HB

207

(File 2)

CITY OF KENAI

" Oil Capital of Alaska "

210 FIDALGO AVE., SUITE 200 KENAI, ALASKA 99611-7794
TELEPHONE 907-283-7535
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May 4, 1995

Senator Loren Leman
State of Alaska
Capitol Building, Room 113
Juneau, AK 99801-1182

RE: *MODIFICATION OF OIL AND GAS ROYALTY RATES*
HOUSE BILL 207

At their regular meeting of May 3, 1995, the Kenai City Council discussed the above-referenced bill and its merits. The Council feels strongly that this bill will give the Commissioner of Natural Resources greater authority to modify oil and gas royalty rates to help open up marginal oil fields to development.

HB 207, as passed by the House of Representatives by a significant margin, provides the flexibility in setting royalty terms for marginal fields. This flexibility will encourage the State and the industry to work together to change the economic equation for marginal fields, bring on new fields, extend the life of existing fields and build a stronger economic base for the future.

The Kenai City Council fully supports HB 207 (as passed by the House) as it is a tool which the State can use to enhance competitiveness of projects in the world market, attracting investments necessary to develop its oil and gas potential. Alaska will benefit from new jobs, long-term revenues and increased economic activity associated with the development of new fields.

This bill, as passed by the House of Representatives, should not be significantly amended or substituted as suggested by the Senate Resources Committee and needs to be passed this year.

CITY OF KENAI

John J. Williams
Mayor

JJW/clf

KENAI PENINSULA BOROUGH
144 N. BINKLEY • SOLDOTNA, ALASKA 99669
PHONE (907) 262-4441

DON GILMAN
MAYOR

Ltr prepared (updated)

May 3, 1995

The Honorable Loren Leman
Senate Resources Chair
State of Alaska Senate
Capital Building
Juneau, AK 99801-1182

Dear Senator Leman:

The Kenai Peninsula Borough Assembly supports the concept of oil and gas royalty adjustments as embodied in HB 207.

It is our understanding the bill would give the Commissioner of Natural Resources greater authority to modify oil and gas royalty rates to help open up marginal oil fields to development. Further, that it would provide the necessary flexibility in setting the royalty terms for marginal field and encourage the state and industry to work together to change the economic equation for the marginal fields.

The Kenai Peninsula Borough depends in large part on the economic viability of the oil industry and to that extent we would strongly encourage the development of a long-term stable financial plan which would include the royalty oil issue.

Sincerely,

Andrew P. Scalzi /kf

Andrew P. Scalzi, President
Kenai Peninsula Borough Assembly

cc: Senate Resources Committee: Senators Pearce, Frank, Halford, Taylor, Lincoln, Hoffman
Senators Torgerson and Salo

FORUM / LETTERS

Debate for royalty relief centers on empty rhetoric

By RICHARD A. FINEBERG

ESTER — Lost in the wrangling over the current state budget is this important fact about the state's spring revenue forecast: Between the current year and 2010, the state now estimates the North Slope will produce 740 million barrels of oil more than it forecasted six months ago.

This 10 percent increase in future production equates to one added year of oil pumped at the peak TAPS throughput of 2 million barrels per day. This forecast increase was accomplished without the aid of the royalty relief measure the governor and a few oil companies are pushing.

This added production is the latest in a trend that has been operating steadily for a decade. Look back to the state's spring 1985 forecast. Then, oil prices were in the high $20s and the state's forecasters thought North Slope production would fall below 1 million barrels per day in 1994. Although oil prices soon plummeted and stayed relatively low, the North Slope in 1994 was in fact producing 1.6 million barrels per day and the forecasters said we wouldn't drop below 1 million until 2003. Six months later, that landmark has moved back to 2006.

If increased production (i.e., slowed production decline) is an established fact, why all the hurry to enact new royalty relief?

The answer is simple: If the state wants to make it easier to give away your money and mine, what corporate official would turn it down?

The debate over whether the public should forego its ownership share of oil production on behalf of private developers is characterized by a curious absence of facts. When the oil industry fought the closing of a tax loophole known as the ELF (economic limit factor) in 1989, Juneau was flooded with detailed and sometimes conflicting spreadsheets as legislators struggled to apprehend the significance of the proposal to end the tax break for large fields.

That year, the industry's arguments collapsed late in the session when a tough-minded Senate Finance Committee called for an explanation of the conflicting numbers. The industry was revealed to be stretching the truth beyond the limits of recognition; the legislature voted to close the loophole. Despite dire predictions in 1989 that future production would suffer if the bill passed, subsequent forecasts and production records consistently have reflected increases in total North Slope production.

This time, the industry is not putting any numbers on the board for review. Instead, the debate in Juneau is couched entirely in rhetoric. And that rhetoric is empty, as the recent forecast indicates.

Even more surprising is the administration's willingness to destroy current procedures that require the industry to make its case for royalty relief public. Some observers of oil and gas policy contend that the public always loses when the industry is allowed to make and keep its arguments behind closed doors. That's precisely what the administration's proposals would do.

Opponents of the current proposal do not say that royalty relief will never be necessary. Rather, they argue that before the stewards of the public's resource give up a portion of our ownership share of production, the industry should be required to make a substantive showing that should be reviewed carefully, and insofar as possible, in the open.

The clear trend established by the state's forecasts demonstrates that world supply and demand and technological improvements successfully are stoking the North Slope's fires without new procedures that would jettison the existing, carefully crafted and effective public safeguards. Since 1985, the state's forecasted and actual production from the North Slope for the 1986-2010 period has increased more than 6.2 billion barrels. This increase equates to the annual addition of one year more of production at current levels than forecasted each preceding year.

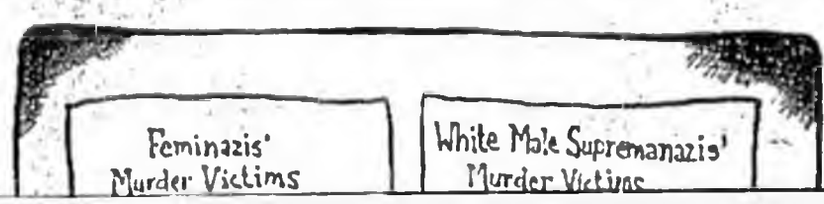
If this issue must be argued with oversimplified generalities, the following maxims must be kept in mind:

1. Those who don't learn from history are doomed to repeat it.
2. Money talks.

Richard A. Fineberg has looked at North Slope economic and environmental issues as a reporter, public official and consultant for nearly 20 years. He lives in Ester.

Let's make our roads safe

If ever there has been an incident-driven example in the argument in favor of capital punishment, the story about the eight-time drunken driver April 15 warrants an award in public awareness education.



crime. I think I have an old solution. I suggest stocks in combination with a park bench. History tells us insects were annoying but taunting crowds were devastating. So few would come forward to give the prisoner some stale bread or a

HB27

THE SEAL OF THE STATE OF ALASKA

Official Business

COMMITTEE: SENATE RESOURCES

DATE: 5/1/95

SIGN-IN

Subject of meeting: HB 207 Adjustments to Oil and Gas Royalties

PLEASE PRINT!

NAME	ADDRESS (MAILING) & (ZIP)	PHONE	REPRESENTING	DO YOU WANT TO TESTIFY?
✓ Michael O'Connor	7141 Montagne Anch AK	561-3200 337-6536	Peak Oilfield Ser. Co	Yes
✓ Keith Burke	4220 B St. Suite 200 Anch. AK	563-2226	The Alliance	Yes
✓ Joe B. Mathis	1001 E. Benson Anch 99508	265-4147 345-5764	NANA Develop. Corp	Yes
Carl Marrs	2525 'C' St Suite 500 Anc 99509	344-5077 274-8678	CIRI	YES
General Manager, Oilfield Operations				

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Date 5-2	# of pages ▶ 1
To [illegible]	From [illegible]
Co./Dept ADN	Co Senate [illegible]
Phone #	Phone # 465-4967
Fax # 258-[illegible]	Fax #

ARCO Alaska, Inc.
Testimony for Senate Resources
05/01/95
RE: HB207

Mr. Chairman, for the record, my name is George Findling. I am the Manager of Government Relations for ARCO Alaska, Inc. I am here to testify in support of HB - 207, Version J, which passed the House, and in opposition to the working draft Version B, dated 4/29/95.

The overarching issue here is Alaska's response to the world wide competition for oil investment. Alaska's leaders have told us that it is in the State's best interest to compete successfully for more capital. We have been very busy responding to requests from the State on ways to do this. We see a simple, three step strategy.

The first step is to quickly signal to investors that the State has the desire and the ability to change. If passed, this is what Version J would do. The second step is to harvest the major opportunities to increase industry investment. This should be an early outcome of the Oil and Gas policy council. The third step is to implement a long term process that would give the State the flexibility to have a competitive position, even if world-wide competition or market conditions change rapidly.

Alaska is facing 1990's competition using statutes drafted in the 1970's. Back then, little competition for investment existed, since oil was perceived to be running out and prices were expected to always go up. But now, competition for investment is worldwide and fierce and the indicators show that Alaska is losing. Alaska production is down, and many major oil companies have withdrawn from the state.

When we saw Version S on Friday we felt very disappointed, because it meant that important state leaders appear to be questioning whether even the most modest first step should be taken to increase Alaska's competitiveness. Although a slight improvement, Version B would still water down the effectiveness of the bill. It introduces new concepts that have received little public discussion. In fact, we find this version to be less helpful than current law and can not support its passage.

Let me mention a few examples of the shortfalls of this working draft by comparing it to what Alaska's competitors are doing. Internationally, greater descretion is being given to oil ministers to make arrangements that will attract investment. In the working draft, the focus on legislative approval would work in the opposite direction. Even more confusing, is the criteria for legislative oversight. By definition royalty adjustments can only be given if the new field would not otherwise be produced: in other words, it seems that there could never be a royalty reduction, if the base case is zero royalty dollars.

Internationally, greater certainty is being given that investors can count on getting the benefits enumerated in the law. Under the working draft, the added procedures and limitations would be so bureautic and onerous that it is unlikely that anyone would apply under these conditions. Finally, oil provinces are making agreements that share risk but give reasonable certainty. They establish prospectively, a method that retains a higher share when economic conditions are good and a reduced share when they are not. The wording on page 3, which apparently gives the Commissioner the ability to reopen this agreement is a fatal flaw.

We support the House Version J, not because it's a "giveaway" to the industry, but because it withstands comparisons to other oil provinces. ARCO has no specific projects to propose today which will use HB-207 provisions. Yet with Version J's passage we would answer our Corporate decision makers, that Alaska has turned the corner and is truly vying in the international arena for capital. Each of us at ARCO wants the tools to get a larger share of capital for Alaska investments.

Version J enjoys many strengths. It is a modest, but real first step. It sets the stage for Alaska both to really begin a return to international competitiveness and to partner with its most important natural resource industry. It also has broad consensus because the bill merits that support.

Therefore, Mr. Chairman, we respectfully register, for the record, our opposition to working draft version B and our support of the House Passed Version J originally referred to your committee.

Anchorage,
Alaska

George R. Findling
Phone 263-4174

5/1/95

Senator Loren Leman

Re: 5/1/95 Resources Hearing: HB-207

I was unable to remain at the Anchorage LIO for your hearing. Please add the attached testimony from ARCO to the record.

Thankyou

George
cc

Testimony

by

Eric M. Luttrell

for

BP Exploration (Alaska) Inc.

to the Senate Resources Committee

May 1, 1995

Mr. Chairman, Members of the Committee, good afternoon. My name is Eric Luttrell, and I am Vice President of Exploration and New Developments for BP Exploration (Alaska) Inc. Thank you for this opportunity to testify to the Committee today on behalf of BP.

I have come here today to testify on legislation that would encourage the development of marginal fields, fields like Badami and Northstar, fields of moderate size away from existing infrastructure. Many of these prospects would not have been considered for development only a few years ago. Because the development of these fields within BP is directly under my control, I have taken a special interest in this legislation.

In particular, I would like to talk to you about the version of this bill that passed the House and the differences between that version and the draft Senate Resources Committee Substitute that we received Sunday evening. We have a number of concerns with the proposed language of the Senate bill, but I only want to address a few of the main ones here today.

Let me begin by briefly reviewing the context for this legislation. In looking at our business in Alaska and our opportunities to develop the business and make it grow, we in BPX Alaska see a number of situations in which the State's present royalty terms may impair our ability to compete within the BP Group for the capital funds to make the investments needed to keep our business sound and healthy for the future. Although BP is a large corporation, it still has only a finite amount of money available each year for capital investments worldwide. Naturally, in allocating these capital funds, priority is given to those investments that are most attractive. So if BP's capital funds are all allocated to more attractive investment opportunities elsewhere before we get down to our Alaskan projects, then the Alaskan projects simply don't get funded even though they may still be quite attractive and feasible economically on their own terms.

This is a fact of life for us, and in this, BP is no different from any of the other oil companies still active in Alaska. The state and those of us who work for BP in Alaska are engaged in a global competition for investment dollars. It is, of course, of great personal concern to those of us working here, because in large part our jobs here are on the line if we don't compete successfully. It is also of concern to us as Alaskans, because the continued oil and gas development of this state is essential for its future economic well-being. So it is extremely important that whatever "economic feasibility" test that is applied to an application for royalty adjustment recognize this global competition.

We have repeatedly stated that we believe this type of legislation is important for two reasons. First, it helps us to successfully compete for investment funds for Alaska. Second, it allows the State to share the risk of low oil prices and to share in the benefits of higher oil prices with us. In fact, the State of Alaska could under a sliding scale royalty scheme based on oil prices receive higher royalty revenue than under the current structure. This is an important point to remember by sharing the low price risk, the State gains increased revenues at higher prices.

There may be some confusion over how a sliding scale royalty mechanism may operate. The royalty rate would be determined by the price of crude oil. For instance, at a $16 crude oil price (the approximate current State forecast), the royalty rate could be 12.5%, which is the current royalty rate. If, for example, the price of oil increased to $18, the royalty rate could increase, say to 15%. On the other hand, if the price of crude oil drops to $12 a barrel, the rate could drop to 10%. This mechanism would allow the royalty rate to follow oil price. The higher the price, the higher the rate - The lower the price, the lower the rate.

The House-passed version of HB 207 would give the commissioner of Natural Resources clear authority to modify the terms of the State's oil and gas royalties in a variety of ways in order to facilitate and encourage the new investments that need to be made in order to bring marginal new fields into production and to sustain production from existing fields that are in decline. At the same time, it contains safeguards to protect the State's best interests. By protecting those interests while allowing our Alaskan opportunities to be made more competitive against the opportunities elsewhere, the House version embodies a win-win approach for the State and its oil industry. It is a good bill, and BP fully supports it.

Unfortunately, the same cannot be said of the draft Senate Resources Committee Substitute for the bill. It is badly flawed, and seriously out of touch with the realities of a mature oil industry in Alaska.

Problem number one is the requirement that any royalty adjustment be ratified by the legislature. This, combined with the extensive findings that the Commissioner must make, is an invitation for long delays in final approval and litigation. It is entirely possible that it would be six months to a year before an applicant would know whether a project would have a revised royalty arrangement. This process will also compromise any ability to keep sensitive proprietary information confidential. All of this adds up to additional uncertainty. We recognize the importance of appropriate oversight, but we need to devise something that would not unduly burden the State's and industry's ability to get

these marginal projects developed. We think the oversight provisions in the house version of HB 207 would be effective.

There is another point that is relevant to the whole question of oversight of the Commissioner's decisions, and that comes in the form of a question: What incentive does BP have to make a deal that is not in the best interest of the State? We will be doing business in Alaska for a long time. Since the nature of the deal will be examined many times after it is made, any undue advantage that we may have gained will become readily apparent. We would fully expect the State to try to recover that advantage in some other way, e.g. increased taxation. In short, it is not in BP's, or any other company's long term interest to make a deal that is bad for the State.

My second major concern is that of encouraging development of new pools within existing fields. Here again, the Senate version could have the effect of discouraging investment and development by carefully removing the words "pool, or portion of a field or pool" everywhere they occur in the House version, leaving only references to "field."

This reflects a fundamental misunderstanding about how investment decisions are made. Fields are not economic monoliths, nor do we view them that way. Each new investment in a field has to be justified at the margin, on its own merits. The profitability (or economic failure, for that matter) of prior investments in a field has no bearing on the decision to make the new investment or not. The plain truth is that there are investment opportunities that are truly marginal in all fields. In terms of competing for limited capital funds, it is just as important to recognize this fact for opportunities in large fields as it is to recognize it in the context of little fields.

A third problem is we do not understand what the State gains by providing that all of the provisions of this bill terminate at the end of March 15, 1999. As a practical matter, if future legislatures and administrations believe that this bill is not in the best interest of the State, it will be repealed. In this sense, the bill and all of the royalty adjustments that are made under its authority will be constantly under review. Nevertheless, if the Committee would be more comfortable with a sunset provision, it should allow a reasonable period for this set of proposals to work. We believe this is a minimum of five years.

What is at stake in the near term? We believe that effective legislation can have a big impact on our decision to develop Badami, and on our decision to develop Northstar. We expect that both of these decisions could be made in 1995 and lead to significant production and revenue by 1998.

Badami: I will tell you candidly, I don't know whether we would request royalty adjustment for Badami. That request awaits complete review of our drilling results and the engineering cost estimates. I can tell you that we have a group of experts working diligently on both issues to get us answers to these questions by mid-summer. Then we will run the economic analyses and take a decision to make a request to DNR, if we believe the field is developable but marginally economic under low price conditions. And if enabling legislation passes this year.

That is a lot of ifs in a row, but that is the nature of our decision at this time. If we defer the decision to develop out of 1995, we, and the State will lose the opportunity to start production and revenues in 1997. We both loose; Production and Revenue... I fail to see how deferral is in the best interest of either of us.

Northstar: Simply stated, development of Northstar in the foreseeable future requires passage of legislation including net profit share adjustments as a part of the negotiation with the State. We had hoped that we would be talking with the Senate about extending the terms of the House bill to net profit share leases. Now, we are in doubt as to whether there will be a royalty adjustment bill that has any practical effect. This means that we are two steps away from any plan to develop this significant prospect. Pretty strong words, but I could not recommend to BPX proceeding with Northstar development without a change in the NPSL terms.

We have been very open with the DNR on our concerns about Northstar and have even proposed some possible agreements that would protect the interests of both the State and BP. But they require legislation. With legislation, we believe we would be negotiating with the State before year end. Delay of legislation or failure to include NPSL would defer the development of Northstar by 1-2 years and, because of that , delay production and revenue from Northstar by 1-2 years. I fail to see how that is in the best interest of the State.

Are there other marginal accumulations on the North Slope that could be developed in the near term? Absolutely. Will their development be encouraged by this legislation? I don't know, they are not mature enough for us to have a clear view of their economic value. I certainly do not expect that all will.

What is in it for the State of Alaska? The State of Alaska stands to benefit greatly from these developments, and from their timely development. At Badami, we project State revenues (using current State price forecasts) of upwards of $350 mm (royalty, severance, ad valorem, income taxes), plus jobs and the infusion of

several hundreds of millions of dollars of additional investment during development. Investment in, and revenues from Northstar are similar.

When we look beyond the specifics for Badami and Northstar, the proposed legislation has the potential of sending a strong message to the Industry, to Houston, to Los Angeles and to London, a message that Alaska wants to work cooperatively with Industry to encourage investment and new development; that Alaska wants to compete. Not passing legislation this year or passing the wrong legislation will send the opposite message. We believe that this bill is both necessary and beneficial to the state and to industry, but it must be in a useful format. The House version was carefully considered and would work. The Senate version would not work very well.

I have tried to be open, direct and candid with you here today, just as we would be with the State in a negotiation. Those of you who know me, know that it is my style and it is BP's style. Like it or not, the State and the industry have much to gain by improved openness and cooperation and we look forward to a long and mutually beneficial relationship.

Thank you for the opportunity to testify.

Testimony of
James F. Branch
On House Bill 207 and the Business and the Investment Climate in Alaska
Before the Senate Resources Committee
May 1, 1995

Mr. Chairman, members of the Committee, my name is Jim Branch. I am the Production Manager with responsibility for Exxon's interests here in Alaska. I appreciate the opportunity to follow-up on my comments of last Wednesday about the need to send a positive signal that our state is trying to improve the investment climate for the oil and gas industry.

We have supported efforts by the Administration and the legislature that attempt to provide clarity, predictability and a reasonable balance to the Commissioner of Natural Resources' existing authority to grant royalty relief. The Administration's original bill and the substitute reported out of the House had that intention. However, the current Senate Resources version appears to send a very negative signal to our industry.

The changes made to the final House bill are significant and numerous. Rather than go line by line through the bill, let me return to some principles for a well designed incentive, which I offered in my testimony of early February. An incentive is ineffective if an investor concludes it can be taken away over time, it has a hidden price tag, or creates an environment for future disputes. This version of the bill would do all of that. The suggestion of reopeners, sunset provisions, legislative review and repeated references to "value" and marketing of oil and gas are enough to discourage any serious investor These conditions send the opposite message to the one I hope you ultimately intend to communicate

Investors are keenly aware of the poor investment climate in this state, relative to other opportunities available to them, and are looking for indications that change is possible. The results of the debate on this bill and more importantly progress on fiscal reform, primarily through spending reductions, are measures by which we will be judged. Until spending is brought more in line with revenues, oil and gas investors will be wary of placing significant new funds in the state. Our industry already provides 85% of the state's funding, and there is a history of looking to us to fill revenue gaps. I applaud the leadership this legislature has demonstrated in beginning to address the fiscal situation.

Investors are prepared to assume the traditional risks associated with finding and developing oil and gas, but not those created by the state in the form of concerns over increased taxes or uncertainty over an incentive granted under this version of HB 207. With their versions of this bill, the Governor and House demonstrated their intention to attempt to provide clarity, predictability, and reasonable balance to the DNR Commissioner's current authority to revise royalty. I urge you to join this effort.

Senator Loren Leman, Chairman
Senate Resources Committee
State Capitol
Juneau, Alaska 99801

May 1, 1995

Dear Senator Leman:

While I am not able to be present at the Senate Resources Committee hearing on House Bill 207 today, I would like to offer this letter to the Committee on behalf of Lynden, Inc. Lynden is vitally interested in the outcome of House Bill 207 because of the extensive amount of our work that is directly related to oil and gas development through Lynden Transport, Alaska West Express/Frontier, Lynden Air Freight, and Lynden Logistics.

Lynden supports the final passage of House Bill 207 this session. We are pleased that the House passed a reasonable bill after extensive public testimony. Even though it is now relatively late in the session, we urge you to adopt the same or very similar bill as arrived in the Senate.

We have reviewed the proposed Senate CS for CS for HB 207 (Res.) and feel that some of the changes will defeat the purposes for which the bill was introduced. In particular, we believe that the decision to adjust a royalty should be made by the Administration - be it Republican, Democrat, or Independent. Legislative approval or review will delay a decision and drag it into the political arena.

Also, the suggested sunset and termination provisions are neither necessary, nor do they send the "signals" to the oil industry that we thought both members of the legislature and the Governor promoted during their recent election campaigns.

Last, because the royalty adjustments may already go both up and down in the House Bill, it is unreasonable to require the State to maintain the power to unilaterally change the terms of the royalty adjustment during the development of the field.

We have watched with dismay and downsized with the oil industry during the past several years of relative polarization between the State and our biggest industry partners. We hope to see a new, more positive attitude. Passage of HB 207 would offer the first concrete steps in this new relationship.

Sincerely,

Dave Haugen

Dave Haugen, Vice President
Lynden, Inc.

Peak
Oilfield Service Co.

FAX

DATE:	05/02/95	
COVER PLUS	2	PAGE(S) TO FOLLOW
TO (COMPANY):		
ATTENTION:	SENATOR LOREN LEMAN	
FAX NO. :	465-3810	
FROM:	M.R. O'CONNOR	
OPERATOR:	SONDRA	PHONE: (907)561-3200

OUR FAX NUMBER: (907) 562-5860

Dear Senator Leman:

The following commentary was prepared for the Senate Resources Committee meeting on HB207 scheduled for May 1, 1995 at 3:30 p.m.

Because of Senate delays, I was unable to stay in Juneau to deliver this testimony. I wanted all members to be advised of my feelings towards HB 207.

Sincerely,

M. R. O'Connor

TESTIMONY
OF
MR. MIKE O'CONNOR

PRESIDENT AND CEO
PEAK OILFIELD SERVICES CORPORATION

TO THE

SENATE RESOURCES COMMITTEE

ON

HB207

JUNEAU, ALASKA

MAY 1, 1995

Mr. Chairman, members of the Committee, for the record my name is Mike O'Connor, President and CEO of Peak Oilfield Services Corporation. We're an Alaskan corporation, employing over 600 employees with offices in Prudhoe Bay, Anchorage, Kenai and Valdez.

I am appearing before you today in support of the royalty reduction bill that was introduced by the Governor and passed overwhelmingly by the House. This legislation will have a demonstrative impact on the future of our company and our employees. Without it, I see a significant loss of revenue and subsequent job losses. Bottom line-I'm here to promote and protect the working class Alaskans who would rather have employment than unemployment.

Quite frankly, I'm somewhat confused and disheartened with the previous version and latest drafts prepared by the Senate Resource Committee. While I understand and certainly respect this committee's prerogative in issuing a new draft, I do not understand the need or motivation for such sweeping changes ~~about~~ without public comment

As I am sure you are aware, the House had a considerable number of hearings and worked diligently in developing a draft that was embraced by the administration, the oil companies and its service contractors, as evidenced by the 35-2 vote in the House. I would strongly urge you to reflect on their deliberations and attempt to draft your version as similar to the House version as possible.

The purpose of this legislation was to encourage additional investment for the benefit of all Alaskans. It is imperative that Alaska be perceived globally as a fair and competitive environment in which to invest. The Senate Resources Committee version stops short of achieving this goal. You've already heard from several folks about deficiencies in the draft before us today.

One specific concern that I would like to add in Section 2, paragraph B (Page 2, line 19). My comment is simple: Industry needs to project a reasonable rate of return. The proposed language in this section requires that a loss be projected prior to application. This does not and will not create the perception that Alaska is a good place to invest.

I'm also concerned about the legislative oversight requirements. The potential delays could result in the entire loss of a construction season. Remember, time is money.

I recently read that the Senate is contemplating adjourning early and find it incomprehensible that this issue not be faced head-on by the Senate floor. I urge all pro-business, pro-development, pro-Alaskan Senate representatives to study and understand this legislation.

In closing, I would like to thank you for this opportunity to testify and again encourage you to reflect on the language passed by the House of Representatives.

★ 1975 *Serving Alaska for 20 years* 1995 ★

Resource Development Council for Alaska, Inc.

121 West Fireweed Lane, Suite 250, Anchorage, Alaska 99503-2035
Phone 907/276-0700 Fax 276-3887

Post-it™ brand fax transmittal memo 7671 | # of pages > 2

To Sen. Kerttula	From Carl Portman	Phone # 276-0700	Fax # 276-3887
Co.	Co. RDC		
Dept.			
Fax # 465-3810			

Testimony of Resource Development Council
on CS HB 207
An Act relating to the reduction of royalties reserved to the state to encourage production of oil and gas from marginal fields
Senate Resources Committee
May 1, 1995

Good afternoon. My name is Carl Portman, Communications Director of the Resource Development Council for Alaska, Inc. On behalf of RDC, thank you for the opportunity to testify on CS for HB 207.

RDC strongly supports HB 207, as passed by the House. The House version of this legislation provides the flexibility needed for the State and industry to work together to change the economic equation for marginal fields. It provides flexibility for working with investors on a case-by-case basis to overcome Alaska's unique challenges and make new development and production a reality. Alaskans will benefit from new jobs, long-term revenues and increased economic activity associated with the development of new fields.

HB 207 is a tool the State can use to enhance the competitiveness of projects whose funding might otherwise go abroad. It sends a clear signal that Alaska aims to be competitive in the world market to attract the investments necessary to develop its oil and gas potential.

The Committee Substitute, however, risks undermining the original purpose of the initiative. It opens the door to potential delays and more uncertainty. Its complexity sends a negative signal and it may, in the end, have no practical effect.

RDC does not believe the latest CS fixes the problems expressed last week with the initial Senate draft. The March 1999 deadline for royalty adjustments on new fields still puts us back to square one as far as future discoveries are concerned. It may be a partial fix for marginal fields that are ready to go forward in the near term, but it doesn't do anything for companies considering investments over the long term. Some of those companies may not even be operating in Alaska today, but are waiting for a clear signal before they invest in prospects that are beyond the short term.

RDC also takes exception to the requirement that a field's operating costs must exceed revenues before a royalty adjustment can be considered. How does a one or two percent rate of return compare with investment returns elsewhere? If Alaska is to be truly competitive, it must be willing to take the necessary steps to ensure that marginal fields here pay as well or better than investments that oil companies could make in other parts of the world.

Other issues of concern include the provisions for legislative oversight beyond what is called for in the House version and the basing of royalty adjustments upon the economic feasibility of production from an entire field as opposed to a pool or portion of the field or pool.

HB 207, as passed by the House, is a good piece of legislation which should not be changed significantly. It protects the State's best interests if a marginal field turns out to be more profitable than anticipated.

RDC believes the House version will send a clearer signal to investors and will do more to strengthen Alaska's competitive position. We believe it is a stronger and more effective royalty adjustment bill.

Thank you.

Union Oil Company of California
Testimony on CS HB 207
Senate Resources Committee
May 1, 1995

Mr. Chairman and members of the Resources Committee--My name is Kevin A. Tabler, Land Manager for Union Oil Company of California (Unocal) in Alaska. I appreciate this opportunity to be heard today and to present Unocal's comments on CSHB 207. I would like to begin my testimony by saying that the Sectional Analysis provided with the Bill is particularly helpful in making a more informed analysis of the Bill. Some of the concerns I expressed in last Wednesday's Hearing have been clarified by the Analysis and therefore the enclosed testimony more accurately reflects Unocal's view and opinion of the Bill today.

Subsection (j)(1)

From purely a Unocal perspective, based on its present acreage position, Unocal is not directly impacted by paragraph (A). Most of the Unocal leases held today are located within producing fields, some of which are nearing the end of their economic viability. We have however, testified in earlier hearings on this Bill that we have not endorsed the concept of Sunset Provisions.

Subsection (j)(4)

We believe the requirement for legislative approval under paragraph (A) will be a time consuming and unnecessary requirement resulting in an administratively burdensome process. Under the House Finance version of the Bill, adequate Commissioner oversight is provided under Subsection (j)(6).

In reading the provisions of paragraph (B) of this Subsection, it is unclear to me as to the intent of the language "in amount or value of the Production". If this is to mean a net 3% floor or a maximum 76% reduction of the current royalty rate, then Unocal is opposed to this revision. Under the House Finance version of the Bill, the floor established for producing and shut-in fields is 90%. There needs to be clarification on this point. Any increase in the floor reducing flexibility would be inconsistent with our position and prior testimony.

Subsection (j)(5)

Although we appreciate the attempt in this CS to address the assignability question, we believe a strong argument still exists for elimination of this restriction all together. The assignment of all right, title and interest in a lease is a fundamental principle in the oil industry. Property trades will be greatly restricted if assignability of a royalty adjustment is not allowed. Because of the confidential nature of property transactions, companies are not going to disclose their intent to the public in asking for permission to assign until negotiations are complete and commitments have been made. Prior approval does not work in this situation. A negative response to a request for assignment could jeopardize

a potentially beneficial trade to the state. The ability and desire to acquire a lease that has favorable royalty terms may be the catalyst and incentive for a company to invest capital and employ new ideas in fields where the current owners may be less inclined. Companies are rationalizing properties and focusing investments in core areas to take advantage of their particular operational, infrastructure or informational strengths. Lost opportunity for additional development of a lease or field is sure to occur if this unecessary limitation is imposed. The intent of this legislation should be to create opportunity with certainty, not further limit the creativity of the industry. The state's best interest will not be served with this restriction.

Subsection (j)(7)

This issue of contractor selection was thoroughly discussed in prior hearings with what we thought was an equitable compromise and consensus opinion of the parties testifying. We see no advantage to changing this Subsection and would prefer tc see Subsection (6) of the House Finance version reinstated.

Subsection (j)(9)

Reviewing and addressing all the requirements under this Subsection will be very expensive, time consuming and may not bo applicable in all circumstances. We believe the Commissioner should have the discretion to provide for the contents of the best interests finding and determination. The Department of Natural Resources is well equipped for this process. The degree to which each of these conditions are to be investigated will be the subject of much debate. If the committee and legislature feel the need to include the details of the finding and determination in this Bill, then paragraphs (A) through (D) should only be suggestions of issues the Commissioner may consider not requirements in a royalty adjustment application.

Subsection (j)(12)

We have a similar comment in this Subsection as in Subsection (j)(4) in that legislative approval is unnecessary, time consuming and administratively burdensome. We contend that Subsection (j)(10) of the House Finance Bill is more appropriate and should replace this Subsection.

In conclusion, we want and need a Bill and process that is, clear ,fair, flexible and equitable, otherwise we will end up with a piece of legislation that is under utilized.

We look forward to working with the Legislature as this Bill progresses through the legislative process.

Thank You

Union Texas Petroleum

May 1, 1995

Union Texas Petroleum Alaska Corporation

1330 Post Oak Boulevard
P. O. Box 2120
Houston, Texas 77252-2120
Telephone: (713) 968-3500

Bruce S. Hamilton
Director, Business Development

VIA FAX

The Honorable Senator Loren Leman,
Chairman, Senate Resources Committee
Capitol Building
Juneau, AK 99811

RE: **SCS CSHB 207 (version B 4/29)**

Dear Senator Leman:

We thank you for being given the opportunity to comment on the Senate Resources Committee's draft substitute for CSHB 207. We reviewed the draft SCS CSHB 207 (version S) and SCS CSHB 207 (version B) which we received this morning. Our comments go toward the intent of the bill.

Union Texas Petroleum Alaska is an indirect wholly owned subsidiary of Union Texas Petroleum Holdings, Inc., one of the largest independent producers located in the United States. Union Texas explores for and produces oil and gas overseas, primarily in the U.K. North Sea, Indonesia and other strategic areas. Our 1995 exploration plans include exploration wells in Alaska, Argentina, Indonesia, Ireland, North Sea, Pakistan, Tunisia, and Vietnam.

During the past four years, Union Texas Petroleum Alaska has increased its exploration activity in Alaska which included participation in ten wells plus three sidetracks in the Colville River Delta area, one well in the Jones Island State Exploration Unit, three wells in the Kuvlum Federal Unit in the Beaufort Sea, and the Diamond #1 well in the Chukchi Sea. Additionally, in late 1993 Union Texas entered into a Kenai Peninsula exploration venture with Cook Inlet Region, Inc.

Internally, Alaska projects compete with international projects for funds. Union Texas has funded Alaska exploration based on its perception of an opportunity as the majors move to the former Soviet Union and on the expectation that the State will perceive and adjust to the world market. Currently, we are experiencing a willingness of countries throughout the world to reduce government take to be more competitive and to entice additional exploration and development risk capital investment within their provinces. With the passage of CSHB 207 by an overwhelming majority in the House, we were encouraged that Alaska was serious in its efforts to move toward competition in a world arena, and is beginning to provide incentives to further investment and exhibit the needed flexibility demanded of all competing oil and gas provinces.

Union Texas Petroleum Alaska supports CSHB 207 as passed by the House.
Union Texas Petroleum Alaska opposes SCS CSHB 207 (version B).

Our optimism with the introduction and overwhelming passage of CSHB 207 in the House was quickly dampened when we read the Senate Resource Committee's redrafts of CSHB 207 (version S) and recently (version B). Not only did both redrafts of CSHB 207 take away from a proposed bill that seemed to provide flexibility, certainty and timeliness, it introduced a sunset clause, legislative approval and many other limiting provisions which are clear, negative signals to Union Texas Petroleum Alaska. This version may negatively impact our long-term strategic exploration investment planning for this province when being measured against other world wide exploration areas.

Among other concerns with SCS CSHB 207 (version B) we offer the following:

- The deletion of the words "pool, or portion of a field or pool" everywhere they occur in the House version, leaving only references to "field", discourages development of new pools within existing fields and should be restored.
- The sunset provision should be deleted in its entirety.
- Legislative approval is unnecessary, burdensome and infuses needless uncertainty in a process that needs flexibility.
- The unconditional ability to assign rights is an absolute necessity.
- Clarify royalty may only be adjusted if agreed to by Lessor and Lessee.

In summary, Union Texas Petroleum Alaska Corporation believed CSHB 207 provided an alternative for companies who expend risk capital over long periods of time with no apparent opportunity for a return on investment. In our view, the major enticement of CSHB 207 for the State and to the investor company was to create a new revenue stream for both.

Very truly yours,

UNION TEXAS PETROLEUM ALASKA CORPORATION

BS Hamilton

Bruce S. Hamilton
Director, Worldwide Business Development

/mw

facsimiie
TRANSMITTAL

to:	Ms. Annette Kreitzer, Senate Resources Staff
fax #:	907-465-3810
re:	CS HB 207 (B)
date:	May 1, 1995
pages:	3, including cover sheet.

Dear Ms. Kreitzer:

Please forward the attached comments from Union Texas Petroleum Alaska Corporation concerning CS HB 207 (B) to Senator Leman.

Your assistance is appreciated.

Please call me at 713-968-2594 if you have any questions.

Union Texas Petroleum Alaska Corporation

Steven R. Fly

EXTRA copy attached.

From the desk of...

S. R. Fly
Manager Business Development
Union Texas Petroleum Alaska Corporation
1330 Post Oak Blvd.
Houston, TX 77056

713-968-2594
Fax 713-968-2593

Testimony of

Paul Wessells
Director of Tax

BP Exploration (Alaska) Inc.

to the

Senate Resources Committee

Juneau, Alaska
April 21, 1995

Good afternoon, Mr. Chairman my name is Paul Wessells, and I am Director of Tax for BP Exploration (Alaska) Inc. Thank you for the opportunity to testify on behalf of BP regarding HB 207.

BP supports HB 207 and encourages this Legislature to enact the bill this year. This bill represents a very positive step along the road to development of the State's marginal new oil fields and marginal projects within existing fields. It is our belief that initiatives such as HB 207 signal a new spirit of cooperation between the oil industry and state government, and it is a joint effort that will be required for the State to fully realize the value of its oil and gas resources.

In what manner does HB 207 promote full development of the State's resources? First, it clarifies the existing statute by specifying that new developments - that is, properties that have never produced oil and gas - may qualify for royalty reduction. Second, the bill provides that relief may be granted for individual leases, rather than solely as part of a unit application, and allows for adjustments with respect to individual pools of oil and gas within a lease.

The bill takes additional steps to protect the public interest by assuring that the Commissioner of Natural Resources will receive the financial and technical information necessary to allow a reasoned judgment on the merits of an application, and by requiring that the cost of third party professional assistance to the Commissioner in analyzing the application be borne by the applicant. In addition, the public interest is served by the provision in the bill that the State must condition a reduction in royalty on a readjustment at a later time if the circumstances which supported the grant of the reduction change.

It is this last aspect of the bill that makes it clear that it is not just about reducing the royalty obligations of producers in the absolute sense. Indeed, it is entirely possible that a royalty adjustment program negotiated by the State and a leaseholder will lead to greater royalty payments over the full life of a property.

BP also believes the bill should allow the Commissioner of Natural Resources to modify state net-profit share interests in the same way that it allows the Commissioner to adjust state royalties. Net-profit payments and royalty payments are similar forms of economic rent

that the State receives from leasing its lands for oil and gas exploration and development. We think giving the Commissioner flexibility to address the full economic picture when reviewing an application for adjustment is a good idea, and so it does not seem appropriate to us to give the Commissioner that flexibility with respect to one form of the economic rent and not the other. Just as the State may gain by modifications of the royalty obligation under a sliding scale royalty mechanism, so it should gain in similar circumstances by allowing appropriate modifications of a net-profits interest.

We in BP believe that HB 207 will make it possible for the State and the oil industry to devise, through open sharing of information and good faith negotiation, methods for sharing the risks of developing marginal properties. It is imperative that we capture the potential of these properties to assure a strong and stable industry and a strong and stable Alaskan economy.

Thank you for the opportunity to testify.

NANA DEVELOPMENT CORPORATION
1001 E. BENSON BOULEVARD, ANCHORAGE, ALASKA 99508
TELEPHONE (907) 265-4100

April 28, 1995

MAY 1 1995

Senator Loren Leman,
Resource Committee Chair
Alaska State Legislature
State Capitol (MS 3100)
Juneau, AK 99801-1182

Dear Senator Leman;

I want to express NANA Development Corporations support of the **original** HB 207. It is imperative that the State of Alaska and Industry work together in the development of marginal fields. As you know, NANA has been a supporter of not only mineral development but also has a small ownership in the Endicott Oilfield.

NANA has seen a severe economic impact on its oilfield subsidiaries. Due to the downturn in oilfield development, NANA was forced to sell it's drilling company Alaska United Drilling Inc. and closed down the oldest operating hotel at Prudhoe Bay, the "NANA Oilfield Hotel". The shut down of these businesses cost Alaska and NANA over 200 jobs in addition to several million dollars in losses.

We cannot survive if we continue to do business the old way. New thinking is needed. HB 207 is new thinking. HB 207 is good legislation and should not be changed. Please lend your support and vote for the **original** HB 207.

Sincerely,

Joe B. Mathis
General Manager
Oilfield Operations
JBM/sb/187

Hawk CONSTRUCTION CONSULTANTS, INC.

Senator Loren Leman
Chairman -- Senate Resource Committee
Alaska State Legislature
State Capital (ms 3100)
Juneau, Alaska -- 99801-1182

27 April 1995

Subject: HB207

Dear Senator Leman, et al.:

Please, don't kill the goose that lays the golden eggs.

We (all the citizens of Alaska) are competing for a very limited resource -- Capital investment funds. The current oil companies in Alaska are all part of an international community who have responsibility to their "stakeholders" and stockholders. As responsible businesspersons they must deliver the best bang for their investment buck. Alaskan's are competing with oil development countries where the cost of doing business is significantly less than in Alaska. Because of this fact, capital investments in other areas of the world offer more potential for profit, the life blood of any business.

My small company has been supporting the oil industry for the past 10 years since being founded here in Alaska in 1985. No other industry so greatly affects my business as does the fortunes of oil. We are small but our existence supports many other local industries and businesses. We spend our profits here in Alaska.

Please pass HB207 in the same form as passed by the House of Representatives. I believe this will give the Commissioner of Natural Resources the flexibility to assess and negotiate with the oil companies a fair and attractive package with the State of Alaska.

As with any business, regardless of the potential for profit, all factors must be considered in choosing to do business anywhere. If a business is constantly confronted with an ever-changing business environment, eventually the business will go where life is easier. The cost trend line and the revenue potential line must run, at a minimum, parallel. If there is any sign where these lines will intersect, the business will not wait for losses to occur, they will eventually leave for a more productive business environment outside Alaska, (e.g., Chevron, Conoco and Shell).

As responsible citizens of this state we must support, and make welcome, those industries that best support our Alaskan quantity and quality of life. As responsible citizens of the United States we must make available and attractive those future opportunities (e.g., ANWR) protecting our strategic independence in an increasingly competitive and unstable world.

Very truly yours,

Maynard V. Tapp -- President
HAWK CONSTRUCTION CONSULTANTS, INC.

cc: Senators:, Drue Pearce; Steve Frank; Rick Halford; Lyda Green; Tim Kelly; Steve Rieger; Randy Phillips; Judy Salo; and John Torgerson.

The Chez Braun Building • 1407 W. 31st Ave. • Suite 800 • Anchorage, Alaska 99503 • (907) 278-1877 • Fax (907) 278-1849

Alaska Support Industry Alliance

Testimony on

Senate CS for CS for House Bill NO.207 (Res)

Adjustments to Oil And Gas Royalties

To The

Senate Resourseso Committee

April 27,1995

DRAFT

The Senate version of house bill 207 (CS for CS HB 207) is completely unacceptable for the following reasons:

Section 1 AS 38.05.180 (j) 1 (A) after the effective date of this Act and not later than January 31,1998 to allow for production from an oil or gas field if etc.

This provision only allows for a three year window for application, which means that it would only apply to fields that are known of today.

(4)may not grant a royalty adjustment for a field
(A) under (1)(A) of this subsection
(i) if the anticipated aggregate value of the proposed royalty adjustment is a reduction that would exceed $5,000,000. or if the royalty adjustment is a reduction that exceeds 50 percent of the royalty originally specified in ---------- unless approved by the legislature.

This is not what was intended with the original house bill. The original bill was intended to be expeditious and have an effective degree of confidentality. This provision with the $5,000,000.00 threshold means that every application will require legislative approval. We disagree with the need for legislative approval, but if you are going to impose a threshold at least make it a reasonable one, such as $100,000,000.

(4) (ii) that allows a royalty adjustment that is a reduction to extend beyond December 31, 2002: for royalty that has been reduced by the commissioner for the reason set out in(1)(A) of this subsection,on and after January 1, 2003, the lessee or lessees shall pay the royalty rate that was in effect immediately before reduction of the rate

This means that if you apply for and get a royalty adjustment in 1995 and the field starts producing in 1997, it is only good for 5 years. It is not acceptable to expect global investors to sign on with that short of a commitment.

Post-it® Fax Note 7671	Date 2	# of pages ▶
To SEN. LEMAN'S OFFICE	From KEITH
Co. Annette K.	Co.
Phone #	Phone #
Fax # 907-465-4307 3870	Fax # 561-8870

I can continue to examine this legislation , but the point is that the bill was passed out of the house 35 to 2. This is the bill that the Senate needs to pass out of the Resourses Committee.

We at the Alliance have always had a positive pro-business working relationship with the Senate Resourses. With the opportunities that have been presented to us by the 1994 November election, we have been very optomistic about this legislative session and the future of oil and development in Alaska

The legislature has stated throughout this session that they are collectively in support of marginal field development. But, the amendments that they have added to the HB 207 are contrary to that position of development.

During the public hearings of House Bill 207 the issure of Sunset Provisions, Legislative Review and Approval were discussed . In fact, there was over 30 hours of public testimony.

It is the position of The Alliance and it's membership that HB 207 should be passed by the Senate without amendments as passed by the House 35 to 2.

DRAFT

ALASKA SUPPORT INDUSTRY ALLIANCE
TESTIMONY ON
HB 207, ADJUSTMENTS TO OIL AND GAS ROYALTIES
TO THE
SENATE RESOURCES COMMITTEE
APRIL 26, 1995

Good afternoon Chairman Leman and members of the Senate Resources Committee. My name is Keith Burke. I am General Manager of the Alaska Support Industry Alliance. I have been a participant in Alaska's oil industry for the past 20 years. I am here today to represent The Alliance, myself and my family. I am here to encourage you to support HB 207.

This legislation will be a great step forward in reversing the downward trend in oil and gas exploration and development activities in Alaska. It also would encourage continued investment in development of Alaska resources by many major multi-national oil companies, the very companies who allow members of The Alliance to provide many quality jobs to our Alaskan employees.

Since 1990, four oil and gas companies have closed their offices and have suspended upstream operations in Alaska: Chevron, Conoco, Amoco, and Texaco.

Downturn in Labor Force/Loss of Jobs

Oil and gas companies have downsized and consolidated operations in an effort to affect maximum cost savings to remain competitive.

With the completion of GHX2, the last major construction project currently planned on the North Slope, job levels are anticipated to continue a slow and steady decline.

According to Neil Fried, Dept. of Labor, producers will probably experience a statewide decrease of 20 percent or more in 1995 over 1994. Producer employment from February, 1994 to February, 1995 shows a decrease of 18 to 19 percent. The combined downturn, factoring in support industry jobs, will probably be around 10 to 11 percent.

Since its peak in 1991 of more than 10,541 jobs, industry employment has declined substantially and is predicted to be approximately 8,000 in 1995, about the same level of employment as in 1987. Attached to copies of my testimony is a graph from the Dept. of Labor titled "Alaska's Oil Industry Employment is on the Wane".

According to the University of Alaska, Institute of Social and Economic Research, oil revenues provide 30 percent of Alaskans' personal income and account for one in every three jobs. As oil production and revenues decline, so too will the number of Alaska jobs supported by petroleum revenues.

Alaska Production/Revenue Decline

Alaska's revenue future closely tracks the continued depletion of petroleum reserves. (Table 1. (attached to my testimony) shows the Dept. of Revenue's Base Case projected petroleum revenues as a percent of total projected state unrestricted revenues.)

Current forecast scenarios project total Alaska oil production to decline at an average annual rate of 6 percent Fiscal Year 95 to Fiscal Year 2000, falling to one-half of current production levels by 2006, in the base case scenario. Although higher oil prices would offset some of the negative impact of lower production levels, ultimately revenues will fall barring some unforeseen oil discovery. (Table 2. (attached to my testimony) shows current and projected oil production through FY 2010.

Half of the oil production projected for the year 2000 and beyond depends on investments yet to be made. This means the fiscal outlook could be worse than current projections unless the state acts to ensure that the new investments implicit in Dept. of Revenue projections are actually made. If the industry is forced to cut back on investment, we'll not only sacrifice significant future growth, but near-term production could plummet as well.

Downturn in Exploration Indicative of Alaska's Lack of Competitive Edge

Lease sale activity is a first indication of industry interest - and exploration interest - in Alaska. It's one way to tell how well Alaska is competing with other areas around the world. Although the number of sales varies from year to year and areas offered varies, data indicate some long term trends. The most notable is that fewer companies are bidding, fewer rigs are active and fewer wells are being drilled.

Alaska Oil and Gas Association statistics indicate that the amount of acreage under lease for potential exploration has declined by nearly 40 percent since 1990.

The Key--Implement a strategy to make Alaska competitive in the world market to encourage capital investment to provide a sustainable economic base for future revenues and jobs.

Throughout the world, relationships between governments and companies are much more positive and creative than only a few years ago. Most governments understand that investors deserve a fair return on capital investment--returns that are comparable with what they could earn elsewhere with similar risk. They realize that investment resources are scarce and they realize there are significant mutual benefits to working cooperatively to develop their resources and share the rewards equitably.

Alaska is competively disadvantaged:

- High transportation costs;
- Crude oil characteristics that discount North Slope oil compared to other crudes in the market;
- High exploration and development costs, long lead times;
- A state revenue structure that takes a bigger share of profits and no clear tax rules.

World oil prices plummeted in 1986 and, with the exception of a short-lived spike caused by the gulf war, have remained low. Adjusted for inflation, prices are about the same today as they were in the late sixties. Considering the distance to market and crude quality, Alaska North Slope crude averages only $10 per barrel at the wellhead.

The bottom line is that returns on Alaska investments are at least $1-2 per barrel lower than in similarly mature oil provinces.

The ability of the industry to bring investment capital into Alaska and the performance of investments also determine the flow of revenues to the state. This, in turn, increases or decreases state revenues.

New exploration is important for long term development, however, development of existing reserves is crucial to the state in the near term. There are a number of undeveloped North Slope oil accumulations, many of which would be on production if they were located in the Lower 48. (Attached, for your reference, is a listing of the accumulations and dates discovered.) Here, low oil prices, high development costs and high transportation costs make them uneconomic.

If the state and the industry can work together to change the economic equation for marginal fields, Alaska's ability to compete for oil industry investment capital will improve and the common goal of sustained economic development that leads to stabilized revenues and stabilized jobs...for the industry and for Alaska...could become reality.

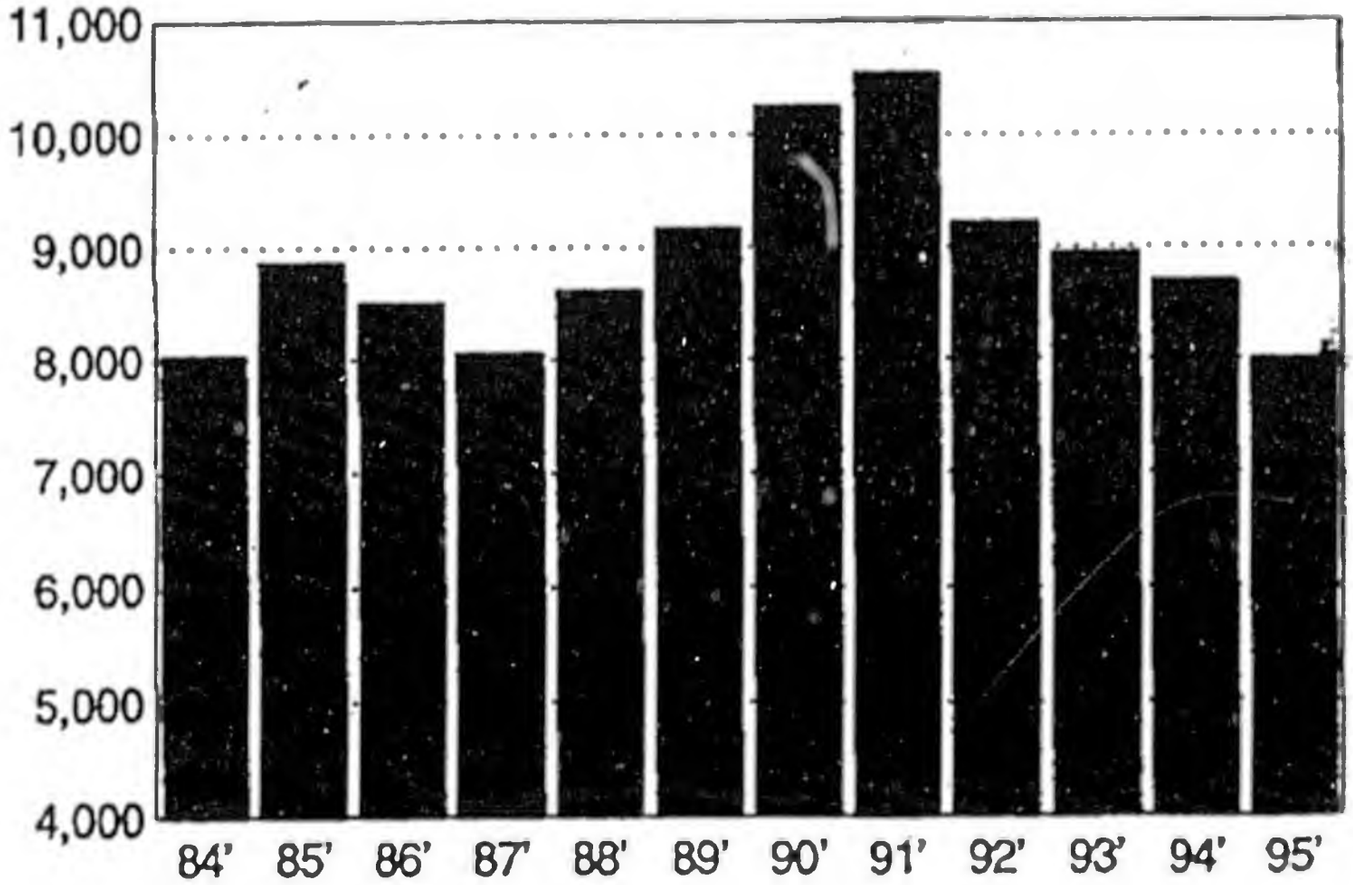
The three hundred Alliance member companies and their thousands of employees urge you to pass HB 207.

Thank you.

Attachments

B 4S.NR.rua

Alaska's Oil Industry Employment Is On The Wane



FISCAL OUTLOOK
STATE OF ALASKA

Alaska's revenue future closely tracks the continued depletion of petroleum reserves. Table 1. shows Dept. of Revenue's Base Case projected petroleum revenues as a percent of total projected state unrestricted revenues. Petroleum revenues are projected to account for appox. 80 % of state unrestricted revenues through 2010. Current forecast senarios project total Alaska oil production to be one-half current levels (approx. .8 million bl/day) by FY 2006 in the base case scenario.

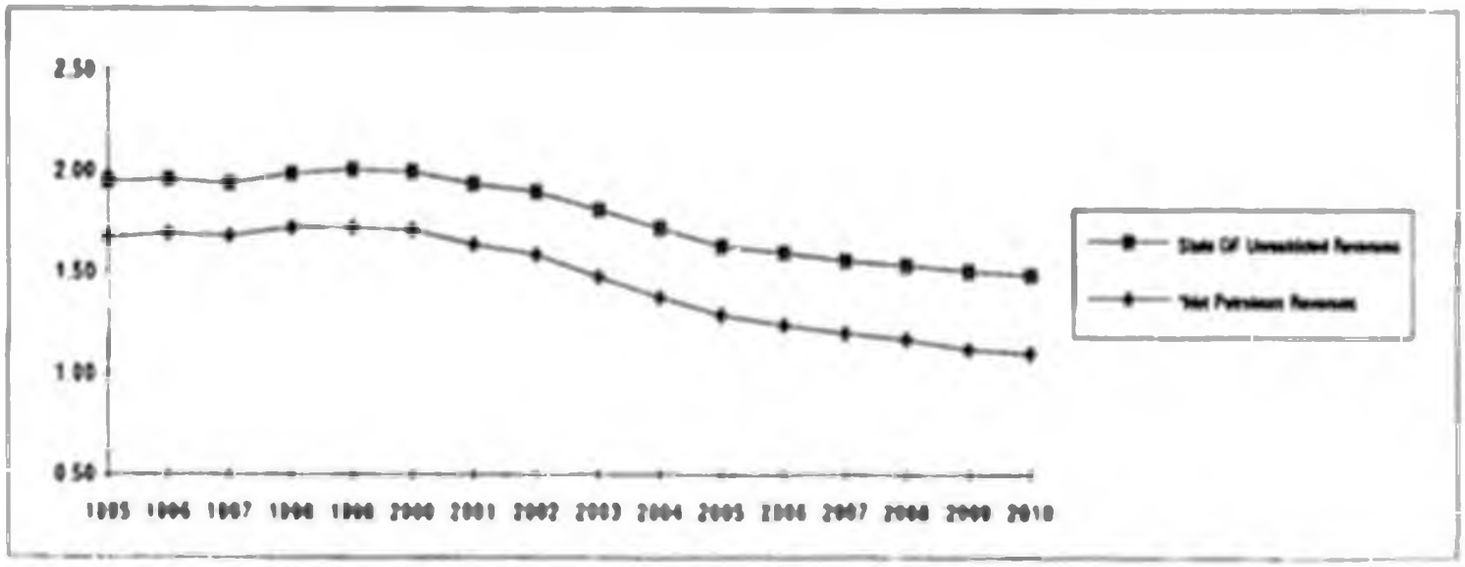
Although higher oil prices would offset some of the negative impact of anticipated lower production levels, ultimately revenues will fall barring some unforeseen oil discovery.

For the base case scenario, oil prices are assumed to increase at .5 percent per year with inflation increasing from 3.86% in FY 96 to 4.38% FY 1997-FY 2000, and to 4.58% FY 2001- FY 2010.

Table 1.

Projected Net General Fund
Unrestricted Revenues/ Projected Net-Petroleum Revenues
(Billions of Dollars)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
State GF Unrestricted Revenue	1.95	1.96	1.94	1.99	2.01	2.00	1.94	1.90	1.81	1.72	1.63	1.60	1.56	1.54	1.51	1.49
*Net Petroleum Revenue	1.67	1.69	1.68	1.72	1.72	1.71	1.64	1.59	1.48	1.38	1.29	1.24	1.20	1.17	1.12	1.10
	86%	86%	86%	86%	85%	85%	84%	84%	82%	80%	79%	77%	77%	75%	74%	74%



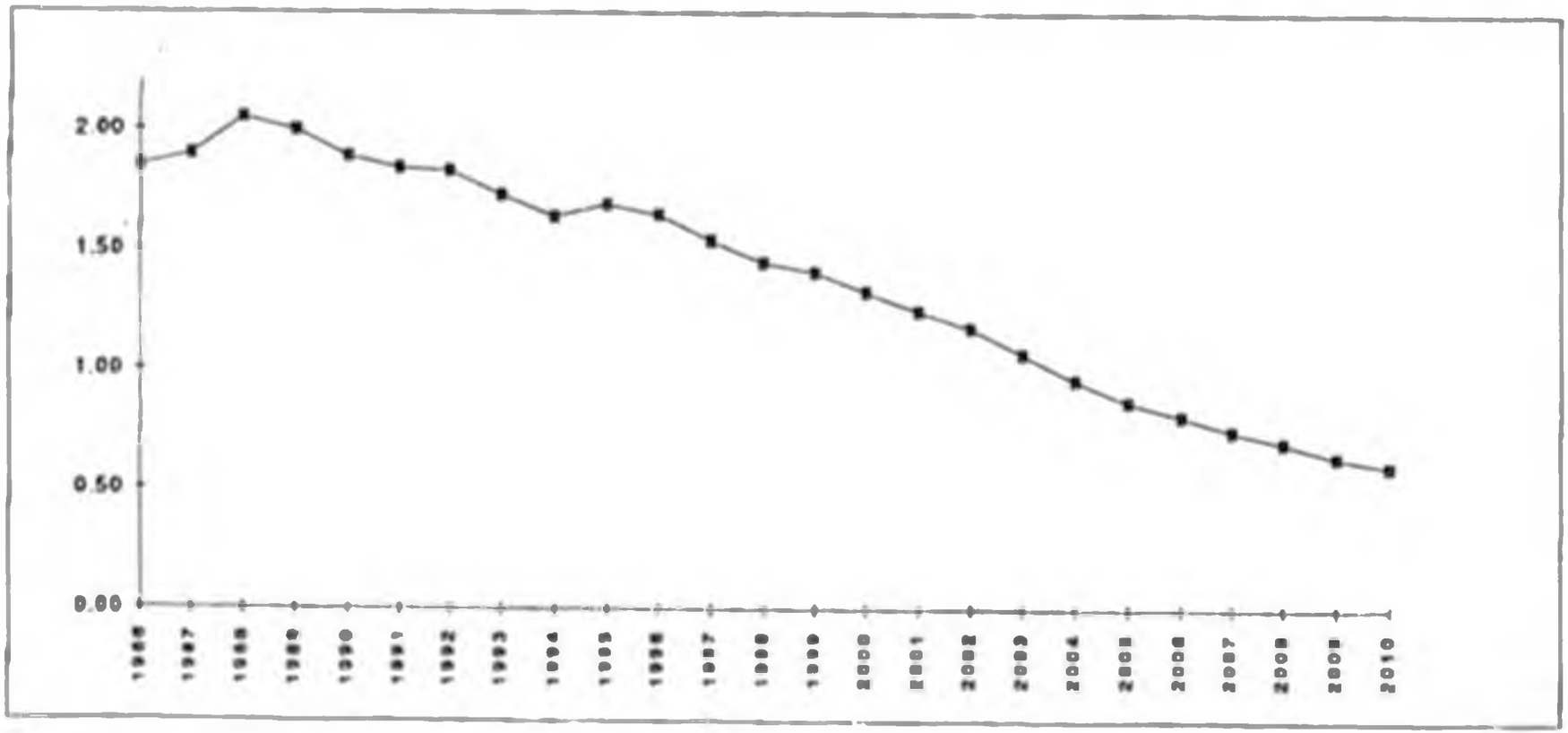
Source AA Department of Revenue
*Net of Permanent Fund Contribution

As production from existing fields continues to decline, state revenues will decline accordingly. Table 2 shows current and projected oil production through 2010. Production is projected to decline 43% in the next 10 years, falling to 1578 production levels of .8 million barrels per day by FY 2006.

Table 2

STATE OF ALASKA
PRODUCTION FORECAST 1986-2010
(MILLIONS BARRELS PER DAY)

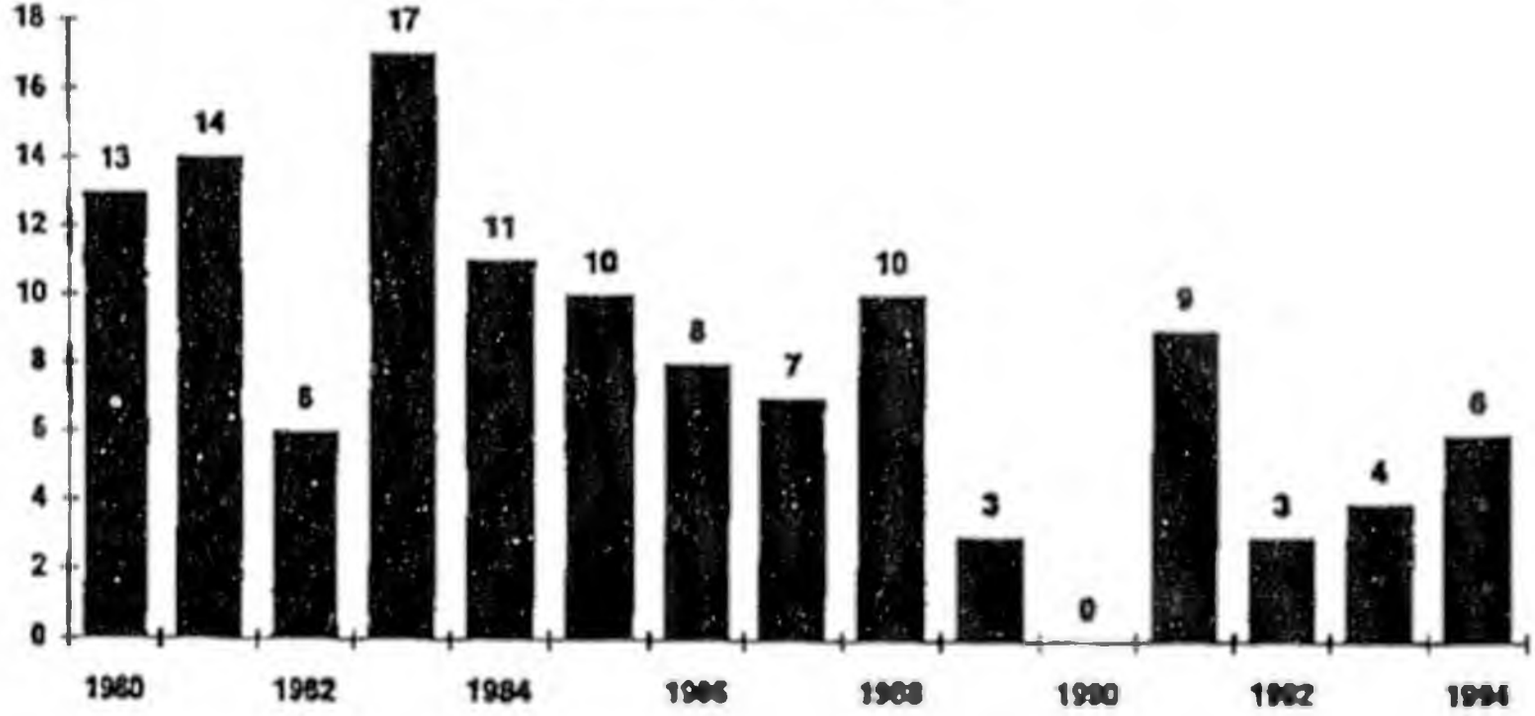
1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
1.85	1.90	2.05	2.00	1.89	1.84	1.83	1.73	1.64	1.69	1.65	1.54	1.45	1.41	1.33	1.25	1.18	1.07	0.96	0.87	0.81	0.75	0.70	0.64	0.60



Source:
Alaska Department of Revenue FY 1986-2010

Alaska Oil & Gas Lease Sales

Average Number of Bidders per Sale



3/10/95

ALASKA WELLS SPUDDED BY YEAR

YEAR SPUD	TALLY
70	69
71	30
72	28
73	38
74	46
75	73
76	82
77	72
78	98
79	109
80	138
81	197
82	229
83	183
84	213
85	311
86	200
87	121
88	149
89	139
90	161
91	151
92	148
93	193
94	160
95	2
	4332

Undeveloped North Alaska Hydrocarbons

Umiat	1946	Point Thomson	1977
Fish Creek	1949	Tern Island	1982
Simpson	1950	North Star	1982
NS Natural Gas	1968	Hammerhead	1985
West Sak	1969	Colville Delta	1985
Ugnu	1969	Sandpiper	1986
Gwyder Bay	1969	Badami	1990
Flaxman Island	1975	Kuvlum	1992

TESTIMONY
BY: GERALD G. BOOTH
VICE PRESIDENT, ENERGY AND MINERALS
COOK INLET REGION, INC.
ON CS FOR CS FOR HB 207
APRIL 28, 1995

DRAFT
OUTLINE
4/28/95
These points need to be put into text.

Good afternoon Mr. Chairman, members of the Committee. My name is Gerald Booth and I'm Vice President of Energy and Minerals for Cook Inlet Region, Inc. CIRI is owned by 6,700 Native shareholders of Athabascan, Eskimo and Aleut descent. The company's principal lines of business are real estate, broadcast communications and natural resource development. I am here today to talk about the latter.

CIRI owns and manages 924,000 acres of surface and 1.6 million acres of subsurface estate in Alaska. CIRI holds various royalty and working interests in several producing and prospective oil and gas fields.

The development of CIRI's lands and resources will play a significant role in the future economic growth and development of south-central Alaska, especially its oil and gas interests on Kenai Peninsula.

CIRI has been marketing its lands on the Kenai Peninsula for oil and gas exploration and has been successful in bringing new exploration of our lands and adjoining State lands.

HB 207 is important to our Company and our shareholders' future and we ask the Committee to passHB 207 as it was adopted by the House of Representatives. Here's why.

My remaining testimony will focus on specific areas of CS for CS for HB 207 that are major concerns to CIRI. All references are to the work draft of CS for CS for HB 207 dated April 26, 1995.

Page 2, line 1 - the recommendation is to change the effective date to an open date. If the State is offering an incentive for long range exploration and development of our oil and gas resources, the legislation should not have a sunset clause.

Page 2, line 9 - "environmentally feasible". If this type of language is required, care needs to be taken to include any and all feasibility based on the world price of oil. EXPAND

Page 2, line 27 - We suggest that the language (concept) use that of the House version ~~in that the process is~~ based on a sliding scale royalty method based on the price of oil. EXPAND.

Page 3, line 3(i) - For any and all developments, a proposed royalty adjustment would be for more than $5,000,000, then all projects would go for legislative review. EXPAND

Page 3, line 12 (ii) - If we are ~~setting~~ adopting an incentive, why is it sunsetted. If the program is not needed due to good profits and high oil prices, no applications will be submitted and if the program is not needed the legislature can terminate the concept. As presently written, the whole royalty concept would be of little value to CIRI in its potential development.

Page 3, Line 18 (B) - Current law permits the Commissioner to go lower than 3% for potential operations in Cook Inlet. I don't see why it is proposed that a floor be established.

Page 3, line 22 (5) - By adding the non-assignable clause, limits investments especially by independents, those companies that are important to Alaska's future development in areas like Cook Inlet. These companies, like the majors, share risk in exploration and development and require new players to come into ventures at different times. The concept as presented in CS for HB 207 is not considered a good one.

Page 3, line 27 (6A) - ~~Here again, by statute you are trying~~ Attempting to identify what may be needed for the Commissioner to make a decision. CIRI does not feel it necessary that this type of guideline to be put in place for the Commissioner. EXPAND

Page 4, line 4 (7) - The concept of selecting the independent contractor as outlined in HB 207 is fair to both parties and is becoming accepted practice at the federal level. We recommend the Senate version adopt the concept in HB 207.

Page 4, line 9 (8) - The comment period should be as reasonable as possible and we suggest that 30 days is sufficient especially when considering all the time constraints that fall into putting projects together.

Page 4, line 14 (9) - The listing of what should or should not be in any findings and determinations should be reserved to regulation. Here again, unnecessary sideboards are added to the legislation that provides openings for future litigation.

Page 5, line 2 (10) - We fail to see the necessity for the Legislative Budget and Audit Committee to be required to go to executive session or whatever to do their work. The time frames suggested again to extend the process. We suggest the time periods go back to those in the House version. In fact, the HB 207 version on the oversight provision by the Legislature is acceptable to CIRI. confidentiality of data.

The objective of all of us is to get more exploration and development in Alaska. We recommend that the Senate reconsider the changes it made to HB 207 and find common ground for the passage of the legislation. The royalty reduction concept is an excellent one and those of us in the business of marketing Alaska resources see it as mandatory to the future development of Prudhoe Bay and more important to us, Cook Inlet.

On behalf of Cook Inlet Region, Inc., I urge you to support HB 207 and reconsider the limiting issues of CS to HB 207. Thank you.

Testimony of John Ellsworth
in support of House Bill 207

Good afternoon Mr. Chairman and members of the committee. My names is John Ellsworth and I'm President and owner of Alaska Interstate Construction, a firm that provides construction services to the mining and oil industries, as well as the State of Alaska. During the construction season Alaska Interstate employs over 200 Alaskans throughout the state. I'm here today on their behalf to tell you why House Bill 207 should be adopted by this committee, and in essentially the same form as it was passed by the House of Representatives last week.

In the past few years we've seen a dramatic shift in the investment activities of international oil companies. A shift away from investment in the United States and a shift towards investing in other areas of the world. This is due, in part, to changing international politics, development of new technologies, and the development of more cooperative relationships with host governments in other oil regions. But what really drives this change in oil company investment strategies is their potential return on investment. And in Alaska, Mr. Chairman, the potential for realizing a reasonable return on investment is growing smaller every year.

The oil industry in Alaska has done everything possible to rein in their costs to remain competitive in the world market. They've downsized their operations, started sharing services, and invested heavily in new technologies. It's a far different industry than when I got my first contract on the North Slope. It's leaner and certainly a whole lot meaner. But the steps the industry has already taken resulted in their remaining reasonably competitive for further investment in the short term.

But there is an obvious limit on how much more they can reduce their costs. Alaskan oil development is inherently expensive. The remoteness of the fields, the high transportation costs and the fact that the oil can only be sold to in the U.S. market, makes oil production here more costly than in other oil provinces.

If we are to attract more investment in the state, particularly in the development of marginal fields, we have to find a way of reducing those costs even further. I submit that it's time for the state to begin acting as a participating partner in this effort, rather than as a dissatisfied spectator. House Bill 207, as passed by the House, helps accomplish this. It helps clarify the law that allows the state to reduce royalties on marginal fields to help spur their development. Otherwise, this oil may never come to market--and Alaska could lose the chance at any royalties at all.

The Committee substitute before you today does not accomplish this. It drags out the royalty adjustment decision process and has the real potential of introducing political wrangling into what should be a strictly economic decision. Furthermore, adoption of this substitute could set the stage for preventing any legislation from being passed this session. And that, in turn, could spell disaster for investments decisions due to be made during the coming year.

On behalf of my 200 employees and their families, I strongly urge you to adopt the version of the bill the House of Representatives passed. Give the state the ability to make a timely decision on these royalty adjustment applications. And help Alaska truly become a partner in the development of its resources.

I thank the committee for its time and I would be happy to answer any questions.

Union Oil Company of California
Testimony on CS HB 207
Senate Resources Committee
April 28, 1995

Mr. Chairman and members of the Resources Committee--My name is Kevin A. Tabler, Land Manager for Union Oil Company of California (Unocal) in Alaska. I appreciate this opportunity to be heard today and to present Unocal's comments on CSHB 207. I would like to begin my testimony by saying that the Sectional Analysis provided after the April 26, 1995 Hearing was particularly helpful in making a more informed analysis of the Bill. Some of the concerns I expressed in Wednesday's Hearing have been clarified by the Analysis and therefore the enclosed testimony more accurately reflects Unocal's view and opinion of the Bill.

Subsection (j)(1)

From purely a Unocal perspective, based on its present acreage position, Unocal is not directly impacted by paragraph (A). Most of the Unocal leases held today are located within producing fields, some of which are nearing the end of their economic viability. We have however, testified in earlier hearings on this Bill that we have not endorsed the concept of Sunset Provisions.

Subsection (j)(3)

Paragraph (B) appears to be a reopener. As long as it is clear the conditions of any future adjustments are determined at the time of royalty reduction and not intended to be a unilateral determination on the part of the Commissioner, we don't have an objection. I believe the wording should be changed to make this point absolutely clear.

Subsection (j)(4)

We believe the requirement for legislative approval under paragraph (A) will be a time consuming and unnecessary requirement resulting in an administratively burdensome process. Under the House Finance version of the Bill, adequate Commissioner oversight is provided under Subsection (j)(8).

In reading the provisions of paragraph (B) of this Subsection, it is unclear to me as to the intent of the language "in amount or value of the Production". If this is to mean a net 3% floor or a maximum 76% reduction of the current royalty rate, than Unocal is opposed to this revision. Under the House Finance version of the Bill, the floor established for producing and shut-in fields is 90%. There needs to be clarification on this point. Any increase in the floor reducing flexibility would be inconsistent with our position and prior testimony.

Subsection (j)(5)

The assignment of all right, title and interest in a lease is a fundamental principle in the oil industry. Property trades will be greatly restricted if assignability of a royalty adjustment is not allowed. The ability and desire to acquire a lease that has favorable royalty terms may be the catalyst and incentive for a company to invest capital and employ new ideas in fields where the current owners may be less inclined. Companies are rationalizing properties and focusing investments in core areas to take advantage of their particular operational, infrastructure or informational strengths. Lost opportunity for earlier development of a lease or field is sure to occur if this limitation is imposed. The intent of this legislation should be to create opportunity with certainty, not further limit the creativity of the industry.

Subsection (j)(7)

This issue was thoroughly discussed in prior hearings with what we thought was an equitable compromise and consensus opinion of the parties testifying. We see no advantage to changing this Subsection and would prefer to see Subsection (6) of the House Finance version reinstated.

Subsection (j)(8)

Thirty (30) days rather than sixty (60) says is an appropriate time period for public comment. The whole review process needs to be streamlined wherever possible.

Subsection (j)(9)

Reviewing and addressing all the requirements under this Subsection will be very expensive, time consuming and may not be applicable in all circumstances. We believe the Commissioner should have the discretion to provide for the contents of the best interests finding and determination. The Department of Natural Resources is well equipped for this process. We feel it is unecessary for this Subsection to be in the Bill, and in fact, the degree to which each of these conditions are to be investigated will be the subject of much debate. If the committee and legislature feel the need to include the details of the finding and determination in this Bill, then paragraphs (A) through (G) should only be suggestions of issues the Commissioner may consider in a royalty adjustment application.

Subsection (j)(12)

We have a similar comment in this Subsection as in Subsection (j)(4) in that legislative approval is unnecessary and administratively burdensome. We contend that Subsection (j)(10) of the House Finance Bill is more appropriate and should replace this Subsection.

We look forward to working with the Legislature as this Bill progresses through the legislative process.

Thank You

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Resource Development Council for Alaska, Inc.

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Testimony of Resource Development Council
on CS HB 207
An Act relating to the reduction of royalties reserved to the state to encourage production of oil and gas from marginal fields
Senate Resources Committee
April 28, 1995

Good afternoon. My name is Becky Gay, Executive Director of the Resource Development Council for Alaska, Inc. On behalf of RDC, thank you for the opportunity to testify on CS for HB 207.

RDC strongly supports HB 207, as passed by the House in an overwhelming 35-2 margin. The House version of this legislation provides the flexibility needed for the State and industry to work together to change the economic equation for marginal fields. It provides flexibility for working with investors on a case-by-case basis to overcome Alaska's unique challenges and make new development and production a reality. Alaskans will benefit from new jobs, long-term revenues and increased economic activity associated with the development of new fields.

HB 207 is a tool the State can use to enhance the competitiveness of projects whose funding might otherwise go abroad. It sends a clear signal that Alaska aims to be competitive in the world market to attract the investments necessary to develop its oil and gas potential.

This clear signal, however, could become blurred due to recent amendments to the bill. RDC does not support the two sunset provisions nor the requirement of legislative approval on royalty reductions exceeding five million dollars or 50% of the royalty originally specified in the lease. RDC believes these new amendments to the bill are counterproductive and undermine the original purpose of changing state law on royalties. Alaska could be left with a bill of good intentions, but one that, in reality, falls short of what's needed. The amendments unfortunately will give way to **more** needless delays and **more** uncertainty. The 1998 deadline for royalty adjustments puts us back to square one as far as future discoveries are concerned. Ending the royalty adjustment itself in 2002 could hit some fields just when they need royalty relief the most.

HB 207, as passed by the House, is a good piece of legislation which should **not** be changed significantly. It **will** help to open up

marginal fields to development. And it does protect the State's best interests if a marginal field turns out to be more profitable than anticipated.

Please do not compromise the effectiveness of this bill and its ability to change the economic equation for marginal fields. Lets send a CLEAR, CLEAR message that Alaska will take the necessary steps to attract new investments, revenues and jobs.

RDC looks forward to working with the Senate toward final passage of a **strong** and **effective** royalty adjustment bill -- one that will serve as a powerful strategy to overcome roadblocks and make Alaska more competitive in the world market so that more dollars are invested here.

Thank you.

DRAFT

Testimony

by

Eric M. Luttrell

on behalf of

BP Exploration (Alaska) Inc.

to the Senate Resources Committee

on

HB207

April 28, 1995

DRAFT

Mr. Chairman, Members of the Committee, good afternoon. My name is Eric Luttrell, and I am Vice President of Exploration and New Developments for BP Exploration (Alaska) Inc. Thank you for this opportunity to testify to the Committee today on behalf of BP.

I have come here today to testify in support of legislation that would encourage the development of marginal fields, fields like Badami and Northstar, fields of moderate size away from existing infrastructure. Many of these prospects would not have been considered for development only a few years ago. Because the development of these fields within BP is directly under my control, I have taken a special interest in this legislation.

In particular, I would like to talk to you about the version of this bill that passed the House and the differences between that version and the draft Senate Resources Committee Substitute that we received two days ago. We have a number of concerns with the proposed language of the Senate bill, but I only want to address a few of the main ones here today.

Let me begin by briefly reviewing the context for this legislation. In looking at our business in Alaska and our opportunities to develop the business and make it grow, we in BPX Alaska see a number of situations in which the State's present royalty terms may impair our ability to compete within the BP Group for the capital funds to make the investments needed to keep our business sound and healthy for the future. Although BP is a large corporation, it still has only a limited amount of money available each year for capital investments worldwide. Naturally, in allocating these capital funds, priority is given to those investments that are most attractive. So if BP's capital funds are all allocated to more attractive investment opportunities elsewhere before we get down to our Alaskan projects, then the Alaskan projects simply don't get funded even though they may still be quite attractive and feasible economically on their own terms.

This is a fact of life for us, and in this, BP is no different from any of the other oil companies still active in Alaska. The state and those of us who work for BP in Alaska are engaged in a global competition for investment dollars. It is, of course, of great personal concern to those of us working here, because in large part our jobs here are on the line if we don't compete successfully. It is also of concern to us as Alaskans, because the continued oil and gas development of this state is essential for its future economic well-being. So it is extremely important that whatever

"economic feasibility" test that is applied to an application for royalty adjustment recognize this global competition.

The House-passed version of HB 207 would give the Commissioner of Natural Resources clear authority to modify the terms of the State's oil and gas royalties in a variety of ways in order to facilitate and encourage the new investments that need to be made in order to bring marginal new fields into production and to sustain production from existing fields that are in decline. At the same time, it contains safeguards to protect the State's best interests. By protecting those interests while allowing our Alaskan opportunities to be made more competitive against the opportunities elsewhere, the House version embodies a win-win approach for the State and its oil industry. It is a good bill, and BP fully supports it.

Unfortunately, the same cannot be said of the draft Senate Resources Committee Substitute for the bill. It is badly flawed, and seriously out of touch with the realities of a mature oil industry in Alaska.

Problem number one is the requirement that any royalty adjustment be approved by the legislature. This, combined with the extensive findings that the Commissioner must make, is an invitation for long delays in final approval and most probably, litigation. It is entirely possible that it would be two years before an applicant would know whether a project would have a revised royalty arrangement. This process will also compromise any ability to keep sensitive proprietary information confidential. All of this adds up to additional uncertainty and, in our view, makes this proposal unworkable. We recognize the importance of appropriate oversight, but we need to devise something that would not unduly burden the State's and industry's ability to get these marginal projects developed. We think the oversight provisions in the existing HB 207 would be effective.

There is another point that is relevant to the whole question of oversight of the Commissioner's decisions, and that comes in the form of a question: What incentive does BP have to make a deal that is not in the best interest of the State? We will be doing business in Alaska for a long time. Since the nature of the deal will be examined many times after it is made, any undue advantage that we may have gained will become readily apparent. We would fully expect the State to try to recover that advantage in some other way, e.g. increased taxation. In short, it is not in BP's, or any other company's long term interest to make a deal that is bad for the State.

My second major concern is that of encouraging development of new pools within existing fields. Here again, the Senate version could have the effect of discouraging investment and development by carefully removing the words "pool, or portion of a field or pool" everywhere they occur in the House version, leaving only references to "field."

This reflects a fundamental misunderstanding about how investment decisions are made. Fields are not economic monoliths, nor do we view them that way. Each new investment in a field has to be justified at the margin, on its own merits. The profitability (or economic failure, for that matter) of prior investments in a field has no bearing on the decision to make the new investment or not. The plain truth is that there are investment opportunities that are truly marginal in all fields. In terms of competing for limited capital funds, it is just as important to recognize this fact for opportunities in large fields as it is to recognize it in the context of little fields.

A third problem with the draft Committee Substitute is that any royalty adjustment for a new, marginal field automatically terminates on December 31, 2002. How does this benefit the State? Limiting the time when a royalty modification can be in effect, whether it applies to some fields or to all, makes little sense — especially if the modification is a restructuring instead of an outright reduction. Our concept is to share risk with the State, a concept that makes an arbitrary cut-off of the deal potentially contrary to the State's best interest.

For similar reasons we do not understand what the State gains by providing that all of the provisions of this bill terminate at the end of 1998. As a practical matter, if future legislatures and administrations believe that this bill is not in the best interest of the State, it will be repealed. In this sense, the bill and all of the royalty adjustments that are made under its authority will be constantly under review. Nevertheless, if the Committee would be more comfortable with a sunset provision, it should allow a reasonable period for this set of proposals to work. We believe this is a minimum of five years.

The fourth problem with the Committee Substitute is that it requires the Commissioner to include as a condition of a royalty modification the power to "restore or increase the state's royalty share if the assumptions upon which the agreement is based ... are subsequently determined to be in error..." This assumes that all errors are made against the state's interest, which is simply not the way things happen. Our intent is to deal with unknown factors during the course of negotiations with the

Commissioner. This unilateral authority to change the agreement inserts another element of uncertainty into the development decision. The negotiation will cover the relationship of royalty rate to price. We would also expect the negotiation to deal with anticipated recoverable reserves, [well productivity?], and the like. The nature of the negotiation process, combined with an appropriate level of oversight, renders such drastic unilateral powers unnecessary.

What is at stake in the near term? We believe that effective legislation can have a big impact on our decision to develop Badami, and on our decision to develop Northstar. We expect that both of these decisions could be made in the next year and lead to significant production and revenue by 1998.

Badami: I will tell you candidly, I don't know whether we would request royalty adjustment for Badami. That request awaits complete review of our drilling results and the engineering cost estimates. I can tell you that we have a group of experts working diligently on both issues to get us answers to these questions by mid-summer. Then we will run the economic analyses and take a decision to make a request to DNR if we believe the field is developable but marginally economic under low price conditions. And if enabling legislation passes this year.

That is a lot of ifs in a row, but that is the nature of our decision at this time. If we defer the decision to develop out of 1995, we, and the State will lose the opportunity to start production and revenues in 1997. We both loose; Production and Revenue... I fail to see how deferral is in the best interest of either of us.

Northstar: Simply stated, development of Northstar in the foreseeable future requires passage of legislation including net profit share adjustments as a part of the negotiation with the State. We had hoped that we would be talking with the Senate about extending the terms of the House bill to net profit share leases. Now, we are in doubt as to whether there will be a royalty adjustment bill that has any practical effect. This means that we are two steps away from any plan to develop this significant prospect. Pretty strong words, but I could not recommend to BPX proceeding with Northstar development without a change in the NPSL terms.

We have been very open with the DNR on Northstar and have even proposed some possible agreements that would protect the interests of both the State and BP. But they require legislation. With legislation, we

believe we would be negotiating with the State before year end. Delay of legislation or failure to include NPSI would defer the development of Northstar by 1-2 years and, because of that , delay production and revenue from Northstar by 1-2 years. I fail to see how that is in the best interest of the State.

Are there other marginal accumulations on the North Slope that could be developed in the near term? Absolutely. Will their development be encouraged by this legislation? I don't know, they are not mature enough for us to have a clear view of their economic value. I certainly do not expect that all will.

What is in it for the State of Alaska? The State of Alaska stands to benefit greatly from these developments, and from their timely development. At Badami, we project State revenues (using current State price forecasts) of upwards of $350 mm (royalty, severance, ad valorem, income taxes), plus jobs and the infusion of several hundreds of millions of dollars of additional investment during development. Investment in and revenues from Northstar are similar.

When we look beyond the specifics for Badami and Northstar, the proposed legislation has the potential of sending a strong message to the Industry, to Houston, to Los Angeles and to London, a message that Alaska wants to work cooperatively with Industry to encourage investment and new development; that Alaska wants to compete. Not passing legislation this year or passing the wrong legislation will send the opposite message. We believe that this bill is both necessary and beneficial to the state and to industry, but it must be in a useful format. The House version was carefully considered and would work. The Senate version would not work.

I have tried to be open, direct and candid with you here today, just as we would be with the State in a negotiation. Those of you who know me, know that is my style and it is BP's style. Like it or not, the State and the industry have much to gain by improved openness and cooperation and we look forward to a long and mutually beneficial relationship.

Thank you for the opportunity to testify.

DRAFT

PROBLEMS WITH
THE DRAFT SENATE RESOURCES CS
FOR HOUSE BILL NO. 207

Supplement to Testimony by
Eric M. Luttrell on behalf of
BP Exploration (Alaska) Inc.
to the Senate Resources Committee

April 28, 1995

Page 2, lines 1-2: We don't believe there is any good reason to have a sunset date for the Commissioner's authority to enter into agreements to modify royalties for new fields that aren't yet in production. As new fields continue to be discovered (hopefully), some of them may well be suitable for modification of their royalty terms. There is no guarantee these new fields will all be discovered by any given sunset date, and particularly by January 31, 1998. At the very least, the sunset should be far enough in the future to give the new program a reasonable time to work — at least five years. But BP believes the best way to deal with this royalty-modification program if there are problems with it in the future, is to amend the law or even repeal it if necessary, instead of using a sunset clause.

Page 2, line 2 (and everywhere else where the phrase "pool, or portion of a field or pool" appears in the House version and is deleted in the draft Senate CS): the Senate version could have the effect of discouraging investment and development by carefully removing the words "pool, or portion of a field or pool" everywhere they occur in the House version, leaving only references to "field."

This reflects a fundamental misunderstanding about how investment decisions are made. Fields are not economic monoliths, nor do we view them that way. Each new investment in a field has to be justified at the margin, on its own merits. The profitability (or economic failure, for that matter) of prior investments in a field has no bearing on the decision to make the new investment or not. The plain truth is that there are investment opportunities that are truly marginal in all fields. In terms of competing for limited capital funds, it is just as important to recognize this fact for opportunities in large fields as it is to recognize it in the context of little fields. Deletion of the words "pool, or portion of a field or pool" reflects a naïve but fundamental misunderstanding of the real world and how our investment decisions are made. They should be restored.

Page 2, lines 10-12: In the draft CS royalty modification for a field in decline will be forbidden until the field is actually losing money. Well before that time, investments to slow down the decline would have to be made, but nothing could be done then to modify the royalty. In other words, any help for declining fields would be too little and too late to help the investment decisions that would slow the decline. The House version does not make this mistake.

Page 2, lines 27-32: These provisions do not reflect enough attention to the restructuring of royalty obligations. Restructuring does not necessarily mean reduction. For example, a fixed royalty could be converted into a sliding-scale royalty rate based on price levels. Such a sliding scale could be designed so that the State's royalty is the same overall if prices follow the State's mid-case price scenario in its revenue forecast. That's not a reduction, it's a sharing of price risk. But it is one that greatly helps the competitive attractiveness of a prospect in Alaska, where high transportation costs give us a unique degree of vulnerability to low prices. A price-based sliding-scale royalty would afford relief just when we need it most, and thus improves the attractiveness of an Alaskan investment by reducing its economic risk.

Moreover, since the application to modify a royalty is filed before the investments are made and before anyone knows how well the investments will actually perform, errors in the assumptions about how they will work can run both ways — not just against the State as the draft CS seems to fear. The House version is more even-handed in its treatment of changes from what either side expected. Thus, the language in lines 27-32 on page 2 of the draft CS should be replaced

with the language in the House version, starting with "provide for" in line 26 on page 2 of CSHB 207(FIN)am and running through the end of line 32 on that page.

Page 3, lines 1-21: BP recognizes the need for appropriate oversight of the royalty restructuring program. The House passed version of HB207 has three types of oversight. First, there is a thirty day public comment period. Secondly, the legislators are given formal notice of the preliminary findings on the first day of public comment period allowing them time to become involved if they decide it necessary. Third, the commissioner of Natural Resources must offer to make a presentation to LB&A regarding the preliminary findings and determination and the administrative process.

The legislators will clearly be aware of any royalty modification agreement and will be able to receive input from their constituencies and apply pressure to the commissioner as they see appropriate. The risk of an unacceptable deal going forward would be minimal. Provisions elsewhere in the draft CS provide for timely review by the Legislative Budget and Audit Committee before the Commissioner makes a final decision on a royalty modification request. That is the right time and the right way for the Legislature to make known to the Commissioner any reservations it may have about the deal. The requirement of obtaining legislative approval will cause excessive and needless delay and uncertainty in concluding royalty agreements. If such an agreement were reached in principle just after the Legislature adjourned, it could not be finalized until it is approved in the next Session, which would be at least eight months later and perhaps almost twelve. For these reasons BP believes lines 1-21 on page 3 of the draft CS should simply be deleted.

Page 3, lines 12-17: The draft committee substitute automatically terminates any royalty adjustment for new marginal fields on December 31, 2002. How does this benefit the State? Why should royalty agreements for new fields expire after 2002 while identical agreements that might be made for fields in decline or for shut-in fields would have no expiration date? Limiting the time when a royalty modification can be in effect, whether it applies to some fields or to all, makes little sense — especially if the modification is a restructuring instead of an outright reduction.

Page 3, lines 22-23: This is a new provision, forbidding any assignment of a royalty agreement from one lessee to a potential new lessee. The Sectional Analysis for the draft CS does not explain

why the State should be concerned about this, nor can BP figure out what the state interest is that needs to be protected this way. Rather, we see a good reason not to ban such assignments: Banning them would make it more difficult to take in new partners to share the risk in a new development, and that could keep new developments from happening. In any event, BP sees no reason why the State's interest — whatever it may be — would not be fully protected by requiring any assignment to be reviewed and approved by the Commissioner before it can be made, instead of banning them altogether. So, either these lines should be deleted, or the words "without the commissioner's prior approval" should be inserted after the word "assignable" and before the semicolon at the end of line 23.

Page 3, lines 27-31: This subparagraph (A) conflicts with subparagraph (B) that immediately follows. (A) says financial and technical data must be disclosed to the extent the Commissioner determines them to be relevant to the decision to enter a royalty modification agreement. But (B) says that information must be kept confidential under AS 38.05.035(a)(9) upon the lessee's request. It can't be both. Either the information will be kept confidential, or it won't. Given that the Legislative Budget and Audit Committee can review a deal before it is consummated — including the confidential information in an executive session — BP believes there will be adequate oversight of the process in a timely fashion, without forcing lessees to choose between seeking a royalty modification and giving up proprietary and confidential information in order to do so. Thus, we recommend deletion of lines 27-31 in their entirety and of the "(B)" in line 32 on page 3 of the draft CS.

Page 4, lines 4-8: This material relates to the independent contractor who is to advise the Commissioner at the lessee's expense in reviewing the lessee's application for a royalty modification. The draft CS deletes a provision in the House version allowing the lessee to choose the contractor from a list of three offered by the Commissioner. That provision strikes a reasonable balance to keep either party from trying to get an undue advantage over the other through the selection of this independent advisor. The draft CS also deletes a provision in the House version making clear that the Commissioner, not the lessee, controls the scope of work of the advisor. This provision, too, is needed to keep balance as the advisor works for the Commissioner. Accordingly, BP believes this material in the draft CS should be replaced with the material appearing in lines 16-22 on page 3 of CSHB 207(FIN)am.

Page 4, line 12: The 60-day period for public comment adds an element of delay in the process. Thirty days is sufficient — after all, the required public comment period for the very regulations to implement this legislation is only 30 days.

Page 4, line 14 to p. 5, line 1: These highly detailed "best interest" findings are a laundry list of litigation issues to challenge a Commissioner's decision to modify a royalty. Some of them — such as "the projected social effects of the proposed royalty adjustment" or "the projected effects of the proposed royalty adjustment upon existing or potential new commercial enterprise, competition, and patterns of investments within the state" — would require extensive speculation and conjecture by the Commissioner in order to address them. The Commissioner's decision should be made on the basis of facts as they are known at the time, not on wild conjecture or speculation of only marginal relevance. Moreover, to the extent any of these factors would be material to the Commissioner's decision, they would be addressed anyway by the Commissioner in the course of explaining the basis for that decision. These provisions should therefore be deleted as unnecessary and potentially harmful to the program.

Page 5, line 4: The words "to protect confidential information" should be inserted immediately after the word "appropriate" at the beginning of the line.

Page 5, lines 27-28: The "(A)" at the beginning of line 27 and the phrase "that does not, under (4)(A)(i) of this subsection, require legislative approval," should all be deleted at the same time as the rest of the provisions relating to legislative veto are deleted.

Page 6, lines 2-3: By making the Commissioner's decision final only as to the applicant, the draft CS creates a strong presumption that everybody else may sue to challenge that decision. The whole purpose in making the decision final is to cut down on litigation. This, instead, would invite it. Therefore, the phrase ", as to the royalty adjustment applicant," should be deleted.

Page 6, lines 4-24: All of subparagraph (B) should be deleted as part of the general deletion of provisions relating to legislative veto, and the remaining subparagraphs should be redesignated accordingly. In addition, the phrase "or (B)" on line 18 should be deleted because it refers to the subparagraph to be deleted .

Official Business

COMMITTEE: S. Resources

DATE: 4/22/95

SIGN-IN

Subject of meeting: HB 207 Adjustments to Oil & Gas Royalties

PLEASE PRINT!

NAME	ADDRESS (MAILING) & (ZIP)	PHONE	REPRESENTING	DO YOU WANT TO TESTIFY?
Paul Wessells	P.O. Box 196612 Anchorage 995	564-4039	BP Exploration	Yes
John Shively	400 W. Willoughby Juneau	465 2400	DNR	Yes

1. Procedures for Royalty Relief Should Be Clearly Framed and the Need for Royalty Relief Should Be Clear to the Owners of the Resource. *(CSHB 207[Fin]Am page 1, line 10)* Particularly in view of the production trends discussed above and the fact that industry statements about profitability fly in the face of every published report of which I am aware,[6] the process, the criteria and the case for royalty relief should be clearly defined and the case should be part of the public record. This bill does the opposite. For example, where the existing statute requires regulations to make procedures clear, this bill removes that requirement.

2. Economic Considerations Should Include Analysis of Pipeline Profits. *(CSHB 207[FIN]Am page 2, line 31 - Page 3, line 1)* This bill mandates consideration of factors such as capital investment but may be read to exclude investment in pipelines. As mentioned above, pipeline costs can be a major factor affecting the development of new fields and the continued production in existing fields. Moreover, guaranteed profits to the pipeline owners are a significant factor influencing production decisions that this language arguably requires the Commissioner to ignore. You may choose to ignore this important aspect of North Slope production economics; prospective producers will not. And you can bet needless litigation fees that the state will have to spend a bunch to counter industry lawyers who are certain to argue that the Legislature, by its exclusion of pipeline profits from its list, intended to exclude this factor.

3. Blanket Confidentiality. *(CSHB 207[[FIN]Am page 3, lines 15-16.)* The requirement that the Commissioner shall hold application material confidential at industry request contravenes the state's sunshine laws, common sense and jurisprudence. The Alaska judge who has probably reviewed more oil industry documents than any other has thrice ruled against blanket grants of confidentiality

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[6] See: Deakin (1989), Oil Industry Profitability in Alaska, 1969 through 1987, p.2 (industry profit $42.6 billion, state share $29.3 billion); Legislative Research Agency (1993), Distribution of Income from Alaska Oil and Gas Operations . . ., p. 14 (1985 industry net income $5.6 billion, 1985 state net revenue $3.3 billion); Fineberg (1992), p. 43, Alaska North Slope Oil Profits . . . (1991 West Coast industry profits $4.95 per barrel, state share $3.82); Wilson-Gillette (1994), Consequences of Exporting Alaska Crude Oil, p. 36 (April 1994 West Coast major field wellhead profits $2.66 per barrel, state share $2.63 per barrel [excludes estimated TAPS industry profits of $1.00 per barrel v. state taxes of approximately $0.30 per barrel]).

END

FAX TO: ANNETTE KREITZER
c/o SEN. LOREN LEMAN

FAX #: 465-3810

DATE: 4/23/95

PAGES: 2 (including this sheet)

From: R.A. Fineberg
907 / 479-7778

Re: HB 207

If my testimony has not yet gone to all members and time permits, please substitute the corrected page 4, enclosed (correcting last sentence of the paragraph preceding "3. Blanket Confidentiality. . . ."

If testimony is already distributed, kindly add make this correcting note to your committee file for the record.

TNX!

END

Testimony to the Senate Resources Committee on CSHB 207(FIN)Am

Richard A. Fineberg
Research Associates
P.O. Box 416
Ester, Alaska 99725

April 21, 1995

A. Data in the State's New Revenue Forecast Demonstrate the North Slope Has Generated and Is Generating the Equivalent of Current TAPS Throughput in Increased Production Every Day.

A substantive case for royalty relief has not been made. To the contrary, new evidence seems to point in the opposite direction. Data in the Department of Revenue's spring revenue forecast released last week greatly strengthen the argument that royalty relief may not be necessary.

1. Over the past decade, the state's North Slope production forecast for 1995-2010 has more than tripled. When forecast production is combined with increases in actual production between 1985 and 1995, by 2010 the North Slope is now expected to generate 6.2 **billion** more barrels of oil than the Department of Revenue forecasted for the 1986-2010 period in 1985. That's more than ten years of additional North Slope production at current levels. Put otherwise: Each and every day over the last ten years, the current tax and royalty regime has generated one day more of production at 1.6 million barrels of oil per day than was forecasted in 1985. This trend of increasing production (i.e., slowed decline in production) was established in the face of declining prices, contradicting the dire warnings of industry and government studies in the late 1980's that said Alaska had seen the end of such increases.[1] This trend was established without royalty relief. This trend continues today: The new state forecast increases production for the 1995-2010 period by 750 million barrels over the previous semi-annual state forecast, issued last fall. That's more than 2.0 million barrels per day for an entire year. On this basis, it seems reasonable to demand that a strong, substantive case for easing the state's existing royalty relief provisions, as proposed in HB 207, must be made before this bill is enacted.

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[1] See attached tables 1 through 4 (see also and graphs V-1 through V-4 summarizing Dept. of Natural Resources forecasts in Richard A. Fineberg, Alaska North Slope Production Prospects: Preliminary Analysis [a report prepared for the Northern Alaska Environmental Center, et al.], Feb. 22, 1995).

2. Marginal Fields. In the new forecast, production from undeveloped fields between 1995 and 2010 increased by 18%, despite a reduction in production from the North Star prospect. Two factors here are worth noting. It is my understanding that in the new Department of Revenue forecast, North Star was delayed in part to higher TAPS tariffs. Could more effective management of pipeline tariffs be an important factor in encouraging or stifling future production? Second, undeveloped fields account for approximately three percent of total forecast production; even with a tripling from the current levels, non-producing fields would comprise less than ten percent of total forecasted production.

3. Profitability. We are told repeatedly that "[t]he target is to get Arco Alaska and BP Exploration to divert exploration and production dollars from foreign areas and put them into marginal areas on the North Slope."[2] This dialogue is weirdly bereft of facts. Alaska's interaction with its meal-ticket and the economics of North Slope production are unique and dimly understood. Arco's North Slope profits are so unusual, in fact, that in considering the flight of domestic capital in 1991, a First Boston report isolated Arco's results from other companies in a separate box. In that same study, BP was alone among the internationals in bucking the trend of greater returns overseas than in the U.S.[3] In Alaska, we just don't get it. Consider the big, front-page presentation in the Anchorage Daily News last spring, one of many on the hard times theme. That one had a color graph showing a slide in Arco Alaska's profits from $700 million in 1990 to $225 million in 1993. The graph excluded Arco's Alaska pipeline profits, estimated at over $100 million per year. Even more important, the story failed to note that in 1993 Arco's Lower-48 and overseas production endeavors lost $180 million. Far from being a millstone around Arco's neck, from this perspective Alaska appears to be Arco's lifeboat.

In fact, North Slope profitability is apparently sufficient to induce the consistent production increases (i.e., slowed decline) identified above. But the public dialogue in

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[2] "Tapping New Oil," Anchorage Times, March 2, 1995, p. B-7.

[3] First Boston Equity Research, "Assessing the Domestic Operations of International Oil Companies: Explaining the Exodus of Capital," September 5, 1991, pp. 2-13. (See Richard A. Fineberg, North Slope Profits and Production Prospects [prepared for the Alaska State Legislature], Nov. 12, 1991, pp. 25-27.)

this area is blunted because North Slope producers steadfastly refuse to disclose information that would justify its position.[4]

B. HB 207 contains serious structural defects

I believe it is unwise to grant royalty reduction without providing for clear and unambiguous clarification on the public record of the necessity for that assistance. Instead, CSHB 207 (FIN)Am deliberately shields the actions of the Commissioner of Natural Resources from the public review that normally safeguards the public interest provisions giving the Commissioner of Natural Resources new powers to grant royalty relief that are ill-conceived and unprecedented. It has been clearly and convincingly documented in other North Slope revenue disputes that public policy evils flourish where confidentiality erodes the checks and balances and balances that normally protect the public interest and keep the public process on a steady course.[5]

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[4] Last May, in an "Open Letter to the People of Alaska" published in major Alaskan newspapers, BP Alaska President John Morgan stated that BP has paid more in taxes and royalties than it has taken out in profits or cash flow. This statement flies in the face of every public study of which I am aware. BP has refused repeated requests to put on the public record information that would substantiate its claim. (See attached correspondence; in 1992 and again in 1993, the importance of BP's refusal to provide clear public data on its North Slope operations were clearly delineated for the Legislature in my 1992 report, North Slope Profits and Production Prospects [prepared under contract to the Senate Finance Committee], Nov. 12, 1992, and by the Legislative Research Agency, Distribution of Income from Alaska Oil and Gas Operations . . . [Report No. 93.001], Sept. 15, 1993.)

[5] In a current case whose very existence would be hidden from the public had Exxon Corp. not been required to make some documents public in the United States Tax Court, Exxon is asking for retroactive tax deductions that the Internal Revenue Service has said could ultimately be worth $18 to 25 billion if applied to all North Slope producers. Exxon argues that ultimate abandonment of costs of Prudhoe Bay are deductible for federal tax years 1977 through 1984 under federal tax law because those claims are both knowable and fixed (United States Tax Court Dockets No. 18618-89 and 18432-90). In December 1994, the Alaska Oil & Gas Association recommended that the state should clarify what it might require for the abandonment of Prudhoe Bay. Ironically, Exxon was identified as the lead source for that recommendation ("AOGA Briefing Paper: Lease Closure," presented to Knowles-Ulmer Transition Team Dec. 28, 1994). The blatant contradiction between Exxon's position in separate arenas is indicative of the kind of games that take place under the cloak of confidentiality.

A second example of public policy abuses flourishing behind the veil of confidentiality is the 1985 TAPS tariff settlement. Due to confidentiality, key elements of that sorry record were not available to the public until after the settlement had been formally approved. In one instance during the latter stages of the TAPS saga, the Governor was briefed on an erroneous document that was subsequently removed from files and replaced with an altered document, in apparent violation of Alaska statutes. (See Richard A. Fineberg, The 1985 TAPS Settlement: A Case Study in the Effects of Confidentiality on Information Available to Decision Makers in Oil and Gas Revenue Disputes (prepared for the Alaska State Legislature), Feb. 5, 1990), pp. 30-36. For a later study of a TAPS settlement defect with enormous state and federal revenue consequences that was mis-stated and consequently overlooked during the flawed 1985 settlement review process, see Richard A. Fineberg, Hidden Billions: The TAPS DR&R Provision (report prepared for Stan Stephens, Valdez, Alaska), August 21, 1992.

1. Procedures for Royalty Relief Should Be Clearly Framed and the Need for Royalty Relief Should Be Clear to the Owners of the Resource. *(CSHB 207[Fin]Am page 1, line 10)* Particularly in view of the production trends discussed above and the fact that industry statements about profitability fly in the face of every published report of which I am aware,[6] the process, the criteria and the case for royalty relief should be clearly defined and the case should be part of the public record. This bill does the opposite. For example, where the existing statute requires regulations to make procedures clear, this bill removes that requirement.

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on industry request. In view of the clearly established right of the public to know what its officials are doing, he said, the industry should make a showing that it is necessary to hold documents confidential.[7] As recently as 1990, after careful review in three committees and despite strong industry opposition, the Alaska State House voted unanimously to prohibit oil and gas settlements from extending confidentiality beyond that already required by law.[8] This bill reverses both precedents.

4. Contractor Analysis. *(CSHB 207[[FIN]Am page 3, lines 17-21)*
Apparently throwing in the towel on a 20-year endeavor to establish and maintain expertise within the state system to protect the public interest in the inevitable dialogue with industry, this bill sets up an unprecedented system in which the Commissioner will rely instead on a contractor to the industry.

5. Review. *(CSHB 207[FIN]Am page 3, line 24 through page 5, line 2)*
The public review contemplated by the latest version of HB 207, although much improved, is seriously flawed in two respects — first, by the unprecedented grant of blanket confidentiality, discussed above, and secondly, by excessive reliance on Legislative review. With all respect, that route is notoriously ineffective. Let me tell you about one confidential oil and gas briefing in which I participated in this very committee room (or the one next door) several years back. Two legislators — the most senior member of the Legislature and a member of this present body — refused to participate because they could not accept the confidentiality requirements imposed by the administration. The briefing continued behind closed doors; I watched as the Legislature was misinformed on issues I considered important. I was ordered silent by my bosses. When a clever response to a misdirected question pulled the legislators off track, I could have spoken out; to do so would have meant

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[7] The court specifically refused to hold material confidential merely at the request of the industry, without a showing for the need for confidentiality, because "the public's right to know what the executive branch is about" outweighed the industry's speculative assertion of possible damage resulting from the release of information about its business. "Memorandum Opinion and Order No. 92-71 (Denying Motions by BP Exploration [Alaska], Inc. for Continued in camera Treatment of Certain Documents in Court Record)," ANS Royalty Litigation, 1JU-77-847 Civil, May 27, 1992 (19 pp.). The judge reaffirmed that order last month. "Order [Denying Motions to File Documents Under Seal]", ANS Royalty Litigation, 1JU-77-847 Civil, March 20, 1995.

[8] HB 541, 1990. Several members of this body, then in the House, voted for the provision limiting settlement confidentiality.

giving up my job — and with it, the ability to directly influence other important executive decisions then pending.[9]

6. Judicial Review. *(CSHB 207[FIN], Page 4, line s 24-25)* It's easy to see why the industry would like to remove judicial review; in view of the long history of increased revenues the state has obtained through the courts, one wonders why the stewards of public resources would recommend this course of action.

C. The current approach to incentives is flawed.

In the policy arena, where the mission is to protect the public interest in both the revenue stream and the environment, industry desires must be balanced against these concerns. It is self-evident that any bill that increases industry revenue at the expense of the State Treasury will tend to stimulate production. The industry will, of course, advocate such a measure. But even if the startling provision that automatically grants confidentiality at lessee (producer) request were removed or replaced with language that guarantees public access to information necessary to evaluation of public policy, it remains to be demonstrated that this legislation is necessary, or that it reflects the wise stewardship of public resources mandated by the Alaska Constitution. In view of the well-documented history of abuses of confidentiality that have found their way into the public record, it makes little sense to allow the lessees, at their own initiative, to prevent these materials from seeing the light of day.[10]

To summarize: Even if the defects discussed above were corrected, the case for the proposed incentives would have yet to be made. This concludes my testimony; I would be happy to answer any questions you may have, and I thank you for the opportunity to testify.

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[9] While I customarily provide footnotes and documentation, I must ask you to accept this general description because I am constrained by confidentiality requirements from identifying the event. Were the briefing identified, you would find no committee tape or substantive record of the meeting — again due to confidentiality requirements.

[10] As the U.S. Supreme Court has observed, "People do not demand infallibility from their institutions, but it is difficult for them to accept what they are prohibited from observing." (Richmond Newspapers, Inc. v. Virginia, 448 U.S. 555, 572 [1980]; quoted in Memorandum 92-71, op. cit., cover page). To accomplish the Governor's well-intentioned desire to reduce litigation, the Legislature might consider introducing legislation that puts more information on the public record — not less.

Table 1 Richard A. Fineberg (4/13/95)

1985, 1990 and 1995 ADOR Production Forecasts thru 2010

Forecast:	(1) DOR 1985 (Spring)	(2) DOR 1990 (Spring)	(3) U.S. DOE* (Fall 1990)	(4) DOR 1994 (Fall)	(5) 1995 DOR (Spring)	(6) CERA 1995 (March)
Years	/ = = = = = = = = = = 000 Barrels Per Day	= = = = = = = = = = = = /				
	Forecast:				*Actual:*	
1986	1,730				*1,800*	
1987	1,760				*1,850*	
1988	1,640				*2,010*	
1989	1,560	*Forecast:*	*Forecast:*		*1,960*	
1990	1,450	1,830	1,806		*1,850*	
1991	1,340	1,710	1,770		*1,800*	
1992	1,240	1,570	1,640		*1,790*	
1993	1,160	1,480	1,628		*1,700*	
1994	1,030	1,430	1,625		*1,610*	*Calendar Yr.*
				Forecast:	*Forecast:*	*Forecast:*
1995	910	1,310	1,590	1,641	1,573	1,710
1996	800	1,200	1,503	1,595	1,503	
1997	710	1,080	1,440	1,489	1,457	1,530
1998	630	1,000	1,323	1,408	1,418	
1999	540	920	1,238	1,366	1,375	
2000	470	900	1,113	1,291	1,342	1,350
2001	380	830	1,022	1,213	1,30[illegible]	
2002	310	760	928	1,146	1,246	
2003	250	690	839	1,036	1,195	
2004	200	650	757	934	1,146	
2005	160	590	652	842	1,103	1,730
2006	130	580	582	784	1,037	
2007	110	520	523	729	974	
2008	90	470	455	677	965	
2009	70	430	405	624	904	
2010	60	380	375	583	843	1,640

	/ = = = = = 000 Barrels Total Production (000 BPD x 365)	= = = = = /				
1995-2010 ==>	2,124,300	4,493,150	5,381,483	6,335,670	7,075,525	Forecast
1986-94 ==>	*4,712,150*	*n.a.*	*n.a.*	*n.a.*	*5,975,050*	*Actual*

* U.S. Dept. of Energy 1990 forecast (Col. [3]) was more optimistic than the contemporary state forecast; five years later, the DOE forecast appears to have been rather conservative.

Table 2

Spring 1990 Production Forecast for 1995-2010 (Alaska Dept. of Revenue)
(000 bbls)

000 Barrels per day:

Year	*Field =>*	Prudhoe*	Kuparuk	Lisburne	Pt. McIntyre	Endicott	Milne Pt.	Niakuk	W. Sak	Other**	Total	
1995		920	160	30	60	70	20	30	20		1,300	*000 bpd*
1996		840	140	30	60	70	20	20	20		1,200	"
1997		750	120	30	60	70	20	20	20		1,090	"
1998		690	100	30	60	70	10	20	40		1,020	"
1999		640	90	20	50	60	10	20	40	0	930	"
2000		570	70	20	50	50	10	20	60	50	900	"
2001		530	60	20	40	50	0	20	60	60	840	"
2002		460	50	20	40	40		20	80	60	770	"
2003		410	40	10	30	40		10	80	60	680	"
2004		370	40	10	30	30		10	110	50	650	"
2005		340	30	10	30	30		10	100	40	590	"
2006		300	30	10	30	30		10	150	30	590	"
2007		250	20	10	20	20		10	150	30	510	"
2008		210	20	10	20	20		10	150	30	470	"
2009		190	20	10	20	20		10	150	20	440	"
2010		160	10	10	20	10		0	140	20	370	"
Total Barrels:		2,784,950	365,000	102,200	226,300	248,200	32,850	80,950	500,050	164,250	4,507,750	(000 bbls)

* Includes all NGL's

** North Star

Source: Alaska Dept. of Revenue, "Revenue Sources Book: Forecast & Historical Data," Spring 1990, p. 47 ("Simulated Oil Production [Mid Case]")

Table 3 (Fall 1994)

Research Associates 4/95

Fall 1994 Production Forecast for 1995-2010 (Alaska Dept. of Revenue)

(000 bbls)

000 Barrels per day:

Year	*Field =>*	Prudhoe *	Kuparuk	Lisburne	Pt McIntyre	Endicott	Milne Pt.**	Nikaitchuq	W.Sak	Other***	Total	
1995		1,084	304	17	106	91	21	16			1,639	*000 bpd*
1996		1,057	292	15	101	80	27	24			1,596	"
1997		969	279	12	93	74	38	24			1,489	"
1998		926	251	11	86	67	39	21		6	1,407	"
1999		874	226	9	79	62	36	19		59	1,364	"
2000		827	204	8	73	58	36	18		68	1,292	"
2001		785	181	6	67	53	35	16		70	1,213	"
2002		753	161	5	62	48	32	14		71	1,146	"
2003		684	143	5	57	42	29	12		65	1,037	"
2004		622	128	4	52	38	25	10		56	935	"
2005		565	113	3	48	34	22	8		50	843	"
2006		536	101	3	44	30	19	7		45	785	"
2007		506	90	2	41	27	16	6		40	728	"
2008		479	80	2	37	24	14	5		35	676	"
2009		453	71	2	34	16	12	4		31	623	"
2010		431	63	1	31	15	11	4	0	28	584	"
Total Barrels:		4,216,115	980,755	38,325	369,015	277,035	150,380	75,920	0	227,760	6,335,305	*(000 bbls.)*

* Includes all NGLs, N Prudhoe, W Beach

** Includes Schrader Bluffs

*** North Star, Cascade

Source: Alaska Dept of Revenue, "Revenue Source Book: Forecast & Historical Data," Fall 1994, p. 43 ("Base Case Simulated Oil Production")

Table 4.

Spring 1995 Production Forecast for 1995-2010 (Alaska Dept. of Revenue)

(000 bbls)

000 Barrels per day.

Year	Field =>	Prudhoe *	Kuparuk	Lisburne	Pt McIntyre	Endicott	Milne Pt **	Niakuk	W Sak	Other***	Total	
1995		1,007	304	18	112	95	20	14			1,570	(000 bpd
1996		919	293	15	111	91	53	27			1,503	"
1997		880	290	13	106	90	52	24			1,455	"
1998		857	290	12	103	83	45	21		7	1,418	"
1999		835	289	10	92	76	40	20		14	1,376	"
2000		808	288	9	83	70	40	18	12	14	1,342	"
2001		796	283	8	75	64	35	16	12	15	1,304	"
2002		769	275	7	68	58	30	14	12	12	1,245	"
2003		740	267	6	60	52	27	12	19	10	1,193	"
2004		713	258	6	53	47	24	11	25	10	1,147	"
2005		685	249	5	47	43	21	9	37	9	1,105	"
2006		646	223	4	41	38	18	8	50	9	1,037	"
2007		607	198	4	37	35	16	7	62	9	975	"
2008		570	177	3	32	31	13	6	74	58	964	"
2009		535	157	3	28	28	12	5	74	61	903	"
2010		504	141	3	25	26	11	4	70	60	844	"
Total Barrels:		4,330,725	1,453,430	45,990	391,645	338,355	166,805	78,840	163,155	105,120	7,074,065	(000 bbls)

* Includes all NGL's, N. Prudhoe, W. Beach

** Includes Schrader Bluff

*** North Star, Cascade

Source: Alaska Dept. of Revenue, Spring 1995 Base Case Forecast ("Base Case Simulated Oil Production")

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Resource Development Council for Alaska, Inc.

121 West Fireweed Lane, Suite 250, Anchorage, Alaska 99503-20
Phone 907/276-0700 Fax 276-383

Testimony of Resource Development Council
on HB 207
An Act relating to the reduction of royalties reserved to the state to encourage production of oil and gas from marginal fields
Senate Resources Committee
April 21, 1995

Good afternoon. My name is Carl Portman, Communications Director of the Resource Development Council for Alaska, Inc. On behalf of RDC, thank you for the opportunity to testify on HB 207.

RDC is a proponent of a strong oil and gas industry and has worked to advance incentives that will encourage the industry to explore for new oil fields in Alaska and to bring into production existing reserves. Oil revenues account for 85 percent of state revenues and one in every three jobs in Alaska. As oil production and revenues decline, so will the number of Alaska jobs supported by petroleum revenues.

Sustaining industry investments in Alaska projects is in the best interests of this state. Half of the oil production projected for 2000 and beyond is based on investments yet to be made. As a result, the outlook for future production and revenues could be worse than current projections if investments are made elsewhere.

Alaska is at a competitive disadvantage in attracting capital investments because of high transportation, exploration and development costs, long lead times, crude oil characteristics that discount North Slope oil compared to other crudes and a state revenue structure that takes a bigger share of profits. Moreover, the opportunities that do exist on the North Slope consist of marginal new oil fields or marginal projects within existing fields. In this global environment, companies are becoming increasingly selective in choosing which projects to pursue. Projects that are funded are those offering the highest returns against the lowest risks.

What we need is a strategy to overcome these disadvantages, to make Alaska more competitive in the world market so that more dollars are invested here. In this emerging era of marginal oil field development, the strategy must be based on the team concept. It is imperative that the oil industry and the State of Alaska work

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together as a team to overcome the challenges and capture the potential for new investments, revenues and jobs.

HB 207, the royalty adjustment legislation, will encourage teamwork and is a step toward making our collective share of oil revenues grow. Flexibility in setting royalty terms for marginal fields will help attract investment capital and maximize long-term benefits to the state. HB 207 is a tool that the State can use to enhance the competitiveness of projects whose funding might otherwise go abroad.

The legislation before you is also an important hedge industry needs against the risk of low oil prices. Low prices is a risk the industry cannot effectively manage alone. As you know, Alaska production is especially vulnerable to low prices due to the current structure of state taxes and royalties. HB 207, however, would help to minimize the industry's exposure to low prices and enhance prospects for making development more viable.

Flexibility in royalty terms would encourage the state and the industry to work together to change the economic equation for marginal fields. And by working together to identify win-win solutions, we can all gain, and in the process, bring on new oil fields, extend the life of existing fields and build a stronger economic base for the future.

Working together to reach shared goals is more important than ever because so much of Alaska's future production will come from marginal fields -- accumulations that would be developed if they were in the lower-cost and lower-risk environment of the Lower 48. HB 207, however, is a step in the right direction. It sends a clear signal that Alaska aims to be competitive in the world market to attract the investments necessary to develop its oil and gas potential. It provides the flexibility needed in working with investors on a case-by-case basis to make new development a reality.

RDC strongly supports this legislation. Thank you for the opportunity to comment.

THE FOLLOWING PAGES
WERE TREATED AS A UNIT
IN THE ORIGINAL FILE

HB 207 BRIEFING PAPER

FOR SENATE RESOURCES COMMITTEE

APRIL 1995

CS FOR HB 207(FIN)AM QUESTIONS & ANSWERS

A. Purpose

1. What, generally, does the bill accomplish?

This legislation amends current law to give the Commissioner of the Department of Natural Resources (DNR) authority to grant royalty reduction for fields that have been delineated, but not produced. The current law allows the commissioner to grant royalty reduction to prolong the economic life of a field or to reestablish shut-in production. The bill requires that the applicant make a clear and convincing showing that any reduction meets certain requirements and is in the best interests of the state. As part of the application the commissioner shall require the applicant to provide financial and technical data (which may be kept confidential at the request of the applicant) to assure that the requirements are met and that a royalty reduction is warranted. If the commissioner determines that a third-party analysis of the submitted data is necessary, then he may require that the applicant pay for this analysis. This bill also provides that if relevant factors change in the future, then the commissioner may raise the royalties that were previously reduced. The commissioner must condition royalties if oil price changes.

These reductions may be applied only if one of the three "trigger events" is met:

- Fields that are delineated, but not previously produced, to allow production that would not otherwise be economically feasible.
- Oil and gas fields whose economic life may be prolonged in light of increasing costs in the later stages of production.
- Reestablishing commercial production of shut-in oil or gas that would not otherwise be economically feasible.

Before approving any royalty reduction, the commissioner must issue written findings assuring compliance with the requirements of this section and that the best interests of the state are preserved. The legislation also requires the commissioner to give notice of his preliminary findings and determination to the legislature and public, and allow for comment before adopting final findings and determination. The current committee substitute also states that the commissioner shall offer to provide the LB&A committee a review of the preliminary findings and determination.

2. Why is a change in the law necessary?

A change is necessary for three reasons. First, a change will help to make Alaska more competitive on a worldwide basis for oil companies' investment dollars. The legislation would give the commissioner greater flexibility than exists under current law and authority to reduce the royalty rate on fields that have been delineated, but have not previously produced oil or gas. Second, it would change the economic standard for a reduction for a mature field to a

point-forward or incremental analysis from a historical investment analysis which is not relevant to a decision whether to abandon or continue producing a field. Third, it would clarify the authority to reduce royalty under AS 38.05.180 (j) & (p).

B. Standards

1. The "best interest" standard seems vague. Should the legislature define the criteria that must be considered in making a best interest decision? Should the legislature maintain the requirement in existing law that the commissioner must find that the "state has obtained the maximum economic return that is compatible with allowing a reasonable rate of return for the lessee"?

Before talking about further defining the best interest standard, there already is a clear limit on the commissioner's authority. The current statute permits the commissioner to grant royalty reduction only if one of two trigger events is met. As discussed above, the legislation would add a third trigger event -- a delineated field that would not otherwise be economically feasible to produce. Only if that showing is met, which must be met by clear and convincing evidence, is the commissioner authorized to even consider whether he should grant royalty relief.

If the commissioner makes a finding that one of the trigger events has been met, then he must decide whether the reduction would be in the best interest of the state before a reduction would be granted. This standard, or a similar standard, is used throughout the statutes without explicit criteria set forth. For example, AS 38.05.180(p) gives the commissioner authority to unitize oil and gas leases if he determines it is necessary to "secure the public interest."

Importantly, DNR has already discussed the best interest standard in connection with Conoco's royalty reduction application. In a published decision document, then Commissioner Heinze noted that the "public interest finding (does) not simply weigh cash gains and losses to the state government" although he determined that lost revenues to the state government would be approximately four times greater than the sum of additional royalties to the state government. The commissioner considered: (1) the effect on the total royalties that would be paid; (2) the additional projected recovery of oil; (3) the ability of the project to render a positive cash flow; (4) the desirability of encouraging further investment that has a direct benefit to the state; (5) the effect of additional production on TAPS throughput; and (6) the benefits of additional employment. At a minimum, the commissioner would consider these factors in making any decision.

The legislature, of course, remains free to put sideboards or restraints on the commissioner's discretion, but any sideboard or restraint could effectively restrain the commissioner's ability to craft practical relief for a given field or reservoir. The current version of the bill requires the commissioner to change the royalty rate if the price of oil changes.

Finally, DNR opposed an amendment to reinstate the "maximum possible economic return to the state" standard. DNR believes that the economic standard set forth in the trigger events is adequate. Moreover, the maximum economic standard is an impossible standard to define, let alone meet.

2. Why does the legislation change the standard for royalty reduction for mature producing fields?

The legislation actually clarifies the confusing old standard of reasonable rate of return on total investment. The old standard is unworkable for fields in the later stages of production. For these fields, the analysis should be based on expected future costs and future revenues. Past profitability has little to do with the decision to produce or abandon a field today or tomorrow. Abandonment decisions are based on a point-forward analysis, not historical performance.

3. Why does the legislation change the standard of persuasion from "clear" to "clear and convincing"?

The "clear and convincing" standard is a term of art in the law which has been defined by the courts and has an accepted definition. A "clear" standard has not been so embraced. This lead to a dispute between DNR and Conoco & Oxy in their application for royalty reduction. The issue was pending before the superior court, but had not been decided, when the parties settled. The change was made in hopes of avoiding litigation.

4. The legislation is non-specific about when and how the royalty could increase. Shouldn't it be more specific?

This provision is basically the same as existing law. Specifying when and how the royalty must increase would take away flexibility. Presumably, the commissioner's decision would provide for an increase if prices increase or costs decrease. However under the governor's bill, there would be flexibility to tailor the terms to the specific facts. The commissioner's final finding or determination would include the terms providing for the increase.

5. What does the term "delineated" mean? Should the term be defined in the statute?

DNR believes that the term "delineated" is a term of art in the industry. Its generally accepted definition is that there is sufficient knowledge of the aerial extent, volume, and productivity of the field to allow a lessee to decide whether to proceed with development and production, including determining costs to develop and produce the field. In other words, delineation is the process by which a resource in a previously discovered accumulation makes the transition to "reserves." Reserves are resources demonstrated with reasonable certainty to be recoverable from a known accumulation under existing economic and operating conditions.

The requisite information varies from field to field and no specific test would suffice for all fields. The information pertinent to making the decision would include drilled wells, seismic data and interpretations, and engineering data on the reservoir's characteristics, including well flow test data of sufficient duration to provide estimates of future development well productivity.

DNR believes that any attempt to specifically define "delineated" would likely create as many problems as it solves.

6. What do the terms "field" and "pool" mean?

The meaning of the term "field" was disputed in the Conoco & Oxy application process. DNR defined the term to include all reservoirs or pools underlying the lease or unit area. "Pool" means an underground reservoir containing a common accumulation of oil or gas. Each zone of a general structure which is completely separated from any other zone in the structure is covered by the term "pool." The terms "pool" and "field" mean the same thing when only one underground reservoir is involved, but "field" - unlike "pool" - may relate to two or more pools. To prevent future disputes, and to increase flexibility, the bill references both "field" and "pool."

7. Can the royalty reduction apply to a single pool on a given lease, as compared to all production from the lease?

The legislation would give the commissioner that discretion. If there had been production from one pool in a field, but not another pool, the commissioner would have authority to consider a royalty reduction only for some or all of the second pool if it had been delineated. Future discoveries or developments on the lease would not be automatically granted a reduction.

On leases that have been developed, such as the Kuparuk-West Sak situation, DNR wants the latitude to consider royalty reductions for the West Sak reservoir, while retaining the original royalty rate for the deeper Kuparuk reservoir.

8. Would the royalty reduction be granted for the entire field or unit area?

The reduction, if granted, would be granted on a lease by lease basis. The lease or unit agreement establishes the royalty rate, and it is the lease or unit agreement that needs to be amended if the royalty rate is to be changed. Of course, the reduction could apply to all leases within the unit area.

9. Would the bill allow the Commissioner to reduce the royalty rate at the state's largest fields, including Prudhoe Bay?

No. The new trigger event in the bill would not allow a royalty reduction for a field like Prudhoe Bay. Both gas and oil have been produced and sold from that field. Consequently, it could not qualify under the new trigger event of a delineated, but not produced field. Simply put, a reduction is not necessary to get the field developed. At some point in the distant future when the field is in steep decline, Prudhoe Bay may become eligible for a reduction under one of the other two trigger events contained in the current royalty reduction statute.

10. What does the term "reasonable rate of return" mean in the current legislation?

DNR recommends dropping the term. This term led to serious disagreements between an applicant and DNR. DNR felt obliged to adopt an objective standard which could be applied consistently regardless of the vagaries of an individual company's financial planning standards. Recognizing that neither the state's oil and gas leases nor statutes guaranteed a company a specific rate of return, or any return at all, Commissioner Heinze adopted a standard – the return on a 90 day Treasury bill – which provided a positive real rate of return, but did not provide an excessive profit at the expense of the state's royalty share. Other potential rates considered by DNR included: (1) the individual company's cost of capitol plus a marginal profit; (2) a public utility type rate of return; (3) the economic yardstick used by DOE to determine if a field is commercially developable; (4) the long-term bond yield; and (5) the rate allowed by DOR in determining reasonable shipping rates for severance tax purposes. As noted previously, once a field is developed (i.e., major investments sunk) any revenue in excess of operating costs is sufficient to keep the field in production.

C. Appealability & Confidentiality

1. The non-appealability clause seems unusual. Why is it in the bill?

The clause has two purposes: The first is to make clear that the statute does not confer on a lessee a right or entitlement to a royalty reduction. Even if the lessee makes a showing that the lessee could not economically produce the field, there is no duty on behalf of the commissioner to grant royalty relief. DNR makes a business judgment whether the state would rather have production on a reduced royalty basis or take back the leases and attempt to relet them. Moreover, the commissioner may have to consider other factors, such as the effect on the bidding process and on the environment, in determining whether a royalty reduction should be granted.

There is some federal law on the subject of royalty reductions on federal leases. Under federal law the Secretary of Interior has authority to reduce a lease's royalty rate under certain circumstances. But federal law holds that:

> [There are] no circumstances which require BLM to reduce royalty. Under the statute, no entitlement to such a reduction can ever arise. BLM

> remains free to accept the economic consequences of denying royalty relief, which may vary from case to case. ... The discretionary authority conferred by (the federal royalty reduction statute) enables BLM to exercise prudent business judgment to accept the alternative that best protects the economic interest of the United States as owner of the mineral resources.

Peabody Coal Co., 93 IBLA 317, 326 (1986) (emphasis added).

Given that there is no entitlement or no right to a royalty reduction, the second purpose is to preclude expensive, time consuming litigation, which can have no basis, by the applicant whose application has been denied. The intent of the provision is to preclude the applicant from appealing. The courts have rejected an argument that there is a constitutionally guaranteed minimum right of judicial review where the "administrative activity ...involves the grant or denial or a privilege which the state government is free to allow or withhold in its discretion ...." Cooper, State Administrative Law 677 (1965). The Department of Law believes that the commissioner's determination regarding a royalty reduction application would fall into that category and thus the court would likely give effect to a provision precluding judicial review.

The general rule, according to Professor Davis, one of the foremost authorities on administrative law, is that:

> [I]f a statute unequivocally precludes judicial review of an agency action, and judicial review is sought on any basis other than a claimed violation of a constitutional right, the Court will give statute effect.... When the scope and effect of an explicit statutory limit on judicial review is less clear, however, and the Court perceives a significant risk of unfairness if the statutory limit is given broad effect, the Court sometimes strains to interpret the limit narrowly.

Davis, Administrative Law, §17.8 at 155. The court could read into the finality provision an implied exception permitting review of constitutional questions, questions regarding the jurisdiction of the agency and the regularity of its procedure, questions affecting the existence of property rights, questions involving bad faith, or questions regarding fraud. Cooper, supra at 679.

The Alaska Supreme Court has stated that a "legislative statement of finality is one which we will honor to the extent that it accords with constitutional guarantees." K & L Distributors, Inc. v. Murkowski, 486 P.2d 351, 357 (Alaska 1971). It is likely that the court will attempt to whittle down any finality language to size to fit the court's sense of fundamental fairness. In other words, a statement of finality will not prevent the court from reviewing the decision to assure compliance with the due process clause under the Alaska constitution. Nevertheless, a finality provision will mean that any review of a royalty reduction decision will

be much more limited than the broad review of an agency decision required by the Alaska Administrative Procedure Act. For example, the court would not review each factual finding to see that it is correct, or even that it is supported by substantial evidence. The court would only examine the commissioner's decision to determine whether it has "passed beyond the lowest limit of the permitted zone of reasonableness to become capricious, arbitrary or confiscatory." Id. at 358. Given this, we believe that it is less likely that a disgruntled lessee would appeal and, therefore, more likely needless court expense would be saved.

2. Should the commissioner's decision be subject to legislative review?

The administration does not object to some type of legislative oversight. The administration believes that the legislature could request a briefing even without a specific provision in the bill. The administration notes that at least one company has opposed a proposed amendment which would have provided for a confidential briefing by the commissioner of the legislature.

3. Why does the bill contain confidentiality provisions?

The confidentiality provision in the bill is no different than existing law. The purpose of this provision is to protect a company's competitiveness relative to other companies. Obviously, a company which has spent millions of dollars to acquire geological, geophysical, and engineering information regarding a potential oil field does not want that information revealed to other companies. Furthermore, releasing financial information about the company would reveal the company's underlying economic philosophy regarding exploration and development and, thus, disadvantage the company with respect to its competitors. The confidentiality provision actually promotes the disclosure of complete and frank information to the state. Given industry's testimony at the hearings, it is likely that without a confidentiality provision for new fields, no company would apply for royalty relief and the benefits of the bill would be lost. Nevertheless, the bill allows the company to disclose its information to the public if it desires.

D. Miscellaneous

1. Why does the legislation delete the provision in former law that the commissioner shall adopt regulations?

Such a provision is unnecessary and would delay the implementation of any new program. Under current law, the commissioner already has the authority to adopt regulations necessary to carry out the purposes of the Alaska Land Act. AS 38.05.020(b)(1). There are already existing regulations which define the procedure for submitting an application for reduction under AS 38.05.180(j). 11AAC 83.185. DNR would plan to amend those regulations to deal with the proposed changes in the statute. DNR, however, does not want to be required to

implement regulations because that could delay implementation of any new statutory changes. The current law allows the commissioner to adopt regulations if needed.

2. Do you have any concerns that the legislation will undermine the competitive bidding process?

The commissioner will have to consider this issue in determining whether a reduction is in the state's best interest. Certainly, if the royalty rate is the bid variable this is a very real concern. In general, the closer the reductions to the time of the bid, the greater the concern. That is one of the reasons why the former law provided for a two year production requirement. That requirement, however, proved unworkable and the legislature dispensed with that requirement in 1990 to allow the commissioner more flexibility.

The proposed amendment tries to balance the need to protect the bidding process with the need to get marginal fields timely developed. For example, a reduction cannot take place until the lessee at least does delineation work. In other words, the commissioner could not grant a reduction the day after the lease sale. More importantly, the commissioner cannot grant a reduction unless the lessee makes a clear and convincing showing that absent relief the field would not otherwise be economically feasible. In making that determination and deciding whether granting relief would be in the state's best interest, the commissioner will have to examine whether other potential lessees would develop or produce the field without royalty relief.

The Alaska Supreme Court has recognized a competitively bid government contract can be amended under certain circumstances without jeopardizing the competitive bid process. Kenai Lumber Co., Inc. v. LeResche, 646 P.2d 215, 220-22 (Alaska 1982). Importantly, every state oil and gas lease contains a royalty reduction so all competitive bidders were on notice that the royalty could be reduced under appropriate conditions.

4. Is it legally required that the permanent fund be held harmless?

Probably not, but a concern has been raised. Article IX, Section 15, provides that: "At least twenty-five per cent of all mineral lease rentals, royalties, royalty sale proceeds ... **received by the state** shall be placed in a permanent fund." The Department of Law believes that the most likely interpretation of the constitutional provision is the permanent fund gets 25% of whatever the state gets and if the state gets a lesser or greater royalty for that matter, the permanent fund gets 25% of that amount.

An argument can be made that the provision means the permanent fund gets 25% of the original royalty rate specified in the lease and the legislature or the commissioner cannot change the amount, at least for the permanent fund. The Department of Law does not believe that such an argument would be persuasive to a court. There have been statutory and lease provisions providing for royalty reduction in one form or another since statehood. These

provisions were in effect at the time the permanent fund provision took effect and no special provision was enacted to keep the permanent fund whole in that instance. Consequently, we believe the permanent fund takes its 25% share subject to the possibility that the royalty share may be reduced. In short, the permanent fund gets at least 25% of whatever the state receives.

A good example would be the administration of the former royalty reduction statute (which still applies today on some of the older leases). That statute provides for reduction of the royalty rate to 5% on a lease where a discovery is made. In that case, the permanent fund has not been held harmless or kept whole. The permanent fund gets 25% of the reduced rate, no more or no less.

The current committee substitute deletes the permanent fund hold harmless provisions which were in the bill as originally introduced. Regardless of whether the bill contains hold harmless provisions, the administration supports a floor for any reduction that does not exceed 75% of the applicable royalty rate.

HB 207 Briefing Paper for Senate Resources Committee

1. Former and Current Versions of the Royalty Reduction Statute

2. Former and Current Versions of the Unitization Statute

3. Royalty Reduction Regulations

4. Former & Current Royalty Reduction Lease Provisions

5. Commissioner Heinze's Decision on Conoco's Application for Royalty Reduction

6. Article re Federal Legislation to Provide Royalty Relief for New Production Off Alaska

VERSIONS OF THE ROYALTY REDUCTION STATUTE

1959 Statute

SLA 1959, Chapter 169, Article VIII, § 2
Leasing of Mineral Lands

Sec. 2. No person, association, or corporation, except as herein provided, shall take or hold coal leases or permits during the life of such lease on Alaska lands....**The Commissioner, for the purpose of encouraging the greatest ultimate recovery of** coal, **oil,** gas, oil shale, phosphate, sodium, potassium, and sulphur, **and in the interest of conservation of natural resources, is authorized,** after public hearing, **to** waive, suspend, or **reduce the** rental, or **minimum royalty,** or reduce the royalty on an entire leasehold, or on any tract or portion thereof segregated for royalty purposes, **whenever in his judgment it is necessary to do so in order to promote development, or whenever in his judgment the leases cannot be successfully operated under the terms provided therein.** In the event the Commissioner, in the interest of conservation, shall direct or shall assent to the suspension of operations and production under any lease granted, any payment of acreage rental or of minimum royalty prescribed by such lease likewise may be suspended during such period of suspension of operations and production; and the term of such lease shall be extended by adding any such suspension period thereto.

1978 Statute

SLA 1978, Chapter 155, Section 1

AS 38.05.180 (j) To prolong the economic life of an oil and gas field, the commissioner shall adopt regulations for all bidding methods to allow reduction of royalty on leases within the field to compensate for increasing costs in the later stages of production decline. The commissioner may not grant a reduction of royalty until two years' initial production from the field has occurred and each lessee requesting the reduction has made a clear showing that the revenue from all hydrocarbonsproduced from the field is insufficient to produce a reasonable rate of return with respect to that lessee'n total investment in the field.

1990 Statute

SLA 1990, Chapter 124, Section 3

AS 38.05.180 (j) To prolong the economic life of an oil and gas field or to reestablish commercial production of shut-in oil or gas that would not otherwise be economically feasible, the commissioner shall adopt regulations to allow reduction of royalty or leases. The commissioner may not grant a reduction of royalty unless the lessee requesting the reduction makes a clear showing that the revenue from the lessee's share of all hydrocarbons produced from the field is and is likely to continue to be insufficient to produce a reasonable rate of return with respect to the lessee's total investment in the field. The commissioner may condition a royalty reduction granted under this subsection in any way necessary to protect the state's interest including restoration of the state's royalty share in the event of an increase in the price of oil or gas. Before approving a royalty reduction, the commissioner shall make a written finding that the state has obtained the maximum possible economic return that is compatible with allowing a reasonable rate of economic return for the lessee, and send copies of the finding to all members of the legislature.

VERSIONS OF THE UNITIZATION STATUTE

1960 Statute

SLA 1960, Chapter 61, Section 18

(Formerly AS 38.05.180 (m)) For the purpose of more properly conserving the natural resources of any oil or gas pool, field, or like area, or any part thereof (whether or not any part of said oil or gas pool, field, or like area is then subject to any cooperative or unit plan of development or operation), lessees thereof and their representatives **may unite with each other**, or jointly or separately with others, in collectively adopting or operating under a cooperative or unit plan of development or operation of such pool, field, or like area, or any part thereof, whenever determined and certified by the Commissioner to be necessary or advisable in the public interest. **The Commissioner is thereunto authorized, in his discretion**, with the consent of the holders of leases involved, to establish, alter, **change**, or revoke drilling, producing, rental, **minimum royalty**, and royalty requirements of such leases and to make such regulations with reference to such leases, with like consent on the part of the lessees, **in connection with the institution and operation of any such cooperative or unit plan as he may determine necessary or proper to secure the proper protection of the public interest**. The Commissioner may provide that oil and gas leases issued under this subsection shall contain a provision requiring the lessee to operate under such a reasonable cooperative or unit plan, and he may prescribe such a plan under which such a lessee shall operate, which shall adequately protect all parties in interest, including Alaska.

1978 Statute

SLA 1978, Chapter 155, Section 1

AS 38.05.180 (p) To conserve the natural resources of all or a part of an oil or gas pool, field or like area, the lessees and their representatives may unite with each other, or jointly or separately with others, in collectively adopting or operating under a cooperative or a unit plan of development or operation of the pool, field, or like area, or a part of it, when determined and certified by the commissioner to be necessary or advisable in the public interest. The commissioner may, with the consent of the holders of leases involved, establish, change, or revoke drilling, producing, and royalty requirements of the leases and adopt regulations with reference to the leases, with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan as he determines necessary or proper to secure the proper protection of the public interest. The commissioner may require oil and gas leases issued under this section to contain a provision requiring the lessee to operate under a reasonable cooperative or unit plan, and he may prescribe a plan under which the lessee must operate. The plan must adequately protect all parties in interest, including the state.

11 AAC 83.183. SLIDING SCALE ROYALTY. If the commissioner selects a method of bidding which sets a royalty reserved to the state, either fixed or as the bid variable, based on a sliding scale, the sliding scale will be determined, according to a method chosen at the commissioner's discretion which will be based on volume of production or other factors. The method chosen by the commissioner will consider the prolongation of the economic life of the oil and gas reservoir or reservoirs underlying the sale area or lease to which the sliding scale is to be applied. (Eff. 11/5/79, Register 72)

Authority: AS 38.05.020
AS 38.05.180

11 AAC 83.185. ROYALTY REDUCTION. (a) An application for a reduction of royalty on leases under AS 38.05.180(j) must comply with 11 AAC 88.105 and

(1) state all the facts entitling the applicant to relief;

(2) state location and status of all past and present activities on the lease;

(3) include a detailed report of all production during the six months preceding the filing of the application;

(4) contain a detailed statement covering the entire life of the lease showing all expenses and costs of operating the lease, including all royalties and overriding royalties and all income from all produced minerals from the lease; and

(5) include an agreement by the applicant to defray the cost of publishing a notice as provided by (b) of this section.

(b) Upon receipt of an application complying with (a) of this section, the commissioner will cause to be published a notice of public hearing as required on the application. The notice will

(1) state the time and place of hearing;

(2) describe the land involved; and

(3) state the name of the applicant and the nature of the relief applied for.

(c) The notice will be published at least once a week for at least two consecutive weeks in advance of the hearing date, which must be at least 15 days after the last date of publication, in at least one newspaper of general circulation in the vicinity of the principal office of the department, and must be posted at the principal office for the same period.

(d) At the time and place specified in the published notice, the commissioner will hear evidence offered by the applicant and any other interested party.

(e) Within a reasonable time following the hearing or any continuation of it, the commissioner will make written findings together with his determination as to the relief that should be granted.

(f) The commissioner will give notice of the findings and determination both to the lessee and to any other person who has filed a written request for it. The action taken is effective on the date specified in the notice. (Eff. 9/5/74, Register 51; am 7/22/79, Register 71)

Authority: AS 38.05.020(b)
AS 38.05.180(e)
AS 38.05.180(j)

11 AAC 83.190. EXTENSION BY COMMITMENT TO AN APPROVED UNIT. If, on or before the expiration date of the primary term of a lease, the lease is committed to a unit agreement approved by the state, the lease will be extended for so long as it remains subject to the unit agreement. (Eff. 7/22/79, Register 71)

Authority: AS 38.05.020(b)

Article 2. Net Profit Share Leasing

Section
201 Purpose
202 Payments due state
204 Net profit share rate
207 Accounting system
209 Production revenue account
212 Development account
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217 Exclusions from accounts
219 Development costs
222 Production revenue
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226 Valuation of oil or gas
230 Sales price
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238 Choice of methods for determining reasonable costs of transportation
239 Calculation of reasonable costs of transportation
231 Extraordinary production revenue or loss
232 Development account and production revenue account — In general
240 Direct operating costs
242 Royalty
243 Direct charges
244 Pricing of materials and supplies
245 Reporting and payment requirements
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Editor's notes — The former Article 2, relating to oil and gas lease discovery royalty, consisting of 11 AAC 83.200, 11 AAC 83.205, 11 AAC 83.210, 11 AAC 83.215, 11 AAC 83.220, 11 AAC 83.225 and 11 AAC 83.230, was repealed effective November 8, 1978.

11 AAC 83.201. PURPOSE. 11 AAC 83.201 — 11 AAC 83.295 establish procedures to be used by the lessee in calculating net profit share payments due the state for the production of oil and gas from any state net profit share lease (NPSL) issued by the department. The

(4) a description of the service rendered by the lessee prior to the request;

(5) a description of the proposed change; and

(6) a statement of the reasons for the proposed change.

(c) The commissioner of natural resources or his authorized representative will act on each completed request as soon as practicable. (Eff. 3/3/74, Register 49)

Authority: AS 38.05.020(b)(1)
AS 38.35.020(a)
AS 38.35.030
AS 38.35.040
AS 38.35.210

11 AAC 80.035. ADMINISTRATIVE DETERMINATION FOR TEMPORARY OR EMERGENCY SERVICE OR TEMPORARY OR EMERGENCY ABANDONMENT, REDUCTION OR IMPAIRMENT OF SERVICE. (a) The commissioner of natural resources, or his authorized representative, will disapprove a request for authorization for temporary or emergency rendering of service or a request for the temporary or emergency abandonment, reduction or impairment of service under AS 38.35.040 only after determining that

(1) the disapproval will promote state interests and goals and will have no adverse effect upon the interstate character of commercial activities which outweighs the public benefit; and

(2) the disapproval will not illegally interfere with an area of regulation pre-empted by federal statute or regulation.

(b) The commissioner of natural resources, or his authorized representative, will exercise the authority conferred upon him by AS 38.35.040 to require temporary or emergency rendering of service or temporary or emergency abandonment, reduction or impairment of service only after determining that

(1) the requirements will promote state interests and goals and will have no adverse effect upon the interstate character of commercial activities which outweighs the public benefit; and

(2) the requirement will not illegally interfere with an area of regulation pre-empted by federal statute or regulation.

(c) In making determinations required by subsections (a) and (b) of this section, the commissioner of natural resources or his authorized representative will investigate and consider all relevant facts and will make written findings which specify

(1) the state interests to be advanced by disapproving the request or by imposing the requirement and the degree to which the state interests will be advanced;

(2) the nature and degree of any adverse effect created on interstate commerce by disapproving the request or by imposing the requirement; and

(3) the nature and degree of the effect of disapproving the request or of imposing the requirement upon areas of federal regulation. (Eff. 3/3/74, Register 49)

Authority: AS 38.05.020(b)(1)
AS 38.35.020(a)
AS 38.35.210
AS 38.35.230(b)

11 AAC 80.045. FIELD GATHERING LINES EXEMPT. Field gathering lines are exempt from the requirement of obtaining a right-of-way lease under AS 38.35. (Eff. 3/3/74, Register 49)

Authority: AS 38.05.020(b)(1)
AS 38.35.020(a)

11 AAC 80.055. FIELD GATHERING LINES DEFINED. "Field gathering lines" means pipe and associated facilities, including separators, test equipment, pumps, treaters and tanks, used in the transfer of gas or oil from a well or other facility used in the production of gas or oil to a point where there is either a custody transfer of the gas or oil or where the gas or oil enters a common carrier pipeline, whichever first occurs. (Eff. 3/3/74, Register 49)

Authority: AS 38.05.020(b)(1)
AS 38.35.020(a)

CHAPTER 82. MINERAL LEASING PROCEDURE

Article
1. Availability of Land (11 AAC 82.100 — 11 AAC 82.115)
2. Qualifications (11 AAC 82.200 — 11 AAC 82.205)
3. Acreage Limitations (11 AAC 82.300 — 11 AAC 82.310)
4. Competitive Bidding (11 AAC 82.400 — 11 AAC 82.475)
5. Noncompetitive Procedure (11 AAC 82.500 — 11 AAC 82.540)
6. Miscellaneous Leasing Procedure (11 AAC 82.600 — 11 AAC 82.675)
7. Royalty Produce (11 AAC 82.700 — 11 AAC 82.715)
8. Records and Reports (11 AAC 82.800 — 11 AAC 82.815)

Editor's notes. — The mineral leasing regulations in 11 AAC 82, 11 AAC 88, 11 AAC 84, 11 AAC 86 and 11 AAC 88, effective September 5, 1974, and distributed in Alaska Administrative Register 51, constitute a comprehensive reorganization and revision of this material, and thus the history line at the end of each section does not reflect the history of the provision before September 5, 1974, and the section numbering may or may not be related to the numbering before that date.

ROYALTY REDUCTION PROVISION

State of Alaska Department of Natural Resources
Competitive Oil & Gas Lease Forms

DL-1

Rental or minimum royalty may be waived, suspended, or reduced, or royalty may be reduced on all of said land or any tract or portion thereof segregated for royalty purposes if Lessor finds that such relief is necessary for the purpose of encouraging the greatest ultimate recovery of oil or gas and is in the interest of conservation of natural resources and either that such relief is necessary in order to promote development or that the lease cannot be successfully operated under the terms provided herein.

DMEM-A revised 8/27/79

After two years' initial production from the field in which the leased area is located has occurred, the State may reduce Lessee's obligations to pay royalty on all of the leased area or on any tract or portion thereof segregated for royalty purposes upon (1) request by Lessee and (2) a clear showing by Lessee that the revenue from all oil, gas and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Lessee's total investment in the field.

DMEM-1-79-A revised 11/5/79

After two (2) years' initial production from the field in which the leased area is located has occurred, the State, in its discretion, may reduce Lessee's obligations to pay royalty on all of the leased area or on any tract or portion thereof segregated for royalty purposes upon (1) request by Lessee, (2) a clear showing by Lessee that the revenue from all oil, gas and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Lessee's total investment in the field, and (3) a clear showing by Lessee that a reduction in royalty will increase total production from the field.

DMEM-4-81 revised 6/23/81

After initial production for two years from the field in which the leased or unit area is located has occurred, the State, in its discretion, may reduce Lessee's obligations to pay royalty on all of the leased area or on any tract or portion thereof segregated for royalty purposes upon (1) request by Lessee, (2) a clear showing by Lessee that the revenue from all oil, gas and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to the Lessee's total investment in the field, and (3) a clear showing by the Lessee that a reduction in royalty will increase total production from the field.

DNR 10-4037 revised 9/90

Lessee may request a reduction of royalty in accordance with the applicable statutes and regulations in effect on the date of application for the reduction.[1]

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[1]This version was revised August, 1993 in lease form DOG 9308AS for Sale 75 to reflect the joint leases between the State and the Arctic Slope Regional Corporation. [No reduction of royalty payable to ASRC shall be effected without ASRC's approval and, likewise, no reduction of royalty payable to the State shall be effected without the State's approval.]

DL-1

Date :

12. REDUCTION OF ROYALTY RATES FOR DISCOVERY. If Lessee shall drill on said land and make the first discovery of oil or gas in commercial quantities in any geological structure, the royalty rate under this lease shall, instead of the rates prescribed in Paragraph 11, be five per cent for a period of ten years following the date of such discovery, and thereafter the royalty rates shall be those prescribed in Paragraph 11. If this lease is committed to a unit agreement approved or prescribed by Lessor as provided in the regulations, the five per cent royalty rate shall apply t all, but only, the production allocated to this lease under such agreement.

13. REDUCTION OF RENTAL AND ROYALTY. Rental or minimum royalty may be waived, suspended, or reduced, or royalty may be reduced on all of said land or any tract or portion thereof segregated for royalty purposes if Lessor finds that such relief is necessary for the purpose of encouraging the greatest ultimate recovery of oil or gas and is in the interest of conservation of natural resources and either that such relief is necessary in order to promote development or that the lease cannot be successfully operated under the terms provided herein.

14. ROYALTY IN KIND. Whenever, at the option of Lessor, which may be exercised from time to time upon not less than six months notice to Lessee, Lessor elects to take its royalty in kind, Lessee shall deliver free of charge (on said land or at such place as Lessor and Lessee mutually agree upon) to Lessor or to such individual, firm, or corporation as Lessor may designate all royalty oil and/or gas produced and saved from said land. Such oil and/or gas shall be in good and merchantable condition. Lessee shall, if necessary, furnish storage for royalty oil free of charge for thirty days after the end of the calendar month in which the oil is produced from said land; provided, that Lessee shall not be held liable for loss or destruction of royalty oil and/or gas from causes beyond Lessee's reasonable control. Should Lessee dehydrate or clean the oil or gas produced from said land, Lessee shall be entitled to an allowance of the actual cost of dehydrating or cleaning said royalty oil or gas.

15. ROYALTY IN VALUE. At the option of Lessor, which may be exercised from time to time upon not less than six months' notice to Lessee, and in lieu of royalty in kind, Lessee shall pay to Lessor the field market price or value at the well of all royalty oil and/or gas. All royalty that may become payable in money to Lessor shall be paid on or before the last day of the calendar month following the month in which the oil or gas is produced. The payments shall be accompanied by copies of run tickets or other satisfactory evidence of sales, shipments, and amounts of gross production.

AMEM - 4
Revised 9/27/79

6. If such oil, gas or associated substances are sold away from the leased or unit area, the volume weighted average price for oil of like grade and gravity, gas of like kind and quality or associated substances of like kind and quality received by other producers in the same field or area from the purchasers thereof less the volume weighted average cost to those other producers of transportation away from the leased or unit area to the point of delivery.

E. Minimum Value Determinations. The State may determine which of the methods contained in paragraph III.D.1. through 6. above shall be used to establish the value of royalty oil and gas, and associated substances, for purposes of computing royalties payable under this lease. Each such determination shall be made only after Lessee has been given notice and a reasonable opportunity to be heard.

F. Reduction of Royalty. After two years' initial production from the field in which the leased area is located has occurred, the State may reduce Lessee's obligations to pay royalty on all of the leased area or on any tract or portion thereof segregated for royalty purposes upon (1) request by Lessee and (2) a clear showing by Lessee that the revenue from all oil, gas and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Lessee's total investment in the field.

G. Payments. All payments to the State under this lease shall be made payable to the State in the manner directed by the State, and shall be tendered to the State at Department of Natural Resources, 323 East Fourth Avenue, Anchorage, Alaska 99501, or to any depository designated by the State with at least sixty (60) days' notice to Lessee.

IV. LEASE OPERATIONS.

A. Plan of Operations.

1. No lease operations other than surface reconnaissance may be undertaken by Lessee, its agents or assigns, on the leased area, except in conformity with a plan of operations approved by the State. Lessee shall file four (4) copies of application for approval of its proposed plan of operations to the State.

2. The application shall set forth a detailed proposed plan of operations, including but not limited to statements and maps or drawings setting forth each of the following:

DMEM-1-79-17 (NPS)
Rec'd. November 5, 1979

9. REDUCTION OF ROYALTY. After two (2) years' initial production from the field in which the leased area is located has occurred, the State, in its discretion, may reduce Lessee's obligations to pay royalty on all of the leased area or on any tract or portion thereof segregated for royalty purposes upon (1) request by Lessee, (2) a clear showing by Lessee that the revenue from all oil, gas and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Lessee's total investment in the field, and (3) a clear showing by Lessee that a reduction in royalty will increase total production from the field.

10. ROYALTY IN VALUE. Unless the State elects to receive all or a portion of its royalty in kind as provided in Paragraph 12 below, Lessee shall pay to the State the value of all royalty oil, gas and associated substances as determined under Paragraph 11 below. Royalty paid in value shall be free and clear of all lease expenses (and any portion of such expenses which is incurred away from the leased area), including, but not limited to, expenses for separation, cleaning, dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substances for transportation off the leased area. All royalty that may become payable in money to the State shall be paid on or before the last day of the calendar month following the month in which the oil, gas or associated substances are produced. Royalty payments shall be accompanied by copies of run tickets or such other information relating to valuation of royalty as the State may require, which may include, but is not limited to, evidence of sales, shipments, and amounts of gross oil, gas and associated substances produced.

11. VALUE. (a) For purposes of computing royalties due under this lease, the value of royalty oil, gas or associated substances shall not be less than the highest of:

(1) the field price actually received by Lessee for such oil, gas or associated substances;

(2) Lessee's posted price in the field for such oil, gas or associated substances;

(3) the volume weighted average field price actually received by other producers in the same field or area for oil of like grade and gravity, gas of like kind and quality or associated substances of like kind and quality at the time such oil, gas or associated substances are removed from the leased or unit area or such gas is delivered to an extraction plant if such a plant is located on the leased or unit area; or

(4) the volume weighted average posted price in the field of other producers in the same field or area for oil of like grade and gravity, gas of like kind and quality or associated substances of like kind and quality at the time such oil, gas or associated substances are removed from the leased or unit area or such gas is delivered to an extraction plant if such a plant is located on the leased or unit area.

(b) If oil, gas or associated substances are sold away from the leased or unit area, the term "field price" in subparagraph (a) above shall be the actual price for such oil, gas or associated substances received from the purchaser thereof less the actual cost of transportation away from the leased or unit area to the point of delivery.

(c) Minimum Value Determinations. The State may establish minimum values for purposes of computing royalties on oil, gas or associated substances obtained from this lease, with consideration being given to the price actually received by Lessee, to the price or prices paid in the same field or area for production of like quality, to posted prices, to prices received by Lessee and/or other producers from sales occurring away from the leased area, and to other relevant matters. Each such determination will be made only after Lessee has been given notice and a reasonable opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty oil, gas or associated substances under this lease may not necessarily equal the price of such oil, gas or associated substances.

12. ROYALTY IN KIND. (a) At the State's option, which may be exercised from time to time upon not less than six (6) months' notice to Lessee, Lessee shall deliver all or a portion of the State's royalty oil, gas or associated substances produced from the leased area in kind. Delivery shall be on the leased area or at a place mutually agreed to by the State and Lessee, and shall be to the State or to any individual, firm or corporation designated by the State.

(b) Royalty oil, gas or associated substances delivered in kind shall be delivered in good and merchantable condition and be of pipeline quality, and shall be free and clear of all lease expenses (and any portion of such expenses which are incurred away from the leased area), including, but not limited to, expenses for separation, cleaning, dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substances for transportation off the leased area.

(c) After having given notice of its intention to take, or after having taken, its royalty oil, gas or associated substances in kind, the State, at its option and upon six (6) months' notice to Lessee, may elect to receive a different portion or none of its royalty in kind. If, under federal regulations, the Lessor's taking of royalty oil, gas or associated substances in value creates a supplier-purchaser relationship, Lessee hereby waives its right to continue to receive royalty oil, gas or associated substances under such a relationship, and further agrees that it will require any purchasers of the royalty oil, gas or associated substances to likewise waive any such rights.

(d) Lessee shall furnish storage for royalty oil and natural gas liquids produced from the leased or unit area to the same extent that Lessee provides storage for Lessee's share of oil and natural gas liquids. Lessee shall not be liable for the loss or destruction of stored royalty oil and natural gas liquids from causes beyond Lessee's reasonable control.

13. RECORDS. Lessee shall keep and have in its possession books and records showing the development and production (including records of development and production expenses) and disposition of all oil, gas and associated substances produced from the leased area. Lessee shall permit the State or its agents to examine such books and records at all reasonable times. Such books and records of development and production must employ methods and techniques that will ensure the most accurate figures reasonably available without requiring Lessee to provide separate tankage and/or meters for each well. Lessee shall use standard and consistent accounting procedures which are common to the industry.

14. APPORTIONMENT OF ROYALTY FROM APPROVED UNIT. The landowner's royalty share of the unit production allocated to each separately owned tract shall be regarded as royalty to be distributed to and among, or the proceeds of it paid to, the landowners, free and clear of all unit expense and free of any lien for it. Under this provision, the State's royalty share of any unit production allocated to the leased area shall be regarded as royalty to be distributed to, or the proceeds of it paid to, the State, free and clear of all unit expenses (and any portion of such expenses which is incurred away from the unit area), including, but not limited to, expenses for separation, cleaning, dehydration, gathering, saltwater disposal, and preparing oil, gas or associated substances for transportation off the unit area, and free of any lien for it.

15. PAYMENTS. All payments to the State under this lease shall be made payable to the State in the manner directed by the State, and shall be rendered to the State at

DEPARTMENT OF NATURAL RESOURCES
323 EAST FOURTH AVENUE
ANCHORAGE, ALASKA 99501

or to any depository designated by the State with at least sixty (60) days' notice to Lessee.

16. PLAN OF OPERATIONS. (a) No lease operations other than surface reconnaissance may be undertaken by Lessee, its agents or assigns, on the leased area, except in conformity with a plan of operations approved by the State. Lessee shall file with the State four (4) copies of its application for approval of its proposed plan of operations.

(b) The application shall set forth a detailed proposed plan of operations, including, but not limited to, statements and maps or drawings setting forth each of the following: (1) the sequence and schedule of the operations proposed to be conducted on the leased area; (2) projected use requirements associated with the proposed operations, including, but not limited to, the location and design of well sites, material sites, water supplies, buildings, roads, utilities, airstrips and all other facilities necessary for exploration, development and production of the leased area; (3) plans for restoration of the leased area upon the completion of operations or phases thereof; and (4) a description of operation procedures designed to prevent or minimize adverse impacts upon other natural resources and other uses of the leased area and adjacent areas.

Smem-4-81. (Royalty.
Revised June 23, 1981

37. REDUCTION OF ROYALTY. After initial production for two years from the field in which the leased or unit area is located has occurred, the State, in its discretion, may reduce the Lessee's obligations to pay royalty on all of the leased area or on any tract or portion of the leased area segregated for royalty purposes upon (1) request by the Lessee, (2) a clear showing by the Lessee that the revenue from all oil, gas, and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to the Lessee's total investment in the field, and (3) a clear showing by the Lessee that a reduction in royalty will increase total production from the field.

IN WITNESS WHEREOF the parties have executed this lease effective as of the day of , 19 .

LESSEE

STATE OF ALASKA

By:

Title:

THE UNITED STATES OF AMERICA)
) ss.
STATE OF ALASKA)

Acknowledgement of Lessor

This certifies that on the day of 19 , before me, a notary public in and for the State of Alaska, duly commissioned and sworn, personally appeared
to me known to be the person who executed the foregoing lease on behalf of the State of Alaska, who, after being duly sworn according to law, stated to me under oath that he or she has authority pursuant to law to execute the foregoing lease on behalf of the State of Alaska, acting through the Department of Natural Resources, and that he or she executed the same freely and voluntarily as the act and deed of the State of Alaska and for the Department of Natural Resources.

WITNESS my hand and official seal.

Notary Public in and for Alaska
My commission expires

INSERT NOTARY ACKNOWLEDGEMENT OF LESSEE'S SIGNATURE HERE.

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Revid 9/90

(3) the lessee's posted price in the field or area for the oil, gas, or associated substances; or

(4) the volume-weighted average of the three highest posted prices in the same field or area of the other producers in the same field or area for oil of like grade and gravity, gas of like kind and quality, or associated substances of like kind and quality at the time the oil, gas, or associated substances are sold or removed from the leased or unit area or the gas is delivered to an extraction plant if that plant is located on the leased or unit area; if there are less than three prices posted by other producers, the volume-weighted average will be calculated using the lesser number of prices posted by other producers in the field or area.

(b) If oil, gas, or associated substances are sold away from the leased or unit area, the term "field price" in subparagraph (a) above will be the cash value of all consideration received by the lessee or other producer from the purchaser of the oil, gas, or associated substances, less the reasonable costs of transportation away from the leased or unit area to the point of sale. The "reasonable costs of transportation" are as defined in 11 AAC 83.228 and 11 AAC 83.229 as those regulations exist on the effective date of this lease.

(c) In the event the lessee does not sell in an arm's-length transaction the oil, gas, or associated substances, the term "field price" in subparagraphs (a) and (b) above will mean the price the lessee would expect to receive for the oil, gas, or associated substances if the lessee did sell the oil, gas, or associated substances in an arm's-length transaction, minus reasonable costs of transportation away from the leased or unit area to the point of sale or other disposition. The lessee must determine this price in a consistent and logical manner using information available to the lessee and report that price to the state.

(d) The state may establish minimum values for the purposes of computing royalties on oil, gas, or associated substances obtained from this lease, with consideration being given to the price actually received by the lessee, to the price or prices paid in the same field or area for production of like quality, to posted prices, to prices received by the lessee and/or other producers from sales occurring away from the leased area, and/or to other relevant matters. In establishing minimum values, the state may use, but is not limited to, the methodology for determining "prevailing value" as defined in 11 AAC 83.227. Each minimum value determination will be made only after the lessee has been given notice and a reasonable opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty oil, gas, or associated substances under this lease may not necessarily equal, and may exceed, the price of the oil, gas, or associated substances.

37. ROYALTY IN VALUE. Except to the extent that the state elects to receive all or a portion of its royalty in kind as provided in Paragraph 38 below, the lessee shall pay to the state that value of all royalty oil, gas, and associated substances as determined under Paragraph 36 above. Royalty paid in value will be free and clear of all lease expenses (and any portion of those expenses that is incurred away from the leased area), including, but not limited to, expenses for separating, cleaning, dehydration, gathering, saltwater disposal, and preparing the oil, gas, or associated substances for transportation off the leased area. All royalty that may become payable in money to the State of Alaska must be paid on or before the last day of the calendar month following the month in which the oil, gas, or associated substances are produced. The amount of all royalty in value payments which are not paid when due under this lease or which are subsequently determined to be due as the result of a redetermination will bear interest from the date the obligation accrued, until it is paid in full, at a variable annual rate equal to 1.25 percent plus the prime rate as announced from time to time by the Bank of America, San Francisco, California. Royalty payments must be accompanied by such information relating to valuation of royalty as the state may require which may include, but is not limited to, run tickets, evidence of sales, shipments, and amounts of gross oil, gas, and associated substances produced.

38. ROYALTY IN KIND. (a) At the state's option, which may be exercised from time to time upon not less than 90 days' notice to the lessee, the lessee shall deliver all or a portion of the state's royalty oil, gas, or associated substances produced from the leased area in kind. Delivery will be on the leased area, unit area, or at a place mutually agreed to by the state and the lessee, and must be delivered to the State of Alaska or to any individual, firm, or corporation designated by the state.

(b) Royalty oil, gas, or associated substances delivered in kind must be delivered in good and merchantable condition, of pipeline quality, and free and clear of all lease expenses (and any portion of those expenses incurred away from the leased area), including, but not limited to, expenses for separating, cleaning, dehydration, gathering, saltwater disposal, and preparing the oil, gas, or associated substances for transportation off the leased area.

(c) After having given notice of its intention to take, or after having taken its royalty oil, gas, or associated substances in kind, the state, at its option and upon 90 days' notice to the lessee, may elect to receive a different portion or none of its royalty in kind. If, under federal regulations, the taking of royalty oil, gas, or associated substances in value by the state creates a supplier-purchaser relationship, the lessee hereby waives its right to continue to receive royalty oil, gas, or associated substances under that relationship, and further agrees that it will require any purchasers of the royalty oil, gas, or associated substances likewise to waive any supplier-purchaser rights.

(d) The lessee shall furnish storage for royalty oil, gas and associated substances produced from the leased or unit area to the same extent that the lessee provides storage for the lessee's share of oil, gas and associated substances. The lessee shall not be liable for the loss or destruction of stored royalty oil, gas and associated substances from causes beyond the lessee's ability to control.

(e) If a state royalty purchaser refuses or for any reason fails to take delivery of oil, gas, or associated substances, or in an emergency, and with as much notice to the lessee as is practical or reasonable under the circumstances, the state may elect without penalty to underlift for up to six months all or a portion of the state's royalty on oil, gas, or associated substances produced from the leased or unit area and taken in kind. The state's right to underlift is limited to the portion of royalty oil, gas, or associated substances that the royalty purchaser refused or failed to take delivery of, or the portion necessary to meet the emergency condition. Underlifted oil, gas, or associated substances may be recovered by the state at a daily rate not to exceed 10 percent of its royalty interest share of daily production at the time of the underlift recovery.

39. REDUCTION OF ROYALTY. Lessee may request a reduction of royalty in accordance with the applicable statutes and regulations in effect on the date of application for the reduction.

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DECISION OF THE COMMISSIONER ON CONOCO'S APPLICATION FOR ROYALTY REDUCTION

Conoco, Inc. submitted an application to the State of Alaska Department of Natural Resources (DNR). That application requested that the State's royalty share of oil and gas produced from the Kuparuk River formation underlying five Milne Point leases be reduced from twenty percent to five percent.

Conoco's application was analyzed by the staff of the Division of Oil and Gas. Mark Myers, Petroleum Geologist, conducted a public hearing on the application, then prepared a Recommended Decision on Conoco's application. The Recommended Decision was accompanied by, and incorporated by reference, an economic analysis of the application prepared by Edward Phillips, Petroleum Economist (retired).

Normally, the Commissioner of the DNR would act on a recommended decision without further input from Conoco. However, Conoco requested and was granted thirty days in which to comment on the Recommended Decision. Conoco's comments consisted of fifty-one pages of text and twenty pages of affidavits, all of which have now been reviewed by this Commissioner.

As Commissioner, I hereby adopt the Recommended Decision as the final decision of DNR, subject to the additional findings and conclusions set forth in the remainder of this Final Decision.

In this Final Decision I do not undertake to address every alleged fact and argument raised by Conoco in its final comments. The bulk of Conoco's final comments simply state alleged facts and arguments which the hearing officer found inaccurate, unsupported,

EXHIBIT 5

or unpersuasive in his Recommended Decision, and which I, too, find inaccurate, unsupported, and unpersuasive. However, portions of Conoco's final comments suggest basic misunderstandings which may be cleared up by a few short words here.

First, the Milne Point Unit Agreement is not an agreement between the State of Alaska and Conoco. It is an agreement between all parties owning a working interest or overriding royalty interest in any lease within the Milne Point Unit. The State of Alaska is not a party to the Unit Agreement; rather, it simply approved the Agreement, subject to certain non-negotiable conditions. Conoco's allegation that paragraphs 1 (Enabling Act and Regulations), 14 (Royalty Settlement), and 18(h)(8) (Reduction of Royalty) of the Unit Agreement were the result of intricate negotiations between the State of Alaska and Conoco is not supported by the record. Nor is Conoco's allegation of linkage between paragraph 14 (increasing the royalty rate from 12.5 percent to 20 percent) and paragraph 18(h)(8) (limiting the availability of royalty reduction).

Second, pursuant to paragraph 14 of the Milne Point Unit Agreement, only five of the leases within the Milne Point Unit are burdened with a twenty percent royalty rate.[1] The remaining leases within the Unit have a 12.5% royalty rate. But paragraph 18(h)(8) of the Milne Point Unit Agreement, by its terms, applies equally to all applications for royalty reduction, whether the royalty rate of the subject leases is 12.5 percent or 20 percent. If there was the

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[1] These five leases would have expired for failure to drill but for the State's approval of the Milne Point Unit Agreement.

linkage between paragraphs 14 and 18(h)(8) which Conoco suggests, then I would expect paragraph 18(h)(8) to set forth two sets of criteria for royalty reduction, one applicable to leases with a 12 ½ percent royalty rate, and another for leases with a 20% royalty rate.

Third, while the Milne Point Unit Agreement may be the only unit agreement which provides for a royalty rate of twenty percent, numerous oil and gas leases issued during the time period in which the Milne Point Unit Agreement was approved also provide for a twenty percent royalty rate. No special provision was made by statute, regulation, agreement, or lease to treat differently applications for royalty reduction on leases bearing a twenty percent royalty rate from applications for royalty reduction on leases bearing a 12.5 percent royalty rate.

Fourth, even if paragraph 18(h)(8) of the Milne Point Unit Agreement governed Conoco's application (AS 38.05.180(j) and (p) having no force or effect), paragraph 18(h)(8): (a) makes relief discretionary, and (b) requires a clear showing by Conoco that the revenue from all oil and gas produced from the field is insufficient to produce a reasonable rate of return on Conoco's total investment in the field. Following the reasoning set forth in the Recommended Decision, I find that: (a) it would be an abuse of my discretion to grant the royalty reduction requested because it is not in the public interest, and (b) Conoco has failed to make

a clear showing that its revenue from the field is insufficient to produce a reasonable rate of return on its total investment in the field.

Fifth, AS 38.05.180(j) is not being applied retroactively. It was incorporated by reference in the Milne Point Unit Agreement. It is being applied to an application submitted after the statute's effective date. And it did not materially and adversely impact Conoco such as to constitute an impairment of contract.

Sixth, footnote 15 of Conoco's comments indicates that the Recommended Decision used as a reasonable rate of return "current T-Bill rates, which are ... 2.4% in real terms." In fact, the Recommended Decision used as a reasonable rate of return the average of the Treasury Bill rates for the life of the Milne Point Unit (1980-1989), which average rate approximates six percent per annum in real terms.

Seventh, when Conoco submitted an application for royalty reduction in 1985, it requested relief under AS 38.05.180(p). AS 38.05.180(p) does not require two years production before relief can be granted. However, Conoco's application was also burdened by the requirements of paragraph 18(h)(6) of the Milne Point Unit Agreement. That paragraph requires two years of production before royalty reduction can be granted. Conoco had not produced for two years from the Milne Point Unit until February 1990. Therefore, if for no other reason, Conoco's 1985 application had to be denied because Conoco had not then produced for two years.

Eighth, public utility law and oil and gas law can be distinguished on grounds other than the costs of capital for utilities and oil and gas producers. A public utility often has a single profit center; if its economic return is insufficient, its entire operation may cease. For that reason, public utility law seeks to guarantee a return adequate to assure continuing services from what is often the sole source for those services. Conversely, the major oil producers, including Conoco, have multiple profit centers. Should Conoco fail to obtain what it considers to be an adequate return on a single profit center--such as the Milne Point Unit--Conoco's other more-profitable ventures virtually assure Conoco's continued existence. But even if Conoco failed to survive, the public's supply of oil and gas is not dependent on a single producer. Therefore, neither this State's oil and gas leases nor the royalty reduction statutes need guarantee an oil producer a specific rate of return, or any return at all. I find that no guarantee of a rate of return was intended by the legislative or executive branches of this State's government.

In addition to clarifying the foregoing matters, I hereby supplement the Recommended Decision's public interest finding. Contrary to the assertions of Conoco, the public interest finding did not simply weigh cash gains and losses to the state government. The Recommended Decision determined that lost revenues to the state government would be approximately four times greater than the sum of additional royalties to the state government plus the total

value of the increase in production assured by royalty reduction.[1] The Recommended Decision also gave weight to additional, though speculative, production which may result from the royalty reduction. However, the Recommended Decision did not specifically or fully address certain feasible benefits of royalty reduction, probably due to their speculative and minute nature. These benefits include the following:

First, if future seismic acquisition and interpretation supports Conoco's current geologic mapping, and the State reduces its royalty to five percent, Conoco will drill two additional production wells which, based on Conoco's expectations, would produce approximately 3 million additional barrels of oil (chance factor times estimated reserves in the two largest fault blocks). This places the maximum possible additional benefit produced by the royalty reduction at 4.2 million barrels (3 million barrels of new

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[1] The Recommended Decision, at page 13, states:

> Assuming first that the average wellhead value for oil produced from the Kuparuk Formation is $12 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose $64,000,000 in royalties on oil produced during the next twenty-two years, and gain $720,000 in royalties on oil produced twenty-two to twenty-five years from now. Total recovery of additional production under a reduced royalty rate is estimated to be 1.2 million barrels of oil valued at $14,400,000.
>
> Assuming that the average wellhead value is $22 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose $109,000,000 in royalties on oil produced during the next twenty-two years, and gain $1,220,000 in royalties on oil produced twenty-two to twenty-five years from now. The total incremental volume of oil that would be achieved through a reduction in this case would be valued at $26,400,000.

reserves plus 1.2 million barrels due to three extra years of production). The royalty value to the State of the speculative additional 3 million barrels of oil at a $22 per barrel well head value is approximately $3.3 million. Consequently, if royalty reduction was granted, the State would forego $109 million in royalties to gain up to $4.5 million in royalties from additional production.

Second, royalty reduction is virtually certain to increase production by 1.2 million barrels, and may increase it by an additional 3 million barrels. The Trans-Alaska Pipeline transports 2 million barrel per day. One million, two-hundred thousand barrels would fill the line for 14.4 hours. Three million barrels would fill the line for 36 hours. The sum of the two volumes would fill the line for just 50.4 hours.

Third, additional production from the Milne Point Unit could mean additional jobs. Based on Conoc.'s statement that it may be able to increase production in the event of a royalty reduction by drilling two additional wells, I estimate that no more than thirty additional workers would be employed for a period no greater than one month.

In weighing the costs and benefits of royalty reduction, foregone royalties, additional royalties, and additional production can be quantified, at least in a relative sense. Assigning dollar values to pipeline fill and additional jobs is more difficult. Yet clearly these benefits are insufficient to overcome the phenomenal costs of granting the royalty reduction requested by Conoco.

Therefore, even after considering benefits not quantified or expressly addressed in the Recommended Decision, I conclude that it is not in the public interest to grant the royalty reduction requested by Conoco.

Subject to the foregoing, the Recommended Decision on Conoco's application for royalty reduction for the Milne Point Unit is hereby adopted as the final Decision of the Department of Natural Resources.

STATE OF ALASKA, DEPARTMENT OF NATURAL RESOURCES

Dated: 4/21/91

Harold C. Heinze

Harold C. Heinze, Commissioner

RECOMMENDED DECISION OF THE COMMISSIONER OF NATURAL RESOURCES REGARDING THE CONOCO APPLICATION FOR ROYALTY REDUCTION ON ADL 47433, 47434, 47437, 47438, AND 28231 (KUPARUK PARTICIPATING AREA: MILNE POINT UNIT).

12/28/90

Finding and Recommendation

Conoco has applied for a reduction of its royalty from 20 percent to five percent on Kuparuk Formation oil produced from the Milne Point Unit. Given the short history of the field, the information provided in Conoco's application and its public comments on the application fail to: (1) provide a clear showing that its revenue over time will not allow for a reasonable rate of return; (2) demonstrate with any certainty that the requested reduction will significantly prolong the life of the field; or (3) demonstrate that the requested reduction would secure the proper protection of the public interest.

A clear showing of a failure to achieve a pre-determined rate of return over time requires accurate forecasting of oil prices over nearly two decades, as well as a clearer understanding of the potential total production from Milne Point, both with and without royalty reduction, than is currently available. The difficulty of reliably quantifying the latter is demonstrated by Conoco's reported decision to proceed shortly with Schrader Bluff production with the goal of ultimately tripling average daily production from the unit. On its face, it is difficult to argue the need for royalty relief at this time for a field which pays no severance tax, and for which the economics will be dramatically altered in the very near future by the operator's decision to pursue development of these shallow oil sands.

You have the discretion to approve a royalty reduction when it is determined to be in the state's best interest. However, our analysis of the potential benefits which may be gained years hence from the forbearance of substantial state royalties for the next twenty years or so, does not

appear to support such a finding in Conoco's case. For the reasons discussed more fully both below in the accompanying confidential Appendix 1, I recommend that you deny Conoco's application on these bases.

The department's analysis of Conoco's application clearly illustrates the need for a policy that limits royalty relief to those instances where sufficient objective factual data, including production revenues and development expenses, are available to establish that the reduction of the state's royalty share will both prolong production and result in benefits which are demonstrably in the state's interest. In addition to maintaining a continuous, though reduced, royalty stream, those benefits could include continued employment, additional capital investments in wells and production facilities (to increase the total recovery of oil from the field) and other factors.

Although Conoco's application fails to make a clear showing of its inability to achieve a reasonable rate of return over time or of being in the state's best interest, our review of its application did point out several concerns common to any application for royalty reduction under the existing statutes. These include defining "reasonable rate of return" consistently and objectively for royalty reduction purposes, and structuring any reduction so as to be effective in achieving the desired results without unduly diminishing the state's royalty interest.

Based upon our analysis and using Conoco's application as an example, I recommend an alternative approach from that advocated by Conoco for setting a reasonable rate of return, and provide documentation to support the use of such a standard for evaluating future applications. If you agree with the use of the rate of return test which is suggested, I recommend that the division prepare appropriate draft regulations and notice them for public comment and hearing so that future applicants who may be affected have the opportunity to comment on the draft regulations.

I. Background and Introduction

Conoco Inc. has applied for a reduction of the State of Alaska's royalty interest in oil and gas production from the Kuparuk River Participating Area of the Milne Point Unit. In its application, Conoco requests that the State's royalty interest in its production from the Kuparuk Formation only, underlying ADLs 47433, 47434, 47437, 47438, and 28231, be reduced from 20% to 5%. Conoco has not requested a royalty reduction for production from the Schrader Bluff Formation, which lies above the Kuparuk Formation throughout much of the Milne Point Unit.

Conoco submitted its formal application for royalty reduction in February 1990. However, the application was not determined to be substantially complete until July 1990. As provided for under 11 AAC 83.185, a public hearing on the application was conducted by the department on August 28, 1990. Conoco continued to submit documents in support of its application through October 9, 1990. Conoco's application has been evaluated under, alternatively, AS 38.05.180(p), AS 38.05.180(j), as it existed at the time the Milne Point Unit Agreement was executed and at the time Conoco's application was submitted, and AS 38.05.180(j), as amended in 1990 by HB 128, effective September 12, 1990.

Two key terms used in these statutes need to be clearly defined in order to make a royalty reduction determination. These terms are discussed in Parts II, III, and IV. Part III defines "field," as used in the royalty reduction context. Part IV analyzes what constitutes a "reasonable rate of return." Part V specifies why a decision to grant royalty relief is discretionary, not mandatory. Parts VI, VII, and VIII address each of the three statutory provisions listed above, as they apply to Conoco's application. Part IX refutes Conoco's assertion that Paragraph 18(h)(8) of the Milne Point Unit Agreement controls disposition of its application for a royalty reduction. Finally, this document concludes with a brief summary of this finding and recommendation.

This document is accompanied by Appendix 1, an economic analysis of rates of return, the cost of capital, Conoco's confidential financial data, and the costs to the state of a royalty reduction as proposed by Conoco in this instance. Appendix 1 was prepared by Ed Phillips, Petroleum Economist (retired) for the Division of

Oil and Gas. Although Appendix 1 supports the conclusions reached herein, it cannot be part of the public record of this recommended decision. It must remain confidential due to its extensive references to Conoco's proprietary information and data which are entitled to confidentiality under state statutes.

II. Definitions

Two key terms used in the statutes need to be clearly defined in order to make a royalty reduction determination. These terms are **reasonable rate of return**, and **field**. Since these terms lack statutory definitions for the purposes of royalty reduction, and since no previous requests for royalty reduction have been granted, these terms are examined with respect to this application. In its August 27, 1990 supplemental brief Conoco attempted to define the terms **reasonable rate of return** and **field** and presented arguments why the department should be bound by the definitions in its review of Conoco's application. The following two sections will explain why, in my opinion, Conoco's proposed definitions are inappropriate and must be rejected. Additionally, these sections will provide alternative definitions of these terms and demonstrate why these definitions are appropriate for royalty reduction analyses.

III. Definition of a Field

AS 38.05.180(j), before and after amendment by H.B. 128, and paragraph 18(h)(8) of the Milne Point Unit Agreement restrict royalty relief to instances in which the "field" would not otherwise produce a reasonable rate of return. AS 38.05.180(j) before amendment also requires that the relief prolong "field" life. AS 38.05.180(j) after amendment by H.B. 128 requires that either the relief be necessary to prolong "field" life or restore shut-in production. Neither the royalty reduction statutes or the Unit Agreement define "field."

Conoco, in its supplemental brief submitted on August 27, 1990, stated its belief that, for the purpose of royalty reduction, the Milne Point leases contain two separate oil fields, the Kuparuk River and Schrader Bluff "Fields." It based its argument on the fact that the two oil pools are vertically separated, have different reservoir properties, and will require

different production techniques. Additionally, Conoco's brief states that the definition it offers is identical to the definition of "field" used in Texas oil and gas law. Conoco's argument for considering the Schrader Bluff and Kuparuk River oil pools as separate fields is summarized by the following statement: "Geologically distinct fields will also be economically distinct, and therefore of little utility in assessing the economics of each other." (Supplemental Brief of Conoco and Oxy USA Inc. p.25).

To support its interpretation of the definition of "field" Conoco referenced *Wotton* v. *Bush*, 261 P.2d 256 (Cal. 1953), in which **for the purpose of well spacing requirements**, an administrative officer of the California Division of Oil and Gas testified that "a field has come to be considered as that expanded area from the region of initial production to the limits of productivity in all lateral directions; and that within a given field there was no structural connection or drainage to or from other fields." It should also be noted that unlike Milne Point, the fields in the *Wotton* case were geographically (laterally) separated and not at different depths on the same leases. The *Wotton* case dealt with the issue of well spacing requirements. Appropriate well spacing is ideally determined by internal reservoir properties including porosity, permeability, heterogeneity, viscosity of oil, reservoir thickness, reservoir pressure, fluid contacts, and other factors. These properties are certainly unique to each pool and/or reservoir and often vary within the same pool or reservoir. A definition of "field" that is applicable for determining production rates, well spacing, participating areas, internal company development plans, tax credit for enhanced oil recovery, etc. may not be applicable or even appropriate to royalty reduction. This is the case with the definition proposed by Conoco.

Conoco argues that its definition is consistent with that used by industry. However, this argument is not persuasive since there is no consistent use of the term "field" within industry. For example, the Kuparuk River Formation within the Kuparuk River Oil Field consists of two separate reservoir intervals, the A and C sands of different geologic age (Valanginian vs. Hauterivian). Additionally, the sands are vertically separated by a major regional unconformity, were deposited in different

depositional settings, and have very different reservoir properties. In spite of these different properties neither industry nor the State differentiates these producing intervals when they refer to the Kuparuk River Oil Field.

For the purpose of royalty reduction, the department must define "field" in a matter that: (1) is consistent with the intent of the royalty reduction statutes, regulations, and, to the extent feasible, the Milne Point Unit Agreement; (2) is founded on accepted geologic and engineering principles; (3) can be applied impartially to all applicants for royalty reduction; and (4) will generally result in reproducible results when applied by different qualified petroleum geologists.

A royalty reduction application under AS 38.05.180(j) must comply with 11 AAC 83.185, which requires the application to:

> ... (2) state location and status of all past and present activities on the lease; (3) include a detailed report of all production during the six months preceding the filing of the application; (4) contain a detailed statement covering the entire life of the lease showing all expenses and costs of operating the lease, including all royalties and overriding royalties and all income from all produced minerals from the lease;

(Emphasis added). This regulation evidences the department's interpretation of "field" as clearly referring to all reservoirs underlying the lease.

This interpretation is consistent with earlier comments in a October 9, 1984 letter to Conoco from Division of Oil and Gas Director Kay Brown in which she stated, "the division has no statutory definition of 'field'..." and listed three possible geologic definitions of "field." "Field may refer (1) to a common source of supply, pool, or reservoir; (2) to multiple reservoirs vertically separated; or (3) to multiple, partially overlapping individual reservoirs...."

Further support for the department's interpretation of "field" comes from the definition of "field" used by another state regulatory agency, the Alaska Oil and Gas Conservation Commission (AOGCC). While AOGCC's

definition of "field" does not govern an application for royalty reduction, it is indicative of a definition accepted by industry in some settings. For the AOGCC, "field" is defined by AS 31.05.170(5), which states:

> "field" means a general area which is underlain or appears to be underlain by at least one pool, and includes the underground reservoir containing oil and gas; and the words "pool" and "field" mean the same thing when only one underground reservoir is involved, but "field" unlike "pool" may relate to two or more pools...

For the purpose of royalty reduction requests, the department defines "field" as encompassing the lateral limits of productivity of all reservoirs or pools within the Milne Point Unit regardless of vertical stratification of reservoirs or pools underlying a lease or leases. This definition meets the standards set out earlier: (1) is consistent with the intent of the royalty reduction statutes, regulations, and to the extent feasible, the Milne Point Unit agreement; (2) is founded on accepted geologic and engineering principles; (3) can be applied impartially to all applicants for royalty reduction; and (4) will generally result in reproducible results when applied by different qualified petroleum geologists.

This definition allows the department to consider all the relevant information with regard to royalty reduction. Commonality of production and transportation facilities and well bores, as well as shared information and economy of scale provided by having multiple stacked reservoirs under a single lease are important factors in the development of an oil field. Not only do multiple stacked reservoirs have lower development costs, but their development also entails lower risk wells. For example, wells can be plugged back and produced from the shallower horizon, if the deeper horizon is not produced due to faulting, lack of net pay, well bore damage, depletion or other factors. The department's definition of "field" is similar to that used by AOGCC in that it considers multiple **vertically** separated pools or reservoirs underlying the same lease or leases a single "field."

Utilizing a definition that encompasses all reservoirs or pools within the Milne Point Unit also helps minimize the incentive for the operator and lessees to manipulate production and/or costs from individual reservoirs within the Unit for the purposes of affecting royalty reduction applications.

Note that the department's definition does not prohibit the commissioner from granting selective relief to individual pools or reservoirs, or even individual leases. In this case, the ability to do so is clearly stated by the Milne Point Unit Agreement and not prohibited by statute.

IV. Definition of Reasonable Rate of Return

Similarly, regardless of whether one is guided by State law or the Milne Point Unit Agreement, there is the potential for serious disagreement between the applicant and the department regarding what constitutes "a reasonable rate of return" for the purpose of evaluating a royalty reduction request. Without providing objective standards, both AS 38.05.180(j) and the Milne Point Unit Agreement leave it up to the commissioner to define a reasonable rate of return for royalty reduction purposes. Against this backdrop, the department has an obligation to adopt a standard that is objective and which may be applied consistently without regard to the vagaries of the financial planning standards of individual companies . Furthermore, the standard should provide a positive real rate of return (more than inflation), yet not allow for excessive profit at the expense of the state's royalty share.

Conoco has argued in its August 27, 1990 supplemental brief and in testimony at the public hearing, that, at a minimum, a reasonable rate of return, for royalty reduction, should be defined as the cost of capital to the company plus a marginal profit. There are obvious problems with this standard. First of all, such a standard would vary widely from company to company. Of the eight major North Slope producers examined, Conoco had the highest cost of capital at a nominal rate of 12.75%. Based upon information available to the department, other North Slope producers' cost of capital ranged from a low of 9.26% (Oxy) to a high of 10.26% (ARCO). Additionally, proprietary financial data of this sort are generally

not directly available to the public, rates are difficult to monitor over time, and many projects are internally financed by the companies.

Thus, defining a reasonable rate of return standard as the individual firm's cost of capital is not acceptable since it treats every firm differently. Such a standard would provide a different level of relief based upon the company, regardless of the field. To protect the state's interest, royalty relief should be based on the economics of the field and not on a company's real or perceived internal financial characteristics. Further, the standard should be impartially applicable to all lessees. A reasonable rate of return that is independent of the particular company financing involved should be adopted to avoid possible manipulation of in-house economics simply for royalty reduction purposes.

In its August 27, 1990 supplemental brief, Conoco cites a number of public utilities law cases in support of its proposed definition of rate of return. These cases are intended to demonstrate examples where the most strict standard for a reasonable rate of return is the cost of capital. However, for royalty reduction purposes, these are invalid analogs. A public utility is granted a rather generous (but capped) rate of return since it is regulated and at the same time must compete with unregulated firms in the capital market. Also, a public utility does not have an opportunity to make large profits in other settings, as does a large, privately owned integrated oil company such as Conoco. Neither Conoco's prices nor its costs are regulated by a public agency therefore, Conoco has no regulated limits on its potential profitability.

It is the potential for large profits that allows Conoco, or any other oil and gas lessee for that matter, to take the risks inherent in wildcat exploration and oil field development. This provides a freedom of operation not granted to a public utility. It is therefore only proper that a more conservative standard for rate of return be applied to Conoco, and other lessees, in determining whether, and to what extent, a reduction in the state's royalty share of production is appropriate. When all the arguments are stripped away, the stated purposes of the royalty reduction statutes are to prolong the economic life of the field and protect the public interest, not

to guarantee the state's lessees a minimum rate of return on every field which they choose to develop.

Standards other than those suggested by Conoco are available to define a reasonable rate of return. For example, the economic yardstick used by the United States Geologic Survey and the U.S. Department of Energy in recent studies has been an after-tax rate of return of 8%. Referring to the development of North Slope reserves in *Economics and the National Oil and Gas Assessment, The Case of Onshore Northern Alaska* (In press Attanasi, Bird, and Mast) the authors state "Fields were considered commercially developable if a discounted cash flow analysis showed that an after-tax return of 8 percent could be achieved. At the time of the assessment, the 8 percent hurdle rate was being used by the U.S. Department of Energy's Energy Information Administration in the national energy base case forecasts (Jon Rasmussen, Energy Information Administration, oral communication)."

Another potential yardstick for defining a reasonable rate of return is the standard used by the State of Alaska Department of Revenue (DOR) in determining reasonable shipping rates for North Slope crude for the purpose of calculating severance tax obligations. Shippers are allowed the Gross National Product deflator (GNPd) plus two percentage points return to capital as allowable expenses (profits). For the 1980-1989 period, the GNPd fell short of the 90 day Treasury bill rate by 4.4 percentage points. Otherwise stated, DOR has allowed, as a reasonable rate of return, a rate which is, on average, 2.4 percentage points less than the 90 day Treasury bill rate.

The standard which I recommend the department choose to define a "reasonable rate of return" for the purposes of this application is the rate of return for a 90 day Treasury Bill. The basis for this recommendation is more fully set out in the text of Appendix 1. For the period of 1980-1989 the real rate of return for the 90 day bill was approximately six percent. This standard compares favorably with other potential standards examined by the department.

V. Discretionary Nature of Royalty Reduction

A well established rule of interpretation specifies that "may" refers to discretionary action, while "shall" dictates mandatory action. Similarly, "may not" constitutes a mandatory prohibition.

AS 38.05.180(p) states the commissioner "**may** ... change ... royalty requirements ...." Paragraph 18(h)(8) of the Milne Point Unit Agreement provides that the State "**may** reduce Lessee's obligation to pay royalty ...." Thus, both AS 38.05.180(p) and paragraph 18(h)(8) of the Milne Point Unit Agreement permit royalty reductions, but they do not mandate royalty reductions, except where a denial of a royalty reduction would be arbitrary or unreasonable.

AS 38.05.180(j), both before and after amendment by HB 128, mandates promulgation of regulations governing applications for royalty reduction: "the commissioner **shall** adopt regulations ...." However, the regulations are "to **allow** reduction of royalty ...." The word "allow," like "may," is permissive, not mandatory. AS 38.05.180(j), both before and after amendment by HB 128, then uses mandatory language to specify one instance in which royalty reduction is **not** allowed: "The commissioner **may not** grant a reduction of royalty" unless the applicant has made a clear showing that its revenue from the field is insufficient to produce a reasonable rate of return on its total investment in the field. In short, while AS 38.05.180(j) contains some compulsory directives, it also permits denial of an application where not unreasonable or arbitrary to do so.

VI. Evaluation of Application Under AS 38.05.180(p)

AS 38.05.180(p) states:

> To conserve the natural resources of all or a part of an oil or gas pool, field, or like area, the lessees and their representatives may unite with each other, or jointly or separately with others, in collectively adopting or operating under a cooperative or a unit plan of development or operation

> of the pool, field or like area, or a part of it, when determined and certified by the commissioner to be necessary or advisable in the public interest. **The commissioner may,** with the consent of the holders of leases involved, establish, **change,** or revoke drilling, producing, and **royalty requirements of the leases** and adopt regulations with reference to the leases, with like consent on the part of the lessees, in connection with the institution and operation of a cooperative or unit plan **as the commissioner determines necessary or proper to secure the proper protection of the public interest.**

(Emphasis added).

Conoco's application, as initially submitted, represented that the Milne Point Unit Kuparuk Formation had an expected field life of twenty-five years, three years of which have almost elapsed. The original application did not indicate that the field life would be lengthened, or more oil produced, should Conoco be granted the royalty relief requested. Subsequently, Conoco amended its application, to clarify that if the State reduced its royalty to 5%, Conoco would produce 1.2 million barrels more than it would otherwise produce in the three years following the first twenty-five years of production.

In evaluating Conoco's application, the department must determine whether the public interest would best be served by the State's receipt of a 20% royalty over a remaining field life of twenty-two years, or by the State's receipt of a 5% royalty over a remaining field life of twenty-five years **and** the production of an additional 1.2 million barrels of oil twenty-two to twenty-five years from now. This determination cannot be made without reference to the wellhead value of Milne Point oil.

It is impossible to accurately calculate the wellhead value of production occurring over the next twenty-two to twenty-five years. The impossibility of the task is exemplified by the wide range of values for oil produced from the Kuparuk Formation in the Milne Point Unit in 1990 alone, when the reported wellhead value tripled between July and September. However, the department is able to model the effects in a gross sense by selecting a low estimated average value and a high estimated average value, then calculating the costs and benefits of granting the requested royalty reduction should values approaching either of these extremes prove accurate.

In this analysis, the department selected a low average wellhead value of $12 per barrel and a high average wellhead value of $22. These wellhead values were chosen to represent possible average wellhead values for the entire life of the field. These wellhead values roughly correspond with United States West Coast average prices of $20 and $30 per barrel, respectively.

Assuming first that the average wellhead value for oil produced from the Kuparuk Formation is $12 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose $64,000,000 in royalties on oil produced during the next twenty-two years, and gain $720,000 in royalties on oil produced twenty-two to twenty-five years from now. Total recovery of additional production under a reduced royalty rate is estimated to be 1.2 million barrels of oil valued at $14,400,000.

Assuming that the average wellhead value is $22 per barrel and the State's royalty is reduced from 20% to 5%, the State will lose $109,000,000 in royalties on oil produced during the next twenty-two years, and gain $1,220,000 in royalties on oil produced twenty-two to twenty-five years from now. The total incremental volume of oil that would be achieved through a reduction in this case would be valued at $26,400,000.

Under both scenarios the cost of the royalty reduction to the State is roughly four times the combined value of the benefits, including the state's royalty share. These analyses were conducted in constant 1989 dollars. Obviously, had they been done in present value terms, the disparity between costs and benefits would have been even greater.

But there are other benefits which may be obtained by reducing the royalty rate to 5%. By letters dated May 16 and October 9, 1990, Conoco committed to expand its 3-D seismic program, and, dependent on the outcome of the seismic program, possibly drill two additional wells to evaluate three regions of the Kuparuk Formation within the Milne Point Field. These wells would be targeted to delineate the resource potential of several small fault blocks and/or the down-dip limit of the field. Conoco first termed the magnitude of reserve additions attributable to these operations as "totally speculative." Subsequently, Conoco

provided reserve estimates for one of the three regions and risk factors for all three regions. Based on the relatively low reserve estimate, coupled with the risk factor, the conditional nature of the commitment to drill, and ownership interests of other parties in the reserves, the department concludes that the potential incremental benefits of royalty reduction are insufficient to tip the scales in favor of granting the reduction requested.

Based on the extraordinary value of lost royalties, the modest benefit of a 1.2 million barrel increase in production, and the highly speculative benefits of Conoco's commitment to additional exploration and development activities, it is extremely difficult to make a finding that granting the royalty reduction which Conoco requests is either necessary or proper to secure the proper protection of the public interest.

VII. Evaluation of Application Under AS 38.05.180(j), Prior to Amendment By HB 128 in 1990

AS 38.05.180(j), as it existed at the time the Milne Point Unit Agreement was executed and at the time Conoco's application was submitted, stated:

> AS 38.05.180(j) "**To prolong the economic life of an oil and gas field**, the commissioner shall adopt regulations for all bidding methods to allow reduction of royalty on leases within the field **to compensate for increasing costs in the later stages of production decline**. The commissioner may not grant a reduction of royalty until two years' initial production from the field has occurred and each lessee requesting the reduction has made a clear showing that the revenue from all hydrocarbons produced from the field is insufficient to produce a reasonable rate of return with respect to that lessee's total investment in the field."

(Emphasis added).

As with AS 38.05.180(p), relief under AS 38.05.180(j) is discretionary. However, the department should not exercise its discretion in favor of royalty reduction unless the reduction is in the public interest. For the reasons discussed in Part VI, above, granting the royalty reduction as requested by Conoco is not in the public interest.

To qualify for relief under AS 38.05.180(j), an applicant must establish that the relief requested: (1) follows two years initial production from the field; (2) will prolong the economic life of the field; (3) will compensate for increasing costs in the later stages of production decline; and (4) is necessary to produce a reasonable rate of return on the applicant's total investment in the field.

Conoco submitted its application for royalty reduction immediately following two years of cumulative production from the Kuparuk Formation of the Milne Point field; therefore, the requirement of two years initial production from the field has been met. However, Conoco has not established that the requested royalty reduction will significantly prolong the economic life of the field. While the field life **might** be extended by three years, more than twenty years in the future, the number of years added is not relevant--the number of additional barrels recovered is. Conoco's unconditional commitment to increased production is limited to 1.2 million barrels. This volume represents less than 2% of the estimated production for the Kuparuk Formation, and an even lesser percentage of estimated production for the Milne Point field. Given the cost to the State of the royalty reduction requested, the amount of potential new production 20+ years hence is almost inconsequential in both absolute and relative terms.

Having failed the second part of a four part test for royalty reduction under AS 38.05.180(j), it is unnecessary to examine elements three and four. However, brief mention of the two remaining elements is appropriate. AS 38.05.180(j) restricts royalty reduction to instances in which it will compensate for increasing costs in the later stages of production decline. First, the department has received no information that would indicate the Milne Point field is in the later stages of production decline. To the contrary, Conoco has announced plans to develop the Schrader Bluff Formation within the Milne Point with the ultimate goal of at least doubling production. Second, the department interprets this requirement as limiting the amount of relief which may be granted to that amount necessary to offset the increase in costs. It is impossible to ascertain whether royalty relief granted after three years of production in a field with an estimated field life of twenty-five to twenty-eight years would compensate for, and be commensurate with, increasing costs in the later stages of production decline. Given the volatility of future oil prices and the remoteness of late-stage costs, the

department should not conclude that this standard would be met by granting the requested royalty reduction at this time.

Finally, AS 38.05.180(j) requires the applicant to make a **clear showing** that the revenue generated by the field is insufficient to produce a reasonable rate of return on the total investment in the field. A clear showing requires evidence which is precise, explicit, and which directly establishes the point. It is very difficult, if not impossible, to provide such evidence here, since the Milne Point field is in the very early stages of production. Use of estimated value, production, and cost data for the remaining twenty-two to twenty-five year life of the field adds a high level of uncertainty to determining the long-term validity of any purported "need" for Conoco's royalty reduction. Particularly disturbing is the unreliability inherent in estimating the value of oil to be produced over the next twenty-two to twenty-five years. As mentioned earlier, this unreliability is dramatically underscored by the tripling of reported wellhead values from the Milne Point Unit between July and September 1990.

Estimating revenue from future production is further complicated by a lack of knowledge regarding the potential volume and value of future production from other pools in the Milne Point field, such as the Schrader Bluff Formation, as well as by price and technology sensitive enhanced oil recovery techniques which may significantly increase total production from all reservoirs or pools within the Milne Point field.

On the other hand, since much of the major field facility development has already occurred, the cost estimates for the remaining field life are easier to approximate. According to the data submitted by Conoco on June 13, 1990, about 87% of the capital investment in field facilities has been completed, leaving only relatively minor capital investment expenses to be estimated. This, however, does not include the costs associated with Schrader Bluff development and production.

In short, the department may reasonably conclude it impossible to make a **clear showing** that the revenue generated by the Milne Point field over its entire life will be insufficient to produce a reasonable rate of return on the total investment in the field when but a small fraction of the minimum estimated field life has transpired.

In conclusion, Conoco's application should not be granted as requested under AS 38.05.180(j) (as it existed before amended by HB 128). Conoco has not established that reducing the royalty rate on the Kuparuk Formation from 20% to 5% would significantly prolong the life of the Milne Point field. A minimal extension of the field at a very high cost to the State is not in the public interest. Furthermore, the uncertainties inherent in estimating revenue and costs for the next twenty-two to twenty-five years allow the commissioner to conclude that Conoco cannot adequately show either the magnitude of increasing costs in the later stages of production decline or total field life rate of return.

VIII. Evaluation of Application Under AS 38.05.180(j), As Amended By HB 128 in 1990

AS 38.05.180(j) was amended by HB 128, effective September 12, 1990. It now reads:

> **To prolong the economic life of an oil and gas field or to reestablish commercial production of shut-in oil or gas that would not otherwise be economically feasible,** the commissioner shall adopt regulations to allow reduction of royalty on leases. The commissioner may not grant a reduction of royalty unless the lessee requesting the reduction makes a clear showing that the revenue from the lessee's share of all hydrocarbons produced from the field is and is likely to continue to be insufficient to produce a reasonable rate of return with respect to the lessee's total investment in the field. The commissioner may condition a royalty reduction granted under this subsection in any way to protect the state's interest, including restoration of the state's royalty share in the event of an increase in the price of oil or gas. Before approving a royalty reduction, the commissioner shall make a written finding that **the state has obtained the maximum possible economic return that is compatible with allowing a reasonable rate of economic return for the lessee,** and send copies of the finding to all members of the legislature.

(Emphasis added).

As with AS 38.05.180(p), and AS 38.05.180(j) prior to its amendment by HB 128, relief under the amended standard is discretionary. The department, however, should not exercise its discretion in favor of royalty reduction unless the reduction is demonstrated to be in the public interest. For the reasons discussed in Part VI, above, granting royalty reduction as requested by Conoco, in this instance is not in the public interest.

Under AS 38.05.180(j) as amended by HB 128, royalty relief cannot be granted unless it will either prolong the economic life of an oil and gas field or reestablish commercial production of shut-in oil or gas that would not otherwise be economically feasible. The royalty reduction requested by Conoco will not substantially prolong the economic life of the Kuparuk Formation or Milne Point field for the reasons discussed in Part VII, above. Nor is the Kuparuk Formation shut-in as it was for several months before Conoco submitted its application. Therefore, Conoco's application fails these alternative requirements of AS 38.05.180(j), as amended by HB 128.

As 38.05.180(j), as amended, also retains the requirement of a clear showing that revenue from the field is insufficient to produce a reasonable rate of return on total field investment. The department's analysis of this requirement is the same under both the former AS 38.05.180(j) and its current amended version. (See Part VII, above).

The 1990 amendment to AS 38.05.180(j) specifies that an application for royalty reduction cannot be approved unless the commissioner makes a written finding that the State has obtained the maximum possible economic return that is compatible with allowing a reasonable rate of economic return for the applicant. Due to volatile oil prices, risks inherent in oil and gas production, and uncertain future costs, the department cannot find that the State will obtain its maximum possible economic return without providing for the recapture of foregone royalties in the event a lessee ultimately achieves more than a predetermined reasonable rate of return. However, in this instance the department need not craft a limited or conditional royalty relief, since the royalty relief requested is inappropriate for other reasons, as discussed above.

IX. Milne Point Unit Agreement, Paragraph 18(h)(8)

Conoco argues in its August 27, 1990 supplemental brief that paragraph 18(h)(8) of the Milne Point Unit Agreement governs its application for royalty reduction; and that AS 38.05.180 (p) and (j) apply only to the extent that they are not inconsistent with the unit agreement. Paragraph 18(h)(8) states:

> Reduction of Royalty. After two years' initial production from the field in which the leased area is located has occurred, the State may reduce Lessee's obligations to pay royalty on all of the leased area or on any tract or portion thereof segregated for royalty purposes upon (1) request by Lessee and (2) a clear showing by Lessee that the revenue from all oil, gas and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Lessee's total investment in the field.

Conoco's argument that paragraph 18(h)(8) prevails where inconsistent with AS 38.05.180(p) or (j) appears to be based on an incomplete reading of paragraph 1 of the Unit Agreement, which states:

> The Alaska Land Act ... and all valid and pertinent oil and gas statutes and regulations including the oil and gas operating statutes and regulations in effect as of the effective date hereof or hereafter issued thereunder governing drilling and producing operations, **not inconsistent with** the terms hereof or the **laws of the State of Alaska** are hereby accepted and made a part of this agreement.

(Emphasis added). Conoco chooses to ignore that all statutes not inconsistent with the laws of the State of Alaska are incorporated by reference in the Unit Agreement. Since the statutes are the laws of the State of Alaska, they cannot be inconsistent with the laws of the State of Alaska (except to the extent that one or more statutes are contrary to the United States or Alaska constitution). Therefore, AS 38.05180(j) and (p) are incorporated by reference in the Unit Agreement, and are thus every bit as much a part of the Unit Agreement as is paragraph 18(h)(8).

In any case, a state agency is without authority to enter into an agreement in conflict with applicable statutes. Thus, even without an explicit incorporation of

Alaska's statutes by reference in Paragraph 1 of the Milne Point Unit Agreement, the statutes control when in conflict with the Unit Agreement.

X. Summary

In this instance, I have recommended that the requested royalty reduction should be denied under AS 38.05.180(p), (j), and (j), as amended by H.B. 128 since the department concludes that Conoco has failed to demonstrate:

(1) that granting the requested royalty relief will be in the public interest;
(2) that reducing the royalty from 20% to 5% will significantly prolong the economic life of the field; and
(3) a clear showing that its revenue from oil, gas, and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Conoco's total investment in the field.

The statutes and regulations do not discuss the quantity or quality of data needed to demonstrate a clear showing (though, obviously, "clear showing" is a high standard) that Conoco's revenue from the field is insufficient to produce a reasonable rate of return with respect to its total investment in the field. Similarly, the statutes and regulations do not list precisely the quantity or quality of data needed to demonstrate that the economic life of the field will be significantly prolonged by a royalty reduction. These determinations must be made by the commissioner based on the discretionary power granted by the statutes, department regulations, and the Milne Point Unit Agreement. However, it becomes apparent that, especially in the case of a field such as Milne Point, with only a few years of production history, determining the long term profitability of the field with any certainty is virtually impossible.

In order to thoroughly evaluate Conoco's application, an extensive financial, economic, and technical analysis was completed by the department. While I recommend that the department deny the application, this analysis provides a groundwork for evaluating future royalty reduction requests since this was the first request completely processed by the department.

Even though it is recommended that Conoco's application for a royalty reduction to 5% be denied, the division felt obligated to carefully analyze the data submitted to determine if an alternative approach for royalty reduction could be developed which would meet the statutory requirements. Among the possibilities examined were a sliding scale royalty based on wellhead value, short term relief, relief down to a floor of 12.5% and combinations of these three methodologies. These limited and/or conditional alternatives to a complete denial were determined to be unacceptable since in all cases examined, even ignoring Conoco's failure to make a clear showing, the estimated return to the state and public was substantially less than the estimated revenue lost by the state in forgone royalty. Therefore, even a limited or conditional royalty does not appear to be in the public interest at this time.

Mozambique gas field marked for development

Mozambique's state owned Empresa Nacional de Hidrocarbonetos de Mocambique (ENH) and South Africa's Sasol Ltd., Johannesburg, plan a $700-850 million joint field development project.

Pande gas field in Mozambique, which lies 20 km inland and 600 km northeast of Maputo, will be developed to supply gas by pipeline to markets in the Johannesburg area.

A Sasol official said Argentine company Pluspetrol SA has been brought in as operator of field development. A pipeline company also is being sought to join in the project with a minority interest in the field.

Pipeline companies have been approached by ENH and Sasol, which expect to select a partner in September. ENH and Sasol expect to begin development as soon as the pipeline partner is chosen.

Pande field interests have not been settled, although ENH and Sasol will almost certainly be major shareholders under a production sharing agreement.

Pande field

Pande field was discovered by Gulf Oil Corp. in 1961, but development was hampered by Mozambique's unstable political situation, said project financial adviser Morgan Grenfell & Co. Ltd., London.

The bank said ENH began appraisal of the field in 1989 and concluded in 1991 that field development was viable. An agreement with Sasol in February 1992 was said to be key because Mozambique's gas market is small.

"While Sasol is likely to invest in the upstream field development," said the bank, "its most important role will be to offtake most of the gas under a long term take or pay contract, develop the local market, and build the distribution system."

Eleven wells drilled so far have proven Pande field reserves to be about 1.7 tcf of gas. The gas is said to be dry, high in methane content with no sulfur. Sasol said further appraisal drilling is planned, with the intent to confirm more reserves before development proceeds.

Morgan Grenfell said reserves discovered to date are expected to support projected market demand for at least 20 years.

Gas pipeline

The ENH-Sasol combine plans to lay a 905 km pipeline from Pande field to Secunda, 100 km east of Johannesburg. About two thirds of the line will be in Mozambique and the rest in South Africa.

Morgan Grenfell said the proposed pipeline route is via the Ressano Garcia/Komatipoort border crossing, with a spur line to Durban and offtakes to Nelspruit, Ngodwana, Bethal, and Pretoria and a lateral line to Maputo.

Two spur line options are being considered: a 605 km line from Ressano Garcia to Durban via Maputo and a 540 km line from Badplaas in the Transvaal to Durban with a separate spur to Maputo.

Capital cost of the pipeline is estimated at $400-500 million, including compressors. Line diameters will range from 16 to 24 in.

Design, procurement, construction, and commissioning of the system are expected to take about 28 months.

Energy markets

Morgan Grenfell estimates South Africa's total primary energy demand is 84 million metric tons/year of oil equivalent. Coal is estimated to provide 80% and is used to produce electricity, gasoline, diesel fuel, and fuel gas.

The Johannesburg area is said to hold 45% of South Africa's urban population and 45% of the country's industrial capacity.

"The South African energy market expects significant growth rates in coming years, and consumers are eager to investigate the use of gas," Morgan Grenfell said.

"Detailed market surveys conducted recently by Sasol suggest a penetrable market for gas of 64 bcf/year, mostly in the paper, metals, mineral processing, and chemicals sectors."

The bank said 76% of potential gas customers currently use coal, with gas derived from coal the second largest energy source.

Total gas use in the Maputo area is predicted to reach 19 bcf/year by 2010, with nearly 15 bcf/year being required for power generation and the remainder for industry.

Deepwater royalty relief to get Clinton support

The Clinton administration is preparing to support U.S. legislation that would provide royalty relief for new deepwater production and any production off Alaska.

Bill White, deputy secretary of the Department of Energy, told the Senate energy committee the administration will support a bill the panel has approved but then qualified that support.

White explained the administration could not support the deepwater—more than 200 m—relief bill and a separate proposal for a $5/bbl tax credit for deepwater production. The administration will study the latter measure and report back to Congress soon.

White, who sits on a White House task force studying energy issues, said the bill "makes sense," but to approve deepwater relief, which would grant a royalty holiday until operators recover their cost of developing otherwise uneconomic fields, and a $5 credit might be "overkill."

Sen. Bennett Johnston (D-La.), energy committee chairman, argued the two proposals are not mutually exclusive because the legislation would not apply to projects that were otherwise economic to develop. Johnston said he soon will press for action on the bill by the full Senate.

Thomas H. Neel, CNG Producing Co. chief executive officer, told the committee, "This is an innovative approach which would provide the economic incentive to develop already discovered domestic hydrocarbons.

"It would be particularly important to companies like CNG, the large independents which are becoming so important in the gulf but do not have financial resources of the majors."

Other issues

The energy committee bill also would order the Minerals Management Service not to revise the present area-wide leasing system in the central and western Gulf of Mexico. MMS is reviewing possible changes to its leasing approach.

And the bill has a provision to amend the 1990 Oil Pollution Act so its oil spill insurance requirements would apply only to offshore facilities and allow MMS to mandate less than the $150 million of insurance required in the original bill.

Assistant Interior Sec. Robert Arm-

THE PRECEDING PAGES
WERE TREATED AS A UNIT
IN THE ORIGINAL FILE

HB 207

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STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

February 27, 1995

The Honorable Gail Phillips
Speaker of the House
Alaska State Legislature
State Capitol
Juneau, AK 99801-1182

Dear Speaker Phillips:

Under the authority of art. III, sec. 18, of the Alaska Constitution, I am transmitting a bill relating to the reduction of royalties reserved to the state to encourage otherwise uneconomic production of oil and gas from marginal fields and to prolong the production life of declining fields.

The bill would change existing royalty reduction provisions to grant the commissioner of the Department of Natural Resources greater discretion to provide royalty relief to lessees when necessary and clarify the commissioner's authority to grant such relief under various provisions in AS 38.05.180.

The proposed changes will require the lessee to make a clear and convincing showing that a royalty reduction is necessary and is in the best interest of the state. The commissioner may condition granting of a royalty reduction in any way necessary to protect the state's best interests, such as increasing the state's royalty share if the price of oil or gas rises.

Finally, the bill maintains the royalty contributions to the permanent fund so that the fund would never receive a royalty less than that provided under existing statutes.

I urge your favorable action on this bill.

Sincerely,

Tony Knowles
Governor

CS FOR HB 207(FIN)AM QUESTIONS & ANSWERS

A. Purpose

1. What, generally, does the bill accomplish?

This legislation amends current law to give the Commissioner of the Department of Natural Resources (DNR) authority to grant royalty reduction for fields that have been delineated, but not produced. The current law allows the commissioner to grant royalty reduction to prolong the economic life of a field or to reestablish shut-in production. The bill requires that the applicant make a clear and convincing showing that any reduction meets certain requirements and is in the best interests of the state. As part of the application the commissioner shall require the applicant to provide financial and technical data (which may be kept confidential at the request of the applicant) to assure that the requirements are met and that a royalty reduction is warranted. If the commissioner determines that a third-party analysis of the submitted data is necessary, then he may require that the applicant pay for this analysis. This bill also provides that if relevant factors change in the future, then the commissioner may raise the royalties that were previously reduced. The commissioner must condition royalties if oil price changes.

These reductions may be applied only if one of the three "trigger events" is met:

- Fields that are delineated, but not previously produced, to allow production that would not otherwise be economically feasible.
- Oil and gas fields whose economic life may be prolonged in light of increasing costs in the later stages of production.
- Reestablishing commercial production of shut-in oil or gas that would not otherwise be economically feasible.

Before approving any royalty reduction, the commissioner must issue written findings assuring compliance with the requirements of this section and that the best interests of the state are preserved. The legislation also requires the commissioner to give notice of his preliminary findings and determination to the legislature and public, and allow for comment before adopting final findings and determination. The current committee substitute also states that the commissioner shall offer to provide the LB&A committee a review of the preliminary findings and determination.

2. Why is a change in the law necessary?

A change is necessary for three reasons. First, a change will help to make Alaska more competitive on a worldwide basis for oil companies' investment dollars. The legislation would give the commissioner greater flexibility than exists under current law and authority to reduce the royalty rate on fields that have been delineated, but have not previously produced oil or gas. Second, it would change the economic standard for a reduction for a mature field to a

point-forward or incremental analysis from a historical investment analysis which is not relevant to a decision whether to abandon or continue producing a field. Third, it would clarify the authority to reduce royalty under AS 38.05.180 (j) & (p).

B. Standards

1. The "best interest" standard seems vague. Should the legislature define the criteria that must be considered in making a best interest decision? Should the legislature maintain the requirement in existing law that the commissioner mast find that the "state has obtained the maximum economic return that is compatible with allowing a reasonable rate of return for the lessee"?

Before talking about further defining the best interest standard, there already is a clear limit on the commissioner's authority. The current statute permits the commissioner to grant royalty reduction only if one of two trigger events is met. As discussed above, the legislation would add a third trigger event -- a delineated field that would not otherwise be economically feasible to produce. Only if that showing is met, which must be met by clear and convincing evidence, is the commissioner authorized to even consider whether he should grant royalty relief.

If the commissioner makes a finding that one of the trigger events has been met, then he must decide whether the reduction would be in the best interest of the state before a reduction would be granted. This standard, or a similar standard, is used throughout the statutes without explicit criteria set forth. For example, AS 38.05.180(p) gives the commissioner authority to unitize oil and gas leases if he determines it is necessary to "secure the public interest."

Importantly, DNR has already discussed the best interest standard in connection with Conoco's royalty reduction application. In a published decision document, then Commissioner Heinze noted that the "public interest finding (does) not simply weigh cash gains and losses to the state government" although he determined that lost revenues to the state government would be approximately four times greater than the sum of additional royalties to the state government. The commissioner considered: (1) the effect on the total royalties that would be paid; (2) the additional projected recovery of oil; (3) the ability of the project to render a positive cash flow; (4) the desirability of encouraging further investment that has a direct benefit to the state; (5) the effect of additional production on TAPS throughput; and (6) the benefits of additional employment. At a minimum, the commissioner would consider these factors in making any decision.

The legislature, of course, remains free to put sideboards or restraints on the commissioner's discretion, but any sideboard or restraint could effectively restrain the commissioner's ability to craft practical relief for a given field or reservoir. The current version of the bill requires the commissioner to change the royalty rate if the price of oil changes.

Finally, DNR opposed an amendment to reinstate the "maximum possible economic return to the state" standard. DNR believes that the economic standard set forth in the trigger events is adequate. Moreover, the maximum economic standard is an impossible standard to define, let alone meet.

2. Why does the legislation change the standard for royalty reduction for mature producing fields?

The legislation actually clarifies the confusing old standard of reasonable rate of return on total investment. The old standard is unworkable for fields in the later stages of production. For these fields, the analysis should be based on expected future costs and future revenues. Past profitability has little to do with the decision to produce or abandon a field today or tomorrow. Abandonment decisions are based on a point-forward analysis, not historical performance.

3. Why does the legislation change the standard of persuasion from "clear" to "clear and convincing"?

The "clear and convincing" standard is a term of art in the law which has been defined by the courts and has an accepted definition. A "clear" standard has not been so embraced. This lead to a dispute between DNR and Conoco & Oxy in their application for royalty reduction. The issue was pending before the superior court, but had not been decided, when the parties settled. The change was made in hopes of avoiding litigation.

4. The legislation is non-specific about when and how the royalty could increase. Shouldn't it be more specific?

This provision is basically the same as existing law. Specifying when and how the royalty must increase would take away flexibility. Presumably, the commissioner's decision would provide for an increase if prices increase or costs decrease. However, under the governor's bill, there would be flexibility to tailor the terms to the specific facts. The commissioner's final finding or determination would include the terms providing for the increase.

5. What does the term "delineated" mean? Should the term be defined in the statute?

DNR believes that the term "delineated" is a term of art in the industry. Its generally accepted definition is that there is sufficient knowledge of the aerial extent, volume, and productivity of the field to allow a lessee to decide whether to proceed with development and production, including determining costs to develop and produce the field. In other words, delineation is the process by which a resource in a previously discovered accumulation makes the transition to "reserves." Reserves are resources demonstrated with reasonable certainty to be recoverable from a known accumulation under existing economic and operating conditions.

The requisite information varies from field to field and no specific test would suffice for all fields. The information pertinent to making the decision would include drilled wells, seismic data and interpretations, and engineering data on the reservoir's characteristics, including well flow test data of sufficient duration to provide estimates of future development well productivity.

DNR believes that any attempt to specifically define "delineated" would likely create as many problems as it solves.

6. What do the terms "field" and "pool" mean?

The meaning of the term "field" was disputed in the Conoco & Oxy application process. DNR defined the term to include all reservoirs or pools underlying the lease or unit area. "Pool" means an underground reservoir containing a common accumulation of oil or gas. Each zone of a general structure which is completely separated from any other zone in the structure is covered by the term "pool." The terms "pool" and "field" mean the same thing when only one underground reservoir is involved, but "field" - unlike "pool" - may relate to two or more pools. To prevent future disputes, and to increase flexibility, the bill references both "field" and "pool."

7. Can the royalty reduction apply to a single pool on a given lease, as compared to all production from the lease?

The legislation would give the commissioner that discretion. If there had been production from one pool in a field, but not another pool, the commissioner would have authority to consider a royalty reduction only for some or all of the second pool if it had been delineated. Future discoveries or developments on the lease would not be automatically granted a reduction.

On leases that have been developed, such as the Kuparuk-West Sak situation, DNR wants the latitude to consider royalty reductions for the West Sak reservoir, while retaining the original royalty rate for the deeper Kuparuk reservoir.

8. Would the royalty reduction be granted for the entire field or unit area?

The reduction, if granted, would be granted on a lease by lease basis. The lease or unit agreement establishes the royalty rate, and it is the lease or unit agreement that needs to be amended if the royalty rate is to be changed. Of course, the reduction could apply to all leases within the unit area.

9. Would the bill allow the Commissioner to reduce the royalty rate at the state's largest fields, including Prudhoe Bay?

No. The new trigger event in the bill would not allow a royalty reduction for a field like Prudhoe Bay. Both gas and oil have been produced and sold from that field. Consequently, it could not qualify under the new trigger event of a delineated, but not produced field. Simply put, a reduction is not necessary to get the field developed. At some point in the distant future when the field is in steep decline, Prudhoe Bay may become eligible for a reduction under one of the other two trigger events contained in the current royalty reduction statute.

10. What does the term "reasonable rate of return" mean in the current legislation?

DNR recommends dropping the term. This term led to serious disagreements between an applicant and DNR. DNR felt obliged to adopt an objective standard which could be applied consistently regardless of the vagaries of an individual company's financial planning standards. Recognizing that neither the state's oil and gas leases nor statutes guaranteed a company a specific rate of return, or any return at all, Commissioner Heinze adopted a standard – the return on a 90 day Treasury bill – which provided a positive real rate of return, but did not provide an excessive profit at the expense of the state's royalty share. Other potential rates considered by DNR included: (1) the individual company's cost of capitol plus a marginal profit; (2) a public utility type rate of return; (3) the economic yardstick used by DOE to determine if a field is commercially developable; (4) the long-term bond yield; and (5) the rate allowed by DOR in determining reasonable shipping rates for severance tax purposes. As noted previously, once a field is developed (i.e., major investments sunk) any revenue in excess of operating costs is sufficient to keep the field in production.

C. Appealability & Confidentiality

1. The non-appealability clause seems unusual. Why is it in the bill?

The clause has two purposes: The first is to make clear that the statute does not confer on a lessee a right or entitlement to a royalty reduction. Even if the lessee makes a showing that the lessee could not economically produce the field, there is no duty on behalf of the commissioner to grant royalty relief. DNR makes a business judgment whether the state would rather have production on a reduced royalty basis or take back the leases and attempt to relet them. Moreover, the commissioner may have to consider other factors, such as the effect on the bidding process and on the environment, in determining whether a royalty reduction should be granted.

There is some federal law on the subject of royalty reductions on federal leases. Under federal law the Secretary of Interior has authority to reduce a lease's royalty rate under certain circumstances. But federal law holds that:

> [There are] no circumstances which require BLM to reduce royalty. Under the statute, no entitlement to such a reduction can ever arise. BLM

> remains free to accept the economic consequences of denying royalty relief, which may vary from case to case. ... The discretionary authority conferred by (the federal royalty reduction statute) enables BLM to exercise prudent business judgment to accept the alternative that best protects the economic interest of the United States as owner of the mineral resources.

Peabody Coal Co., 93 IBLA 317, 326 (1986) (emphasis added).

Given that there is no entitlement or no right to a royalty reduction, the second purpose is to preclude expensive, time consuming litigation, which can have no basis, by the applicant whose application has been denied. The intent of the provision is to preclude the applicant from appealing. The courts have rejected an argument that there is a constitutionally guaranteed minimum right of judicial review where the "administrative activity ...involves the grant or denial or a privilege which the state government is free to allow or withhold in its discretion ...." Cooper, State Administrative Law 677 (1965). The Department of Law believes that the commissioner's determination regarding a royalty reduction application would fall into that category and thus the court would likely give effect to a provision precluding judicial review.

The general rule, according to Professor Davis, one of the foremost authorities on administrative law, is that:

> [I]f a statute unequivocally precludes judicial review of an agency action, and judicial review is sought on any basis other than a claimed violation of a constitutional right, the Court will give statute effect.... When the scope and effect of an explicit statutory limit on judicial review is less clear, however, and the Court perceives a significant risk of unfairness if the statutory limit is given broad effect, the Court sometimes strains to interpret the limit narrowly.

Davis, Administrative Law, §17.8 at 155. The court could read into the finality provision an implied exception permitting review of constitutional questions, questions regarding the jurisdiction of the agency and the regularity of its procedure, questions affecting the existence of property rights, questions involving bad faith, or questions regarding fraud. Cooper, supra at 679.

The Alaska Supreme Court has stated that a "legislative statement of finality is one which we will honor to the extent that it accords with constitutional guarantees." K & L Distributors, Inc. v. Murkowski, 486 P.2d 351, 357 (Alaska 1971). It is likely that the court will attempt to whittle down any finality language to size to fit the court's sense of fundamental fairness. In other words, a statement of finality will not prevent the court from reviewing the decision to assure compliance with the due process clause under the Alaska constitution. Nevertheless, a finality provision will mean that any review of a royalty reduction decision will

be much more limited than the broad review of an agency decision required by the Alaska Administrative Procedure Act. For example, the court would not review each factual finding to see that it is correct, or even that it is supported by substantial evidence. The court would only examine the commissioner's decision to determine whether it has "passed beyond the lowest limit of the permitted zone of reasonableness to become capricious, arbitrary or confiscatory." Id. at 358. Given this, we believe that it is less likely that a disgruntled lessee would appeal and, therefore, more likely needless court expense would be saved.

2. Should the commissioner's decision be subject to legislative review?

The administration does not object to some type of legislative oversight. The administration believes that the legislature could request a briefing even without a specific provision in the bill. The administration notes that at least one company has opposed a proposed amendment which would have provided for a confidential briefing by the commissioner of the legislature.

3. Why does the bill contain confidentiality provisions?

The confidentiality provision in the bill is no different than existing law. The purpose of this provision is to protect a company's competitiveness relative to other companies. Obviously, a company which has spent millions of dollars to acquire geological, geophysical, and engineering information regarding a potential oil field does not want that information revealed to other companies. Furthermore, releasing financial information about the company would reveal the company's underlying economic philosophy regarding exploration and development and, thus, disadvantage the company with respect to its competitors. The confidentiality provision actually promotes the disclosure of complete and frank information to the state. Given industry's testimony at the hearings, it is likely that without a confidentiality provision for new fields, no company would apply for royalty relief and the benefits of the bill would be lost. Nevertheless, the bill allows the company to disclose its information to the public if it desires.

D. Miscellaneous

1. Why does the legislation delete the provision in former law that the commissioner shall adopt regulations?

Such a provision is unnecessary and would delay the implementation of any new program. Under current law, the commissioner already has the authority to adopt regulations necessary to carry out the purposes of the Alaska Land Act. AS 38.05.020(b)(1). There are already existing regulations which define the procedure for submitting an application for reduction under AS 38.05.180(j). 11AAC 83.185. DNR would plan to amend those regulations to deal with the proposed changes in the statute. DNR, however, does not want to be required to

implement regulations because that could delay implementation of any new statutory changes. The current law allows the commissioner to adopt regulations if needed.

2. Do you have any concerns that the legislation will undermine the competitive bidding process?

The commissioner will have to consider this issue in determining whether a reduction is in the state's best interest. Certainly, if the royalty rate is the bid variable this is a very real concern. In general, the closer the reductions to the time of the bid, the greater the concern. That is one of the reasons why the former law provided for a two year production requirement. That requirement, however, proved unworkable and the legislature dispensed with that requirement in 1990 to allow the commissioner more flexibility.

The proposed amendment tries to balance the need to protect the bidding process with the need to get marginal fields timely developed. For example, a reduction cannot take place until the lessee at least does delineation work. In other words, the commissioner could not grant a reduction the day after the lease sale. More importantly, the commissioner cannot grant a reduction unless the lessee makes a clear and convincing showing that absent relief the field would not otherwise be economically feasible. In making that determination and deciding whether granting relief would be in the state's best interest, the commissioner will have to examine whether other potential lessees would develop or produce the field without royalty relief.

The Alaska Supreme Court has recognized a competitively bid government contract can be amended under certain circumstances without jeopardizing the competitive bid process. Kenai Lumber Co., Inc. v. LeResche, 646 P.2d 215, 220-22 (Alaska 1982). Importantly, every state oil and gas lease contains a royalty reduction so all competitive bidders were on notice that the royalty could be reduced under appropriate conditions.

4. Is it legally required that the permanent fund be held harmless?

Probably not, but a concern has been raised. Article IX, Section 15, provides that: "At least twenty-five per cent of all mineral lease rentals, royalties, royalty sale proceeds ... **received by the state** shall be placed in a permanent fund." The Department of Law believes that the most likely interpretation of the constitutional provision is the permanent fund gets 25% of whatever the state gets and if the state gets a lesser or greater royalty for that matter, the permanent fund gets 25% of that amount.

An argument can be made that the provision means the permanent fund gets 25% of the original royalty rate specified in the lease and the legislature or the commissioner cannot change the amount, at least for the permanent fund. The Department of Law does not believe that such an argument would be persuasive to a court. There have been statutory and lease provisions providing for royalty reduction in one form or another since statehood. These

provisions were in effect at the time the permanent fund provision took effect and no special provision was enacted to keep the permanent fund whole in that instance. Consequently, we believe the permanent fund takes its 25% share subject to the possibility that the royalty share may be reduced. In short, the permanent fund gets at least 25% of whatever the state receives.

A good example would be the administration of the former royalty reduction statute (which still applies today on some of the older leases). That statute provides for reduction of the royalty rate to 5% on a lease where a discovery is made. In that case, the permanent fund has not been held harmless or kept whole. The permanent fund gets 25% of the reduced rate, no more or no less.

The current committee substitute deletes the permanent fund hold harmless provisions which were in the bill as originally introduced. Regardless of whether the bill contains hold harmless provisions, the administration supports a floor for any reduction that does not exceed 75% of the applicable royalty rate.