Bristol Bay Native Corporation
445 E. 5TH AVENUE / P.O. BOX 220 / ANCHORAGE, ALASKA 99510 / PH (907) 278-3602

March 10, 1978

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

RE: H.B. 854

Dear Mr Chairman:

It is my understanding your committee will be holding hearings on H.B. 854 on March 16th and 17th, 1978. Unfortunately, we will have no representative at the hearings to testify and therefore, we respectfully request this letter be included in the official record of the hearings.

First of all, we object to most sections of this Bill as it is very complex, creates a multiple choice system that is unworkable, discourages exploration on State lands, and above all would have a serious impact on the development of our lands. We strongly urge that no action be taken on H.B. 854 this year.

Previous State selections and proposed selections in our region total several million acres with oil and gas potential in the Nushagak Basin (Bristol Bay Basin). BBNC lands in the onshore portion of this sedimentary basin would total about 1,750,000 acres surrounding 17 villages, several of which the Native lands are not contiguous. In other words, most of our lands with the new proposed State selections would be adjacent to or surrounded by State lands. In many instances, a drilling unit would involve both State and Native lands and in some instances, Federal lands. Therefore, any changes in leasing of State lands will have a direct effect on BBNC lands. Most of the provisions of H.B 854 would change the economics of State and Native lands in a producing unit. The net result will be that the portion of the unit under State leases would become uneconomical and abandoned first and the Native portion of the unit would then become less economical followed by early abandonment and thusly leaving large amounts of oil or gas in the ground. This could hardly be called conservation.

BBNC has had a joint agreement with a major oil company whereby, with commercial production, we will become a producing oil company. We do not lease our lands! Knowing some of our selected lands might not be adequate to cover undefined seismic structures, we anticipated leasing State or Federal lands in order to form drilling units for early development of our lands. About three years ago, we filed the necessary qualifying documents to hold both State and Federal oil and gas leases and have filed offers to lease on several thousand acres of Federal lands.

We have no problem with the present leasing system as it has been tried, tested, proven and above all, is understandable. Such a mixed bag of radical, czarist possibilities as proposed in H.B. 854 is uncomprehensible, unjustified and will no doubt have the opposite effect of the original intent, unless the intent was to retard development of State lands indefinately and in effect retard development of much of our lands.

Again, we strongly urge the postponement of any action on this Bill.

Sincerely,

W. C. Bishop

W. C. Bishop
Manager, Subsurface Resources

Bristol Bay Native Corporation
445 E. 5TH AVENUE / P.O. BOX 220 / ANCHORAGE, ALASKA 99510 / PH (907) 278-3602

March 10, 1978

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

Dear Al:

Due to previously scheduled meetings, we will be unable to have anyone at the hearings on H.B. 854, rescheduled for March 16th and 17th, 1978. Enclosed are sufficient copies of our testimony for each of the committee members.

Al, this Bill, if passed, would be disasterous for BBNC or any other region that has large areas of State selected lands with oil and gas potential. We would be especially hard hit as the State proposes to select several million more acres in our region which we had earlier supported.

This Bill would be a disservice to the entire State and a disaster to the Natives. It is so complex that few, even with an oil industry leasing background, would or could understand it. Certainly it would take months of research in order to salvage much that would be logical. Since there is a somewhat limited time this session, I would strongly urge you, as Chairman, to hold this Bill in committee without any further action.

With best regards.

Sincerely,

Bill

W. C. Bishop
Manager, Subsurface Resources

Encl: a/s

cc: Rep Nels Anderson, Jr.

SUMMARY OF FEDERAL OCS REGULATIONS

PERTAINING TO GEOLOGICAL AND GEOPHYSICAL INFORMATION

Title 30, Section 251.12 of the Code of Federal Regulations specifies that individuals and companies granted OCS exploration permits are required to allow the Department of the Interior (DOI) to inspect and select the forms of information listed below. The permittee must notify the DOI immediately of the acquisition or analysis of any geological data (part a of the section) or the acquisition, processing, or reprocessing of any geophysical data (in part b) collected under the permit. The DOI has at least one year after such notification to choose the material. A longer time period may be specified in the individual permits. The permittee is not required to submit interpreted geological or geophysical information for inspection and selection. If the permittee transfers geophysical data or processed geophysical information to a third party or a third party who has received geophysical data or processed geophysical information directly or indirectly from a permittee transfers said data or information to another third party, the transferor must notify the DOI of the action and bind the third party to the obligations of the permittee. The first set of regulations of this type were approved and put into effect in November, 1975.

The geological data from which the DOI may select includes: (This applies to COST-type and other stratigraphic test holes.)

1. Complete record of all geological and geochemical data and information resulting from each operation;

2. Paleontological reports identifying the microfossils by depth, unless washed samples are kept for inspection by the USGS;

3. Copies of well logs or charts (electrical, radioactive, sonic, etc.);

4. Core or bottom samples analyses or a representative cut of the samples;

5. Detailed descriptions of hydrocarbon shows or hazardous conditions; and

6. Other geological data and analyzed geological information obtained under the permit, as specified by DOI.

The geophysical data, processed geophysical information and reprocessed geophysical information which may be selected includes:

1. A complete record of each geophysical survey conducted, including the final location maps of all survey locations;

2. All common depth point and high resolution seismic data;

3. Processed geophysical information derived from the seismic data;

4. Geophysical data and processed information obtained from, but not limited to:

a. Shallow and deep subbottom profiles

b. Bathymetry

c. Side-scan sonar

d. Magnetometer systems

e. Bottom profiles

f. Gravity surveys

g. Magnetic surveys

h. Special studies such as refraction and velocity surveys, and

5. Reprocessed information such as true amplitude sections, migrated sections, and bright spot analyses.

The DOI may choose any or all of the above data or information at any stage of processing. Thus far the local USGS Conservation Division Office has been selecting final processed data and information. The geophysical data must be kept confidential for ten years after the issuance of the permit. Processed, reprocessed, and interpreted geophysical information is released to the public ten years after it has been submitted to the USGS. Geological data and analyzed and interpreted geological information obtained from deep stragigraphic tests are released five years after completion of the test well or 60 calendar days after the issuance of the first Federal lease within 50 geographic miles of the test site, whichever is earlier.

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.

TESTIMONY ON

ALASKA LEASING POLICY BILL

(H.B. 854)

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

Before The
State of Alaska
House Resources Committee

Juneau, Alaska

March 17, 1978

Mr. Chairman and Members of the Committee --

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

* * * * *

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.

TESTIMONY ON H.B. 854

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

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

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

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

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

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

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

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

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

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

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

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

First, the wide variety of bidding methods:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The right to explore is paid for in advance.

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

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

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

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

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

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

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

* * *

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

* * *

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 signifi cantly 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.

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		

31-Q1LH

STATE OF ALASKA

THE LEGISLATURE

BUDGET AND AUDIT COMMITTEE

AUDIT DIVISION
POUCH W—ALASKA OFFICE BUILDING

FINANCE DIVISION
POUCH WF—STATE CAPITOL

JUNEAU 99801

April 3, 1978

M E M O R A N D U M

TO: Members of the Legislature

FROM: Gerald L. Wilkerson, CPA
Legislative Auditor
Division of Legislative Audit

SUBJECT: Release of Audits

In accordance with AS 24.20.311, the following audit report was approved for release to the Legislature and the public on April 3, 1978:

A Review of Alaska Coastal Management Program, Grant No. 04-6-158-50029, Office of the Governor, Division of Policy Development and Planning

A Special Review of The Division of Marine Transportation, Department of Transportation and Public Facilities

Enclosed is a short digest covering the audit for your convenience. Should you desire a copy of the completed report, it is available at the following libraries or through our office (465-3830):

Alaska State Library
Alaska Historical Library
University of Alaska Library, College
University of Alaska Library, Anchorage
Z. J. Loussac Public Library, Anchorage
Fairbanks-North Star Borough Library, Fairbanks
Ketchikan Public Library
Kotzebue Public Library
Bethel Public Library
A. Holmes Johnson Public Library, Kodiak

Enclosure

31-Q1LH

STATE OF ALASKA

THE LEGISLATURE

BUDGET AND AUDIT COMMITTEE

AUDIT DIVISION
POUCH W—ALASKA OFFICE BUILDING

FINANCE DIVISION
POUCH WF—STATE CAPITOL

JUNEAU 99801

March 3, 1978

SUMMARY OF: A Special Review of the Division of Marine Transportation, Department of Transportation and Public Facilities

PURPOSE OF THE REVIEW

In accordance with your request and Title 24 of the Alaska Statutes, this special report has been prepared on all passenger service aspects of the Division of Marine Transportation, Southeast System. The Steward's Department is responsible for passenger services. The report encompasses:

1. Purchasing and warehousing of supplies used by the Steward's Department.

2. Operating procedures of the Steward's Department on board vessels.

3. Accounting and management control of all passenger services activities.

FINDINGS AND RECOMMENDATIONS

Most of the problem areas noted in our review have been addressed in prior audits, not only by the Division of Legislative Audit (November, 1973 and April, 1976) but also by the Governor's Management and Efficiency Review (May, 1976), the Department of Transportation and Public Facilities' Internal Review (November, 1977), and the Department of Administration's Division of Internal Audit (April, 1966). Each of the previously mentioned reviews emphasized the inadequacy of the Division's accounting and management information system. Yet, management still lacks any effective means of evaluating the Passenger Services Operation.

In addition, all reports noted deficiencies in procedures for purchasing and/or controlling inventory. Our current review again addresses the supply function. Unresolved problems exist in purchasing, receiving, record-keeping,

controlling merchandise transfers, and reconciling physical inventories with accounting records.

The dates of the above audits show that a sufficient period of time for effective action has elapsed since problem areas were initially addressed.

1. DOT-PF should review the total system of providing passenger services for the Marine Transportation Division--including supply, operating, and accounting functions--in order to coordinate efforts and clearly define responsibilities. When the analysis has been completed, procedures should be documented in an operating manual, distributed to appropriate personnel, and regularly updated.

2. The current system of reporting operating results to management is totally inadequate. Management must develop and utilize informational tools to effectively monitor current operations and to make sound long range policy decisions.

3. Material usage should be determined for all retailing operations of the Steward's Department. The usage should be regularly compared to developed usage standards and to sales.

4. Purchases should be planned in advance and based upon realistic usage expectations.

5. The Department should regularly dispose of inventory which exceeds reasonable need. The variety of inventory items should be reduced.

6. The Department's supply section should periodically conduct a complete inventory at all warehousing locations. The accounting section should develop and maintain inventory control accounts for all warehouse locations. These accounts should be reconciled by accounting to its project ledger data as well as to the results of supply's physical counts.

7. The Department's supply section should strengthen warehouse controls in two areas: 1) Receiving goods and 2) accuracy of warehouse records.

8. Accounting for merchandise transfers would be improved by controlling documents.

9. Control over goods and the accuracy of information generated by vessel personnel would be improved by instituting written procedures (see Recommendation

No. 1), training personnel, and improving communications between shore and vessels.

10. Petty cash accounts on vessels should be reduced to minimum amounts necessary for making change and small expenditures.

11. Coin-operated vending machines on vessels should be either owned by the State or covered by a valid contract.

12. Payments to foreign vendors should be made directly to the vendor. When a voucher is prepared the exchange rate should be determined from a local bank and the adjustment in U.S. funds should be recorded on the vendor's invoice.

31-Q1LH

STATE OF ALASKA

THE LEGISLATURE

BUDGET AND AUDIT COMMITTEE

AUDIT DIVISION
POUCH W—ALASKA OFFICE BUILDING

FINANCE DIVISION
POUCH WF—STATE CAPITOL

JUNEAU 99801

February 3, 1978

SUMMARY OF: A Review of the Alaska Coastal Management Program

PURPOSE OF THE REVIEW

To perform a review of the Alaska Coastal Management Program second year grant (Grant No. 04-6-158-50029). The review included audit determinations in the areas of:

1. Financial Compliance
2. Economy and Efficiency
3. Program Results

FINANCIAL ACTIVITIES

$1,788,169.52 was expended by the Alaska Coastal Management Program during the second grant year. As a result of this audit, we have questioned $548,480.34 of the expenditures.

FINDINGS AND RECOMMENDATIONS

1. Property records maintained by the five departments purchasing equipment with Coastal Zone Management (CZM) funds should identify the source of funds used to acquire the property.

   Twenty-five equipment items purchased with CZM funds were examined. Seven of 25 items were not on the property list. Twelve of the remaining 18 items did not indicate funding source.

2. The Alaska Coastal Management Program should not conduct primary research for purposes of completing an Alaska Coastal Management Plan in accordance with the Coastal Zone Management Act of 1972. (PL 92-583, PL 94-37)

   The Department of Environmental Conservation (DEC) purchased equipment in the amount of $6,376 for use in gathering primary data. These expenditures were not authorized by ACMP.

3. Approved time reports should be submitted for all employees charging time to the grant.

Four departments, Office of the Governor, DEC, Natural Resources and Community and Regional Affairs do not require approved time sheets from their CZM employees. Consequently we were unable to determine if payroll charges were properly charged to CZM.

4. The methods of accounting for CZM Federal and match funds by the grantee and subgrantees need to be improved.

We found several exceptions in auditing the CZM funds which individually are insignificant, but when looked at together indicate weaknesses in the accounting for CZM funds.

5. The Alaska Coastal Management Program should establish policies and procedures for the accounting and reporting of in-kind match contributions.

Two departments, Fish and Game and Natural Resources have commingled CZM State match funds with regular operating funds. Consequently, we were unable to separately identify CZM expenditures.

EFFICIENCY AND ECONOMY OF OPERATIONS AND PROGRAM RESULTS

6. The Office of Coastal Zone Management should establish a work schedule that identifies and assigns priority to work program elements which must be completed and included as part of the federally approved Alaska Coastal Management Plan.

The Policy Base Document, which is the heart of the Coastal Management Program, is several months behind schedule.

7. The Office of Coastal Zone Management should review all work program elements to be sure all sections of the Alaska Coastal Management Act and the Federal Coastal Management Act are complied with.

We noted several program compliance contingencies which may prevent Federal and State approval of the Alaska Coastal Management Plan.

8. The Office of Coastal Zone Management should establish policies and procedures to assure effective use is made of available management and financial aids.

A. ACMP did not timely file required quarterly financial and progress reports.

B. ACMP did not timely process reimbursement requests. This cost the State approximately $100,000 in lost interest income.

9. State departments participating in the Alaska Coastal Management Program should obtain a federally approved indirect cost rate and apply it to eligible Federal reimbursable expenditures.

State departments did not claim indirect costs for reimbursements. This amounted to approximately $50,000.

HB 857

February 17, 1978

The Honorable Hugh Malone
Speaker of the House
Alaska State Legislature
Juneau, Alaska 99811

Dear Mr. Speaker:

Under authority of art. III, sec. 18 of the Alaska Constitution, and in accordance with AS 24.30.060(b) and the Uniform Rules of the Alaska State Legislature, I am transmitting a bill extensively amending and updating AS 38.05.180, Oil and Gas Leasing.

I am pleased to present for your consideration this major piece of legislation dealing with Alaska's energy future. Not since statehood has the legislature addressed itself to determining how best to lease our petroleum land. Conditions have changed dramatically since then, both for the petroleum industry and the state, and it is time to make such a reappraisal.

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

How Alaska leases its oil and gas lands will in large part determine our continuing relationship with the oil industry. Many of the problems we now confront in determining the state's fair share of the Prudhoe field could certainly best have been resolved at the time the initial leases were offered by the state. This legislation would make that more likely in the future.

As you are aware, Congress is presently debating a new law covering federal oil and gas leasing on the

Outer Continental Shelf. As you are also aware, much of the attractive OCS land is directly adjacent to Alaska's three-mile offshore land. For this reason, my proposed legislation attempts to be as inclusive as the federal OCS legislation, but more workable, and thus, hopefully, more acceptable to the oil and gas industry.

This legislation is designed to accomplish a number of important state objectives. First, it requires state land to be offered competitively under any of several new leasing methods, including bidding by royalty, sliding royalty net profits and work commitment or a combination of any of these methods. Under certain circumstances, land may be offered on a noncompetitive basis.

Second, it reduces the length of the term of a lease from ten years to five years, to assure that exploration begins promptly once state land is leased. Under certain severe environmental conditions a lease may be for a longer period, but not to exceed ten years.

Third, the legislation increases rentals, including those on shut-in fields, to increase incentives to explore and produce oil and gas fields.

Fourth, the bill grants to the state the right to purchase up to 16 2/3 per cent of the oil and 100 per cent of the natural gas or gas products from the lease, thereby protecting sale commitment of royalty oil and gas in the event the state's royalty is reduced on marginal fields.

Fifth, it reduces the acreage limitation on state uplands so that more companies will have an opportunity to participate in exploring in Alaska and, for the same reason, it allows the state to restrict joint bidding by major or international oil companies.

Finally, the legislation provides that the executive branch will file two reports with the legislature each year. One will outline the state's leasing program for the forthcoming five years. The other will explain the leasing methods used or to be used. I have chosen this method of informing the legislature and the public because I believe there is a need to create as much certainty in leasing policies and procedures as possible. Requiring a five-year state

leasing program to be made public will, I believe, lend stability and predictability to the petroleum exploration business in Alaska and will also raise the level of consciousness of the citizens of Alaska about the workings of the oil business. I can think of no better way to the inform the legislature and the public than to report on a regular basis what land will be made available for oil and gas leasing and by which of several leasing methods the state proposes to offer that land.

The second report will note which leasing methods were used during the preceding year and which methods are proposed to be used in the coming year. Hopefully, enough explanation as to why one method was chosen over another will help educate us all. Although this places an increased burden on those chosen to make these day-to-day decisions, I think it appropriate to use this public accounting procedure for all subsequent state oil and gas lease sales.

Through your leadership, the legislature and my Department of Natural Resources have worked together in an effort to find a solution to Alaska's future leasing policy.

The legislature's action in commissioning Dr. Mason Gaffney's study last year and the subsequent work by the department has paid dividends in developing our understanding of the options available to the state. I wish to thank you for your foresight and cooperation in this most important matter.

Sincerely,

Jay S. Hammond
Governor

DEPARTMENT OF NATURAL RESOURCES

INTRA-DEPARTMENT ROUTE SLIP

TO:
DIV/SEC: _____ LOCATION: _____

ATTN: Hugh Malone

☐ Approval	☐ Note & Return
☒ Signature	☐ Initial & Return
☐ Comment	☐ Return As Requested
☐ Contact Me	☐ Return For Approval
☐ Prepare Reply	☐ Necessary Action
☐ For Your File	☒ Your Information

REMARKS:

APR 26 1978

TB54

FROM:
BY: Jack Roderick DATE: 4/24/78

DIV/SEC: Special Projects DNGM. LOCATION: Anch

STATE
of ALASKA

MEMORANDUM

HB 854

DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINERALS AND ENERGY MANAGEMENT

TO: Robert LeResche
Commissioner, DNR

DATE: April 24, 1978

FROM: Jack Roderick JR
Special Projects, DMEM

HB 854 - Alberta's Oil and Gas Incentive Credit regulations.

Having reviewed Alberta's drilling and geophysical incentive credit programs, I think we should familiarize ourselves before Michael Day, or some Alberta official, briefs us as to how the programs are actually administered. (see my 4/18 memo to Boness)

From reading the attached incentive regulations, it appears that the Board of Energy Resources Conservation (5 appointed persons regulating all energy matters in Alberta) decides which wells qualify for incentive credits. The Minister of Energy and Natural Resources (formerly mines and minerals) decides which seismic surveys qualify. In both cases, a certificate is issued to the qualifier when the permit is issued, prior to the actual drilling or shooting.

Credits may be taken against bonuses, rentals, royalties, and taxes for a fixed period of time (until December 31, 1978 under existing law). Please note that neither drilling nor geophysical credits are transferable. However, in the case of geophysical credits, if a licensee can show that he is not a holder of a "mineral right" under Alberta law the Minister may pay him an amount of money equivalent to the amount of credit he has earned. Gas credits are treated differently from oil credits.

For drilling credit purposes, Alberta is divided into 3 drilling and 4 geophysical regions. The intent, obviously, is to make certain areas of the Province more attractive for exploration by increasing (or decreasing) incentive credits in those areas.

The noninterpretive geophysical data collected by the licensee is made available by the licensee to the public for a period of not less than five years after acquisition at a designated percentage cost of the credit allowance. The government, therefore, enforces the law and regulations but the actual transfer of information takes place within the petroleum industry, not the government.

I have attached copies of Alberta's basic incentive credit regulations. I caution that they have been amended several times since their adoption, but in no structural way that I am aware of.

Michael Day, or whomever, can give us the details when and if he comes to Juneau. Milton Lipton, being a consultant to Alberta, will be able to contribute some comments, also.

cc: Green
Dobey
Speaker Hugh Malone
Gregg Erickson

Speedisel ® Moore Business Forms, Inc.-a

GOVERNMENT OF THE PROVINCE OF ALBERTA

ALBERTA REGULATION 18/74

(Filed January 31, 1974)

THE MINES AND MINERALS ACT

(O.C. 210/74)

Approved and Ordered,

GRANT MacEWAN,

Lieutenant Governor. Edmonton, January 30, 1974.

Upon the recommendation of the Honourable the Minister of Mines and Minerals, the Lieutenant Governor in Council, pursuant to section 14, clause (h) and sections 31 and 142 of The Mines and Minerals Act, makes the regulations in the Appendix attached hereto, being the "Exploratory Drilling Incentive Regulations, 1974".

PETER LOUGHEED (Chairman)

EXPLORATORY DRILLING INCENTIVE REGULATIONS, 1974

1. In these regulations,

(a) "Board" means the Energy Resources Conservation Board;

(b) "class A footage" and "class B footage" mean the respective intervals of depth that are deemed by the Board to qualify for credit of an incentive exploratory well in accordance with section 6 of these regulations;

(c) "crude oil" means crude oil as defined under The Oil and Gas Conservation Act;

(d) "Department" means the Department of Mines and Minerals;

(e) "gas" means gas as defined under The Oil and Gas Conservation Act;

(f) "incentive exploratory well" means a well certified by the Board on or after January 1, 1974 as an incentive exploratory well;

(g) "licensee" means the person to whom a licence is granted under The Oil and Gas Conservation Act for a well certified as an incentive exploratory well;

(h) "Minister" means the Minister of Mines and Minerals;

(i) "plains area", "northern area" and "foothills area" mean the respective areas of Alberta defined in SCHEDULE C to these regulations.

2. (1) Where a licence is granted on or after January 1, 1974 for the drilling of a well for oil or gas, the Board, on the advice of its Geology Department, shall determine whether or not the well qualifies as an incentive exploratory well.

(2) Where a well qualifies as an incentive exploratory well under subsection (1), the Board shall so certify and attach a copy of the certification to each copy of the well licence.

(3) Within 30 days after the granting of a licence for a well that did not qualify as an incentive exploratory well, the applicant for the licence may request the Board to review the eligibility of the well for certification.

(4) Upon conclusion of the review under subsection (3) the Board shall notify the applicant of its decision and if the well qualifies as an incentive exploratory well the Board shall send two copies of the certification to the licensee.

3. (1) A certification lapses 30 days after the date thereof unless the drilling of the well has been commenced.

(2) Where the drilling of an incentive exploratory well is not being conducted to the satisfaction of the Board until completion or abandonment of the well, the Board shall so notify the licensee and thereupon the certification lapses.

(3) When a certification lapses the Board shall inform the Department.

4. (1) When a certification for an incentive exploratory well lapses the holder of the well licence may, within 30 days after the date on which certification lapsed, apply to the Board for a new certification and if the well qualifies as an incentive exploratory well the Board shall so certify subject to subsections (2) and (3).

(2) If any other well has been licensed and certified in the area influenced by the well for which an application for new certification is made under subsection (1), the Board will determine the amount of qualifying footage for the well as though the existing incentive exploratory well had not been certified, and in the event of more than one well having been licensed and certified, priority for credit will be determined by the date of certification.

(3) For the purpose of determining priority for credit between a well under subsection (1) and a well under subsection (2), the application for new certification under subsection (1) shall be treated by the Board as though it were an initial application for well licence and certification.

(4) Where the well referred to in subsection (1) or (2) is certified as an incentive exploratory well, the Board shall send two copies of the certification to the licensee.

5. The Board shall send a copy of each certification to the Department.

6. (1) After the drilling of an incentive exploratory well is completed and upon receipt by the Board of all relevant information relating to the well the Board shall determine what intervals of depth, if any, of the well qualify as class A footage and class B footage.

(2) Upon conclusion of the determination under subsection (1) the Board shall notify the licensee of its decision.

(3) The licensee may forthwith advise the Board that he accepts the determination indicated under subsection (2).

(4) Within 30 days of the notification made under subsection (2) the licensee may apply to the Board to review the determination and the application shall be accompanied by particulars to substantiate any alternative determination of class A footage or class B footage made by the licensee.

(5) Upon conclusion of the review under subsection (4) the Board shall notify the licensee of its decision.

7. When an incentive exploratory well is completed or abandoned to the satisfaction of the Board, it shall inform the Department

(a) the date that the well was completed or abandoned,

(b) the depth of the well in feet, and

(c) the intervals of depth that qualify as class A footage or class B footage.

8. (1) When an incentive exploratory well has been completed or abandoned to the satisfaction of the Board, a credit shall be determined by the Department in accordance with SCHEDULE A or SCHEDULE B and the licensee shall be notified of the credit as determined.

(2) The licensee, within 30 days after the notification made under subsection (1) shall inform the Department in writing as to the manner of allocation of the credit among the participants including those referred to in subsection (5), and the credit shall be allocated and established accordingly.

(3) If the licensee fails to inform the Department within 30 days of the manner of allocation of credit, the credit as determined in subsection (1) shall be established in the records of the Department in the name of the licensee

(4) If an amendment to a well licence is obtained to deepen an incentive exploratory well beyond the formation originally authorized by the well licence, the credit with respect to the deepened portion of the well shall be established according to subsection (2) or (3) unless within 30 days after being notified under subsection (1) the licensee informs the Department in writing as to the manner of allocation of the credit relating to the deepened portion of the well, and thereupon the credit shall be allocated and established accordingly.

(5) The licensee in allocating credit under subsection (2) or (4) shall not allocate more than 20 per cent of the credit to those participants who do not contribute to the actual cost of drilling the well.

(6) Credit established for an incentive exploratory well may, after its allocation, be revised at the discretion of the Minister if the revision is warranted based on information not previously regarded or correctly processed by the Board or the Department.

(7) Credit established under this section is not transferable

9. A credit shall not be established for any incentive exploratory well the drilling of which is commenced after December 31, 1977.

10. Credit established pursuant to section 8, upon the written request of the holder thereof, and subject to procedures established by the Department, may be applied in satisfaction of

(a) moneys payable by him with respect to any applications and dispositions made under Part 5 of The Mines and Minerals Act,

(b) moneys payable by him pursuant to section 40 of The Mines and Minerals Act, or

(c) taxes levied under The Freehold Mineral Taxation Act,

and becoming due and payable between January 1, 1974 and December 31, 1979.

11. Crude oil production

(a) obtained from the class A or class B footage interval of an incentive exploratory well that was certified after January 1, 1974 and that commenced drilling before December 31, 1977,

(b) obtained from a pool in which no other well within three miles has been exempted from payment of royalty to the Crown either under these regulations or under Alberta Regulation 378/72, and

(c) attributable to the drilling spacing unit of the incentive exploratory well referred to under (a),

shall be exempt from payment of royalty to the Crown for a period terminating five years after the date on which production of the well commences.

12. (1) Gas production

(a) obtained from the class A or class B footage interval of an incentive exploratory well that was certified after January 1, 1974 and that commenced drilling before December 31, 1977,

(b) obtained from a pool in which no other well within three miles has been exempted from payment of royalty to the Crown under these regulations, and

(c) attributable to the drilling spacing unit of the incentive exploratory well referred to under (a),

shall be exempt from payment of royalty to the Crown for a period terminating two years after the date on which production of the well commences.

(2) The exemption in subsection (1) is void at the end of seven years from the original finished drilling date of the incentive exploratory well but may be extended at the discretion of the Minister.

13. Where a drilling spacing unit contains a well that is completed for crude oil production in accordance with clauses (a) and (b) of section 11, it shall be exempt from the payment of tax under The Freehold Mineral Taxation Act with respect to petroleum for a period of five calendar years immediately following the year in which the well was completed.

14. Where a drilling spacing unit contains a well that is completed for gas production in accordance with clauses (a) and (b) of section 12, it shall be exempt from the payment of tax under The Freehold Mineral Taxation Act with respect to natural gas for a period of two calendar years immediately following the year in which the well was completed.

15. A decision of the Board under these regulations is final.

SCHEDULE A

Applicable to Class A Footage

Class A footage shall be determined as being the depth interval of a well that has not been duplicated either by

(i) a drilled and abandoned well within approximately one and one-half miles, or

(ii) a completed well or a well that in the opinion of the Board warrants completion, within approximately three miles

Depth, Feet	*Basis for Credit, Plains Area*		*Basis for Credit, Northern Area*		*Basis for Credit, Foothills Area*	
	Cumulative Dollars	*Incremental $/foot*	*Cumulative Dollars*	*Incremental $/foot*	*Cumulative Dollars*	*Incremental $/foot*
0	0		0		0	
		4.00		6.00		8.00
1,000	4,000		6,000		8,000	
		4.00		6.00		9.00
2,000	8,000		12,000		17,000	
		5.00		7.00		10.00
3,000	13,000		19,000		27,000	
		6.00		8.00		11.00
4,000	19,000		27,000		38,000	
		7.00		9.00		12.00
5,000	26,000		36,000		50,000	
		8.00		11.00		14.00
6,000	34,000		47,000		64,000	
		10.00		13.00		17.00
7,000	44,000		60,000		81,000	
		15.00		19.00		23.00
8,000	59,000		79,000		104,000	
		20.00		23.00		28.00
9,000	79,000		102,000		132,000	
		26.00		30.00		36.00
10,000	105,000		132,000		168,000	
		35.00		40.00		48.00
11,000	140,000		172,000		216,000	
		47.00		50.00		56.00
12,000	187,000		222,000		272,000	
		62.00		66.00		72.00
13,000	249,000		288,000		344,000	
		83.00		85.00		96.00
14,000	332,000		373,000		440,000	
		110.00		107.00		120.00
15,000	442,000		480,000		560,000	
		147.00		148.00		160.00
16,000	589,000		628,000		720,000	
		196.00		184.00		200.00
17,000	785,000		812,000		920,000	
		255.00		228.00		240.00
18,000	1,040,000		1,040,000		1,160,000	
		340.00		316.00		320.00

SCHEDULE B

Applicable to Class B Footage

Class B footage shall be determined as being the depth interval of a well that has been duplicated by the deepest drilled and abandoned well within approximately one and one-half miles, providing that such depth interval has not been duplicated within approximately three miles by a completed well or a well that in the opinion of the Board warrants completion.

Depth, Feet	*Basis for Credit, Plains Area*		*Basis for Credit, Northern Area*		*Basis for Credit, Foothills Area*	
	Cumulative Dollars	*Incremental $/foot*	*Cumulative Dollars*	*Incremental $/foot*	*Cumulative Dollars*	*Incremental $/foot*
0	0		0		0	
		3.00		4.00		6.00
1,000	3,000		4,000		6,000	
		3.00		5.00		7.00
2,000	6,000		9,000		13,000	
		4.00		5.00		8.00
3,000	10,000		14,000		21,000	
		4.00		6.00		8.00
4,000	14,000		20,000		29,000	
		5.00		7.00		9.00
5,000	19,000		27,000		38,000	
		6.00		8.00		11.00
6,000	25,000		35,000		49,000	
		8.00		10.00		13.00
7,000	33,000		45,000		62,000	
		11.00		14.00		16.00
8,000	44,000		59,000		78,000	
		15.00		18.00		21.00
9,000	59,000		77,000		99,000	
		20.00		22.00		27.00
10,000	79,000		99,000		126,000	
		26.00		30.00		36.00
11,000	105,000		129,000		162,000	
		35.00		38.00		42.00
12,000	140,000		167,000		204,000	
		47.00		49.00		54.00
13,000	187,000		216,000		258,000	
		62.00		64.00		72.00
14,000	249,000		280,000		330,000	
		83.00		80.00		90.00
15,000	332,000		360,000		420,000	
		110.00		111.00		120.00
16,000	442,000		471,000		540,000	
		147.00		138.00		150.00
17,000	589,000		609,000		690,000	
		191.00		171.00		180.00
18,000	780,000		780,000		870,000	
		255.00		237.00		240.00

SCHEDULE C

FOOTHILLS AREA

The Foothills Area consists of the lands in Alberta listed below and those lands within Alberta located south and west of the listed lands:

Township 1, Range 24; Township 2, Range 25; Township 3, Range 26; Township 4, Range 27; Township 5, Range 28; and Townships 6 to 11 inclusive, Range 29, all west of the 4th Meridian;

and

Townships 12 and 13, Range 1; Townships 14 to 20 inclusive, Range 2; Townships 21 and 22, Range 3; Townships 23 to 28 inclusive, Range 4; Townships 29 and 30, Range 5; Townships 31 to 34 inclusive, Range 6; Townships 35 and 36, Range 7; Township 37, Range 8; Township 38, Range 9; Townships 39 and 40, Range 10; Township 41, Ranges 11, 12 and 13 inclusive; Township 42, Range 14; Township 43, Ranges 15 and 16; Township 44, Range 17; Townships 45 and 46, Range 18; Townships 47 and 48, Range 19; Township 48, Range 20; Township 49, Ranges 21 and 22; Township 50, Range 23; Townships 51 and 52, Range 24; Townships 53 and 54, Range 25; Township 54, Range 26; Townships 55 and 56, Range 27, all west of the 5th Meridian;

and

Township 56, Range 1; Townships 57 and 58, Range 2; Township 58, Range 3; Townships 59 and 60, Range 4; Township 60, Ranges 5 and 6; Township 61, Ranges 7 and 8; Township 62, Ranges 9, 10 and 11; Townships 63 and 64, Range 12; and Township 65, Ranges 13 and 14, all west of the 6th Meridian.

PLAINS AREA

The Plains Area consists of the lands in Alberta contained within the outer perimeter of the lands listed below:

On the east by Townships 1 to 52 inclusive, Range 1; on the north by Township 52, Ranges 1 to 12 inclusive; on the east by Townships 53 to 58 inclusive, Range 13; and on the north by Township 58, Ranges 13 to 26 inclusive; all west of the 4th Meridian;

and

On the north by Township 58, Ranges 1 to 4 inclusive; on the west by Townships 35 to 58 inclusive, Range 4; all west of the 5th Meridian;

and

On the west from Townships 1 to 34 inclusive, the lands immediately adjacent to the FOOTHILLS AREA.

and

On the south by Township 1, Ranges 1 to 23 inclusive, all west of the 4th Meridian.

NORTHERN AREA

The Northern Area consists of the remaining lands in Alberta not included in the FOOTHILLS AREA or the PLAINS AREA.

(Extract from *The Alberta Gazette*, February 15, 1974)

Printed by L. S. WALL, Queen's Printer for the Province of Alberta, EDMONTON

Return to Legislative Research
Library Edmonton, Provl. Y

GOVERNMENT OF THE PROVINCE OF ALBERTA

ALBERTA REGULATION 35/75

(Filed February 11, 1975)

THE MINES AND MINERALS ACT

(O.C. 219/75)

Approved and Ordered,

RALPH G. STEINHAUER,

Lieutenant Governor. Edmonton, February 10, 1975.

Upon the recommendation of the Honourable the Minister of Mines and Minerals, the Lieutenant Governor in Council, pursuant to section 14, clause (h) of The Mines and Minerals Act, makes regulations in accordance with the Appendix attached hereto, being the Geophysical Incentives Program Regulations.

PETER LOUGHEED (Chairman)

GEOPHYSICAL INCENTIVE PROGRAM REGULATIONS

1. In these regulations,

(a) "Department" means the Department of Mines and Minerals;

(b) "foothills area", "green area", "yellow area" and "plains area" mean the respective areas of Alberta described in Schedule C to these regulations;

(c) "geophysical incentive program" means a seismic survey conducted for the purpose of exploring for petroleum or natural gas or both and certified by the Minister as a geophysical incentive program;

(d) "geophysical information and data" means all field data, field reports and the standard processed sections that are stacked after filtering and correction for statics and normal moveout;

(e) "licence" means a licence issued pursuant to Part 9 of The Mines and Minerals Act;

(f) "licensee" means the holder of a licence;

(g) "minimum subsurface coverage" means the coverage obtained when seismic pulses generated from not less than four different source positions are reflected from a subsurface point;

(h) "Minister" means the Minister of Mines and Minerals;

(i) "seismic survey" means a survey conducted by the use of the geophysical prospecting technique known as the seismic reflection method.

2. These regulations do not apply to a seismic survey the recording of which commenced before January 1, 1975.

3 (1) A licensee may, in accordance with these regulations, apply to the Minister to have a seismic survey certified as a geophysical incentive program.

(2) An application under subsection (1) shall be made

(a) prior to commencing the recording of the seismic survey, or

(b) in a case where the recording of the seismic survey commenced on or after January 1, 1975 and before the coming into force of these regulations, not later than February 28, 1975.

(3) The application shall be in Form 1 of Schedule A to these regulations.

(4) Where a seismic survey initially qualifies as a geophysical incentive program, the Minister shall issue an Interim Certificate in Form 2 of Schedule A to these regulations which shall be attached to the copy of the licence in the records of the Department.

(5) A copy of the Interim Certificate shall be sent to the licensee.

4. (1) An Interim Certificate lapses one year after the date thereof unless the seismic survey to be conducted under the Interim Certificate has been commenced.

(2) An Interim Certificate may be granted for one or more seismic surveys to be conducted thereunder.

5. Where a seismic survey is being conducted under an Interim Certificate, the Minister or any person authorized by him may at any time for the purposes of investigation and inspection have access to all the field data and field reports obtained by the licensee during the course of conducting the seismic survey, and the licensee or his representative shall render to the Minister or the person authorized by him such assistance as may be necessary.

6. (1) Within 90 days of completing a seismic survey or surveys under an Interim Certificate, the licensee shall submit to the Minister a final report in Form 3 of Schedule A to these regulations for each seismic survey so completed.

(2) The final report in subsection (1) shall be executed on behalf of the licensee by a registered member of The Association of Professional Engineers, Geologists and Geophysicists of Alberta under seal.

(3) Upon submitting the final report or reports, the licensee may in writing request the Minister to approve a reduction in the size or extent of a seismic survey, and where the Minister approves the reduction the Interim Certificate shall be amended accordingly and a copy shall be sent to the licensee.

(4) Upon receipt of the final report or reports, the licensee shall, at the request of the Minister, make available to the Department for purposes of investigation and inspection all geophysical information and data obtained from each seismic survey completed under the Interim Certificate.

7. (1) When the seismic survey or surveys under an Interim Certificate are completed to the satisfaction of the Minister, the Minister shall certify the seismic survey or surveys as a geophysical incentive program and a credit shall be determined by the Minister in accordance with Schedule B to these regulations, and the licensee shall be notified of the credit as determined.

(2) The Minister shall not give a certification under subsection (1) where he is satisfied that

(a) the seismic survey fails to meet the minimum subsurface coverage, or

(b) the seismic survey is not conducted in accordance with the standards of good geophysical practices.

(3) The licensee, prior to the recording of a seismic survey that is the subject of an application under section 3, shall inform the Minister

in writing as to the manner of allocation of the credit among the participants who have contributed to the actual cost of conducting the seismic survey.

(4) If the licensee fails to inform the Minister of the manner of allocation of the credit, the credit as determined in subsection (1) shall be established in the records of the Department in the name of the licensee.

(5) A credit established pursuant to this section is not transferable.

8. (1) Subject to subsection (2), a credit established pursuant to section 7 may, upon the written request of the licensee, be applied in satisfaction of

(a) moneys payable by him pursuant to dispositions under Part 5 of The Mines and Minerals Act; or

(b) taxes levied under The Freehold Mineral Taxation Act.

(2) Where a licensee provides the Minister with satisfactory evidence indicating that the licensee is not the registered owner of a mineral right within the meaning of The Freehold Mineral Taxation Act or the holder of an agreement under Part 5 of The Mines and Minerals Act, the Minister may pay to the licensee an amount in money equivalent to the amount of credit established in his name in the records of the Department.

9. (1) Any geophysical information and data obtained pursuant to a certified geophysical incentive program shall be made available by the licensee to any person for a period of not less than five years,

(a) three years after the date upon which the geophysical incentive program was certified under section 7, and

(b) at a cost to that person of not more than 60 per cent of the credit established under section 7 for each mile of minimum subsurface coverage.

(2) If a licensee, within the three-year period referred to in subsection (1),

(a) withdraws from Alberta and ceases carrying on business in Alberta, or

(b) being a corporation, is dissolved or is struck off the register pursuant to The Companies Act

he shall place in trust with a person approved by the Minister all the geophysical information and data obtained pursuant to a certified geophysical incentive program until the three-year period has expired and for an additional period of five years, and any credit held in the name of the licensee in the records of the Department shall be cancelled.

10. (1) Where a seismic survey or surveys conducted under an Interim Certificate are not completed to the satisfaction of the Minister and certification as a geophysical incentive program is not granted, all geophysical information and data obtained from the seismic survey or surveys shall be made available in accordance with section 9.

(2) Where a licensee fails to make available geophysical information and data in accordance with section 9, his licence and any credit established under section 7 shall be cancelled.

11. Any of the powers of the Minister under these regulations may be exercised by any employee of the Department authorized in writing by the Minister for that purpose.

SCHEDULE A

Form 1

(Section 3)

APPLICATION FOR CERTIFICATION OF A GEOPHYSICAL INCENTIVE PROGRAM

DATE: .....

NAME OF LICENSEE: .....

ADDRESS: .....

LICENCE NO. .....

PROGRAM NO. ..... NUMBER OF SURVEYS IN PROGRAM:

PROGRAM COMMENCEMENT DATE:

ANTICIPATED PROGRAM COMPLETION DATE:

LICENSEE REPRESENTATIVE: TELEPHONE NO.

.....

(Note: Complete one survey schedule for each survey indicated in above application.)

SURVEY SCHEDULE

SURVEY NO.

NAME OF PERMITTEE:

ADDRESS:

PERMIT NO. PARTY NO.

SURVEY RECORDING TO COMMENCE:

ANTICIPATED RECORDING COMPLETION DATE:

ENERGY SOURCE:

SOURCE SPACING (FEET):

RECEIVER SPACING (FEET):

NUMBER OF TRACES:

yellow-plains *green* *foothills*

MILES PLANNED (APPROX.):

INCENTIVE ANTICIPATED (APPROX.):

TOTAL INCENTIVE ANTICIPATED:

Licensee

(Note: Application must be accompanied by a map or maps on a scale of not less than 1" = 1 mile.)

Form 2
(Section 3)
INTERIM CERTIFICATE NO.

DATE:

NAME OF LICENSEE:

ADDRESS:

LICENSE NO.

PROGRAM NO. NUMBER OF SURVEYS IN PROGRAM:

Minister of Mines and Minerals

Form 3
(Section 6)
FINAL REPORT

LICENSEE:
LICENSE NO.:
ADDRESS:
INTERIM CERTIFICATE NO.: INTERIM CERTIFICATE DATE
RECORDING COMMENCEMENT DATE
RECORDING COMPLETION DATE
PERMITTEE:
PERMIT NO.:
ADDRESS: PARTY NO.
RECORDING COMMENCEMENT DATE
RECORDING COMPLETION DATE
AMPLIFIER MAKE MODEL NO. OF TRACES
24 48 Other

SOURCE INTERVAL RECEIVER INTERVAL SOURCE TYPE

	yellow-plains	*green*	*foothills*
No. of miles of minimum subsurface coverage. (Accurate to two significant decimals)			
	500 x 1	500 x 2	500 x 3
Credit (in dollars) applied for	= $	= $	= $
			Total $

I, the undersigned, certify that I am qualified to report on this program and have personal knowledge of and attest to the accuracy of the above report.

Name and Seal *APPEGGA Class*

(Note: Must be accompanied by a map or maps on a scale of not less than 1" = 1 mile showing location of data recorded.
A final report must be completed for each seismic survey in a program.)

SCHEDULE B

DETERMINATION OF CREDIT

The credit in dollars for a certified geophysical incentive program shall be calculated in accordance with the following equation:

Credit (in dollars) = 500 KM

where K is the incentive factor for the area of Alberta described in Schedule C in which the geophysical incentive program was conducted,

and

M is the number of miles of minimum subsurface coverage in that area.

Incentive Factors

For the purposes of section 7 and this Schedule, the incentive factors established for the areas of Alberta described in Schedule C are:

(a) 1 for the yellow area and the plains area;

(b) 2 for the green area; and

(c) 3 for the foothills area.

SCHEDULE C

Foothills Area

The foothills area consists of the lands in Alberta listed below and those lands within Alberta located south and west of the listed lands:

Township 1, Range 24; Township 2, Range 25; Township 3, Range 26; Township 4, Range 27; Township 5, Range 28; and Townships 6 to 11 inclusive, Range 29, all west of the 4th Meridian;

and

Townships 12 and 13, Range 1; Townships 14 to 20 inclusive, Range 2; Townships 21 and 22, Range 3; Townships 23 to 28 inclusive, Range 4; Townships 29 and 30, Range 5; Townships 31 to 34 inclusive, Range 6; Townships 35 and 36, Range 7; Township 37, Range 8; Township 38, Range 9; Townships 39 and 40, Range 10; Township 41, Ranges 11, 12 and 13 inclusive; Township 42, Range 14; Township 42, Ranges 15 and 16; Township 41, Range 17; Townships 45 and 46, Range 18; Townships 47 and 48, Range 19; Township 48, Range 20; Township 49, Ranges 21 and 22; Township 50, Range 23; Townships 51 and 52, Range 24; Townships 53 and 54, Range 25; Township 54, Range 26; Townships 55 and 56, Range 27, all west of the 5th Meridian;

and

Township 56, Range 1; Townships 57 and 58, Range 2; Township 58, Range 3; Townships 59 and 60, Range 4; Township 60, Ranges 5 and 6; Township 61, Ranges 7 and 8; Township 62, Ranges 9, 10 and 11; Townships 63 and 64, Range 12; and Township 65, Ranges 13 and 14, all west of the 6th Meridian.

Green Area

The green area consists of that part of Alberta in which public lands are classified a forest land not available for agricultural develop-

ment other than grazing by an order of the Minister of Lands and Forests pursuant to section 12 of The Public Lands Act, but does not include those lands described in this Schedule as the foothills area.

Yellow Area

The yellow area consists of that part of Alberta in which public lands are classified as being adaptable to any kind of disposition by an order of the Minister of Lands and Forests pursuant to section 12 of The Public Lands Act.

Plains Area

The plains area consists of the remaining lands in Alberta not described in the foothills area, the green area or the yellow area.

(Extract from *The Alberta Gazette*, February 28, 1975)

Printed by the QUEEN'S PRINTER for the
Province of Alberta, Edmonton