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COMMITTEE REPORT
SENATE

FURTHER: _____

5/19/78

Date: 5/21/78

Mr. President:

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

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

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

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

(x) recommends it be replaced with CS for CS 115 854 49224

and _____ () new title (x) same title

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

() reports it back without recommendation

() and recommends it be referred to the _____ Committee

MEMBERS SIGNING DO PASS:

OTHER RECOMMENDATIONS:

Robert J. No Rec

John P. ... NO REC

R. Pollock

Chairman

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

by

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University of California

Santa Barbara, California

May 15, 1978

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

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

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

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

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

I. BIDDING ALTERNATIVES

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

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

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

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

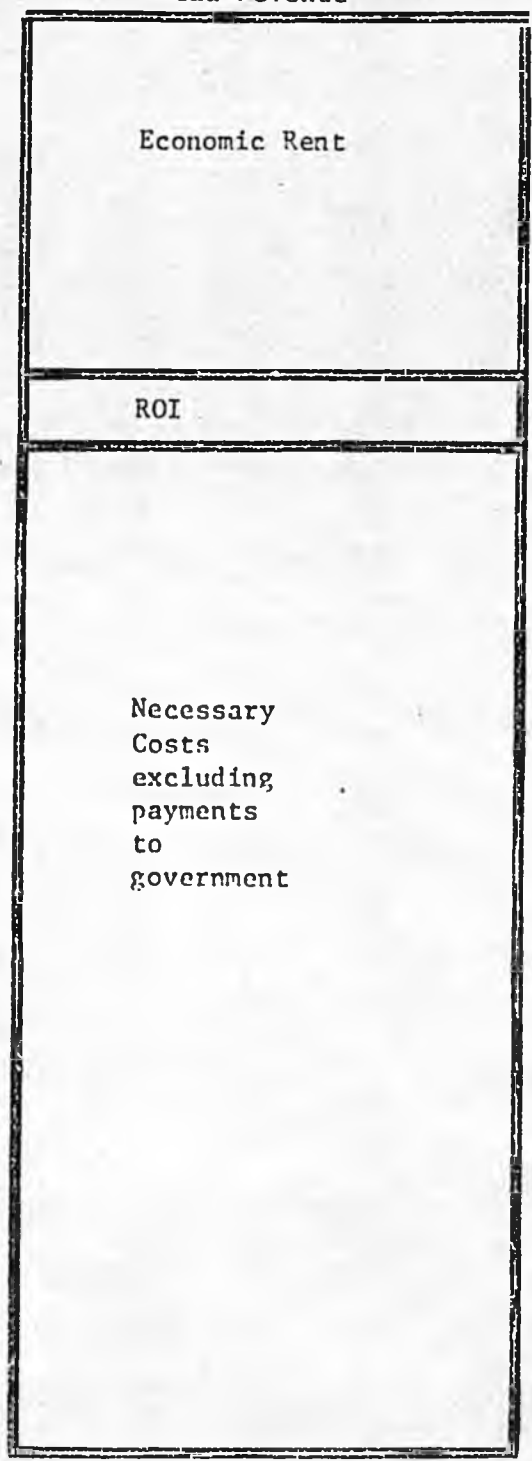
The ROI segment of the figure represents the Return on the Investment for all capital costs incurred by the lessee. This ROI is assumed to be a necessary minimum as determined by competition.

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

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

Total Revenue

Discounted
Present
Values



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

(1) Bonus Bidding

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

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

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

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

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

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

The corresponding disadvantages of bonus bidding are two-fold.

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

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

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

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

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

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

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

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

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

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

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

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

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

(2) Royalty Bidding.

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

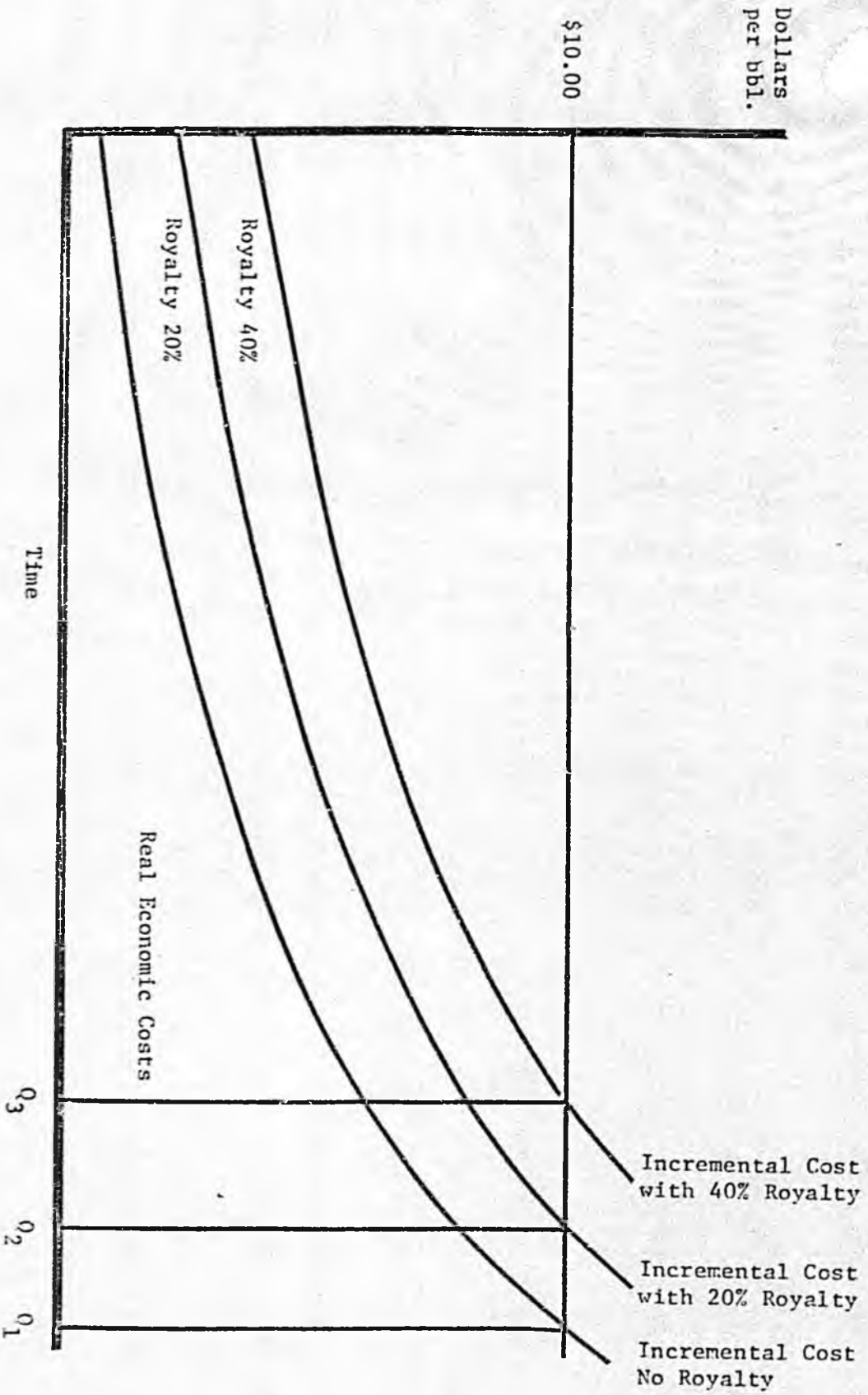
First, payments to the government correspond with production. If a lease is found to be dry, then no payments are required. If a lease is highly productive, then payments correspond with the value of production. Royalty is calculated as some specified percent of production, or of the value of production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

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

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

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

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



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

Where a 20% combination royalty and severance tax is levied, production would be terminated at Q₂. If bidding takes place on the royalty, the royalty payments would rise to higher levels. Figure 2 illustrates a 40% combination royalty and severance tax. With this payment, the property illustrated in Figure 2, would be abandoned at Q₃. Thus a royalty leads to premature abandonment of valuable resources. It is correct to describe this as "premature abandonment" because the royalty payments are merely transfer payments from the operator to the government. They are not true economic costs in the sense that labor and materials are economic costs.

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

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

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

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

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

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

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

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

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

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

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

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

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

(3) Profit-Share Bidding.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(4) Work Commitment Bidding.

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

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

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

The disadvantages of this system are overwhelming.

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

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

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

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

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

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

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

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

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

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

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

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

III. CONCLUSIONS

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

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

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

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

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

Pacific Gas and Electric and Southern California

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

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

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

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

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

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

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

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

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

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

IN THE HOUSE

BY THE RULES COMMITTEE BY
REQUEST OF THE GOVERNOR

HOUSE BILL NO. 854

IN THE LEGISLATURE OF THE STATE OF ALASKA

TENTH LEGISLATURE - SECOND SESSION

A BILL

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

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

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

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

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

(A) maximize the economic recovery of the resources;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

AGO 546833

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

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

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

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

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

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

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

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

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

(E) deleted

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

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

(1) bonus bidding

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

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

(2) royalty bidding

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

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

(1) bonus bidding

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

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

(2) royalty bidding

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

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

(3) net profit bidding

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

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

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

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

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

(3) net profit bidding

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

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

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

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

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

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

(d) To prolong the economical life of an oil and gas field, the commissioner shall adopt regulations for all bidding methods to allow reduction of royalty to compensate for increasing costs in the later stages of production decline. The commissioner may grant such a reduction of royalty so long as the reduced royalty begins no sooner than two years after initial production from the lease.

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

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

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

(e) Deleted

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

Deleted



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

*Two questions
1) Information
2) Transferrable*

AGO 546839

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

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

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

(h) Deleted.

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

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

AGO 546841

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

(h) An oil and gas lease must cover a reasonably compact area not exceeding 5,760 acres, unless tract size in adjacent lands, economic or geological factors relating to that locality require a larger area, and must have a term of ten years. The commissioner may grant a lease for a term less than ten years, but not less than five years, and only where the commissioner finds that environmental and economic conditions do not severely restrict operations. An oil and gas lease shall be automatically renewed if and for so long thereafter as oil or gas is produced in paying quantities from the lease or, if the lease is committed to a unit approved by the commissioner. A lease issued under this section covering land on which there is a well capable of producing oil or gas in paying quantities does not expire because the lessee fails to produce oil or gas unless the lessee is allowed reasonable time to place the well on a producing status. Upon renewal, the commissioner may increase lease rentals so long as the increased rental rate does not exceed 150 per cent of the rate for the preceding year. If drilling has commenced on the expiration date of the primary term of the lease and is continued with reasonable diligence, taking into account the limitations imposed on drilling operations by Alaskan environmental conditions and including such operations as redrilling, sidetracking, or other means necessary to reach the originally proposed bottom hole location, the lease shall continue in effect until 90 days after drilling has ceased and for so long thereafter as there is a well thereon capable of producing oil or gas in paying quantities.

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

- (1) for the first year, \$1.00 per acre;
- (2) for the second year, \$1.50 per acre;
- (3) for the third year, \$2.00 per acre;
- (4) for the fourth year, \$2.50 per acre;
- (5) for the fifth year, \$3.00 per acre;

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

- (1) for the first year, \$1.00 per acre;
- (2) for the second year, \$1.50 per acre;
- (3) for the third year, \$2.00 per acre;
- (4) for the fourth year, \$2.50 per acre;
- (5) for the fifth year, \$3.00 per acre;

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

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

(m) To conserve the natural resources of all or a part of an oil or gas pool, field, or like area, whether or not the part is then subject to a cooperative or unit plan of development or operation, lessees and their representatives may unite with each other, or jointly or separately with others, in collectively adopting or operating under a cooperative or a unit plan of development or operation of the pool, field, or like area, or a part of it, when determined and certified by the commissioner to be necessary or advisable in the public interest. The commissioner may, with the consent of the holders of leases involved, establish, change, or revoke drilling, producing, rental minimum royalty, and royalty requirements of the leases and adopt regulations with reference to the leases, with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan as he determines necessary or proper to secure the proper protection of the public interest. The commissioner may require oil and gas leases issued under this section to contain a provision requiring the lessee to operate under a reasonable cooperative or unit plan, and he may prescribe a plan under which the lessee must operate. The plan must adequately protect all parties in interest, including the state.

(k) To promote the most efficient development of the natural resources of all or part of an oil or gas pool, field, or like area, whether or not the part is then subject to a cooperative or unit plan of development or operation, lessees and their representatives may unite with each other, or jointly or separately with others, in collectively adopting or operating under a cooperative or a unit plan of development or operation of the pool, field, or like area, or a part of it, when determined and certified by the commissioner to be necessary or advisable in the public interest. The commissioner may, with the consent of the holders of leases involved, establish, change, or revoke drilling, producing, rental minimum royalty, and royalty requirements of the leases and adopt regulations with reference to the leases with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan as he determines necessary or proper to secure the proper protection of the public interest. The commissioner may require oil and gas leases issued under this section to contain a provision requiring the lessee to operate under a reasonable cooperative or unit plan, and he may prescribe a plan under which the lessee must operate. The plan must adequately protect all parties in interest, including the state.

(n) A plan authorized by (m) of this section, which includes land owned by the state, may contain a provision vesting the commissioner, or a person committee, or state agency with authority to modify from time to time the rate of prospecting and development and the quantity and rate of production under the plan. All leases operated under a plan approved or prescribed by the commissioner are excepted in determining holdings or control under sec. 140 of this chapter. The provisions of this section concerning cooperative or unit plans are in addition to, and do not affect AS 31.05.

(o) Producing acreage on a known geologic structure of a producing oil or gas field is excluded from chargeability as against the acreage limitation provisions of sec. 140 of this chapter.

(l) A plan authorized by (j) of this section, which includes land owned by the state, may contain a provision vesting the commissioner, or a person, committee, or state agency with authority to modify from time to time the rate of prospecting and development and the quantity and rate of production under the plan. All leases operated under a plan approved or prescribed by the commissioner are excepted in determining holdings or control under sec. 140 of this chapter. The provisions of this section concerning cooperative or unit plans are in addition to, and are subject to the state's authority to prohibit waste of oil and gas in AS 31.05.

(m) Producing acreage on a known geologic structure of a producing oil or gas field is excluded from chargeability as against the acreage limitation provisions of sec. 140 of this chapter.

(p) When separate tracts cannot be individually developed and operated in conformity with an established well-spacing or development program, a lease, or a portion of a lease, may be pooled with other land, whether or not owned by the state, under a communitization or drilling agreement providing for an apportionment of production or royalties among the separate tracts of land comprising the drilling or spacing unit when determined by the commissioner to be in the public interest. Operations or production under the agreement are considered as operations or production as to each lease committed to the agreement.

(q) The commissioner may, on conditions which he prescribes, approve drilling, or development contracts made by one or more lessees of oil or gas leases, with one or more persons, when, in his discretion, the conservation of natural resources or the public convenience or necessity requires it or the interests of the state are best served. All leases operated under approved drilling or development contracts, and interests under them, are excepted in determining holding or control under sec. 140 of this chapter. Drilling or development contracts may include, at the discretion of the commissioner, provisions authorizing the state to share in the costs of exploration.

(n) When separate tracts cannot be individually developed and operated in conformity with an established well-spacing or development program, a lease, or a portion of a lease, may be pooled with other land, whether or not owned by the state, under a communitization or drilling agreement providing for a apportionment of production or royalties among the separate tracts of land comprising the drilling or spacing unit when determined by the commissioner to be in the public interest. Operations or production under the agreement are considered as operations or production as to each lease committed to the agreement.

(o) The commissioner may, on conditions which he prescribes, approve drilling, or development contracts made by one or more lessees of oil or gas leases, with one or more persons, when, in his discretion, the conservation of natural resources or the public convenience or necessity requires it or the interests of the state are best served. All leases operated under approved drilling or development contracts, and interests under them are excepted in determining holding or control under sec. 140 of this chapter. Drilling or development contracts may include, at the discretion of the commissioner, provisions authorizing the state to share in the costs of exploration.

(r) To avoid waste or to promote conservation of natural resources, the commissioner may authorize the subsurface storage of oil or gas whether or not produced from state land, in land leased or subject to lease under this section. This authorization may provide for the payment of a storage fee or rental on the stored oil or gas, or instead of the fee or rental, for a royalty other than that prescribed in the lease when the stored oil or gas is produced in conjunction with oil or gas not previously produced in paying quantities.

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

(p) To promote conservation of natural resources, the commissioner may authorize the subsurface storage of oil or gas whether or not produced from state land, in land leased or subject to lease under this section. This authorization may provide for the payment of a storage fee or rental on the stored oil or gas, or, instead of the fee or rental, for a royalty other than that prescribed in the lease when the stored oil or gas is produced in conjunction with oil or gas not previously produced in paying quantities.

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

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

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

AGO 546849

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

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

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

(c) No person may take or hold at one time phosphate leases on state lands exceeding the aggregate 10,240 acres. No person may take or hold sodium leases or permits for up to 15,360 acres. No person may take or hold at any one time oil or gas leases exceeding in the aggregate 200,000 (500,000) acres granted on tide and submerged lands, and 400,000 acres on all land (LANDS) other than tide and submerged land (LANDS), including leases held both as lessee and under option or operating agreement from others. A person has five years from the effective date of this Act to conform to the 200,000-acre upland limitation. Where more than a single person holds an interest in an oil or gas lease, each person shall be charged only with that percentage of the total acreage which corresponds to its percentage share of the total beneficial interest in the lease.

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

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

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

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

(c) No person may take or hold at one time phosphate leases on state lands exceeding the aggregate 10,240 acres. No person may take or hold sodium leases on state lands, exceeding in the aggregate acreage 5,120 acres, except that the commissioner may, where it is necessary in order to secure the economic mining of sodium compounds, permit a person to take or hold sodium leases or permits for up to 15,360 acres. No person may take or hold at any one time oil or gas leases exceeding in the aggregate 500,000 acres granted on tide and submerged lands, and 400,000 acres on all land (LANDS) other than tide and submerged land (LANDS), including leases held both as lessee and under option or operating agreement from others. Where more than a single person holds an interest in an oil or gas lease, each person shall be charged only with that percentage of the total acreage which corresponds to its percentage share of the total beneficial interest in the lease.

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

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

(delete)

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

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

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

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

AGO 546851

How to Bid for Offshore Rights

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

The Work Obligation Permit Plan

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

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

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

Royalty Bidding

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

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

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

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

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

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

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

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

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

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

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

ALBERTA, CANADA

Exploratory Drilling Incentive System

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

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

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

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

(1) Commencement Date of the Forthcoming Program

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

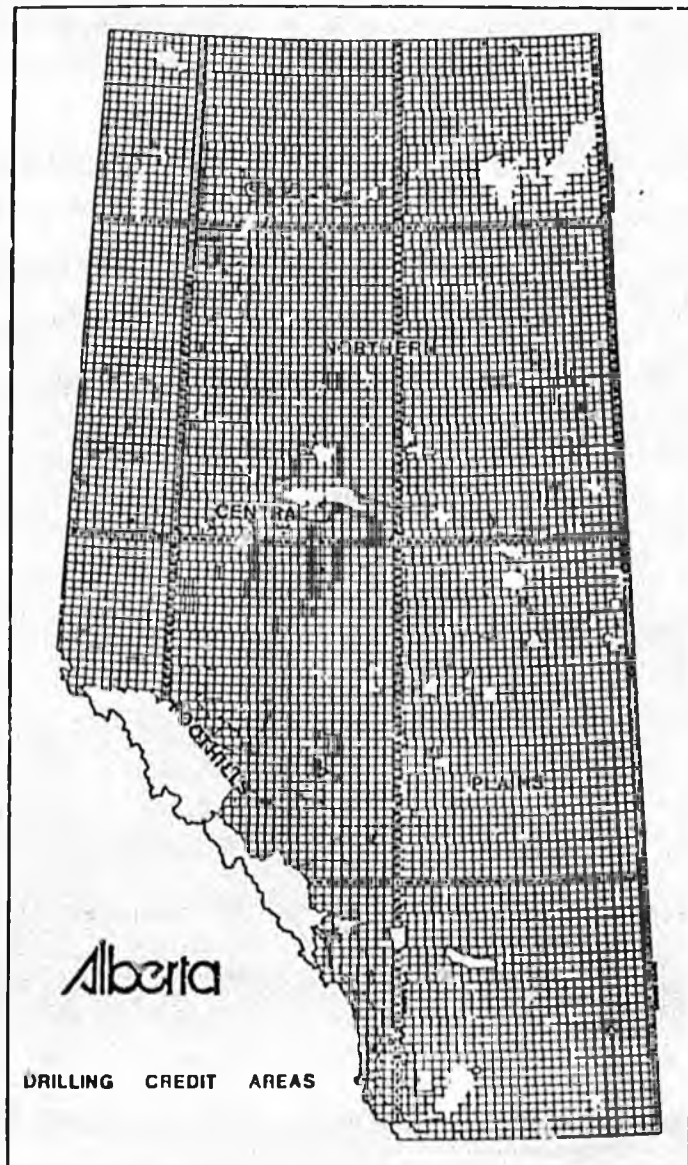
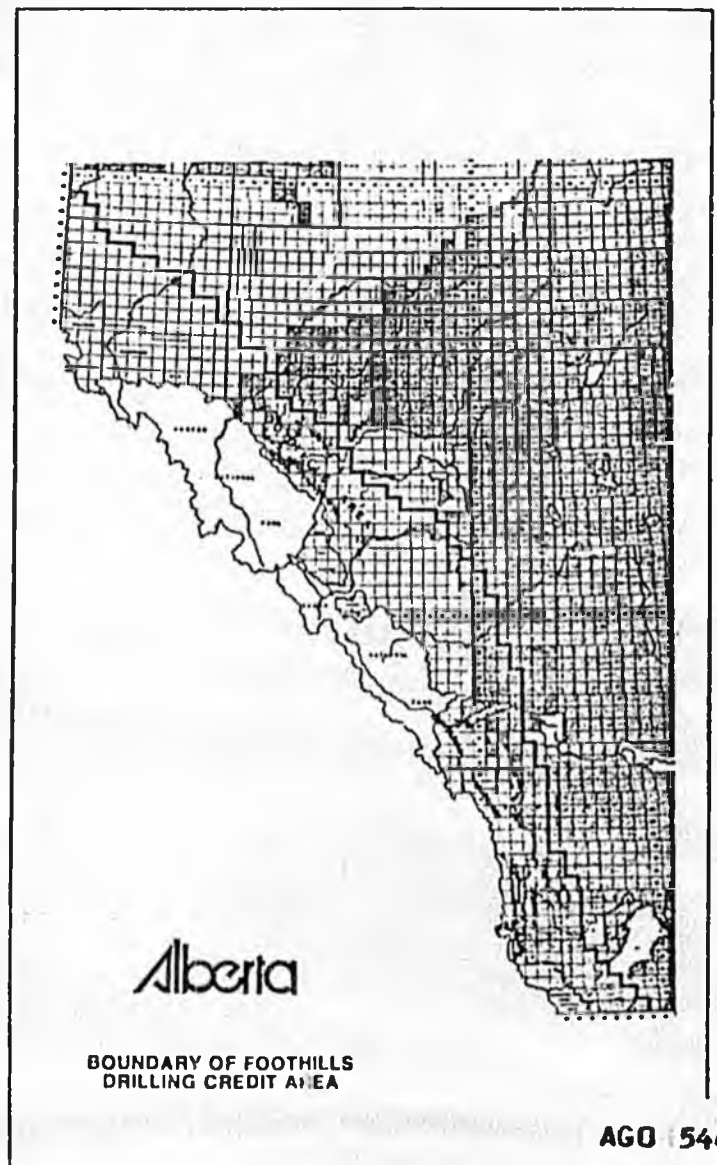


Figure 1



AGO 546915

Figure 2

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

(2) Drilling Credit Areas

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

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

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

(3) Drilling Credit Schedules

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

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

Figure 3

SCHEDULE G						
Applicable to the Class B Interval of an Incentive Exploratory Well that Commences Drilling on or after January 1, 1978						
The Class B interval of an incentive exploratory well that commences drilling on or after January 1, 1978 shall be determined by the Board as the interval below the depth of 2,000 feet that						
(i) has been duplicated by a drilled and abandoned well within one and one-half miles.						
(ii) occurs more than 500 feet below the base of the deepest accumulation of crude oil or natural gas that in the opinion of the Board has been penetrated by another well within three miles, and						
(iii) occurs immediately below the base of the member or formation containing the deepest oil sands deposit that in the opinion of the Board may underlie the location of the said incentive exploratory well.						
Where neither (ii) nor (iii) above applies, the Class B interval shall be determined from the depth of 2,000 feet to the total depth of the said incentive exploratory well.						
Depth, Feet	Basic for Credit Plains Area		Basic for Credit Central Area		Basis for Credit Northern and Foothills Areas	
	Cumulative Dollars	Incremental \$/Foot	Cumulative Dollars	Incremental \$/Foot	Cumulative Dollars	Incremental \$/Foot
2,000	0	15	0	20	0	28
3,000	15,000	14	20,000	20	28,000	29
4,000	29,000	14	40,000	20	57,000	29
5,000	43,000	14	60,000	19	86,000	24
6,000	57,000	18	79,000	26	110,000	30
7,000	75,000	25	105,000	30	140,000	40
8,000	100,000	30	135,000	40	180,000	45
9,000	130,000	40	175,000	50	225,000	60
10,000	170,000	55	225,000	65	285,000	75
11,000	225,000	65	290,000	90	360,000	95
12,000	290,000	90	380,000	120	455,000	125
13,000	380,000	120	500,000	150	580,000	155
14,000	500,000	160	650,000	180	735,000	190
15,000	660,000	210	830,000	270	925,000	275
16,000	870,000	270	1,100,000	300	1,200,000	310
17,000	1,140,000	360	1,400,000	400	1,510,000	420
18,000	1,500,000	360	1,900,000	400	1,930,000	420

Figure 4

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

(4) Royalty Exemptions

(4.1) Eligibility

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

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

(4.2) Duration

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

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

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

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

Work Commitment Bidding

GREGG K. ERICKSON

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

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

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

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

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

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

EVALUATION OF WORK COMMITMENT BIDDING

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

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

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

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

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

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

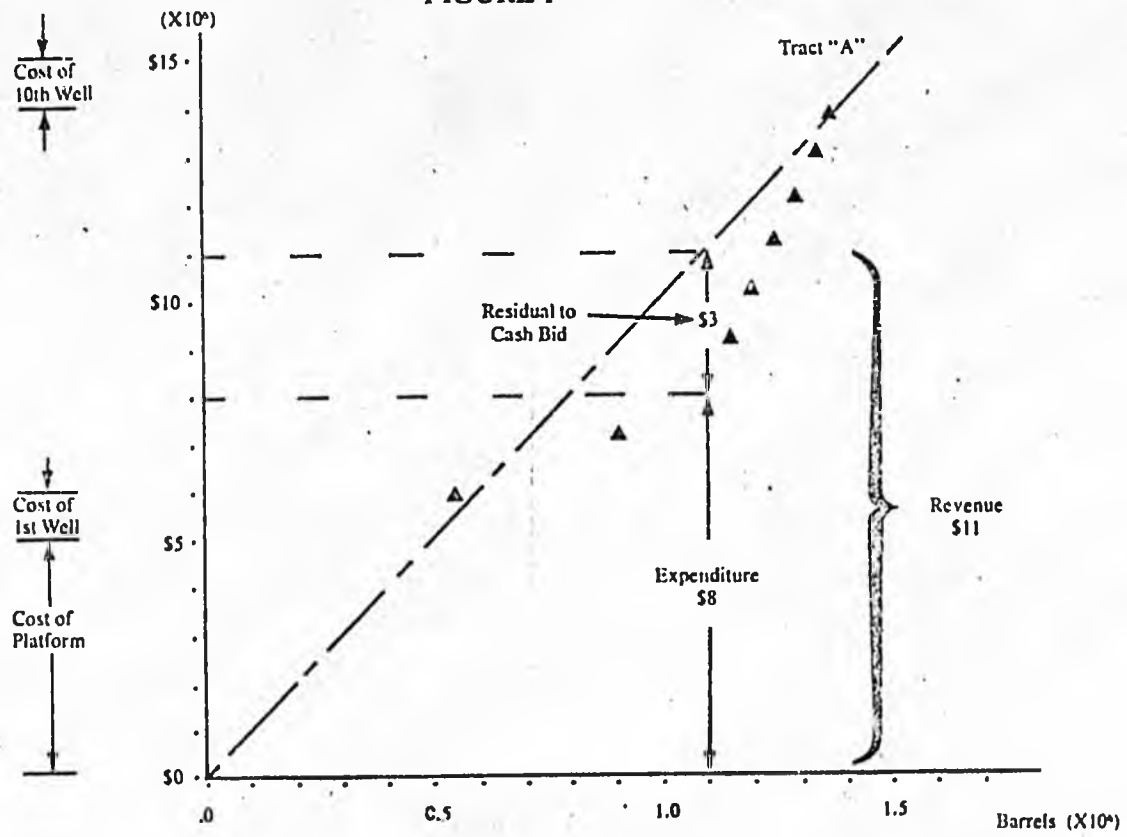
This is most easily demonstrated with a numerical example. Let us assume that a prospective bidder, in determining how much of a cash bonus he can offer for an oil and gas lease on a hypothetical tract A, has calculated the relationship between expenditures on development of the tract and expected production,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

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

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

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

FIGURE 1



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

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

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

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

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

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

AGO 546924

FIGURE 2

