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NOTES

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Statement of David S. Mace
Sohio Petroleum Company
before the
Senate Resources Committee
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3. Articles from Mineral Leasing as an Instrument of Public Policy, British Columbia Institute for Economic Policy Analysis, 1977:

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

In this environment, the importance of 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 Athabascan tar sands, Rocky Mountain oil shale and Orinoco tar belt--and substitutes for conventional oil and gas--will increase. Again, to quote Dr. Tussing, "if you choose to 'sit on' your oil and the decision was wrong, the resultant imbalances could be serious."

A final serious consideration for Alaska relates to a realistic assessment of the 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. Additional, 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 describ 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 occuring only in the most favorable circumstances. This happens because firms have little or nothing to lose by bidding high and then failing to explore or develop..." 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,

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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 . . . 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

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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 advantagous 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 (a) 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 Governments 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, minumum 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 appeciable 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 extemely high risk. Drilling is the only definitive test to determine the presence of oil or gas. Thus, bonus bids must be submitted by bidders and accepted or rejected by the government when neither the buyer nor the seller knows whether and in what quantities oil is present..." 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 esblishing government drilling corporations:

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

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 dissappointing, 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 off the royalty — i.e., out of the public's pocket. A developer might deliberately bid high initially in order to obtain a tract, anticipating that he will renegotiate later; and he might go through a whole series of renegotiations as his costs for enhanced recovery techniques begin to appear.

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

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

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

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

ALBERTA, CANADA

Exploratory Drilling Incentive System

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

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

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

(1) Commencement Date of the Forthcoming Program

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

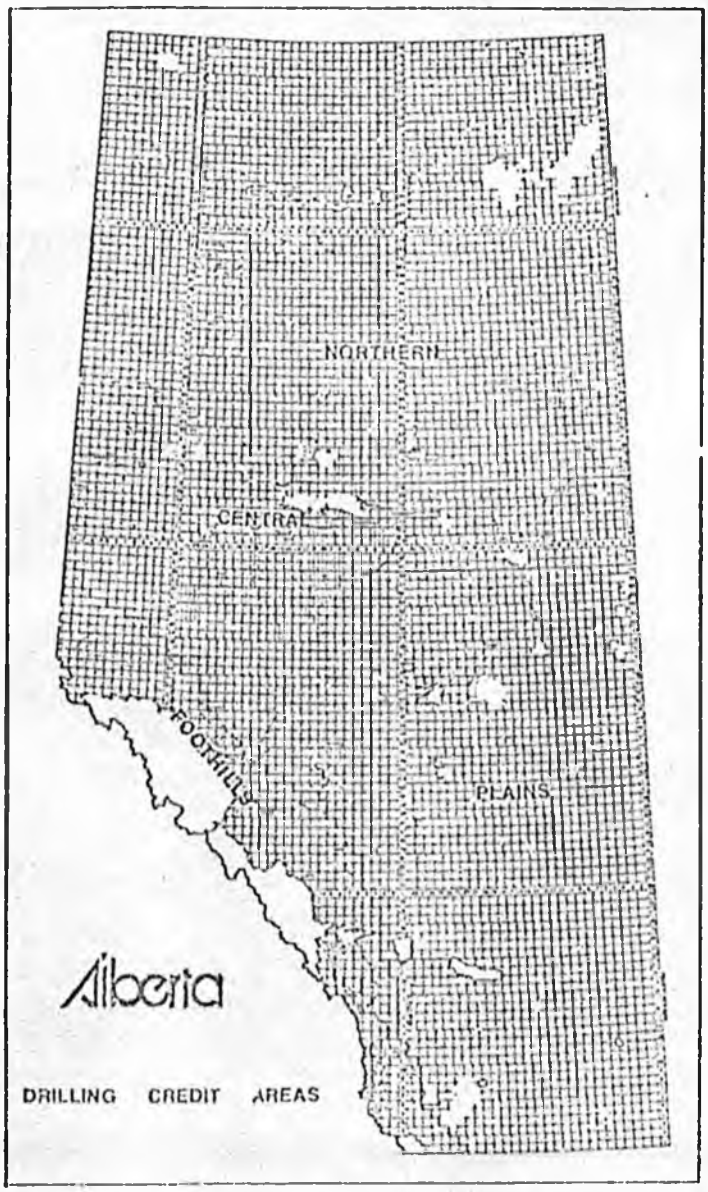


Figure 1

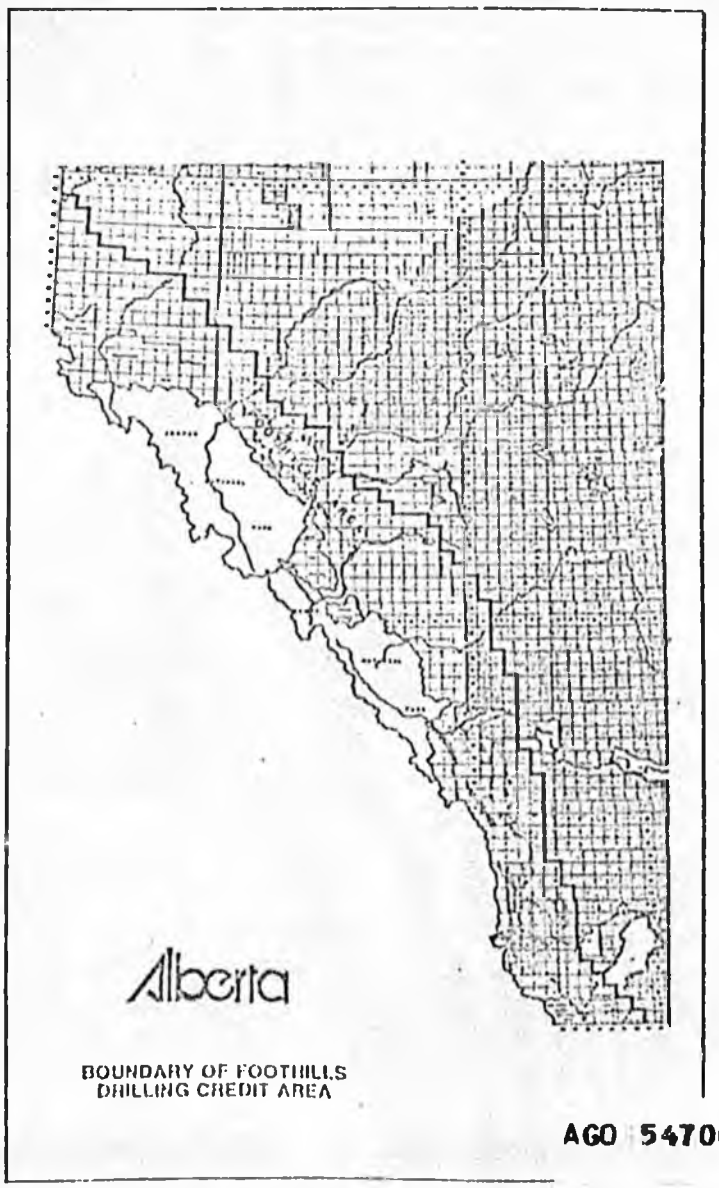


Figure 2

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

(2) Drilling Credit Areas

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

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

(3) Drilling Credit Schedules

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

SCHEDULE F

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

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

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

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

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

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

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

Figure 3

SCHEDULE G

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

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

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

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

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

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

	Basic for Credit Plains Area		Basic for Credit Central Area		Basis for Credit, Northern and Foothills Areas	
Depth, Feet	Cumulative Dollars	Incremental $/Foot	Cumulative Dollars	Incremental $/Foot	Cumulative Dollars	Incremental $/Foot
2,000	0	15	0	20	0	28
3,000	15,000	14	20,000	20	28,000	29
4,000	29,000	14	40,000	20	57,000	29
5,000	43,000	14	60,000	19	86,000	24
6,000	57,000	18	79,000	26	110,000	30
7,000	75,000	25	105,000	30	140,000	40
8,000	100,000	30	135,000	40	180,000	45
9,000	130,000	40	175,000	50	225,000	60
10,000	170,000	55	225,000	65	285,000	75
11,000	225,000	65	290,000	90	360,000	95
12,000	290,000	90	380,000	120	455,000	125
13,000	380,000	120	500,000	150	580,000	155
14,000	500,000	160	650,000	180	735,000	190
15,000	660,000	210	830,000	270	925,000	275
16,000	870,000	270	1,100,000	300	1,200,000	310
17,000	1,140,000	360	1,400,000	400	1,510,000	420
18,000	1,500,000	360	1,800,000	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 quality 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 nonceconomist policy maker.[5] This is unfortunate not only because of the substantial public and private interests involved; the system has significant implications for minerals other than petroleum and in places other than the United States OCS. The purpose here is to provide such an analysis.

EVALUATION OF WORK COMMITMENT BIDDING

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

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

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

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

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

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

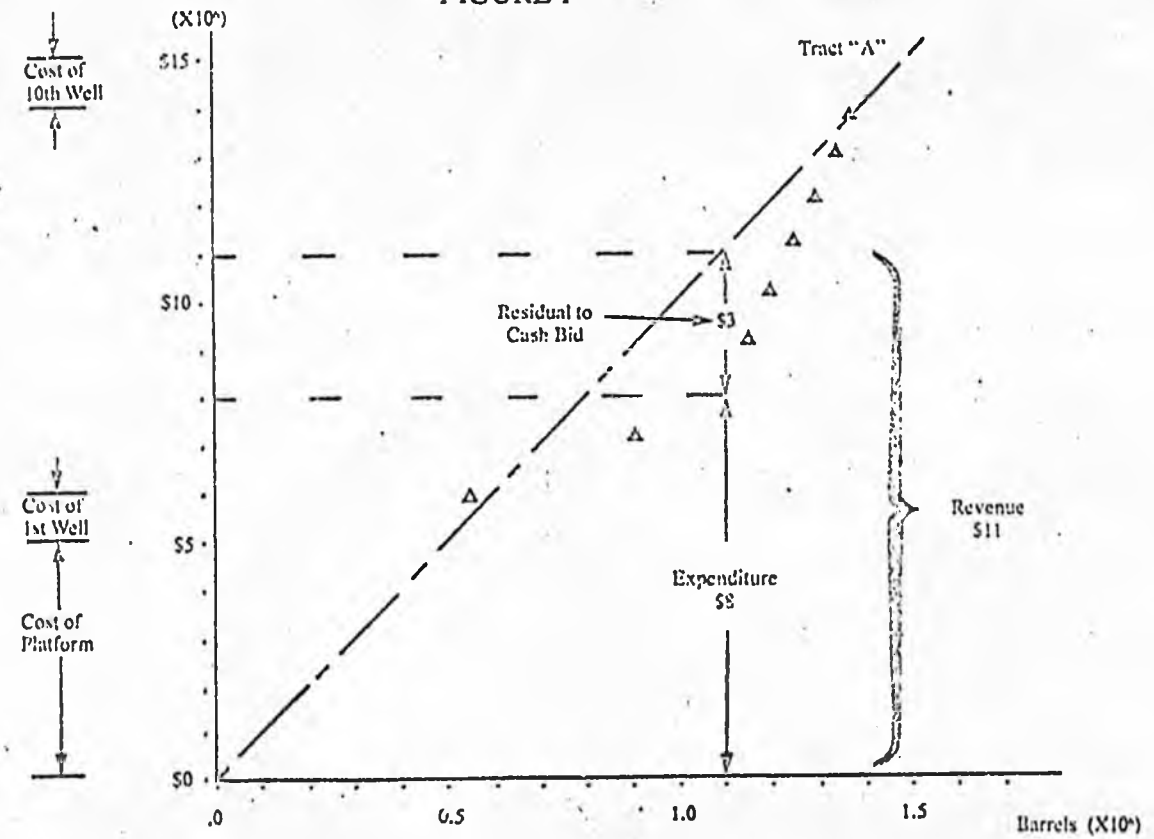
This is most easily demonstrated with a numerical example. Let us assume that a prospective bidder, in determining how much of a cash bonus he can offer for an oil and gas lease on a hypothetical tract A, has calculated the relationship between expenditures on development of the tract and expected production,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

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

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

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

FIGURE 1



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

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

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

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

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

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

FIGURE 2

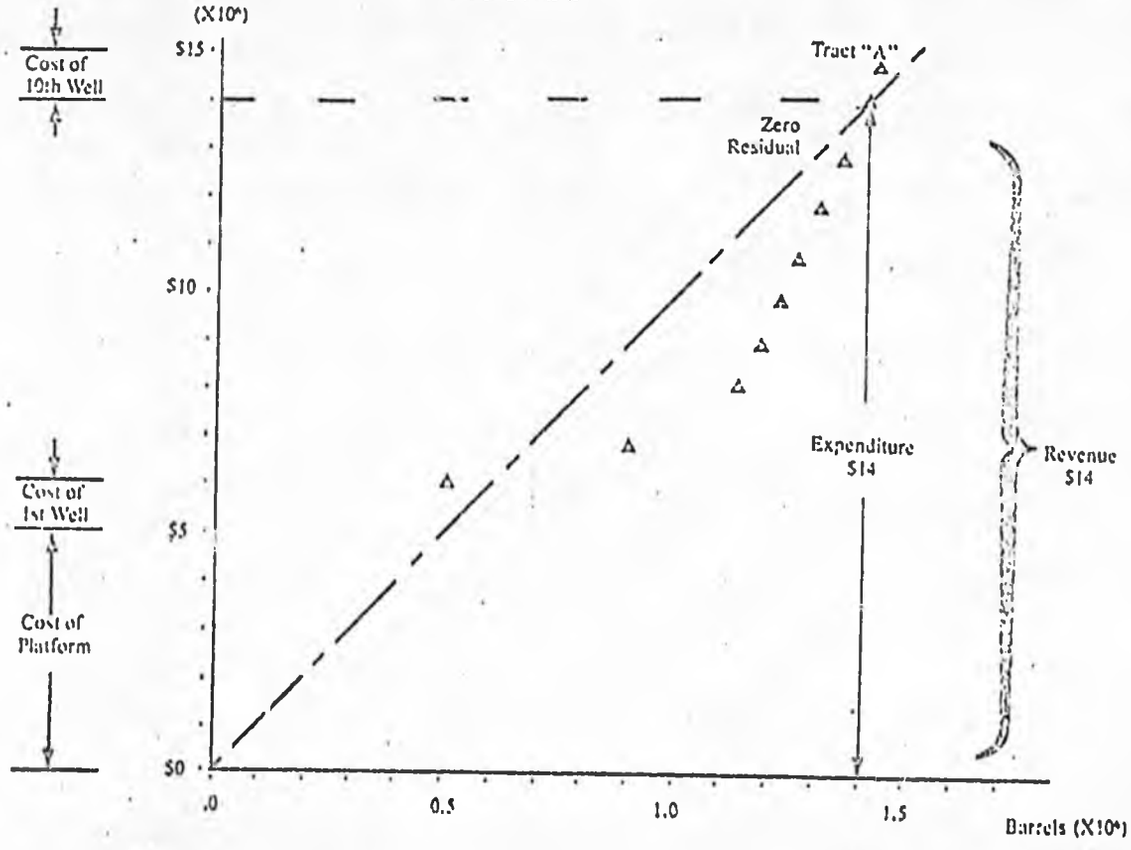
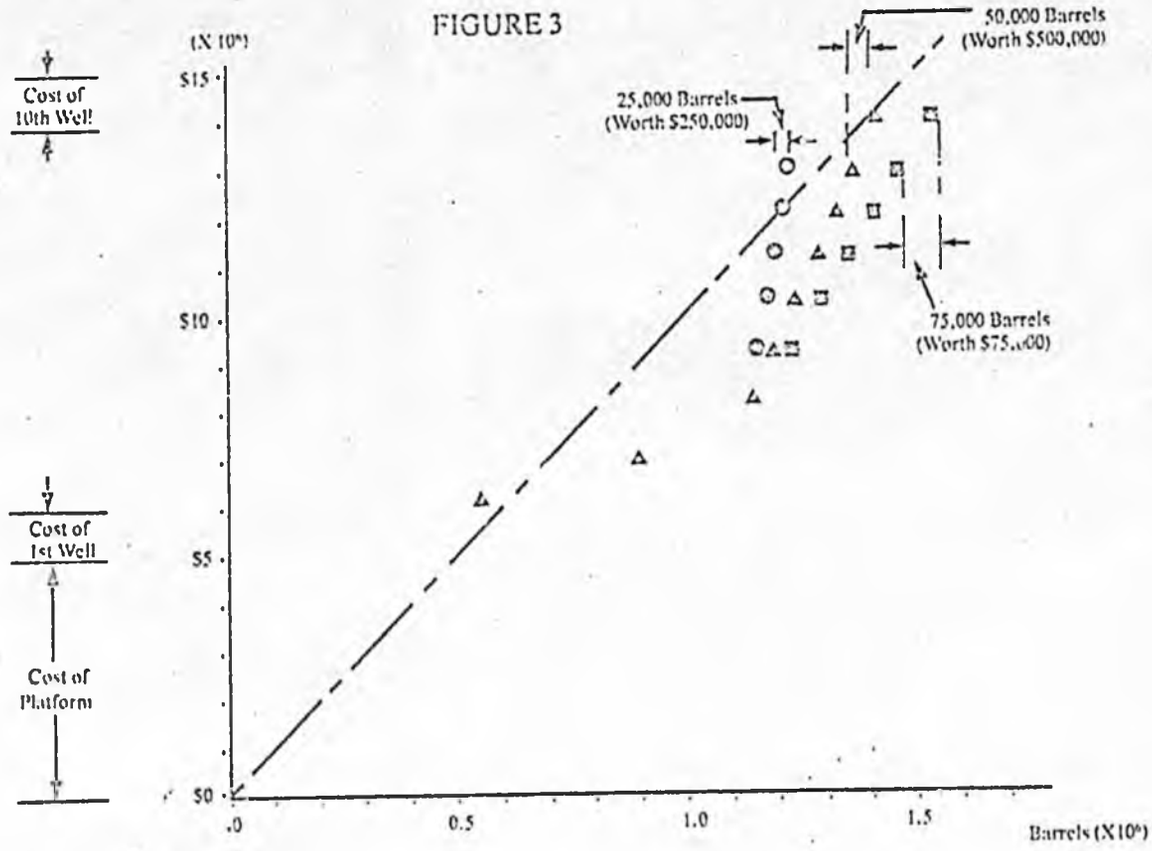


FIGURE 3



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

TRANSFERABILITY OF COMMITMENTS

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

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

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

TABLE 1

WORK COMMITMENT BIDDING

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

Note: All figures in millions

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

FIGURE 4

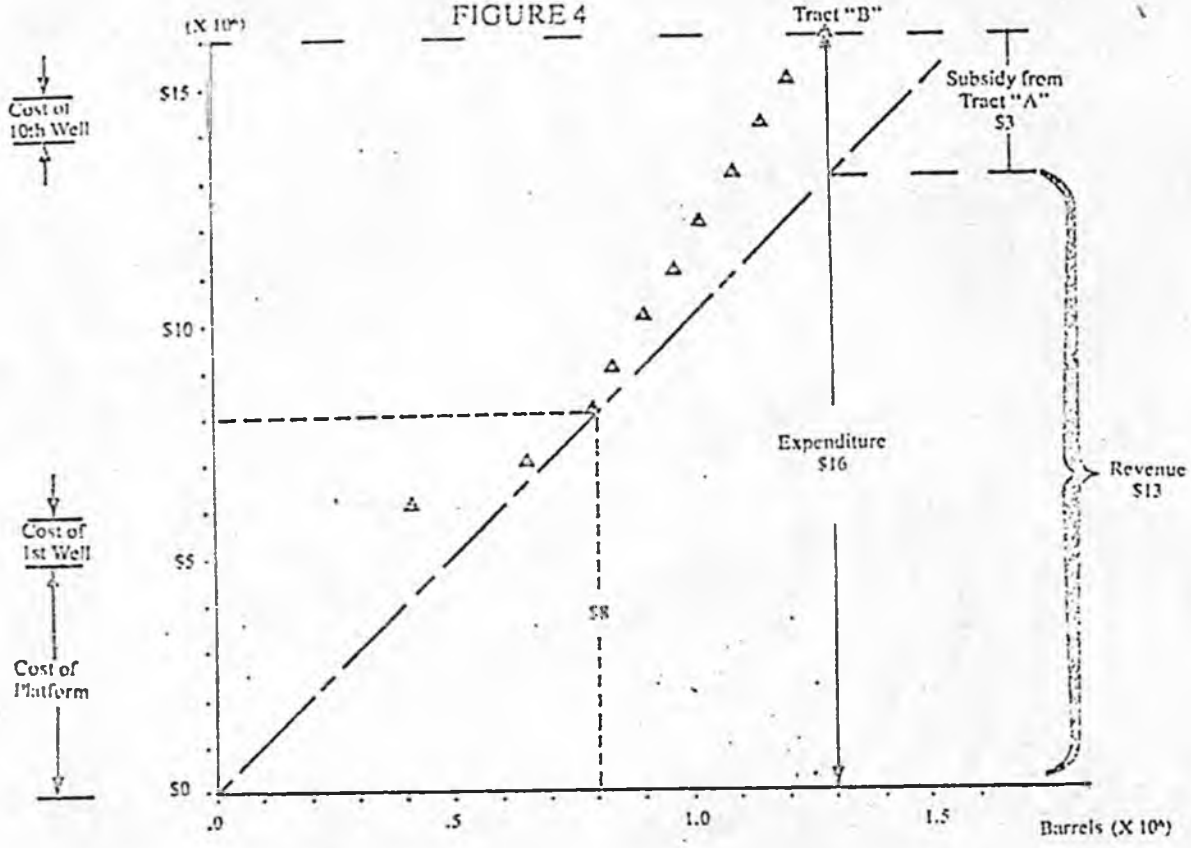


FIGURE 4

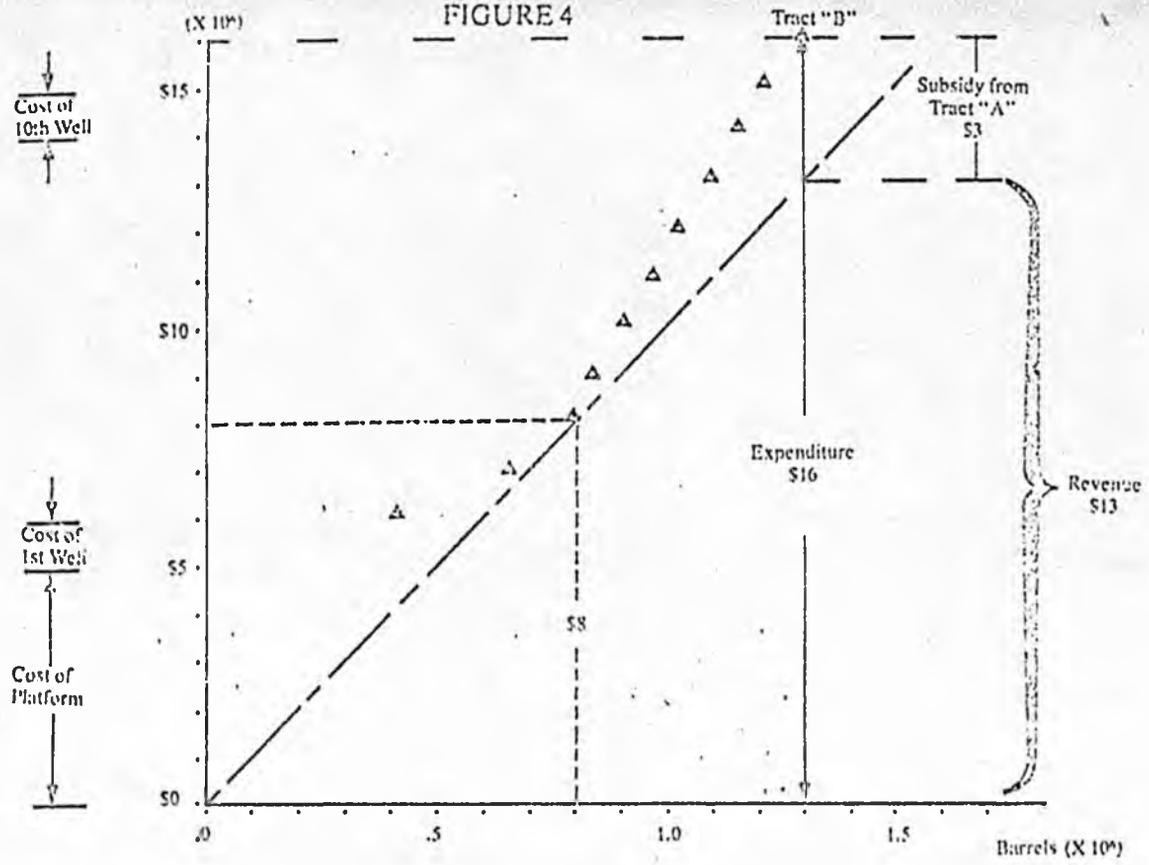


TABLE 2

WORK COMMITMENT BIDDING
(Internal Subsidy Allowed)

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

Note: All figures in millions

EXTENT OF DEVELOPMENT

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

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

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

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

TABLE 3

WORK COMMITMENT BIDDING
(Internal Subsidy Allowed)

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

Note: All figures in millions

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]

FIGURE 6

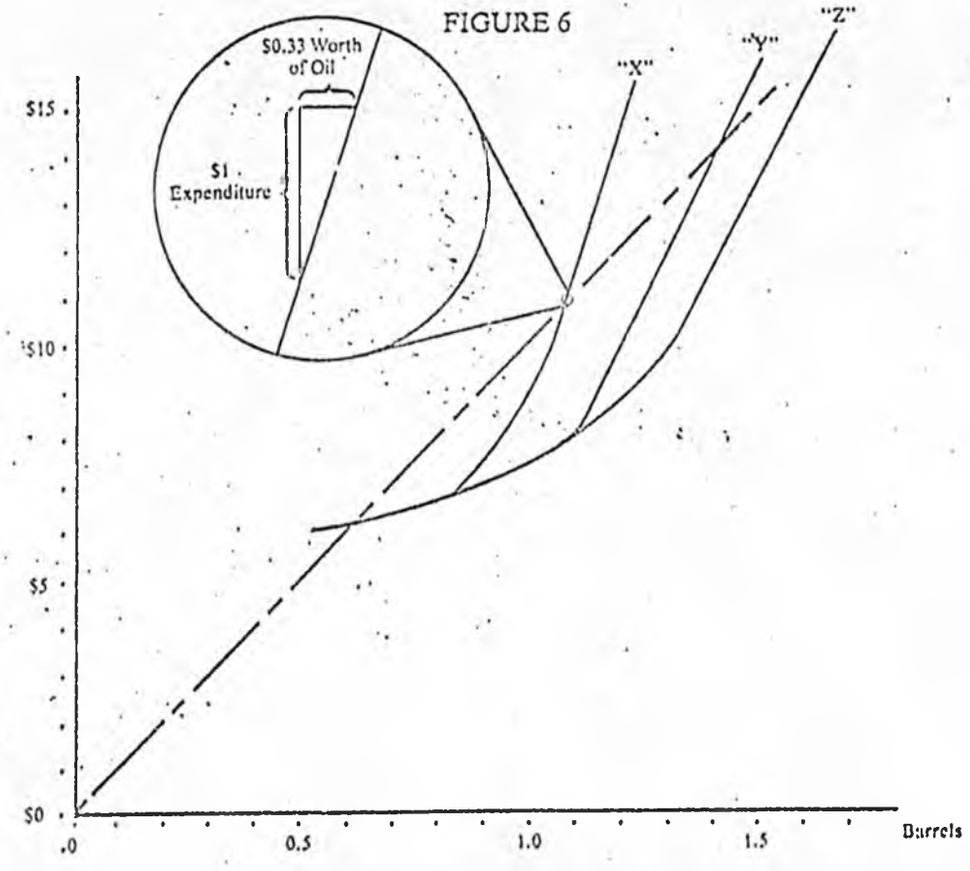
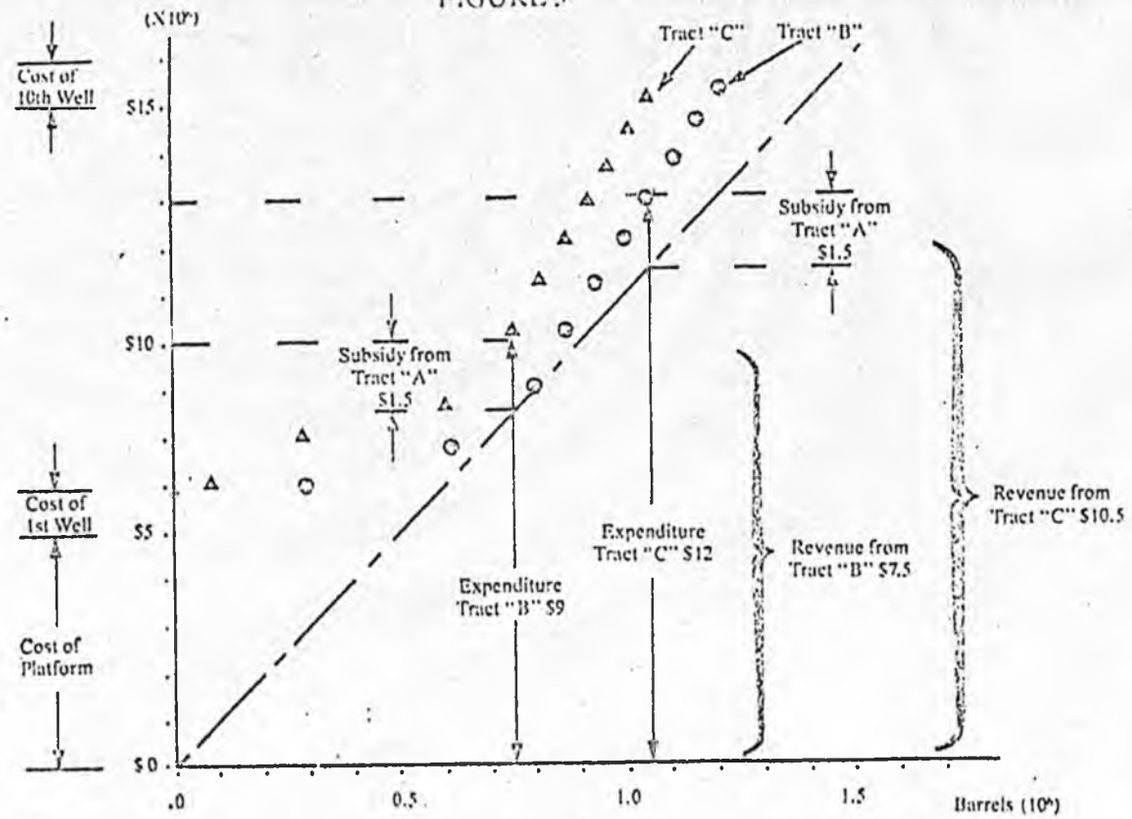


FIGURE 5



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

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

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

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

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

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

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

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

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

The efficiency with which the subsidy provided by the work commitment system works to increase output will be a function of the output curve's shape to the right of the point where bonus income would be maximized. Three hypothetical configurations for this part of the curve are shown, and the difference this shape makes to the level of additional output educed by the sacrifice of the residual can be seen. The significance of the price at which commitments change hands will be determined by the slope of the output curve at the point where it intersects the 45° breakeven line. Curves Y and Z both cross at an angle which indicates that, at that point, $1 of expenditure produces $0.50 worth of additional output. In either situation the market price for assumption of a $1 million commitment would be $500,000. Curve X, however, crosses the line at a steeper slope (as shown in the inset), indicating that $1 of expenditure will produce $0.33 worth of additional output. If curve Z accurately represents the overall output curve, the market price for the assumption of a $1 million work commitment will be about $333,000.

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

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.335. 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 32 per cent of the oil and 18 per cent of the gas in this area had been found, leaving an estimated 0.82 billion barrels of oil and 47.56 trillion cubic feet of gas still to be discovered. Although there was considerable potential still remaining for the oil and gas explorer, the area was small compared to Alberta and Saskatchewan, and it was much smaller than the vast geological potential north of the 60th parallel.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

THE LEASING SYSTEM

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

GOVERNMENT OPTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

CASH BONUS BIDDING

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

TABLE I

ALTERNATIVE BIDDING FORMS

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

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

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

Combination of Bonus and Royalty Bidding

Bidding on the Work Programme

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

Present procedures in the United States include modest rental charges payable between the points of sale and production. When production begins, rental payments cease and royalty payments take over. Rental payments in OCS oil and gas lease income are insignificant. In 1972, they amounted to 0.3 per cent of total revenue from such leases.[1] The rental requirement apparently was introduced to motivate the lessees toward early production. If they were of significant size, this result would in fact occur, because rents cease when production begins.

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

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

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

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

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

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

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

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

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

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

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

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

g. The most conclusive test of the workability of cash bonus bidding based on the United States record of OCS oil and gas lease sales is in terms of the rate of return on capital earned by the successful bidders. An analysis has been made of 184 offshore Louisiana oil and gas tracts leased in 1954 and 1955. Precise data are available on bonus payments, rental payments, oil and gas royalty payments, and production of oil and gas during the period from 1954 through 1967. Cost estimates were made for exploration, well drilling and equipment, and operation. Annual cost and annual wellhead values were discounted to obtain a net internal rate of return. The calculations indicate that these early OCS leases generated a 7.5 per cent before tax rate of return to the lessees.[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 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:

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

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

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

8. Ibid., p. 56.

The Role of Public Enterprise

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

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

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

GOVERNMENT OWNERSHIP

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

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

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

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

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

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

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

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

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

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

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

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