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HEARING
ALASKA HOUSE RESOURCES COMMITTEE
Juneau, Alaska
August 6 and 7, 1979

INTRODUCTION

Mr. Chairman, I join the other Prudhoe Bay Unit Owners in thanking you for the opportunity to discuss the Prudhoe Bay reservoir at this hearing. My name is Paul Norgaard and I serve as Vice President of ARCO Oil and Gas Company, a division of Atlantic Richfield Company. I am responsible for ARCO's activities north of Fairbanks, which includes the Prudhoe Bay Field and I am here today as a management representative of the major owners.

To begin, I would like to summarize some of the activities in which the major owner companies have been engaged since field discovery. As you recall, the Prudhoe Bay State No. 1, Sag River State No. 1, and Put River No. 1 wells were all completed during 1968. Data from these wells, together with seismic data, were immediately input into mathematical reservoir simulations by the major interest owner companies and we initiated our first reservoir studies. The initial data was incomplete and the results of these studies were simply used as a guide to facility design and general reservoir mechanics.

Owner companies initiated a very aggressive data gathering program at the start of development drilling in 1969. We obtained basic data from cores (underground rock samples), fluid samples, and logs. In addition, we developed highly sophisticated interpretive data from laboratory tests and studies. The owner companies began immediately to share the bulk of this data to assure the best possible reservoir studies and reservoir management. In addition, the owner companies agreed on facility sizing and location to assure minimum disturbance to the field area. The major interest owners met on many occasions to discuss plans and results of both reservoir and facility studies, and on several occasions discussed these results before legislative committees and the Oil and Gas Conservation Committee.

I should mention that we continually changed and improved the mathematical reservoir simulations to better reflect the real reservoir. As development wells were drilled, the frequency and location of shale and rock qualities became better known, and as laboratory studies were completed, additional rock characteristics and fluid qualities were refined. The major owners, in general, were making improvements and refinements in their reservoir descriptions and mathematical simulations every year.

Prior to the May, 1977 unitization hearings, the three major interest owner companies finalized a series of extensive studies to address the major reservoir management questions. These were offtake rate, gas sales, water injection, and timing of facility additions. The results were summarized at the May, 1977 Pool Rules Hearing and are a matter of public record. It should be noted that this operating plan provides for:

A. oil production at the rate of 1.5 million barrels per day;

B. gas pipeline deliveries of 2 billion standard cubic feet per day when treating and transportation facilities are available;

C. drilling of wells on 160-acre spacing or closer if warranted;

D. installation of low pressure gathering systems and artificial lift when necessary to maintain production rates;

E. selective injection of produced water into the Sadlerochit in areas of low natural depletion recovery when the volumes became significant; and

F. supplemental injection of source water when optimum injection locations and volumes could be ascertained, additional recovery predictions verified, and the project's economic viability could be substantiated.

One key point made at the hearing and later by the Oil and Gas Conservation Committee was the need for production history to verify the study results and provide a basis to calibrate the mathematic simulations. We are now two years into production and now possess some of this history. During this two-year period, extensive data has been obtained and has been continually analyzed. We have provided summary reports, as well as the basic data itself, to the Oil and Gas Conservation Commission. The owner companies have developed fieldwide three-dimensional models to fully utilize this data and have conducted studies to again refine and improve the quality of our reservoir management plan. This careful analysis demonstrates that the field is performing very well, at least as well as predicted, and slightly better in some regards. Nevertheless, much additional study and analysis will be required in the future to fully optimize field development.

The planned studies of a source water injection system have moved forward in parallel with the reservoir studies. The pace and detail of these studies has increased during the past two years with good progress in all study areas. Permit applications have been filed with the Army Corps of Engineers. We shall discuss these items later in more detail.

Moving now to our presentation. All three major owner companies have participated in the studies which we shall be discussing and in the preparation for this hearing.

We have broken our discussion into three parts.

1. <u>Field Performance</u> - To be presented by Brian Davies from Sohio.

2. <u>Reservoir Management Studies</u> - To be presented by Larry Smedley from Exxon.

3. <u>Waterflood Study Progress</u> - To be presented by David Griffiths from ARCO.

Since the pieces of our presentation all inter-relate, we suggest that questions be deferred to the conclusion of the three parts. Copies of the text will be available at the conclusion of our presentation.

TESTIMONY BEFORE ALASKA HOUSE RESOURCES COMMITTEE
JUNEAU, ALASKA
AUGUST 6 and 7, 1979

PRUDHOE BAY UNIT
PRODUCTION PERFORMANCE

Mr. Chairman, Members of the House Resources Committee, Ladies and Gentlemen; my name is Brian Davies. I hold a Honors Degree in Natural Sciences from Trinity College, Dublin. I have been employed by British Petroleum and Sohio in petroleum production and exploration activities for 16 years in the North Sea, Arabian Gulf, Colombia and Alaska. Since 1971, I have been involved in the development of the Prudhoe Bay Field, as District Petroleum Engineer and as Sohio's representative to the Prudhoe Bay Unit Planning Subcommittee in Anchorage. My current position is Supervisor of Production Planning for Sohio and as such I continue to be involved with the development plans for the Prudhoe Bay Field.

The purpose of my presentation to you today is to describe the production performance of the Prudhoe Bay Field. I will start with a summary of the field development since the commencement of production in June 1977. Next I will briefly discuss the reservoir surveillance methods that the operators are using to monitor the field performance. I will then discuss the production and pressure behavior, well performance, and the fluid contact movements in the reservoir. Overall the production performance has been good and essentially as predicted.

The Prudhoe Bay Field has been on sustained production for just over two years. Initial offtake from the field was restricted to about 720 thousand barrels per day, because of the accident at Alyeska Pump Station #8. After repairs to the Pump Station were completed in March 1978, the rate of production was increased to about 1.16 million barrels per day. Since then, the performance of the pipeline system has been progressively improved so that currently an offtake level of 1.28 million barrels per day is being achieved. In the field we have maintained sufficient producing potential to continuously produce at pipeline capacity rates.

Early production from the field was sustained by approximately 100 wells in total serving two flow stations in the Eastern Operating Area and two Gathering Centers in the Western Operating Area. By the end of the first 3 months of production, all facilities were functioning satisfactorily. Also, the flaring of gas ceased except during the commissioning of new facilities and for emergencies caused by minor upsets in the operation of the plant. Of the total of 500 billion standard cubic feet of gas produced since January 1, 1978, over 99.8% has been reinjected into the reservoir or used as fuel.

The third Gathering Center in the Western Operating Area was commissioned in March 1978, and the third Flow Station in the East came on stream in March of this year. These facilities have enabled additional wells to be progressively brought on production and have permitted offtake to be distributed more evenly over the field. Currently nearly 200 wells have been drilled and connected for production. Over a period of two years this represents a doubling of the number of wells available for production. We are proceeding with the further development and operation of the Prudhoe Bay Field in a manner which is consistent with the plans presented in the May 1977 Pool Rules Hearing before the Oil and Gas Conservation Committee. These plans permit the degree of flexibility that is necessary for good reservoir and production management control.

RESERVOIR SURVEILLANCE

In the previous testimony to the Oil and Gas Conservation Committe in May 1977 the Unit owner companies described their plans for reservoir surveillance. The owners recognized that a comprehensive reservoir surveillance program was necessary to provide the data needed to optimize the continued development of the field. The response of the reservoir to production is indispensable in understanding the recovery mechanisms and in checking the accuracy of reservoir descriptions. In addition to frequent well testing the owners proposed an intensive reservoir pressure measurement effort, a program designed to monitor changes in gas saturation and an evaluation of techniques to monitor changes in the water saturation of the reservoir. Subsequently the Alaska Oil and Gas Conservation Committee issued Conservation Order No. 145 which incorporates rigorous surveillance requirements in the Prudhoe Oil Pool Rules.

Over the last two years the surveillance program has generated a tremendous volume of field performance data. In our view the level of reservoir surveillance and testing activity which has been carried out and which is continuing in the Prudhoe Bay Field has rarely been surpassed. This viewgraph summarizes this surveillance activity. Over 450 measurements of reservoir pressure have been obtained, and 220 flow meter surveys have been run. These flow meter surveys are used to establish the contribution of the various intervals that are open to production in the wellbore. Also, 215 initial baseline and follow-up surveys have been done to monitor the changes in gas saturation in the reservoir. The neutron logging tools used in these surveys have proved to be extremely valuable in locating the leading edge of the advancing gas cap, and also in monitoring other changes in gas saturation around the well bore.

Some 60 surveys have been made to attempt to monitor the changes in the water/oil contact in the reservoir. As was pointed out in the May 1977 hearing this is a difficult technical problem. However the aggressive evaluation program has given us encouraging indications that a technique is available which will yield quantitative estimates of the changes in water saturation caused by any rise in the water/oil contact.

Overall the surveillance and testing program is providing a wealth of basic information. This enables us to understand the production performance and to continue to optimize future development.

PRODUCTION AND PRESSURE BEHAVIOR

Let me now briefly review the production history since June 1977. The viewgraph shows the buildup in oil production from an initial rate of 720 thousand barrels a day to the level of 1.28 million barrels per day in June 1979. Also shown is the production of gas which is associated with the oil. The ratio of the produced amount of gas to oil at any particular time is referred to as the gas/oil ratio. At the start of production this was approximately 750 standard cubic feet of gas per barrel of oil. The ratio has risen somewhat and currently in July 1979 is approximately 920 standard cubic feet of gas per barrel. This slight increase in overall gas/oil ratio is primarily due to wells in the Eastern part of the field, particularly in the Flow Station 2 area. This is mainly caused by the localized influx of gas cap gas under the continuous shales in this area. Currently the operators have considerable flexibility in controlling the gas/oil and water/oil ratios. They are deliberately producing high gas/oil ratio wells located high on the structure and close to the gas cap so as to maximize the recovery of the gas condensate liquids, while excess gas reinjection capacity is available.

Before we leave this viewgraph I would like to point out that the bottom line, that is barely distinguishable from the lowermost axis of the graph, represents the water production which, as predicted, has been very low and currently amounts to just under 20,000 barrels per day.

The data obtained from the reservoir pressure measurement program is, among other analyses, used to draw maps of the pressure decline at various times. This particular viewgraph shows such a map corresponding to our interpretation of the decline at August 1, 1978. Each line connects points at which we believe the reservoir pressure is the same. This line, for instance, is the contour line corresponding to the 100 pounds per square inch decline level. You will note that the area showing the greatest decline occurs in the Flow Station 2 region. This is caused by the unusually high incidence of shales which prevent good vertical communication of the producing intervals with the overlying gas cap. As I mentioned before, these shales are also the cause of the localized influx of the gas cap gas. We will discuss this matter in more detail later, and show that this performance is as was predicted. We should also emphasize that this is a relatively small area of the field and that the intervals affected contain less than 6% of the oil in place in the reservoir.

To avoid further increase in the pressure decline in this area we changed our production offtake distribution and reduced the amount of oil that was being withdrawn from the Flow Station 2 area. This next map shows the reservoir pressure decline corresponding to August 1, 1979. Due to the reduced production from the Flow Station 2 area, the pressure sink has stabilized and is now no greater than it was one year ago. In fact, in specific wells, there has been an increase in reservoir pressure during the past year.

Another factor that I should point out, is that the pressure measurements reflect primarily the pressures in the reservoir intervals that are being drained. Where the presence of extensive shales impairs communication with other parts of the oil column, the measured reservoir pressure will be lower than the average pressure of the total oil column in the reservoir at that location. When we take into account the distribution of the pressure, both areally and vertically through the sand intervals, then the pressure decline for the oil column is approximately 185 pounds per square inch. This is actually less than was predicted prior to production and certainly is no cause for alarm.

WELL PERFORMANCE

The well capacities average about 11,500 barrels per day and are in good agreement with the preproduction predictions.

It has been suggested that gas coning is causing production problems at Prudhoe Bay. It is a fact that in wells, where there is relatively good communication in the vertical section between the producing interval and the overlying gas cap, there is a potential that early gas production will occur. This phenomenum is known as gas coning, and the mechanism is illustrated in this viewgraph. As oil from the perforated interval of the well is produced, a pressure drop is felt at the gas/oil contact, which can result in the contact being locally drawn down around the well bore, until eventually gas is produced through the uppermost part of the perforated interval. As was discussed at the May 1977 hearing, we have deliberately restricted the interval of the reservoir that is open to production in such wells. We have generally maintained a distance of 200 to 260 feet between the top of the production interval and the gas cap in order to minimize the potential for this coning effect. This policy has been very successful in preventing gas coning in the highly productive wells completed under the gas cap. In short, gas coning has not been a significant problem at Prudhoe Bay.

This practice also has the effect of reducing the production capacity of such wells and thereby increases the number of wells required to achieve a given production rate from the field. Similar restrictions are placed upon how close to the oil/water contact we open up for production. By adopting such measures we surrender the short term benefits in well productivity in exchange for the longer term benefits that will be derived from the more efficient displacement of oil by overlying gas and underlying water. In essence we have spent more money, drilling more wells early, in order to ensure better long term reservoir performance.

MOVEMENT OF GAS/OIL AND OIL/WATER CONTACTS

As I mentioned previously, the neutron tool has proven to be a highly effective method for monitoring changes in gas saturation in the reservoir. Based upon the results of these surveys, we interpret that the overall movement of the gas/oil contact is of the order of 15-20 feet per year, on average. This is certainly very close to what was predicted prior to production, for the oil offtakes we have maintained to date.

We have observed gradual rises in water/oil ratios in a number of wells over the last 2 years. When we match the individual well performance with reservoir models, the results suggest that the heavy oil-tar zone, which is often present just above the oil/water contact, does not present a barrier to water influx. This is consistent with our predictions prior to production. To date monitoring of the oil/water contact with the logging techniques available has indicated very little overall movement of the contact, which is also in agreement with previous predictions.

In summary I would like to emphasize the following points:

1. A very extensive data gathering program has been undertaken during the first two years of production and is continuing, to ensure adequate surveillance of the reservoir performance in the Prudhoe Bay Field.
2. The data generated by this program is largely consistent with our pre-production predictions, and there have been, remarkably few surprises to date. In overall terms the field is performing well.

The next speaker, Mr. Smedley of EXXON will provide more details of the comparisons between the predicted reservoir behavior and that which has been observed in the field to date.

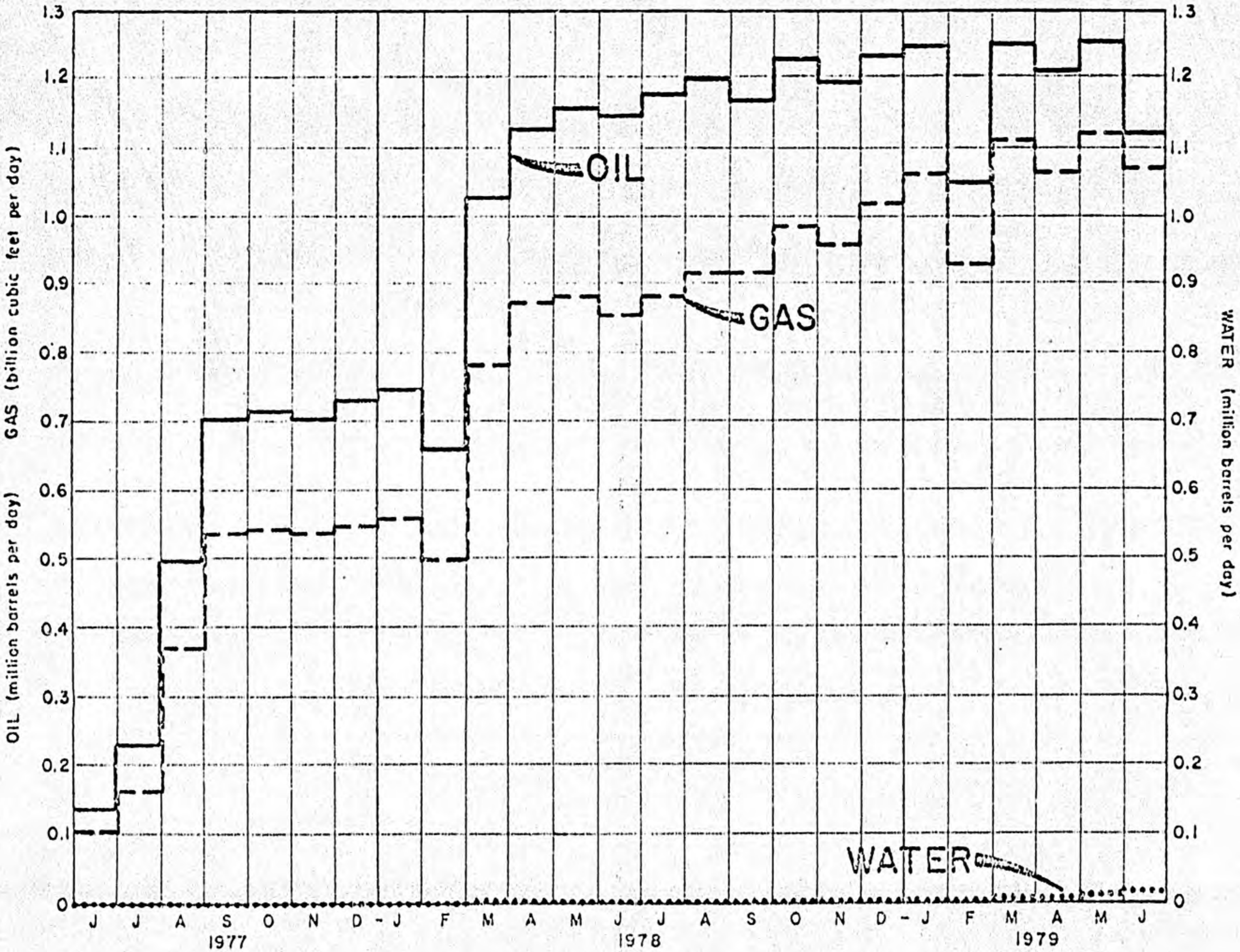
- FIELD DEVELOPMENT SINCE PRODUCTION START-UP.
- RESERVOIR SURVEILLANCE ACTIVITIES.
- PRODUCTION AND RESERVOIR PRESSURE BEHAVIOR.
- WELL PERFORMANCE.
- GAS-OIL CONTACT MOVEMENT.
- OIL-WATER CONTACT MOVEMENT.

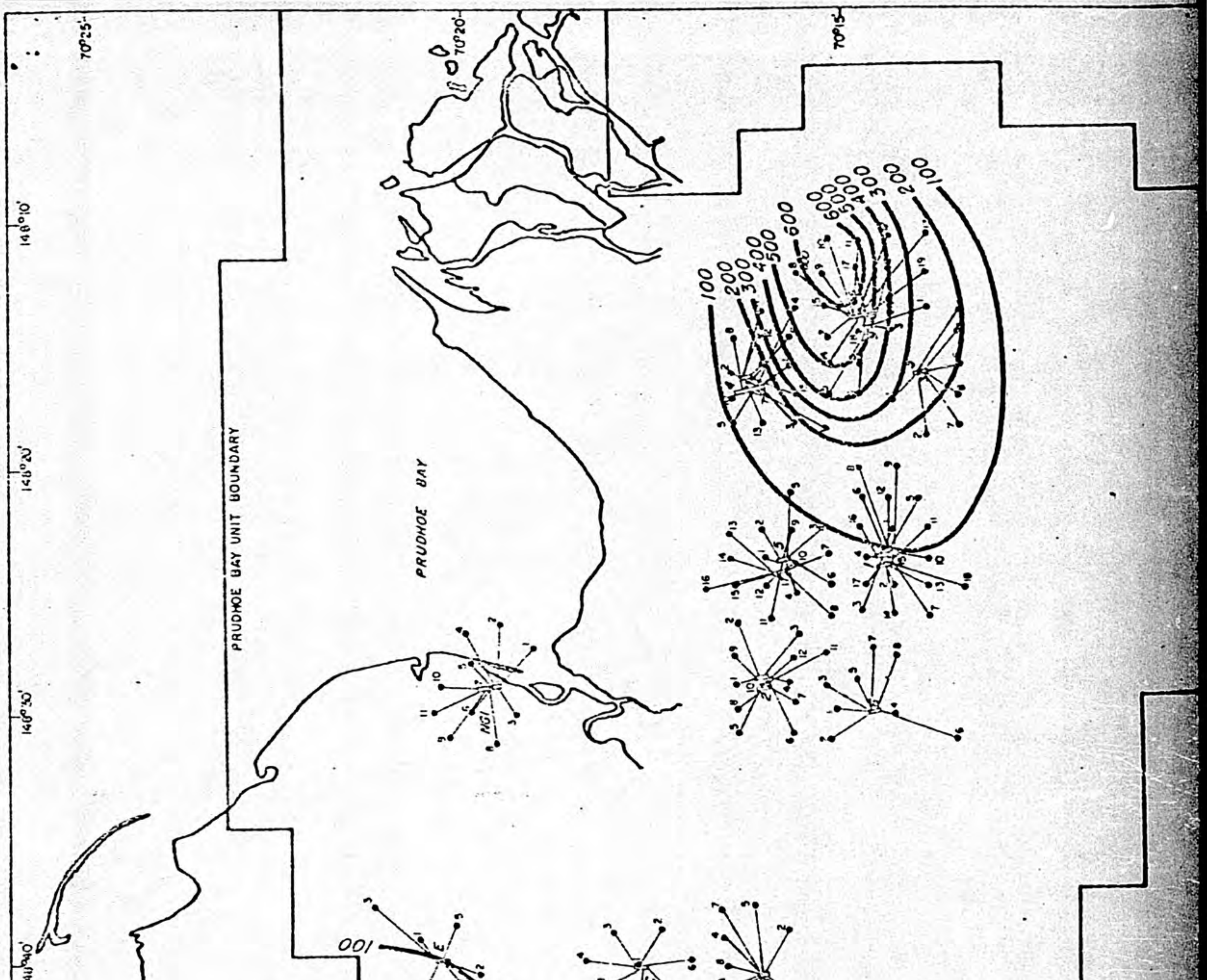
SUMMARY OF BOTTOM-HOLE SURVEYS

JUNE 1977 - JUNE 1979

• RESERVOIR PRESSURE SURVEYS	450
• FLOWMETER SURVEYS	220
• GAS-OIL CONTACT SURVEYS	215
• WATER-OIL CONTACT SURVEYS	60

PRUDHOE BAY FIELD
PRODUCTION HISTORY



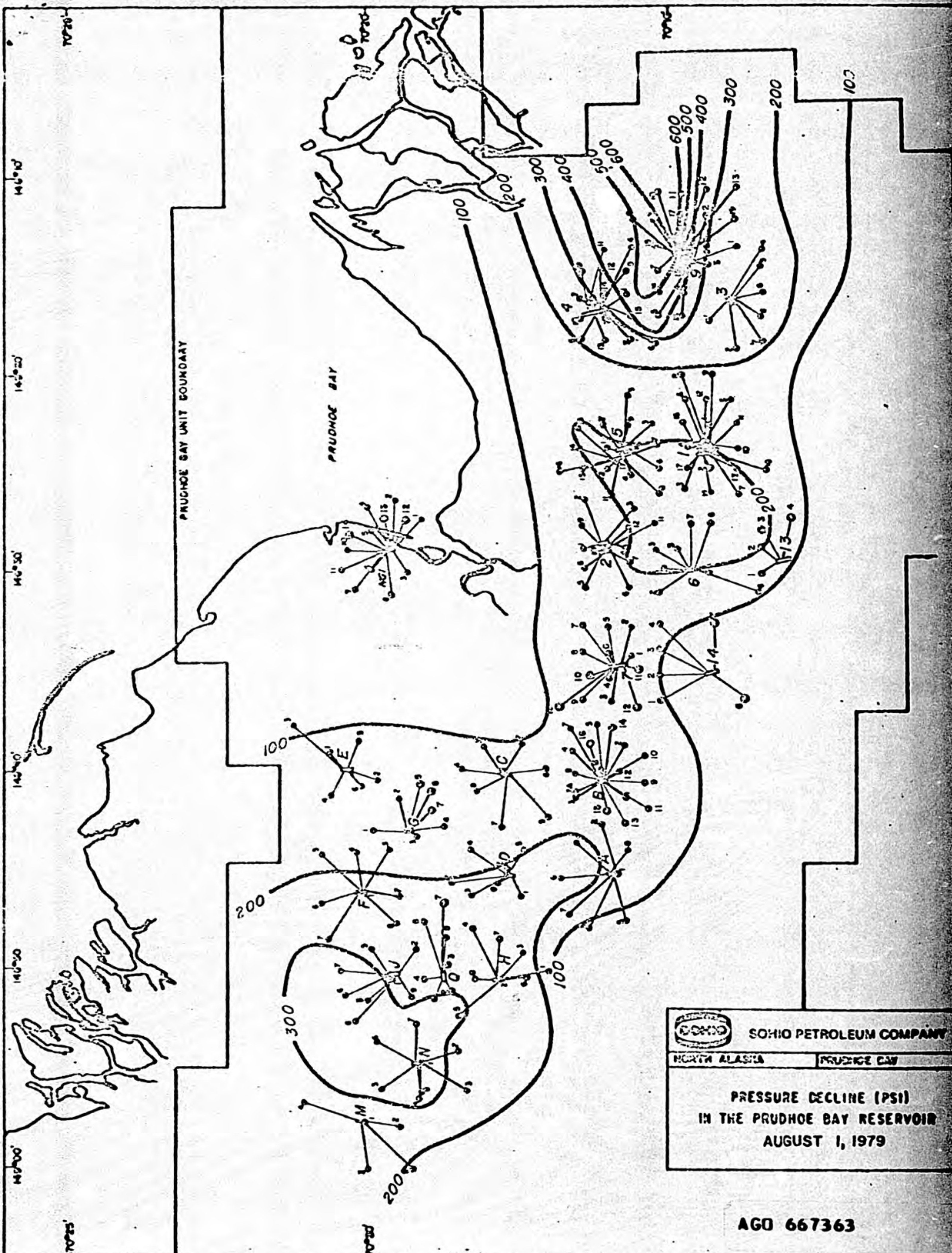


SOHIO PETROLEUM COMPANY

NORTH ALASKA	PRUDHOE BAY

PRESSURE DECLINE (PSI)
IN THE PRUDHOE BAY RESERVOIR
AUGUST 1, 1978

AGO 667362



SOHIO PETROLEUM COMPANY

NORTH ALASKA | PRUDHOE BAY

PRESSURE DECLINE (PSI)
IN THE PRUDHOE BAY RESERVOIR
AUGUST 1, 1979

AGO 667363

HEARING
ALASKA HOUSE RESOURCES COMMITTEE
Juneau, Alaska
August 6 and 7, 1979

PRUDHOE BAY UNIT
WATERFLOOD STUDY PROGRESS

Members of the House Resource Committee, ladies and gentlemen, my name is David Griffiths. I received a Bachelor of Science degree in Petroleum Engineering from the University of Texas in 1958, and was employed by Atlantic Richfield Company as an engineering trainee. Following three years of military service, I rejoined ARCO where I have had a number of reservoir engineering and production engineering assignments. Since moving to Alaska in 1974, I have been directly associated with North Slope activities. For the past two years I have been a member of the Prudhoe Bay Unit Planning Subcommittee, which has had the responsibility to coordinate the waterflood studies which have been conducted in the Unit.

During the next few minutes, I would like to discuss the progress of the waterflood studies that have been underway during the past several years. I will briefly reflect on the work that has been done to date and describe the current status of the waterflood project. Following this, I will outline the future waterflood project plans as they are now envisioned.

Between 1969 and 1974, five waterflood feasibility studies were undertaken by ARCO, Exxon, and Sohio. The studies led to these conclusions: 1) a waterflood system for Prudhoe Bay is mechanically feasible; 2) the most probable source of water is the Beaufort Sea; and 3) field performance history is needed to properly design the system.

Work done between 1974 and 1976 established eighteen engineering studies that would need to be undertaken prior to completing the conceptual design of a waterflood system. Such studies would include analysis of water source; freeze problems; soils and permafrost; ice; weather; materials selection; water treatment; and more general project interface studies such as environmental and permitting requirements, project planning, and cost estimating. While many of these study areas were common to many waterfloods, some were unique to Prudhoe Bay.

Following the formation of the Unit, owners have maintained an aggressive program to resolve questions regarding the viability of a waterflood. This effort has proceeded on two fronts: improving our knowledge of the reservoir and development of the waterflood design.

Reservoir Studies

As has been mentioned, reservoir studies have recognized the potential benefits of returning produced water to the reservoir and of supplementing the produced water with a source waterflood. Estimates of additional oil recovery ranged from four to seven percent of the oil-in-place. We recognized that production history would be needed to verify the need, locations, and volumes of water injection. We identified areas of engineering interpretation, such as flood efficiency, stratification in the reservoir, and injection well capacity as important factors affecting the expected benefits resulting from waterflooding. In addition, early in the reservoir study period we recognized the effects of geological factors such as faults, the heavy oil/tar mat, and shale continuity on the selection on flood location, volumes, and flood performance.

As an example, shale continuity is perhaps the most important geological factor affecting choice of recovery mechanism. The two most efficient recovery mechanisms available -- gravity drainage and waterflooding -- are each capable of higher than average recoveries in particular areas of the field. Normally, gravity drainage works better in thick oil columns which have no continuous shale barrier blocking oil movement, while waterflooding works better where the oil column is broken up by continuous shales into several isolated layers.

It is vitally important to identify areas where gravity segregation is most effective prior to injecting water. If water is injected into areas where the shales are discontinous, the waterflood recovery will be poor and the more effective natural recovery mechanism will be eliminated. On the other hand, if the shales are continuous, gravity segregation will be less efficient than waterflooding. However, reservoir studies show that even in these areas the ultimate recovery is effectively unchanged with a minor delay of two to five years in initiation of waterflooding. Consequently, it is far more important to know where to waterflood than when to waterflood.

Since shale continuity is such an important factor, a group composed of ten geologists from five companies has spent thousands of man hours verifying and updating shale correlations and making predictions as to their continuity between wells and in undrilled areas in the field. This work has indicated that the shales are less continuous than previously predicted, which emphasizes the need to proceed with caution. Further improvement in the shale description will result from continued drilling and history matching the production performance of the field and wells with reservoir models. Also, the vast number of pressure buildups and the interference test data are providing insight into shale continuity and reservoir depletion mechanisms.

A reservoir engineering study group from the Unit Owner companies has been working steadily to narrow the uncertainties related to this project. The group has identified seven potential waterflood areas in the field and has undertaken specific reservoir studies in all of the major areas.

The key to verifying the benefits to be derived from waterflooding is the analysis of the production and test data that is constantly being collected. Highly sophisticated "state-of-the-art" reservoir models have been developed and we are now comparing the detailed performance history with the model predictions. By next year the owners expect to have the knowledge upon which to base initial waterflood decisions.

Water Injectivity Tests

To enable an early evaluation of the many reservoir and mechanical factors which can affect the success of a large scale waterflood, the Unit Owners have implemented two water injectivity tests in the Sadlerochit reservoir. One of the tests, located in the Western Operating Area near Gathering Center No. 3, was completed recently and the data that has been obtained is being analyzed. The other test, located in the Eastern Operating Area near Flow Station No. 1, is underway and will continue for about nine months.

The tests have been designed to evaluate reservoir parameters such as injection pressures and injection capacity in the wells, the efficiency of water in displacing oil in the reservoir, aquifer properties, and the impact of water quality on injectivity. The mechanical factors under investigation include an evaluation of two artificial lift systems, potential corrosion, scaling and freezing problems, and design parameters. In addition, a valuable benefit from the tests is the opportunity to gain general operating experience with a North Slope waterflood. Although very costly ($33 million), the tests are providing extremely worthwhile data.

Waterflood Design

Soon after unitization, the owners formed a Waterflood Task Force. The Task Force, consisting of sixteen full-time engineers from several owner companies, was charged to accomplish the design studies previously mentioned and develop a conceptual design for a waterflood project.

The normal sequence of events in the design and implementation of a waterflood is first to define the benefits to be derived from the flood and specify design parameters, such as flood location, volumes, pressure, water quality requirements, etc., and then design a system to meet these requirements. Because of the time required to fabricate and construct a major facility such as this at Prudhoe Bay, we have carried out the facility design and the reservoir engineering studies concurrently. As a result, the design was developed to accommodate a range of potential flood volumes.

As is the case with most projects of this magnitude, a wide range of alternative concepts was developed for practically every facility. In July, 1978, we retained Bechtel Inc., an engineering contractor, to fully evaluate these alternatives. An average of fifty contractor personnel have been employed in the conceptual design studies.

Early this summer, we developed a conceptual waterflood design which will accommodate a range of potential injection requirements. The slide before you shows a layout of the waterflood system. The conceptual design envisions the Beaufort Sea as the water source. The seawater would be treated in a facility located near the end of the west dock at Prudhoe Bay. Low pressure lines would carry the treated water to two water injection plants. From the plants, high pressure injection water will be transported to appropriate drill sites and drill pads for injection. Although we still need to resolve several design questions during the next phase of engineering (which is already underway), the project is mechanically feasible and environmentally sound.

The Prudhoe Bay owners recently submitted applications to the Corps of Engineers for major permits required to install waterflood facilities. Supporting these applications is a two-volume document entitled, Prudhoe Bay Unit Waterflood Project Overview. Volume 1 of the overview contains a rather complete description of the facilities and Volume 2 is an environmental overview prepared by Woodward Clyde Consultants. We are submitting for the record, a copy of both of these documents.

Project Schedule

The waterflood implementation schedule envisions a 1984 startup. The chart shown in this slide depicts the timing of events leading to the startup.

The startup of waterflood in 1984 requires a major decision on the part of the Unit Owners to commit significant funds for the program in mid-1980. To meet this objective, we must complete the preliminary engineering design and sufficiently resolve the reservoir uncertainities in order to verify recovery benefits by that time. Also, I know that you can appreciate our need to have permits in hand prior to major commitment of funds to the project.

If the decision is to proceed with the waterflood, long lead-time equipment orders will be placed and final design of the system will commence. Fabrication will begin in mid-1981. Sealifts will occur in 1982 and 1983 for the first increment, and construction of the facilities on the North Slope would take place between 1982 through 1984.

I'm sure you will recognize that most of the areas constituting the project schedule are inter-related and delay in finalizing one segment could impact the overall schedule. I would like briefly to discuss each of these major segments and identify those areas that potentially could delay the implementation of the waterflood.

The reservoir studies have been discussed extensively in our presentation. We have collected vast amounts of data and have developed the tools to analyze it. Consequently, by building on the work that has been done over the past years, we have a high degree of confidence that the reservoir studies will develop the necessary design parameters and recovery benefits on time.

The major permit applications have recently been submitted, and consequently, will probably be several months before a firm assessment of the permit timing can be made. Since the potential exists for considerable slippage in this area, permitting could become a critical factor in achieving startup in 1984.

The preliminary engineering design phase is an in-depth review of the system that has been developed in the conceptual design. At the completion of this phase, all major equipment for a system to handle a finite volume of water at specified locations and pressures will be identified. This is a major engineering effort.

Final design is the phase in which equipment and piping layouts, valve and vessel design, control system layouts, and construction drawings are prepared. Again, for a project of this magnitude, this will be a massive effort involving about 1000 owner company and contractor engineering personnel.

Long lead items include structural steel, turbine-driven pumps, water treatment equipment, and other special items associated with the flood. We have forecasted delivery times based on our previous experience with such equipment and forecasts of market conditions and availability. Unforeseen changes in availability of these items could cause delayed deliveries, which if severe, would delay sealifts.

In the fabrication stage, the equipment previously mentioned is assembled in modules for sealift to Prudhoe Bay. The principle variables affecting this schedule are material deliveries and manpower availability. The critical factor here is that minor slippage could cause a delay of one year in the sealift.

Sealifts are the vital link between the North Slope and the Lower 48. Due to the size of the modules, no other transportation system is feasible. The critical factors affecting the success of a sealift are the ice conditions in the Beaufort Sea and the ability to unload the barges when they arrive at Prudhoe Bay. The ice factor is beyond our control, however, we have been able to achieve at least a partially successful sealift even under the worst conditions experienced during the past five years.

Our planning calls for the waterflood equipment to be sealifted at the time other major facilities are programmed for the Prudhoe Bay Field. The total forecasted requirements will tax the existing dock facilities, and our ability to achieve this goal would be highly questionable if it were not for the West Dock and causeway. With this facility, we can develop the offloading capacity.

The North Slope construction schedule is based on several years of experience. The primary factor that would affect this schedule is an unforeseen lack of construction manpower.

The commissioning and startup of the waterflood system will, in some respects, be a unique experience and as such, could encounter minor delays. By 1984, however, we will have had a produced water injection system in operation for three years which, along with the injectivity tests, will develop valuable operating experience.

In general, we feel we have a realistic implementation schedule and are confident it can be achieved. On the other hand, we feel there is very little chance the schedule can be accelerated. The one area that will have the most impact on the schedule is the timely receipt of the necessary permits. The permit schedule carries the greatest chance for slippage and could easily delay the project a year or more.

Summary

In summary, the Prudhoe Bay Owners have proceeded in an aggressive and orderly manner to verify the feasibility of a waterflood in the Sadlerochit Reservoir. This course follows very closely the program outlined in the Unit Owners' presentations before the Oil and Gas Conservation Committee during the hearings in May, 1977.

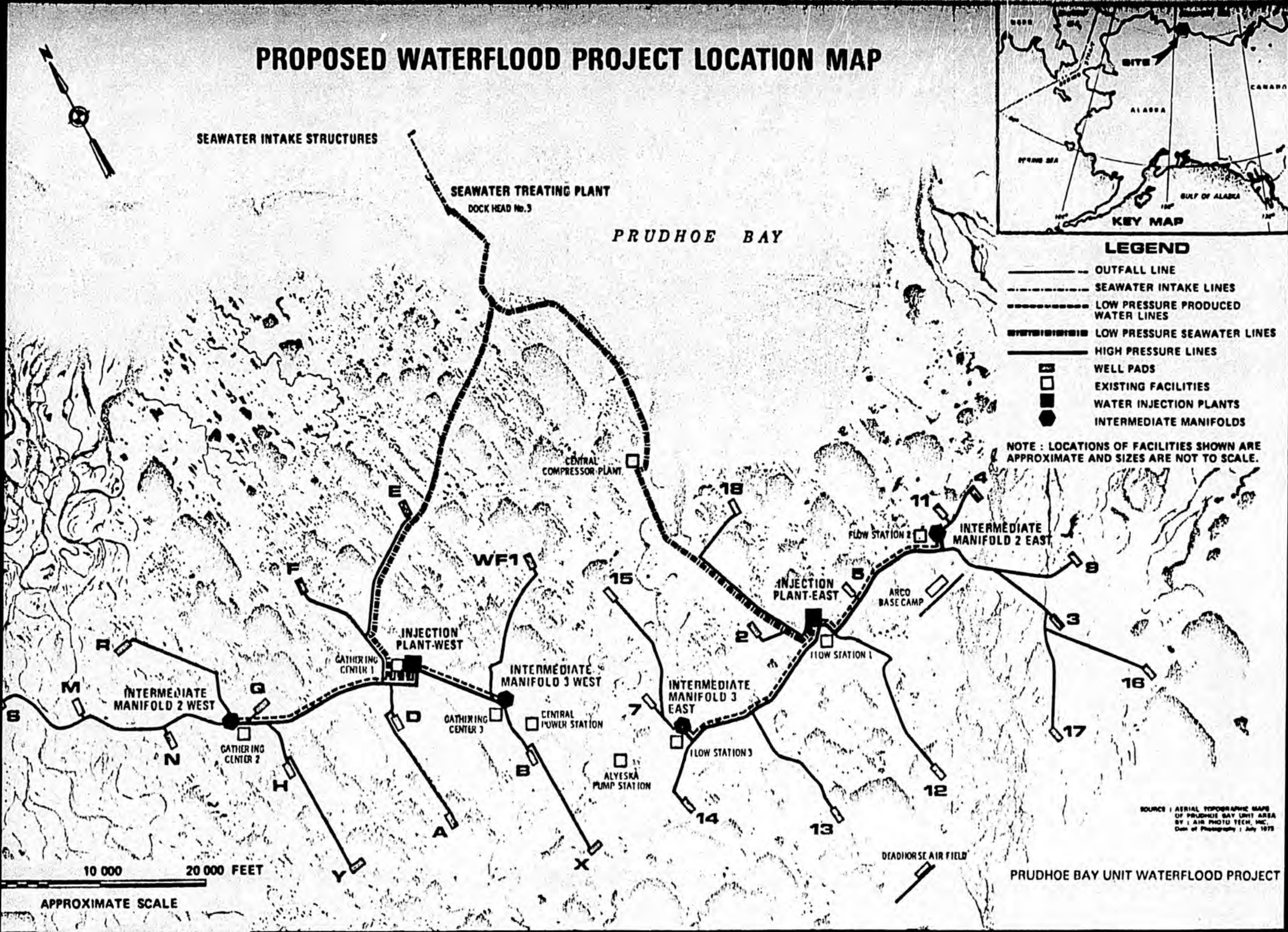
Reservoir studies and design studies have progressed concurrently. Injectivity tests have been designed and implemented, and analysis is progressing with the production history and test data obtained to date. As a result of many years of reservoir studies and the analysis of field production, we feel we are developing an excellent understanding of the Prudhoe Bay reservoir and its future performance. We intend to continue our extensive efforts to build on this foundation.

During the past two years alone, the Prudhoe Bay Unit Owners have invested over 40 million dollars in engineering studies and special tests designed to reduce the risks associated with a source waterflood.

The Waterflood Task Force has developed a conceptual design based on a Beaufort Sea water source and the Task Force is proceeding into the next phase of engineering.

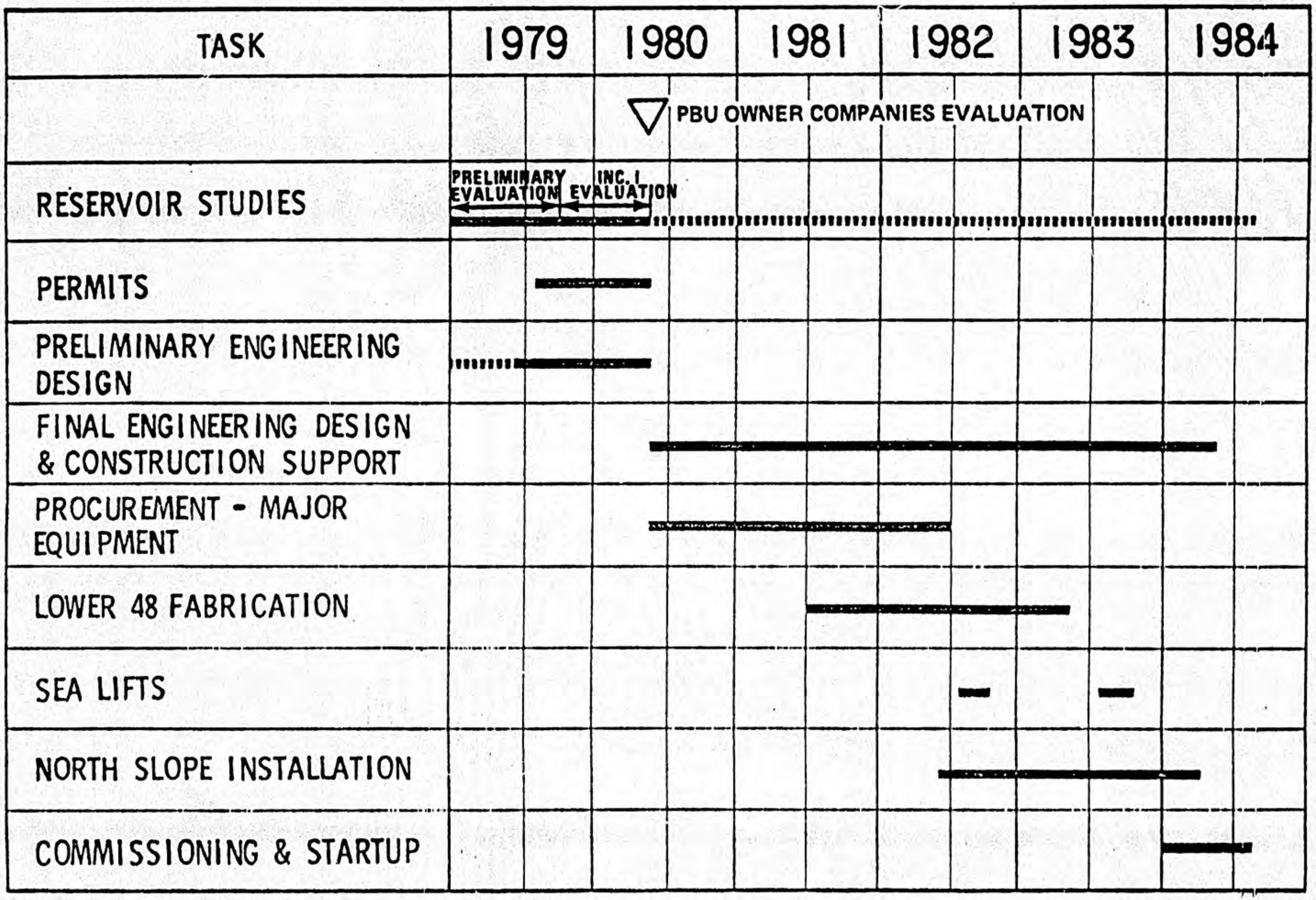
Permit applications have been submitted to the Corps of Engineers. It is anticipated that an Environmental Impact Statement will be prepared. Permitting could become the critical factor in meeting a 1984 startup of the project. The Unit Owners plan to be in a position to make the decision to proceed with a source waterflood project by mid-1980 if the permits are in hand.

Mr. Chairman, this concludes my testimony. Mr. Norgaard now has some concluding remarks.


PROPOSED WATERFLOOD PROJECT LOCATION MAP
N
SEAWATER INTAKE STRUCTURES
SEAWATER TREATING PLANT
DOCK HEAD No.3
PRUDHOE BAY
KEY MAP
LEGEND
OUTFALL LINE
SEAWATER INTAKE LINES
LOW PRESSURE PRODUCED WATER LINES
LOW PRESSURE SEAWATER LINES
HIGH PRESSURE LINES
WELL PADS
EXISTING FACILITIES
WATER INJECTION PLANTS
INTERMEDIATE MANIFOLDS
NOTE : LOCATIONS OF FACILITIES SHOWN ARE APPROXIMATE AND SIZES ARE NOT TO SCALE.
CENTRAL COMPRESSOR PLANT
INJECTION PLANT-WEST
INJECTION PLANT-EAST
GATHERING CENTER 1
GATHERING CENTER 2
GATHERING CENTER 3
INTERMEDIATE MANIFOLD 2 WEST
INTERMEDIATE MANIFOLD 3 WEST
INTERMEDIATE MANIFOLD 3 EAST
INTERMEDIATE MANIFOLD 2 EAST
FLOW STATION 1
FLOW STATION 2
FLOW STATION 3
CENTRAL POWER STATION
ALYESKA PUMP STATION
ARCO BASE CAMP
DEADHORSE AIR FIELD
E
F
WF1
R
M
Q
S
N
H
D
A
B
X
Y
15
18
7
2
5
11
4
8
3
16
17
12
13
14
10 000
20 000 FEET
APPROXIMATE SCALE
SOURCE : AERIAL TOPOGRAPHIC MAPS OF PRUDHOE BAY UNIT AREA BY : AIR PHOTO TECH, INC.
PRUDHOE BAY UNIT WATERFLOOD PROJECT

AGO 667377

PROJECT SCHEDULE
PRUDHOE BAY UNIT WATERFLOOD PROJECT



AGO 667378

PRUDHOE PERFORMANCE ON TARGET

Production behavior in the Prudhoe Bay field has been normal, and there is no reason for concern about ultimate oil recovery and waterflooding plans for the field, according to the producers.

Information concerning the field performance was described by the Prudhoe Bay producers in testimony before the House Resources Committee in Juneau.

Reservoir behavior during the first two years of production supports the original studies which were made prior to start-up, the producers said. These studies provided the basis for the plan of development being implemented at Prudhoe Bay which includes oil production up to 1.5 MMBPD and gas production for sales up to 2 billion CFPD when gas sales facilities are available. Overall, the producers stated that early field performance supports earlier predictions that ultimate recovery will be about 40% of the original oil in place.

The producers have identified one small part (about 6%) of the field where the pressure has declined about three times more than average. This occurred because the geology of this area is different. According to the producers, this performance is predictable, was predicted and is not damaging to the reservoir. The measured field-wide pressure decline of about 200 psi is just as predicted, indicating the field is performing well.

The producers pointed out that the recovery benefits from water injection are not very sensitive to the timing of the start of injection, but that the selection of proper injection locations and volumes is very important to achieve maximum oil recovery benefits. Because of this, the plan of development provides for a period of observing performance before making final decisions on the proper injection locations and volumes. This will better quantify oil recovery benefits and, in turn, the overall economic viability of the project.

The producers said they have been conducting waterflood design and water injection tests for over two years at a cost of over $40 million. They have already ordered equipment for the first phase of injection of water produced with the oil into the main Sadlerochit reservoir. This injection is planned to start in 1981.

In addition, the field operators have applied for permits for a major $2 billion waterflood program, utilizing water from the Beaufort Sea. If permits are obtained in a timely manner, the producers said they anticipate a decision on proceeding with the major waterflood in about one year. This timing would allow start-up as early as 1984. Studies indicate this timing is appropriate for the waterflood to achieve maximum oil recovery benefits.

HEARING
ALASKA HOUSE RESOURCES COMMITTEE
CONCLUDING REMARKS

Juneau, Alaska
August 6 and 7, 1979

In summary, our presentation has stated that the Prudhoe Bay Field is performing consistant with our expectations. The field performance and our continuing reservoir simulation work indicates that development should proceed as planned and that this operating plan is a prudent one for both the owner companies and the state of Alaska. We believe that in the various aspects of the operating plan, the interests of the state of Alaska and the owner companies are essentially identical. The plan has been designed to achieve maximum recovery of oil and gas from the Prudhoe Bay Field. We owner companies plan to continue working with your Oil and Gas Conservation Commission to achieve this common goal.

HEARING BEFORE ALASKA HOUSE RESOURCES COMMITTEE
JUNEAU, ALASKA
AUGUST 6 and 7, 1979

PRUDHOE BAY UNIT
RESERVOIR MANAGEMENT STUDIES

Members of the House Resources Committee, ladies and gentlemen, my name is Larry Smedley. I have been employed by Exxon Company, U.S.A. since receiving my engineering degree at the University of Missouri at Rolla in 1966. I have spent most of the past 13 years involved in various aspects of petroleum reservoir engineering. I first became involved in Prudhoe Bay reservoir studies in 1970 and I have spent some 6 years either studying or supervising others' study of this field. I am currently Division Reservoir Engineer for Exxon's Western Production Division.

Each of the major owners of Prudhoe Bay, ARCO, Sohio, and Exxon, carry out comprehensive reservoir management studies independently on an almost continuous basis. These independent analyses, followed by exchange and comparison of results, provide us added insights to reservoir behavior. While the study results are not identical, they are similar and have led to the same general conclusions regarding the proper operating plan for Prudhoe Bay. Each company presented their independent results to the Oil and Gas Conservation Committee at the May, 1977 Pool Rules Hearing. That testimony is a matter of public record. In the interest of time, I will present only Exxon's reservoir management studies today.

Viewgraph 1

The first figure summarizes the areas I plan to cover. I will briefly review the reservoir description, highlighting the oil zone rock properties and major shale complexes used in our reservoir model studies. Description of the reservoir is the key to accurate performance predictions, and I will show that the Prudhoe Bay description has not changed much from pre-production studies.

Next, I will compare observed pressure and production history to predictions made by our three-dimensional reservoir model which was constructed prior to start-up in 1976 and described at the May, 1977 Pool Rules Hearing. You will see that performance to date has been encouragingly similar to these predictions.

Finally, I will review the reservoir study results which led to the Prudhoe Bay operating plan, and will highlight the various development options under study, such as well spacing, artificial lift, waterflooding, etc. I'll also review sensitivity study results describing the impact of oil and gas offtake and the timing of water injection on ultimate oil recovery.

Viewgraph 2

The next figure is a well log (Well 33-11-13) showing the geologic zonation, the gamma-ray and sonic log responses, and the location of major, correlatable shale complexes in the Sadlerochit sandstone interval. Also shown are average rock properties such as thickness, porosity, horizontal permeability, net sand to gross thickness ratio, and vertical to horizontal permeability ratio. This same figure was presented at the May, 1977 Pool Rules Hearing.

I've included this rather technical figure here for two reasons. First, the average rock properties give an indication that the reservoir quality is good. It is these favorable rock properties in combination with the thick oil column and large overlying gas cap that lead to good natural depletion recovery at Prudhoe Bay. The second reason I've included the figure is to point out that the description of average rock properties we provided over two years ago is still valid. We have obtained enormous quantities of additional information from drilling, logging, coring, and running pressure buildup tests since start-up, and the new data generally confirms our pre-production estimates.

Several newspaper articles in Alaska have suggested that a "shale problem" has been recently discovered in the field. The major shale complexes identified on this log were mapped and included in our reservoir model studies long before the start of production. We provided the Alaska Oil and Gas Conservation Commission maps of the shale complexes in 1976. At that time, we also described a technique used to evaluate the impact of the numerous minor, non-correlatable shales on vertical permeability. Although continued drilling and production data has resulted in some revisions to the anticipated extent of the shales, the changes have generally been toward less shale continuity than originally forecast, rather than more shale as suggested in the newspapers.

Viewgraph 3

This next figure is an example. The Main Sadlerochit Reservoir productive limit is shown by the dashed line. The shaded area shows the areal extent of the uppermost correlatable shale within the oil column, based on our pre-production interpretation. The cross-hatched area shows the current interpretation of the extent of this shale. In general, the shale is now believed to be less continuous over most of the reservoir. Decreased shale continuity should increase the efficiency of the natural recovery process. Both interpretations show that the shale is quite continuous over the eastern sixth of the reservoir where two such shale complexes have tended to isolate portions of the oil column from gas cap pressure support. Consequently, greater than average pressure declines and increasing gas-oil ratios have been observed in this small area.

This performance was expected because we have included the effect of such shales in our model studies for many years. It is through monitoring and modeling pressure behavior and gas-oil contact movement that we can confirm the extent and continuity of the shales which have been mapped primarily with well information.

Viewgraph 4

This figure is a map of measured pressure drawdown from original in the field. The lines represent contours of equal pressure drawdown as measured at the producing wells. The pressure drawdown in the producing intervals is somewhat greater than the average drawdown over the entire thickness of the oil column. Overall, the oil rim is demonstrating excellent gas cap pressure support. As you can see, the pressure drawdown varies from 100 psi in areas of low production to 600 psi in the eastern segment of the reservoir where shale complexes restrict gas cap pressure support. The large drawdown indicates that the shales are quite continuous in this small portion of the reservoir.

Viewgraph 5

The pressure behavior observed to date is very similar to our 1976 model prediction which is shown on the next figure. The simulator has predicted both the shape of the contours and the approximate magnitude of the pressure drawdown. The inset compares the predicted April, 1979 average reservoir pressure of 4135 psi to the observed value of 4155 psi. It is important to recognize that this simulation study, when carried out over the full field life, predicts expected production behavior and recovery.

Viewgraph 6

The next figure compares historical production performance to the model prediction and shows predicted performance for the next several years. The oil production history is identical because we produced the model at actual field rates. As you are aware, the TAPS pipeline owners have announced that pipeline capacity will be increased to about 1.5 million barrels per day by the end of 1979.

Observed and predicted gas production rates are also shown. As was pointed out earlier, the Operators have considerable latitude in controlling the amount of gas production at Prudhoe Bay. The model has predicted slightly higher gas production rates than observed. Field gas production is currently about 1.1 to 1.2 billion cubic feet per day, which is quite close to prediction. As shown, an increasing trend of gas production is expected in the future. Such performance is normal for an oil field like Prudhoe Bay with a large overlying gas cap. As oil is withdrawn, the gas cap expands and overrides along the top of the reservoir and under major shales.

The lower curve shows water production which is currently quite low, as expected, and is forecast to gradually increase with time. The upper curve is a plot of observed and predicted average reservoir pressure versus time. As discussed earlier, the measured pressure decline agrees quite well with predictions. The fact that reservoir pressure has declined only about 200 psi to date supports that the expected efficient natural depletion process of gas cap expansion and gravity drainage is dominating over most of the reservoir. Indeed, if an inefficient, solution gas drive mechanism was dominant as some have suggested, the pressure decline to date would be in the order of 400 psi, or about twice the measured value.

Viewgraph 7

With that comparison of measured and predicted performance as a backdrop, I would like to review the results of studies which led to the current operating plan for the Prudhoe Bay Unit. As shown on the next figure, testimony presented at the May, 1977 Pool Rules Hearing indicated that ultimate oil recovery from the Main Area Sadlerochit would be approximately 40% of the original oil-in-place (OOIP) with full development and the planned oil and gas offtake rates. However, we pointed out that enormous future investments would be required to achieve that recovery level.

Completing development well drilling on 160 acre spacing rather than 320 acre spacing is projected to increase recovery about 4% OOIP. The Operators have been proceeding with development drilling, increasing the producing well count from 100 at start-up to about 200 today. However, some 300 additional wells are anticipated for full development. Drilling and equipping these wells to produce will cost $2 to $3 billion. Studies are underway to evaluate the proper development limits and well density for the field.

The second potential facility addition shown is a low pressure gathering system to allow reduced wellhead producing pressures. The study indicates an additional recovery potential of about 5% OOIP. Total cost for such a system fieldwide has been estimated at $1.5 to $2 billion. The first increment was recently approved by the Unit Owners and equipment has been ordered for installation at Flow Station 2 in 1982. Other increments must be analyzed, designed and justified.

The study indicates additional recovery potential of about 5 percent for an artificial lift system at Prudhoe Bay. Again, the cost is estimated to be in the order of $1.5 to $2 billion. Although it is at a very early stage of planning, we expect to install such a system when needed to maintain production rates.

The studies also indicate potential for up to 2% additional recovery by injecting the water produced with the oil into portions of the Sadlerochit Reservoir which experience poor natural depletion recovery. Depending on the final design, this system has been estimated to cost in the order of $1 billion. The Unit Owners recently approved funds for the first increment of produced water injection. Equipment has been ordered and we expect the first increment to be operational in the Eastern Operating Area in 1981. The produced water injection system will be expanded as volumes increase and as production performance allows refinement of design.

Source water injection facilities also offer potential to increase ultimate oil recovery. Exxon's studies indicate the additional recovery may be in the order of 4% OOIP, as shown. Sohio, on the other hand, has projected that the additional recovery from source water injection could be as much as 7% OOIP. The cost of the source water injection system has been estimated to be in the order of $1.5 to $2 billion. The next speaker will describe studies and tests which will cost in excess of $40 million which the Unit Owners have already undertaken to evaluate and design a water injection system.

Estimated recovery without the development additions described would be approximately 20% OOIP. The remaining half of forecast recovery depends upon additional facilities and investments which will cost in excess of $10 billion, just to develop the Main Sadlerochit Reservoir. This compares to less than $4 billion spent to date on field development. These enormous future investments must be justified and facilities designed based on field performance data, detailed studies, and economic factors. As I have indicated, the Unit Owners are already proceeding with several of these projects. Others are under active study.

News reports have suggested that the Prudhoe Bay Owners need to decide soon on a major water injection program. As you can see, water injection is but one of the many future development activities we plan for Prudhoe Bay. Indeed, others may have a more significant impact on ultimate oil recovery. We are moving forward in a prudent manner on all of these projects.

Viewgraph 8

This figure summarizes several sensitivity studies Exxon presented at the May, 1977 Hearing. As we pointed out at the Hearing, because of the large number of cases involved, the sensitivity studies were performed with a two-dimensional cross-section model. Our fieldwide three-dimensional model has verified the cross-section results.

Cases with oil offtakes ranging from 1.2 to 1.8 million barrels per day show no significant effect of oil offtake on ultimate recovery. These cases were run with produced water injection and 2.0 billion cubic feet per day gas pipeline deliveries after 5 years.

The second sensitivities shown investigate the impact of gas pipeline deliveries beginning in 1982, compared to delayed deliveries. With only produced water injection, a 10 year delay in the gas offtake increased recovery only slightly, from 36.2 to 37.5% OOIP. Studies show that appropriate modifications to the reservoir management plan could offset this relatively small impact of gas deliveries on oil recovery. For instance, with source water injection and gas deliveries commencing in 1982, recovery varied from 39.3 to 40.2% depending on the level of injection, compared to 40% recovery with gas deliveries commencing in 1987.

As you are aware, progress has been slow on the proposed gas pipeline. Consequently, 1985 is the earliest likely timing for gas deliveries.

The final results shown represent the sensitivity of ultimate recovery to various water injection programs. With natural depletion supplemented by produced water injection, the studies indicate a recovery level of about 36% OOIP. This relatively high recovery without source water injection is due to the favorable rock properties which provide for efficient gas cap expansion and gravity drainage over most of the reservoir.

The studies show that source water injection commencing from 1982 to 1986 at rates of from 1.7 to 2.5 million barrels per day results in recovery of about 39% OOIP. Larger water injection programs commencing in 1982 to 1984 result in recovery of about 40% OOIP. The studies indicate that ultimate oil recovery is not very sensitive to the timing of injection start-up. Cases with injection beginning later result in the same recovery if the rate of injection is increased to "catch up" with earlier injection program.

The major benefit of water injection at Prudhoe Bay is improved conformance or sweep efficiency rather than pressure maintenance. Therefore, selection of proper injection locations and volumes is more important than the timing of start-up. Decisions on proper injection locations and volumes in this complex and diverse field will require substantial performance and testing data as well as detailed studies. There is too much risk of reducing recovery if we were to proceed without sufficient data and injected water at improper locations so as to impair gravity drainage where it is the most efficient recovery process. The risk of reducing recovery by improper water injection more than offsets any potential reduction due to deferring the start of injection.

With the natural depletion process being very efficient, there is time available to obtain the necessary data and perform the required studies and still be in a position to initiate water-flooding so as to achieve maximum oil recovery benefits.

Viewgraph 9

This final chart summarizes our reservoir management conclusions:

- o First, the Operating Plan studies submitted at the May, 1977 Oil and Gas Conservation Commission hearings are still valid. Field performance and testing hasn't significantly changed the outlook provided then.

- o Secondly, the oil and gas offtake rates approved by the Oil and Gas Conservation Committee in Conservation Order No. 145 are consistent with achieving maximum economic recovery from the Prudhoe Bay Field.

- Finally, the ultimate recovery estimates of 40% for oil and 75 to 80% for gas still appear reasonable. However, achieving this recovery will require enormous future investments for facilities. These investments must be evaluated and justified individually, considering such factors as the amount of additional oil to be recovered, the value of the oil and associated operating costs and taxes. Additional production performance and testing data will be required before many of these decisions can be finalized.

LMS/md
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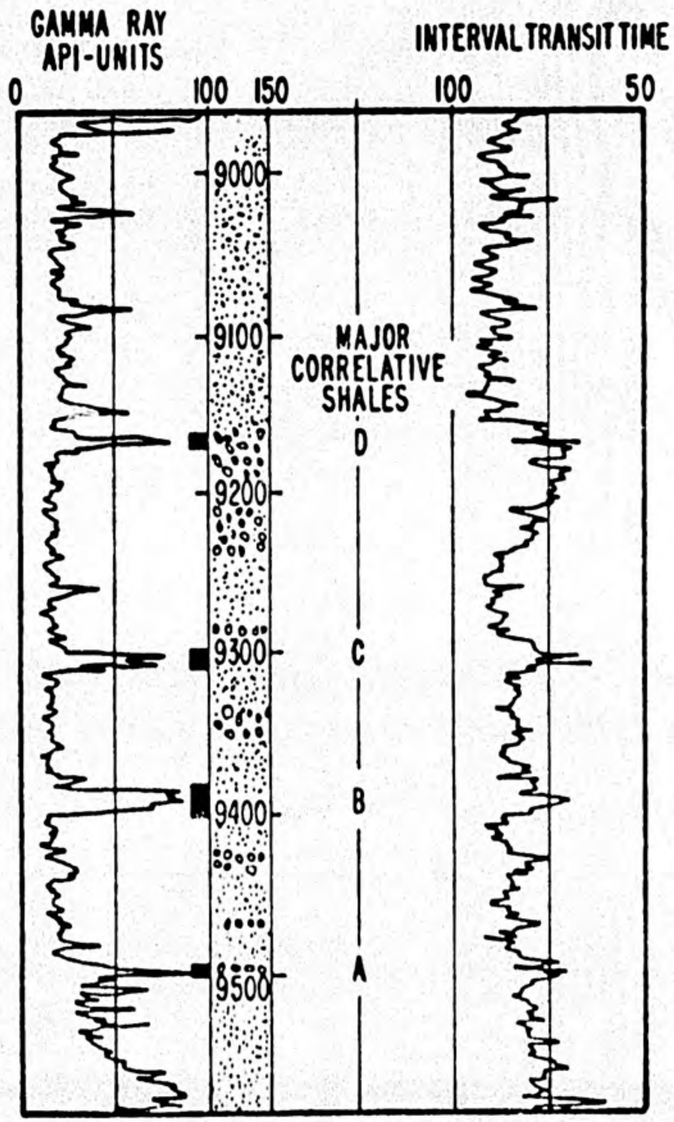
5403

PRUDHOE BAY UNIT

RESERVOIR MANAGEMENT STUDIES

- REVIEW RESERVOIR DESCRIPTION PARAMETERS
  - Oil Zone Rock Properties
  - Major Shale Complexes
- COMPARE PERFORMANCE TO PREDICTIONS
  - Pressure and Production
  - 1976 Model vs. Actual
- REVIEW OPERATING PLAN STUDIES
  - Development Options
  - Sensitivity Studies

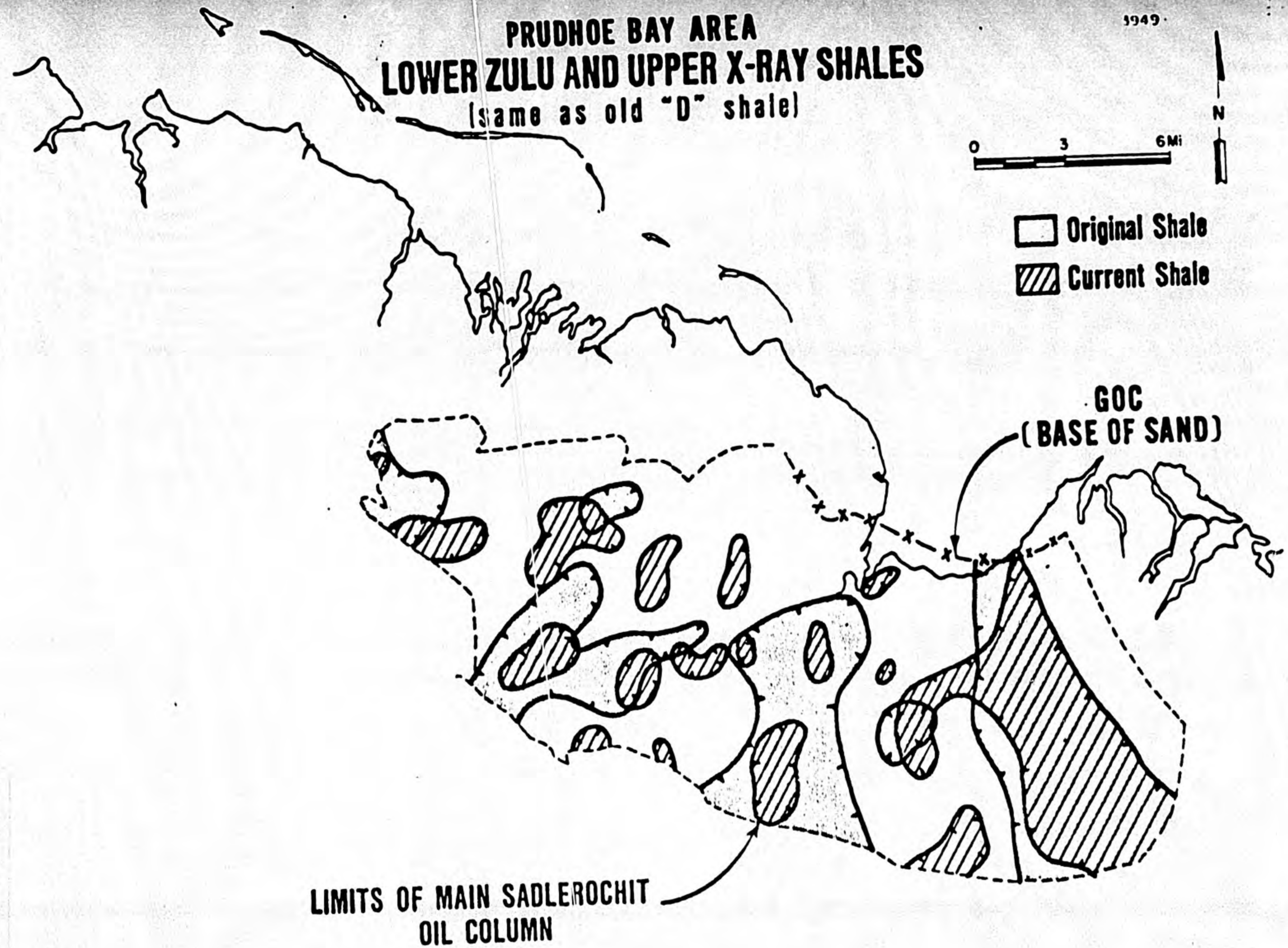
PRUDHOE BAY
SADLEROCHIT FORMATION



ZONATION GEOLOGICAL	AVERAGE PROPERTIES (OIL ZONE)				
	H(ft.)	Ø (%)	K(md)	N/G Ratio	Kv/Kh
4	160	24.0	260	.89	.12
3	70	17.8	910	.98	.39
2	250	24.7	660	.88	.15
1	70	21.6	240	.73	.01

1949

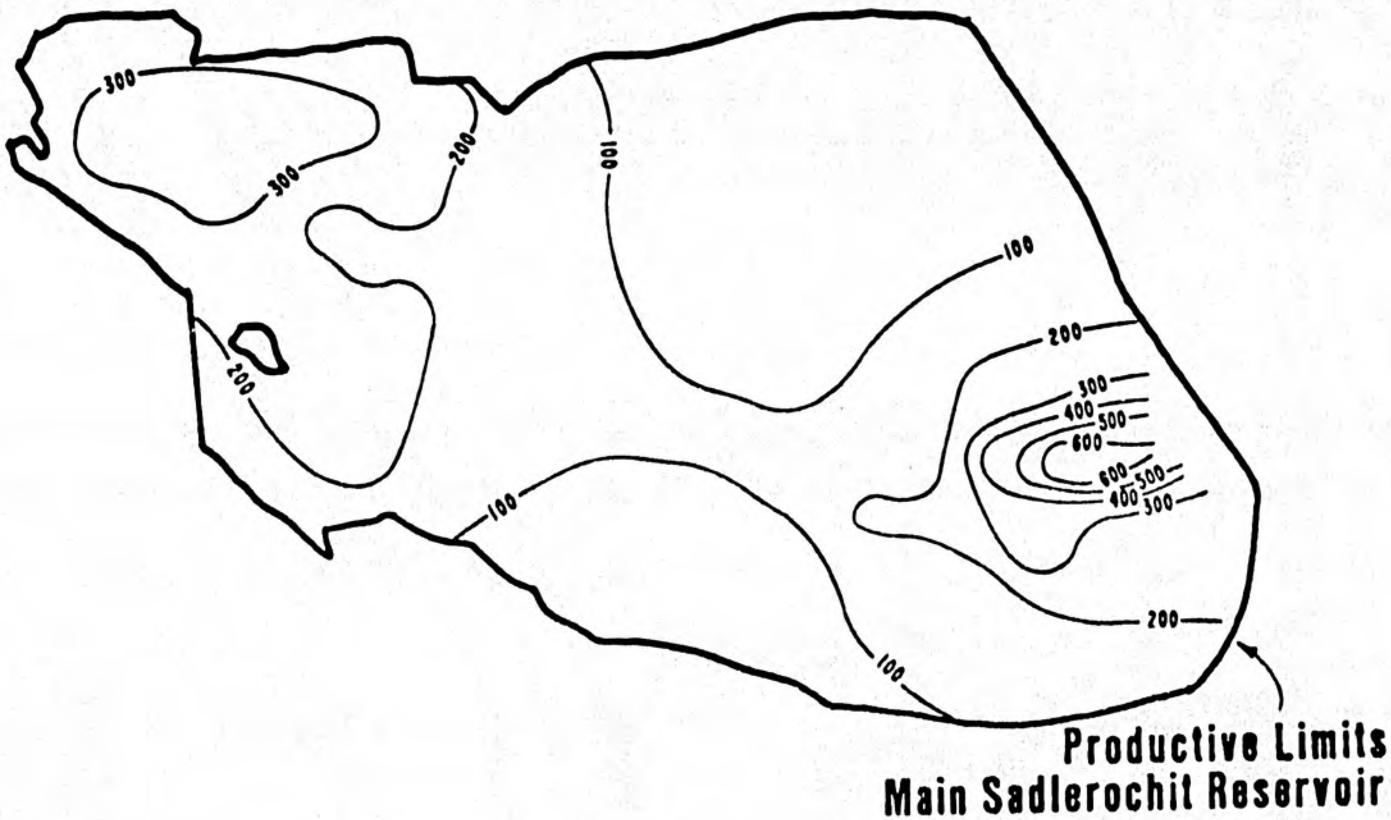
PRUDHOE BAY AREA
LOWER ZULU AND UPPER X-RAY SHALES
(same as old "D" shale)



AGO 667397

PRUDHOE BAY UNIT

PRESSURE DRAWDOWN FROM ORIGINAL
APRIL 1, 1979
MEASURED

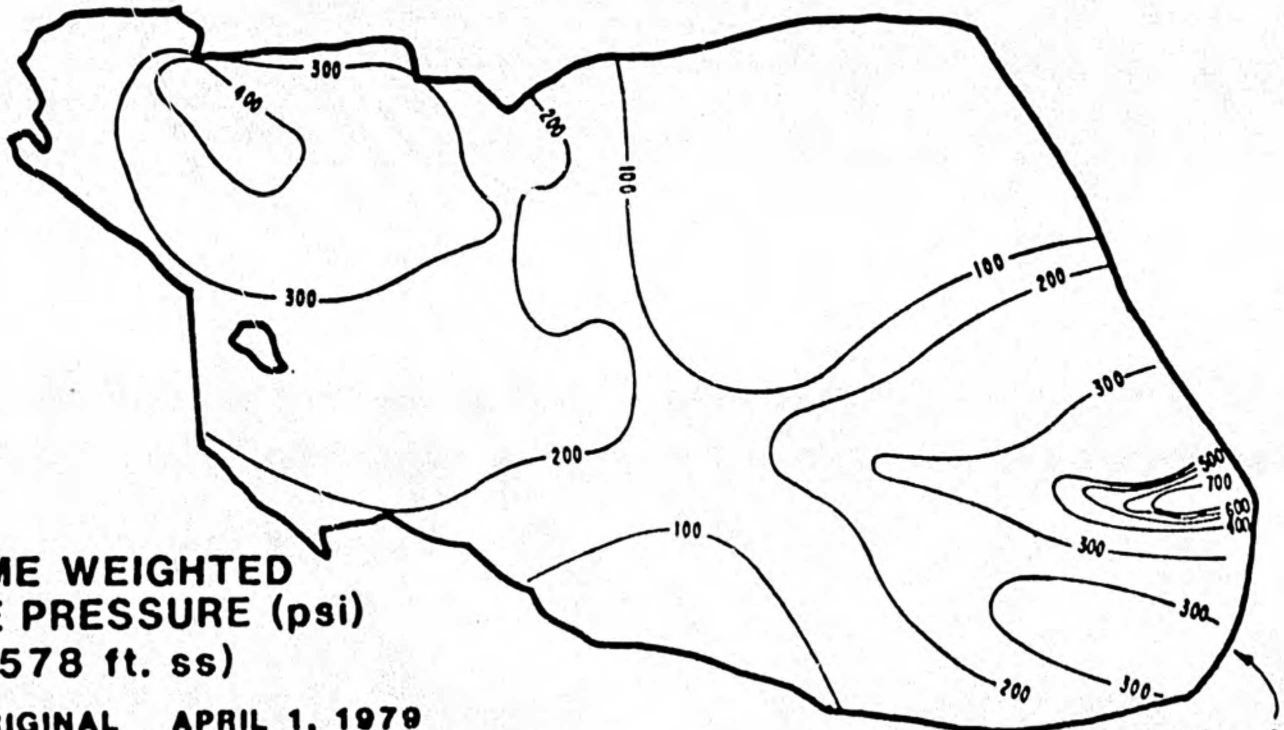


5401

PRUDHOE BAY UNIT

PRESSURE DRAWDOWN FROM ORIGINAL APRIL 1, 1979

PREDICTED



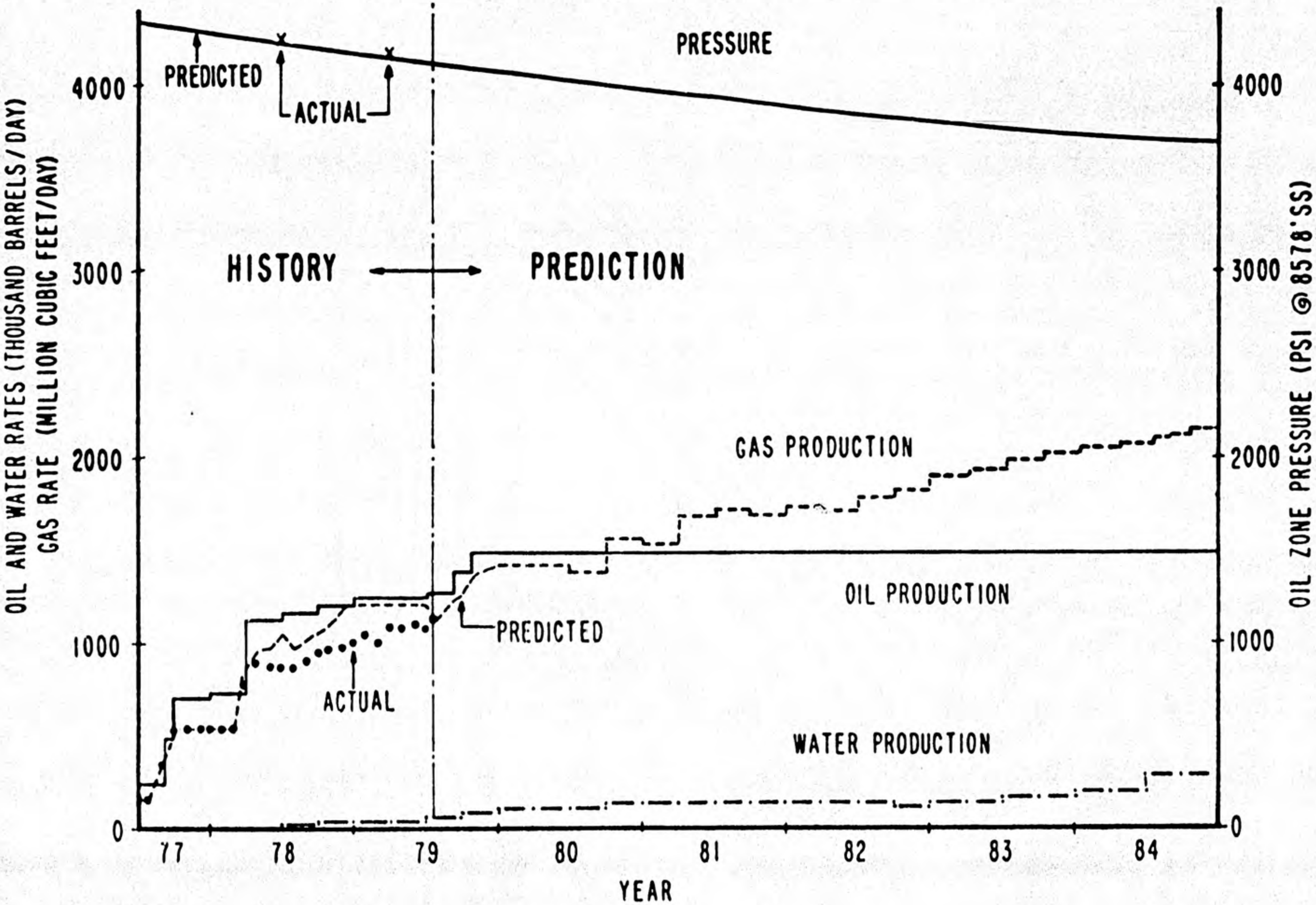
Productive Limits
Main Sadlerochit Reservoir

VOLUME WEIGHTED AVERAGE PRESSURE (psi) (8578 ft. ss)

	ORIGINAL	APRIL 1, 1979
Predicted	4335	4135
Measured	4335	4155

5402

PRUDHOE BAY UNIT
PRODUCTION PERFORMANCE



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RESERVOIR MANAGEMENT STUDIES
PRESENTED AT MAY, 1977 POOL RULE HEARING
MAIN AREA SADLEROCHIT

	POTENTIAL OIL RECOVERY % OOIP
• POTENTIAL ULTIMATE RECOVERY WITH FULL DEVELOPMENT	40
• RECOVERY ATTRIBUTABLE TO PRODUCTION FACILITY ADDITIONS	
— 160 Acre Wells vs. 320 Acre Wells	4
— Low Pressure Gathering System	5
— Artificial Lift System	5
• RECOVERY ATTRIBUTABLE TO WATER INJECTION	
— Produced Water	2
— Source Water	4
• ESTIMATED RECOVERY WITHOUT DEVELOPMENT ADDITIONS	20

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER / POUCH M – JUNEAU 99811

October 8, 1979

REVISED SCHEDULE: Beaufort Sea Sale Preparations

Week of October 8:

Oct. 8 -- House Interim Committee on Oil and Gas Leasing Policy public hearing in Anchorage, 7 p.m. Final draft of pre-sale analysis distributed.

Oct. 8 -- Deadline for submission of written testimony to NSB Assembly on CZM plan.

Oct. 9 -- LeResche meets with Tom Cook on bidding method, lease form, other details. 8 am at DMEM.

Oct. 9 -- LeResche gets geologic briefing from DMEM staff in Anchorage. 9 am at DMEM.

Oct. 9 -- Joint Issue Document completed and circulated in D.C., Juneau and Anchorage. (probably 2-3 days later) problem w/ Interior

Oct. 9 -- NSB Assembly to act on CZM plan.

Oct. 9 -- LeResche meets with NSB representatives on proposed tract deletion. 1:30 pm at DMEM.

Oct. 10 -- LeResche meets with DMEM staff on economic analysis, bidding method selection; 9a.m. at DMEM. Hayne Leland will attend.

Oct. 10 -- Revenue staff briefs LeResche and Williams on revenue analysis; 1 pm at DMEM.

Oct. 12 -- Presale economic analysis published.

Oct. 13 -- LeResche, Williams brief Governor on bidding method selection; Av Gross will attend. 2 pm.

Weekend October 13-14: LeResche, Haynes, Condon, Gross, Williams -- general strategy, bidding method and lease document.

10-J9LM

AGO 667402

Week of October 15:

Oct. 15 -- Agenda and briefing paper for 1~~8~~9th meeting from DNR to Governor's Office.

Oct. 15 -- State submits formal comments on sale to Interior (DPDP and DNR Commissioner's office will prepare response; LeResche and Ulmer will sign off.)

Oct. 15 -- LeResche makes decisions on bidding methods, possible deletion of acreage, other sale terms. (Cook in Juneau).

Oct. 15 -- Sale maps/supplementals distributed to industry.

Oct. 16 -- Summary of Alaska position prepared by Interior's PBA and distributed.

Oct. 16 -- .345 navigability determination.

Oct. 16 -- LeResche, Gross, Arruda and Shelley Higgins meet with Solicitor Krulitz on Interim agreement and Unitization Agreement. Washington, D. C.

Oct. 17 -- Briefing in D.C. for Interior officials, LeResche, DMEM and Law to attend.

Oct. 17 -- .345 1st notice.

Oct. 17 -- Briefing of Interior Secretary by Interior staff.

Oct. 19 -- LeResche meets with Governor to make final recommendations on sale terms. Governor makes decisions on bidding methods and other sale aspects. (Fran Ulmer, Av Gross will participate.) 2 p.m. Governor's office.

Week of October 22:

Oct. 24 -- .345 2nd notice.

Oct. 24 -- Proposed Notice of Sale transmitted to DOE.

Oct. 24 - Nov. 2 -- Department of Law finalizes lease document.

Oct. 26 -- Governor meets with Interior Secretary to make final decisions on sale terms. Seattle.

Oct. 26 -- DOE comments due on proposed Notice of Sale.

Oct. 26 -- Final Notice of Sale signed by Governor/Secretary; Notice to Federal Register.

Oct. 26 -- Last date to start .345 notices.

Oct. 26 -- Last date for state/feds to execute Interim Agreement and Unitization Agreement.

*Oct. 27 -- State sale announcement. (not a legal deadline; purpose is to inform industry on terms of sale).

Week of October 29:

Oct. 29 -- .035 notice issued.

Oct. 31 -- .345 3rd notice.

Nov. 2 -- Final Notice of Sale to Federal Register. (last possible date)

Week of November 5:

will get them 10-9

Nov. ~~5~~ 9 -- Leasing regulations effective. (published Commission 10-9)

Nov. 5 or 6 -- Representatives from Law (Lowenfels), DMEM (Cook) and DNR Commissioner's Office (LeResche and Haynes) and possibly others to Providence, Rhode Island for observation of federal North Atlantic Sale #42.

Nov. 7 -- North Atlantic Sale #42 held in Providence, R.I.

Nov. 7 -- .345 last notice.

shooting for 10-29 → *Nov. 7 -- Public notice of unitization regulations.

Nov. 9 -- Final Notice of Sale published in Federal Register.

Nov. 9 -- Publication of Commissioner's finding and final state sale notice.

Nov. 10 -- Last date to publish .305 notice.

Week of November 26:

Nov. 26 -- Beaufort Sea Sale training.

Week of December 3:

Dec. 3 -- Mock Sale.

Dec. 3 - 7 -- Presale evaluation.

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* Tentative

AGO 667404

Week of December 10:

Dec. 10 -- Press briefing; Fairbanks.

Dec. 11 -- Lease sale.

Dec. 12 -- Post-sale analysis.

Dec. 13 -- Sale summary and post-sale analysis to Department of Justice.

TESTIMONY BEFORE THE INTERIM COMMITTEE

ON OIL AND GAS LEASING POLICY

ALASKA STATE LEGISLATURE

HOUSE OF REPRESENTATIVES

on

ECONOMIC ISSUES RELATING TO THE PROPOSED BEAUFORT SEA LEASE SALE

BY

Philip E. Sorenson
Professor of Economics
Florida State University
Tallahassee, Florida

and presently

Visiting Professor of Economics
University of California
Santa Barbara, California

October 8, 1979

The decision on how to lease State lands in the Beaufort Sea for oil and gas development is of critical importance to the future welfare of the people of Alaska. In addition, the nation's future energy supply may be significantly affected by the nature and timing of development activities in this important province. Not only Alaskans, but all Americans must hope for future success in finding and then recovering hydrocarbons from this province.

This Committee has been exposed to a large and complex body of analytical reports and viewpoints during its deliberations. The Committee staff has prepared their own synthesis of these materials and made recommendations. In addition, the Commissioner of the Department of Natural Resources has presented a large and comprehensive report of its views. I will not attempt to review all of these materials nor to correct all errors of fact or interpretation that may have been included in these reports. I compliment the Committee and the Commissioner for the high quality of the analytical work that has been carried out in advance of this important decision. While I will cite some major areas of disagreement in my remarks, I believe the issues you have raised are the relevant ones and in many cases my views parallel those expressed in the reports.

The question of an optional leasing policy for the Beaufort Sea is best addressed, I believe, with a clear perception of the nature of economic rent potentially available from natural resources. A representation of the important economic relationships is presented in Figure I. Over its lifetime, an oil and gas lease will produce a series of cost and revenue flows. Viewed from the date of the lease sale, these flows can be added together using the technique of discounting to provide a single integrated view of the lease's economic history. Thus the entire area of the bar in Figure I represents the present discounted value of the total revenue obtained through sale of oil and gas recovered from the lease over its lifetime. We discount revenues (or costs) for future years in recognition of the fact that present revenues are preferred to future revenues while present costs are more burdensome than future costs. Now out of the total present discounted revenues produced by a lease, all necessary costs of labor and capital must be paid before any surplus is left over to be paid to the resource owner. Among these necessary costs of production is a normal rate of return to the capital invested in the lease, the area labeled ROI in Figure I. If the lessee is not allowed to earn a normal return on his lease investments, he will make no investments in the lease and nothing will be produced. You will note that the necessary costs of developing the lease (as shown in Figure I) do <u>not</u> include payments to the government. Such payments, whether called "taxes", "royalties", "profit shares", or "bonuses", are not necessary costs of production comparable to costs of labor and capital. They are "transfer payments", and they can be paid only out of any surplus of revenues above necessary costs. In technical language they are paid out of the "economic rent" produced by the lease. All these are familiar concepts, but they are critical to an understanding of the major analytical errors, as I see them, contained in the report prepared by the Division of Minerals and Energy Management dated August, 1979 (the DMEMS report). This is the report which forms the basis for much of the analysis presented in the reports by the Committee staff and the Commissioner.

The conclusions reached in the DMEMS report are based upon a theoretical model of lease development and return of net rent. The critical assumptions which underlie these conclusions are invalid. As a result, the conclusions themselves must be questioned.

1. The total revenue produced by a hypothetical lease is fixed and invariant to the choice of leasing policy.

2. The time profile of lease development and cost outlays is fixed and invariant to the choice of leasing policy.

3. The social time preference discount rate for the State is zero, in real terms. The discount rate used by the company lessees is 8 percent, in real terms.

Assumptions #1 and #2 necessarily imply that the true time profile of economic rents produced by the lease is fixed. The choice of leasing option has no effect on the size or timing of these rent yields. The different leasing options merely move the dates of payment of rents forward or backward. Since any earlier payments by the lessee to the State are assumed to carry an 8 percent real rate of interest, any leasing policy which substitutes later payments for earlier payments will be preferred by the lessee. That is to say, the actual payments to the State will be larger the later in time they are made by the lessee. From the point of view of the company, a $100,000 payment made today is the same as a $147,000 payment made five years from now. But since the State is assumed to be indifferent as between a payment today and a payment ten years from now, the total rents paid to the State will be largest under the leasing policy which postpones rent payments farthest into the future.

Given the assumptions of the DMEMS model, the conclusions are inescapable. But the model suggests an even better policy for the State: Delay all rent payments until the year 2000. This will produce a larger total rent payment to the State (maintaining the assumption of a zero real discount rate) than any of the options modeled in the DMEMS report. But does this policy make sense in fact?

The real question to be asked is whether it is reasonable to assume that the people of Alaska regard the real discount rate on income to be zero. We make an error by extrapolating from the present temporary situation in which inflation rates exceed the rate of return on most financial investments. The true (long-run) real rate of interest on financial investments is positive, and in the neighborhood of 3 percent. If the choice of leasing policy for Alaska is predicated upon the fear of a too-early return of rent to the State, this problem can be alleviated through creation of a trust fund or the purchase of high-yielding annuities. These systems would delay the date of receipt of rent payments, but at the same time enhance their value through real interest compounding.

The DMEMS report and most other reports filed in this case explicitly assume that bidders (companies) are risk-averse while the State is risk-neutral. This assumption implies that the bidders will pay less than the expected value of a lease over to the State under a bonus bidding system. It also ignores the real risks facing Alaska, by assuming that Alaska is indifferent as between a sure thing and a gamble as long as the two have the same expected value.

To exemplify this point, let us assume that the Beaufort can contain either $100 billion in net rents or it can contain nothing. Assume, in addition, that the probabilities in the case are 50-50. Risk-neutrality implies that Alaska would not prefer a $50 million certain payment to the gamble involving double or nothing. I don't believe this assumption is reasonable for a State whose future fiscal condition depends so critically on the payment of rent from oil and gas resources. If the Beaufort is, indeed, one of the last great potential oil and gas provinces in Alaska, a significant amount of risk-aversion should certainly attend the choice of leasing policy. It is much more reasonable for oil company bidders to behave as though expected value was equal to true value. They can spread their risks over hundreds of prospects around the world.

A research project which I have been involved with for the past five years provides valuable evidence of the extent to which the traditional bonus bidding plus royalty system used by the federal government in its OCS leasing program has returned the full value of economic rent to the federal government. (See R. Jones, W. Mead, and P. Sorensen, "Free Entry Into Crude Oil and Gas Production and Competition in the U.S. Oil Industry," Natural Resources Journal, October, 1978, pp. 859-75.) We have studied the first 839 OCS leases issued in the Gulf of Mexico from 1954 through 1962 using precise data on all aspects of revenues and costs including data on the timing, the type and the depth of all wells drilled. This study is the most complex empirical analysis of the economics of offshore production now available. Our findings are surprising. The lessees (companies) have earned only a 9.5 percent rate of return on their offshore investments before taxes. This may be compared to a 19.2 percent before tax-rate of return earned by all U.S. manufacturing during these same years. In total, therefore, oil companies operating in the Gulf of Mexico paid more than the true economic rent in these resources to the government. Instead of under-bidding, as the risk-aversion theory suggests, companies consistently over-bid under the bonus bidding system. The reason why companies consistently over-bid in competitively lease auctions is important to note. The explanation is captured in the phrase "the winner's curse". In a competitive auction, the lease will be awarded to the highest bidder. Since each bidder separately evaluates the potential of the tract, the winner must obviously be the one who puts the highest value on the tract. This means that the bidder who makes the greatest error on the high side will win, and that leases will be consistently over-bid.

Now this same phenomenon of over-bidding will characterize both royalty bidding and profit share bidding. The bidder offering the highest royalty or profit share bid will be most likely to have over-bid. We see evidence of this fact in the two experimental OCS royalty sales (1974 and 1977) and in the Long Beach sale (1965). But when a bonus bid is too high, the State keeps the money. When a royalty or profit share bid is too high, the lease will probably never be developed, or if developed, will not be developed in an optimal manner and will likely be prematurely abandoned.

It is often contended that the bonus bidding system retards potential competition for leases by screening out the small companies which cannot afford the high front-end payments. I would answer this contention in two ways. First, a company with poor credit and limited financial resources is not an appropriate candidate for investment in oil and gas production in as hostile an environment as Alaska. Second, smaller companies with the required expertise can easily participate in bonus bidding through the vehicle of joint bidding. There is plenty of evidence in studies by economists and federal government staff to show that joint bidding primarily facilitates entry by small firms and that the total number of bids received for a lease rises as the incidence of joint bidding increases. (See our paper cited above, p. 871).

In a forthcoming journal article, we have presented a comprehensive evaluation of the economic effects of different leasing options. (See R. Jones, W. Mead and P. Sorensen, "An Economic Analyais of the OCS

Lands Act Amendments of 1978", Natural Resources Journal, in press). I will not repeat those evaluations here. The DMEMS report (and other reports) have correctly identified the problems with royalty leasing, and other leasing alternatives permitted under the new OCS Act are not being seriously considered in Alaska.

But I must comment on the proposed profit share leasing idea which appears to have captured the support of many staff people in Alaska. Let me quickly list the major drawbacks of profit share leasing:

1. The winning bidder in a profit leasing system may not be the most efficient operator. The losses suffered through inefficiency will be shared by the State.

2. If dry hole risks under a profit share system cannot be shared with the State, the lease may never be developed at all.

3. The cost of administration of a profit share lease will be high for both the lessee and the government. While it is easy to assume that all potential future problems of definition and allocation under a profit share lease can be spelled out in regulations before the fact, in truth there is no such thing as an all-contingencies contract. Such a contract is constrained by the fact of bounded rationality, in essence meaning the limits of what any person can know or anticipate. Thus much litigation and continuing administrative hassles will be experienced under any profit share

lease. These costs will be paid out of potential net rents, to the detriment of the people of Alaska.

4. The risk of cheating is high. If a choice is possible, a profit share lessee will use less efficient equipment and manpower on his profit share leases as compared to his regular leases. The over-allocation of R and D, public relations, and overhead expenses to the profit share lease is likely. Outright corruption of public officials is possible.

5. The fundamental incentive toward efficiency is undermined under a profit share lease. Where the profit share exceeds 50 percent, and in combination with State royalties, severance taxes, and State and federal income taxes, the gain to the lessee from saving a dollar drops below 25 cents. (In the cast of the Wilmington leases in California, the net incentive is now below 1¢ on each dollar saved.) This will naturally lead to major inefficiencies, bureaucratic over-staffing, "gold-plating", or the condoning of waste. To try to control these inefficiencies will require more and more State manpower and expense. The net effect will be to reduce both the total production from the lease and the net rents paid to the State. (See Figure 1). Before a major commitment to profit share leasing is made by Alaska, the Long Beach experience should be carefully analyzed. The theoretical attractions of the profit share system will be, I believe, quickly washed out by its practical difficulties and problems.

This Committee must consider the important question of whether each structure in the Beaufort Sea should be leased under a single bidding system as the federal government recommends. I believe in this case the federal proposal is a good one. If a single producing unit were to contain federal leases issued under the traditional system and State leases issued (let us say) under a profit share system, the inherent administrative weaknesses of the profit share system would be magnified. Problems of cost and revenue allocation, the size and timing of exploratory drilling and other investments and the timing of abandonment would all arise. Since the interests of the State and federal owners would not be strictly parallel, at least three and possibly more parties would be involved in all major decisions -- the lease operator, the State, the federal government and possibly owners of individual lease interests. Administrative and legal costs would be high in this situation. The costs of all this administrative drag ought to be recognized before the State chooses to go its own way on the leases in question. Since the traditional bonus bidding system has so many other advantages to the State, the decision to lease lands on the same basis as the federal government would be the course of wisdom, in my opinion.

SUMMARY AND CONCLUSIONS

1. The assumption that the total revenue and net rents yielded by a prospective lease are not affected by the choice of leasing option is invalid. Profit share leasing creates incentives for non-optimal lease development and inefficiency in operation. It will require additional administrative costs on the part of both the State and the lessee. These factors will reduce potential economic rent.

2. The State of Alaska should not be assumed to be risk-neutral with respect to the Beaufort Sea sale. The optimal amount of risk which should be shared by the State must be a policy decision in which both fiscal responsibility and the frontier character of the prospective lands to be leased are recognized.

3. The DMEMS analysis showing that profit share leasing returns the greatest amount of rent to the landowner is based upon a set of arbitrary assumptions. If these assumptions are changed to more closely reflect reality, the conclusions then do not follow. These analyses should not become the basis for a policy decision.

4. The traditional bonus bidding plus royalty leasing system has returned more than the true value of net rents from Gulf of Mexico oil and gas leases for a period of extensive historical experience. This finding contradicts the hypothesis that companies are risk-averse, or that absence of competition is a characteristic of bonus bidding. In historical fact, of $33.4 billion in total revenues produced from all federal (OCS) oil and gas leases through 1977, $25.3 billion (or 76 percent of gross revenues) has been paid to the federal government.

5. Each structure in the Beaufort Sea should be leased under a single leasing system by both the State and the federal government. Non-parallel leasing systems would produce serious administrative and incentive problems.

6. The bonus bidding plus royalty system combines a mixture of risk sharing, security of revenue to Alaska, and incentives for efficiency in development and ultimate recovery of oil not offered by alternative leasing systems. This leasing system should be adopted by Alaska for the forthcoming Beaufort Sea sale. If the State wishes to delay receipt of funds from these lands to later years, this can best be accomplished by means of a trust fund. Alaska should not reject a proven, effective system for collecting economic rent from its lands simply to effect a delay in revenues.

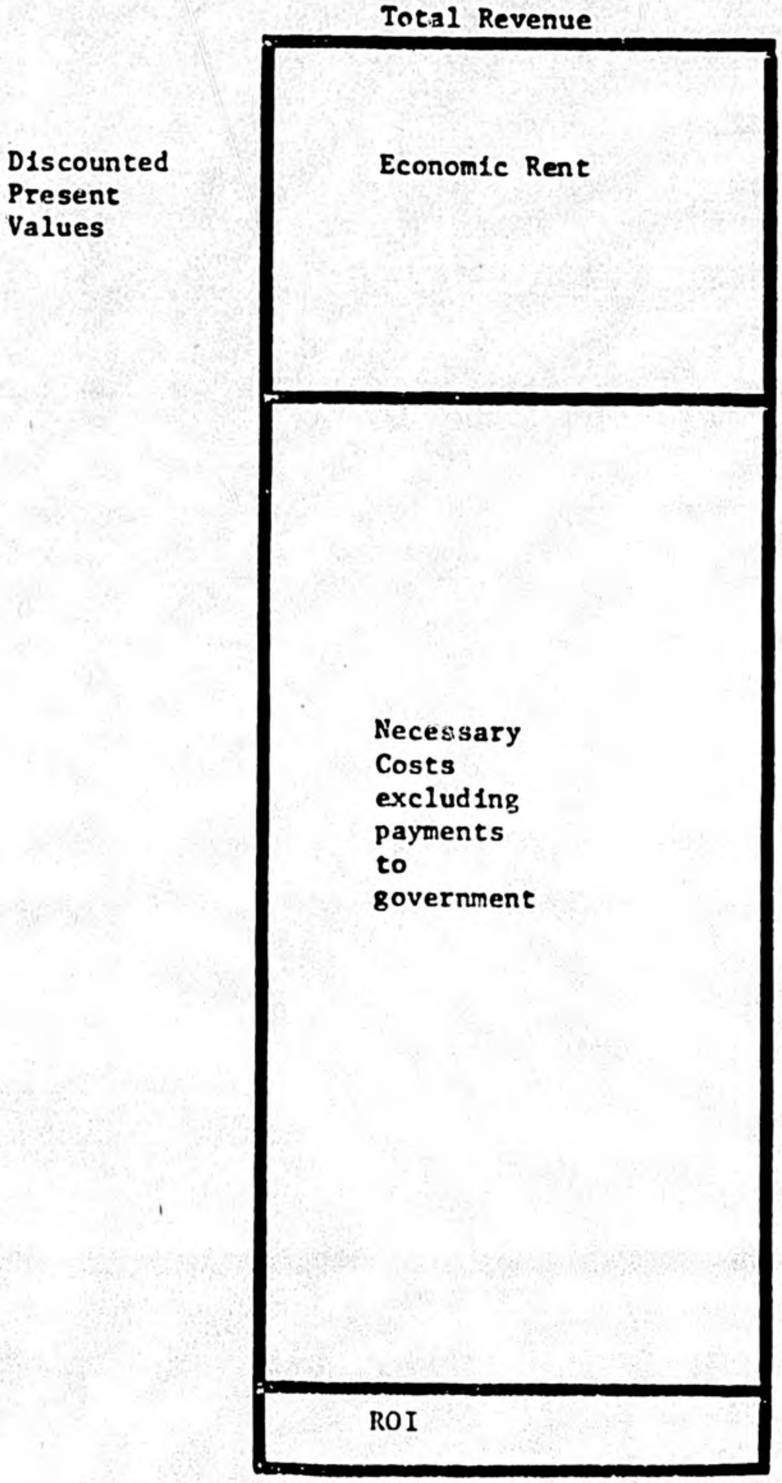

Figure 1

AGO 667419

Alaska State Legislature • House of Representatives
Interim Committee on Oil and Gas Leasing Policy

Rep. Joe McKinnon
Chairman
Rep. Chat Chatterton
Rep. Sam Cotten
Rep. Joe Hayes
Rep. Hugh Malone
Rep. Bill Miles
Rep. Brian Rogers

727 N St., Suite 2
Anchorage, Alaska 99501
907-276-1955

September 28, 1979

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

Re: Beaufort Sea Lease Sale Issues;
Public Hearing of October 8, 1979

Dear Bob:

Attached is a Committee Staff Report which details some of the important issues in the upcoming Beaufort Sea lease sale. We know you are currently studying these issues in-depth, and are encouraged by your efforts in preparing for the lease sale. We offer our analyses and recommendations as an aid to you and the Governor in your deliberations. The decisions soon to be made on how to lease the Beaufort Sea are among the most critical ones to face this Administration. Accordingly, we believe that as many points of view -- and analyses -- as possible be considered.

Because of the importance of the issues, we feel that they deserve a thorough public discussion before final decisions are made by the State. With your cooperation, we have scheduled a Public Hearing in Anchorage for Monday evening, October 8, 1979, at 7:00 p.m. in room 402 of the State Court House. In the Hearing we will present the Committee Staff's recommendations, detailed below, for your comment, and discuss the current results of the work by your own staff. Our goal is to have the best possible information at your disposal during the hectic pace of the next few weeks. We understand the pressures and deadlines you face, and appreciate your willingness to discuss Beaufort issues with the Committee in a public forum.

Our recommendations, more fully explained in the Staff Report, are summarized as follows:

1. Leasing Procedures on Disputed Acreage: The State should not agree to the proposal by the Federal government to use the Federal Sliding Scale/Bonus Bid system on disputed acreage. The

Committee has proposed an alternative -- and better -- sliding scale system for the disputed acreage in our September 14th Report to you.

We also urge you to reject the Federal government's proposal to lease all structures under a single bidding system. Besides usurping State authority, the proposal is reprehensible because of the lack of certainty in delineating structures prior to actual exploration.

2. Consideration of Projected Revenues: The current budget picture of present surplus and future deficit should be a primary concern in choosing a bidding method. A long-term view, spanning several decades, is a prerequisite to a wise decision on bidding methods. Our analyses demonstrate that the Bonus Bid system, by failing to delay lease revenues, denies a fair return to the people of Alaska and abrogates the fiduciary responsibility of the State government to its citizens.

3. Post-Lease Sale Administration: In the interests of State and industry efficiency, the Committee recommends that production audit functions be consolidated into one department.

4.. The Department's Economic Analysis: At this time the Committee has had the opportunity to review DMEM's rough draft economic analysis. We compliment DMEM on the quality of the draft report. As you have indicated, the final report will consider the additional economic issues of competition, split-leasing, on-structure drilling and reserved acreage. All these ideas have played an important role in oil development throughout the world, and deserve consideration by Alaska.

We note from the latest timetable of your Department's activities, that on October 5th the final regulations in 11 AAC 83 will be forwarded to the Lieutenant Governor and that the completed Economic Analysis will be dispatched from DMEM to you. The Committee would very much like to receive a copy of each of these documents that same day. Obviously, they are of central importance to the October 8th Public Hearing.

The Committee looks forward to meeting with you and your staff on Monday evening, October 8th.

Sincerely,

House Interim Committee on
Oil and Gas Leasing Policy

Joe

Joe McKinnon, Chairman

Attachment

cc: Governor Jay Hammond
Thomas K. Williams, Commissioner, Department of Revenue
Thomas Cook, Director, DMEM
Representative Terry Gardiner
Representative Russ Meekins
Senator Clem Tillion
Senator John Sackett
Senator Bill Sumner
Cecil D. Andrus, Secretary of the Interior
Alaska Outer Continental Shelf Office (BLM)
Alaska Oil and Gas Association

M E M O R A N D U M

TO: Joe McKinnon, Chairman
House Interim Committee on Oil & Gas Leasing Policy

FROM: Committee Staff

DATE: September 28, 1979

RE: Beaufort Sea Lease Sale Issues and Recommendations

The committee staff has been carefully reviewing preparations and developments regarding the upcoming Beaufort Sea lease sale. In addition to extensive research, this has involved multifaceted contacts with numerous industry officials and myriad State and Federal agencies, as well as attendance at official briefings on developments.

The result is this report. Though it is not offered as an exhaustive study of every point involved in the sale, it is nonetheless a carefully drawn analysis of important issues, accompanied by our recommendations. We hope it will be helpful for the Committee's upcoming public hearing the night of October 8th, not only to Committee members, but to State and Federal officials and representatives of the oil industry as well.

BIDDING SYSTEMS ON DISPUTED ACREAGE

The genesis of the attempt to resolve the problem of bidding systems on disputed acreage was the Memorandum of Understanding which Governor Hammond and Interior Secretary Andrus signed in March of 1978, which outlined the policies and procedures that were to be followed in the proposed joint Federal/State oil and gas lease sale in the Beaufort Sea. This Memorandum of Understanding ("the M.O.U.", as it is generally known) was the culmination of negotiations between the State and Federal governments on procedures to be followed in leasing properties whose title is still in dispute in the Beaufort Sea area. Negotiations had been in progress since December 1975, when Governor Hammond had cancelled a proposed Beaufort Sea lease sale because of the land dispute.

The objectives of the Memorandum of Understanding, stated in its introduction, are:

> -- to identify general policies and procedures for joint leasing and administrative activities associated with an oil and gas sale in the Beaufort Sea.
>
> -- to develop guidelines for allocating costs and responsibilities associated with pre-sale and post-sale administration.
>
> -- to describe a means of refining the principles cited in this document into specific processes and responsibilities. (M.O.U., p. 1).

Since its signing, the Memorandum of Understanding has been used as the cornerstone for policy decisions in the joint sale negotiations between State and Federal officials. In a Press Release issued on March 2, 1978, before he signed the Memorandum of Understanding, Governor Hammond stated that it expressed two fundamental principles:

> One: That neither party may unalterably determine policies or practices applying to areas of disputed ownership; and two, that uniform operating guidelines will apply to the entire sale area.

While the Memorandum of Understanding established a set of guidelines for joint sale negotiations, it did not create any binding or contractual obligations on either of the parties.

> The parties agree that nothing contained in this Memorandum of Understanding or done pursuant to it shall affect in any way the legal rights, interest, and claims of the parties in the area of the Call for Nominations described above. Though this Memorandum of Understanding is intended to be a morally binding guidance document, it is not intended to create enforceable contractual duties. (M.O.U., p. 8).

The Memorandum of Understanding establishes who has legal jurisdiction and management responsibility over disputed acreage within the sale area. This is the most significant point expressed in the M.O.U. The State has jurisdiction over undisputed State land. The Federal government has jurisdiction over all disputed acreage and the undisputed Federal acreage. To quote directly from the Memorandum:

> Being more inclusive, Federal standards and legal requirements will as a general principle, apply to activities on all tracts which contain any Federal acreage and/or disputed acreage. State standards, policies and legal requirements will apply to tracts containing exclusively undisputed State acreage. Each entity shares the responsibilities as an equal partner on all decisions pertaining to tracts containing disputed acreage or to tracts of split ownership and neither party may unilaterally determine policies or practices which apply to disputed or split tracts. (M.O.U., p. 1).

What this means is that disputed acreage must be leased under a Federal bidding system, but the State must concur.

Both the State and Federal governments have considerable statutory authority in choosing a bidding system for an oil and gas lease sale: the State authority pursuant to AS 38.05.180(f), its oil and gas leasing statute; the Federal authority comes from the Outer Continental Shelf Lands Act, 43 U.S.C. 1331-43. Both Federal and State laws allow variations of bonus, royalty, or net profit bidding with provisions for work commitments.

The State is presently in the administrative review process on regulations to implement the provisions of AS 38.05.180, as it was amended by ch 155 SLA 1978 and ch 65 SLA 1979. The proposed Article 2 of 11 AAC 83 on Net Profit Share Leasing establishes procedures for calculating the net profit share due to the State from any net profit share lease issued by the Department of Natural Resources (hereinafter referred to as "DNR" or "the Department"). The proposed Article 1 of 11 AAC 83 authorizes the Department to offer a lease on a sliding scale royalty to be "chosen at the commissioner's discretion".

The net profit share system proposed by the Department in the proposed Article 2 of 11 AAC 83 is an "Investment Account" system commonly referred to as a front-end capital recovery system. This system allows a lessee to fully recover costs plus interest before the State collects a net profit share from a lease. The decision to use an "Investment Account" system was based on an economic analysis of various types of net profit leasing systems, which was a joint effort of DNR and the Department of Revenue.

The proposed Article 1 of 11 AAC 83 authorizes a sliding scale royalty but does not specify a particular type of sliding scale royalty system. The system to be used is to be "chosen at the commissioner's discretion". The primary purpose of the proposed 11 AAC 83.183, as we stated in earlier reports, appears to be administrative flexibility.

The Federal government is still in the midst of evaluating different net profit share leasing systems, but agrees that a front-end capital recovery system is economically superior to other bidding systems. However, the Federal government is undecided as to whether to allow interest on development costs, as the State has opted for in its "Investment Account" system, or whether to apply a multiplier to pre-production expenses in lieu of an interest rate. The State considered this point irrelevant as both systems are economically so similar. But, because of this debate, the Federal government will not have net profit leasing regulations in place in time for the sale.

Our preliminary research supports the Department's choice of the Investment Account system as the optimal leasing system. By a simple cash-flow analysis, it can be demonstrated that if the State defers the taking of income until the oil companies have recovered their costs, the State will receive more in total discounted present-value dollars, because of the relatively high discount rate used by an oil company. Money received 15 or 20 years downstream is worth very little to the oil companies and does not figure significantly in their bids. The oil companies are more than willing to share a larger percentage of the downstream income in return for early recoupment of costs. This is in accordance with the State's time preference for money, because the State has a significantly lower discount rate than an oil company. Downstream income is worth considerably more to the State.

Recently, the State was informed that because of bureaucratic delay the Federal government would not have regulations for net profit share bidding in place in time for the sale. Because of this delay, the Federal government has offered the State only two bidding choices for disputed tracts: (1) cash bonus bid with a fixed royalty; and (2) cash bonus bid with a fixed sliding scale royalty.

As the analyses the Committee submitted to the Department on September 7th and 14th concluded, the Federal Sliding Scale Formula would result in significantly less income to the State than the alternative developed by the Committee, which it termed "the Committee Sliding Scale". State income, the September 14th Report concluded, is reduced because of two reasons: (1) the Federal Sliding Scale Formula relies too heavily on the bonus, thereby reducing the effective royalty percentage; (2) the Federal Sliding Scale Formula ignores the realities of unitized production by using a logarithmic formula which establishes the royalty on a tract-by-tract basis. What this means is that if two units produce identical amounts of oil, but one of the units contains more tracts than the other, the royalty percentage from the unit with more tracts is lower.

The problems encountered with the Federal Sliding Scale Formula do not occur with the Committee Sliding Scale. However, it is important to emphasize that, in our opinion, the Committee Sliding Scale, superior as it is to the Federal Sliding Scale Formula, is still inferior to the Net Profit Investment Account System. The Committee Sliding Scale royalty was developed as a possible compromise for use on disputed acreage, mainly because the Federal government did not have sufficient time to implement net profit share leasing regulations and its Sliding Scale Formula is unsuitable.

It has been the consistent policy of the Department that if the Federal government does not come up with a system which will maximize State income, the State will not agree to lease the acreage. In the public hearing the Committee held in Anchorage on August 13, 1979, DNR Commissioner LeResche, testifying before the Committee, was asked what was the State's position if it is determined that it is locked into an inferior bidding system on disputed acreage because the Federal government has not adopted net profit leasing regulations. The Commissioner's response, in effect, was that if in the Department's economic analysis it is determined that the Federal options are significantly inferior to other options available under State law, he would propose withdrawing that acreage from the sale. The Commissioner further reiterated this position in Fairbanks on August 23, 1979, in a briefing for the Governor on the Beaufort Sea lease sale. In regard to bidding systems on disputed acreage, Commissioner LeResche stated that

> "If the cost of agreeing is that we will choose a bidding method that is less favorable to the State, just to lease the acreage, our decision will be that we won't do it. We'll cancel the disputed leases."

On September 18, 1979, Committee Staff met with a representative of the Federal government regarding use of the Federal Sliding Scale Formula. Based on the results of the Committee's analysis of September 14th, three alternatives to the present Federal Sliding Scale Royalty Formula were discussed for use on disputed acreage. The alternatives are: (1) changing the factors in the Federal Sliding Scale Formula to increase the effective royalty and decrease the bonus; (2) consider using the Committee Sliding Scale as described in the September 14th Committee Report; (3) withdraw the disputed acreage from the sale. These alternatives are to be considered for inclusion in the Secretarial Issue Document (SID) for the Beaufort Sea sale, which will be presented to the Secretary of the Interior before he makes his final determination regarding the sale.

In is our recommendation that the State should not agree to lease the disputed acreage under the original Federal Sliding Scale Formula.

Bidding Systems on Single Structures

The Federal government has consistently maintained that all tracts on each structure should be leased using the same bidding system. This recommendation was presented to State officials in a July 13th meeting in which Thomas Cook, Director of DNR's Division of Minerals and Energy Management (DMEM) and spokesperson for the State, tentatively agreed to the recommendation.

If the State finally does agree to this recommendation, it will be giving up a significant amount of management authority for deciding bidding systems within the proposed sale area. If a structure as delineated prior to the sale is located primarily on State acreage but a small portion of that structure crosses into disputed acreage, the structure would have to be leased under a Federal bidding system. As the Federal government has offered only two bidding choices (Cash Bonus/Fixed Royalty and Cash Bonus/Sliding Scale Royalty), this limits the State's options severely. To make matters worse, it is possible that after exploration the only oil or gas discovered in the structure will lie under State land. This would mean the State would be collecting lease payments under a Federal bidding system for an oil pool located beneath State land.

The rationale for this single-bid-per-structure recommendation is the oil industry claim that leasing a structure under different bidding systems will make it difficult, if not impossible, to Unitize. This question arose before while HB 854 (which ultimately became ch 155 SLA 1978) was being considered by the Senate Resources

Committee in 1978. In a 5-30-78 memorandum from the Legislative Affairs Agency (LAA) to the Chairman of the Senate Resources Committee, the opinion of the LAA Research Division was summarized thusly:

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

Unitization, as we all know, is basically a conservation technique designed to protect lessees' rights in a field and prevent waste of hydrocarbons. Unit participants are allocated working interest percentages in the field and share costs and revenues in relation to their working interest. Based on the prior research conducted by the Legislative Affairs Agency and our own research, it is our opinion that basic incentives for unitization are present under any bidding system. The primary engineering and economic incentives remain unchanged, i.e., amount of oil, location, geologic considerations, development costs, and efficient management of the oil pool.

In our research on this question, we contacted Bob Jones of the Louisiana Minerals Board, which administers offshore leases in conjunction with its Conservation Division. A number of these offshore leases are administered jointly with the Federal government, and contain different royalty provisions, different tax structures, and many were leased at different times. According to Mr. Jones, none of these differences have prevented unitization from occurring, nor have they caused any problems for Louisiana officials in administering the leases, or for Federal OCS officials in New Orleans for that matter.

We also discussed the matter with Ron Kaplan of the Department of the Interior, who agreed that this recommendation of a single bidding system is not absolutely essential. Unit accounting might become more difficult, he conceded, but it would not actually prevent a field from being unitized.

Based on our analysis, we see no reason whatsoever why the State should agree to a recommendation that would have the effect of depriving the State of so much management authority. It would undermine the State's authority over undisputed State land by narrowing or maybe even eliminating its choice of bidding systems.

In addition, the single-bid-per-structure recommendation has a practical problem. As Hoyle Hamilton, Chairman of the Alaska Oil and Gas Conservation Commission (AOGC) said in early September at an Anchorage meeting of State and Federal officials on this matter,

> "I'm not sure how definite the seismic data will be in determining the location of the structure."

In other words, one could end up trying to match up bidding systems on adjacent tracts that bear no relation to the position of the structure.

Because the location of structures cannot be positively determined, the State should not limit its available choices by agreeing to the Federal recommendation. To make such a compromise, based on imprecise data, would be foolish and not in the State's best interest.

The Department's position on the single-bid recommendation, however, apparently has not yet been resolved. In the Committee's August 13th Public Hearing in Anchorage, Commissioner LeResche indicated to the Committee that the extent to which this recommendation would be adhered to depended upon the relative position of a structure in relation to State and disputed land. In other words, if 95% of the structure was on State land and 5% was on Federal land, the State would not concede to using a Federal bidding system. If the situation were reversed, i.e., 95% of a structure on Federal land and 5% on State land, the Department would agree to use of a Federal bidding system. Commissioner LeResche did not indicate, however, what would happen if half a structure was on State land and half on Federal land.

As the Memorandum of Understanding put it, "State standards, policies and legal requirements will apply to tracts containing exclusively undisputed State acreage". It is our opinion that under no circumstances should the State relinquish any authority over undisputed State acreage.

State Taxes

During the course of State/Federal negotiations, a significant question has arisen over what to do about State taxes on disputed acreage. AS 43.55.011 requires a lessee to pay a production tax, but Federal law does not. The State also requires oil companies to calculate the amount of State income tax differently from Federal income tax. This results in a higher effective State income tax rate. The differences in the State and Federal tax laws have posed the problem of what to do with what the Federal government considers to be excess State taxes due from disputed tracts.

Most of the lease payments due from a lessee having an interest in an oil pool located beneath disputed acreage will be placed in escrow pending resolution of the disputed lands question. Precise requirements are to be outlined in the Joint Interim Agreement. However, the Federal government has been consistently opposed to collecting State taxes that exceed Federal taxes and placing these in escrow with other lease payments due from disputed acreage. Federal officials feel this will adversely affect bids on Federal tracts. They are, however, amenable to including a provision in each Federal lease which provides that the lessee will be liable for all back taxes plus interest in the event the State ultimately wins the title dispute.

Commissioner LeResche has agreed with the Federal position that State taxes would not be collected and placed in escrow pending resolution of the land dispute, but has, however, indicated that he supports a provision that will require lessees to retain liability for payment of back taxes. In our opinion, State taxes should be collected and placed in escrow, or at the very least the lessee's liability should be spelled out clearly in the Federal lease form.

TITLE TO DISPUTED LANDS

At the end of January, 1979, State and Federal officials approved the Federal/State Leasing & Nomination Map -- the official joint sale map. The joint sale map established specific sale boundaries and its approval was an important procedural requirement in the regulatory preparation for the sale. The map delineated three types of land that would be leased in the sale: State lands, Federal lands, and "disputed" lands. Generally, State lands lie within three miles of the coastline or near-shore islands, while Federal lands lie outside the three-mile limit. The disputed lands are claimed by both the State and Federal governments because of different legal theories on the fixing of boundaries of State coastal waters.

Because the Barrier Islands form a continuous chain of State land offshore, there are actually two categories of disputed land. One major portion of disputed land forms an enclave between the shore and the Barrier Islands, which is totally surrounded by State land. This area would be considered State land under the "inland waters" theory; the State has a good chance of prevailing on this theory.

The second area of disputed land lies outside the Barrier Islands. This would be considered State land under the "straight baseline" theory. Based on International Law, this theory holds that territorial boundaries are drawn as straight lines three miles out from the furthermost land area. A conflicting theory requires three-mile arcs to be drawn around the furthermost land area. Unfortunately, the baseline theory -- which would work out best for the State -- has been rejected twice by the U.S. Supreme Court.

And the final determination here of who finally is granted title to the disputed land will be decided by the U.S. Supreme Court, which has original jurisdiction in the matter. The State and Federal governments have agreed to settle the issue that way. Accordingly, a lawsuit was filed in the U.S. Supreme Court in June (United States of America v. State of Alaska, File No. 84 Original).

A requisite to the sale, the lawsuit focused originally on the disputed lands delineated on the joint sale map. The lawsuit enables the State and Federal governments to enter into an interim agreement setting out procedures for leasing and handling revenues from the disputed lands. In addition, Attorney General Gross has testified that the State has attempted to raise in the lawsuit the issue of disputed lands in the Colville Delta area and off the shore of the Arctic Wildlife Range.

Unfortunately, since the signing of the joint sale map, Federal officials have attempted to nullify the map and their previous position, calling into dispute the use of two salient points for establishing boundaries of disputed acreage. Those points are Dinkum Sands and the ARCO Pier Dock. Both claims are disadvantageous to the State.

Dinkum Sands

Even though the chances are slim that the straight baseline theory for establishing territorial boundaries will be ultimately upheld by the U.S. Supreme Court, the State still has a decent chance at title to the enclave of disputed acreage within the Barrier Islands per the Submerged Lands Act. But, if Dinkum Sands -- an island, the State claims -- is removed as a salient point for determining State territorial waters, the State's case is weakened considerably. The effect would be to open up the enclave of "State land" within the Barrier Islands. A link would then be created between the disputed tracts inside the Barrier Islands and the undisputed Federal acreage beyond the Islands. At stake are 18,035 acres and untold revenues.

The issue of Dinkum Sands first surfaced in a letter dated June 21, 1979 from the Chief of the BLM's Division of Cadastral Survey to the State's Chief Cadastral Engineer, which declared that:

> Information has been furnished to this office that the area known as Dinkum Sands shown as upland on Nautical Charts 16046 and 16061 has in fact eroded to such an extent that no upland or low tide elevations remain. As this area is encompassed by the area of the proposed joint Federal/State oil and gas lease sale in the Beaufort Sea scheduled to be held in December, 1979, this office proposes to drop the salient points previously selected on Dinkum Sands and heretofore used for computations of split blocks for the upcoming sale. New split block computations without using the Dinkum Sands salient points will be initiated.

As a small member of the Barrier Islands, Dinkum Sands has appeared on Federal Nautical Charts since at least 1955, but in the maps that are part of the Final Environmental Impact Statement (8-79) and in the Federal proposed notice of sale (8-22-79), the area including and surrounding Dinkum Sands is shown as "disputed tracts".

The BLM's position was buttressed -- later -- by the results of a bathymetric survey for USGS conducted on July 25, 1979 by the R/V Karluk. In a transcribed radiotelephone message to Ed Kempema, a participant in the survey from Erk Reimnitz, another participant, Mr. Reimnitz described what he believed to be Dinkum Sands:

> The minimum depth of the shoal was 30 to 40 centimeters and the shoal covered an area approximately 30 meters in diameter. The shoal was composed of very gravelly sand.

Mr. Reinmnitz also mentioned that "it was foggy for part of the survey, with a minimum visibility of 100 meters."

State officials have made several visits to Dinkum Sands. On July 11th, Thomas Cook (DMEM's Director), Michael Arruda (Asst. Attorney General), and Claud Hoffman (DMEM's Chief Cadastral Engineer) visited Dinkum Sands. In a sworn affidavit issued on August 2nd, Mr. Hoffman testified that:

> The sandy, rocky island upon which we landed has large chunks of ice along its northerly and southerly sides and was exposed approximately 3 1/2 - 4 feet above the water level. There appeared to be several such islands in the group extending approximately 1,000 - 2,000 feet in a generally southwesterly and northeasterly (or westerly and easterly) direction. We landed in what appeared to be the middle of this island string.
>
> In my experience as a cadastral engineer and in consideration of my familiarity with the maps of the Beaufort Sea area, I am convinced that the island upon which we landed is part of a group of islands historically known as Dinkum Sands.

In other words, the island was above water, as it was also found to be on August 13, 1979.

On August 23rd, however, State and Federal representatives made a joint visit to Dinkum Sands and found it under eight inches of water. But extraordinary tidal conditions prevailed that day, creating a "tidal surge" that may have resulted in the water level being up to a foot above the mean high tide mark.

In Washington during the week of August 9th, Attorney General Gross negotiated a "settlement" with the Federal government of the Dinkum Sands question. The area in question is to be leased and managed by the State. A joint Federal/State monitoring team will observe the island for a continually acceptable period to determine when the island is above mean high tide (or high water, which is still being negotiated). If the island is under water part of the time, revenues will be split proportionately with the Federal government. The Federal government will receive revenue in proportion to the time the island is under water. This "agreement" affects only leasing, administration, and revenues; ultimate ownership still must be decided by the U.S. Supreme Court. (As of yet, however, no formal written agreement has been reached).

ARCO Pier

The second point of contention to arise since the approval of the joint sale map is the use of the ARCO Pier on the northwest shore of Prudhoe Bay as a salient point for determining the disputed area for the Beaufort Sea sale.

The ARCO Pier was built in 1974. Two years later the pier was extended to twice its former length under an emergency permit issued by the Corps of Engineers. As of this moment, it is only the extension that is at issue. The issue was put in writing in a letter dated June 15, 1979, from Interior Solicitor Leo Krulitz to Attorney General Avrum Gross. In it, Mr. Krulitz complained that:

> When the leasing map for the joint Beaufort Sea sale was being prepared, it came to our attention that the State of Alaska considered the ARCO pier to have extended its coastline. Unfortunately, I cannot concede that valuable Federal land was conveyed to the State through the issuance of an emergency permit, without proper review by this Department or approval by Congress. Therefore, the Federal Government will be forced to require removal of the entire pier to erase any doubt as to the location of the coastline, unless the State is willing to drop its claim. Removal of the pier seems to be a somewhat unreasonable solution to this problem. However, I believe it is equally unreasonable for the State to take advantage of the fact that ARCO's application was not properly reviewed due only to the emergency circumstances. If the State is unwilling to waive its claim in this case, we will feel constrained to refuse approval of all such permits in the future, when a true emergency exists.

The threat of removal now, we assume, is limited to the extension of the pier.

Mr. Krulitz claimed that Federal regulations (33 C.F.R. 320.4(f)) required that his office be consulted before structures were approved which may alter the coastline, and contended that neither the BLM nor his office was given the chance to comment on ARCO's application. The regulation reads as follows, in pertinent part:

> All applications for structures or work affecting coastal waters will therefore be reviewed specifically to determine whether the coast line or base line might be altered. If it is determined that such a change might occur, coordination with the Attorney General and the Solicitor of the Department of the Interior is required before final action is taken.

We recently examined the "Beaufort Sea 10" file of the Regulatory Functions Agency in the Anchorage office of the Corps of Engineers, which contains all materials involved in the granting of the permits for the original ARCO Pier and the extension. We found the following items of interest:

(1) A 12-10-75 letter from the Department of Interior's Fish and Wildlife Service to the Alaska District Engineer of the Corps of Engineers, stating that "Interested agencies of the Department of Interior have reviewed the Atlantic Richfield Co. (ARCO) request for an emergency permit..."

(2) A 12-15-75 memorandum to the file by William Bleggi of the Regulatory Functions Branch stating that "I informed [Col. Poteat of OCE] that EPA, NMFS, USF&WS and Coast Guard were involved and agreed on the conditions. Also we had touched base with General Rollins (Federal Pipeline Office) and Bill Moses (Interior's General Counsel) who gave their concurrence."

(3) The 1-6-76 Statement of Findings by the Corps of Engineers stating that "General Rollins of the Federal Pipeline Office, Department of the Interior, was contacted in regard to the proposed project and the conditions that were submitted. Concurrence was received on 15 December 1975 from the Pipeline Office."

We have made no conclusions other than to surmise that a gap in communications of considerable magnitude must exist within the Interior Department.

The above notwithstanding, Harvey Sullivan, Counsel for the Corps of Engineers, contends that the emergency permit was nonetheless issued properly per the 1973 Trans-Alaska Pipeline Authorization Act (43 U.S.C. 1651 et seq), citing 43 U.S.C. 1652(b) as the authority and direction for

> the Secretary of the Interior and other appropriate Federal officers and agencies to issue and take all necessary action to administer and enforce rights-of-way, permits, leases and other authorizations that are necessary for or related to the construction, operation, and maintenance of the Trans-Alaska oil pipeline system...

43 U.S.C. 1652(c) allows Federal officers to waive any procedural requirements of law which they deem desirable to further the interest of the Act. That intent, stated in 43 U.S.C. 1652(a), is to ensure that

> the trans-Alaska oil pipeline be constructed promptly without further administrative or judicial delay or impediment.

The extension of the ARCO Pier in 1976 was necessary to allow the unloading of 13 barges trapped in the ice. The barges were loaded with cargo for construction of facilities at Prudhoe Bay.

Although Mr. Sullivan claims the emergency permit was issued properly, he also maintains, loyally, that it was never intended that the extension of the pier be a "permanent structure" to be used as a salient point to measure coastal boundaries. However, ARCO and other officials of the Corps of Engineers believe the pier to be a permanent structure, and the entire pier is an integral part of the proposed plan for the Prudhoe Bay Waterflood Project which was submitted in July 1979 by the Prudhoe Bay Unit Waterflood Task Force as part of the various permit applications. Counsel for the Corps of Engineers has expressed approval of the use of the ARCO dock in the waterflood project.

As stated earlier, only the <u>extension</u> of the pier is at issue at this date. Approximately 765 acres are at stake.

<u>Summary</u>

Sometime in the hopefully not-too-distant future, the U.S. Supreme Court will resolve the disputes over acreage. The actions of Federal officials in the Dinkum Sands and ARCO Pier controversies, however, have caused a cloud of acrimony to hover over the joint sale. Governor Hammond summed it up well in a July 17th letter to Interior Secretary Andrus in which he discussed the Federal government's changes of position on the disputed acreage:

> I bring these matters to your attention at this time because they have the potential to create major stumbling blocks to proceeding with the proposed Beaufort Sea sale in December of this year. There are several legal issues involved in the proposed sale requiring intensive discussion and cooperation between the State and the Federal Government. Your department's unilateral attempt to deviate from the already agreed-upon guidelines for determining the

> boundaries of State-owned lands and Mr. Krulitz' attempt to coerce the State into abandoning a legitimate legal claim certainly do not foster an atmosphere conducive to cooperation; if anything, they pose a serious threat to the sale being held at all.

But at the briefing for Governor Hammond in Fairbanks on August 23rd, Attorney General Gross, referring to the disputed lands issues, said that "these disputes will not hold up the sale in any way." In the briefing, he had reviewed the Dinkum Sands compromise but made no mention of the ARCO Pier.

REVENUE FORECASTS

The timing of revenues from oil and gas lease sales to fit the State's monetary needs is a critical element in selection of the optimal bidding system -- and one the DNR should not decide unilaterally. In a bonus bid sale with a low fixed royalty, a large portion of the lease payment is made at the front end. In a royalty bid system, payment is deferred until production begins. In a net profit bidding system per the proposed Article 2 of 11 AAC 83, payment is deferred even longer or until there has been sufficient production to allow the lessee to recoup its capital costs.

In determining the timing of income, the Department of Revenue needs to establish the State's appropriate discount rate. This factor determines the State's time value of money and measures the return the State can earn on its investments. Current forecasts predict a huge surplus for the next few years, resulting from recent OPEC price hikes and the ongoing increase in pipeline throughput. The July price hike boosted the State's income from the production tax and the sale of royalty oil, and was compounded by the increase in Prudhoe production to 1.4 million barrels per day (to rise to 1.5 million by December).

The Legislative Finance Division, in a September 5, 1979 Budget Projection, concluded that the State will have a liquid surplus of 3.6 billion dollars during the next fiscal year. This is over 2.5 billion dollars above the amount of the current operating budget. Commissioner of Revenue Thomas K. Williams has testified that his Department's projections developed by the Petroleum Revenue Division (using its PETREV computer model) are substantially the same. Depending upon the rate of growth of the State budget, the surplus revenues can be expected to continue until some time between 1998 and 1995. Sobering deficits are predicted to occur some time during the 1990's as the Prudhoe Bay field reserves are depleted.

This forecast points to the conclusion that the State currently has a negative time value of money. That is to say, it may be better for the State to take a loss of current revenue so as to have more income ten-to-twenty years in the future. This forecast argues strongly for the taking of lease payments in the form of a royalty or net profit share, rather than a front-end bonus.

DMEM's apparent insensitivity to the effect a huge surplus has on the State's discount rate and time value preference for income was recently displayed in a front-page story in the Anchorage Times of September 18, 1979. The article quoted Thomas Cook, DMEM's Director, as follows:

> One of the related considerations is the State's need for income and the timing of that income.
>
> "There's a funny thesis that we should be concerned with deferring income," he said. "Of course the ultimate deferral is never."

Not all State officials, however, feel that deferring State income is "a funny thesis." Thomas K. Williams, Commissioner of Revenue, said at the briefing of the Governor on the Beaufort Sea lease sale on August 23rd in Fairbanks,

> "What we are trying to do is optimize the flow of funds through time so we don't have a big valley in terms of revenue in the late 1980's. Perhaps a cataclysm would be a better word of what could happen through the 1990's."

Commissioner Williams also indicated that his Department was going through the exercises of matching budget growth with revenue forecasts. Regarding those analyses, Commissioner Williams stated, at the same meeting:

> "We see the State going broke despite the billions of dollars on hand in the early 2000's."

In our opinion, decisions which affect the State's financial position and its time value preference for income, whether from a lease sale or State investment, should be made in close consultation with the Department of Revenue. DNR can assist by providing technical information that would bear on the timing and expected value of revenues from an oil and gas lease sale. However, the choice should be made in large part by the Department of Revenue so as to be as compatible as possible with the State's actual money needs. Furthermore, it is of critical importance that the State time its lease revenues from the Beaufort Sea to replace declining revenues from Prudhoe Bay in the early 1990's.

There is yet another reason for spreading payment of lease revenues. As experience shows, State income can be more wisely spent if it is stretched out over a period of years, instead of collected in a lump sum. Massive one-time increases strain the ability of policy makers and administrators to properly manage State agencies or programs. A striking example is the ten-fold growth of the University's budget during the 1970's, which created a management crisis that is only now being remedied. Leasing procedures should enable revenues to be timed to ensure wise fiscal management, as well as maximizing economic benefits.

In the August 13th public hearing of this Committee in Anchorage, Commissioner of Revenue Williams said, "We have more revenue anticipated for this fiscal year than we need for our operating budget." The Commissioner added that in general the price increase for crude oil has pushed back the time when the State's current revenue surplus would be exhausted, which would be sometime near the mid-1990's. If a major portion of rent from the Beaufort is collected as a cash bonus payment, it would not fit well with the State's current revenue situation.

POST-LEASE SALE ADMINISTRATION

A major criticism leveled at net profit leasing by DMEM, again, is that post-sale audit difficulties may make net profit share leasing unworkable. In the words of Thomas Cook, "Net profits would be an administrative nightmare". Currently the Department is responsible only for auditing royalty payments from actively producing lease tracts. A net profit share lease would require auditing allowable costs as defined in the proposed Article 2 of 11 AAC 83.

Late in the 1979 Legislative Session, the Legislative Budget and Audit Committee published a report which concluded that:

> The Department of Revenue and the Department of Natural Resources should coordinate their efforts to provide a more comprehensive audit program. Even though the oil and gas tax and royalty are treated separately by statute, their bases are so similar that auditing both should be considered one function.

This conclusion is based on the fact that even though DNR audits royalty and the Department of Revenue audits the production tax, the audit functions are so similar that they should be consolidated in one department.

This issue of audits is further complicated by certain confidentiality requirements which apply to tax information obtained by the Department of Revenue, which may not divulge information regarding taxpayers' returns except in official administrative or judicial proceedings. AS 43.05.230. And though the Department of Revenue conducts field audits for production tax payments (AS 43.55) and the oil and gas corporate income tax (AS 43.21), it may not share this information with DNR. But DNR is not staffed to conduct field audits to verify royalty payments; all DNR does is simple desk audits. Information obtained by the Department of Revenue would greatly increase the accuracy of royalty audits if it could be shared with DNR.

HCS CSSB 51 (Judiciary) am H (1979) would have allowed this very information obtained by the Department of Revenue to be made available to DNR if that information related to the value of oil or gas in which the State has an interest under AS 38.05.180. The bill, unfortunately, failed to pass the House.

A different solution, perhaps a more permanent one, would be to shift the entire audit responsibility to one of the two departments. This question of post-sale administration of a net profit share lease was posed to the Commissioner of Revenue. Commissioner Williams told the Committee that the audit burden, as it related to a net profit share lease, has been reduced significantly because of the similarity of the proposed net profit share leasing regulations to the oil and gas corporate income tax regulations and proposed production tax regulations. Because of this similarity, Commissioner Williams said, auditors from Revenue could double up the functions of the tax audits and a net profit share lease audit.

In our opinion, because the Department of Revenue has been increasing its staff to audit the production tax and corporate income tax, it is the logical choice for audits of net profit share leases. Another point that supports this choice is the fact that the proposed net profit share leasing regulations in 11 AAC 83 are modeled on the oil and gas corporate income tax regulations and the proposed production tax regulations (15 AAC 05.700 et seq). And because of Revenue's familiarity with these audit procedures and the similarity of its regulations to the proposed net profit share leasing regulations, Revenue is the best Department to have the audit responsibility for net profit share leases. This could be achieved in the short-term by an inter-agency agreement, and in the long run by new legislation.

ECONOMIC CONSIDERATIONS

Selection of the bidding system for the Beaufort Sea lease sale is one of the most important economic decisions now facing the State. That decision could affect the State's financial position for several decades. It cannot be taken lightly and must be based on a thorough economic analysis. In the August 23rd Fairbanks briefing of the Governor on the Beaufort Sea lease sale, Commissioner LeResche stated,

> "It is not a philosophic question; it is very clearly a technical question. . . . We have fought hard to withhold any serious consideration of bidding methods until we have all the information available to us. . . . That information includes a theoretical analysis of how different bidding behaves under different production scenarios. . . . It includes the final geologic assessment; that is, what we think is there."

We agree with Commissioner LeResche that the choice of a bidding system should be based on the best information available -- with maximizing State income as the primary policy objective.

The responsibility of matching leasing decisions to revenue needs is strictly the landowner's (the State's here). If one system proves to be consistently more favorable under prevailing and alternative situations, that one is the logical choice. To quote from the rough draft of DMEM's Economic Analysis:

> If the decision maker consistently selected the alternative having the highest positive expected monetary value his total net gain from all decisions will be higher than his gain realized from any alternative strategy for selecting decisions under uncertainty. This statement is true even though each specific decision is a different drilling prospect with different probabilities and conditional profitabilities. (pp. 17-18).

In other words, the decision-maker must consistently choose the best system for maximizing economic return.

The State has a variety of systems available to it for leasing oil properties pursuant to AS 38.05.180(f). It can lease by requiring a cash bonus, a royalty share, or a net profit share. The State can combine the systems and can require work commitments. The State can reserve acreage within the sale area, or it can choose not to sell it. The final choice must be consistent with the State's time value preference for income.

From the State's point of view, the decision is simple to conceptualize. First, assume a certain amount of oil, worth X dollars. Then assume it will cost Y dollars for a company to develop it, including a return on its investment. If X is greater than Y, the field is economic.

The only question the lessor (again, the State here) need ask is how to collect Z -- the difference. The crucial question is how to collect Z in a way that will maximize return to the State.

Briefly, the State has three basic choices facing it in the upcoming sale: (1) The traditional system is the Cash Bonus/Low Fixed Royalty system. Under this system, the State sells the lease to the bidder who, at a competitive auction, offers the highest bonus bid. The bonus is paid shortly after the auction. (2) A second choice is to fix a low bonus, or a bonus just high enough to weed out irresponsible bidders, and require the companies to bid a percentage of future royalty. (3) The third choice is to set a low bonus and award the lease to the bidder offering the highest percentage of its net profit. The net profit is simply gross value less cost. A variation of the first system is to either set a higher royalty or net profit percentage and use the bonus as the bid variable.

All the systems involve risk. In royalty or net profit systems, payment is contingent upon a find. If oil or gas is not produced in commercial quantities, the State receives no income. In bonus bidding, the State faces risk that an unexpectedly significant quantity of oil will be found. It also faces the risk that oil prices will rise substantially during the life of a field. In an era when world oil prices are being set politically, the full benefits of those price rises won't necessarily enure to the State under a bonus system. A bonus bid, for reasons explained in this Report, fails to produce a fair return on the resource. This point was explained by Governor Hammond to Don Langston, Exxon's Vice-President of Exploration, at the Fairbanks briefing of August 23rd. The Governor said:

> "We're talking about risk which reduces revenue to the State. . . . If we have a field with an enormous net profit and the State took a lower bonus, then there is a risk -- the risk that we get less than we had to if we had chosen net profits."

The bonus system has some bureaucratic appeal. It is simple, requires little skill to manage, and promises occasional successes. For example, in 1974 the Federal government received over two billion dollars in bonus payments for salt domes off the coast of Florida. But there is a flip side to the bonus system. From 1964 to 1969, the State of Alaska sold the leases that make up the Prudhoe Bay Unit for bonuses totalling approximately 90 million dollars. The current worth of the Unit is well over 100 billion dollars. The battles over taxation so the State could finally obtain a fair share of the value of its field were fought at enormous cost to all parties.

The bonus system has strong proponents within DNR. Speaking on behalf of DMEM, Thomas Cook puts it this way:

> "I'm hellbent to see something feasible, that we can administrate. My views are well known. I have a decided bias for proven leasing methods, unless someone can show me what we could accomplish that way (net profits) that we can't accomplish another way."
>
> (Anchorage Times, 9-18-79, p. 2).

Clearly the bonus system accomplishes the task of conveying mineral interests beneath State lands to oil companies. Its ability to ensure maximum economic returns, provide incentives for exploration, and guarantee adequate competition, however, is questionable. In examining how to best maximize State income from a lease, the State should measure this policy against these four economic criteria: (1) Discounting; (2) Incentives; (3) Competition; and (4) Risk. The rough draft of DMEM's economic analysis considers these criteria.

Discounting

In the example of $X - $Y = $Z, the basic question is: How does the State want $Z paid to it? Does the State want $Z (generally termed economic rent) paid in a lump sum as a bonus, or does it want it spread out over time as a net profit or royalty payment? How much the State receives in bids by the companies is related to their discount rate. The worth of the bid to the State is affected by its discount rate.

The State has a lower discount rate than an oil company. If the State's discount rate is measured by the return on Permanent Fund investments or as DMEM calls it in its rough draft, "the opportunity cost of capital," the State's discount rate is currently around 0.0% in real terms. In other words, the State is barely able to keep its current revenue surplus and Permanent Fund balance from being eroded by inflation. DMEM's rough draft assumes 0.0%; we concur.

An oil company's discount rate is much higher than the State's, because, unlike the State the company's investments are not statutorily restricted. In DMEM's rought draft, its base case assumes 8%. We feel that adding 12% and 16% scenarios provides a fuller, more realistic range for study.

Discounting measures the present-day value of income or spent through time. Measured in real terms, $100 is worth a lot more to an oil company if it can invest it today and earn up to 16%, than the $100 is to the State which can only earn 0.0%. DMEM puts it this way in its rough draft:

> The difference in private and public discount rates is extremely important in evaluating the relative attractiveness of the various leasing alternatives from the state's point of view. It means that future dollars are worth more to the state than the industry. (p. 15).

As DMEM's rough draft concludes, against the criteria of discounting, a royalty or net profit share system is far superior to the bonus system for both the State and the oil companies. Companies are in a position to bid more dollars when, during the exploration and development phases, they have the use of the money that would have been paid as a bonus. They are willing to bid more as a net profit share than a bonus or royalty because they are thus permitted to recover their capital outlays, which allows them additional years to plow earnings back into this -- and other -- fields.

Incentives

This second economic criterion is related to the incentives different bidding systems offer the lessee to (1) explore and develop and (2) to recover the maximum amount of oil from a pool.

> The systems are also evaluated in terms of their potential ability to encourage economically efficient resource use. For example, a system may generate substantial revenues to the state but discourage the development of marginal fields and encourage abandonment of producing fields before all of the economically recoverable oil is recovered. Other things being equal, it is desirable that all economically recoverable oil and gas be extracted in an efficient (cost minimizing) manner. (DMEM rough draft, p. 2).

An oft-repeated criticism of royalty or net profit share bidding is that these systems encourage speculative bidding, which will adversely affect exploration and development decisions. Conversely, as DMEM states on p. 6 of its rough draft:

> It is also argued that the payment of a large front end bonus will lead to the diligent development of a lease.

We find no concrete evidence, however, to support this latter argument.

Because there is no historical evidence of alternative bidding systems on State leases, we have been limited to examining the <u>actual</u> performance of <u>actual</u> Cash Bonus/Low Fixed Royalty leases to determine whether the detractors of net profit share leasing are right.

Currently pending before the Department are applications for Unitization involving 56 unexplored about-to-expire leases -- leased under a Cash Bonus/Low Fixed Royalty. Unitization here is being attempted to extend the leases without having to bring them into production as required by law. We need not belabor here the worthy concept of Unitization as a conservation practice designed to protect lessees' correlative rights in the development of an oil pool, and the preventing of the waste of hydrocarbons. We have mentioned it earlier in this Report. As we mentioned in a Report to the Department on August 17th, too, Unitization as a device for extending leases is of dubious value in cases where "it is uncertain whether any oil or gas exists in commercial quantities."

Here, however, the issue is not Unitization, but whether the method used in leasing these 56 properties encouraged exploration. All the leases in question were granted to the bidder offering the highest cash bonus payment, with a royalty fixed at 12.5 percent. The operators have not explored any of these leases, even though industry maintains that payment of a bonus will encourage development.

So, while payment of a bonus doesn't necessarily ensure development of a lease tract, there is still the argument that without bonuses you encourage speculative bidding.

This problem supposedly occurs, the industry claims, with royalty or net profit share bidding. This particular problem is easily solved, however, by simply setting a moderate fixed bonus high enough to screen out irresponsible bidders. This point is not addressed in DMEM's rough draft -- but should be. And besides setting bonuses, DNR also has the authority to require work commitments, i.e., to require a certain number of wells to be drilled on a lease or in a particular geographic area.

The recent departure from prior State policy evinced in the Duck Island controversy cannot help but discourage speculation. If a company knows that it will in fact be allowed to hold acreage only for the primary term of the lease unless it explores and brings the property to development, it will no longer be in its interest to sit on a lease in anticipation of higher future oil prices. Under the alleged prior State policy, the lessee could use unitization as an excuse for extending the primary lease term. Under Federal law, this problem is surmounted by employment of a five-year lease term. Under State law, the primary lease term is ten years. This point should also be addressed in DMEM's analysis.

What we do find in DMEM's rough draft is the following:

> If the value of reserves was growing at 15 percent per year in real terms and the firm's opportunity cost of capital was 10 percent, it is not obvious that the bonus would assure "diligence". (p. 6).

We would merely point out here that the value of the Prudhoe Bay reserves has risen ten-fold during the past decade.

On the point relating to marginal production and extending the economic life of a field, net profit share leasing is clearly the best system. On a net profit share lease the net profit share paid to the State can decline to zero. This is definitely a positive effect in terms of extending the life of a field.

Unless the Commissioner's discretion is invoked per AS 38.05.180(1), the royalty cannot decline below 12.5% under both the bonus and royalty systems. AS 38.05.180(f). Because of this, there is always a contingency payment which may have the effect of shutting down a field. This problem was solved regarding the production tax by applying the economic limit factor, which allows the production tax rate to decline as production from wells declines. A royalty acts economically like the production tax. Both are perceived as costs to the oil company, and may make a marginal field uneconomic.

As a comparison of net profit share to royalty bidding, note the following point made by DMEM:

> The net profits system adopted by the state, because it allows for the capital recovery of additional field investment, is much more likely to encourage secondary efforts. (DMEM rough draft, p. 19).

When a company invests in secondary recovery systems, it reduces the amount it pays as a net profit share to the State.

Competition

It is to the lessor's advantage to attract as many bidders as possible to a lease auction. But under current State leasing policy, there are two deterrents to competition: lack of adequate information on geologic potential, and large up-front bonus payments.

Under current law as interpreted by DNR, well data that relates to the valuation of nearby unleased acreage must be kept confidential for a reasonable time after disposition of the affected area. See AS 31.05.035(c), as amended by ch 160 SLA 1978. Ch 160 SLA 1978 had the effect of locking up data from certain wells adjacent to the proposed sale area. Attempts to repeal the effect of ch 160 SLA 1978 were made by the House during the 1979 Legislative Session, but were unsuccessful. Prior to ch 160 SLA 1978, well data was routinely made public after two years.

The companies without access to this data are placed at a keen disadvantage in the upcoming sale. Companies with proprietary data protected by AS 31.05.035(c) (as amended) contend that they drilled wells in anticipation of a previously scheduled Beaufort Sea lease sale. When that lease sale was cancelled, the companies claimed it was unfair that this data was to become public. In December 1975, Governor Hammond cancelled a Beaufort Sea lease sale scheduled for 1976. All the wells protected by AS 31.05.035(c) were spudded after December 1975. The wells which became public prior to the ch 160 SLA 1978 conclusively confirm the presence of oil and gas offshore in the Beaufort Sea. As Don Langston of Exxon put it at the Governor's briefing in Fairbanks on August 23rd,

> "I don't think there is much risk that there is not oil in the Beaufort Sea."

Included as part of the Department's economic analysis should be the effect of reserving the tracts adjacent to acreage where well data is locked up pursuant to AS 31.05.035(c). Because the State has access to the data, that should make the evaluation fairly precise. If oil is eventually discovered around these tracts, their value would increase dramatically.

Another point on competition is the effect of requiring the payment of a large bonus to acquire a lease. Smaller companies do not have the cash on hand to compete with larger companies on the choicest tracts. By restricting the number of bidders, the State may be losing out in the long run. This point is well-documented in the literature. See, e.g., Alternative Oil and Gas Leasing Policies, A Report to the Alaska Legislature, Mason Gaffney, 1978. The fact that large bonuses screen out smaller companies, combined with the effect a bonus would have on the State revenue surplus, makes yet another powerful argument for use of royalty or net profit share bidding. This point is mentioned on p. 6 of DMEM's rough draft:

> Finally, from the lessor's viewpoint, the extent to which the bonus transfers the economic rent to the lessor is extremely sensitive to the level of competition. Paradoxically, it is alleged that the traditional cash bonus system hinders competition because of the requirement of a high front end bonus. Smaller firms lack the financial resources to compete effectively in the bidding process and the geological risk is too great to rely on traditional capital markets for the necessary funds.

Risk

The final economic consideration -- and the one least understood -- is risk. The key to understanding risk is expected value. What course of action will result in the largest net gain from a large number of independent trials? In other words, the odds of success or failure will even out over the long-term, so one should choose the system which will maximize revenues over an extended period of time, not on a tract-by-tract or trial-by-trial basis. DMEM states it this way, by asking:

> Does the repeated trial aspect of expected value vitiate its use where each choice has a different set of economic parameters and geological risks? The answer is no. The expected value concept can be applied to leasing decisions if it is applied consistently to all decisions. (DMEM rough draft, p. 17).

The question of risk is also addressed in the paper by Hayne E. Leland, Professor of Business Administration at the U. of California (Berkeley), regarding the Department's proposed Net Profit Share Leasing regulations. In the introduction to his paper, Dr. Leland states that

> Because of risk, firms may require higher rates of return than the state. Risk sharing through net profit share leasing will be advantageous, in that expected revenue will by [sic] higher. The risks borne by the state will also be higher, however.

Risk sharing is particularly advantageous to the State, because it bears different risks than an oil company. Oil companies must evaluate risk on a tract-by-tract basis, and will discount their bids accordingly. The State, however, averages its risk over all tracts. Accordingly, the risk that a particular tract on which a company happens to be bidding is dry is much greater than the risk that all tracts are dry. It is illogical for the State to accept the company's perception of risk, because the State's is less. It is to the State's advantage to share in the risks. The bidding system in which the State shares the most risk is the net profit share.

DMEM's rough draft analysis compares revenues from two risk scenarios: a 50 percent chance of finding what you expect is there, and a 10 percent chance. In both cases, net profit share leasing generates more expected revenue than either bonus or royalty bidding. We recommend that DMEM model the 100% case as well.

Conclusion

We compliment DMEM for its rough draft economic analysis; it is an encouraging first step in developing the theoretical framework needed to evaluate leasing systems. In summary, we are anxious to see the following in the final Economic Analysis that DMEM sends DNR:

(1) The evaluation of the effect of obtaining better geologic data by drilling wells on-structure prior to a lease. This must be evaluated on an expected value basis and in terms of increasing competition.

(2) The evaluation of split-leasing, which separates the exploration phase from the development phase of oil and gas production. Implicit in this analysis is a reduction of risk to the company that ends up developing the lease.

(3) The evaluation of the effect of withholding certain highly prospective tracts within the sale area, and tracts where competition may be reduced because of unavailable confidential data.

(4) A comparison of all scenarios at 100 percent chance of success, to evaluate each system simply in terms of its efficiency in collecting rent.

Alaska State Legislature • House of Representatives
Interim Committee on Oil and Gas Leasing Policy

Rep. Joe McKinnon
Chairman
Rep. Chat Chatterton
Rep. Sam Cotten
Rep. Joe Hayes
Rep. Hugh Malone
Rep. Bill Miles
Rep. Brian Rogers

727 N St., Suite 2
Anchorage, Alaska 99501
907-276-1955

September 14, 1979

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

Re: Amendments to Title 11, Chapter 83 of the Alaska Administrative Code, relating to Oil and Gas Leasing Policy

Dear Bob:

Attached are the Committee Staff's additional comments on the proposed leasing regulations announced on August 3, 1979. Our original comments were filed on September 7th with your office and with the Division of Minerals and Energy Management (DMEM). This report deals with the Sliding Scale Royalty, as proposed in 11 AAC 83.183.

I am quite concerned about this regulation because it provides for a Sliding Scale formula which is "chosen at the commissioner's discretion." Our report demonstrates that differing formulas can result in substantially varying revenues to the State. The selection of any Sliding Scale formula should therefore take place in a more public manner and should be open to public comment. Ideally the formula should be adopted as a regulation. At a minimum the regulations should provide for public comment before any formula proposed by the Commissioner becomes effective.

The Staff report specifically examines the Federal Sliding Scale system and compares it to an alternative system developed by the Committee based on the economic limit factor of the State production tax (A.S. 43.55.013). Because the Federal government is pushing for the use of the Federal Sliding Scale system on disputed acreage in the Beaufort Sea lease sale, we feel the Federal system merits close scrutiny.

Briefly, our analysis shows that the use of the Federal Sliding Scale system would fail to provide a fair return to the State for the value of its resources. Although the Federal rate theoretically runs as high as 65%, a close look at the formula shows that -- under the most optimistic assumptions -- an actual field would have an effective royalty rate of approximately 30% during the life of the field.

The Federal Sliding Scale system also lacks basic logical premises. Distortions occur because the formula used in the system is tract-sensitive, ignoring the realities of unitized production. After intense, detailed examination and study of the Federal system, we find it overly complex, muddled, and riddled with excessive abstractions. Viewed from all angles, the Federal system would be a poor choice for the State to employ.

Because of the Federal government's strong desire to use its system on the disputed tracts, careful study of the system by the Department is vital. The Committee could only undertake a basic, quick analysis. The problems we found should serve as a warning, and point to areas for further investigation by the Department.

We urge you to carefully examine both the Federal Sliding Scale system and the Committee Sliding Scale described in the attached report. Once more, we also urge you to set forth your choice of Sliding Scale system by regulation with an appropriate period for public comment.

Sincerely,

House Interim Committee on
Oil and Gas Leasing Policy

Joe

Joe McKinnon, Chairman

Attachment

cc: Tom Cook, Director, DMEM (for official record)
Michael Arruda, Department of Law
Tom Williams, Commissioner, Department of Revenue
Representative Terry Gardiner
Representative Russ Meekins

AGO 667453

M E M O R A N D U M

TO: Joe McKinnon, Chairman
House Interim Committee on Oil & Gas Leasing Policy

FROM: Committee Staff

DATE: September 14, 1979

RE: Proposed Oil and Gas Leasing Regulations
(Second Report)

In our analysis of September 7, 1979 we briefly addressed the question of Sliding Scale Royalty. The sole regulation proposed on it, 11 AAC 83.183, would allow the commissioner to set any sliding scale royalty formula he chooses at the time of the lease sale. As we surmised in our earlier analysis, the primary purpose of 11 AAC 83.183 appears to be administrative flexibility. We also suggested that a comprehensive economic analysis of Sliding Scale Royalty Systems is required at a minimum, and that an optimal system be set forth by regulation. The possibility of the unfortunate selection of an inferior Sliding Scale Royalty system could actually work against the primary objectives of the Sliding Scale Royalty, i.e., prolongation of the economic life of a field and assurance of a fair economic return to the State

Here we present a brief comparison of two Sliding Scale Royalty systems the Department may wish to consider. The first one is the Federal Sliding Scale Royalty Formula; the second one, mentioned on page 14 of our analysis of September 7, 1979, will be referred to here as the Committee Sliding Scale. Although this comparison is not offered as an exhaustive in-depth analysis, it does serve to show how selection of the wrong system may lessen the return to the State and still not necessarily increase industry incentives.

Federal Sliding Scale Formula

In its proposed notice of sale, the Federal government publishes the sliding scale royalty formula to be used for particular tracts within the sale area. The formula is a natural logarithm which affixes the percentage of royalty due from a particular tract based on the value of quarterly production from that tract. The value of quarterly production is adjusted for inflation (to reflect real dollars); this adjusted value is then used in the formula. The calculated royalty percentage is then re-applied to the unadjusted value of quarterly production. The formula itself is:

Royalty % = B (ln V/S)

Two of the variables in this formula are fixed before the sale. In an unofficial draft of the proposed notice of sale for the December Beaufort lease sale, these were shown as:

B = 8.0
ln = natural logarithm
S = 2.5
V = value of production for a given quarter

In the above formula, "B" adjusts the value of the natural logarithm. As specified by Federal regulation, "B" may range from 1.0 to 10.0. "B" affects the absolute value of the royalty percentage: the higher the value of "B", the higher the royalty. The "B" factor is employed by Federal officials to reflect regional cost differences as they relate to development of an oil field. In a recent offshore sale in the Gulf of Mexico (where costs are relatively low), "B" was 10.0. For an OCS sale in California, where costs are higher, the "B" factor was 9.0. The Federal government is now proposing 8.0 as the "B" factor for the disputed and Federal acreage in the Beaufort Sea sale.

The value of "S" is the same for all Federal sales -- fixed at 2.5. We have examined the "S" factor from every possible angle, and have had lengthy conversations about it with the Federal officials who developed the formula. What we <u>know</u> is that the "S" factor determines the slope of the logarithmic curve. It is, for all practical purposes, a constant (at 2.5) for <u>every</u> Federal sale. It was derived by computer analysis and chosen because it fits what Federal officials have determined to be the optimal logarithmic curve. Federal officials use the "B" (and not the "S") factor to adjust the absolute value of the royalty percentage in the Federal Sliding Scale Royalty Formula.

Below are examples of how the Federal Sliding Scale Royalty Formula works. All values of "V" (quarterly value of production) are in real dollars.

<u>Example (1)</u>:

V = $100 MM

Royalty % = 8 (ln 100/2.5)
= 29.5%

Example (2):

V = $ 50 MM

Royalty % = 8 (ln 50/2.5)
= 24%

Example (3) :

V = $10 MM

Royalty % = 8 (ln 10/2.5)
= 11.1%

As these three examples illustrate, the royalty percentage declines as the value of production declines. Theoretically, the declining royalty is supposed to prolong the economic life of a field.

In Example (1), the value of oil produced is $100 million; the royalty due is 29.5%. In Example (2), the value of production is $50 million, and the royalty due is 24%. Finally, in Example (3), when the value of production is $10 million, the royalty -- according to the Federal formula -- is 11.1%. Because the minimum royalty percentage under Federal law is 16.667%, the calculated royalty percentage must be scaled upward to that minimum. The maximum royalty percentage allowed by Federal law is 65%; for the royalty to reach 65% the quarterly value of production would have to be approximately $8 billion -- from one tract. There is no field anywhere in the world with production this high. As can be readily seen, the Federal formula is not sensitive to costs as they are actually incurred during production.

Committee Sliding Scale

In our analysis of September 7th, we offered an alternative Sliding Scale Royalty formula for consideration. The formula works like the economic limit factor on the production tax, and operates in such a way as to adjust the royalty percentage as a function of operating costs to total value of production. Again, the formula is:

X = Base Royalty Rate

(1 - PC/VP) = Sliding Scale FActor

X (1 - PC/VP) = Effective Royalty

PC = Operating costs defined in 11 AAC 83.240
VP = Value of production defined in 11 AAC 83.225

Here, as the ratio of PC/VP approaches one, the effective royalty percentage declines. This ratio will approach one when operating costs are increasing in relation to the value of production. The formula may also be adjusted by use of an exponent (discussed below).

Compare the following examples. Again, the formula is:

Royalty % = X (1 - PC/VP)

Assume X = 50%

The value of "X" can be set by the Department prior to a sale, or can be used as the bid variable.

Example (A) :

Royalty % = 50 (1 - 100/600)
= 42%

Example (B) :

Royalty % = 50 (1 - 200/400)
= 25%

Example (C) :

Royalty % = 50 (1 - 300/400)
= 12.5%

In Example (A), PC/VP equals 0.1667 and the royalty percentage is 42%. In Example (B), PC/VP is 0.5; the royalty correspondingly declines to 25%. And in Example (C), PC/VP equals 0.75 and the royalty due is 12.5%. Notice how, as the value of PC/VP approaches one, the royalty percentage declines. Unlike the Federal formula, this formula is sensitive to actual field operating costs.

As mentioned above, the Committee Sliding Scale may be adjusted by the use of an exponent. For example:

$$\text{Royalty \%} = 5\ (1 - 200/400)^2$$
$$= 12.5\%$$

The use of an exponent determines the slope of the sliding scale curve, as the "S" factor does for the Federal Sliding Scale Royalty system.

Evaluation

In our analysis we compared sliding scale royalty systems using a custom version of the Garrett GREAT Computer Program. The GREAT system is currently employed by the Department in its own economic analysis. Called "DMEM", this custom version is designed to provide lease sale economics to both the oil companies and the State. "DMEM" has the capability of comparing:

(1) the Net Profit Investment Account system;

(2) the Net Profit Income Tax system;

(3) the Federal Sliding Scale Royalty Formula;

(4) the Committee Sliding Scale; and

(5) the Cash Bonus and Royalty system.

Our analysis was conducted from the perspective of an oil company estimating the amount it would be willing to bid in a lease sale. This was done by calculating the value of the bid variable that would allow the company an overall rate of return equal to its discount rate. This is the company's internal rate of return, determined by adjusting the bid variable to a level that results in a discounted after-tax cash flow total of zero.

For example, assume that a company is evaluating a particular tract. Its annual cash flow picture would look something like this:

Gross Value of Oil

- minus Royalty
- minus Taxes
- minus Operating Costs
- minus Investment Costs

= Cash Flow Total

The cash flow totals would be discounted annually. These annual totals would be summed up to determine the total value of the discounted cash flow. "Discounting" measures the present value of future dollars.

At this point it is helpful to see how the internal rate of return is arrived at. The following example utilizes strictly hypothetical values. The discounted totals are hypothetical, assuming n years and x discount %. What's important here are not actual values, but the principle involved.

<u>Assume</u>:	Gross Value of Oil	= 100
	minus Royalty	- 30
	minus Taxes	- 20
	minus Operating Costs	- 10
	minus Investment Costs	- 30
	Cash Flow Total	= 10
	Discounted Total	= -10

In this example, the company would analyze the cumulative cash flow total employing a thirty percent effective royalty. Assume the total discounted value is -10. What this means is that the company would be overbidding if it offered a thirty percent royalty, and would have to adjust the bid downward to eliminate this negative total discounted value.

Compare what happens in the same situation if the company bids a 10% royalty:

<u>Assume</u>:	Gross Value of Oil	= 100
	minus Royalty	- 10
	minus Taxes	- 20
	minus Operating Costs	- 10
	minus Investment Costs	- 30
	Cash Flow Total	= 30
	Discounted Total	= 10

Here the company would be <u>underbidding</u> by offering a ten percent royalty if the discounted total was 10. This means it would be earning a value of <u>ten</u> above its internal rate of return. In this case, the company would adjust the bid upward to eliminate this positive value.

Finally, consider the following example if the company were to bid a twenty percent royalty:

<u>Assume</u>:	Gross Value of Oil	= 100
	minus Royalty	- 20
	minus Taxes	- 20
	minus Operating Costs	- 10
	minus Investment Costs	- 30
	Cash Flow Total	= 20
	Discounted Total	= 0

Here the company would be willing to bid a 20% royalty, if we assume that the total discounted value of the cash flow is zero. Trying to zero out the cash flow may seem, at first blush, to not to be in the company's best interest. However, the value of the lease is not measured by the amount of residual cash flow; it is measured by the discount rate. If a company views the investment to be risky, it will compensate by raising the discount rate. If the annual cash flow totals were discounted at 15% in the above example, the rate of return would be 15%. If the company desired a higher rate of return, i.e., because it viewed the venture as a risky one, it would not leave a positive balance in the cash flow total, but would increase the discount rate instead.

Assumptions

In our analysis, we used the "medium" and "maximum" fields -- with their associated development and operating costs -- published in the draft Beaufort Sea Environmental Impact Statement (EIS). These are two of the same scenarios that DMEM is evaluating in its own analysis. To prevent distortion of the discounted cash flow analysis, we cut off the last three years of production and operating costs. This was necessary because of certain constraints of the Garrett computer system. Total production from the "medium" field was 730 MM/bpd; the total from the "maximum" was 1220 MM/bpd.

Wellhead value was assumed to be $ 12.00/BBL escalated at 2% per year. Company cash flows were discounted at two rates: 10% (low risk) and 15% (higher risk). Because the Federal system is designed to calculate the royalty percentage due from a field on a tract-by-tract basis, we compared the fields assuming three, four, and five tracts. In each case production was allocated evenly among the tracts. State income was discounted at 0.0% and 5.0%. All dollar figures represent real values.

To summarize:

Two Field Sizes

Minimum = 730 MM/bpd
Medium = 1120 MM/bpd

Two Company Discount Rates

10% = low risk
15% = higher risk

Two State Discount Rates

0.0%
5.0%

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Federal Sliding Scale

3 Tracts/Field
4 Tracts/Field
5 Tracts/Field

Committee Sliding Scale

exponents = 1.0
1.5
2.0

The scheduling of investments and production is shown year-by-year in Appendix "A". All costs used in our analysis were inflated by 10% to reflect real 1979 dollars. The State income tax rate was assumed to be 10%; the production tax rate is 12.5%.

Cases and Conclusions

Tables I-IV summarize results from the computer. As every situation indicates, the Committee Sliding Scale results in more income to the State -- all things remaining equal. The most important point here is that even under situations where the value of State income is increased, the company earns the same rate of return. This happens because the analysis employs the internal rate of return concept explained above. So the most important criterion to be considered, if not the only one, is the total value of income to the State.

In the tables showing total State income, column # 1 gives the total value of production from the field. Column # 2 shows the amount of the bonus paid; column # 3 the total amount paid in taxes. Taxes include production tax and state income tax. Column # 4 shows the total value of the royalty, and column # 5 the overall average royalty percentage. The percentage by year varies depending on the system being analyzed. The last two columns show total State income. The first total is the undiscounted total, or the total discounted at 0.0%. The second, State income column is discounted at 5.0%. All figures are in real dollars.

Under the column labeled Sliding Scale Systems there are two sub-titles: Federal Sliding Scale and Committee Sliding Scale. The analysis compares the effect of varying the rate at which the effective royalty slides. We found that the Federal Sliding Scale Royalty is sensitive to the number of tracts which overlay a particular field. So in the analysis we compared three tracts, four tracts, and five tracts. As is shown, the greater the number of tracts sharing unit production the smaller the overall effective royalty percent.

For the Committee Sliding Scale, we examined the difference caused by using different exponents. The exponents employed were 1.0, 1.5 and 2.0. The use of exponents did not result in a change in the overall effective royalty. It did, however, affect the base royalty amount bid by the company. Generally, the higher the exponent the higher the base royalty the company would be willing to bid. In general, the Committee Sliding Scale is not as sensitive to the exponent because this factor can be applied to the unit as a whole. As mentioned above, the Federal system must be used on a per-tract basis.

Table I shows that under the best of the Federal options the overall royalty is 25%. This would be the case assuming only three tracts overlay the field. Total State income discounted at 5 percent is $ 2.394 billion. Under the worst case of the Committee Sliding Scale, the overall royalty is 41% (rounded); total State income, discounted at 5%, is $ 2.962 billion. Accordingly, total State income is approximately 24 percent higher with the worst case of the Committee Sliding Scale than under the best case using the Federal Sliding Scale Royalty formula. The other tables show similar results.

* * *

We believe there are two basic problems inherent in the Federal Sliding Scale Royalty formula. In the first place, the Federal system uses a cash bonus as the bid variable. In effect, this limits the effective royalty from our scenarios (and DMEM's) to approximately 30%. Other analyses have indicated that it's not in the State's best interest to receive its income up front, particularly at a time when the State is debating how to spend its current revenue surplus. Second, we believe that setting the royalty based on a logarithmic formula which is tract-sensitive cannot maximize the royalty income due from a unit.

Again, Table I shows that the value of bonuses under the Federal system ranges from $230 million to $280 million. The royalty percentage ranges from 21% to 25%. Under the Committee Sliding Scale, bonuses were fixed at $10 million per field. The royalty percentage in all cases is 41%.

Notice how the Federal system affects State income: the larger the value of the bonus the smaller the percentage of royalty. This results in less total State income. Conversely, the smaller the bonus the larger the percentage of royalty becomes-- thereby increasing State income. This is because royalty payments are deferred until production begins. In the two field sizes we modeled with the Garrett program, production begins ten years after payment of the bonus.

In general, the longer you defer the company's payments, the more the company is willing to pay. Downstream income isn't worth as much to an oil company as it is to the State. Consequently, the oil company is willing to pay a larger percentage of downstream income if it doesn't have to come up with a large front-end bonus payment. Downstream income is worth more to the State because it has a lower discount rate than an oil company. In our analysis we assumed the State's discount rate to be between 0.0% and 5.0%. The company discount rate was assumed to be 10% in one case and 15% in the other. The discount rate is the measure of the yield each entity could earn on alternate investments. In general, the higher discount rate reflects a riskier investment from the company's point of view.

The second problem with the Federal Sliding Scale Royalty formula is more subtle. Notice again how the percentage of royalty drops as the number of tracts per field increases. This happens because, by increasing the number of tracts per field, you lower the per-tract value of production. By lowering the per-tract value of production, you lower the value of the logarithmic formula. This in turn lowers the royalty due from the field.

This is <u>not</u> the case with the Committee Sliding Scale. There, for all practical purposes, the royalty remains constant even when the exponent is varied. The royalty income is related strictly to the total value of production from the unit.

Although our analysis has been somewhat brief, the results point out the necessity of the Department examining in greater depth some of the problems we have discovered. A major question we have not addressed is the supposed positive effect of a sliding scale royalty prolonging the economic life of a field. We have yet to hear of an actual case of premature shutdown due to excessive royalty rates. The computer runs we employed in our analysis show that even with high royalty rates there is no danger of shortening the life of a field. This is because, we believe, the two field sizes we considered are so huge and the development and operating cost numbers from the draft EIS are so rough. We suggest that the Department undertake an analysis using smaller fields like Cook Inlet as a model where costs are definitely known.

TABLE I STATE INCOME

Sliding Scale Royalty System	Total Value Production $ MM	Bonus $ MM	Taxes $ MM	Royalty $ MM	Royalty Percent	State Income at 0%	Discount at 5%
Federal Sliding Scale							
3 Tracts/Field	12,543.	230	1991	3096	25%	5317	2394
4 Tracts/Field	12,543	259	2014	2833	23%	5105	2318
5 Tracts/Field	12,543	280	2031	2640	21%	4951	2262
Committee Sliding Scale							
Exponent 1.0	12,543	10	1803	5193	41%	7005	2980
Exponent 1.5	12,543	10	1808	5139	41%	6957	2971
Exponent 2.0	12,543	10	1813	5088	41%	6911	2962

* Field Size: 730 MM BBL'S

Company Discount Rate: 10%

All figures are in real dollars

TABLE II STATE INCOME

Sliding Scale Royalty System	Total Value Production $ MM	Bonus $ MM	Taxes $ MM	Royalty $ MM	Royalty Percent	State Income at 0%	Discount at 5%
Federal Sliding Scale							
3 Tracts/Field	12,543	26	2011	3096	25%	5133	2197
4 Tracts/Field	12,543	38	2036	2833	23%	4907	2107
5 Tracts/Field	12,543	48	2054	2640	21%	4742	2040
Committee Sliding Scale							
Exponent 1.0	12,543	10	1978	3440	27%	5428	2306
Exponent 1.5	12,543	10	1983	3393	27%	5386	2296
Exponent 2.0	12,543	10	1987	3348	27%	5345	2285

* Field Size: 730 MM BBL'S

Company Discount Rate: 15%

All figures are in real dollars

TABLE III STATE INCOME

Sliding Scale Royalty System	Total Value Production $ MM	Bonus $ MM	Taxes $ MM	Royalty $ MM	Royalty Percent	State Income at 0%	Discount at 5%
Federal Sliding Scale							
3 Tracts/Field	20,768	429	3244	5967	29%	9639	4429
4 Tracts/Field	20,768	481	3285	5501	27%	9266	4296
5 Tracts/Field	20,768	520	3316	5148	25%	8985	4194
Committee Sliding Scale							
Exponent 1.0	20,768	10	2901	9812	47%	12723	5516
Exponent 1.5	20,768	10	2910	9720	47%	12640	5500
Exponent 2.0	20,768	10	2919	9631	47%	12560	5485

Field Size : 1218 MM BBL'S

Company Discount Rate : 10%

All figures are in real dollars

TABLE IV STATE INCOME

Sliding Scale Royalty System	Total Value Production $ MM	Bonus $ MM	Taxes $ MM	Royalty $ MM	Royalty Percent	State Income Discount at 0%	at 5%
Federal Sliding Scale							
3 Tracts/Field	20,768	95	3277	5967	29%	9339	4110
4 Tracts/Field	20,768	119	3321	5501	27%	8940	3949
5 Tracts/Field	20,768	137	3355	5148	25%	8639	3827
Committee Sliding Scale							
Exponent 1.0	20,768	10	3111	7707	37%	10829	4692
Exponent 1.5	20,768	10	3121	7611	37%	10742	4670
Exponent 2.0	20,768	10	3130	7518	36%	10659	4649

* Field Size: 1220 MM BBL'S

Company Discount Rate: 15%

All figures are in real dollars

Appendix A

APPENDIX A, INVESTMENTS & PRODUCTION PROFILES (Medium Beaufort Case)

Year	Explor Exp. $ MM	Plfms $ M	Wells $ MM	Facil. $ MM	Oper. Costs $ MM	Production MM BBL
1979 (Bonus)						
1980						
1981	33					
1982	67					
1983						
1984						
1985		22				
1986		44	30	57		
1987		22	72	122		
1988			126	170		
1989			144	170	28	15
1990			108	57	45	40
1991			72	57	72	54
1992			60	29	78	55
1993			24	57	81	55
1994			24	57	86	55
1995			24	29	102	54

Year	Expl. Ex. $ MM	Plfms $ M	Wells $ MM	Facil. $ MM	Oper. Costs $ MM	Production MM BBL
1996			24	8	105	53
1997			12		108	52
1998					108	48
1999					109	43
2000					108	38
2001					105	32
2002					96	27
2003					86	23
2004					76	19
2005					67	16
2006					60	14
2007					54	12
2008					48	10
2009					42	8
2010					38	7
TOTALS:	100	88	720	813	1702	1218

All figures are in real 1979 dollars.

APPENDIX A, INVESTMENTS & PRODUCTION PROFILES (Maximum Beaufort Case)

Year	Explor Exp. $ MM	Plfms $ M	Wells $ MM	Facil. $ MM	Oper. Costs $ MM	Production MM BBL
1979 (bonus)						
1980						
1981	33					
1982	67					
1983						
1984						
1985		22				
1986		44	18	91		
1987		41	72	196		
1988		11	144	274		
1989			180	274	83	45
1990			180	91	85	75
1991			144	91	119	90
1992			108	46	129	91
1993			72	91	134	91
1994			54	91	142	91
1995			36	46	172	91

Appendix A, Cont. . . . .

Year	Expl. Ex. $ MM	Plfms $ M	Wells $ MM	Facil. $ MM	Oper. Costs $ MM	Production MM BBL
1996			12	13	179	91
1997					184	89
1998					185	82
1999					177	70
2000					169	60
2001					164	50
2002					150	42
2003					130	35
2004					119	30
2005					105	25
2006					88	20
2007					76	16
2008					66	14
2009					55	11
2010					47	9
TOTALS	100	118	1020	1304	2799	1226

All figures are in real 1979 dollars.

Alaska State Legislature • House of Representatives
Interim Committee on Oil and Gas Leasing Policy

727 N St., Suite 2
Anchorage, Alaska 99501
907-276-1955

CRITERIA FOR EVALUATION OF LEASING METHODS FOR THE BEAUFORT SEA SALE

a report prepared

by

Matthew D. Berman

Assistant Professor
Lyndon B. Johnson School of Public Affairs
University of Texas at Austin

August 26, 1979

CRITERIA FOR EVALUATION OF LEASING METHODS FOR

THE BEAUFORT SEA SALE

The purpose of an economic analysis of leasing methods for the proposed Beaufort Sea oil lease sale is to evaluate which methods of leasing provide the greatest economic value to the State of Alaska. Since there are a number of aspects of the Beaufort sale which are not readily generalized to other sales, the economic analysis for this sale should consider carefully practical, as well as theoretical advantages of different leasing methods.

State law permits a variety of methods to be employed for obtaining bids on oil and gas leases. The three ways permitted for the state to collect revenue from a lease are 1) cash bonus, 2) royalty share, and 3) share of net profits obtained from a lease. In addition, the state may elect to reserve a certain percentage of the tracts for sale after exploration has taken place. Thus the best leasing method as determined by the economic analysis may technically include any combination of withheld acreage, cash bonus, royalty share and net profit share. One of the latter three variables is the bid variable while the others would be set administratively as a condition of the sale.

There are four criteria which one may use to evaluate the various leasing methods. 1) Discounting of revenue: What bidding would give the most revenue to the state for any given perceived which must be considered for the case of the State of Alaska. One factor is the interest rate on state bonds. This rate represents the time value of money to the state on its borrowed capital funds. Historically, state bond rates have stayed at a level close to the rate of inflation, i. e., a zero real rate of return. Another factor related to the state's discount rate is the rate of return on the permanent fund. This factor represents the time value of money on investment of state revenues from such sources as oil and gas leases. The rate of return on the permanent fund is roughly one percent higher than the rate the state pays on its borrowed funds, or around one percent in real terms.

Finally, the appropriate discount rate for the State of Alaska needs to consider the timing of lease income in relation to the state's revenue forecasts and expenditure needs. This factor in the state's time value of money is a measure of the liquidity of the state treasury. Current forecasts predict a huge surplus for the next few years, due to increased prices from royalty oil and severance taxes from Prudhoe Bay. Since sobering deficits are predicted within two decades as the field's reserves are depleted, consideration of revenue forecasts argues for a negative state time value of money. That is, it would be better for the state even to take a loss of current revenues in order to have more income fifteen or twenty years in the future.

No matter how it is measured, the State of Alaska's time value of money for discounting future revenues is no more than about cost by the industry? 2) Risk: What is the impact of risk to bidders on the revenue which the state might expect to receive under different leasing options? 3) Incentives: Does the leasing method selected contain disincentives for diligence and orderly development of the field? 4) Competition: What leasing methods would bring the most bids, and the greatest range of bids, to the sale?

All four of these criteria are important, and a bidding method which is superior with respect to one or two criteria may not be optimal when evaluated against all four criteria. Accordingly, each criterion will be discussed separately for its impact on the expected value of revenue which the state might receive using the various alternative bidding methods.

Discounting of Revenue

Economists who have studied the industry have concluded that the rate used by the oil companies to discount future values to the present is very high -- over 20%, or at least 15% in real terms, after subtracting inflation. With a "time value of money" as high as this, costs which have to be paid several years into the future are valued much less than costs which have to be paid right away.

The time value of money for the State of Alaska, on the other hand, is much lower than that of the oil companies. Although there is some argument among economists about the appropriate way to compute the social rate of discount, there are three factors

If the royalty share is set too high for a particular tract, there will be no bids. If the share is set too low, and there are large bonuses, the state will lose substantial revenues from the high discounting of future earnings into the bonus bid. If the same tracts were bid with the royalty share as the bid variable and a cash bonus set administratively, the state would not need as much geologic information, it would have a much lower administrative cost in preparation for the sale, and it would be protected against mistakes in estimation of the value of the leases.

Risk

Risk is an important factor in discounted cash flow analysis and can have a large impact on the revenue the state is likely to receive from alternative leasing methods. In particular, companies tend to increase their discount rates for evaluating risky investments, given any expected payoff. The time value of money is higher if the return on the investment is more uncertain. While the same principle also might be said to apply to the time value of money for the State of Alaska, it can be shown that the bidders in a lease auction bear much higher risks than does the state.

There are two main types of risk involved in oil or gas leasing. There is the exploration risk -- the risk that the bidders will purchase a tract which after exploration produces only dry holes one percent above the rate of inflation. This compares to at least fifteen percent above the rate of inflation for the companies likely to bid on the Beaufort Sea oil leases. Since the bidders' time value of money means that they are willing to pay a great deal more if they can delay the payment until many years into the future, the state should take advantage of this fact in the choice of leasing methods. The criterion of discounting of revenue from a lease argues that the state should choose a bidding method which takes as much revenue as possible as far into the future as is practical. In particular, low royalty bonus bidding, which requires a large cash down payment, is greatly inferior to all other options in this regard. When compared to bonus bidding, royalty bidding, net profit bidding and various forms of split leasing and withholding acreage have relatively minor differences with respect to the discounting criterion.

Comparison of these other methods depends on practical matters, as well as the other criteria of risk, incentives and competition. For example, one can in theory set administratively net profit shares or royalty shares to capture nearly all of the lease revenues, and still have the cash bonus as the bid variable. In this case, the revenue stream to the state would be nearly identical to that which would result from a royalty share or net profit share sale. However, the method of setting high administrative royalties, for example, requires that sufficient geologic information be present so that the state may calculate in advance the appropriate royalty share on each tract leased.

some of their risk. Since the state has a lower risk to begin with, this risk sharing arrangement benefits both parties.

Considering the criterion of risk for evaluation of the alternative leasing methods, the disparity is increased between the expected revenue from bonus bidding when compared to the royalty share and net profit bidding methods. This observation follows, of course, from the fact that the latter methods do not obligate the bidders to pay large sums of money to the state unless oil or gas is discovered in paying quantities and brought into production.

In addition, further gains to the state from reduction of risk are likely with the reserved acreage and split leasing options. When the state waits to lease a tract until exploration has occurred in the surrounding area, there will be far less uncertaintly in the price of oil and in the cost of development, in addition to the greater certainty about the size of oil reserves. Bidders are willing to pay more for this reduction in risk. The economic analysis of leasing methods must consider carefully the opportunities for revenue gains from the risk-reducing properties of split leasing.

Incentives

One set of issues which has been raised about leasing methods is that alternatives to the traditional low royalty bonus bid system have poor incentives for diligence in exploration and or noncommercial discoveries. Then there is the development risk -- the uncertainty, if oil is discovered on a lease, about future prices of oil, about the size of the recoverable reserves, and about development and transportation costs.

The development risks are roughly similar for the state as compared to the industry. Both parties depend heavily, but not exclusively upon oil revenues for income, and the state has little advantage or disadvantage over the industry as a party to a lease agreement. Of the three methods of collecting revenue, net profit bidding involves the least risk to the bidders, but correspondingly the most risk to the state since, in a sense, it is sharing development costs with the industry using this method.

The exploration risks, however, are likely to be much lower for the state than are perceived by the bidders. This is because a firm, when bidding on a particular tract, must prepare its bid with the realization that it is unlikely it will be successful in the competitive lease auction on any other individual tract. The exploration risk to that firm is the probability that there will be no oil present on each tract for which it submits a bid. The State of Alaska, however, is not concerned about the risk on any single tract by itself. It is concerned rather with the risk that there will be little oil discovered within the <u>entire sale area</u>. Since the exploration risk is always higher for any given tract than for the sum of many tracts, the state can gain in lease revenue by choosing a leasing method which shifts some of the exploration risks from the bidders to the state. The bidders are willing through the lease agreement to pay the state to share a "sunk cost," and has little impact on the future decisions of the firm with respect to that lease. The decision to explore involves a comparison of whether the additional amount spent on drilling is likely to pay off its costs, and this comparison is irrelevant to the amount which may already have been paid as a cash bonus.

Of course it is true when comparing areas bid under a bonus system that the tracts receiving the highest bids are likely to be those which are explored first. But this is because the tracts receiving larger bonuses have the higher predicted payoff from additional drilling, not because the bidders have already put down more money.

When one considers systematically the incentives contained in the alternative bidding methods, net profit bidding is definitely superior to both bonus bidding and royalty share bidding. The royalty share is like an excise tax on production, and affects the expected payoff from exploration. Net profit share bidding is like an excess profits tax. As such, it cannot affect which course of action is most profitable for the companies. Since a bonus-bid lease also includes a significant royalty payment, the incentives for diligence are actually weaker than with net profit bidding.

Another related problem which has been raised about contingent payment bidding methods is that they encourage irresponsible bidding. That is, there is little cost to the bidders of placing bids on tracts which are too high for profitable development except under optimistic geologic and economic scenarios. The lead to early abandonment of fields. These are important concerns, and merit careful analysis. Consideration of incentives of alternative leasing methods must go beyond theoretical precepts, however. One must examine the evidence on diligence and lease speculation and discuss practical measures which can be included in lease conditions to mitigate any predicted problems.

As a first step in such an analysis, one should examine the track record of the traditional bonus bidding system for encouraging diligence in drilling in Alaska. The recent controversy over the formation of exploration units at the end of the life of ten-year leases on the North Slope certainly should cast doubt on the efficacy of the traditional bonus bid system for encouraging diligence. Regardless of whether or not the extension of these leases is viewed as proper under the circumstances, it is apparent that low royalty bonus bids do not in themselves guarantee that exploration will take place soon after the sale of a lease.

An issue which is sometimes raised regarding incentives for diligence with bonus bidding is that a bidder who has paid a large sum for a tract will be more anxious to commence exploration and production than a bidder who has not paid any cash up front. The argument is that the bonus bidders have a greater need to explore so as to recover their investment. This argument, despite its apparent popularity, is not based on sound economic reasoning. Even a large bonus bid for a tract is a very small sum for a major oil company. In any case, the amount paid for a bonus is

Split leasing is another option which needs to be compared to the other methods for its incentives for timely exploration. With two-stage leasing, the costs of exploration are all charged to a single bidder for each geologic structure. Withholding a large fraction of the acreage until after exploration, with the first set of tracts sold under an exploration agreement, is a possible compromise. In both cases, the exploratory tracts might have to be leased under an overriding bonus, overriding royalty or overriding share of net profits from all the surrounding leases. In order to insure that the overriding bids are as low as possible, the state may have to commit itself to leasing the remaining tracts for development within a short time, say eighteen months, after exploration is completed if there is a commercial discovery. Such a plan, which guarantees diligence, is a proposal which merits serious consideration in an economic analysis.

The concern that some bidding systems might lead to premature abandonment of fields, with the accompanying waste of oil, is another for which one needs to consider practical measures as well as theoretical arguments. Theoretically speaking, the comparison of bidding methods is the same as for the issue of diligence. That is, net profit bidding is the superior method since the royalty payments characteristic of the other methods tax the payoff from additional investments in the field.

As a practical matter, however, the Oil and Gas Conservation Commission regulates oil field operations for the purpose of conservation. The presence of this regulation dilutes the effect of economic incentives of different bidding methods. In addition, problem with this type of behavior is that the irresponsible bidder is forced to speculate on the value of the lease before incurring the cost of exploration. While it has been alleged from evidence on the North Slope in Alaska that such behavior is possible under bonus bidding as well, it is true that the speculators have paid a higher sum to the state for this privilege than would be the case in a pure royalty or net profit lease sale.

An economic analysis of alternative leasing methods needs to go beyond arguments about incentives of bidding methods in the abstract, however, and consider practical measures which could be undertaken to encourage responsible bidding behavior. One practical measure which could mitigate the alleged incentives for irresponsible bidding under contingent payment methods would be the imposition of a moderate cash bonus set administratively as a condition of a royalty share or net profit share lease sale. The economic analysis should consider how high a cash bonus is likely to be needed to discourage irresponsible bidding, and weigh the tradeoff between the expected gains in responsibility on the part of the bidders against the expected loss of lease revenue from the bonus requirement.

Another proposal which should receive careful attention is that the state lease all tracts in the same geologic structure under an exploration agreement, requiring drilling a certain number of wells in a given period with a cost-sharing arrangement. Such an agreement would probably lead to higher bids, despite the diligence requirement, because the bidders would know in advance that adjacent tracts would be drilled and costs would be shared.

The key to a competitive lease sale is information. How much information is available to potential bidders? How widely shared is this information? When considering the quantity and quality of information available to potential bidders, one must remember that the information must be pertinent to each tract offered for sale if the state expects to receive adequate competition for all the tracts.

Confidential information relevant to certain tracts such as that obtained from private wells drilled on adjacent leases is particularly harmful to a competitive sale. It is well known to potential bidders that some companies have confidential information on certain tracts scheduled for sale in the Beaufort Sea. The companies without access to this information will not bid for these tracts or will depress their bids. Those with privileged information will be aware of the noncompetitive nature of certain tracts, and will also lower their bids. The problem of confidential data shared by only a few firms is such a serious threat to competition in certain areas in the Beaufort Sea that the state should consider the gains from withholding these tracts from the sale until exploration has taken place over the rest of the sale area.

There are such clear advantages to having widely-shared information that the state should consider measures to increase the amount of information available on each tract offered for sale. The first step, of course, is for the state to obtain as much geologic information as possible about the sale area, and make its geologic assessments public. The geologic information which the Commissioner of Natural Resources has the statutory authority to reduce royalty shares on any lease if the operators claim economic hardship. Although this authority has never been used, the Commissioner already has the powers to modify royalty leases in order to extend the producing life of a field. It is also likely that practical probl ms can be worked out for royalty leasing so that the state's share declines for secondary and tertiary recovery operations. Such practical measures need to have specific attention in an economic analysis if one is to evaluate alternative leasing methods against the criterion of incentives.

Competition

There seems to be a myth among the public and among some government officials that an oil lease sale is properly conducted in a shroud of mystery. That geologic information should be kept secret, aired only by rumor, and the bidders left trying to guess what information other bidders have that is not known to them. Nothing could be farther from the truth. An oil lease sale is not a negotiated settlement, it is an auction. As such, the state can expect to receive more revenue from the sale, other things equal, if it can attract more bidders.

Concluding Observations: Consideration of Split Leasing

An economic evaluation of alternative leasing methods for the Beaufort Sea sale needs to consider fully the four criteria of discounting (timing) of revenues, risk, incentives and competition. All four criteria are important for an accurate assessment of the advantages and disadvantages of each proposed leasing strategy. It can not be predicted in advance which method of collecting revenue will emerge from such an analysis as superior. One can suggest, however, some reasons for a serious consideration of two-stage leasing.

There are two distinct ways to perform the first stage, or exploration phase, of a two-step leasing procedure. One way is for the exploratory wells to be drilled simply under contract to the state, without transfer of rights to any oil found. With the other method, companies agree to a package of exploration commitments in exchange for the low bid on an overriding bonus, royalty share or net profit share from any future lease sale in the specified area. There are advantages and disadvantages to each procedure.

The most straightforward way to accomplish the task is for the state to contract directly for exploration from the private sector. This procedure insures that the expected value of bids in the second stage is the greatest. There is no lien on leasing revenues from the exploration phase, and the state accrues all the state needs on every tract in order to perform the economic analysis of the alternative bidding methods should also be used to appraise the value of each tract. The appraisals can then be used to assess whether each tract is receiving a sufficient number of bids, and to determine accurately when to reject bids as too low. The economic analysis should consider the advantages of making these minimum acceptable bids public prior to the sale for the purpose of promoting competition.

In addition, the discussion of the advantages of widely-shared information on each tract offered for sale suggests that withholding a substantial portion of the sale tracts would have an important beneficial impact on the degree of competition for those tracts remaining to be sold. If the state reduces the acreage sold in the first stage, the bidders need to obtain and assess data on fewer tracts. This cost-savings makes it possible for a given company to prepare bids on a higher percentage of the tracts offered, and each tract will then have more bidders.

When the remaining acreage is leased after exploration, there will be, of course, much more information available about the geology and economics of the area, and this information can be made public. The second stage of a two-step leasing plan will always be more competitive than the first stage for this reason. The economic analysis of alternative leasing methods should not overlook the likely positive impact on revenues from the increased competition accompanying two-stage leasing.

not overlook the significant gains from employing this leasing method.

In the first place, two stage leasing method has the advantage that it makes no commitment on the bidding method for the development phase. When more is known after exploration, the analysis will be able to predict more accurately the relative merits of different ways of collecting lease revenue. Two-stage leasing allows the state to obtain much more information on the lease tracts prior to sale. If this information is released to the public, the increased competition will bring gains in revenue not obtainable by other leasing methods. Since the state assumes most of the risk of the size of oil reserves in the exploration phase, the low risk to the bidders in the second stage also means large gains in expected revenue.

Problems with diligence are minimal with two-stage leasing. With its greater involvement in the exploration phase, the state can specify contractually the rate of drilling of the lease area. Since the extent of the oil pool will be substantially known before the tracts are leased for development, the state can remove an additional source of friction and uncertainty by formulating the unit operating agreement for the tracts prior to the sale. The bidders will be bidding then on a share of the unit operating costs and revenues.

Split leasing also has some particular advantages suited to the special problems presented by the Beaufort Sea sale. The development rights for disputed tracts do not need to be sold the advantages of purchasing risk from the bidders. An additional advantage is that there is no necessary commitment to rapid development after exploration has been completed, allowing more future options. The disadvantages of the straight contract procedure are that an appropriation for drilling must be obtained from the legislature, and there may be a political problem from such active state involvement in oil exploration.

When the exploration phase is leased using a revenue override on a given set of tracts, there is the advantage that no legislative appropriation need be obtained. In addition, it is likely that the override lease can be written so that the bidders can claim the available federal tax advantages for oil exploration, including the credit for intangible drilling costs. If this is the case, the loss of revenue from an overriding bonus, net profit or royalty share can be reduced substantially, since the federal government is financing throught the tax credits and deductions a large portion of the drilling expenses.

The principle disadvantages of the revenue override procedures for exploration are that the state loses the override from the second stage lease sale and that the state must be committed to leasing the development rights in advance, with the implied loss of flexibility. An analysis of which two-stage leasing procedure is more financially advantageous to the state, including the analysis of revenue loss from an overriding bonus, royalty share or net profit share, should be given a serious place in the overall economic analysis. Despite the greater degree of advance preparation needed by the state for two-stage leasing, the state should until the status of this land is resolved, although the dispute need not limit exploration of the area. Split leasing also allows exploration to continue while information from the ongoing biological assessments is incorporated into lease stipulations for the development phase. It allows more time to consider the proposed Coastal Zone Management regulations before major development activities alter irreversibly the fragile ecology of the region, mitigating another potential source of conflict.

When one considers the possibility of split leasing for the Beaufort Sea sale, the advantages of this alternative suggest strongly that it be given careful attention in the economic evaluation. It should be pointed out that reserving acreage may be used as a compromise between split leasing and a more traditional method, especially if one considers leasing tracts under exploration agreements.

Lawmakers say state shouldn't use Interior bid system

By JOHN GREELY
Daily News reporter

A bidding system adopted by the Interior Department for oil and gas leasing in the Beaufort Sea shouldn't be used by the state, a legislative committee has concluded.

Instead, the state should consider shunning higher bonus bids from the oil industry and attracting higher royalties, in part to avoid a possible windfall of cash at a time when the treasury doesn't need it.

That conclusion was forwarded to Commissioner of Natural Resources Bob LeResche this week by Rep. Joe McKinnon of Anchorage, who calls the federal bidding system "overly complex, muddled and riddled with excessive abstractions."

In August, the Interior Department announced it would use a form of "sliding scale royalty bidding" on some 89,000 acres it plans to sell in the Beaufort under a joint sale with the state Dec. 11.

More importantly, the department said it hoped to use the bidding method on another 77,000 acres whose ownership both the state and federal government claim. Negotiations over how to sell that land may be completed late next month.

In turn, the outcome of those negotiations could influence the way state officials sell another 347,000 acres that belong to Alaska in the 500,000-acre sale, generally considered the hottest unsold petroleum prospect under state ownership.

Under the federal bidding system, oil companies would win individual tracts by putting the most cash on the table. Ultimate royalties — or the amount of oil and gas retained in public ownership — then would be determined by the value of production, up to 65 percent for any tract gushing \$32 billion worth of oil each year.

"There is no field anywhere in the world with production this high," said McKinnon's Interim Committee on Oil and Gas Leasing Policy.

More likely, the report to LeResche said, the federal system would produce "under the most optimistic assumptions" an effective royalty of about 39 percent during the life of any field discovered in the Beaufort.

McKinnon's staff also faulted Interior's use of single tracts as the basis for determining production values, and thus royalties, contending the base should be "units," or tracts that are combined for production purposes.

If tracts are used in the bidding formula, the report said, royalties tend to drop as more tracts are combined to form an individual field.

By comparison, production from a hypothetical field of 730 million barrels of oil would yield total state income of \$2.4 billion during its life under the federal system, and nearly \$3 billion under an alternative suggested by McKinnon, the report said.

That alternative pegged state royalties at 41 percent, assuming that oil companies bid a flat \$10 million on each tract.

"In general," the report said, "the longer you defer the (bidding) company's payments, the more the company is willing to pay."

And, McKinnon's staff concluded, income received in 1990, for example, is "worth more to the state because it has a lower discount rate than an oil company."

Discount rates, in essence, represent the value of earnings which could be made on an investment, if it were put into a secure savings account rather than a risky venture, such as an oil lease. For the oil industry, the discount rate in the Beaufort Sea would be between 10 and 15 percent, compared to zero and 5 percent for the state, the committee said.

In any event, McKinnon wrote, he believed the state could receive 24 percent more under the "worst-case assumptions" in his suggested bidding method than it could under the best assumptions of the federal system.

McKinnon has been in the forefront of legislators and other observers urging LeResche to consider selling Beaufort leases on a basis of companies offering a share of "net profits," rather than bonus bids or royalties.

The system announced by Interior on Aug. 27 is similar to one used in a federal oil sale in the Gulf of Mexico last year.

AGO 667492

Interim Committee on Oil and Gas Leasing Policy

Rep. Joe McKinnon
Chairman
Rep. Chat Chatterton
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Rep. Joe Hayes
Rep. Hugh Malone
Rep. Bill Miles
Rep. Brian Rogers

727 N St., Suite 2
Anchorage, Alaska 99501
907-276-1955

August 24, 1979

To: Committee members MW
From: Mark Wittow
Re: Report on "Governor's Briefing on Key Issues Surrounding the Joint Beaufort Lease Sale," held August 23, 1979 in Fairbanks

The briefing was organized by the Division of Policy Development and Planning, with Commissioner LeResche's office, and was an informal meeting of the Governor's Agency Advisory Committee on Leasing. (The committee is made up of all cabinet-level officials.) Several members of the media attended, as did approximately a dozen involved state employees, a score or more of oil company people, and several representatives from public interest and environmental groups.

A copy of the planned agenda is attached.

Governor Hammond offered the introduction, stating that he had called the meeting for the purpose of receiving comments from the involved state agencies, in a public format. He mentioned that his interest in the sale would continue even if he left the state for national office, since the federal government was also involved.

Commissioner LeResche stated that the meeting was organized to discuss the issues still remaining to be decided by the Governor.

I. Is the sale on schedule? (Commissioner LeResche)

The commissioner stated that the state preparations will be completed at the appropriate times for a December 11th sale. (A copy of the current schedule is attached.) He listed the important steps still remaining as:

a. finalization of the interim agreement between the feds and state
b. finalization of the bidding regulations
c. completion of the economic analysis of various bidding alternatives
d. completion of geologic analysis

II. The significance of a joint sale. (Commissioner LeResche)

The commissioner reviewed the reasons for having a joint sale:

a. it provides a way for the state to influence federal OCS operations
b. the state enjoys the benefits of using federal data and personnel
c. it is the <u>only</u> way to lease disputed acreage

Drawbacks result from the administrative complexities stemming from the mutual agreement that has to be reached on all issues. LeResche stated that, "Under your (JSH) direction, we have taken the position all along, if the costs of incurring these (mutual agreements) mean that we choose a bidding method that is less favorable to the state, just to lease the acreage, our decision will be that we won't do it, we'll cancel the disputed leasing sale (sic) before we agree to something that's not in our best interests."

III. Disputed Acreage (Attorney General Avrum Gross)

The Attorney General explained the various areas in contest, highlighting the provisions agreed to in last week's meeting in D.C. between state and federal officials on Dinkum Sands Island. Since the feds maintain the island is not always there, and the state maintains that it is, a joint monitering team will watch the island for the next three years. The state will administer the affected area; any revenues will be split, if necessary, based on the amount of time the island is above high water. (note: the state and the feds had previously agreed to the existence of Dinkum Sands by signing the joint sale map that included Dinkum Sands in January. The feds have since reneged on this agreement.)

The island is important because of a portion of the disputed acreage lying soley within state waters. If the island did not eixst, a "bridge" of federal land would be created, and the state's legal case on that portion of the disputed tracts would be weakened.

Mr. Gross then reviewed the various legal theories of fixing coastal boundaries that have led to the dispute. He stated, "these disputes will not hold up the sale in any way."

The federal government has filed a complaint against the state claims in the U.S. Supreme Court. The state response will also raise the issue of disputed lands in the Colville Delta area and offshore of the Arctic Wildlife Range.

Governor Hammond asked about the status of the ARCO causeway.

The A.G. replied that the feds are disputing the use of the extension of the pier as a salient point for boundary measurement, claiming that the extension was improperly permitted. This issue is still unresolved, but affects only a few hundred acres.

IV. Technological aspects--should tracts outside the Barrier Islands be leased?

Commissioner LeResche pointed out that in addition to options to lease or not lease, outside tracts capable of being reached by directional drilling could be leased.

Bill Stringer, the directing officer of the large Arctic scientific task force, explained his group's work on technical and environmental questions invloved in the sale.

Lou Shapiro, an ice expert, explained that ice hazards vary with water depth. Shore ice within the lagoons and other nearshore areas is relatively stable, and can be drilled in safely. The technology used in the Canadian MacKenzie Delta would be adequate for these areas.

Dr. Shapiro stated that great pressures and masses of ice build up in the 13-20 meter water depth area. This entire zone would provide significant hazards to any drilling operations, and no area comparable to this has been explored. Directional drilling could reach some of the tracts, and would be feasible.

Dr. Shapiro concluded by recommending phased development, with drilling prohibited outside the 13 meter mark until test work has been done. He also recommended a ten-year lease term, to allow the companies sufficeint exploration time during limited drilling seasons.

Herb Bartlin, planning director for the North Slope Borough, generally conccurred with Dr. Shapiro's testimony. He strongly urged that only directional drilling should be allowed beyond the Barrier Islands. He asked that some of the Barrier Islands be set aside as conservation areas.

He said that the Borough is working towards these points in their own coastal management plan, and distributed a letter from Mayor Eben Hopson that outlined the Borough's schedule for adoption of their coastal ordinances.

An additional witness for the North Slope Borough, whose name was inaudible (Warren ?), stressed the importance of the Bowhead to the North Slope community, and repeated the lack of appropriate technology for drilling beyond the Barrier Islands. He also warned of the danger of oil spills.

Hans Jahns,of Exxon, testified on behalf of AOGA. (Jahns is Senior Research Advisor with Exxon Production in Houston, and holds degrees in geology and engineering.)

Jahns stated that industry is prepared to operate safely outside the Barrier Islands. He discussed similar succesful operations in the Canadian Beaufort-MacKenzie area; the extensive scientific studies of ice conditions beyond the Barrier Islands; and sound industry safety precautions against unusual ice conditions.

Jahns stressed that cost, not technology, was the limiting factor for Beaufort development, and the concurrent need for a ten year lease term.

Governor Hammond asked Mr. Jahns what other structures besides man-made islands could be used in offshore Arctic operations.

Mr. Jahns stated that the gravel and ice islands were the only proven structures, but that some work had been done on concrete forms.

V. Exploratory drilling restrictions

Commissioner LeResche stated that the bowhead problem has received undue importance because, as an endangered species, it offers an administrative remedy for those who seek to delay the sale. He declared, "What little data there is has been thoroughly analyzed." He pointed out that many area residents feel that there are a lot of bowheads around that the scientists aren't aware of. Governor Hammond replied that he thought the residents were concerned with the danger to existing Bowheads from future operations.

Dick Logan, Chief Habitat Officer from the Alaska Dept. of Fish and Game, described the numerous summer populations of ducks, shorebirds, fish and snow geese, as compared with the sparse winter fauna.

He stressed the need for strong seasonal stipulations to protect the summer populations, in order to limit general harrasment from exploratory activity, and to reduce the danger from a possible blowout.

The options are for a shutdown of operations on March 31, or on May 31. F&G strongly favors the 3/31 deadline because of the huge impact that would result from a spill after that date.

Governor Hammond suggested a shutdown date of April 31. Logan replied that 60 days were required to clean up a spill, and that after breakup,cleanup would be impossible. (Breakup usually occurs between May 15 and June 15.)

Logan also described the blowouts from gas hydrates in the Canadian Beaufort, as an example of exploratory drilling that had gone out of control, and the efforts to clean up the Mexican Gulf of Mexico spill.

Pete Van Dusen, from ARCO Operations, spoke on behalf of AOGA. He described the impact of a limited drilling season on exploratory operations, detailing what the elimination of 60% of the year would do to their efforts.

With seasonal limitations, the construction of shallow wells would take almost 2½ years, instead of the normal 2/3 of a year. A deep, twenty thousand foot well would require 4½ years to complete, as compared with one year under normal conditions. The cost of putting a rig on standby varies from sixteen to eighteen thousand dollars a day, depending on the number of rigs in the area. This results in adding from six to thirteen million dollars to the cost of an exploratory well (about 30% of the total cost).

Year round operations are safer, and summer operating conditions are more secure and economical; continuous,instead of uneven employment results. Mr. Van Dusen pointed out that more economical operations would result in higher bonus bids for the state, and that he had full confidence in industry's ability to drill throughout the year.

Governor Hammond asked if there were activities that could continue without danger byond the March 31 date. A detailed discussion of drilling and casing procedures ensued. The conclusion was that it was the actual drilling that needed to stop on March 31.

Tom Fink, the ARCO Environmental Conservation Manager, discussed the bowhead problem. He cited the analysis of the whales that went through the Santa Barbara oil slick--autopsies of beached grey whales showed that none of the whales had died as a result.

Dr. Fink recommended following the policy of the Canadian gov't, which stations a qualified biologist on the site to act as a consultant to industry operations. Reviewing the nature of the Mexican oil spill, Fink showed why such a spill would be extremely unlikely in the Beaufort. He stated that the primary threat to the bowheads was commercial whaling, and that the bowheads activities should be monitered during the early years of operations before reaching any conclusions that oil exploration would be harmful.

Flossie Hopson, North Slope Borough Dept. of Conservation and Environmental Protection, discussed the effect of oil activities on subsistence activities. She stated the helicopter traffic had disrupted the annual caribou migration, and that c[illegible]rent industry activities in the Beaufort had hurt seals and [illegible]sh. She described the huge effects on subsistence that a blowout would have, and declared that the Inupiat way of life needed to be protected from damage. She closed by stressing the difference between experience and experiments.

Rob Mintz, of Trustees for Alaska, testified on behalf of the North Slope Borough. He called for a strict cutoff of industry activites on March 31, because of unsatisfactory experiences with the case-by-case decision-making and its lack of clear guidance. He pointed out the fact that the state Division of Minerals and Energy treats the individual operating plans as confidential, so that outside groups cannot examine them. DMEM hadespecified a March 31 cutoff date in the original Duck Island Unit, and later lifted the restriction without notifying Fish and Game; this fact was discovered in a rleated lawsuit.

The North Slope Borough's Coastal Zone Management plan specifies a March 31 cutoff date for all industry operations.

VI. Bidding methods

Commissioner LeResche opened by pointing out that this topic provided a hot topic for debate with the state legislature. He called reaching for premature conclusions the greatest danger. A bidding method decision needs to be based on complete information and is a technical, not a philosophic question. Theoretical, economic and geologic questions; state revenue needs; and bidder behavior all need to be considered. The method will be chosen in Oct.

Tom Williams, Commissioner of the Dept. of Revenue, stated that the dollar flow over time was an important consideration in judging leasing method. The immediate cash picture shows no need for revenues from the Beaufort to fund operating costs. If the state relies on revenues from oil, it will eventually go broke, and require the raiding of the Permanent Fund--hence the great need to invest our current surpluses wisely. In conjunction with the Dept. of Natural Resources, the Dept of Revenue has been developing hypothetical cases for various sized oil fields and bidding methods. A crucial fact is the time value of money--because oil companies require a greater return on their investments than the state can obtain from its investments, delaying revenues results in more revenues for the state. On the other side of the coin, the state faces increased risk if non-commercial amounts of oil are found. The final decision will strike a balance between the benefits of delaying revenues, and of avoiding risk.

James Love, of the Alaska Public Interest Research Group, began by offering kudos to Commissioner LeResche for this public forum, and for the general thouroughness and quality of the state's Beaufort preparation. Mr. Love pointed out that the discount rate described by Commissioner Williams was especially important in the Arctic, where great delays before production occur.

Mr. Love pointed out that the advantage of bonus-bidding was that it was administratively simple. Royalty bidding is also easy to administer, but conservation problems late in the life of the field can result from over-bidding. Net profits bidding has an

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advantage in that a bidder can be overly optimistic and still have a positive cash flow. Love recommended placing work commitments on each structure. A per acre contribution would be required from each lessee for the exploratory work if they wanted to keep the lease. Under this system, companies could simply make an economic decision to determine if they would rather contribute towards exploration, or let the lease revert to the state.

Mr. Love pointed out the diligence problems that have resulted from the use of the bonus bid in Alaska--a large amount of acreage on the North Slope has been leased but inadequately explored under the system.

Love pointed out the beneficial effects that would result from having a large amount of pre-sale information available to bidders. He stated that, as an example, Sohio-BP currently enjoys an unfair competitive adantage because of the confidential information obtained from drilling on leases adjacent to the sale area. Companies without leases in the area are unable to obtain this type of information. He recommended that the state look into the benefits of on-structure drilling, to be bid out on the basis of a royalty overide, and of reserving acreage in the sale area so that it can be leased after adequate information about the oil potential is known.

Governor Hammond asked about the possiblity of placing something similar to the severence tax economic limit factor on a royalty bid, since bidders should know beforehand how royalties late in the life of a field would be reduced.

Commissioner LeResche replied that the sliding-scale royalty, which is tied to the value of production, accomplishes this.

Mr. Love stated that that a royalty sliding on the basis of operating costs, or the "elf" factor, would be best.

Governor Hammond asked how the state could help those companies facing losses from dry holes.

Mr. Love expressed his support for using the recently enacted exploration incentive credit, prior to a lease sale, as a way of sharing exploratory costs with the oil companies.

Governor Hammond inquired ab out Mr. Love's comments that certain things were also better for the companies--how do the companies feel?

Mr. Love replied that some things help all companies, but others help the smaller companies compete against the larger ones.

Don Langston, Vice-President of Exploration for Exxon, offered testimony that was a summary of his March 31, 1979 testimony before House ad hoc committee on the Beaufort sale.

Mr. Langston stated that bonus bidding was the fairest system, since it provided incentives for the companies to explore, no risk to the state, and did not hinder the decision to develop marginal fields. He pointed out the data from a USGS study of bonus bid sales in the Gulf of Mexico showed high returns to the federal government from the system.

Mr. Langston stated that a net profits system depended on the efficiency of the operators, but that the most efficent operator would not necessarily win the bid. He warned of the huge administrative burdens that a net profits system would place upon the state. The companies will be able to goldplate their expenses, unless the state becomes deeply involved in industry decisions. Recent OCS sales have seen large bonuses paid for dry tracts--but risk is properly the responsibility of private industry.

Mr. Langston discussed the administrative difficulties that would resulty from the state using a different bidding system than the federal government on tracts lying over a common structure. He called for the state's adoption of the federal sliding-scale royalty with a bonus bid for the Beaufort sale.

Governor Hammond stated that nine hundred million dollars in revenues from a bonus sale would probably result in a greater increase in state government than the administration of any bidding system. He pointed out that the state assumes risks with any system, since producing revenues from royalties and severence tax fuel the government. He declared that even Mr. Langston had implied that some benefits would result from the use of a net profits system, and that the state would be closely examining all systems.

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Note: The federal notice of proposed sale was published late this week in the Federal Register, covering federal and disputed acreage in the Beaufort sale area. Key provisions:

1. Bonus-bidding, with a sliding scale royalty running from 16.67% on up will be used. The sliding scale, based on the value of production form the lease, runs up to 65%, but will probably range from the bottom level to 25% (barring the discovery of a field much larger than Prudhoe Bay).

2. In kind royalties are limited to 16.67%.

3. Federal leases will be for eight years.

4. Exploratory Drilling is limited to the period from Nov. 1 to March 31. This policy will be reevaluated after two years.

---although the feds have proposed that all of the above provisions be used on the disputed acreage, the state has concurred in none of the above.

The notice includes the statement, "Because technology for structures in the transition (ice) zone has not been demonstrated in U.S. waters, particular attention will be given to structures proposed for water depths of 13 meters or more."

agenda see pp 2 for Cook assignment

MEETING AGENDA

Governor's Briefing on Key Issues Surrounding the Joint Beaufort Lease Sale

Time: 9:00 AM, Thursday, August 23, 1979

Place: Fairbanks City Council Chambers, 9:00 AM - noon

	Issue	Presentation	
Issue 1:	Is the State on schedule in programming for the Beaufort sale? What are the critical decisions and dates for those decisions?	Department of Natural Resources Commissioner LeResche	10 min
Issue 2:	What is the significance of and limitations on a "joint" sale? If the federal government delays, can the State proceed or vice versa? Which decisions must be jointly made and on which could either act independently?	Department of Natural Resources Commissioner LeResche	10 min
Issue 3:	What is the schedule for the resolution of the disputed acreage and how does it impact the sale?	Department of Law Attorney General Gross	10 min
Issue 4:	Technological aspects of oil & gas operations ~~outside~~ Near the barrier islands.	Fairbanks Arctic Project Office, NOAA OCSEAP	10 min
	Bill Sings	North Slope Borough	10 min
	Bartel		
	John	Alaska Oil and Gas Association	10 min
Issue 5:	Should exploratory drilling be restricted to certain months of the year and if so, what period should be included and how should a seasonal restriction be implemented?		
	a) options for seasonal drilling restrictions and their possible biological consequences (including present level of knowledge and research).	Department of Fish & Game ~~Commissioner Skoog~~ Habitat Director Richard Logan	10 min

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J Fink, ARCO

	b) operational costs to industry resulting from various seasonal drilling restriction options.	Alaska Oil & Gas Association	10 min.
	c) status of state-federal discussions on the seasonal drilling issue.	Department of Natural Resources Commissioner LeResche	10 min.
Issue 6:	Other stipulations and mitigating measures: status. Cook Not covered	Department of Natural Resources Commissioner LeResche	10 min.
Issue 7:	What major points of agreement and disagreement exist between the North Slope Borough's coastal management plan and proposed stipulations and mitigating measures? Rogers	Department of Natural Resources Commissioner LeResche	10 min.
Not covered	a) explanation of the local coastal management program.	Department of Community & Regional Affairs Commissioner McAnerney	10 min.
	b) Borough perspective and recommendations for resolution of such questions as subsistence, marine mammals and mitigating measures.	North Slope Borough	10 min.
Issue 8:	How will leasing method be chosen?	Department of Natural Resources Commissioner LeResche	10 min.
	a) general state revenue projections and their relationship to bidding method selection.	Department of Revenue Commissioner Williams	10 min.
	b) merits of various leasing and bidding methods.	Alaska Public Interest Research Group	10 min.
		Alaska Oil and Gas Association	10 min.

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER / POUCH M -- JUNEAU 99811

August 21, 1979

UPDATED SCHEDULE: Beaufort Sea sale preparations

Week of August 20:

Federal Proposed Notice published.

Net profit share leasing analysis published.

RPA net profit study available from DOI. (Kay Brown to get.)

ISER (Mike Scott) review of state and federal economic models completed.

August 21 -- Task Force meeting; 2 p.m., BLM/OCS office, Anchorage.

August 23 -- Governor's briefing; 9 a.m., Fairbanks.

Week of August 27:

August 27 -- Draft presale analysis on bidding methods currently authorized in law completed by Ed Phillips and given to typist.

August 28-29 -- Draft presale analysis circulated for review to DMEM staff, commissioner's office, Commissioner of Revenue.

* August 29 -- Mike Arruda to Washington, D.C., to work on Unitization Agreement.

August 30 -- Deadline for completing written testimony of the North Slope Borough's coastal zone ordinances and zoning maps. Pam Rogers to write. To be submitted Sept. 11.

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* Tentative; subject to change to accommodate schedules

Week of September 3:

Sept. 5 - 7 -- Public hearings in Anchorage on leasing regulations; 9 a.m., Anchorage Assembly Chambers, 3500 E. Tudor Road. Hayne Leland will attend, will meet with commissioner, DMEM staff.

Sept. 5 -- Leland's analysis of regulations to commissioner.

* Sept. 5 -- Legislative attorney John Hedland completes analysis of net profit share regulations.

Sept. 6 - 7 -- Ron Kaplan and others from Interior meet with Task Force, DNR commissioner's office and state Department of Law on preparation of a joint, final SID; in Anchorage.

Week of September 10:

Sept. 11 -- NSB Assembly holds public hearing on the coastal zone ordinances and framework plan; 7:30 p.m., Barrow. Pam Rogers to attend.

Sept. 12 -- Informal briefing by LeResche and Cook for Rep. Joe McKinnon's interim leasing committee; 2 p.m. at DMEM offices in Anchorage.

* Sept. 10 - 13 -- LeResche meets with industry, AkPirg, North Slope Borough.

Sept. 14 -- Regulation hearing record closes.

Sept. 14 - 18 -- LeResche out of town, unavailable.

Week of September 17:

Sept. 20 -- LeResche meets with Tom Williams, Tom Cook, Mike Arruda, Pam Rogers and possibly others to discuss and finalize regulations; 2 p.m. in Juneau.

Sept. 21 -- AACL meeting in Juneau to finalize seasonal drilling stipulation and other stips and mitigating measures; 8 a.m.

Week of September 24:

Sept. 27 -- Completed regulations to Art Peterson for review.

* Sept. 28 - Oct. 1 -- Leland in Anchorage for work on presale analysis.

Week of October 1:

* Oct. 1 -- Consider announcing any terms, conditions and decisions already made, if any.

Oct. 1 -- .305 (traditional uses) notice issued.

Oct. 1 -- USGS geologic maps available.

Oct. 1 -- Draft presale economic analysis finished by Phillips (includes "alternate strategies" analysis) and circulated to DMEM staff, DNR commissioner's office and Commissioner of Revenue for review.

* Oct. 1 -- Interim Agreement (including Dinkum Sands Island Agreement) and Unitization Agreement completed and agreed to by state decision makers. LeResche, Jeff Haynes, Av Gross, Tom Cook and Tom Williams meet in Juneau to discuss agreements. (internal deadline, to allow time for federal consideration.)

Oct. 1 -- State agencies and local governments submit comments on SID and Proposed Notice to DPDP.

Oct. 2 -- SID and Proposed Notice comments forwarded to DNR commissioner's office from DPDP.

Oct. 2 -- Ron Kaplan and other Interior officials meet with Task Force, DNR commissioner's office and Law to prepare joint, final SID; in Anchorage.

Oct. 3 -- Comments on draft presale economic analysis forwarded to Pam Rogers for a rewrite.

Oct. 5 -- Presale economic analysis finished and sent to commissioner. (Cook and Phillips sign off on final version.)

Oct. 5 -- Regulations to Lt. Gov.

Oct. 5 -- Assumptions for analysis sent from DMEN to Revenue.

(geological) Rev. (confidential)

Weekend October 6-7: LeResche, Haynes, Will Condon, Tom Williams--general strategy, bidding methods and lease document.

Week of October 8:

Oct 9 private meeting with 9:00

Oct. 9 -- LeResche gets geologic briefing from DMEM staff in Anchorage.

Oct. 9 -- LeResche meets with Tom Cook on bidding method, lease form, other details.

Oct. 9 -- LeResche meets with Carolita Kallaur and Ron Kaplan of Interior.

Oct. 10 -- LeResche meets with DMEM staff on economic analysis, bidding method selection; 9 a.m.

Oct. 10 -- Revenue staff briefs LeResche and Williams on revenue analysis; 1 p.m.

Oct. 10 -- LeResche and Williams meet with legislators (to be selected by McKinnon); 3 p.m., Legislative Information Office, Anchorage.

11 th

Oct. 12 -- Presale economic analysis published.

Oct. 12 -- LeResche, Williams brief governor on bidding method selection.

Weekend October 13-14: LeResche, Haynes, Condon, Williams--
general strategy, bidding method and lease document.

Week of October 15:

Oct. 15 -- State submits formal comments on SID, Proposed Notice to Interior. (DPDP and DNR commissioner's office will prepare response; LeResche will sign off.)

Oct. 15 -- LeResche makes decisions on bidding methods, possible deletion of acreage, other sale terms.

Oct. 16 -- .345 navigability determination.

Oct. 17 -- .345 1st notice.

Oct. 18 -- LeResche meets with governor to make final recommendations on sale terms. Governor makes decisions on bidding methods and other sale aspects.

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Week of October 22:

Oct. 22 -- Governor meets with Interior Secretary to make final decisions on sale terms.

*Oct. 23 -- State sale announcement. (not a legal deadline; purpose is to inform industry on terms of sale.)

Oct. 24 -- .345 2nd notice.

Oct. 24 - Nov. 2 -- Department of Law finalizes lease document.

Week of October 29:

Oct. 29 -- .035 notice issued.

Oct. 31 -- .345 3rd notice.

Nov. 2 -- Final Notice of Sale to Federal Register.

Week of November 5:

Nov. 5 -- Regulations effective.

Nov. 7 -- .345 last notice.

Nov. 8 -- Last date for feds/state to sign Interim Agreement (including Dinkum Sands Island) and Unitization Agreement.

Nov. 9 -- Final Notice of Sale published.

December 11: SALE

Alaska State Legislature • House of Representatives
Interim Committee on Oil and Gas Leasing Policy

Rep. Joe McKinnon
Chairman
Rep. Chat Chatterton
Rep. Sam Cotten
Rep. Joe Hayes
Rep. Hugh Malone
Rep. Bill Miles
Rep. Brian Rogers

727 N St., Suite 2
Anchorage, Alaska 99501
907-276-1955

July 25, 1979

To: Leasing Policy Committee members
From: Mark Wittow MW
Re: Possible questions concerning the Beaufort sale.

1. TIMETABLE

a. When will the bidding system be announced? Will the companies have enough time to make their bid decisions?

2. BIDDING METHODS

a. How and when will the results of the state's economic analysis of the various bidding systems be announced?

b. Are there any preliminary views on which bidding system is likely to be chosen?

c. What consideration will be given to the state's long-term revenue picture in choosing a bidding system? In general, what role will the Dept. of Revenue play in deciding which method of collecting "Beaufort rents" is best?

d. What effect will the new revenue projections have on the choice of a bidding method?

3. COOPERATION WITH THE FEDS--BIDDING

a. Is the state committed to using one of the exisiting federal systems on the disputed tracts? How binding is the Memorandum of Understanding, which commits the state to a mutually agreeable system?

b. Is the state commited to using a common bidding system with the feds on structures that cross into disputed lands? What are the advantages and disadvantages of such a commitment? What are the experiences of other states (eg, Louisiana) that have border disputes with the federal government, and shared units?

c. How will bid acceptance differences between the state and the feds on disputed tracts be resolved? Given the differing tax structures, is it possible that they would reject a bid that the state should accept?

4. DISPUTED LANDS

a. What is the current status of the dispute over the ARCO pier and Dinkum Sands? How much state land do these disputes involve?

5. ENVIRONMENTAL STIPULATIONS

a. What is the state's position on seasonal drilling requirements?

b. Will a backup drill rig be required in case of blowouts, such as the recent Pemex Bulf of Mexico disaster? (app. yearly cost for such a backup rig?)

c. What provisions are being made for the protection of the Boulder Patch?

6. UNITIZATION

a. What is the status of cooperative arrangements with the feds regarding cooperative and unit agreements for exploration and production?

7. LOCAL GOVERNMENT

A. What effect with the North Slope Borough's Coastal Zone Management Plan have on the sale?

Alaska State Legislature • House of Representatives
Interim Committee on Oil and Gas Leasing Policy

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Rep. Brian Rogers

727 N St., Suite 2
Anchorage, Alaska 99501
907-276-1955

September 28, 1979

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

Re: Beaufort Sea Lease Sale Issues;
Public Hearing of October 8, 1979

Dear Bob:

Attached is a Committee Staff Report which details some of the important issues in the upcoming Beaufort Sea lease sale. We know you are currently studying these issues in-depth, and are encouraged by your efforts in preparing for the lease sale. We offer our analyses and recommendations as an aid to you and the Governor in your deliberations. The decisions soon to be made on <u>how</u> to lease the Beaufort Sea are among the most critical ones to face this Administration. Accordingly, we believe that as many points of view -- and analyses -- as possible be considered.

Because of the importance of the issues, we feel that they deserve a thorough public discussion before final decisions are made by the State. With your cooperation, we have scheduled a Public Hearing in Anchorage for Monday evening, October 8, 1979, at 7:00 p.m. in room 402 of the State Court House. In the Hearing we will present the Committee Staff's recommendations, detailed below, for your comment, and discuss the current results of the work by your own staff. Our goal is to have the best possible information at your disposal during the hectic pace of the next few weeks. We understand the pressures and deadlines you face, and appreciate your willingness to discuss Beaufort issues with the Committee in a public forum.

Our recommendations, more fully explained in the Staff Report, are summarized as follows:

1. <u>Leasing Procedures on Disputed Acreage</u>: The State should <u>not</u> agree to the proposal by the Federal government to use the Federal Sliding Scale/Bonus Bid system on disputed acreage. The

Committee has proposed an alternative -- and better -- sliding scale system for the disputed acreage in our September 14th Report to you.

We also urge you to reject the Federal government's proposal to lease all structures under a single bidding system. Besides usurping State authority, the proposal is reprehensible because of the lack of certainty in delineating structures prior to actual exploration.

2. Consideration of Projected Revenues: The current budget picture of present surplus and future deficit should be a primary concern in choosing a bidding method. A long-term view, spanning several decades, is a prerequisite to a wise decision on bidding methods. Our analyses demonstrate that the Bonus Bid system, by failing to delay lease revenues, denies a fair return to the people of Alaska and abrogates the fiduciary responsibility of the State government to its citizens.

3. Post-Lease Sale Administration: In the interests of State and industry efficiency, the Committee recommends that production audit functions be consolidated into one department.

4.. The Department's Economic Analysis: At this time the Committee has had the opportunity to review DMEM's rough draft economic analysis. We compliment DMEM on the quality of the draft report. As you have indicated, the final report will consider the additional economic issues of competition, split-leasing, on-structure drilling and reserved acreage. All these ideas have played an important role in oil development throughout the world, and deserve consideration by Alaska.

We note from the latest timetable of your Department's activities, that on October 5th the final regulations in 11 AAC 83 will be forwarded to the Lieutenant Governor and that the completed Economic Analysis will be dispatched from DMEM to you. The Committee would very much like to receive a copy of each of these documents that same day. Obviously, they are of central importance to the October 8th Public Hearing.

The Committee looks forward to meeting with you and your staff on Monday evening, October 8th.

Sincerely,

House Interim Committee on
Oil and Gas Leasing Policy

Joe

Joe McKinnon, Chairman

Attachment

cc: Governor Jay Hammond
Thomas K. Williams, Commissioner, Department of Revenue
Thomas Cook, Director, DMEM
Representative Terry Gardiner
Representative Russ Meekins
Senator Clem Tillion
Senator John Sackett
Senator Bill Sumner
Cecil D. Andrus, Secretary of the Interior
Alaska Outer Continental Shelf Office (BLM)
Alaska Oil and Gas Association

M E M O R A N D U M

TO: Joe McKinnon, Chairman
House Interim Committee on Oil & Gas Leasing Policy

FROM: Committee Staff

DATE: September 28, 1979

RE: Beaufort Sea Lease Sale Issues and Recommendations

The committee staff has been carefully reviewing preparations and developments regarding the upcoming Beaufort Sea lease sale. In addition to extensive research, this has involved multifaceted contacts with numerous industry officials and myriad State and Federal agencies, as well as attendance at official briefings on developments.

The result is this report. Though it is not offered as an exhaustive study of every point involved in the sale, it is nonetheless a carefully drawn analysis of important issues, accompanied by our recommendations. We hope it will be helpful for the Committee's upcoming public hearing the night of October 8th, not only to Committee members, but to State and Federal officials and representatives of the oil industry as well.

BIDDING SYSTEMS ON DISPUTED ACREAGE

The genesis of the attempt to resolve the problem of bidding systems on disputed acreage was the Memorandum of Understanding which Governor Hammond and Interior Secretary Andrus signed in March of 1978, which outlined the policies and procedures that were to be followed in the proposed joint Federal/State oil and gas lease sale in the Beaufort Sea. This Memorandum of Understanding ("the M.O.U.", as it is generally known) was the culmination of negotiations between the State and Federal governments on procedures to be followed in leasing properties whose title is still in dispute in the Beaufort Sea area. Negotiations had been in progress since December 1975, when Governor Hammond had cancelled a proposed Beaufort Sea lease sale because of the land dispute.

The objectives of the Memorandum of Understanding, stated in its introduction, are:

> -- to identify general policies and procedures for joint leasing and administrative activities associated with an oil and gas sale in the Beaufort Sea.
>
> -- to develop guidelines for allocating costs and responsibilities associated with pre-sale and post-sale administration.
>
> -- to describe a means of refining the principles cited in this document into specific processes and responsibilities. (M.O.U., p. 1).

Since its signing, the Memorandum of Understanding has been used as the cornerstone for policy decisions in the joint sale negotiations between State and Federal officials. In a Press Release issued on March 2, 1978, before he signed the Memorandum of Understanding, Governor Hammond stated that it expressed two fundamental principles:

> One: That neither party may unalterably determine policies or practices applying to areas of disputed ownership; and two, that uniform operating guidelines will apply to the entire sale area.

While the Memorandum of Understanding established a set of guidelines for joint sale negotiations, it did not create any binding or contractual obligations on either of the parties.

> The parties agree that nothing contained in this Memorandum of Understanding or done pursuant to it shall affect in any way the legal rights, interest, and claims of the parties in the area of the Call for Nominations described above. Though this Memorandum of Understanding is intended to be a morally binding guidance document, it is not intended to create enforceable contractual duties. (M.O.U., p. 8).

The Memorandum of Understanding establishes who has legal jurisdiction and management responsibility over disputed acreage within the sale area. This is the most significant point expressed in the M.O.U. The State has jurisdiction over undisputed State land. The Federal government has jurisdiction over all disputed acreage and the undisputed Federal acreage. To quote directly from the Memorandum:

> Being more inclusive, Federal standards and legal requirements will as a general principle, apply to activities on all tracts which contain any Federal acreage and/or disputed acreage. State standards, policies and legal requirements will apply to tracts containing exclusively undisputed State acreage. Each entity shares the responsibilities as an equal partner on all decisions pertaining to tracts containing disputed acreage or to tracts of split ownership and neither party may unilaterally determine policies or practices which apply to disputed or split tracts. (M.O.U., p. 1).

What this means is that disputed acreage must be leased under a Federal bidding system, but the State must concur.

Both the State and Federal governments have considerable statutory authority in choosing a bidding system for an oil and gas lease sale: the State authority pursuant to AS 38.05.180(f), its oil and gas leasing statute; the Federal authority comes from the Outer Continental Shelf Lands Act, 43 U.S.C. 1331-43. Both Federal and State laws allow variations of bonus, royalty, or net profit bidding with provisions for work commitments.

The State is presently in the administrative review process on regulations to implement the provisions of AS 38.05.180, as it was amended by ch 155 SLA 1978 and ch 65 SLA 1979. The proposed Article 2 of 11 AAC 83 on Net Profit Share Leasing establishes procedures for calculating the net profit share due to the State from any net profit share lease issued by the Department of Natural Resources (hereinafter referred to as "DNR" or "the Department"). The proposed Article 1 of 11 AAC 83 authorizes the Department to offer a lease on a sliding scale royalty to be "chosen at the commissioner's discretion".

The net profit share system proposed by the Department in the proposed Article 2 of 11 AAC 83 is an "Investment Account" system commonly referred to as a front-end capital recovery system. This system allows a lessee to fully recover costs plus interest before the State collects a net profit share from a lease. The decision to use an "Investment Account" system was based on an economic analysis of various types of net profit leasing systems, which was a joint effort of DNR and the Department of Revenue.

The proposed Article 1 of 11 AAC 83 authorizes a sliding scale royalty but does not specify a particular type of sliding scale royalty system. The system to be used is to be "chosen at the commissioner's discretion". The primary purpose of the proposed 11 AAC 83.183, as we stated in earlier reports, appears to be administrative flexibility.

The Federal government is still in the midst of evaluating different net profit share leasing systems, but agrees that a front-end capital recovery system is economically superior to other bidding systems. However, the Federal government is undecided as to whether to allow interest on development costs, as the State has opted for in its "Investment Account" system, or whether to apply a multiplier to pre-production expenses in lieu of an interest rate. The State considered this point irrelevant as both systems are economically so similar. But, because of this debate, the Federal government will not have net profit leasing regulations in place in time for the sale.

Our preliminary research supports the Department's choice of the Investment Account system as the optimal leasing system. By a simple cash-flow analysis, it can be demonstrated that if the State defers the taking of income until the oil companies have recovered their costs, the State will receive more in total discounted present-value dollars, because of the relatively high discount rate used by an oil company. Money received 15 or 20 years downstream is worth very little to the oil companies and does not figure significantly in their bids. The oil companies are more than willing to share a larger percentage of the downstream income in return for early recoupment of costs. This is in accordance with the State's time preference for money, because the State has a significantly lower discount rate than an oil company. Downstream income is worth considerably more to the State.

Recently, the State was informed that because of bureaucratic delay the Federal government would not have regulations for net profit share bidding in place in time for the sale. Because of this delay, the Federal government has offered the State only two bidding choices for disputed tracts: (1) cash bonus bid with a fixed royalty; and (2) cash bonus bid with a fixed sliding scale royalty.

As the analyses the Committee submitted to the Department on September 7th and 14th concluded, the Federal Sliding Scale Formula would result in significantly less income to the State than the alternative developed by the Committee, which it termed "the Committee Sliding Scale". State income, the September 14th Report concluded, is reduced because of two reasons: (1) the Federal Sliding Scale Formula relies too heavily on the bonus, thereby reducing the effective royalty percentage; (2) the Federal Sliding Scale Formula ignores the realities of unitized production by using a logarithmic formula which establishes the royalty on a tract-by-tract basis. What this means is that if two units produce identical amounts of oil, but one of the units contains more tracts than the other, the royalty percentage from the unit with more tracts is lower.

The problems encountered with the Federal Sliding Scale Formula do not occur with the Committee Sliding Scale. However, it is important to emphasize that, in our opinion, the Committee Sliding Scale, superior as it is to the Federal Sliding Scale Formula, is still inferior to the Net Profit Investment Account System. The Committee Sliding Scale royalty was developed as a possible compromise for use on disputed acreage, mainly because the Federal government did not have sufficient time to implement net profit share leasing regulations and its Sliding Scale Formula is unsuitable.

It has been the consistent policy of the Department that if the Federal government does not come up with a system which will maximize State income, the State will not agree to lease the acreage. In the public hearing the Committee held in Anchorage on August 13, 1979, DNR Commissioner LeResche, testifying before the Committee, was asked what was the State's position if it is determined that it is locked into an inferior bidding system on disputed acreage because the Federal government has not adopted net profit leasing regulations. The Commissioner's response, in effect, was that if in the Department's economic analysis it is determined that the Federal options are significantly inferior to other options available under State law, he would propose withdrawing that acreage from the sale. The Commissioner further reiterated this position in Fairbanks on August 23, 1979, in a briefing for the Governor on the Beaufort Sea lease sale. In regard to bidding systems on disputed acreage, Commissioner LeResche stated that

> "If the cost of agreeing is that we will choose a bidding method that is less favorable to the State, just to lease the acreage, our decision will be that we won't do it. We'll cancel the disputed leases."

On September 18, 1979, Committee Staff met with a representative of the Federal government regarding use of the Federal Sliding Scale Formula. Based on the results of the Committee's analysis of September 14th, three alternatives to the present Federal Sliding Scale Royalty Formula were discussed for use on disputed acreage. The alternatives are: (1) changing the factors in the Federal Sliding Scale Formula to increase the effective royalty and decrease the bonus; (2) consider using the Committee Sliding Scale as described in the September 14th Committee Report; (3) withdraw the disputed acreage from the sale. These alternatives are to be considered for inclusion in the Secretarial Issue Document (SID) for the Beaufort Sea sale, which will be presented to the Secretary of the Interior before he makes his final determination regarding the sale.

In is our recommendation that the State should not agree to lease the disputed acreage under the original Federal Sliding Scale Formula.

Bidding Systems on Single Structures

The Federal government has consistently maintained that all tracts on each structure should be leased using the same bidding system. This recommendation was presented to State officials in a July 13th meeting in which Thomas Cook, Director of DNR's Division of Minerals and Energy Management (DMEM) and spokesperson for the State, tentatively agreed to the recommendation.

If the State finally does agree to this recommendation, it will be giving up a significant amount of management authority for deciding bidding systems within the proposed sale area. If a structure as delineated prior to the sale is located primarily on State acreage but a small portion of that structure crosses into disputed acreage, the structure would have to be leased under a Federal bidding system. As the Federal government has offered only two bidding choices (Cash Bonus/Fixed Royalty and Cash Bonus/Sliding Scale Royalty), this limits the State's options severely. To make matters worse, it is possible that after exploration the only oil or gas discovered in the structure will lie under State land. This would mean the State would be collecting lease payments under a Federal bidding system for an oil pool located beneath State land.

The rationale for this single-bid-per-structure recommendation is the oil industry claim that leasing a structure under different bidding systems will make it difficult, if not impossible, to Unitize. This question arose before while HB 854 (which ultimately became ch 155 SLA 1978) was being considered by the Senate Resources

Committee in 1978. In a 5-30-78 memorandum from the Legislative Affairs Agency (LAA) to the Chairman of the Senate Resources Committee, the opinion of the LAA Research Division was summarized thusly:

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

Unitization, as we all know, is basically a conservation technique designed to protect lessees' rights in a field and prevent waste of hydrocarbons. Unit participants are allocated working interest percentages in the field and share costs and revenues in relation to their working interest. Based on the prior research conducted by the Legislative Affairs Agency and our own research, it is our opinion that basic incentives for unitization are present under any bidding system. The primary engineering and economic incentives remain unchanged, i.e., amount of oil, location, geologic considerations, development costs, and efficient management of the oil pool.

In our research on this question, we contacted Bob Jones of the Louisiana Minerals Board, which administers offshore leases in conjunction with its Conservation Division. A number of these offshore leases are administered jointly with the Federal government, and contain different royalty provisions, different tax structures, and many were leased at different times. According to Mr. Jones, none of these differences have prevented unitization from occurring, nor have they caused any problems for Louisiana officials in administering the leases, or for Federal OCS officials in New Orleans for that matter.

We also discussed the matter with Ron Kaplan of the Department of the Interior, who agreed that this recommendation of a single bidding system is not absolutely essential. Unit accounting might become more difficult, he conceded, but it would not actually prevent a field from being unitized.

Based on our analysis, we see no reason whatsoever why the State should agree to a recommendation that would have the effect of depriving the State of so much management authority. It would undermine the State's authority over undisputed State land by narrowing or maybe even eliminating its choice of bidding systems.

In addition, the single-bid-per-structure recommendation has a practical problem. As Hoyle Hamilton, Chairman of the Alaska Oil and Gas Conservation Commission (AOGC) said in early September at an Anchorage meeting of State and Federal officials on this matter,

> "I'm not sure how definite the seismic data will be in determining the location of the structure."

In other words, one could end up trying to match up bidding systems on adjacent tracts that bear no relation to the position of the structure.

Because the location of structures cannot be positively determined, the State should not limit its available choices by agreeing to the Federal recommendation. To make such a compromise, based on imprecise data, would be foolish and not in the State's best interest.

The Department's position on the single-bid recommendation, however, apparently has not yet been resolved. In the Committee's August 13th Public Hearing in Anchorage, Commissioner LeResche indicated to the Committee that the extent to which this recommendation would be adhered to depended upon the relative position of a structure in relation to State and disputed land. In other words, if 95% of the structure was on State land and 5% was on Federal land, the State would not concede to using a Federal bidding system. If the situation were reversed, i.e., 95% of a structure on Federal land and 5% on State land, the Department would agree to use of a Federal bidding system. Commissioner LeResche did not indicate, however, what would happen if half a structure was on State land and half on Federal land.

As the Memorandum of Understanding put it, "State standards, policies and legal requirements will apply to tracts containing exclusively undisputed State acreage". It is our opinion that under no circumstances should the State relinquish any authority over undisputed State acreage.

<u>State Taxes</u>

During the course of State/Federal negotiations, a significant question has arisen over what to do about State taxes on disputed acreage. AS 43.55.011 requires a lessee to pay a production tax, but Federal law does not. The State also requires oil companies to calculate the amount of State income tax differently from Federal income tax. This results in a higher effective State income tax rate. The differences in the State and Federal tax laws have posed the problem of what to do with what the Federal government considers to be excess State taxes due from disputed tracts.

Most of the lease payments due from a lessee having an interest in an oil pool located beneath disputed acreage will be placed in escrow pending resolution of the disputed lands question. Precise requirements are to be outlined in the Joint Interim Agreement. However, the Federal government has been consistently opposed to collecting State taxes that exceed Federal taxes and placing these in escrow with other lease payments due from disputed acreage. Federal officials feel this will adversely affect bids on Federal tracts. They are, however, amenable to including a provision in each Federal lease which provides that the lessee will be liable for all back taxes plus interest in the event the State ultimately wins the title dispute.

Commissioner LeResche has agreed with the Federal position that State taxes would not be collected and placed in escrow pending resolution of the land dispute, but has, however, indicated that he supports a provision that will require lessees to retain liability for payment of back taxes. In our opinion, State taxes should be collected and placed in escrow, or at the very least the lessee's liability should be spelled out clearly in the Federal lease form.

TITLE TO DISPUTED LANDS

At the end of January, 1979, State and Federal officials approved the Federal/State Leasing & Nomination Map -- the official joint sale map. The joint sale map established specific sale boundaries and its approval was an important procedural requirement in the regulatory preparation for the sale. The map delineated three types of land that would be leased in the sale: State lands, Federal lands, and "disputed" lands. Generally, State lands lie within three miles of the coastline or near-shore islands, while Federal lands lie outside the three-mile limit. The disputed lands are claimed by both the State and Federal governments because of different legal theories on the fixing of boundaries of State coastal waters.

Because the Barrier Islands form a continuous chain of State land offshore, there are actually two categories of disputed land. One major portion of disputed land forms an enclave between the shore and the Barrier Islands, which is totally surrounded by State land. This area would be considered State land under the "inland waters" theory; the State has a good chance of prevailing on this theory.

The second area of disputed land lies outside the Barrier Islands. This would be considered State land under the "straight baseline" theory. Based on International Law, this theory holds that territorial boundaries are drawn as straight lines three miles out from the furthermost land area. A conflicting theory requires three-mile arcs to be drawn around the furthermost land area. Unfortunately, the baseline theory -- which would work out best for the State -- has been rejected twice by the U.S. Supreme Court.

And the final determination here of who finally is granted title to the disputed land will be decided by the U.S. Supreme Court, which has original jurisdiction in the matter. The State and Federal governments have agreed to settle the issue that way. Accordingly, a lawsuit was filed in the U.S. Supreme Court in June (United States of America v. State of Alaska, File No. 84 Original).

A requisite to the sale, the lawsuit focused originally on the disputed lands delineated on the joint sale map. The lawsuit enables the State and Federal governments to enter into an interim agreement setting out procedures for leasing and handling revenues from the disputed lands. In addition, Attorney General Gross has testified that the State has attempted to raise in the lawsuit the issue of disputed lands in the Colville Delta area and off the shore of the Arctic Wildlife Range.

Unfortunately, since the signing of the joint sale map, Federal officials have attempted to nullify the map and their previous position, calling into dispute the use of two salient points for establishing boundaries of disputed acreage. Those points are Dinkum Sands and the ARCO Pier Dock. Both claims are disadvantageous to the State.

Dinkum Sands

Even though the chances are slim that the straight baseline theory for establishing territorial boundaries will be ultimately upheld by the U.S. Supreme Court, the State still has a decent chance at title to the enclave of disputed acreage within the Barrier Islands per the Submerged Lands Act. But, if Dinkum Sands -- an island, the State claims -- is removed as a salient point for determining State territorial waters, the State's case is weakened considerably. The effect would be to open up the enclave of "State land" within the Barrier Islands. A link would then be created between the disputed tracts inside the Barrier Islands and the undisputed Federal acreage beyond the Islands. At stake are 18,035 acres and untold revenues.

The issue of Dinkum Sands first surfaced in a letter dated June 21, 1979 from the Chief of the BLM's Division of Cadastral Survey to the State's Chief Cadastral Engineer, which declared that:

> Information has been furnished to this office that the area known as Dinkum Sands shown as upland on Nautical Charts 16046 and 16061 has in fact eroded to such an extent that no upland or low tide elevations remain. As this area is encompassed by the area of the proposed joint Federal/State oil and gas lease sale in the Beaufort Sea scheduled to be held in December, 1979, this office proposes to drop the salient points previously selected on Dinkum Sands and heretofore used for computations of split blocks for the upcoming sale. New split block computations without using the Dinkum Sands salient points will be initiated.

As a small member of the Barrier Islands, Dinkum Sands has appeared on Federal Nautical Charts since at least 1955, but in the maps that are part of the Final Environmental Impact Statement (8-79) and in the Federal proposed notice of sale (8-22-79), the area including and surrounding Dinkum Sands is shown as "disputed tracts".

The BLM's position was buttressed -- later -- by the results of a bathymetric survey for USGS conducted on July 25, 1979 by the R/V Karluk. In a transcribed radiotelephone message to Ed Kempema, a participant in the survey from Erk Reimnitz, another participant, Mr. Reimnitz described what he believed to be Dinkum Sands:

> The minimum depth of the shoal was 30 to 40 centimeters and the shoal covered an area approximately 30 meters in diameter. The shoal was composed of very gravelly sand.

Mr. Reinmnitz also mentioned that "it was foggy for part of the survey, with a minimum visibility of 100 meters."

State officials have made several visits to Dinkum Sands. On July 11th, Thomas Cook (DMEM's Director), Michael Arruda (Asst. Attorney General), and Claud Hoffman (DMEM's Chief Cadastral Engineer) visited Dinkum Sands. In a sworn affidavit issued on August 2nd, Mr. Hoffman testified that:

> The sandy, rocky island upon which we landed has large chunks of ice along its northerly and southerly sides and was exposed approximately 3 1/2 - 4 feet above the water level. There appeared to be several such islands in the group extending approximately 1,000 - 2,000 feet in a generally southwesterly and northeasterly (or westerly and easterly) direction. We landed in what appeared to be the middle of this island string.
>
> In my experience as a cadastral engineer and in consideration of my familiarity with the maps of the Beaufort Sea area, I am convinced that the island upon which we landed is part of a group of islands historically known as Dinkum Sands.

In other words, the island was above water, as it was also found to be on August 13, 1979.

On August 23rd, however, State and Federal representatives made a joint visit to Dinkum Sands and found it under eight inches of water. But extraordinary tidal conditions prevailed that day, creating a "tidal surge" that may have resulted in the water level being up to a foot above the mean high tide mark.

In Washington during the week of August 9th, Attorney General Gross negotiated a "settlement" with the Federal government of the Dinkum Sands question. The area in question is to be leased and managed by the State. A joint Federal/State monitoring team will observe the island for a continually acceptable period to determine when the island is above mean high tide (or high water, which is still being negotiated). If the island is under water part of the time, revenues will be split proportionately with the Federal government. The Federal government will receive revenue in proportion to the time the island is under water. This "agreement" affects only leasing, administration, and revenues; ultimate ownership still must be decided by the U.S. Supreme Court. (As of yet, however, no formal <u>written</u> agreement has been reached).

<u>ARCO Pier</u>

The second point of contention to arise since the approval of the joint sale map is the use of the ARCO Pier on the northwest shore of Prudhoe Bay as a salient point for determining the disputed area for the Beaufort Sea sale.

The ARCO Pier was built in 1974. Two years later the pier was extended to twice its former length under an emergency permit issued by the Corps of Engineers. As of this moment, it is only the extension that is at issue. The issue was put in writing in a letter dated June 15, 1979, from Interior Solicitor Leo Krulitz to Attorney General Avrum Gross. In it, Mr. Krulitz complained that:

> When the leasing map for the joint Beaufort Sea sale was being prepared, it came to our attention that the State of Alaska considered the ARCO pier to have extended its coastline. Unfortunately, I cannot concede that valuable Federal land was conveyed to the State through the issuance of an emergency permit, without proper review by this Department or approval by Congress. Therefore, the Federal Government will be forced to require removal of the entire pier to erase any doubt as to the location of the coastline, unless the State is willing to drop its claim. Removal of the pier seems to be a somewhat unreasonable solution to this problem. However, I believe it is equally unreasonable for the State to take advantage of the fact that ARCO's application was not properly reviewed due only to the emergency circumstances. If the State is unwilling to waive its claim in this case, we will feel constrained to refuse approval of all such permits in the future, when a true emergency exists.

The threat of removal now, we assume, is limited to the extension of the pier.

Mr. Krulitz claimed that Federal regulations (33 C.F.R. 320.4(f)) required that his office be consulted before structures were approved which may alter the coastline, and contended that neither the BLM nor his office was given the chance to comment on ARCO's application. The regulation reads as follows, in pertinent part:

> All applications for structures or work affecting coastal waters will therefore be reviewed specifically to determine whether the coast line or base line might be altered. If it is determined that such a change might occur, coordination with the Attorney General and the Solicitor of the Department of the Interior is required before final action is taken.

We recently examined the "Beaufort Sea 10" file of the Regulatory Functions Agency in the Anchorage office of the Corps of Engineers, which contains all materials involved in the granting of the permits for the original ARCO Pier and the extension. We found the following items of interest:

(1) A 12-10-75 letter from the Department of Interior's Fish and Wildlife Service to the Alaska District Engineer of the Corps of Engineers, stating that "Interested agencies of the Department of Interior have reviewed the Atlantic Richfield Co. (ARCO) request for an emergency permit..."

(2) A 12-15-75 memorandum to the file by William Bleggi of the Regulatory Functions Branch stating that "I informed [Col. Poteat of OCE] that EPA, NMFS, USF&WS and Coast Guard were involved and agreed on the conditions. Also we had touched base with General Rollins (Federal Pipeline Office) and Bill Moses (Interior's General Counsel) who gave their concurrence."

(3) The 1-6-76 Statement of Findings by the Corps of Engineers stating that "General Rollins of the Federal Pipeline Office, Department of the Interior, was contacted in regard to the proposed project and the conditions that were submitted. Concurrence was received on 15 December 1975 from the Pipeline Office."

We have made no conclusions other than to surmise that a gap in communications of considerable magnitude must exist within the Interior Department.

The above notwithstanding, Harvey Sullivan, Counsel for the Corps of Engineers, contends that the emergency permit was nonetheless issued properly per the 1973 Trans-Alaska Pipeline Authorization Act (43 U.S.C. 1651 et seq), citing 43 U.S.C. 1652(b) as the authority and direction for

> the Secretary of the Interior and other appropriate Federal officers and agencies to issue and take all necessary action to administer and enforce rights-of-way, permits, leases and other authorizations that are necessary for or related to the construction, operation, and maintenance of the Trans-Alaska oil pipeline system...

43 U.S.C. 1652(c) allows Federal officers to waive any procedural requirements of law which they deem desirable to further the interest of the Act. That intent, stated in 43 U.S.C. 1652(a), is to ensure that

> the trans-Alaska oil pipeline be constructed promptly without further administrative or judicial delay or impediment.

The extension of the ARCO Pier in 1976 was necessary to allow the unloading of 13 barges trapped in the ice. The barges were loaded with cargo for construction of facilities at Prudhoe Bay.

Although Mr. Sullivan claims the emergency permit was issued properly, he also maintains, loyally, that it was never intended that the extension of the pier be a "permanent structure" to be used as a salient point to measure coastal boundaries. However, ARCO and other officials of the Corps of Engineers believe the pier to be a permanent structure, and the entire pier is an integral part of the proposed plan for the Prudhoe Bay Waterflood Project which was submitted in July 1979 by the Prudhoe Bay Unit Waterflood Task Force as part of the various permit applications. Counsel for the Corps of Engineers has expressed approval of the use of the ARCO dock in the waterflood project.

As stated earlier, only the <u>extension</u> of the pier is at issue at this date. Approximately 765 acres are at stake.

<u>Summary</u>

Sometime in the hopefully not-too-distant future, the U.S. Supreme Court will resolve the disputes over acreage. The actions of Federal officials in the Dinkum Sands and ARCO Pier controversies, however, have caused a cloud of acrimony to hover over the joint sale. Governor Hammond summed it up well in a July 17th letter to Interior Secretary Andrus in which he discussed the Federal government's changes of position on the disputed acreage:

> I bring these matters to your attention at this time because they have the potential to create major stumbling blocks to proceeding with the proposed Beaufort Sea sale in December of this year. There are several legal issues involved in the proposed sale requiring intensive discussion and cooperation between the State and the Federal Government. Your department's unilateral attempt to deviate from the already agreed-upon guidelines for determining the

> boundaries of State-owned lands and Mr. Krulitz' attempt to coerce the State into abandoning a legitimate legal claim certainly do not foster an atmosphere conducive to cooperation; if anything, they pose a serious threat to the sale being held at all.

But at the briefing for Governor Hammond in Fairbanks on August 23rd, Attorney General Gross, referring to the disputed lands issues, said that "these disputes will not hold up the sale in any way." In the briefing, he had reviewed the Dinkum Sands compromise but made no mention of the ARCO Pier.

REVENUE FORECASTS

The timing of revenues from oil and gas lease sales to fit the State's monetary needs is a critical element in selection of the optimal bidding system -- and one the DNR should not decide unilaterally. In a bonus bid sale with a low fixed royalty, a large portion of the lease payment is made at the front end. In a royalty bid system, payment is deferred until production begins. In a net profit bidding system per the proposed Article 2 of 11 AAC 83, payment is deferred even longer or until there has been sufficient production to allow the lessee to recoup its capital costs.

In determining the timing of income, the Department of Revenue needs to establish the State's appropriate discount rate. This factor determines the State's time value of money and measures the return the State can earn on its investments. Current forecasts predict a huge surplus for the next few years, resulting from recent OPEC price hikes and the ongoing increase in pipeline throughput. The July price hike boosted the State's income from the production tax and the sale of royalty oil, and was compounded by the increase in Prudhoe production to 1.4 million barrels per day (to rise to 1.5 million by December).

The Legislative Finance Division, in a September 5, 1979 Budget Projection, concluded that the State will have a liquid surplus of 3.6 billion dollars during the next fiscal year. This is over 2.5 billion dollars above the amount of the current operating budget. Commissioner of Revenue Thomas K. Williams has testified that his Department's projections developed by the Petroleum Revenue Division (using its PETREV computer model) are substantially the same. Depending upon the rate of growth of the State budget, the surplus revenues can be expected to continue until some time between 1998 and 1995. Sobering deficits are predicted to occur some time during the 1990's as the Prudhoe Bay field reserves are depleted.

This forecast points to the conclusion that the State currently has a negative time value of money. That is to say, it may be better for the State to take a loss of current revenue so as to have more income ten-to-twenty years in the future. This forecast argues strongly for the taking of lease payments in the form of a royalty or net profit share, rather than a front-end bonus.

DMEM's apparent insensitivity to the effect a huge surplus has on the State's discount rate and time value preference for income was recently displayed in a front-page story in the Anchorage Times of September 18, 1979. The article quoted Thomas Cook, DMEM's Director, as follows:

> One of the related considerations is the State's need for income and the timing of that income.
>
> "There's a funny thesis that we should be concerned with deferring income," he said. "Of course the ultimate deferral is never."

Not all State officials, however, feel that deferring State income is "a funny thesis." Thomas K. Williams, Commissioner of Revenue, said at the briefing of the Governor on the Beaufort Sea lease sale on August 23rd in Fairbanks,

> "What we are trying to do is optimize the flow of funds through time so we don't have a big valley in terms of revenue in the late 1980's. Perhaps a cataclysm would be a better word of what could happen through the 1990's."

Commissioner Williams also indicated that his Department was going through the exercises of matching budget growth with revenue forecasts. Regarding those analyses, Commissioner Williams stated, at the same meeting:

> "We see the State going broke despite the billions of dollars on hand in the early 2000's."

In our opinion, decisions which affect the State's financial position and its time value preference for income, whether from a lease sale or State investment, should be made in close consultation with the Department of Revenue. DNR can assist by providing technical information that would bear on the timing and expected value of revenues from an oil and gas lease sale. However, the choice should be made in large part by the Department of Revenue so as to be as compatible as possible with the State's actual money needs. Furthermore, it is of critical importance that the State time its lease revenues from the Beaufort Sea to replace declining revenues from Prudhoe Bay in the early 1990's.

There is yet another reason for spreading payment of lease revenues. As experience shows, State income can be more wisely spent if it is stretched out over a period of years, instead of collected in a lump sum. Massive one-time increases strain the ability of policy makers and administrators to properly manage State agencies or programs. A striking example is the ten-fold growth of the University's budget during the 1970's, which created a management crisis that is only now being remedied. Leasing procedures should enable revenues to be timed to ensure wise fiscal management, as well as maximizing economic benefits.

In the August 13th public hearing of this Committee in Anchorage, Commissioner of Revenue Williams said, "We have more revenue anticipated for this fiscal year than we need for our operating budget." The Commissioner added that in general the price increase for crude oil has pushed back the time when the State's current revenue surplus would be exhausted, which would be sometime near the mid-1990's. If a major portion of rent from the Beaufort is collected as a cash bonus payment, it would not fit well with the State's current revenue situation.

POST-LEASE SALE ADMINISTRATION

A major criticism leveled at net profit leasing by DMEM, again, is that post-sale audit difficulties may make net profit share leasing unworkable. In the words of Thomas Cook, "Net profits would be an administrative nightmare". Currently the Department is responsible only for auditing royalty payments from actively producing lease tracts. A net profit share lease would require auditing allowable costs as defined in the proposed Article 2 of 11 AAC 83.

Late in the 1979 Legislative Session, the Legislative Budget and Audit Committee published a report which concluded that:

> The Department of Revenue and the Department of Natural Resources should coordinate their efforts to provide a more comprehensive audit program. Even though the oil and gas tax and royalty are treated separately by statute, their bases are so similar that auditing both should be considered one function.

This conclusion is based on the fact that even though DNR audits royalty and the Department of Revenue audits the production tax, the audit functions are so similar that they should be consolidated in one department.

This issue of audits is further complicated by certain confidentiality requirements which apply to tax information obtained by the Department of Revenue, which may not divulge information regarding taxpayers' returns except in official administrative or judicial proceedings. AS 43.05.230. And though the Department of Revenue conducts field audits for production tax payments (AS 43.55) and the oil and gas corporate income tax (AS 43.21), it may not share this information with DNR. But DNR is not staffed to conduct field audits to verify royalty payments; all DNR does is simple desk audits. Information obtained by the Department of Revenue would greatly increase the accuracy of royalty audits if it could be shared with DNR.

HCS CSSB 51 (Judiciary) am H (1979) would have allowed this very information obtained by the Department of Revenue to be made available to DNR if that information related to the value of oil or gas in which the State has an interest under AS 38.05.180. The bill, unfortunately, failed to pass the House.

A different solution, perhaps a more permanent one, would be to shift the entire audit responsibility to one of the two departments. This question of post-sale administration of a net profit share lease was posed to the Commissioner of Revenue. Commissioner Williams told the Committee that the audit burden, as it related to a net profit share lease, has been reduced significantly because of the similarity of the proposed net profit share leasing regulations to the oil and gas corporate income tax regulations and proposed production tax regulations. Because of this similarity, Commissioner Williams said, auditors from Revenue could double up the functions of the tax audits and a net profit share lease audit.

In our opinion, because the Department of Revenue has been increasing its staff to audit the production tax and corporate income tax, it is the logical choice for audits of net profit share leases. Another point that supports this choice is the fact that the proposed net profit share leasing regulations in 11 AAC 83 are modeled on the oil and gas corporate income tax regulations and the proposed production tax regulations (15 AAC 05.700 et seq). And because of Revenue's familiarity with these audit procedures and the similarity of its regulations to the proposed net profit share leasing regulations, Revenue is the best Department to have the audit responsibility for net profit share leases. This could be achieved in the short-term by an inter-agency agreement, and in the long run by new legislation.

ECONOMIC CONSIDERATIONS

Selection of the bidding system for the Beaufort Sea lease sale is one of the most important economic decisions now facing the State. That decision could affect the State's financial position for several decades. It cannot be taken lightly and must be based on a thorough economic analysis. In the August 23rd Fairbanks briefing of the Governor on the Beaufort Sea lease sale, Commissioner LeResche stated,

> "It is not a philosophic question; it is very clearly a technical question. . . . We have fought hard to withhold any serious consideration of bidding methods until we have all the information available to us. . . . That information includes a theoretical analysis of how different bidding behaves under different production scenarios. . . . It includes the final geologic assessment; that is, what we think is there."

We agree with Commissioner LeResche that the choice of a bidding system should be based on the best information available -- with maximizing State income as the primary policy objective.

The responsibility of matching leasing decisions to revenue needs is strictly the landowner's (the State's here). If one system proves to be consistently more favorable under prevailing and alternative situations, that one is the logical choice. To quote from the rough draft of DMEM's Economic Analysis:

> If the decision maker consistently selected the alternative having the highest positive expected monetary value his total net gain from all decisions will be higher than his gain realized from any alternative strategy for selecting decisions under uncertainty. This statement is true even though each specific decision is a different drilling prospect with different probabilities and conditional profitabilities. (pp. 17-18).

In other words, the decision-maker must consistently choose the best system for maximizing economic return.

The State has a variety of systems available to it for leasing oil properties pursuant to AS 38.05.180(f). It can lease by requiring a cash bonus, a royalty share, or a net profit share. The State can combine the systems and can require work commitments. The State can reserve acreage within the sale area, or it can choose not to sell it. The final choice must be consistent with the State's time value preference for income.

From the State's point of view, the decision is simple to conceptualize. First, assume a certain amount of oil, worth X dollars. Then assume it will cost Y dollars for a company to develop it, including a return on its investment. If X is greater than Y, the field is economic.

The only question the lessor (again, the State here) need ask is how to collect Z -- the difference. The crucial question is how to collect Z in a way that will maximize return to the State.

Briefly, the State has three basic choices facing it in the upcoming sale: (1) The traditional system is the Cash Bonus/Low Fixed Royalty system. Under this system, the State sells the lease to the bidder who, at a competitive auction, offers the highest bonus bid. The bonus is paid shortly after the auction. (2) A second choice is to fix a low bonus, or a bonus just high enough to weed out irresponsible bidders, and require the companies to bid a percentage of future royalty. (3) The third choice is to set a low bonus and award the lease to the bidder offering the highest percentage of its net profit. The net profit is simply gross value less cost. A variation of the first system is to either set a higher royalty or net profit percentage and use the bonus as the bid variable.

All the systems involve risk. In royalty or net profit systems, payment is contingent upon a find. If oil or gas is not produced in commercial quantities, the State receives no income. In bonus bidding, the State faces risk that an unexpectedly significant quantity of oil will be found. It also faces the risk that oil prices will rise substantially during the life of a field. In an era when world oil prices are being set politically, the full benefits of those price rises won't necessarily enure to the State under a bonus system. A bonus bid, for reasons explained in this Report, fails to produce a fair return on the resource. This point was explained by Governor Hammond to Don Langston, Exxon's Vice-President of Exploration, at the Fairbanks briefing of August 23rd. The Governor said:

> "We're talking about risk which reduces revenue to the State. . . . If we have a field with an enormous net profit and the State took a lower bonus, then there is a risk -- the risk that we get less than we had to if we had chosen net profits."

The bonus system has some bureaucratic appeal. It is simple, requires little skill to manage, and promises occasional successes. For example, in 1974 the Federal government received over two billion dollars in bonus payments for salt domes off the coast of Florida. But there is a flip side to the bonus system. From 1964 to 1969, the State of Alaska sold the leases that make up the Prudhoe Bay Unit for bonuses totalling approximately 90 million dollars. The current worth of the Unit is well over 100 billion dollars. The battles over taxation so the State could finally obtain a fair share of the value of its field were fought at enormous cost to all parties.

The bonus system has strong proponents within DNR. Speaking on behalf of DMEM, Thomas Cook puts it this way:

> "I'm hellbent to see something feasible, that we can administrate. My views are well known. I have a decided bias for proven leasing methods, unless someone can show me what we could accomplish that way (net profits) that we can't accomplish another way."
>
> (Anchorage Times, 9-18-79, p. 2).

Clearly the bonus system accomplishes the task of conveying mineral interests beneath State lands to oil companies. Its ability to ensure maximum economic returns, provide incentives for exploration, and guarantee adequate competition, however, is questionable. In examining how to best maximize State income from a lease, the State should measure this policy against these four economic criteria: (1) Discounting; (2) Incentives; (3) Competition; and (4) Risk. The rough draft of DMEM's economic analysis considers these criteria.

Discounting

In the example of $X - $Y = $Z, the basic question is: How does the State want $Z paid to it? Does the State want $Z (generally termed economic rent) paid in a lump sum as a bonus, or does it want it spread out over time as a net profit or royalty payment? How much the State receives in bids by the companies is related to their discount rate. The worth of the bid to the State is affected by its discount rate.

The State has a lower discount rate than an oil company. If the State's discount rate is measured by the return on Permanent Fund investments or as DMEM calls it in its rough draft, "the opportunity cost of capital," the State's discount rate is currently around 0.0% in real terms. In other words, the State is barely able to keep its current revenue surplus and Permanent Fund balance from being eroded by inflation. DMEM's rough draft assumes 0.0%; we concur.

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An oil company's discount rate is much higher than the State's, because, unlike the State the company's investments are not statutorily restricted. In DMEM's rought draft, its base case assumes 8%. We feel that adding 12% and 16% scenarios provides a fuller, more realistic range for study.

Discounting measures the present-day value of income or spent through time. Measured in real terms, $100 is worth a lot more to an oil company if it can invest it today and earn up to 16%, than the $100 is to the State which can only earn 0.0%. DMEM puts it this way in its rough draft:

> The difference in private and public discount rates is extremely important in evaluating the relative attractiveness of the various leasing alternatives from the state's point of view. It means that future dollars are worth more to the state than the industry. (p. 15).

As DMEM's rough draft concludes, against the criteria of discounting, a royalty or net profit share system is far superior to the bonus system for both the State and the oil companies. Companies are in a position to bid more dollars when, during the exploration and development phases, they have the use of the money that would have been paid as a bonus. They are willing to bid more as a net profit share than a bonus or royalty because they are thus permitted to recover their capital outlays, which allows them additional years to plow earnings back into this -- and other -- fields.

Incentives

This second economic criterion is related to the incentives different bidding systems offer the lessee to (1) explore and develop and (2) to recover the maximum amount of oil from a pool.

> The systems are also evaluated in terms of their potential ability to encourage economically efficient resource use. For example, a system may generate substantial revenues to the state but discourage the development of marginal fields and encourage abandonment of producing fields before all of the economically recoverable oil is recovered. Other things being equal, it is desirable that all economically recoverable oil and gas be extracted in an efficient (cost minimizing) manner. (DMEM rough draft, p. 2).

An oft-repeated criticism of royalty or net profit share bidding is that these systems encourage speculative bidding, which will adversely affect exploration and development decisions. Conversely, as DMEM states on p. 6 of its rough draft:

> It is also argued that the payment of a large front end bonus will lead to the diligent development of a lease.

We find no concrete evidence, however, to support this latter argument.

Because there is no historical evidence of alternative bidding systems on State leases, we have been limited to examining the actual performance of actual Cash Bonus/Low Fixed Royalty leases to determine whether the detractors of net profit share leasing are right.

Currently pending before the Department are applications for Unitization involving 56 unexplored about-to-expire leases -- leased under a Cash Bonus/Low Fixed Royalty. Unitization here is being attempted to extend the leases without having to bring them into production as required by law. We need not belabor here the worthy concept of Unitization as a conservation practice designed to protect lessees' correlative rights in the development of an oil pool, and the preventing of the waste of hydrocarbons. We have mentioned it earlier in this Report. As we mentioned in a Report to the Department on August 17th, too, Unitization as a device for extending leases is of dubious value in cases where "it is uncertain whether any oil or gas exists in commercial quantities."

Here, however, the issue is not Unitization, but whether the method used in leasing these 56 properties encouraged exploration. All the leases in question were granted to the bidder offering the highest cash bonus payment, with a royalty fixed at 12.5 percent. The operators have not explored any of these leases, even though industry maintains that payment of a bonus will encourage development.

So, while payment of a bonus doesn't necessarily ensure development of a lease tract, there is still the argument that without bonuses you encourage speculative bidding.

This problem supposedly occurs, the industry claims, with royalty or net profit share bidding. This particular problem is easily solved, however, by simply setting a moderate fixed bonus high enough to screen out irresponsible bidders. This point is not addressed in DMEM's rough draft -- but should be. And besides setting bonuses, DNR also has the authority to require work commitments, i.e., to require a certain number of wells to be drilled on a lease or in a particular geographic area.

The recent departure from prior State policy evinced in the Duck Island controversy cannot help but discourage speculation. If a company knows that it will in fact be allowed to hold acreage only for the primary term of the lease unless it explores and brings the property to development, it will no longer be in its interest to sit on a lease in anticipation of higher future oil prices. Under the alleged prior State policy, the lessee could use unitization as an excuse for extending the primary lease term. Under Federal law, this problem is surmounted by employment of a five-year lease term. Under State law, the primary lease term is ten years. This point should also be addressed in DMEM's analysis.

What we do find in DMEM's rough draft is the following:

> If the value of reserves was growing at 15 percent per year in real terms and the firm's opportunity cost of capital was 10 percent, it is not obvious that the bonus would assure "diligence". (p. 6).

We would merely point out here that the value of the Prudhoe Bay reserves has risen ten-fold during the past decade.

On the point relating to marginal production and extending the economic life of a field, net profit share leasing is clearly the best system. On a net profit share lease the net profit share paid to the State can decline to zero. This is definitely a positive effect in terms of extending the life of a field.

Unless the Commissioner's discretion is invoked per AS 38.05.180(1), the royalty cannot decline below 12.5% under both the bonus and royalty systems. AS 38.05.180(f). Because of this, there is always a contingency payment which may have the effect of shutting down a field. This problem was solved regarding the production tax by applying the economic limit factor, which allows the production tax rate to decline as production from wells declines. A royalty acts economically like the production tax. Both are perceived as costs to the oil company, and may make a marginal field uneconomic.

As a comparison of net profit share to royalty bidding, note the following point made by DMEM:

> The net profits system adopted by the state, because it allows for the capital recovery of additional field investment, is much more likely to encourage secondary efforts. (DMEM rough draft, p. 19).

When a company invests in secondary recovery systems, it reduces the amount it pays as a net profit share to the State.

Competition

It is to the lessor's advantage to attract as many bidders as possible to a lease auction. But under current State leasing policy, there are two deterrents to competition: lack of adequate information on geologic potential, and large up-front bonus payments.

Under current law as interpreted by DNR, well data that relates to the valuation of nearby unleased acreage must be kept confidential for a reasonable time after disposition of the affected area. See AS 31.05.035(c), as amended by ch 160 SLA 1978. Ch 160 SLA 1978 had the effect of locking up data from certain wells adjacent to the proposed sale area. Attempts to repeal the effect of ch 160 SLA 1978 were made by the House during the 1979 Legislative Session, but were unsuccessful. Prior to ch 160 SLA 1978, well data was routinely made public after two years.

The companies without access to this data are placed at a keen disadvantage in the upcoming sale. Companies with proprietary data protected by AS 31.05.035(c) (as amended) contend that they drilled wells in anticipation of a previously scheduled Beaufort Sea lease sale. When that lease sale was cancelled, the companies claimed it was unfair that this data was to become public. In December 1975, Governor Hammond cancelled a Beaufort Sea lease sale scheduled for 1976. All the wells protected by AS 31.05.035(c) were spudded after December 1975. The wells which became public prior to the ch 160 SLA 1978 conclusively confirm the presence of oil and gas offshore in the Beaufort Sea. As Don Langston of Exxon put it at the Governor's briefing in Fairbanks on August 23rd,

> "I don't think there is much risk that there is not oil in the Beaufort Sea."

Included as part of the Department's economic analysis should be the effect of reserving the tracts adjacent to acreage where well data is locked up pursuant to AS 31.05.035(c). Because the State has access to the data, that should make the evaluation fairly precise. If oil is eventually discovered around these tracts, their value would increase dramatically.

Another point on competition is the effect of requiring the payment of a large bonus to acquire a lease. Smaller companies do not have the cash on hand to compete with larger companies on the choicest tracts. By restricting the number of bidders, the State may be losing out in the long run. This point is well-documented in the literature. See, e.g., Alternative Oil and Gas Leasing Policies, A Report to the Alaska Legislature, Mason Gaffney, 1978. The fact that large bonuses screen out smaller companies, combined with the effect a bonus would have on the State revenue surplus, makes yet another powerful argument for use of royalty or net profit share bidding. This point is mentioned on p. 6 of DMEM's rough draft:

> Finally, from the lessor's viewpoint, the extent to which the bonus transfers the economic rent to the lessor is extremely sensitive to the level of competition. Paradoxically, it is alleged that the traditional cash bonus system hinders competition because of the requirement of a high front end bonus. Smaller firms lack the financial resources to compete effectively in the bidding process and the geological risk is too great to rely on traditional capital markets for the necessary funds.

Risk

The final economic consideration -- and the one least understood -- is risk. The key to understanding risk is expected value. What course of action will result in the largest net gain from a large number of independent trials? In other words, the odds of success or failure will even out over the long-term, so one should choose the system which will maximize revenues over an extended period of time, not on a tract-by-tract or trial-by-trial basis. DMEM states it this way, by asking:

> Does the repeated trial aspect of expected value vitiate its use where each choice has a different set of economic parameters and geological risks? The answer is no. The expected value concept can be applied to leasing decisions if it is applied consistently to all decisions. (DMEM rough draft, p. 17).

The question of risk is also addressed in the paper by Hayne E. Leland, Professor of Business Administration at the U. of California (Berkeley), regarding the Department's proposed Net Profit Share Leasing regulations. In the introduction to his paper, Dr. Leland states that

> Because of risk, firms may require higher rates of return than the state. Risk sharing through net profit share leasing will be advantageous, in that expected revenue will by [sic] higher. The risks borne by the state will also be higher, however.

Risk sharing is particularly advantageous to the State, because it bears different risks than an oil company. Oil companies must evaluate risk on a tract-by-tract basis, and will discount their bids accordingly. The State, however, averages its risk over all tracts. Accordingly, the risk that a particular tract on which a company happens to be bidding is dry is much greater than the risk that all tracts are dry. It is illogical for the State to accept the company's perception of risk, because the State's is less. It is to the State's advantage to share in the risks. The bidding system in which the State shares the most risk is the net profit share.

DMEM's rough draft analysis compares revenues from two risk scenarios: a 50 percent chance of finding what you expect is there, and a 10 percent chance. In both cases, net profit share leasing generates more expected revenue than either bonus or royalty bidding. We recommend that DMEM model the 100% case as well.

<u>Conclusion</u>

We compliment DMEM for its rough draft economic analysis; it is an encouraging first step in developing the theoretical framework needed to evaluate leasing systems. In summary, we are anxious to see the following in the final Economic Analysis that DMEM sends DNR:

(1) The evaluation of the effect of obtaining better geologic data by drilling wells on-structure prior to a lease. This must be evaluated on an expected value basis and in terms of increasing competition.

(2) The evaluation of split-leasing, which separates the exploration phase from the development phase of oil and gas production. Implicit in this analysis is a reduction of risk to the company that ends up developing the lease.

(3) The evaluation of the effect of withholding certain highly prospective tracts within the sale area, and tracts where competition may be reduced because of unavailable confidential data.

(4) A comparison of all scenarios at 100 percent chance of success, to evaluate each system simply in terms of its efficiency in collecting rent.

Beaufort Bidding Analysis
by Ed Phillips, DMEM

INTRODUCTION ROUGH DRAFT

Because of perceived inadequacies in the State's oil and gas leasing, the Legislature amended the law in 1978 and again in 1979. These amendments added a variety of net profit and royalty options to the existing law. This study was undertaken to analyze the potential economic tradeoffs to the State from exercising these options, some of which depart significantly from the State's traditional method of leasing potential oil and gas lands (cash bonus plus a minimum royalty of 12.5 percent).

The analysis was performed using an orthodox, oil industry cash flow model designed by Garrett Computing Systems, Inc. of Dallas, Texas. The computer simulations were run under a variety of assumptions concerning field size, oil prices, production costs and risk assumptions.

The basic data on field size and cost (both operating and capital) were gleaned from the Department of Interior's Beaufort Sea EIS. The State's Division of Minerals and Energy Management played a major role in assembling the original data for the EIS and it was felt that these data represented the best available information.

Three general leasing systems are directly compared: Traditional (cash bonus plus minimum royalty), Royalty, and Net Profit Shares.

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A compromise system involving a sliding-scale royalty is analyzed separately. The leasing systems are evaluated in terms of their ability to transfer economic rent to the state as well as the timing of the potential revenues that the state would receive from leasing its potential oil and gas lands.

The systems are also evaluated in terms of their potential ability to encourage economically efficient resource use. For example, a system may generate substantial revenues to the state but discourage the development of marginal fields and encourage abandonment of producing fields before all of the economically recoverable oil is recovered. Other things being equal, it is desirable that all economically recoverable oil and gas be extracted in an efficient (cost minimizing) manner.

The systems differ in the way in which income generated from the leasing process is distributed among the participants. This distribution is affected by the risk sharing nature of the arrangements and the level of competition among bidders.

The risks to be shared are of two major types: geologic and commercial. Geologic risk refers to the possibility of oil and gas being discovered in the absence of direct information (drilling). The commercial risk is attendant upon the anticipated costs of development and production as well as possible future prices. Leasing systems that shift the burden of payment from ex ante estimation (cash bonus) to ex post results (royalty,

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net profit share) shift a proportion of the risks from the lessee to the lessor. Lease arrangements that shift the burden of payment from estimates to actual results are referred to as contingency payment systems in that the payments are contingent upon the actual discovery of oil and gas in commercial quantities. Royalty bidding is an example of a contingency payment system. As this study will show, the shifting of these risks dramatically affects the potential income division between lessee and lessor.

Economists often refer to the distribution issue as the division of the economic rent between the resource owner (lessor) and the producer (lessee), rent being viewed as the economic surplus reamining after labor and capital have earned their competitive or opportunity cost returns.

Contingency systems potentially offer the lessee a larger portion of this rent as a direct result of sharing more of the risks inherent in the oil and gas discovery process. This sharing also implies that the lessor's income will vary in response to the quality and quantity of oil discoveries, that is to say, rich, productive fields will yield high incomes and marginal fields very little.

The first section of this study describes the basic leasing systems. The systems are evaluated in terms of how they influence the behavior of the participants. That is, does the system encourage economic efficiency? A potential tradeoff with any leasing system is between more revenue for the lessor but less ultimate recovery from the field. Theoretically, contingency payment systems offer the lessor more income but at the loss of economically recoverable reserves.

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Following the discussion of the basic systems, the results of the computer simulations are presented. The alternative leasing systems are compared under two sets of price, cost and risk assumptions. These assumptions are applied to four hypothetical fields ranging in size from 500 million barrels recoverable reserves to 4.2 billion barrels.

The sliding scale royalty system proposed by the Department of Interior is examined. This compromise system has royalty rates that vary with the real value of quarterly output up to a maximum rate of 65 percent. The specification of the sliding-scale royalty was developed with North Slope geologic and economic parameters and is therefore roughly comparable to the other systems analyzed.

The final section of the paper summarizes and assesses the tradeoffs among the leasing systems.

DESCRIPTION OF BASIC LEASING SYSTEMS

Cash Bonus Low Royalty (12.5%)

The winning bidder for a tract submits the highest sealed bid. The low royalty means that most of the geological and economic uncertainty (risk) is borne by the lessee and a substantial portion of the lessor's total revenue is based upon the ex ante evaluation of the tract's net present value. The magnitude of the bid is influenced not only by the firm's estimates of potential costs, revenues and reserve size, but by the number of potential bidders for the tract. Other things being equal, the average level of bids will increase with an increase in the number of potential bidders.

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The cash bonus system with a low royalty is essentially symmetrical with respect to risk sharing. That is to say, the winning bidder absorbs any divergence from his original expectations in the form of profits or losses. The lessor has effectively transferred risk to the lessee.

This traditional leasing system is economically efficient in that virtually all economically recoverable oil will be extracted. Even if the geology is less favorable than originally anticipated, if the rate of return on additional investment is at least equal to the opportunity cost of capital, the field will probably be developed. The cash bonus plays no role in the development decision. The firm stands to capture all but 12.5% of the anticipated future cash flow. As long as the present value of this cash flow, net of taxes, discounted at the firm's opportunity cost, is at least equal to the incremental field investments required for production, the decision to develop the field will be made. It should be noted that the decision would be the same in the absence of the bonus. It is the low level of contingency payments that leads to the economically efficient decision to develop, not the bonus.

It is also argued that the payment of a large front end bonus will lead to the diligent development of a lease. This is true to the extent that the firm's opportunity cost of capital exceeds the rate at which the value of oil in the ground is growing. If the value of reserves was growing at 15 percent per year in real terms and the firm's opportunity cost of capital was 10 percent, it is not obvious that the bonus would assure "diligence."

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Finally, from the lessor's viewpoint, the extent to which the bonus transfers the economic rent to the lessor is extremely sensitive to the level of competition. Paradoxically, it is alleged that the traditional cash bonus system hinders competition because of the requirement of a high front end bonus. Smaller firms lack the financial resources to compete effectively in the bidding process and the geological risk is too great to rely on traditional capital markets for the necessary funds.

There are two obvious possibilities for reducing this financial barrier. Small firms can bid jointly, thereby pooling their financial resources and reducing financial risk. The other possibility entails improving the quality of information available before a sale, and in the extreme case splitting the leasing procedure into a two-stage process and holding a sale for field development after oil had been discovered. Once the geological risk is removed, the reserves become a bankable asset and smaller firms could borrow from traditional sources in the capital market to bid in lease sales. Under these conditions the winning bidder would likely be the most efficient firm.

Royalty Bid - Fixed Cash Bonus ROUGH DRAFT

Under this system the bidder pays a minimum fee, then pledges a proportion of future gross revenues and/or production. The winning bidder is the one that pledges the largest share of future gross revenues or output to the lessor.

The initial financial payments to the lessor are minimal; hence the front end burden is lessened. Lessor income is now largely dependent upon the discovery of oil and gas in commercial quantities. Making the payment contingent upon discovery and development shifts some of the geological risk to the lessor.

Likewise, some of the economic or commerical risk is also shifted to the lessor. The specification of the royalty in terms of gross revenue means that the lessor is sharing some of the future price risk. The higher the royalty rate, the more is the price risk shifted to the lessor.

The royalty bid is made ex ante and represents the bidder's best estimates of future prices and costs. In effect, the royalty is an excise tax on future production. Based only on gross revenues, the royalty is insensitive to operating costs associated with production. A 40 percent royalty on a $10.00 barrel of oil (wellhead) is $4.00 whether the cost of producing the barrel is $1.00 or $9.00. This insensitivity to costs has important implications for the decision to develop fields and how to best develop a particular field or tract.

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High fixed royalties are not economically efficient. Oil that has a market value of $10.00 at the wellhead will not be produced with a 40% (or greater) royalty if the variable production costs are in excess of $6.00. When a field is developed, "high grading" will occur. That is, only the best tracts will be developed, leaving other tracts with valuable oil reserves untouched. The tracts that are developed are developed less intensively than had the royalty been minimal. This happens because the royalty payment directly reduces the expected present value of the future cash flow. The net result is to reduce field investment, lengthen field life and reduce ultimate recovery. The introduction of the high royalty distorts the relationship between the market price and the cost of production, leading to economically inefficient decisions.

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Part of this distortion is also related to the asymmetric nature of the risk sharing under high royalties. The lessor shares in the benefits of profitable developments but does not participate fully in the dryhole risk associated with unsuccessful ventures; as a result, the expected value of benefits (from the lessee's view) are reduced while the expected value of costs are unaffected. This asymmetry will, ex ante, reduce the value of all tracts in a lease sale.

Balanced against this economic inefficiency is the likelihood of increased competition under a royalty bidding scheme. Bidder eligibility is greater because the front end cash payment is less. The increased competition will increase the present value of the bids from a lessor's point of view. Over the long run, the possibility does exist that the lessor will gain more income from royalty bidding than from the traditional cash bonus/low royalty alternative. This result clearly obtains if the fields are actually developed.

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This qualification is important, as the speculative holding of leased tracts could be a problem with royalty bidding. High and/or higher bids involve few resources at the time of sale; hence a bidder that holds an extreme view of the likely state of nature can express that view with little immediate sacrifice. A 70 percent royalty bid involves the same out-of-pocket cost as a 60 percent royalty bid but has a greater chance of winning the auction. There is nothing in the logic of royalty bidding to prevent a tract from repeatedly being sold at uneconomic royalty rates.

When production commences, revenues minus operating expenses, state taxes and/or royalties are credited against the investment account. No profit share payments are due until the account balance is zero. At this time the firm has recovered its investments as well as earning a stipulated interest rate. The lessor (State) now begins to receive the profit share that was bid or stipulated at the time of the lease sale. The investment account would be re-opened whenever the firm invests in field facilities or makes secondary recovery expenditures. Profit share payments would be reduced or eliminated until the additional investments were recovered.

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The advantage of a net profits system could include the enhancement of competition among bidders, improving the ability of the lessor to capture a larger portion of the economic rent of valuable hydrocarbon deposits, and moderating the decline in revenues to the lessor late in field life. Because this system considers both costs and revenues it is economically more efficient than a royalty system that would raise the equivalent revenue.

Provided that costs and revenues are appropriately defined, this system is much less likely to distort behavior in the same sense as high fixed royalties. A portion of the geological risk is shared as payments only occur on profitable discoveries. Both cost and price uncertainty are shared with the lessee, thus the excise tax effect present in the royalty system is absent.

The speculative problem can be resolved by requiring large fixed bonuses, but this solution reduces the attractiveness of royalty bidding as a means of enhancing competition. On balance, it appears that high royalties are a less than optimal mechanism to increase competition for oil and gas leases and increase potential income to the state.

Net Profit Share with Fixed or Variable Cash Bonus

In a general sense, profits are the difference between revenues and costs. In an economic sense, net profits are the return to the firms that allow them to replace their capital. In the state's new leasing regulations, net profits are treated as the return over and above the recovery cost of capital. This form of net profits leasing is called the Investment Account or capital recovery system.

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Under this system, all capital expenditures (including pre-production as well as post-production expenditures such as secondary recovery investments) are placed in an interest-bearing account. As long as this account has a positive balance it accrues interest. The interest rate on this account represents the earnings on field investment that the lessee would recover before making profit share payments to the state. Ideally, if the state was concerned only with the maximum recovery of its economically recoverable oil and gas resources, the allowed interest rate under the investment account system would represent the industry's opportunity cost of capital.

Therefore, marginal tracts are more likely to be developed than is the case under royalties that would generate comparable revenues. The possibility of extracting all of the economically recoverable oil and gas exists.

However, the net profits system is not without resource efficiency problems. Certainly high profit shares, say in excess of 50%, reduce incentives for efficiency in the firm's operations. At the margin more effort will be expended to save $0.60 than $0.30. High marginal tax rates are generally thought to have disincentive effects and there is no reason to suspect that high net profits shares would be immune from this influence.

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More importantly, the current net profit system shares risks asymmetrically. This is to say, it potentially shifts a large share of the commercial gain to the lessor, but leaves the burden of the dryhole risk with the firm, thereby deflating the expected value of a given field or tract. A a result, not all economically attractive tracts will be developed.

A further problem centers on the difficulty of correctly defining costs and revenues, and the increased administrative burden associated with implementing the system. The fact that net profit systems have not been widely used in the United States may make oil companies uncertain of how the system would be interpreted and administered by the state.

There is a political uncertainty that a net profits system will clearly reduce. The ability of the legislature to raise taxes ex post of the lease sale will be constrained. State taxes are deductable against the net profit share. Thus, if the legislature increased taxes by $1.00 and if the profit share was 50%, net profit payments would be reduced by 50 cents.

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ECONOMIC ANALYSIS

This chapter presents the results of a computer simulation exercise that compares the three basic leasing methods: cash bonus with minimum royalty, royalty bidding and net profit bidding. In all cases the results can be viewed as symmetric. That is, had the royalty or net profit share been specified in advance, the resulting bonus bid would be the same as the fixed bonus with the contingency payments as the bid variable. This is so because once the geologic and economic parameters are specified there is only one value of the variable payment cnsistent with the fixed payment that will yield a given rate of return.

The following assumptions are used in the base case (750 MM bbls recoverable):

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1. All prices and costs are expressed in 1979 dollars. The wellhead price is assumed to be $14.00 at the time of the lease sale (1979). This price is escalated at 2.0 percent per year in real terms throughout the life of the field. Alternative cases are examined whereby the real price is held constant. In the base case (750 MM bbls), average operating costs are $1.90 per barrel. Capital costs are $2.53 per barrel of recoverable reserves.

2. With the exception of the 500 MM bbl case, a 23-year production profile is used. Production commen-

eight years after the lease sale.

3. Firms are assumed to require an 8 percent real rate of return (beyond inflation) on their investment (after federal income taxes). Later, this assumption is relaxed and the leasing systems are compared with the firms requiring real rates of return of 12 and 16 percent.

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4. Risk aversion is not explicitly modeled. Firms are assumed to be indifferent among certainty equivalent values. Therefore, all bidding systems are evaluated at the same discount rate. State revenues are evaluated at a zero real discount rate. This implies that the state is indifferent as to when it receives its funds and/or the opportunity cost to the state of delaying the receipt of funds is zero. This is obviously a strong assumption, implying that the reinvestment possibilities faced by the state are poor. The oil industry is assumed to have a <u>real</u> discount rate of 8% reflecting the opportunity cost of capital.

The difference in private and public discount rates is extremely important in evaluating the relative attractiveness of the various leasing alternatives from the state's point of view. It means that future dollars are worth more to the state than the industry. The state benefits from an exchange that sacrifices current income for future income while industry prefers to give up future income to increase its near term positive cash flows or reduce current negative cash flows. It means that both participants in the leasing process can, in essence, exchange cash flows, with the state sacrificing current income for potential future income. While the industry sacrifices potential future income (relatively low valued) for much smaller current negative cash flows (bonuses).

Had risk aversion been explicitly modeled, the variation in revenue among the basic leasing systems would have been more pronounced. The traditional bonus bid/minimum royalty system would have generated less revenue, as the potential exposure of large amounts of capital for the chance at uncertain prospects would have led to further risk discounting. Explicit recognition of risk would also have led to more divergence between the royalty and net profit systems, because the net profit system shares cost uncertainty as well as price uncertainty.

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5. Net profits system only allows for capital recovery with no implicit real interest earnings.

Tables I through V summarize the results for four field sizes, two risk probabilities and three basic leasing systems. All monetary values are in 1979 dollars and represent total income generated under each leasing system. Under all systems there is a minimum of 12.5 percent royalty, 10.8 percent severance tax and a 9.4 percent state income tax. Thus, the variation in income among the systems is related to the characteristics specific to the system.

In all cases the royalty and profit share systems generate a higher expected present value of revenue to the state than the traditional leasing method. The key concept to understanding these results is expected value. This suggests that the results are the weighted average of a large number of independent trials. Thus, the results are the average revenue streams per trial that would be realized over a series of repeated trials.

Does the repeated trial aspect of expected value vitiate its use where each choice has a different set of economic parameters and geological risks? The answer is no. The expected value concept can be applied to leasing decisions if it is applied consistently to all decisions. To quote a respected authority in petroleum risk analysis:

ROUGH DRAFT

> If the decision maker consistently selected the alternative having the highest positive expected monetary value his total net gain from all decisions will be higher than his gain realized from any alternative strategy for selecting decisions under uncertainty. This statement is true even though each specific decision is a

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(?) rest of quote

The net profits system adopted by the state, because it allows for the capital recovery of additional field investment, is much more likely to encourage secondary recovery efforts.

The traditional method of leasing with a minimum royalty is also encouraging of secondary investment as the firm can capture most of the financial gain from the effort. The traditional leasing method clearly encourages economic efficiency; the only issue is how the rewards of efficiency are distributed among the participants of the leasing process.

ROUGH DRAFT

If the rate of return assumption is relaxed and the required rate of return is permitted to increase to 16 percent, the revenue generated by all systems declines. Raising the opportunity cost of capital lowers the economic rent generated by the natural resource. After all, rent is defined as the earnings in excess of opportunity costs. Increasing the opportunity costs of the variable resources reduces the rent generating capacity of the natural resource.

Of the basic leasing methods, the traditional method suffers the greatest relative decline. As Table V demonstrates, the expected revenues from the traditional method fall by 22.6 percent. The concomitant declines for the royalty and profit systems are 14.1 percent and 10.6 percent. In other words, the relative performance of the contingency payment systems improves as the industry's required rates of return increase.

This result must obtain from the relative importance of the bonus in the total revenue stream received by the state from the traditional leasing system. The bonus falls from approximately $1.16 billion to $269 million, or by almost 77 percent. While the relative decline in the bonus is the same for the contingency systems it only represents a loss of $177.2 million.

At the higher discount rate the bonus as a share of total income declines from 31.4 percent to 9.4 percent in the traditional case, and from 3.3 percent to one percent or less in the contingency cases. The equilibrium royalty share falls from 62.85 to 51.90. The corresponding net profit share falls from 77.1 to 65.9 percent. Most of the decline in total payments is the result of the lower equilibrium contingency shares.

ROUGH DRAFT

The results displayed in Tables I through VI are a function of the parameters built into the model. Table VII illustrates the effect of doubling the operating costs over the life of the field. Average operating costs increase to $3.80 per barrel and exceed $10.00 near the end of field life. Even though the contingency systems show a greater response to this cost increase, the results are hardly dramatic with the profit share income showing the greatest decline, 10.8 percent.

The reason for the apparent insensitivity of the systems to cost increases is the price/cost assumptions built into the model. The two percent per year increase in the real price of oil moderates the impact of the cost increase. Later, the price cost relationship will be altered and the effect will be shown to be significant.

If the real price of oil is assumed to remain constant at $14.00 a barrel throughout the period of analysis, the resulting revenues to the state are sharply deflated regardless of the leasing method. The revenue totals in Table VIII are about 46 percent of their counterparts in Table V. Relatively, the incomes from the contingency systems fall slightly more. Even so, under the constant price assumption the contingency systems generate about 70 percent more potential income than the traditional system.

ROUGH DRAFT

At the 16 percent required rate of return the net profits system performs relatively better than either royalty or traditional systems. A doubling of the required rate of return only reduces the potential income to the state by 14.6 percent. Income from the traditional method is reduced by over 20 percent. Much of this reduction can be attributed to the reduced bonus as a doubling of the required rate of return reduces the bonus by almost 79 percent. The reduction in the bonus of $477.7 million is more than the total reduction in state revenues. State revenues only fall by $432.8 million. The difference, $44.9 million, is from increased state income taxes resulting from the reduced bonus write off.

Table IX combines high operating costs with the constant price assumption. This case would be regarded as "realistic" by the industry and "outrageous" by AKPIRG. Compared to the optimistic base case illustrated in Table II, the resulting income flows are severely depressed. The traditional method yields a bonus reduced by 62.7 percent and total revenues are down by 48 percent from $3.68 billion to $1.91 billion. The concomitant declines in income from the royalty and net profit systems are 57.1 percent and 56.3 percent.

Where the assumed rate of return is 8 percent, the equilibrium royalty bid of 40.70 percent results in a loss of 24.5 million barrels of reserves. The net profit bid still generates a full recovery of the economically recoverable reserves. Under the 16 percent rate of return assumption no reserves are left in the ground, as the royalty bid is only 28.2 percent.

ROUGH DRAFT

Tables VIII and IX provide an indication of the impact of the cost assumption on the revenues generated by the various leasing systems. The only difference in the two cases is the difference in operating costs. These costs are doubled in the high cost case. This cost change appears to affect revenues from the contingency systems more than the traditional cash bonus system. Traditional revenues fall by 11 percent when operating costs are doubled. Income from the net profit system falls 19.7 percent. The royalty decline is 20.6 percent. Note, if the royalty bid had been made on the basis of the cost estimates in the Low Cost Case, but the higher costs were realized, 60.25 million barrels of economically recoverable reserves would have been left in the ground.

When the required rate of return is increased to 16 percent, the equilibrium royalty rate is sufficiently suppressed so that all oil is recovered. A higher bonus or other investment cost would achieve a similar effect. This result indicates that the state could minimize the loss of recoverable reserves by setting the initial bonus high enough so that the equilibrium royalty rate (given an 8 percent ROR) is low enough to ensure complete recovery. This would entail the loss of some expected revenue.

Tables X and XI along with the accompanying graph illustrate the relationship between the royalty and the rate of return under the different operating cost assumptions. The difference becomes important after royalties reach 20 percent. This explains why the Traditional method was relatively insensitive to the operating cost assumption. The doubling of operating costs exerts only a modest influence on the rate of return until late in field life and these returns are weighted relatively low owing to the discounting process.

ROUGH DRAFT

The leasing systems under investigation have different time profiles of income to the state. The Traditional system yields over 30 percent of its income immediately and the remainder over the life of the field. The contingency systems generate only slightly more than 3 percent of their total revenues immediately and over 96 percent over the productive life of the field, but there is an average 8-year delay before production-related revenues commence. This suggests that the ranking of the systems in terms of the present value of the revenues is sensitive to the rate of interest.

Some might argue that assuming a zero real rate of interest to value state revenues biases the resulting ranking of the systems in favor of the contingency systems. Tables XII through XIV with their accompanying graphs present the present value of income from the various leasing systems at different real rates of interest. The only difference among the tables is the assumed required rate of return. As the required rate of return increase, the real interest rate that equates the present value of the various leasing methods increases. This occurs because the higher earnings requirement is reflected in the discounting of future net revenues and consequently deflates the bonus.

ROUGH DRAFT

The most favorable assumption for the Traditional system is that the industry requires a relatively low real rate of return. Where the industry earns 8 percent the present value of income among the systems is approximately equal at a 10 percent real interest rate. When the required rate reaches 16 percent, the real interest rate that equates the present value of the various systems approaches 20 percent.

The generally high real interest rates required to equate the present value of the various income streams suggests that the state can gain by utilizing contingency systems. One has to argue that the state's opportunity losses are at least 10 percent in real terms before shifting to the Traditional is justified on a present value basis.

This analysis was done under the assumption that firms are risk neutral. Explicit recognition of "risk averse" behavior on the part of firms would have improved the performance of the contingency systems relative to the Traditional. All of the cases examined in this paper suggest that risk shifting is advantageous to the state. This does not imply that the state is risk neutral, which it certainly is not, but that the potential gains from risk bearing are significant.

ROUGH DRAFT

TABLE I

ROUGH DRAFT

REVENUE TO STATE*

FIELD SIZE 500 MM = MILLION BBLS.
PROBABILITY OF SUCCESS: 50%

Leasing Method:	Total Revenue (10^6)	Bonus (10^6)	Royalty or Profit Share %	Bonus %
Traditional	$2,482.34	$779	12.5	31.4
Royalty	4,493.88	155.8	62.30	3.5
NPS	4,626.23	155.8	75.55	3.4

FIELD SIZE 500 MM BBLS.
PROBABILITY OF SUCCESS: 10%

Leasing Method:	Total Revenue (10^6)	Bonus (10^6)	Royalty or Profit Share %	Bonus %
Traditional	$514.00	$177.0	12.5	34.4
Royalty	888.49	35.40	61.0	4.0
NPS	915.15	35.40	73.70	3.9

* Price: $14.00 + 2.0% per year
Firms earn 8% ROR

TABLE II

REVENUE TO STATE*

ROUGH DRAFT

FIELD SIZE 750 MM = MILLION BBLS.
PROBABILITY OF SUCCESS: 50%

	Total Revenue (10^6)	Bonus (10^6)	Royalty or Profit Share %	Bonus %
Leasing Method:				
Traditional	$3,682.51	$1,155.0	12.5	31.4
Royalty	6,721.64	231.0	62.85	3.4
NPS	6,923.6	231.0	77.10	3.3

FIELD SIZE 750 MM BBLS.
PROBABILITY OF SUCCESS: 10%

	Total Revenue (10^6)	Bonus (10^6)	Royalty or Profit Share %	Bonus %
Leasing Method:				
Traditional	$735.33	$252.0	12.5	33.5
Royalty	1,295.91	50.40	59.6	3.9
NPS	1,333.98	50.40	72.1	3.8

* Price: $14.00 + 2.0% per year
Firms earn 8% ROR
Average operating cost: $1.90 per bbl.

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TABLE III

REVENUE TO STATE*

ROUGH DRAFT

FIELD SIZE 150 MMM = BILLION BBLS.
PROBABILITY OF SUCCESS: 50%

	Total Revenue (10^6)	Bonus (10^6)	Royalty or Profit Share %	Bonus %
Leasing Method:				
Traditional	$ 6,154.71	$2,040.0	12.5	33.0
Royalty	11,106.53	408.0	64.4	3.67
NPS	11,449.00	408.0	81.25	3.56

FIELD SIZE 150 MMM BBLS.
PROBABILITY OF SUCCESS: 10%

	Total Revenue (10^6)	Bonus (10^6)	Royalty or Profit Share %	Bonus %
Leasing Method:				
Traditional	$1,274.44	$458.50	12.5	36.0
Royalty	2,195.79	91.70	62.5	4.2
NPS	2,231.75	91.70	75.0	4.1

* Price: $14.00 + 2.0% per year
Firms earn 8% ROR

TABLE IV

REVENUE TO STATE*

ROUGH DRAFT

FIELD SIZE 4.2 BILLION BBLS.
PROBABILITY OF SUCCESS: 50%

	Total Revenue (10^6)	Bonus (10^6)	Royalty or Profit Share %	Bonus %
Leasing Method:				
Traditional	$19,333.15	$6,825.0	12.5	35.3
Royalty	36,143.88	1,365.0	70.35	3.8
NPS	36,708.75	1,365.0	78.85	3.7

FIELD SIZE 4.2 BILLION BBLS.
PROBABILITY OF SUCCESS: 10%

	Total Revenue (10^6)	Bonus (10^6)	Royalty or Profit Share %	Bonus %
Leasing Method:				
Traditional	$4,034.39	$1,555.0	12.5	38.5
Royalty	7,164.80	311.0	69.1	4.3
NPS	7,272.72	311.0	77.1	4.3

* Price: $14.00 + 2.0% per year
Firms earn 8% ROR

TABLE V

TOTAL REVENUE TO STATE

MEDIUM CASE* 750 MM BBLS.
DIFFERENT ASSUMPTIONS ABOUT RATE OF RETURN

	Rate of Return: 8%	12%	16%	% Change
Leasing Method:				
Traditional	$3,682.51	$3,138.91	$2,850.60	-22.6
Royalty	6,721.64	6,262.78	5,775.08	-14.1
NPS	6,923.60	6,570.57	6,192.46	-10.6

*Average operating cost: $1.90/bbl

ROUGH DRAFT

TABLE VI

"GAINS" IN POTENTIAL REVENUE (10^6)
AT DIFFERENT REQUIRED REAL RATES OF RETURN
PROBABILITY OF SUCCESS:50%
750 MM CASE

	Rate of Return: 8%	12%	16%
Leasing Method:			
Royalty	$3,039.13	$3,123.78	$2,924.48
NPS	3,241.09	3,431.66	3,278.86

Gains measured as amounts in excess of traditional.

ROUGH DRAFT

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different drilling prospect with different probabilities and conditional profitabilities. (Newendorp, Paul D., Decision Analysis for Petroleum Exploration, Petroleum Publishing Company, Tulsa, Oklahoma, 1975, p. 67.)

The continued application of expected value maximization over different decision alternatives satisfies the independent trial criterion associated with decision making under uncertainty.

ROUGH DRAFT

In the examples in Tables I through IV, the bonus under the contingency payment systems is set at 20 percent of the traditional level. Column 3 of the tables shows the royalty and net profit shares consistent with the arbitrarily selected bonus. In all cases the royalty and net profit share systems generate over 80 percent more expected income to the state than the traditional method and the royalty performs almost as well as the net profits system. The relatively good performance of the royalty is due to the fact that operating costs only rise to a little over \$5.10 at the end of field life, whereas the price of oil is over \$26.00. This price/cost behavior minimizes the distorting effect of the royalty and improves its relative performance.

Clearly, high royalties would discourage secondary recovery investments by severely reducing the discounted positive cash flow associated with the necessary investment expenditures.

TABLE VII

EFFECT OF CHANGE IN OPERATING COST
ON REVENUE TO STATE FROM DIFFERENT LEASING METHODS
FIELD SIZE 750 MM
PROBABILITY OF SUCCESS: 50%

	Case I	Case II	% Change
Leasing Method:			
Traditional	$3,682.51	$3,461.11	-6.0
Royalty	6,721.64	6,022.23	-10.4
NPS	6,923.60	6,172.60	-10.8

Price: $14.00 + 2.0 percent per year
Case I: Average operating cost = $1.90/bbl
Case II: Average operating cost = $3.80/bbl

ROUGH DRAFT

TABLE VIII

PRICE $14.00 HELD CONSTANT
FIELD SIZE 750 MM REGULAR CASE*
PROBABILITY OF SUCCESS 50%

8% ROR

	Total Revenue (10^6)	Bonus (10^6)	Royalty or Profit Share %
Leasing Method:			
Traditional	$2,147.27	$605.00	12.5
Royalty	3,628.92	121.00	52.25
NPS	3,769.18	121.00	74.1

ROUGH DRAFT

16% ROR

	Total Revenue (10^6)	Bonus (10^6)	Royalty or Profit Share %
Leasing Method:			
Traditional	$1,714.47	$127.30	12.5
Royalty	2,957.86	25.46	40.15
NPS	3,216.88	25.46	57.35

*Average operating cost: $1.90/bbl

TABLE IX

TOTAL REVENUE TO STATE

FIELD SIZE 750 MM HIGH COST*
$14.00 PRICE
PROBABILITY OF SUCCESS: 50%

8% ROR

	Total Revenue (10^6)	Bonus (10^6)	Royalty or Profit Share %
Leasing Method:			
Traditional	$1,911.80	$431.00	12.5
Royalty	2,880.27	86.20	40.70**
NPS	3,025.77	86.20	70.25

ROUGH DRAFT

16% ROR

	Total Revenue (10^6)	Bonus (10^6)	Royalty or Profit Share %
Leasing Method:			
Traditional	$1,586.81	$72.30	12.5
Royalty	2,292.81	14.46	28.2
NPS	2,410.53	14.46	43.15

*Average operating cost: $3.80/bbl
**Loss of 24.250 MM bbls of recoverable reserves.

TABLE X
ROR VS. ROYALTY

FIELD SIZE 750 MM BBLS.
PROBABILITY OF SUCCESS: 50%
$\$50 \times 10^6$ BONUS
PRICE: $14.00

ROUGH DRAFT

Royalty	ROR
0	22.65
10	20.81
20	19.09
30	17.04
40	14.29
50	11.02
60	7.03
70	0.84
72	0

Average operating cost: $1.90/bbl

TABLE XI

ROR VS. ROYALTY

ROUGH DRAFT

FIELD SIZE 750 MM BBLS.
PROBABILITY OF SUCCESS: 50%
$\$50 \times 10^6$ BONUS
PRICE: $14.00

Royalty	ROR
0	19.67
10	18.11
20	15.53
30	13.14
40	9.44
50	4.80
55	2.27
58	0

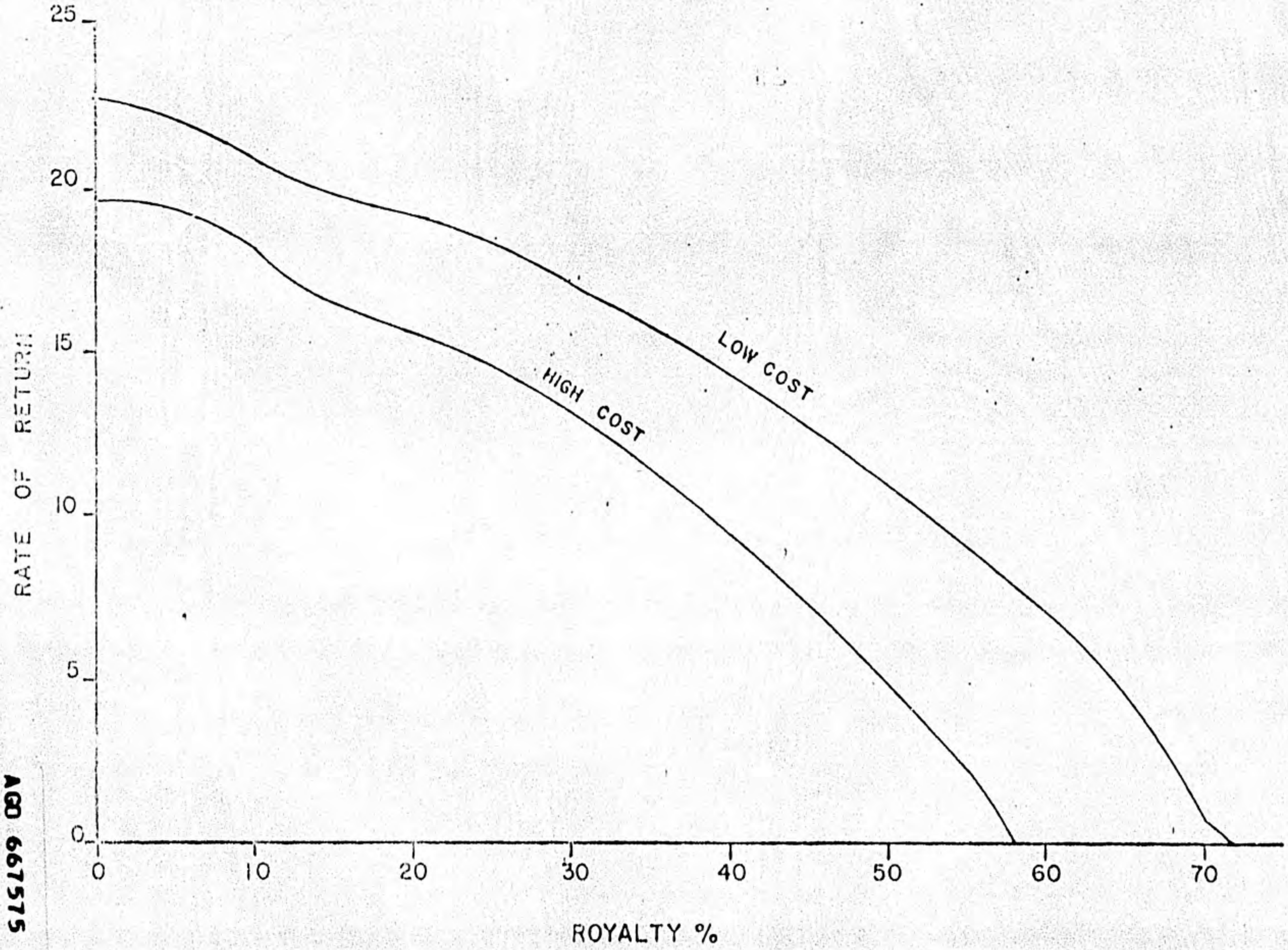
Average operating cost: $3.80/bbl

ROYALTY VS. RATE OF RETURN

HIGH AND LOW COST

PRICE = 14.00 750 MMBBL

BONUS = 50.00×10^6



HIGH AVERAGE OPERATING COST = 3.80 BBL
LOW AVERAGE OPERATING COST = 1.90 BBL

TABLE XII

PRESENT VALUE OF INCOME RECEIVED BY STATE
AT VARIOUS REAL RATES OF INTEREST (10^6)

FIELD SIZE 750 MM
PROBABILITY OF SUCCESS: 50%

ROUGH DRAFT

Interest Rates: (Real)	Traditional	Royalty	NPS
0	$3,682.51	$6,721.16	$6,923.60
5	2,287.78	3,201.12	3,231.85
10	1,687.83	1,678.89	1,658.94
15	1,411.14	972.67	942.92
20	1,277.42	625.48	598.64

Price: $14.00 + 2.0% per year
Firms assumed to earn 8% ROR
All cases have royalty & severance tax

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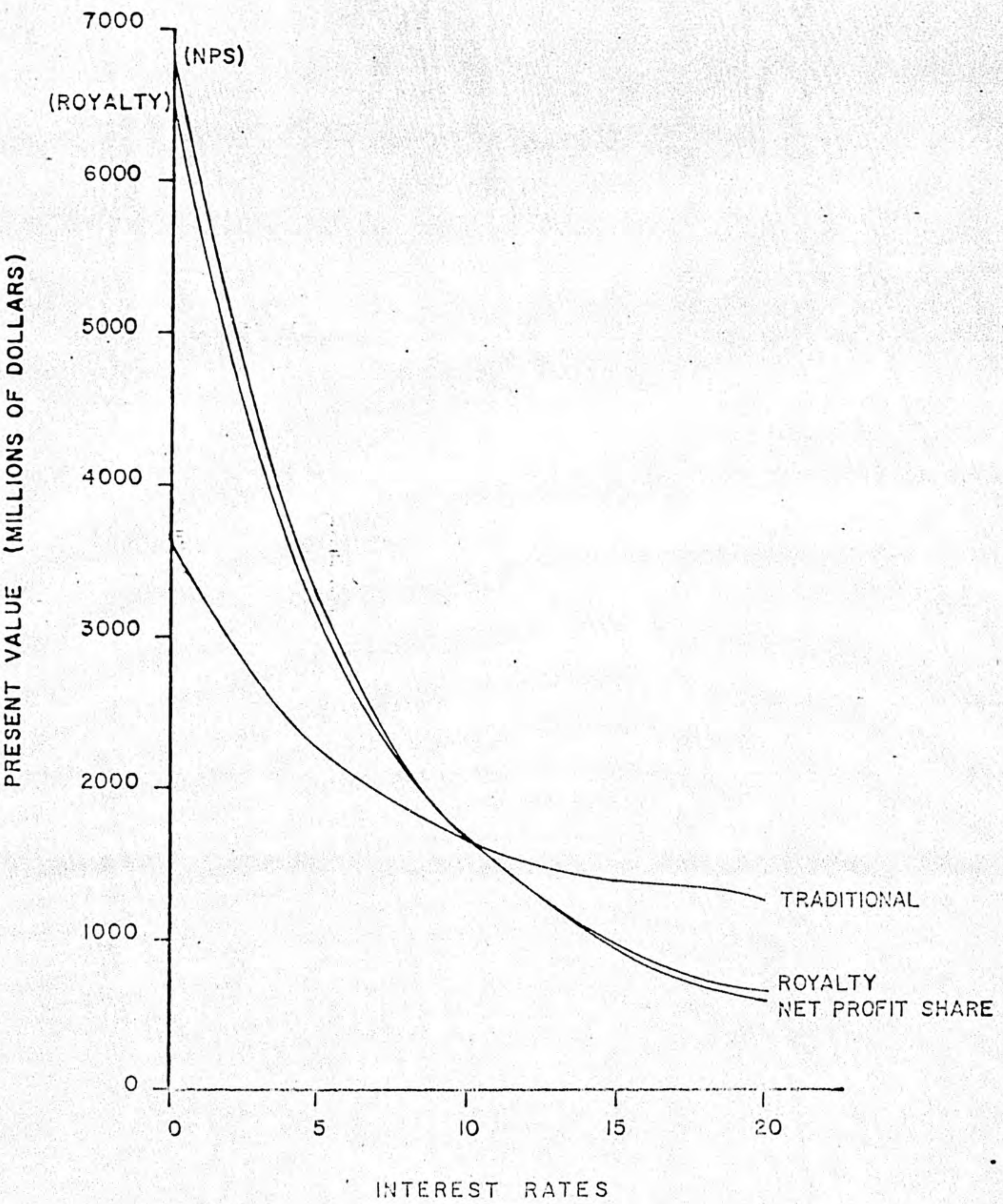
PRESENT VALUE OF INCOME RECEIVED BY THE STATE
AT VARIOUS REAL INTEREST RATES (10^6)
750 MM FIELD 50% CHANCE OF SUCCESS



FIRMS ASSUMED TO EARN 8% RATE OF RETURN

AGO 667577

TABLE XIII

PRESENT VALUE OF INCOME RECEIVED BY STATE
AT VARIOUS REAL RATES OF INTEREST (10^6)

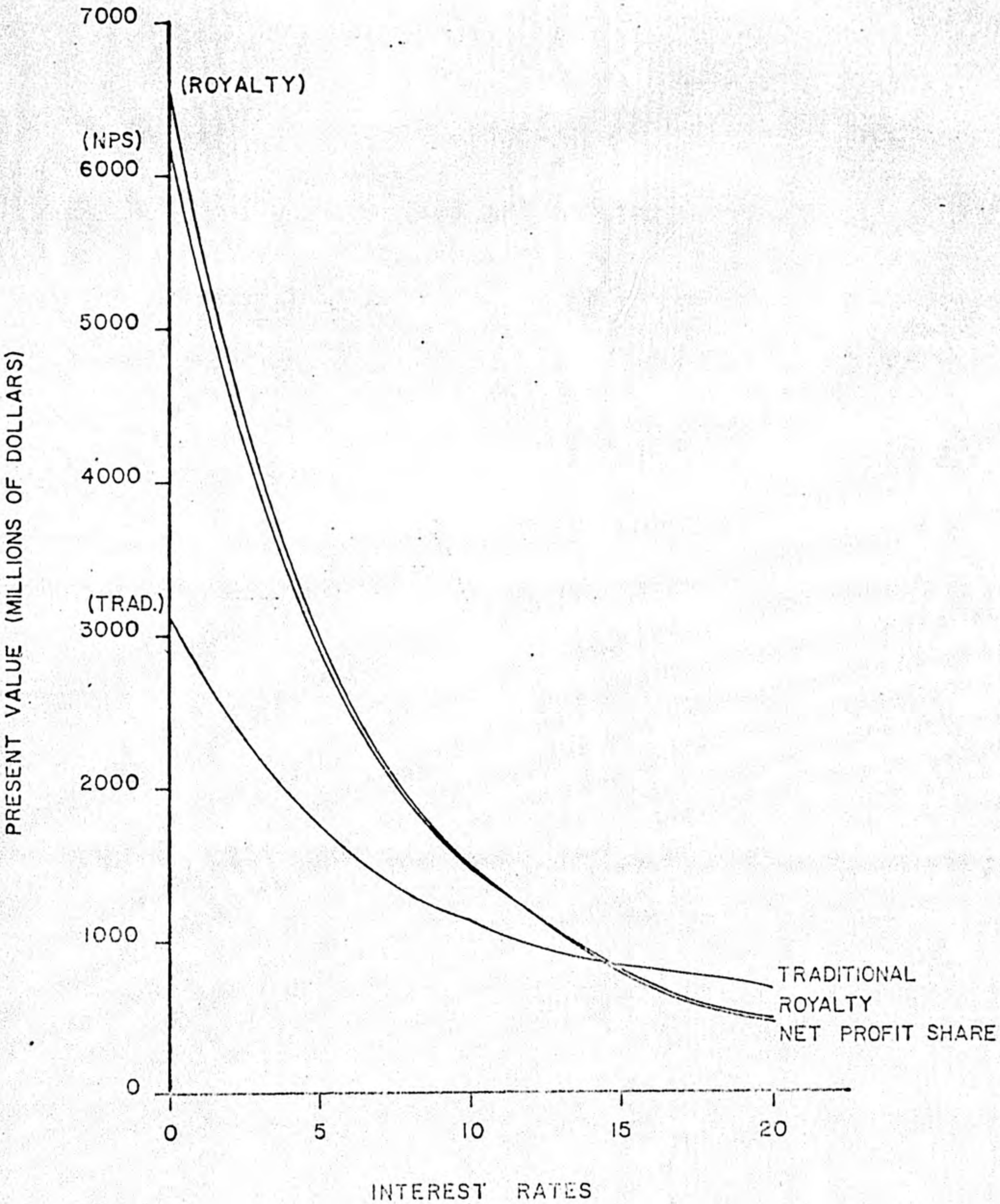
FIELD SIZE 750 MM
PROBABILITY OF SUCCESS: 50%

Interest Rates: (Real)	Traditional	Royalty	NPS
0	$3,138.91	$6,199.78	$6,536.64
5	1,725.60	2,898.16	2,990.24
10	1,115.60	1,470.32	1,480.00
15	833.82	807.90	793.07
20	696.32	482.18	463.13

Firms assumed to earn 12% ROR

ROUGH DRAFT

PRESENT VALUE OF INCOME RECEIVED BY THE STATE
AT VARIOUS REAL INTEREST RATES (10^6)
750 MM FIELD 50% CHANCE OF SUCCESS



FIRMS ASSUMED TO EARN 12% RATE OF RETURN

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TABLE XIV

PRESENT VALUE OF INCOME RECEIVED BY STATE
AT VARIOUS REAL RATES OF INTEREST (10^6)

FIELD SIZE 750 MM
PROBABILITY OF SUCCESS: 50%

Interest Rates: (Real)	Traditional	Royalty	NPS
0	$2,879.80	$5,717.00	$6,160.46
5	1,457.63	2,646.90	2,793.19
10	843.10	1,319.03	1,358.28
15	558.62	702.91	705.04
20	419.33	399.91	309.93

Firms assumed to earn 16% ROR

ROUGH DRAFT

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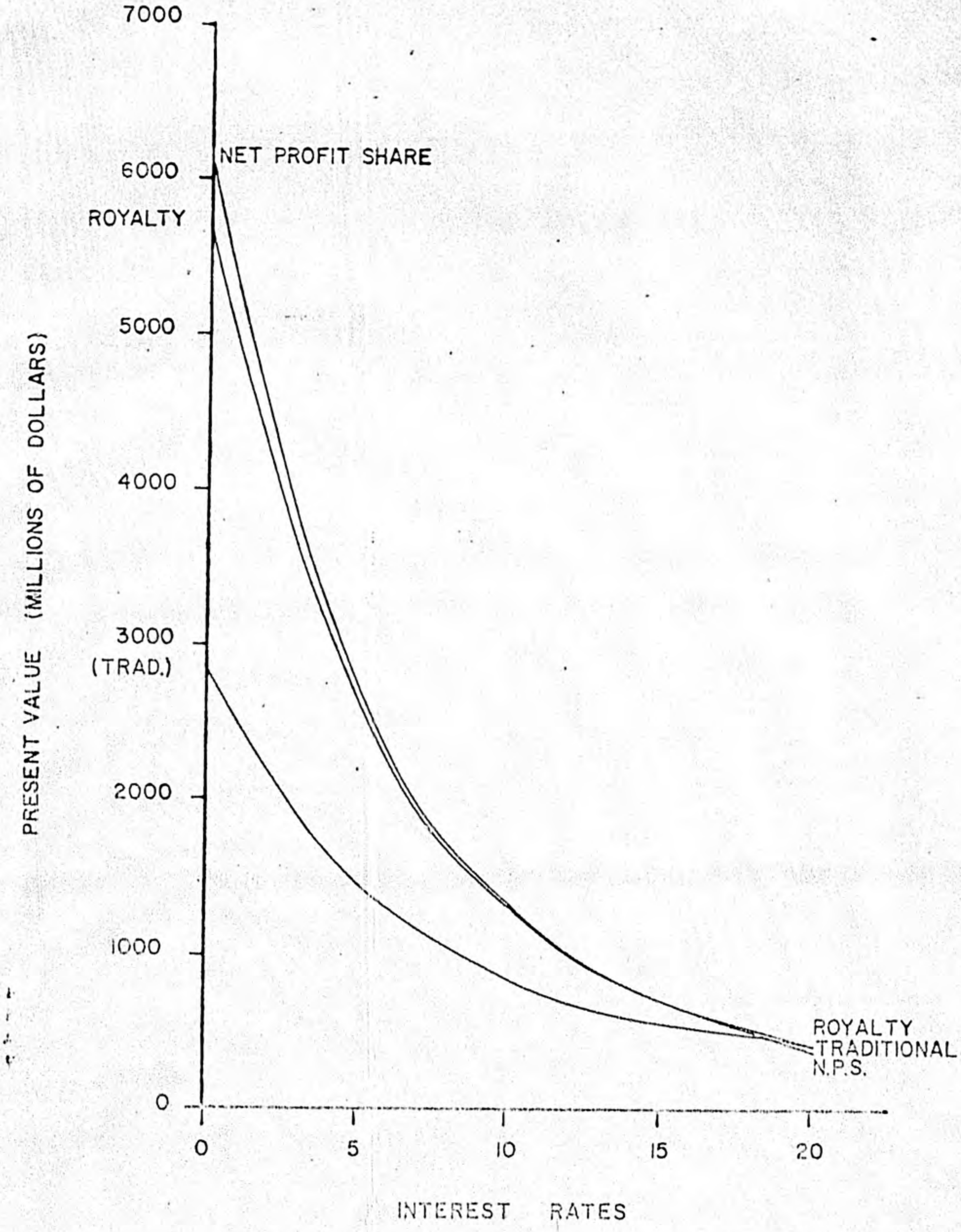
PRESENT VALUE OF INCOME RECEIVED BY THE STATE
AT VARIOUS REAL INTEREST RATES (10^6)
750 MM FIELD 50% CHANCE OF SUCCESS



FIRMS ASSUMED TO EARN 16% RATE OF RETURN

AGO 667581

STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

MINERALS AND ENERGY MANAGEMENT

JAY S. HAMMOND, GOVERNOR

703 W. NORTHERN LIGHTS BLVD.
ANCHORAGE, ALASKA 99503

July 23, 1979

Rep. Joe McKinnon, Chairman
Interim Committee on Oil & Gas Leasing Policy
Alaska House of Representatives
727 N Street, Suite 2
Anchorage, AK 99501

Dear Rep. McKinnon:

In a letter of July 12 from Bob Williams of your staff, you asked for clarification regarding the state's position on certain matters related to the Beaufort Sea lease sale.

The state is not now committed, nor will it be on August 1, to the selection of a particular bidding system for leasing the disputed acreage. At the request of the Department of Natural Resources and the state members of the Task Force, the federal government has agreed not to include the selection of a bidding system for disputed/federal acreage in the Proposed Notice of Sale, which is scheduled for publication August 16. However, the selection of a bidding system for the disputed acreage must be made no later than late October. The earlier the bidding systems are determined, the better.

The department's pre-sale economic analysis of the bidding systems currently authorized by state law should be completed by mid-August. We will not make a commitment to a bidding system for the disputed acreage until this analysis is complete. It is our intention to make the substance of the pre-sale analysis public after it is completed and reviewed by the Commissioner and the Governor. However, certain specifics of the methodology for determining bid acceptance/rejection must be held on a confidential basis. The analysis will demonstrate why a particular system or systems may be better than other alternatives.

The state is not committed, at this time, to using the same bidding system on each structure. There are many valid reasons why the state and federal governments should consider using the same bidding system on structures or prospects which overlap state, federal or disputed acreage. For such reasons, the Task Force may formally recommend that identifiable structures (or prospects) be leased under a common system.

The differences between the state and federal procedures regarding post-sale bid acceptance or rejection have not yet been resolved, but the Task Force will draft criteria and guidelines for the acceptance or rejection of bids on disputed tracts. This joint recommendation to the Governor and the Secretary will be presented as a Task Force recommendation during the week of August 6. This recommendation will be confidential, since it must not be made known to prospective bidders.

Task Force members from the USGS and DMEM have been negotiating with oil industry representatives for some time in an effort to work out a way in which confidential well data (presently in the possession of the state) can be made available to the USGS. We are optimistic that such well data will be made available to the USGS when we have worked out an agreement which safeguards the proprietary nature of the data. Several companies have agreed in principle to release the well data to the USGS. Seismic data in the custody of DMEM and USGS are being shared presently; the exchange of the seismic data is subject to the conditions of several letters of agreement which have previously been made available to the Legislature.

I have enclosed for your information a timetable of the remaining administrative tasks to be accomplished before the December sale date target.

You also inquired regarding the scheduling of future Task Force meetings. Such meetings are held as needed, often on very short notice. Presently, the Task Force has scheduled a meeting for Wednesday, 9:00 a.m. at the OCS office. This meeting is for the purpose of discussing the draft stipulations and mitigating measures. No other meetings have been set at this time.

I will be happy to discuss these points in more detail, as well as any other matters about which you may have questions, at the informal briefing now scheduled for Thursday, July 26.

Sincerely,

Thomas Cook

Thomas Cook
Director

Enclosure
cc: Robert E. LeResche, Commissioner
Jeff Haynes, Deputy Commissioner
Jeff Lowenfels, Assistant Attorney General
John Miller, Petroleum Manager, DMEM

BEAUFORT SEA SALE TASKS	COMPLETION DATE	RESPONSIBILITY
Select a net profits bidding system.	7/18/79	DMEM/DNR
Environmental Impact Statement (EIS) circulated for agency review.	7/18/79	Task Force
29/74 meeting on environmental stipulations in Washington, D.C.	7/18/79	DOI/DOE
Complete recommendations for Secretarial Issues Document (SID).	7/27/79	Task Force
Complete final drafts of regulations on net profits, sliding royalty and royalty bidding, work commitments and exploration incentive credit.	7/31/79	DMEM/Law/DNR
Complete testing of economic models.	7/31/79	DMEM/USGS
Give notice of regulations on net profits, sliding royalty and royalty bidding, work commitments and exploration incentive credit.	8/1/79	DMEM/Law/DNR
Send "Proposed Notice of Sale" on disputed/federal lands to Washington, D.C., for review.	8/1/79	Task Force
EIS to printer.	8/2/79	Task Force
Send final SID to Washington for review.	8/6/79	Task Force
EIS released.	8/10/79	Task Force

Interim Legal Agreement completed.	8/13/79	Task Force/Law/DMEM/DNR
Interior Secretary approves Proposed Sale Notice.	8/13/79	Interior Secretary
Second Notice of regulations on net profits, sliding royalty and royalty bidding, work commitments and exploration incentive credit.	8/15/79	DMEM/Law
Proposed Notice of Sale published for disputed and federal lands.	8/16/79	DOI
Economic pre-sale analysis of bidding alternatives completed.	8/16/79	DMEM
Complete revisions of lease document.	8/27/79	DMEM/Law
Complete geologic model.	8/31/79	USGS
Hearing on net profits, sliding royalty and royalty bidding, work commitments and exploration incentive credit regulations.	9/4-7/79	DMEM
Hearing record on regulations closes.	9/19/79	DMEM
Regulations to Lieutenant Governor.	10/5/79	DMEM/Law
State Notice of Sale under AS 38.05.305 (traditional uses).	10/1/79	DMEM/Law/DNR
State Notice of Sale under AS 38.05.345 (general notice).	10/16 - 11/7	DMEM/Law/DNR
Regulations effective.	11/5/79	
Final Notice of Sale (joint state and federal).	11/9/79	DNR/DOI
Sale.	12/11/79	

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