applying these completely different lease burdens to the production allocated to each lease under a proposed unit are obvious. These difficulties constitute a disincentive to unitization and therefore nullify the conservation benefits of unitization.

Sec. 38.05.180(o)

This section concerns the acreage chargeability of KGS leases and is unobjectionable.

Sec. 38.05.180(p)

This section is a re-enactment of the present authorization for the pooling of state leases. Like the provisions concerning unitization, the problems inherent in alternate leasing methods will make pooling more difficult, to the detriment of the conservation objectives of pooling.

Sec. 38.05.180(q)

This section authorizes the State to share in the costs of exploration under a drilling or development contract. Oil and gas exploration is extremely risky and historically the province of private enterprise. Financial participation by the state in an exploration venture raises fundamental questions as to the appropriate role of state government. Given the fact that most wells drilled are unsuccessful, and the substantial sums involved in drilling in Alaska, additional challenges may be anticipated as to the authority or wisdom of the State to participate in a particular drilling project.

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Sec. 38.05.180(r)

This section is a re-enactment of present law concerning the sub-surface storage of oil or gas on state leases. However, the present law's provision concerning the extension of the lease used for storage for the period of storage and so long thereafter as oil and gas are produced was deleted. This extension provision should be retained.

Sec. 38.05.180(s)

This section concerns the employment of state residents on state leases is substantially the same as the existing law.

Sec. 38.05.180(t)

This section is an attempt by the state to encourage exploration on lands on which no bids have been tendered. This philosophy is laudable. However, the Commissioner should not be restricted by the leasing details of this section.

Sec. 38.05.180(u)

This section would restrict joint bidding and should be deleted. Joint bidding can very well be to the advantage of the state as it tends to increase the size of the bids submitted and facilitates the exploration process. See, for example, the paper in the November 1976 issue of "Journal of Petroleum Technology" in which the authors conclude that "joint bidders tend to bid on more sought-after (and apparently more valuable) leases and that they tend to bid higher, on the average, than solo-bidding

competitors". Industry testimony before the U.S. Senate has indicated that since the first OCS sale in 1954, 172 companies have purchased OCS leases. 42% of these leases were not purchased by the major companies, and in recent years the smaller companies have increased their share of OCS production at the expense of the major oil companies.)

Depending on the content of the regulations adopted, this section may violate Article 8, §17 of the Alaska Constitution. This Constitutional provision requires that laws and regulations governing the use or disposal of natural resources must apply equally to all persons "similarly situated".

Sec. 38.05.180(v)

This section grants the state an unfettered option to purchase 16-2/3 percent of oil and up to 100 percent of gas produced from a state lease. This section will in effect eliminate the lessee's ability to use the gas sales contract as a method of financing. Consequently, gas exploration in Alaska will be discouraged if not precluded. Similarly, if the state should wait several years before deciding to take up to 100 percent of the gas, the discoveror of a gas field would be deprived of all income from his legally obtained gas, because he could not enter into a contract with any other user. This section would also eliminate or impair the ability of lessees to utilize the production payment as a method of financing, likewise discouraging exploration.

Sec. 38.05.180(w) This section requires state access to all of a permittee or lessee's exploration data and should be eliminated from the bill. This section is, in essence, a confiscation of valuable proprietary data, for the sole purpose of deciding whether the explorer has found anything or not. If the state decides he has, the area could then be thrown open to all other competitors, thereby removing any incentive for an aggressive company to be a leader or employ innovative ideas to discover new resources. This section completely removes that incentive, and thereby will cause significant state natural resources to remain unsought.

In addition, grave problems as to the preservation of the confidential nature of the data are inherent in this section. It is common knowledge that such information is extremely confidential and closely guarded by the individual members of the industry.

The existing law upon which the oil and gas industry has relied for the confidentiality of information is contained in AS 38.05.035(a)(9)(C). This existing provision requires the director to keep geological, geophysical and engineering data confidential "upon request of the persons supplying the information." As the Bill's provision requires disclosure of information to the Commissioner, not the director, and since it requires also access, as distinct from supplying copies, are the confidentiality provisions incumbent upon the director not

applicable to the information required to be disclosed to the Commissioner?

If this section is to be applicable to existing exploration data, then the Commissioner's access and utilization of such existing data is almost certainly an unconstitutional taking of this valuable and expensive property. If the Commissioner is to be allowed access at all to such data, such access should be limited to future data only. Further, there should be a requirement of the adoption of regulations prescribing the confidentiality of this data and the addition of statutory criminal penalties for intentional disclosure of such data.

Section 2

There are no objections to this section concerning notice of mineral leasing.

Section 3

This section would amend AS 38.05.140(c) to reduce the upland acreage limitation from 500,000 acres to 200,000 acres. In Alaska, where there are large areas of state lands which are potentially eligible for bid, a 500,000 acre limitation, which the present statute contemplates, is not unreasonable. The effect of a 200,000 acre limitation would clearly be to limit the participation of those individuals who are most active in exploration business in Alaska, i.e., those individuals who have

historically submitted the highest bids to the state. It is not at all clear why the state would seek to discourage, rather than to encourage, the continued involvement of those individuals in Alaska. Further, this section's applicability to the holding of existing lessee's -- requiring them to reduce their holdings within 5 years -- is an unconstitutional taking of leasehold estates.

Prepared by:

Legislative Affairs Agency
Research Division
17 June 1978

Differences Between House and Senate
Versions of HB 854
(Page Numbers Refer to Side-by-Side Analysis)

Senate

House

1. Senate added word "physical"(p.1)
2. Gives legislature right to "veto" any part of leasing program (p.2).
3. Includes words "pipeline quality" in description of how royalty shall be delivered (p.4).
4. Sliding scale royalty allowed, with bonus as bid variable (p.4).
5. *REDUCTION OF WORKING COMMITMENTS* Sliding scale royalty allowed as bid variable (p.5).
6. Allows straight royalty bidding, but only in "drainage" situations (p.5). Allows straight royalty bidding (p.5).
7. Commissioner may defer bonus bid payment (p.8).
8. Calls generally for ten year term (p.9).
9. Rental terminates whenever royalty is greater (p.10). Rental terminates when royalty is greater for three consecutive years (p.10).
11. Includes provision for reduction of royalty (p.11).
12. Requires use of sliding scale royalty for reoffered leases (p.14).
13. Provides for possible restriction on joint bidding (p.14).
14. Provides for possible inclusion in lease of provision under which producers could be required to sell for instate use (p.14).

Senate

House

15. Changed "activity" to "lease" in section giving commissioner access to "noninterpretive data" (p.15).
16. Senate made technical amendment: "lands" to "land" (p.16).
17. Retains 500,000 acre limitation contained in current law (p.16).
18. Senate made conforming amendment to 38.05.140(d). Effect is to insure that (j) of both bills has intended result of setting standards for royalty reduction.

How to Bid for Offshore Rights

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

The Work Obligation Permit Plan

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

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

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

Royalty Bidding

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

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

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

tract; such oil will be more expensive than primary oil but still less costly than foreign crude.

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

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

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

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

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

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

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

ALBERTA, CANADA

Exploratory Drilling Incentive System

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

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

The department expects that the principles and details outlined here will be incorporated, without a change in mean-

ing, into the 1978 Regulation. If, however, such a change does occur, the 1978 Regulation would, of course, take precedence.

(1) Commencement Date of the Forthcoming Program

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

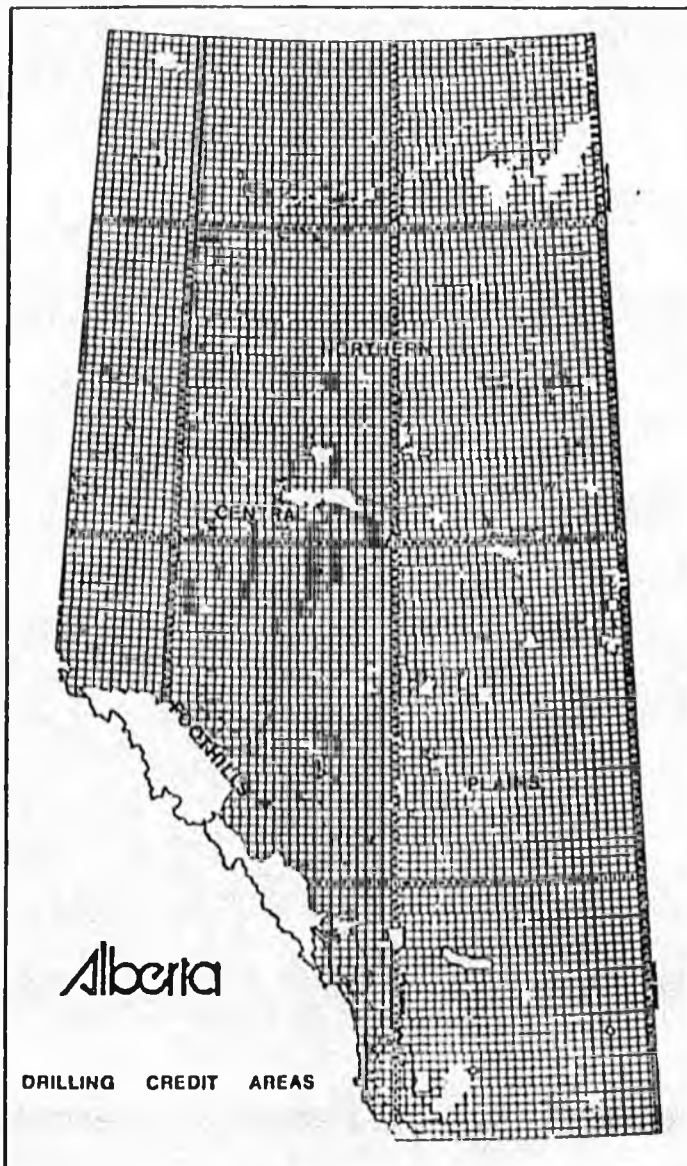


Figure 1

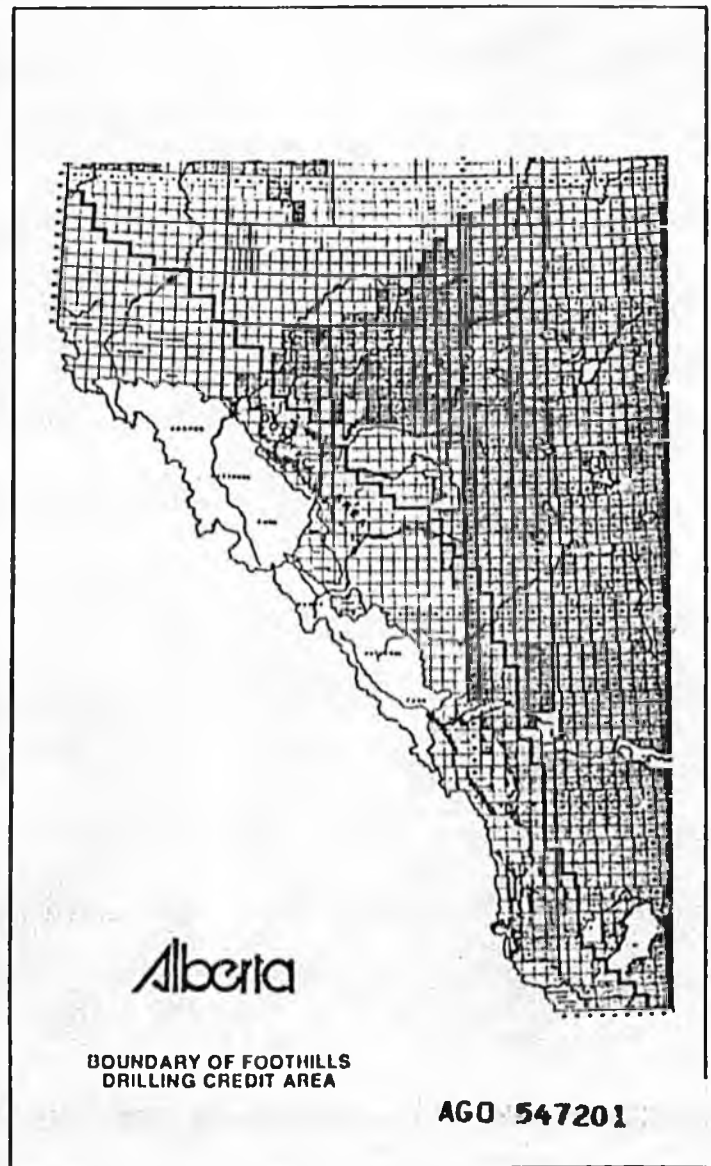


Figure 2

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

(2) Drilling Credit Areas

Figure 1 shows the drilling credit areas as they will be defined under the 1978

Regulation. The Plains and Foothills Areas have not been changed. The subsisting Northern Area, however has been divided into the new Central and Northern Areas shown by the illustration. The boundary between the two new areas was defined by the Department on the basis of well cost data and topographic and access considerations.

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

(3) Drilling Credit Schedules

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

SCHEDULE F						
Applicable to the Class A Interval of an Incentive Exploratory Well that Commences Drilling on or after January 1, 1978						
The Class A interval of an incentive exploratory well that commences drilling on or after January 1, 1978 shall be determined by the Board as the interval below the depth of 2,000 feet that						
(i) has not been duplicated by a drilled and abandoned well within one and one-half miles.						
(ii) occurs more than 500 feet below the base of the deepest accumulation of crude oil or natural gas that in the opinion of the Board has been penetrated by another well within three miles, and						
(iii) occurs immediately below the base of the member or formation containing the deepest oil sands deposit that in the opinion of the Board may underlie the location of the said incentive exploratory well.						
Where neither (ii) nor (iii) above applies, the Class A interval shall be determined from the depth of 2,000 feet to the total depth of the said incentive exploratory well.						
Depth, Feet	Basis for Credit Plains Area		Basis for Credit Central Area		Basis for Credit, Northern and Foothills Areas	
	Cumulative Dollars	Incremental \$/Foot	Cumulative Dollars	Incremental \$/Foot	Cumulative Dollars	Incremental \$/Foot
2,000	0	20	0	30	0	40
3,000	20,000	18	30,000	25	40,000	35
4,000	38,000	18	55,000	25	75,000	40
5,000	56,000	20	80,000	25	115,000	35
6,000	76,000	24	105,000	35	150,000	35
7,000	100,000	30	140,000	40	185,000	50
8,000	130,000	40	180,000	50	235,000	65
9,000	170,000	55	230,000	70	300,000	80
10,000	225,000	75	300,000	90	380,000	100
11,000	300,000	100	390,000	110	480,000	120
12,000	400,000	110	500,000	160	600,000	180
13,000	510,000	160	660,000	200	780,000	210
14,000	670,000	210	860,000	240	990,000	260
15,000	880,000	280	1,100,000	350	1,250,000	350
16,000	1,160,000	340	1,450,000	400	1,600,000	425
17,000	1,500,000	500	1,850,000	550	2,025,000	575
18,000	2,000,000	500	2,400,000	550	2,600,000	575

Figure 3

SCHEDULE G						
Applicable to the Class B Interval of an Incentive Exploratory Well that Commences Drilling on or after January 1, 1978						
The Class B interval of an incentive exploratory well that commences drilling on or after January 1, 1978 shall be determined by the Board as the interval below the depth of 2,000 feet that						
(i) has been duplicated by a drilled and abandoned well within one and one-half miles.						
(ii) occurs more than 500 feet below the base of the deepest accumulation of crude oil or natural gas that in the opinion of the Board has been penetrated by another well within three miles, and						
(iii) occurs immediately below the base of the member or formation containing the deepest oil sands deposit that in the opinion of the Board may underlie the location of the said incentive exploratory well.						
Where neither (ii) nor (iii) above applies, the Class B interval shall be determined from the depth of 2,000 feet to the total depth of the said incentive exploratory well.						
Depth, Feet	Basis for Credit Plains Area		Basis for Credit Central Area		Basis for Credit, Northern and Foothills Areas	
	Cumulative Dollars	Incremental \$/Foot	Cumulative Dollars	Incremental \$/Foot	Cumulative Dollars	Incremental \$/Foot
2,000	0	15	0	20	0	28
3,000	15,000	14	20,000	20	28,000	29
4,000	29,000	14	40,000	20	57,000	29
5,000	43,000	14	60,000	19	86,000	24
6,000	57,000	18	79,000	26	110,000	30
7,000	75,000	25	105,000	30	140,000	40
8,000	100,000	30	135,000	40	180,000	45
9,000	130,000	40	175,000	50	225,000	60
10,000	170,000	55	225,000	65	285,000	75
11,000	225,000	65	290,000	90	360,000	95
12,000	290,000	90	380,000	120	455,000	125
13,000	380,000	120	500,000	150	580,000	155
14,000	500,000	160	650,000	180	735,000	190
15,000	660,000	210	830,000	270	925,000	275
16,000	870,000	270	1,100,000	300	1,200,000	310
17,000	1,140,000	360	1,400,000	400	1,510,000	420
18,000	1,500,000	360	1,800,000	400	1,930,000	420

Figure 4

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

(4) Royalty Exemptions

(4.1) Eligibility

Crude oil or gas production must originate from a Class A or Class B interval to qualify for a royalty exemption. Production from any source shallower than 2,000 feet will thus not qualify for royalty exemption under the 1978 Regulation. An exception to the foregoing exclusion is found under the following circumstances: If conventional crude oil is produced from a source shallower than

2,000 feet in the new Northern Area, and if the 2,000-foot interval would have qualified as Class A or Class B footage pursuant to the 1974 Regulations, the crude oil production will be eligible for the normal royalty exemption applicable to deeper production.

(4.2) Duration

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

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

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

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

Work Commitment Bidding

GREGG K. ERICKSON

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

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

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

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

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

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

EVALUATION OF WORK COMMITMENT BIDDING

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

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

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

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

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

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

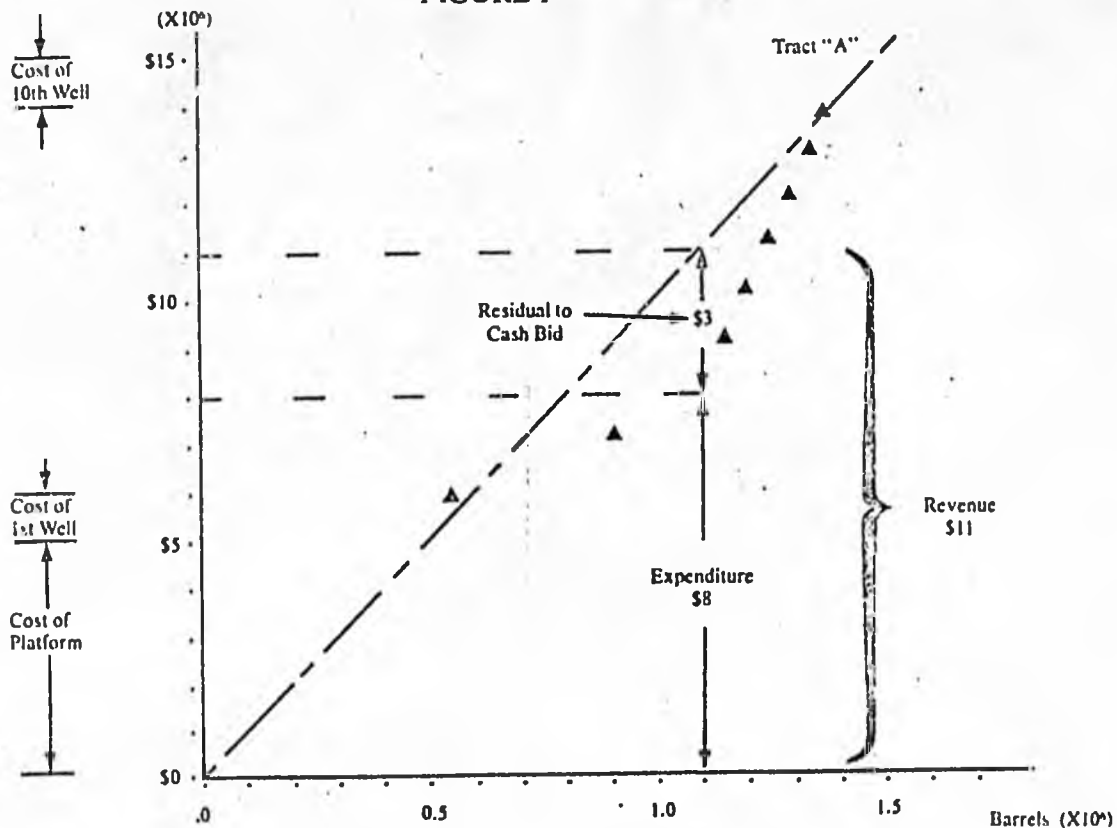
This is most easily demonstrated with a numerical example. Let us assume that a prospective bidder, in determining how much of a cash bonus he can offer for an oil and gas lease on a hypothetical tract A, has calculated the relationship between expenditures on development of the tract and expected production,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

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

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

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

FIGURE 1



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

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

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

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

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

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

FIGURE 2

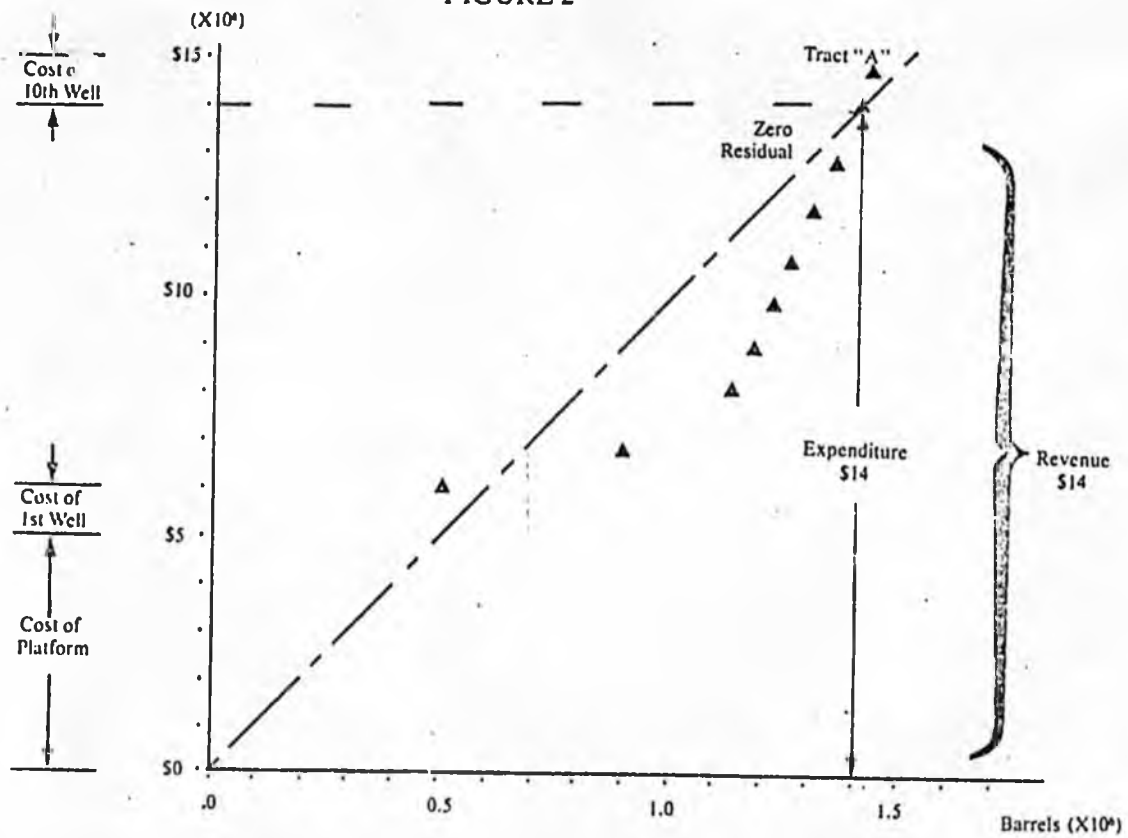
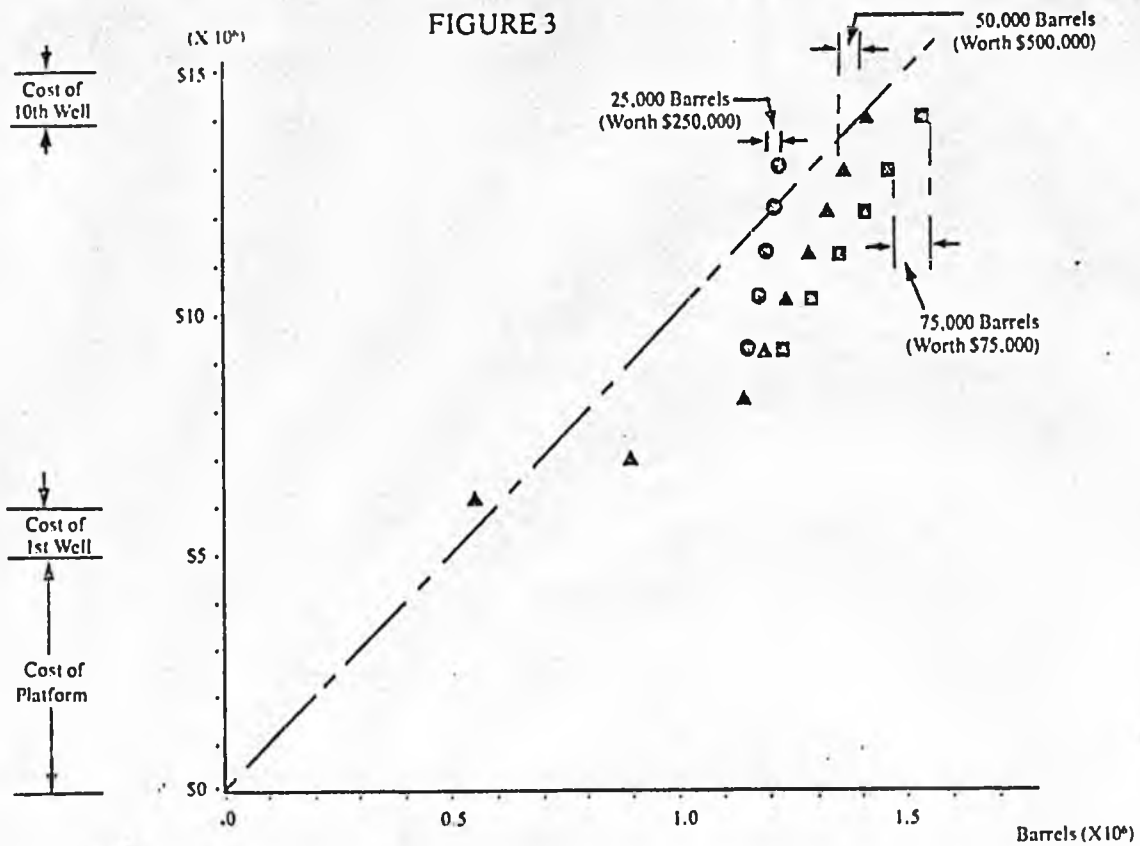


FIGURE 3



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

TRANSFERABILITY OF COMMITMENTS

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

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

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

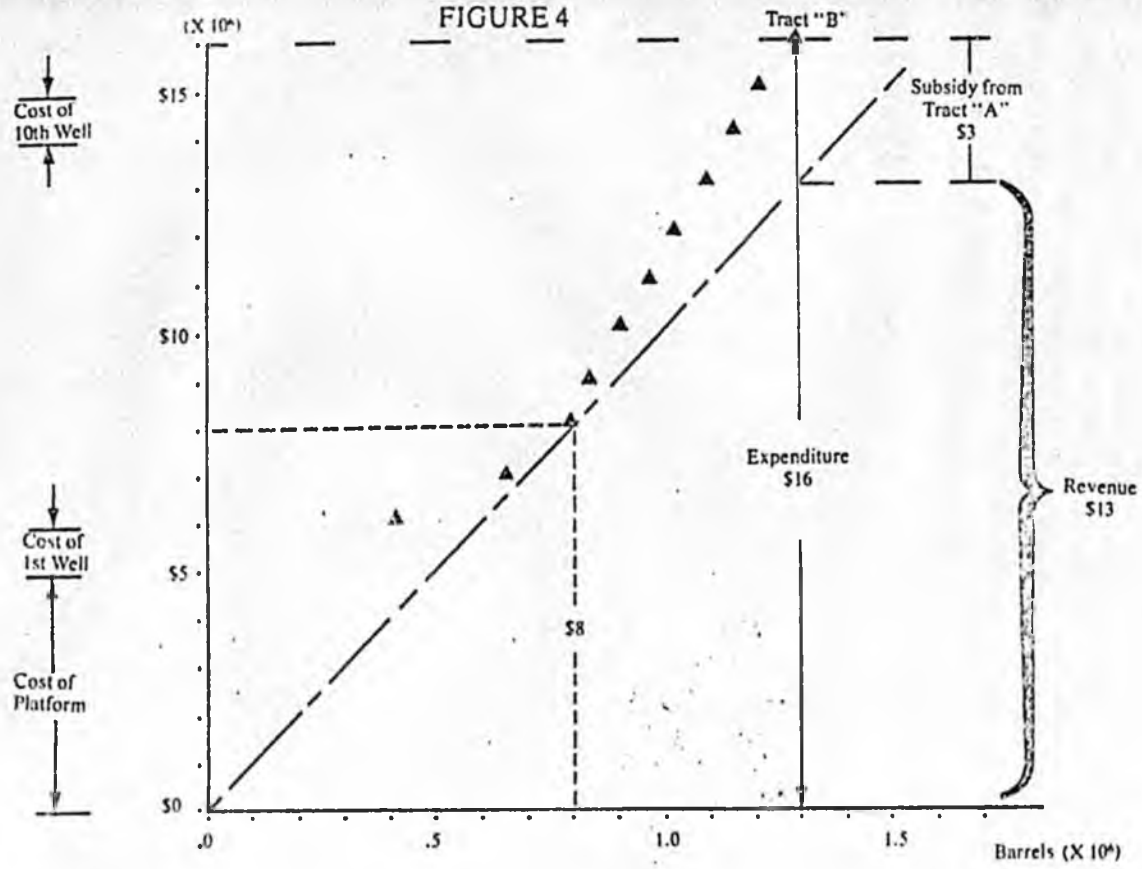
TABLE 1
WORK COMMITMENT BIDDING

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

Note: All figures in millions

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

FIGURE 4



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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)
	<u>2.4</u>	<u>24</u>	<u>24</u>	<u>0</u>

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?

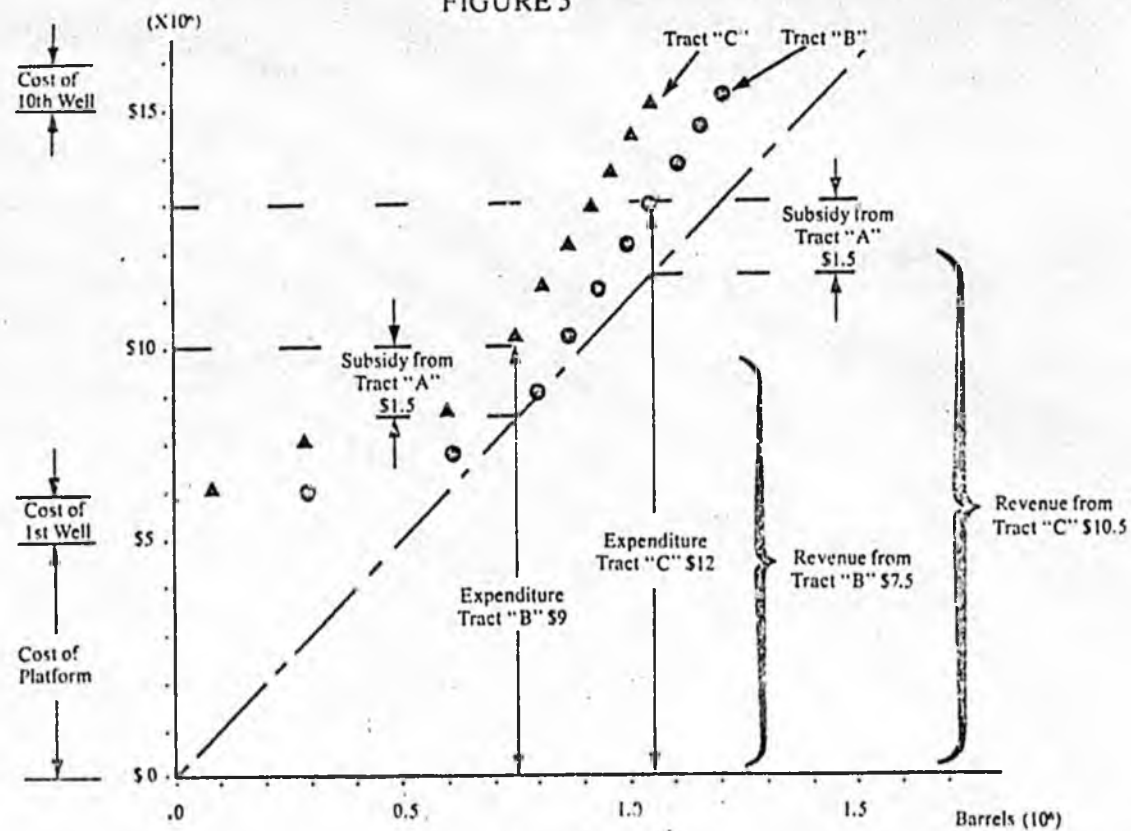
The firm had previously planned to use the \$3 million residual generated on tract A to internally subsidize tract B. If tract C is added to the inventory, the firm could apply to C \$1.5 million of the internal subsidy that would have otherwise gone to tract B and thereby make the development of tract 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)
	<u>2.90</u>	<u>29.0</u>	<u>29.0</u>	<u>0</u>

Note: All figures in millions

FIGURE 5



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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.

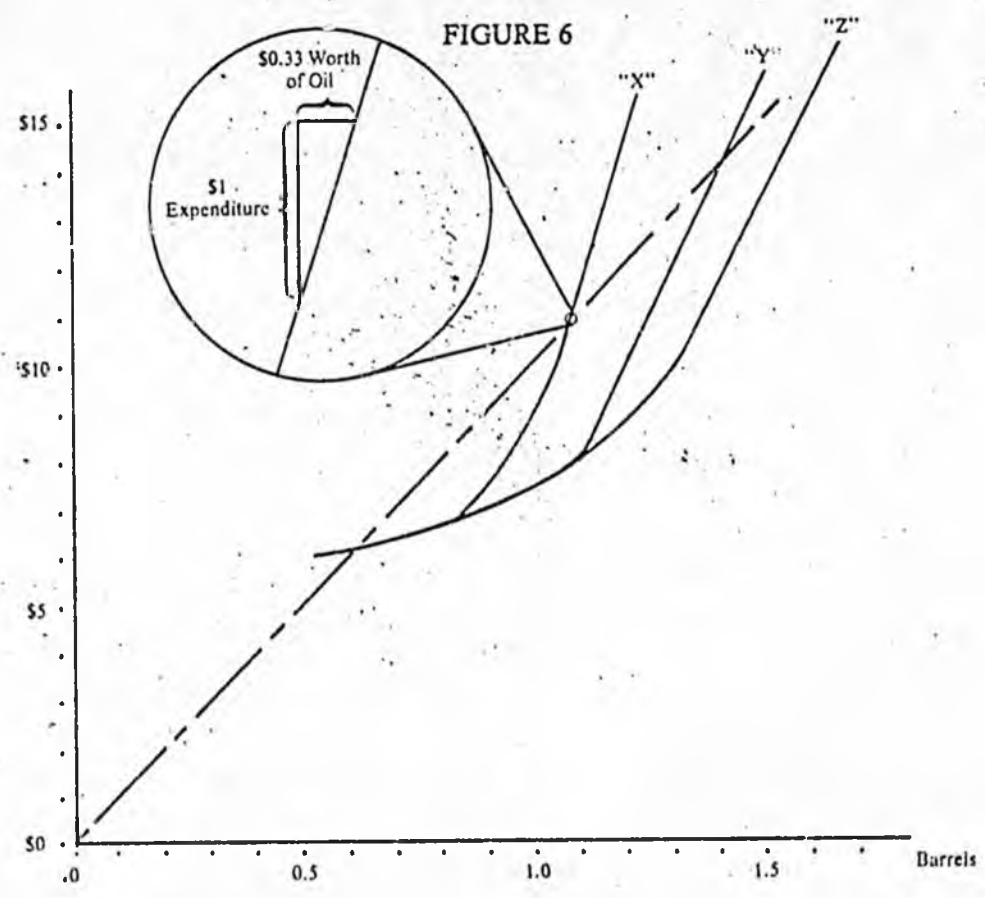
A minor but interesting benefit of a market in commitments would be the information it would provide concerning the efficiency with which the work commitment system is eliciting additional output.

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

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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 37 per cent of the oil and 18 per cent of the gas in this area had been found, leaving an estimated 0.82 billion barrels of oil and 47.56 trillion cubic feet of gas still to be discovered. Although there was considerable potential still remaining for the oil and gas explorer, the area was small compared to Alberta and Saskatchewan, and it was much smaller than the vast geological potential north of the 60th parallel.

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

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

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

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

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

When an oil or gas explorer's cash flow comes from production outside any particular province, then for money for exploration to flow into that province, that jurisdiction 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 jurisdictions. 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 involved 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 resources 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:

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

$P_i Q_i$ 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 16⅓ 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.⁴ 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 Scaled 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:

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

where Y is the high bid and the unit of measure is \$100,000, X₁ 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, X₂ 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, X₃ is the corporate structure of the high bidder coded as 10 for a joint venture and zero for a single firms, X₄ is the number of acres with a unit of measure in 100 acres, X₅ is the number of bidders per sale multiplied by 10, and X₆ 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 combinations.

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 thresholds.

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,² 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 Norg 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).

ROBERT DEAR

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.

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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 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.

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(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 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 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.

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.

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(d) 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.

(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 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

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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 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 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 re-drilling, sidetracking or other means necessary to reach the originally proposed

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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."

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(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

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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

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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.

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 $12\frac{1}{2}$ 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 $12\frac{1}{2}$ 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 $12\frac{1}{2}$ 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 ^{net} less than $12\frac{1}{2}$ percent, to be taken in kind or in value.

(2) Net profit

(A) cash bonus bid with a royalty at not less than $12\frac{1}{2}$ 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 $12\frac{1}{2}$ 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 $12\frac{1}{2}$ percent at the beginning of the lease period 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} their increasing costs in the later ^{stages} states 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 withhold 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 exploration 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 (1) 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 38.05.13^(D) 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.

AGO 547278

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
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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.

AGO 547279 +

(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;

(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

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may grant such reduction so long as it takes effect 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 withhold 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 net 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

AGO 547284

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

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,

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, 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 subsection (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 $16 \frac{2}{3}\%$ 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 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.

File
HB 854

APR 25 1978

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.

AGD 547289 +

April 21, 1978

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