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Here, however, arises another hazard. Consuming states would like nothing better than to capture oil and gas reserves in Alaska, subject to mandatory delivery at regulated low prices. A paramount consideration in leasing policy should always be to blunt the impact of regulation by the FPC and the FEA, agencies whose policies seem calculated to effect a large transfer of wealth from producers to consumers. There need be no sense of guilt about this. California has no more claim on the resources of Alaska than Alaska has on the resources of California; and if California did have such a claim, underpricing gas and oil would be a most inefficient way to assert it. We are not suggesting that Alaska exploit consumers in a monopolistic way; we are, rather, suggesting that Alaska avoid being exploited by consumers in a monopsonistic way by consumers with the club of federal power at their command.

Dealing with vertically integrated concerns (with dedicated reserves designated for specific plants and consuming regions) lends itself to this kind of exploitation. Long-term leases dedicated to costly pipelines financed by consumers make the State vulnerable. The shorter the term of the lease, the later it is written, and the more the State depends on the free market, the stronger is its position. All these are complex and ramifying questions beyond our present scope. The present point is that they urgently require attention when a leasing policy is being formed.

Closer to home, access to any common carrier pipeline needs to be aggressively assured by exercise of the good offices of the State. Attorney John Lamont has indicated that equal access to common carrier

pipelines is far from automatic (Lamont, 1974). In order to sell additional North slope leases the State clearly must guarantee potential buyers full and equal access to the pipeline. In the event that producing capacity may exceed transporting capacity, the formula for allocating capacity needs to be specified in advance. Second-class treatment for nonowners of the line will result in second-class bids for State leases.

The choice of a bid variable

There should be a bid variable. There should be an auction at some point in the leasing process. Otherwise we are back at a noncompetitive system with its propensity towards prematurity or "soonerism." We now ask which of the leasing elements makes the best bid variable.

An argument for choosing the royalty as the variable is that a sliding scale is needed to make high royalty rates tolerably workable, and one way of making the scale slide is to let the bidders decide what the rate is to be.

The trouble is, variable royalties will slide on ex ante expectations rather than ex post disclosures. If we do opt for sliding royalties, it would be more feasible in my opinion to base them on objective ex post conditions such as depth, location, size, pressure, bearing strength of surface, length of working season, and so on.

The same considerations, pro and con, apply to profit share bidding in somewhat lesser degree.

When we get to the rent share element there is no need for any sliding scale. Sliding scales are simply means to make royalty and

profit share systems more nearly approximate rent share systems. The idea is to capture as close to 100 percent of the rent as the State can. There is no need to settle for less because rent is a surplus above necessary payments for costs and incentives. It is exactly the value imputable to the natural resource which the State contributes to the production process.

The bonus makes a logical bid variable because it is hard to set in any other way. It is not a percentage of anything fixed or known. To be sure, it could be set equal to the State's appraisal, but this is based on imperfect knowledge ex ante. An additional advantage of the bonus as the bid variable is familiarity and custom.

The problem with the bonus bid variable is that whatever is variable may tend to increase over time in relative importance and we are trying to get away from heavy reliance on bonuses. We may solve this problem easily by tying the bonus and the rental together at a fixed percentage, with the rental being a high percentage of the bonus. If the percentage were 50 percent the bonus bid would be converted to a rental bid with a double rental paid in year 1.

An annual rent has most of the good qualities of a bonus with few of its failings. We would recommend, therefore, that the rent-to-bonus ratio be set quite high. Indeed, the main reason for retaining the bonus element at all is its familiarity.

If we choose to let the ad valorem charge (AVC) be a large element in subsequent lease income, there is attractiveness in using the same rate for both the charge and the rent-to-bonus ratio, let's say 25

percent. Then there may be a smooth transition from the bonus bid as the basis of valuation to an assessment of reserves as the basis, maintaining the same 25 percent rate on each.[4]

If we choose a high delay rental and a system of production-based payments, we can probably improve on the present concept of letting the delay rental lapse when production is shown to be commercially feasible. This contains an arbitrary element, permitting token production or token shows of producibility to terminate the rental. It might be better to let the rental continue and be creditable against production payments. This will pose another arbitrary decision later on when pressure is dropping and production falling, but later arbitrary decisions are less harmful than earlier arbitrary decisions and in this case probably less consequential.

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[4] Looking farther ahead, the State may wish to consider actually transferring land title, and go out of the leasing business. The Legislature could create a special class of property, to wit, oil and gas rights transferred to private hands after the date of legislation, subject to a 25 percent ad valorem property tax. The proposed system would lend itself to a smooth transition from public to private property, without there being any giveaway element.

D. Timing Lease Sales

Our position on this question has now been foreshadowed at several points. We will only summarize and recapitulate here.

Decisions about timing lease sales entail the following sequence:

1. The State must determine which leasing procedure and method of repayment it will use before it is possible to determine rationally the optimal timing of lease sales.

2. Potentially leasable lands should be ranked according to "ripeness" or maturity for lease sale. This ranking will be roughly in the order of value. Economists generally agree that it makes sense to use the best resources first, but value is not the only criterion nor is it unambiguous since it could mean value per acre, value per barrel, value per well or value per parcel. The correct criterion does not involve these ambiguities, because it is a percentage.

We are discussing the value of the State's share of the income from the lease and not the value of the leasehold interest. We mean the present value or discounted cash flow of the State's share. This reduces it to a unitary figure. It will be a substantial job to make these estimates and to attach appropriate degrees of certainty to them. This job is indeed impossible so long as preleasing exploration is a monopoly of the potential lessees and the information is not shared with the State. The State must buy or otherwise acquire more information. Professors Rooney and Norgaard both address this vital point (Appendixes G and E).

The next step is to arrive at a forecast of how rapidly we anticipate the present value of the State's share will be rising. This is not a mysterious concept. If we had a simple bonus bidding system it would mean how fast we expected that bonus bids would be rising. If we have a State participation system it means that we calculate the present value or DCF of anticipated State revenues, first on the assumption that we begin the process this year, second on the assumption that we begin next year, third on the assumption that we begin the year after that, and so on.

This all might be done by hunch, but it would be much better to lay the whole process out explicitly on paper in a very systematic way with all the assumptions being stated. This will involve a substantial amount of work the first few times, but specialized personnel may quickly become familiar with the routines involved and devote most of their time to the few questions of judgment which have to be factored in.

3. The basic criterion for ripeness is now assessable. We calculate each year the anticipated percentage growth in the present value of the State's interest in the lease. So long as this figure is higher than the relevant interest rate the time is still unripe for selling.

This is a very difference criterion from a "high display of interest" by the industry. It is likely that the "sooner" interest will be high at a time when sooners anticipate future values to be rising at a very high percentage rate. They would like to get in on the fast

part of the growth curve, but there is no advantage in this for the State.

In calculating the State's share, we must be sure to deduct all associated costs and figure only the net value of the State's share. The gross share will always be growing at a slower percentage rate than the net share, so if we focus on the gross we will sell too soon.

We should add State tax collections to the gross, but be sure to subtract associated public costs from the total to arrive at the net. Adding taxes without subtracting public costs will cause us to sell too soon.

We should resist the blandishments of those whose incomes are our costs. Their interest will be to urge us to sell before the time that is optimal for the State.

We should not accept the argument to speed up selling so that development can occur before costs of development rise further. No cost of development is rising anywhere like as fast as the value of oil in the ground, a fact documented earlier. The wellhead price of Swanson River Oil in 1961 was $1.50 a barrel. If we produced that oil beginning today, fifteen years later, and had it classified as new oil and sold it for $12.00 a barrel, that is an eightfold increase in fifteen years, which works out to 15 percent per annum compounded. The State can borrow money at a much lower rate than that.

We should not give in to the pressure applied by "socners" who see the value of their map files depreciating with each passing year. The State owes them nothing.

We should not think that selling for top dollar will tend to screen out leaner firms. Lean, efficient firms can pay well for something they can sell quickly. It is long waiting periods that screen out lean firms: they work with impatient money. We can also reduce the price of entry by shrinking the size of the units we well, as the price per barrel goes up. The later we sell the more profit is to be made on each barrel and the fewer barrels it requires to make a viable operation.

We should remain constantly aware that the owners of the pipeline have much less interest than the State does in waiting for higher prices. Since they own the pipeline and the costs are mostly fixed, their value for oil is at Valdez while ours is at Prudhoe. The percentage increase in value at Prudhoe will always be greater than the percentage increase at Valdez because of the leverage effect.

In forecasting needs for production from new leases, the State should bear in mind the finding from other areas that the major increment to new reserves each year does not come from new discoveries but from the revaluation of proven reserves on extant leases (Lovejoy and Homan, 1967).

4. The appropriate interest rate for the State to use should be no higher than its borrowing rate and might be lower if the State has surplus funds which it is being forced to invest in ventures of questionable marginal productivity merely in order to do something with the Permanent Fund. The State should add a "shadow cost" to its interest rate to account for its freedom from its own State and local taxes. It does not make sense for the State to invest capital or withhold assets

earning 4 percent from its own citizens who might be earning 5 percent, where the extra 1 percent goes to pay State and local taxes. But as to the extra 3 or 4 percent required to pay federal taxes, that is another question. This is 99 percent leakage from the State and so, as a matter of State policy, should not be considered. Federal policy is something else, but that is not our present concern.

5. Just as there is an optimal time to sell leases, so there is an optimal time to begin preleasing exploration. Where the State is contracting this out, the time to begin should be calculated essentially in the same way as the time of selling leases. This will necessarily be done on a much lesser base of information.

6. At the time of lease auctions the State should set a reservation price. The Public Land Law Review Commission found that where all bids were rejected, they were substantially higher at the next auction. Professor Norgaard's analysis (Appendix E) pinpoints this as one of the most needed reforms.

7. The State should give some concern to maintaining a steady flow of lease sales, but should not let that dominate policy. For one thing, it tends to follow automatically from the criteria suggested. That is, a bulge in lease sales will overload the industry and reduce present bids and create, therefore, an expectation of higher future bids.

An artificially contrived steady flow in the face of roller coaster world prices is not advisable. It is extremely costly in lost revenues and one of its major effects is to help the largest firms overcome their diseconomies of scale, that is, their large commitment of

fixed capital. Smaller, more flexible firms are better able to move in and out and take advantage of unstable conditions.

Something along the line of the procedure sketched above has been attempted by Kalter, Tyner and Hughes in their "Alternative Energy Leasing Strategies and Schedules for the Outer Continental Shelf" (Kalter, et al., 1975). I do not vouch for everything in the Kalter report and I believe it leaves out some of the steps specified, yet I recommend it as a first step towards demonstrating how to apply these procedures.

A particular problem in the context of current federal price controls is the need to watch federal regulators carefully with their tendency to discriminate against what they call "old oil." In many natural resource tenure questions there is a grandfatherhood principle of favoritism applied. This indeed is the basis of "soonerism." Federal price control of oil and gas has taken exactly the opposite tack, a reverse grandfatherhood principle, with new producers being allowed better prices than old producers. So long as we may expect this regulatory philosophy to continue, the interest of the State obviously is to defer leasing commitments longer than otherwise. This consideration reinforces other arguments for deferral of leasing and argues strongly for withholding lands from lease. This would not be an antisocial gesture towards the lower 48, but a defensive posture forced on the State by a counterproductive, uneconomical, and irrational Federal policy to which the State has no choice but adapt as best it can.

The State should guard against losing control of its own priorities by being forced into drainage sales along the boundaries of federal and native lands. Some are born decisive, some achieve decisiveness, and some have decisions thrust upon them, often by others with other axes to grind. The State should push for early resolution of uncertain tenures: native over-claims and State selections. It should push for a drainage agreement with federal and native landowners. The more oil- and gas-prone lands it selects, the greater its decision-making role in the energy industry. Whether the recreation industry, one alternative, will be equally consequential in a future of higher energy and transportation costs is a question to which State officials should give much thought.

Another argument for deferring lease sales is the State's desire to extract more tax revenue from the windfalls at Prudhoe Bay. Heavy taxes on petroleum income received by private firms would be borne by the State in lower bids for new leases. If there is to be a period of high taxation of corporate income from petroleum, it would be well not to sell many new leases until this phase shall have ended.

E. Procedural Implications: Administrative Load and Staff Needs

We may now summarize and recapitulate our observations about staff needs.

Past policy has been dominated and limited by a traditional emphasis on economy of staff. Sales policy over a considerable period was dominated by the short-run cash needs of the State, a passive posture of nonmanagement. These traditions are inappropriate now that the State's oil and gas assets have become so large and are ripening into even higher values.

Yet the Legislature is appropriately cautious about plunging ahead blindly, building a costly administrative empire without making careful, discriminating judgments as to what is most required. One need not look far for examples of valuable public resources whose administrations eat up much of the rents that might be returned to the Treasury.

Economists are aware of a serious perceptual bias, however, which makes most people more aware of padded payrolls than padded capital budgets, the latter being in general a worse problem. The capital-intensive and land-intensive bias of bureaucracies is easily explained: once capital is acquired and captured, its annual cost no longer appears in the budget. Payrolls, on the other hand, are a regular cash outflow, highly visible and much easier to jump on, fairly or not.

A recommendation, therefore, is to make a conscious effort to compensate for this bias. An excellent way is to maintain a constant appraisal of the value of the assets disposed over by the bureaucracy and impose a

"shadow mortgage" on the agency equal to the appraised value of its resources. If we discover that the annual value of the nonlabor input, measured in this way, is much greater than the cost of the personnel we are using to administer it, it will give us a better perspective on the potential productivity of additional personnel.

Having said that we still want to economize on personnel. This does not mean underpaying them, which is one of the more expensive "economies" known to public administration. It does mean adopting those leasing methods which involve the least lost motion. Lost motion results when the basic leasing concept fails to bind the lessee and the lessor in a community of interest. The cheapest leasing method to administer is the one which sets up the least conflict.

High royalties rate poorly on this score. The State shares in the gross income but not in the costs. The State is a landlord administering a share-cropping system. Historical experience with sharecropping shows that successful landlords always oversee many details of their tenants' operation. They have to require the tenant to apply minimum amounts of labor and capital per acre. Thus, a royalty system leads inevitably towards work commitments, with extensive State intervention into operating decisions, which in turn presupposes large staff requirements. Thus, the royalty system, which at first seems so simple, is not simple to administer successfully.

The next step beyond royalty is profit sharing. This in turn requires constant auditing of expenditures. Staff requirements here may be compared with Internal Revenue Service requirements in the kind and

quantity of personnel. Some staff requirements could be obviated by borrowing information from the federal agency. However, the kind of information required for the net proceeds approach, presupposed with individual leases, might be difficult to obtain. In addition, federal tax returns are limited by the peculiar institutions of federal taxation of oil and gas, which we do not wish to emulate.

If we use a profit share system or a rent share system where the interest rate is guaranteed, we must solve complex problems about the useful lives and depreciation paths of capital assets. Many of these are treated as current expenses for federal purposes so that we cannot simply borrow the federal rules, even if we regard them as well conceived in the first place.

An advantage of the front-end recovery system is that we do not have to decide about depreciation lives and paths.

All cost sharing schemes, however, pose us a choice between two evils. We may submit to exploitation through cost padding or we may build up a large audit staff whose job is to trace down the endless and mind-bending maze of avoidance devices which may be and have been utilized to transfer profits to controlled companies elsewhere.

If we opt for the ad valorem charge approach, we need to staff up a large appraisal section. We need a staff of professional appraisers supported by additional reservoir engineers. On the other hand, we can dispense with the auditors and we need not be involved in imposing work commitments on lessees. Appraisal itself is a species of audit, and the ad valorem charge imposes its own kind of work commitment on the

person who has to pay it. Where the administration of cost sharing may be compared with the Internal Revenue Service, the administration of the ad valorem charge may be compared with property tax assessment.

Whether we choose royalties or cost sharing or ad valorem charge, we cut into private motivation to explore the underground and will need to allocate some cash to acquire the information in other ways, either in-house, or by contracting out exploration, or by Rooney's Exploration Expenditure Bidding (Appendix G). Either way, the appropriations committee will see the cash outflow and have to use inference and analysis to be persuaded that the bids received for State property are higher as a result. We should guard against the resulting perceptual bias leading us to overestimate the costs relative to the gains.

The next step in eliminating administrative costs is to move back to an ex ante system with emphasis on the bid bonus and/or a corresponding delay rental. These systems appear to relieve us of some administrative burden.

Note well, however, that in order to time sales properly we need the services of an appraisal staff, even if we use a simple bonus system. We need to be able to set a reservation price in case the bids are all too low, and above all we need to know the rate at which probable sales prices are increasing, in order to know the optimal time to sell. We would obviate the simpler appraisal task of valuing resources ex post discovery and description, but make more critical the more difficult task of appraisal before disclosure of outcomes.

An appraisal staff is also needed to assess environmental impacts which may be measured as the difference in the value of property before and after the impact.

Our most unambiguous staffing recommendation is, therefore, the creation and staffing of an appraisal section. Appraisal gets right to the heart of the rent-collecting business which is to distinguish high-cost deposits from low-cost deposits. It gets right to the heart of timing leasing sales which is putting a value on the State's share and its rate of growth. It gets to the matter of environmental impacts as just mentioned. It supplies an inventory to be used in planning. It is a means of collecting and organizing information in the most generally useful way.

Whatever leasing method is selected, staff resources should be set aside for constant review and evaluation. There should be a postmortem on every sale. How did we do? What mistakes did we make? How can we avoid them next time? Few of us would welcome intensive scrutiny of all our past decisions and understand the reluctance of others to be similarly scrutinized. Yet we all recognize the potential value in such review when applied to others, like the surgeon who just took out our kid's tonsils. It would be desirable, therefore, to institutionalize the postmortem review procedure.

While these are all important matters an excessive concern with them would be premature at this time. The first priority is to legislate basic businesslike guidelines for managing the State's extremely valuable resources. No administration can perform any better than its legislative

mandate allows and an excessive concern with administrative questions at this time would interfere with putting full priority on the larger question of specifying the basic conceptual guidelines and criteria for businesslike management.

F. Leasing and Taxation

Comparisons of leasing alternatives and taxation alternatives have been made throughout this Report. We will not repeat, but bring out points not made elsewhere.

Various lease elements have their counterparts in various taxation elements, but a lease is a binding contract which cannot be unilaterally changed by future legislatures, unlike a tax. A lease can discriminate against interstate commerce unlike a tax (for example, by allowing deduction of in-State costs but not out-of-State costs). A lease is an interest in real estate from which the State can reserve all manner of powers to itself, which it can hardly do when imposing a tax.

A lease differs from most familiar taxes in that it is in rem, that is it is attached to a piece of real estate rather than being in personam, that is an obligation of individuals as such. While this differentiates it from most taxes, it makes it similar to the property tax which is also in rem.

Any attempt to use the corporate income tax in lieu of an adequate leasing policy meets with only limited success because the tax is in personam, and requires an audit of all the affairs of the corporation, and requires interstate sharing, and is subject to the interstate commerce clause. The alternative, "net proceeds" tax, has been criticized by Ziefman and Ainsworth. (Ziefman and Ainsworth, 1977).

The tax instrument that we see as most capable of substituting for leasing policy would be a special, classified property tax to be imposed

either on leasehold interests in oil and gas, or on title to oil and gas after that had been passed from the State to a private buyer. This would closely resemble the proposed ad valorem charge, but would be subject to future changes of rates since the present legislature cannot biud future legislatures in tax matters.

G. Tentative Recommendations

Recommendations are offered tentatively by listing alternative leasing elements in what the consultant now believes to be their order of preference. This listing is not designed to persuade. On the contrary, it may serve to put readers on notice of the consultant's personal judgments which may have unconsciously affected his marshaling of the arguments. Nor is our position ready to be chiseled in stone. This is a complex new field; we have a lot to learn and the consultant reserves the right to change his mind subject to new information and new insights.

I would screen out the systems based on ex ante forecasts, and go with one of the ex post systems. This means primarily that I would not continue depending on a high front-end bonus. This is not because of any universal antipathy to bonuses. In the analogous matter of timber sales from federal forests, I prefer the bonus system as practiced by the BLM in preference to a stumpage rate based on scaled volume as practiced by the Forest Service. Standing timber may be cruised with tolerable accuracy before bids are made and accepted, and the period of time involved is or can be short.

Here on the other hand, we are dealing with resources much less well known in advance and whose extraction extends over two or three decades following the investment in the bonus. Even a five-year contract, as used in some forest sales, screens out many worthy operators without accumulated wealth and would much better be payable on the installment

plan to avoid this problem. To require bidders to pay in advance for an unknown possibility of acquiring a 20- or 30-year supply is virtually to substitute wealth for productivity as the effective basis of allocation. The possession of great wealth suggests there may have been past productivity, although predation and privilege are also sources of wealth. It is no guarantee of present or future productivity.

Whatever system is chosen it needs to be accompanied by vigorous inquiry into the transfer prices being used as the basis of valuation. If costs are to be made deductible the same holds true in spades.

I would place greatest emphasis on that lease element I have called the ad valorem charge (AVC). As indicated earlier, use of this element detracts from the motivation for exploratory drilling and this needs to be compensated for. A high and rising delay rental is recommended.

If we wish to retain the form and terminology of the bonus system, we could describe this as a low signature bonus paid on the installment plan followed by a high production bonus or discovery bonus whose size depends on the flow of production.

To strengthen the State's hand in appraisal and minimize concealment of reserves it would be desirable to accompany this system with a program of State-financed contract exploration with publicity of findings. (Appendix E and Appendix G) This is not, however, absolutely necessary. We could have AVC postlessing, while continuing to rely on the present system of privately financed preleasing exploration.

An ad valorem charge (AVC) at a high rate obviates reservations of acreage for the purpose of getting top dollar at drainage sales. AVC

assures that the State will collect these surpluses anyway.

My second choice would be profit sharing, without front-end recovery or recovery of interest at a guaranteed rate. This is a compromise among the pros and cons of different systems. Royalties, on the one hand, impose too much deadweight loss as the landlord shares revenues without sharing the costs. Sharing costs, on the other hand, in a high degree at a high rate is not administrable. There will be excessive padding.

Profit sharing is somewhat less paddable and hence, with severe policing, would be workable. Since costs may be written off against royalties, but without interest, its bias is mostly against costs which are incurred long before they result in increased production. We have noted that there is too much of that anyway, that several factors conspire to stretch out the period between investment and recovery of capital.

There is a substantial policing benefit to compensate for the social cost of not letting interest costs be deductible against production payments. Interest costs are invisible to most people, and somewhat mysterious, and not so easily perceived as padding. Most people perceive padding in terms of putting relatives on the payroll, featherbedding, girlfriends, and other labor-related offenses. These are highly visible and easily understood, hence likely to be overstressed relative to padding of interest payments. But capital can be lazy, too, and undoubtedly will be if interest payments are guaranteed. Profit sharing avoids this problem.

My third choice is a variable royalty with rates varying according to a variety of objective criteria which could be combined in a point system. Rates would be high where costs are low and vice versa. It would

not do simply to assume that volume of flow is the only important factor affecting costs and to have a sliding or step scale increasing with flow. Several other cost factors, probably including several not even alluded to in our previous discussion, need to be entered into the formula. We could remove the future shift effect by limiting the term of the lease to about 25 years or less.

The advantage of this system over actual deduction of cash expenses is the absence of opportunities for padding. Royalty rates would be low where the characteristics of deposits indicated that a prudent operator of average capability would incur high costs. Individuals who performed better than this standard would reap the rewards of their own efficiency.

The system could be progressively amended and improved over the years as experience indicated that the cost of overcoming certain handicaps had been overestimated or underestimated.

In some ways this system resembles the AVC, being based on an outside objective appraisal of the differential value of different deposits. It is something like having the Legislature play the role of assessor when it sets up the point system. Whether this is practicable is partly a question of how many variables there are which affect costs of production. If there are only a few whose effects on costs can be accurately specified then this system might be workable.

My fourth choice would be front-end recovery. This is preferable to guaranteeing a rate of interest because fast recovery is so much more important to lean firms than to rich ones. This system is to be compared with the privilege of expensing capital investments for income tax purposes.

The problem is that any capital expenditure could be written off immediately against a flush producer, opening the door to extensive goldplating and dissipation of rent. Auditing problems are not insurmountable: there is a limit to the credulity of any auditor as to what may legitimately be justified in expending to develop a specific mineral deposit, and auditors would be highly specialized in the oil and gas business.

If either the profit-share, variable royalty, or front-end recovery system is adopted it needs to be preceded by a substantial delay rental to commit the lessee to performance.

We would not recommend returning to the non-competitive or other claim-staking system. We would not recommend high front-end bonuses. We would not recommend exclusive reliance on annual rentals determined ex ante. We are mildly enthusiastic about unitization, b t prefer a two-tier system coupling individual operation of tracts with overall reservoir management subject to control by lessees themselves, and encouraged by the State to maximize discounted cash flow for the group. An effective two-tier system might permit parcels to be smaller than now, a subject we have not explored.

We would not object to putting an upper limit on the acreage controlled by any one lessee, but regard this as difficult to enforce, somewhat arbitrary, and probably unnecessary if other suggested changes are made. We would not object to leases' being subject to an antitrust impact evaluation by the Attorney-General, although we view this as legalistic, potentially arbitrary, and less desirable than generalized incentives designed to encourage competition.

We believe that liability for environmental damages downstream from a lease should be a lien on the leasehold interest (not on the State's interest) up to the full value of the leasehold interest, provided the damages occur in Alaska. It would be desirable for this lien to extend to all the leasehold interests held by the company committing the damages, introducing a progressive element into risk liability.

Leases should be transferable. All information generated on State-owned lands should be reserved to the State and made public immediately. The State should extend its good offices in the form of a guarantee to all leaseholders that they may have equal access to common carrier transportation. Differences among different leaseholders on the same structure as to desired rates of production are to be resolved by transfers from those preferring slower rates to those who prefer faster rates at a field price to be set by State authority, based on an appraisal of true market value.

Various lesser recommendations on a variety of points have been made from time to time as we proceeded.

We believe the measures recommended would constitute an effective response to the challenge of oil and gas leasing policy in Alaska.

Acknowledgments

I wisn to thank many people who have given of their time and ideas to help make this Report a more useful product. The initiative of the Commissioner of Natural Resources, Guy Martin, his organizational input, and his continuing interest and support are particularly appreciated. In addition, there has been excellent support from the Assistant Commissioner, Jack Roderick, and the DNR staff: O. K. Gilbreth, Pedro Denton, Pat Dobey, and Hoyle Hamilton, particularly.

Gregg Erickson and Fred Boness of the Legislative Affairs Agency have been most helpful. I feel especially supported by the several years of prior research conducted by Gregg Erickson, all of which has been most helpful.

Time has been freely given by James Rhode, David Knudson, Thomas Williams, Barbara Sorenson, and Vincent Wright. I also benefited from an early meeting with the Legislative Interim Committee on Oil and Gas Leasing and Taxation, attended by Senators Croft, Huber, and Poland, and Representatives Anderson, Davis, and Malone.

Alaska citizens outside of government who have given helpful counsel are Robert Atwood, Jamie Love, Tina Stonorov, Peg Tileston, and Arlon Tussing.

Outside of Alaska, I have benefited from the advice of large numbers of informed people of whom I would particularly mention Eugene Corrigan, Executive Director of the Multistate Tax Compact; Professor Robert Kalter, Cornell University; Professor Duncan Harkin, University of Wisconsin; Professor William Lord, University of Colorado; Professor

Stephen Smith, University of Wisconsin; Dr. John Wilson of John Wilson Associates, Washington, D.C.; Dr. William Pendleton of the Ford Foundation; Professor Walter Mead, University of California, Santa Barbara; Robert Paschall, California State Board of Equalization; Ronald Welch, California State Board of Equalization (retired); Professor Albert Church, University of New Mexico; Professor Delworth Gardner, Giannini Foundation, Berkeley, California; Professor Anthony Clunies-Ross, University of Papua, New Guinea; Professor Don Kash, University of Oklahoma; Professor Stephen Cheung, University of Washington; Loren Sivertson, Department of Economic Development, Government of British Columbia; Professor Fred Peterson, Council of Economic Advisors; and Dr. Jack Stockfisch, American Petroleum Institute.

I have benefited from an enormous volume of written words, only part of which are acknowledged in the text. Some particularly helpful works have been several articles by Gregg Erickson; Stephen McDonald's book on "Oil and Gas Conservation"; Lovejoy and Homan on "Estimating Mineral Reserves"; the Public Land Law Review Commission Report, quarterbacked by Duncan Harkin at the University of Wisconsin, dealing with Alaska; Stephen Cheung's book on "The Theory of Share Tenancy"; Gale Johnson's earlier seminal article on the same subject; the report of Professors Kalter, Tyner, and Hughes to the Department of the Interior on OCS leasing policy and scheduling; the California State Assessor's handbook, "Guide to Mineral Valuation"; the recent Library of Congress summary of alternative leasing methods by Useem and Lindahl; the report of the Jackson Committee; the Van Poollen report on the effect of different

rates of extraction from the Sadlerochit Reservoir; the Tanzer report to the State Legislature; the Lipton statement; the work of Campbell Watkins on the economics of oil reservoir development; and Martin Stern's paper, "A Policy Impact Model for the Supply of Depletable Resources." All of these have proved to be fertile sources of information and ideas along with many other works too numerous to list, some of which no doubt should be listed on the same level with those already mentioned if memory only served and time were long enough.

Special mention is due to Professor Guy Phillips, University of California, Riverside, who researched recent changes and prospective changes in federal tax policy related to oil and gas.

Finally, I must thank my associates, Professor Michael Crommelin, Professor Richard Norgaard, and Professor Robert Rooney, whose work is in the Appendixes to this Report. In addition to this independent research, they improved my mind by frequent consultation. They added many ideas to the final Report and subtracted several bad ones. Final responsibility for the Report, however, rests with the author.

SEC. A

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

IN THE HOUSE

BY THE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

HOUSE BILL NO. 854

IN THE LEGISLATURE OF THE STATE OF ALASKA

TENTH LEGISLATURE - SECOND SESSION

A BILL

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

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

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

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

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

(A) maximize the economic recovery of the resources;

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

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

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

(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, develop-

ment, 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:

(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 leasi 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 interests 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

(A) receipt and consideration of nominations for any

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.

(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.

(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 for 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 produced 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.

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

as the term of the federal or private lease, but may not exceed five years.

(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.

(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.

(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.

(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.

(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 noncompetitively. 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).

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

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

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

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

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

A STUDY OF STATE

PETROLEUM LEASING METHODS

AND POSSIBLE ALTERNATIVES

A REPORT TO THE STATE OF ALASKA, JAY S. HAMMOND, GOVERNOR, DEPARTMENT OF NATURAL RESOURCES, GUY MARTIN, COMMISSIONER, AND TO THE ALASKA STATE LEGISLATURE, INTERIM COMMITTEE ON OIL AND GAS TAXATION AND LEASING POLICY, CHANCY CROFT, CHAIRMAN

FEBRUARY 1977

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
OFFICE OF THE COMMISSIONER

JAY S. HAMMOND, GOVERNOR

11TH FLOOR, STATE OFFICE BLDG.
POUCH M — JUNEAU 99811

February 17, 1977

The Honorable Jay S. Hammond
Governor of Alaska
Pouch A
Juneau, Alaska 99811

Dear Governor Hammond:

The following report regarding State oil and gas leasing has been prepared by the Department of Natural Resources as a part of a joint Administration-Legislature effort to evaluate the present leasing system and to explore alternatives for the future. The overall study effort, for which I served as Project Director, also includes other Department documents, the reports of independent consultants and miscellaneous other information.

The information in this report, and the entire study, is intended to serve as basic background material to illuminate alternative State objectives and leasing methods which may be desirable for the future. Although some conclusions are reached in parts of the various studies, no final comprehensive conclusions or positions have been reached, pending further analysis of the results of the study project and discussion thereof.

The complexity and importance of the oil and gas leasing issue for the future of the State has thus far sustained an ideal level of constructive cooperation between the Administration and Legislature, and I am hopeful that this report will contribute to an informed outcome on this matter.

Very truly yours,

Guy R Martin

Guy R. Martin
Commissioner

Acknowledgements

This study was prepared in sections by different people in the Department of Natural Resources. Staff members active in the preparation of the specific sections include:

For the Sensitivity of State Petroleum Income to Various Leasing Methods

Patrick Dobey — Blair Wondzell

Beverly Thompson — Kristina O'Connor

Karen Gibson — Kelly Duncan

Victoria Burgess

For the Variation of Petroleum Leasing Criteria with Geographic Location

Patrick Dobey — Victoria Burgess

For the History of Leasing in Alaska

Pedro Denton — Pete Nelson

Judy Rhodes — Duke Lung

Linda Gardner

For the Staff and Budgeting Needs of Some Leasing Methods Considered

Jack Roderick — Ted Fons

Foreword, Statutory, and Administrative

O. K. Gilbreth, Jr.

In addition, Michael Scott of the Institute of Social and Economic Research and Frank McMordie and David Cook of Garrett Computing Services provided invaluable consulting services.

FOREWORD

This report has been prepared in response to Departmental and Legislative interest in the methods and policies of competitive leasing of state lands for oil and gas purposes. A fairly complete history has been compiled showing pertinent information on past practices of the State. Summaries of all lease sales, bonuses, rentals, receipts and results of drilling and royalty awards are discussed. As a result of this report, it can be concluded that some types of bidding will theoretically yield greater income to the State under specific circumstances than other types will. From strictly a monetary point of view, this study reveals that four major factors will determine which method of bidding would be most advisable for the State to follow. The amount of income to be derived by the State will be determined by the level of risk, the size of the reservoir, the cost of exploration and development, and the value of the oil at the wellhead.

This report has revealed some areas that require further study and this will be done in the coming months. For example, the study reveals that with current economic, royalty, and tax conditions, the minimum size field that an oil and gas operator can afford to look for in Alaska must exceed 55 million barrels in close in areas such as Cook Inlet and could be 100 million barrels or more in remote areas. Also since special cases arise from marginal fields, more detail analysis should be made of effects of reducing royalties to encourage production in sub-economic fields.

Since the purpose of this report is to show variations that can result from various types of bidding most of the emphasis is on types of bidding

other than the cash bonus system. It should not be construed however, as condemning cash bonus bidding nor recommending any alternate type of bidding. The analyses are presented merely to show relative income under specific sets of assumed conditions. A change in some of the input factors can give substantial changes in results.

Risk is the most significant of the variables which would affect income to the State. In unknown, undrilled, untested areas, where the information level is low the risk will be extremely high and these analyses indicate that the cash bonus bidding method would yield greater income to the State. As more information becomes available and as the risk decreases, the method which yields the greatest monetary return revolves around some type of royalty bidding. After a discovery is made, any open acreage on the structure in essence becomes drainage acreage, risk will be low and royalty or some other type of bidding may yield a far greater income to the State than the cash bonus type of bidding. Somewhere then between the extremes of no information and maximum information the method yielding the greatest income probably will switch from cash bonus bidding to some other type of bidding. A significant result of this study indicates that state income can be increased for all leasing methods studied by using a percentage acreage option which is withholding a portion of the structure for later leasing. Other types of bidding are discussed to accomplish other purposes.

There are increasing pressures on government to secure more information about state lands and to know more about the possibilities of petroleum occurrences before the lands are leased. These analyses have been made on the assumption that more information will be available to the State

and if those conditions exist we feel that the values shown give reliable indications of benefits to be derived from one method as compared to another method of bidding.

Risk is dependent on the amount of information available to industry and income to the State is dependent on the knowledge industry has in an area. This study assumes that geological and geophysical information is available to the State at a level above that which it now has. Obtaining this additional information will require expenditure of larger sums of money than in the past. The reader is cautioned not to use the values shown as indicative of all conditions, because as mentioned above, significantly different results are obtained as input factors change. The uncertainty of crude oil prices in remote areas could cause input parameters to change significantly with corresponding changes in analysis results. Therefore, the information presented is to compare one method of bidding versus another method of bidding for a specific set of circumstarces.

Administrative costs and number of personnel can vary greatly depending on the leasing method used. An ad valorem type of leasing could cost up to $240,000 more per year to administer where a net profits system might add $500,000 with the same number of operators and leases as we now have. In Alberta it is pointed out that 100 people administer 50,000 lease agreements and 60 people are involved with auditing in a cost sharing leasing system.

From an administrative cost standpoint, the present method of operation results in the lowest total operating cost at about $1.1 million per year. Depending on the level of data acquisition and analysis, costs will increase

from the present quarter million dollars per year. To obtain adequate seismic data for managing an area of 100 miles by 15 miles will cost from $70,000 to over $1,500,000. The present budget contains $110,000 for the purpose in FY 78.

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ATTACHMENTS, TABLES, FIGURES

DESCRIPTION OF LEASING METHODS IN HB854

Currently, the State of Alaska's leasing system is a cash bonus bid with a minimum fixed royalty of 12.5 percent. The methods outlined below include the present system with different fixed royalties, sliding scale royalty with bonus bid, sliding scale royalty bid with fixed bonus, net profit share bid with fixed bonus, royalty bid with fixed bonus and exploration work commitment. The basic elements of these methods are summarized below.

(1) Bonus Bid With Fixed Royalty

Bonus bid with fixed royalty is the system currently used by the State of Alaska. In a lease sale, the winning bid for a tract is the one which makes the highest sealed or auctioned cash bonus bid. There is also a minimum royalty of 12.5 percent. An advantage of this system is that government receives revenue regardless if there are economical quantities of oil or gas found and/or produced. To avoid early termination of production, royalties need to be flexible during a field's declining years.

(2) Sliding Scale Royalty With Bonus Bid (or Sliding Scale Bid with Fixed Bonus)

Under this system, the government receives a cash bonus bid and a sliding scale royalty. We used 12.5 percent as a minimum figure and 62.5 percent as a ceiling wherein the rate in any period is dependent upon the production of that period.

The royalty rate is graduated in much the same manner as the federal personal income tax. Table I gives two examples of a sliding scale royalty schedule. The royalty is progressive, that is, the royalty on additional production increases. For example, in the South Central Area, the initial 500 barrels pay a royalty of 12.5 percent, the next 500 barrels pay 25 percent. The royalty rate increases by 12.5 percentage points per 500 barrels until 2000 barrels of output are achieved. All production beyond 2001 barrels pays a royalty of 62.5 percent. Thus, if production reaches 5000 barrels, the average royalty rate is 50 percent. In the limit, the average rate would converge towards 62.5 percent as daily production continues to increase.

As field productivity declines and well production falls, the producer backs down the schedule and royalties decline. In order to optimally exploit the field, the royalties should decline to zero near the end of field life. Actually, final rates of five or six percent would result in minimal early shut down.

TABLE I
TYPICAL SLIDING SCALE ROYALTY SCHEDULES

SOUTH CENTRAL AREA

Daily Average Prod. Rate (Bbls./day)	Incremental Royalty Rate (%)	Royalty For Specific Producing Rates: Producing Rate (Bbls./day)	Royalty Production (Bbls./day)	Average Royalty Rate (%)
-500	12.5	500	62.5	12.50
501-1000	25.0	1000	187.5	18.75
1001-1500	37.5	1500	375.0	25.00
1501-2000	50.0	2000	625.0	31.25
2001-2500	62.5	2500	937.5	37.50
		3500	1562.5	44.64
		4500	2187.5	48.61
		5000	2500.0	50.00

NORTH SLOPE AREA

Daily Average Prod. Rate (Bbls./day)	Incremental Royalty Rate (%)	Royalty For Specific Producing Rates: Producing Rate (Bbls./day)	Royalty Production (Bbls./day)	Average Royalty Rate (%)
-1000	12.5	1000	125	12.50
1001-2000	25.0	2000	375	18.75
2001-3000	37.5	3000	750	25.00
3001-4000	50.0	4000	1250	31.25
4001 and above	62.5	5000	1875	37.50
		7000	3125	44.64
		9000	4375	48.61
		10000	5000	50.00

Note: The Sliding Scale Royalty Schedule for the North Slope area is significantly higher than for the South Central area because the higher North Slope operating costs result in a much higher economic limit.

Hopefully, this illustration clarifies the relationship between production rates and royalty rates.

Greater flexibility in setting the initial rate is the major advantage of this system while not running the risk of an uneconomically (for Industry) high royalty rate. On the other hand, to achieve an overall lower royalty payment, a company might spread out production over a longer period of time. Usually, however, because of the time value of money and increased operating costs, oil companies generally try to accelerate production.

(3) Net Profit Share Bid With Fixed Bonus

A small fixed bonus is required as earnest money. The bonus is low enough to encourage producers to bid a high net profit share while permitting profitable development.

(4) Royalty Bid With Fixed Bonus

This system utilizes the same method to calculate fixed bonus as described for Net Profit Share. The bid parameter is a function of production instead of net profits. Since the bonus is fixed, interested parties bid on the royalty rate that the government is to receive. The advantage of royalty bidding is that little front end money is needed by Industry. However, this could encourage speculation causing an overbid. Royalty bidding should encourage more competition among bidders and may allow the smaller companies a better chance of winning the tract.

(5) Work Commitment With Fixed Bonus, Royalty or Net Profit Share

The government itemizes the performance criteria such as the rate and amount of work to be performed on each tract. The total bid specified in dollar terms and a portion of the bid used for exploration and development activities. This system gives the government some control over the rate and extent of resource development.

of ALASKA

MEMORANDUM

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINERALS AND ENERGY MANAGEMENT

DATE: February 28, 1978

Robert E. LeResche
Commissioner Natural Resources

FILE NO:

TELEPHONE NO:

FROM: [redacted]

SUBJECT: Rationale and Apparent Objections to HB 854- Oil and Gas leasing Bill.

Predictability, certainty and an acceptable political climate. These are the three things the petroleum industry looks for in an area attractive for exploration.

I contend it is the availability of land, not the method by which land is offered, that is the critical consideration. In other words, Alaska will become more attractive, less subject to severe criticism by the industry, once land is made available for leasing. The methods of leasing will quickly become secondary.

This contention, of course, will be disputed by the industry. They will argue that because the law allows administrators to choose from a wide variety of leasing methods the industry will remain uncertain about what to expect. I contend that the industry will be given plenty of advance notice of what method will be used in a sale and will therefore have enough time to plan financial strategy.

Industry's contention that Alaska must compete with other areas in the world within company budgets is, of course, correct. This does not mean, however, that Alaska has to settle on one, or perhaps two, leasing methods so as to make the Alaska budget dollar compete within a particular company. The company can estimate how much Alaska's prospective oil is worth to them and can calculate how much will be spent on a particular sale based on the method of lease offering, along with a multitude of other considerations. My basic assumption, of course, is that the oil is here and, eventually, the companies will come looking for it.

Which brings me back to my first point. Certainty and predictability will be established once the industry is convinced that a regular, stable procedure for offering oil and gas lands has been established by Alaska. Once lands are available and administrators are directed to offer leases to the public, most of the pressure will relax.

Industry's objection to the two reports to the legislature by the executive, I think, dramatizes my point. I think the industry will eventually accept the 5-year leasing program as a giant step toward predictability and, even though given wide public accountability, will come to believe that the report will not result in more governmental interference. Industry looks,

however, I think on the annual leasing method report as a way for the legislature to probably work its way into the day-to-day leasing decisions best left to the governor. They fear "politics" in leasing, and I am less sure of this one that I am the leasing program report.

The underlying criticism of HB 854 you will hear, I believe, is that Alaska is "experimenting" with leasing methods. We are said to be trying to adapt all the good features used in other states and jurisdictions and are trying to make them work where they were not designed to work. Alaska is frontier; Alaska is different, goes the argument.

I believe I was to take the first cut at a comprehensive review of Alaska's oil and gas leasing law following Dr. Gaffney's study. I do not claim infallibility but I do claim to have weighed the many considerations which make Alaska like and unlike other jurisdictions. As I have told you, I have tried to confront, head-on, the question of the question of the number of participants in exploration in Alaska. You have mentioned the concept of "incentives", at least as it applies to information, and I have indicated that whereas incentives are not directly dealt with in the legislation I think we may get there in the future.

So, with that background let me set forth the rationale for and some of the anticipated objections to HB 854.

Several concepts were examined and rejected. Found to be not applicable, at least at this time, are the so-called dual-leasing system (Ted Stevens' amendment to S-9). Congress may yet include something like it in OCS legislation. Also, the concept which involves distinguishing between exploration leases and those development and production activities which would be allowed after oil or gas is discovered. We have not included this concept because we believe that Alaska can know before it offers its land for drilling what development and production activities it expects to take place.(Incidentally, the conference committee on S-9 and HR 1614 is scheduled shortly.)

We examined the "ante" versus "post" royalty impact. The post (after) charge is the economic recommendation Dr. Mason Gaffney drew in his study of February, 1977 for the legislature. Dr. Gaffney concluded that the ideal way for a government (any lessor) to determine its economic rent was to determine such rent after a discovery at the price then existing and based upon the size of the field discovered. Determining the value of the field after the discovery is much like the present

calculations of the reserves tax. Its newness, being untried and the unsettling effect its introduction and application would have had on exploration activities in Alaska we felt would be primarily negative. Also, we felt that the legislature could follow-up on Dr. Gaffney's recommendations if they wished. Canada, in its new law for leasing of the North and offshore, has proposed a "progressive incremental royalty" similar in concept to Dr. Gaffney's ad valorem charge. Perhaps, it will be in Alaska's future.

We examined the incentive programs existing in the Province of Alberta, and other jurisdictions, and determined that although some incentives may be needed in the future, they should not be dealt with in this bill. Giving direct tax and other incentives to exploration operators may be necessary, particularly to stimulate the much needed geological and geophysical information data, but we felt future legislatures could deal with this basic policy charge. Rather than incentives, we believe the pace of exploration can best be determined at the time and by the terms of the original lease. And, as I note later, the work commitment lease method can be used to offer incentives.

We examined the trends all over the world toward governments retaining ownership interests (equity) in leases, and toward government-owned and operated exploration companies. We rejected both of these ideas for Alaska. Equity interests in leases makes no sense so long as the state has the flexibility to deal with the many and varied leasing situations which will confront it. Government sponsored exploration, if at all, can be achieved by contract with industry rather than by bureaucrats.

Again, the petroleum industry, not unlike any business, needs certainty and predictability in order to be comfortable doing business. A "stable and predictable leasing policy" - Tom Kelly. "The industry will initially tend to go where it's wanted and an orderly contract and dependable lease sale schedule would undoubtedly provide an impetus to further exploration in the state" - Pennzoil.

The state's need for a flexible, comprehensive, all-inclusive means of leasing appears to conflict with the industry's desire for predictability. One company (Chevron) in an informal paper went so far as to say that giving these many alternatives to the state (HB 854, before a significant change) amounts to "overkill" and makes Alaska an "experimental laboratory in oil and gas leasing." They conclude by saying: "We consider this to be capricious".

In the name of predictability and certainty, oil operators of size almost without exception opt for the cash bonus bid with a fixed royalty as the preferred leasing method. They want the simplest and most predictable method possible

I believe Alaska needs a flexible leasing law so that it may adjust to changes as they occur. The world, national and Alaska energy and oil and gas future is in a state of flux and will remain so for the two decades for which this bill is designed to accomodate. No one can be sure what future developments in energy will be and particularly in Alaska where exploration condition are so diverse.

Alaska is now one of the largest oil owning entities in the world. It will be dealing with petroleum matters, directly, for at least the next two decades, probably much longer. It's immediate future depends in large part on how it deals with petroleum matters. As such, it should become familiar with most of the alternative methods it can use to control petroleum exploration. HB 854, we believe, once it is enacted and in operation will provide the industry the certainty it requires. Admittedly, it calls for State land to be offered by methods including but also other than bonus bid where feasible. The bill introduces more alternatives than now exist, but once these methods are in place and have been used, we believe, most uncertainty will disappear.

One last word on flexibility. In addition to the State, the Federal government and Native Regional Corporations will be leasing land for oil and gas exploration for the next several decades. Terms and conditions under which leases are issued by these entities will include all the variables addressed in HB 854, and, undoubtedly, more. To protect its interest and to operate effectively in this constantly changing exploration picture, the State needs a flexible leasing law by which to respond.

Following, are an itemized list of the objections which I anticipate will be made to HB 854.

1. Term of 5 years. All operators want a lease term as long as possible. In HB 854, Commissioner can go up to 10 years if "extreme conditions, etc." exist. The majors usually know what they intend doing when they bid and lease. The smaller companies will argue that they need more time to put drilling blocks together. The State's interest is to have leases explored and it is not in having leased acreage on the books paying rentals only. Deals can be made in five years. Drilling should proceed as soon as possible, or the land should be offered again to a more agressive operator.

   The time between Cook Inlet lease sales in 1962 and 1965 until first production was begun from Middle Ground,

McArthur, Trading Bay and Granite Point averages under 4 years. Note this is production, not beginning drilling date. Average time from sale to drilling in New Mexico is 6 years.

As I have indicated before, I believe this is the most important term in the lease. The ideal would be for the commissioner to have discretion to set the length of the lease, but I do not believe the legislature or the industry would accept such discretionary authority.

2. Methods of leasing

a. Royalty bidding creates no incentive to develope leases (Chevron). This is particularly true if "surrounding leasehold were such that early evaluation was likely" -(Champlin Petroleum). Same lack of incentive argument is said to apply to high net profits and/or work commitment.

Loss of revenue to state, too risky and premature shutdown problem - (SE Alaska Empire editorial; a reprint of Fairbanks News-Miner editorial, 1977-no date) Rumor has it the USGS in Anchorage (Jones, et al) don't like royalty bidding and DOI forced it on So. Cook Inlet sale. But ARCO's first location appears to be on a royalty tract.

b. Work commitment is faulted for several reasons. Economists, including Gregg Erickson, see it as stimulating activity which the marketplace would not otherwise require. In fact, it can be used to stimulate exploration and, specifically, to acquire exploration information in areas which otherwise might not be explored. There can be an element of incentive in this method.

Tom Kelly sees the use of work commitments as pre-empting small companies. (It is interesting to note that Chevron favored the work commitment so long as the bonus or royalty was fixed and the work commitment was the sole biddable factor). Kelly sees it discouraging the promoting of participations (partners?) in drilling deals because the amount of dollars bid has been fixed. Frankly, I don't quite understand his argument, and contrary to hurting the small companies, I believe it could be used to encourage them to explore. Kelly believes a work commitment works best when it is negotiated and I agree with

him, but we agree that it is unlikely that the Alaskan legislature and public would condone negotiated lease terms by public officials. (unlike royalty sales.)

c. No mention is made of sliding scale royalty by any of the AOGA participants or companies who replied to your letter. All in the department, including Easy Gilbreth and Pedro Denton (from past memorandum in file), feel this is a most satisfactory answer. We are preparing several sliding scale examples for the Cook Inlet and the North Slope so as to focus on the factors which must be taken into consideration in setting the appropriate scale for an area.

d. Net profit will be objected to because it gets the government into the oil company's books and it will will be more costly to administer. Economists Lipton, Erickson, et al will argue it returns the most to the state.

Most economists will agree, I believe, it is the best way if "gold plating " can be controlled, but there seems to be disagreement as to whether it is best used where risks are high or low. Government encroachment will underlie the opponent's arguments.

3. The acreage limitation of 200,000 acres on state uplands (rather than present 500,000) has been objected to thus far only by a few majors. The reduction in the maximum is obviously aimed at the larger companies, and we should so state directly. (A list of state leaseholdings as of 2/10/78 is attached).

Some background may be helpful. No other state that I am aware of, has an acreage limitation. But no other state is Alaska's size nor has any state tens of millions of acres available to lease.

The Federal government has an acreage maximum for its land within each state. During Alaska's territorial days the Federal oil and gas acreage limitation in Alaska was 100,000 acres. In other states it was 46,080.

After 1961, Alaska's rose to 300,000 in the Northern district (approximately north of the Yukon River) and 300,000 in the Southern district. These apply today. Presently the acreage limitation is 246,080 acres of Federal leases per state, other than Alaska.

Finally, note that in HB 854 companies are given five years from the effective date of the act to comply with the 200,000 acre maximum.

Hopefully, a lesser upland acreage maximum in Alaska will act as, albeit a small, incentive for companies other than the majors now here to explore in Alaska.

4. The state's right to purchase up to 16 2/3% of the oil and 100% of the gas will be opposed on the grounds that it is a negative incentive for integrated companies who wish to find and use the oil and gas. We should be careful of this one, but suffice to say that in 1972 New Mexico passed a similar law (N. Mexico can purchase 100% of gas and oil), which though never exercised or tested in court, remains on the books. (a copy attached).

5. Rentals may be opposed as being too high. The authority of the commissioner to up the rental at least 150% each year on shut-in leases may begin to bind the operator without a market, but there is no easy answer to the shut-in field unless we investigate something like the reserves tax concept, which I don't believe will solve the problem.

6. Leases offered noncompetitively after receiving no bids appear to be favored by the industry. Tom Kelly comments that such leases should be offered immediately (automatically?) after the competitive sale.

Please note that HB 854(t), as written, allows the commissioner three options. He can offer tracts immediately, at any time up to 5 years after receiving no bids, or not at all. If he intended to offer tracts noncompetitively immediately after a competitive sale he would so announce in the notice of the competitive sale.

The problem inherent in giving the administrator this many options, it will be argued, is that unpredictability will occur. Unless the operator knows before hand that he can fill out his block of acreage, he is at a distinct disadvantage. The administrator should take these matters into consideration before he notices a sale.

Milton Lipton, Gregg Erickson and others may oppose this open-ended authority to lease noncompetitively following an unsuccessful competitive sale on the grounds that an administrator might rig a competitive sale so that it will not elicit bids so that an immediate noncompetitive lease can be awarded. I don't think such a hit-and-run transaction can exist these days, particularly with HB 854's public disclosure procedures, but, perhaps, I'm too naive.

7. Sealed bids or oral auction or sliding sealed bids (like Alberta). HB 854 permits the commissioner to use any or all of these. Sealed bids will be most commonly used. They are easy to administer. Oral bidding is used in New Mexico and Colorado. Champlin recommends oral bidding on "low potential" land so as to avoid preparing bid forms and "leaving money on the table." New Mexico, on the contrary, uses oral bidding about 50% of the time when it perceives that there will be alot of competition in a sale. About 50% of the time New Mexico offers tracts by sealed bid.

   Alberta allows bidders to slide bids from one tract to another in a sale. Thus, if bidder A's sealed bid fails to win on tract 1, he can direct his bonus be slid to tract 2, and so on.

   Tom Kelly, when commissioner, had his staff investigate this sliding bid method in Alberta in hopes that it might be used for the 1969 Prudhoe Bay $900 million sale. The idea was rejected because the industry objected on the grounds that it would cause too much uncertainty so close to the time of sale. Score one for certainty. Obviously, the advantage to the state would be that more money would be paid at the sale if bids were allowed to slide. Before actually using this system, Alberta's procedures should be studied again.

8. By regulation, the lessee may earn only to the depth drilled(j). I envision that the state would not invoke this right until it felt deeper horizons contained oil, and then would give the lessee a reasonable time to explore deeper. If the lessee failed to drill deeper, the deeper horizons would be offered at a competitive lease sale. Alberta woke up to this problem late and solved it by changing terms of existing lease contracts with all that political controversy.

   I will ask Peter Froehlich to research whether this issue of drilling deeper might not be solved by tightening-up terms of the lease form to require due diligence by the operator at the request of the state.

2-10-78

Alaska - O+G Acreage Holdings

COMPANY	ACRES
Amoco	126, 134.64
ARCO	411, 482.68
BP Alaska	103, 218.99
Bond Oil	71, 260.49
Chevron	126, 493.55
Cities Service	140, 071.58
Exxon	158, 627.73
Hamilton Oil	71, 538.36
Mobil	120, 375.19
Phillips Pet.	250, 748.38
Pure Pet.	135, 588.28
Tenneco	156, 927.03
Union	293, 712.05
Getty	29, 857.30
Shell Oil	40, 603.10
Sun Oil	27, 453.87

CHAPTER 26

AN ACT

RELATING TO STATE LANDS; REQUIRING THE COMMISSIONER OF PUBLIC LANDS TO RESERVE CERTAIN RIGHTS TO THE STATE IN LEASES OR OTHER CONVEYANCES OF STATE LANDS GRANTING ANY INTEREST IN OR RIGHTS TO MINERALS OF WHATSOEVER KIND, INCLUDING OIL AND GAS; PROVIDING FOR A WAIVER OF THE REQUIRED RESERVATION; PROVIDING FOR DISPOSAL OF RESERVED MINERALS.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF NEW MEXICO:

Section 1. COMMISSIONER OF PUBLIC LANDS TO RESERVE CERTAIN RIGHTS TO THE STATE IN LEASES OR OTHER CONVEYANCES OF ANY MINERAL INTERESTS OR RIGHTS TO MINERALS IN STATE LANDS.--In any lease or other conveyance of state lands granting any interest in or rights to minerals of whatsoever kind, including oil and gas, in those lands executed by the commissioner of public lands after the effective date of this section, the following reservation of rights to the state shall be made: "The state has a continuing option to purchase at any time and from time to time, at the market price prevailing in the area on the date of purchase, all or part of any minerals (specify the minerals) that may be produced from the lands covered by this lease (or other conveyance).".

Section 2. WAIVER OF REQUIREMENTS FOR RESERVATION OF RIGHTS IN LEASES OR CONVEYANCE FOR SPECIFIC MINERALS--PROCEDURES FOR WAIVER.--

A. The commissioner of public lands may waive by written order the reservation of rights required under Section 1 of this act in respect to any specific mineral, other than fossil fuels, for which

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Approved March 9, 1973

there is no significant consumptive use within the state, but such order may be made only:

(1) after written notice is mailed by certified mail at least twenty days before the hearing required by Paragraph (3) of this subsection to the governor;

(2) after notice of the hearing required by Paragraph (3) of this subsection is posted in the same manner as notice of public sale of mineral leases is required to be posted under Section 7-9-34 NMSA 1953;

(3) after a public hearing on the issue of waiver under this subsection has been held by the commissioner of public lands or his designated representative in accordance with procedure adopted by the commissioner of public lands; and

(4) if the commissioner of public lands finds after considering the evidence produced at the hearing that a waiver of the provision would be in the best interests of the trust beneficiaries considering long-range and short-range benefits.

B. A waiver granted under Subsection A of this section shall be limited to a definite period of time not to exceed five years. Waivers may be renewed by the commissioner but only after following the procedure required under Subsection A of this section.

Section 3. DISPOSAL OF MINERALS BY COMMISSIONER OF PUBLIC LANDS --The commissioner of public lands shall dispose of any minerals reserved under this act at the best price available in order to gain the maximum benefit for the trust beneficiaries.

STATE'S RIGHT TO PURCHASE OIL & GAS IN HB 854

The State has the right in HB 854(v) to purchase not more than 16 2/3% of the oil and up to 100% of the gas at the regulated price or fair market value at the point of sale. The right to purchase is needed to protect the "in kind" taking of its royalty by Alaska, a sale of said royalty, and a subsequent reduction of the royalty in the later stages of production (d).

New Mexico, 1973, enacted a law which gives it the right to reserve an option to purchase at any time at the prevailing market price any or all minerals, including oil and gas, produced from State land. Thus, New Mexico may purchase 100% of the oil and gas found on State land.

Whereas the New Mexico Commissioner is authorized to waive the reservation option with respect to any specific mineral, he may not do so for oil or gas.

The Act, Chapter 26 of the Session Laws of 1973, has never been exercised by New Mexico; thus no opportunity has been given to test its constitutionality.

If Alaska were to reserve an option to purchase up to the amount of the royalty, fixed or bid, an equivalent net profit share would have to be determined.

LEASING METHODS EXAMINED

BUT NOT INCLUDED IN HB 854

1. The so-called "dual leasing" system which would authorize the State to issue separate exploration and production leases. Senator Ted Steven's amendment to S-9 would permit the exploratory lessee to share with the government (Federal) the costs of the exploratory drilling program, which would be managed by the lessee, in exchange for a share of the revenues received by the government from a subsequently issued production lease.

   The Administration believes that the State can know before it offers its land for drilling what development and production activities it expects to take place.

2. Dr. Mason Gaffney's ad valorem charge, or a "post" royalty system versus the "ante" systems in HB 854. In other words, the state determines its take before discovery, not after. Other governments, like the Canadian national, are going to the "post" systems, i.e. "progressive incremental royalty."

3. Incentives. There are no direct incentives to lessees contemplated in HB 854, except that "work commitment" would allow cash bonuses not to go to the government but instead used by industry for exploration.

4. Government equities in leases or state-owned and operated exploration companies are not envisioned in HB 854.

5. Oil Payment Bidding - shift royalty to rental.

6. Performance System which provides government with the authority to specify the exact rate and extent of resource development.

7. Share Bidding or Phillips Plan. Bonus bids are entered for the entire structure instead of for a specific tract. Based on their equity in the field, each company receives a percent of the profits or losses with a maximum percentage participation by any one company.

8. Alberta's so-called "checkerboard" leasing system wherein a reservation holder may apply for leases over not more than 50% of the area in the reservation in a checker-board pattern. These leases convey the right to produce and sell the Crown's oil and gas, and the government retains the right to alter unilaterally the terms and conditions of the arrangement.

SUMMARY OF ACREAGE LIMITATION
CHANGE IN HB 854

The acreage any one State lessee may hold is 500,000 acres upland and 500,000 acres offshore. HB 854 reduces the uplands to 200,000 acres. This is to help increase the number of upland lessees by limiting the holdings of the larger major oil companies. Offshore holdings will be unaffected.

No other state that we are aware of has an acreage limitation. But no other state is Alaska's size nor has any state tens of millions of acres available to lease.

The Federal government has an acreage maximum for its uplands within each state. During Alaska's territorial days the Federal oil and gas acreage limitation in Alaska was 100,000 acres. In other states it was 46,080 acres.

After 1961 the Federal maximum for Alaska rose to 300,000 acres in the Northern district (approximately north of the Yukon River) and 300,000 in the Southern district. These apply today. There is no Federal acreage limitation on the Outer Continental Shelf. Presently, the acreage limitation is 246,080 uplands acres of Federal leases per state, other than Alaska.

HB 854 grants companies five years from the effective date of the act to comply with the 200,000 upland acre maximum.

A list of major leaseholdings as of February, 1978, (showing uplands and offshore holdings of those companies which now exceed 200,000 acres) follows:

ALASKA OIL AND GAS ACREAGE HOLDINGS
(as of March 13, 1978)

COMPANY	ACRES		
ARCO	408,151.21	356,882.86	acres of uplands
		51,268.35	offshore
		408,151.21	total
UNION	287,032.83	233,138.75	uplands
		53,894.08	offshore
		287,032.83	total
PHILLIPS PETROLEUM	243,227.94	80,332.74	uplands
		162,895.20	offshore
		243,227.94	total
EXXON	158,627.73		
TEXACO	156,027.03		
SOHIO PETROLEUM	135,588.28		
BP ALASKA	103,218.99		
CITIES SERVICE	140,071.58		
CHEVRON	126,493.55		
AMOCO	126,134.64		
MOBIL	120,375.19		
MARATHON OIL	71,538.36		
BEARD OIL	71,260.49		
SHELL OIL	40,603.10		
GETTY	29,857.30		
SUN OIL	27,453.87		

DESCRIPTION OF LEASING METHODS IN HB854

Currently, the State of Alaska's leasing system is a cash bonus bid with a minimum fixed royalty of 12.5 percent. The methods outlined below include the present system with different fixed royalties, sliding scale royalty with bonus bid, sliding scale royalty bid with fixed bonus, net profit share bid with fixed bonus, royalty bid with fixed bonus and exploration work commitment. The basic elements of these methods are summarized below.

(1) Bonus Bid With Fixed Royalty

Bonus bid with fixed royalty is the system currently used by the State of Alaska. In a lease sale, the winning bid for a tract is the one which makes the highest sealed or auctioned cash bonus bid. There is also a minimum royalty of 12.5 percent. An advantage of this system is that government receives revenue regardless if there are economical quantities of oil or gas found and/or produced. To avoid early termination of production, royalties need to be flexible during a field's declining years.

(2) Sliding Scale Royalty With Bonus Bid (or Sliding Scale Bid with Fixed Bonus)

Under this system, the government receives a cash bonus bid and a sliding scale royalty. We used 12.5 percent as a minimum figure and 62.5 percent as a ceiling wherein the rate in any period is dependent upon the production of that period.

The royalty rate is graduated in much the same manner as the federal personal income tax. Table I gives two examples of a sliding scale royalty schedule. The royalty is progressive, that is, the royalty on additional production increases. For example, in the South Central Area, the initial 500 barrels pay a royalty of 12.5 percent, the next 500 barrels pay 25 percent. The royalty rate increases by 12.5 percentage points per 500 barrels until 2000 barrels of output are achieved. All production beyond 2001 barrels pays a royalty of 62.5 percent. Thus, if production reaches 5000 barrels, the average royalty rate is 50 percent. In the limit, the average rate would converge towards 62.5 percent as daily production continues to increase.

As field productivity declines and well production falls, the producer backs down the schedule and royalties decline. In order to optimally exploit the field, the royalties should decline to zero near the end of field life. Actually, final rates of five or six percent would result in minimal early shut down.

TABLE I
TYPICAL SLIDING SCALE ROYALTY SCHEDULES

SOUTH CENTRAL AREA

Daily Average Prod. Rate (Bbls./day)	Incremental Royalty Rate (%)	Royalty For Specific Producing Rates: Producing Rate (Bbls./day)	Royalty Production (Bbls./day)	Average Royalty Rate (%)
-500	12.5	500	62.5	12.50
501-1000	25.0	1000	187.5	18.75
1001-1500	37.5	1500	375.0	25.00
1501-2000	50.0	2000	625.0	31.25
2001-2500	62.5	2500	937.5	37.50
		3500	1562.5	44.64
		4500	2187.5	48.61
		5000	2500.0	50.00

NORTH SLOPE AREA

Daily Average Prod. Rate (Bbls./day)	Incremental Royalty Rate (%)	Royalty For Specific Producing Rates: Producing Rate (Bbls./day)	Royalty Production (Bbls./day)	Average Royalty Rate (%)
-1000	12.5	1000	125	12.50
1001-2000	25.0	2000	375	18.75
2001-3000	37.5	3000	750	25.00
3001-4000	50.0	4000	1250	31.25
4001 and above	62.5	5000	1875	37.50
		7000	3125	44.64
		9000	4375	48.61
		10000	5000	50.00

Note: The Sliding Scale Royalty Schedule for the North Slope area is significantly higher than for the South Central area because the higher North Slope operating costs result in a much higher economic limit.

Hopefully, this illustration clarifies the relationship between production rates and royalty rates.

Greater flexibility in setting the initial rate is the major advantage of this system while not running the risk of an uneconomically (for Industry) high royalty rate. On the other hand, to achieve an overall lower royalty payment, a company might spread out production over a longer period of time. Usually, however, because of the time value of money and increased operating costs, oil companies generally try to accelerate production.

(3) Net Profit Share Bid With Fixed Bonus

A small fixed bonus is required as earnest money. The bonus is low enough to encourage producers to bid a high net profit share while permitting profitable development.

(4) Royalty Bid With Fixed Bonus

This system utilizes the same method to calculate fixed bonus as described for Net Profit Share. The bid parameter is a function of production instead of net profits. Since the bonus is fixed, interested parties bid on the royalty rate that the government is to receive. The advantage of royalty bidding is that little front end money is needed by Industry. However, this could encourage speculation causing an overbid. Royalty bidding should encourage more competition among bidders and may allow the smaller companies a better chance of winning the tract.

(5) Work Commitment With Fixed Bonus, Royalty or Net Profit Share

The government itemizes the performance criteria such as the rate and amount of work to be performed on each tract. The total bid specified in dollar terms and a portion of the bid used for exploration and development activities. This system gives the government some control over the rate and extent of resource development.

TWO VIEWS ON BIDDING STRATEGIES

WEALTH MAXIMIZING STRATEGIES FROM THE STATE'S VIEWPOINT

The choice of bidding method cannot be made on the basis of any single criteria but is the result of evaluating a number of factors including but not limited to the potential economic payoff and physical characteristics of the lease area. HB854 offers essentially four leasing schemes: (1) Bonus Bid - Fixed Royalty, (2) Royalty Bid - Fixed Bonus, (3) Net Profit Bidding with Fixed Bonus, (4) Work Commitment with Bonus Bidding. These options will be briefly evaluated.

Bonus Bid - Fixed Royalty

If the royalty is fixed at 12-½%, there is no reason to use this option. It is of historical value only. At higher fixed royalties, it has some merit, but the higher fixed royalty means a lower bonus bid which is supposedly the advantage of the system. Private discount rates are too high for bonus bidding to be advantageous to the State. For example, a brief examination of an annuity table suggests that increases in the discount rate rapidly diminish the present value of a future income stream. This income stream can be interpreted as the discounted net revenues resulting from the potential discovery and development of an oil field. Table II illustrates the discount rate effect.

Table II
Present Value of an Annuity of $1 Million
(Values in 10^0\$)

Number of Years	Discount Rates					
	6%	10%	14%	16%	18%	20%
20	$11.470	$ 8.514	$6.623	$5.929	$5.353	$4.870
30	13.765	9.427	7.003	6.177	5.517	4.979
N	16.67	10.00	7.14	6.25	5.56	5.00

From the State's viewpoint, a 6% discount rate may properly reflect the present value of the income generated by the potential oil discovery. The industry, on the other hand, is likely to discount the future net income stream at much higher rates, say 20%. Thus, the maximum bid under ideal circumstances would be $5 million for an income stream that would yield net revenues of on million per year in perpetuity. Perpetuity is longer than the life of Prudhoe Bay.

Royalty Bid - Fixed Bonus

Relatively easy to administer - reduces risk and front end filter to the private sector. With sliding scale, most early shut down problems are avoided. The fact

that the State receives a revenue stream over a 20^{+} year time horizon also is an attractive feature. The Beaufort Sale is an ideal candidate for a royalty bidding scheme.

Net Profit Bidding

This is very attractive from a risk sharing point of view. All risks (geologic, exploration, development, and production costs as well as product price) are shared with the industry. Would increase exploration and development in remote high risk areas. May be useful where there is low probability of bid find. Under ideal circumstances (political) is the best of all possible options but does have serious administrative problems.

Work Commitment

Cases where State wants information and is willing to specify type of information desired. Good for high risk areas in remote locations. May also be used where the State wants more information before putting structures up for competitive bidding scheme.

On balance, the royalty bidding schemes represent a substantial improvement over bonus bidding and are administratively tractable. Given the time to build the expertise, it may be advisable to shift to profit sharing or ad valorem schemes.

MULTIPURPOSE STRATEGIES

Bonus Bids

Bonus bidding should be applied in cases where the State has either:

(a) A very great amount of knowledge about the resource, or
(b) The prospect is of extremely high risk, the lessor has little knowledge of the resource and expected value revenues would be marginal.

The first case (a) where tracts might be offered for Bonus Bidding could be that of a drainage or near drainage situation where the State wished to maximize its near term discounted revenues. It would be advisable to not offer all of the tracts for bonus bidding, but to withhold a percent of acreage to be sold at a later date, (Report 2-77). Also, since royalty and other bidding methods have shown to offer higher expected value revenues for lower risk cases it could be advisable to mix royalty bidding with the bonus bidding, a practice followed by the Federal Government in the recent Cook Inlet OCS sale.

In the second case (b), that of extreme high risk, bonus bidding can be used as a filter to determine the value of marginal tracts. This is discussed under the section on (t) low potential, high risk and previously leased.

Report 2-77 indicates that for very high risk cases all bidding methods approach the same level of expected value income for the State. In cases of small and marginal potential reservoirs the bonus bid method with its ease of administration might afford optimum State revenues. Report 2-77 also indicates that in probability of success percents of 1 percent or less bonus bids could afford higher revenues, but the State should ensure that leasing under such high risk cases only occurs when sufficient knowledge is gained to indicate that the land to be leased is of such a low potential. For example, a geologic structure as large as the Prudhoe Bay anticline may have had a high degree of risk before it was drilled but its potential to hold enormous reserves was there. Bonus bidding should not have been used in that instance.

In summary, bonus bidding can be used when:

(1) Very small potential reservoirs are expected;

(2) Extreme risk is expected and the gaining of sufficient knowledge to determine the presence of reservoirs is unwarrented because of marginal to low potential indications.

(3) A sliding royalty should be considered in all bonus bid cases;

(4) This method could be used in a mixture with other methods such as royalty bidding;

(5) Also, in general, this method should only be considered when leasing in the less desirable state areas, i.e. those below the top 10 rank.

Royalty Bidding - Fixed Bonus

Report 2-77 indicates that royalty bidding and profit sharing deliver the highest expected value revenues to the State of all bidding methods. It is particularly effective where the probability of occurrence is high (i.e. low risk) and especially when the expected reservoirs are large. A sliding scale should be added in the declining production years to eliminate the problem of premature shut down. Cases for royalty bidding would be when:

(1) The State has enough knowledge to assess the size of potential traps.

(2) Potential reservoirs are not extremely small or of extreme risk.

The Beaufort Sea sale is a good example of a case for using Royalty bidding on tracts. In general, this method should be considered when leasing in the top 10 leasing areas on the desirability scale.

Net Profit Bidding

Net profit bidding would be most advantageous when costs and oil prices are in a state of extreme fluctuations making economic predictions unreliable. In remote high risk areas, this method might attract stronger bids than the royalty

or the bonus bid method.

Of the 35 potential State leasing areas, this method might be used to advantage on those areas below the top 10 in desirability.

Work Commitment

(See section (t)).

This bidding method can be best used where the State has a large (i.e. 100,000+ acres) area of probable low potential where industry has shown a general lack of interest in exploration and leasing. By offering a large area for lease to one lease owner, the State provides an extra incentive to undertake exploration and the State ensures the exploration by making the bid variable.

This method would be used in remote low potential high risk areas. Some of the State's 3 mile limit lands such as Area IX might be applicable to this method.

Low Potential & High Risk and Previously Leased Section (t)

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

As a means of encouraging the evaluation and possible development of these low potential lands, the department could:

(1) Offer the lands for competitive lease using a bonus bid with sliding royalty. A minimum bid equal to the first year's rentals could be used to filter the bids. This should give a check on the potential of the lands. The sliding royalty would act as a safeguard for very low value bonus bid tracts if a discovery is made later on the lands.

(2) On tracts that receive no acceptable bids, the commissioner could hold a non-competitive similtaneous drawing after proper notice (30 days). Tracts not receiving applications for the drawing could then be opened for over the counter applications. Tracts could be offered at fixed 50¢/year rentals, 5 year terms. A sliding scale royalty would be used in all cases to provide a revenue safeguard against future potential discoveries.

(3) In some cases, all tracts not receiving acceptable bids could be aggregated into large blocks (100,000 acres or more) and offered for work commitment bidding or development contracts.

RESULTS OF LEASING MODEL SIMULATION @ 10% RISK AND LOW COST REGION

EXPECTED VALUE STATE INCOME

Leasing Method	Oil Rec MM/Bbls.	OIL CO. PROFIT *Total	OIL CO. PROFIT *PW @ 10%	STATE INCOME *Bonus	STATE INCOME Royalty	BONUS, ROYALTY & TAXES *Total	BONUS, ROYALTY & TAXES *PW @ 6%	BONUS, ROYALTY & TAXES *PW @ 10%
BONUS 12-½%								
I.	137.6	72.6	14.7	.5	27.6	61.2	24.9	14.6
II.	633.8	376.3	93.2	48.1	127.0	338.9	171.6	118.7
III.	5238.1	3189.1	697.2	385.3	1048.1	2807.0	1347.8	917.1
BONUS 12-½% Acreage Withheld (initial sale)								
II.	633.8	1524.8	289.9	179.9	533.5	1408.3	711.0	490.4
III.	5238.1	17905.3	2950.6	1780.0	6079.1	15900.8	7510.1	5035.4
BONUS 25%								
I.	uneconomic							
II.	633.6	316.9	77.9	38.5	292.5	445.1	214.3	141.8
III.	5236.9	2698.2	582.8	316.3	2095.7	3693.4	1681.2	1091.1
SLIDING ROYALTY								
I.	137.6	71.1	14.2	.1	31.0	63.9	26.2	15.4
II.	633.9	274.6	64.7	30.0	344.8	519.8	249.0	161.3
III.	5238.5	1388.6	265.1	117.1	4891.8	6046.5	2591.7	1568.3
ROYALTY								
I.	137.5	70.0	14.1	0.0	33.1	65.7	26.6	15.5
II.	632.6	178.9	42.4	15.0	547.9	688.9	311.4	193.4
III.	5230.1	1400.5	281.0	125.0	4861.2	6024.1	2555.6	1544.1
NET PROFITS								
II.	634.0	169.8	40.4	15.0	567.0	706.6	318.6	197.1

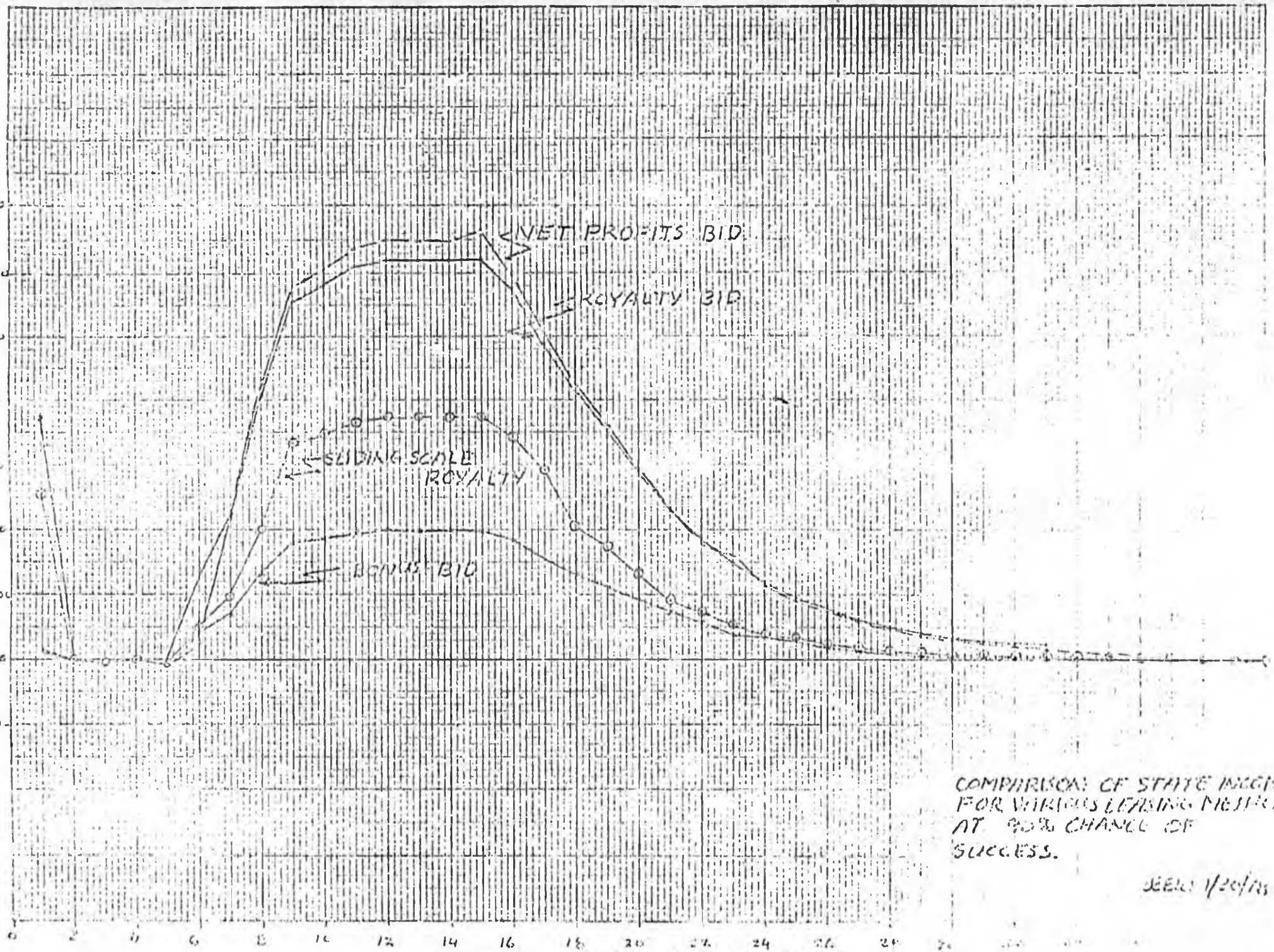
RESULTS OF LEASING MODEL SIMULATIONS @ 90% RISK AND LOW COST REGION

EXPECTED VALUE STATE INCOME

Leasing Method	Oil Rec MM/Bbls.	OIL CO. PROFIT *Total	OIL CO. PROFIT *PW @ 10%	STATE INCOME *Bonus	STATE INCOME Royalty	BONUS, ROYALTY & TAXES *Total	BONUS, ROYALTY & TAXES *PW @ 6%	BONUS, ROYALTY & TAXES *PW @ 10%
BONUS 12 ½%								
I.	137.6	635.0	98.6	44.5	24.9	603.4	275.2	180.8
II.	633.8	3247.7	585.0	377.5	1143.3	3012.2	1520.2	1048.0
III.	5238.1	27716.2	4452.9	2709.9	9433.1	24630.1	11618.3	7780.9
BONUS 25%								
I.	137.4	523.1	79.2	30.6	49.7	815.5	358.0	226.8
II.	633.6	2737.5	492.6	308.9	2285.9	3984.8	1917.6	1267.6
III.	5236.9	23473.1	3746.7	2228.6	18861.8	32734.2	14723.2	9443.5
SLIDING ROYALTY								
I.	137.6	622.1	95.5	42.1	279.0	628.4	287.2	188.1
II.	633.9	2376.0	407.6	256.1	3103.4	4678.2	2249.0	1461.2
III.	5238.5	12200.0	1832.0	820.6	44026.2	54260.4	23201.8	14001.0
ROYALTY								
I.	136.8	308.4	42.9	2.5	972.7	1219.5	516.4	314.2
II.	629.2	495.3	80.5	15.0	7261.1	8216.0	3665.7	2238.2
III.	5216.7	5666.5	836.4	125.0	58312.9	66525.9	27704.6	16370.0
NET PROFITS								
I.	137.7	271.6	38.6	2.5	1054.8	1295.5	538.8	323.7
II.	634.0	433.8	71.6	15.0	7419.0	8369.7	3712.6	2255.9

RESULTS OF LEASING MODEL SIMULATION @ 100% RISK (PERFECT CERTAINTY) & LOW COST REGION

Leasing Method	Oil Rec MM/Bbls.	OIL CO. PROFIT		EXPECTED VALUE STATE INCOME STATE INCOME (10^6)				
		*Total	*PW @ 10%	*Bonus	Royalty	*Total	*PW @ 6%	*PW @ 10%
BONUS + 12-½% ROYALTY								
I.	137.6	705.6	109.6	49.4	27.7	670.4	305.8	200.9
II.	633.8	3608.6	650.0	419.4	1270.3	3346.9	1689.1	1164.4
III.	5238.1	30795.8	4947.7	3011	10481.2	27366.8	12909.2	8644.4
BONUS + 25% ROYALTY								
I.	137.4	581.2	88	34	55.2	906.1	397	251
II.	633.6	3041.7	547.3	343.2	2539.9	4427.6	2130.7	1408.4
III.	5236.9	26081.2	4163	2476.2	20957.6	36371.1	16359.1	10492.8
SLIDING ROYALTY								
I.	137.6	691.2	106.1	46.8	310	698.2	318.9	209
II.	633.9	2640	452.9	284.6	3448.2	5198	2498.9	1624.4
III.	5238.5	13555	2035.6	911.8	489.8	60289.3	25778.9	1556.7
ROYALTY BIDDING								
I.	136.8	342.7	47.7	2.8	1080.8	1355	573.8	349.1
II.	629.2	550.3	89.4	16.7	8017.8	9128.9	4073	2486.9
III.	5216.7	6296.1	929.3	138.9	64792.9	73917.7	30782.2	18188.9
NET PROFITS								
I.	137.1	301.8	42.9	2.8	1172	1439.4	598.7	359.7
II.	634.0	482	79.6	16.7	8243.4	9299.7	4125.1	2506.6



COMPARISON OF STATE INCOME FOR VARIOUS LEASING METHODS AT 20% CHANCE OF SUCCESS.

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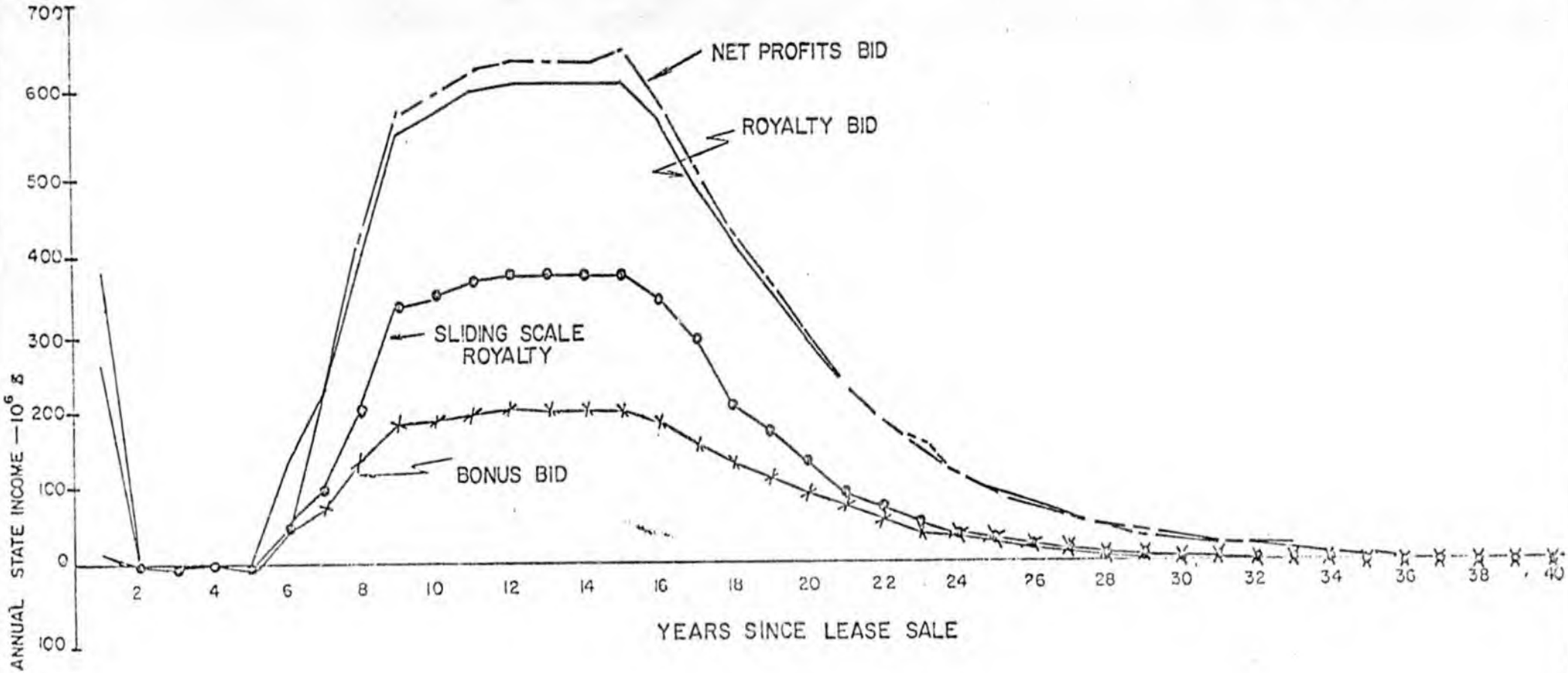

COMPARISON OF STATE INCOME
FOR VARIOUS LEASING METHODS
AT 90% CHANCE SUCCESS

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