

HB

380

HFIN

FILE

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

130 Seward Street, Suite 409
Juneau, Alaska 99801-2105

MEMORANDUM

March 30, 1998

SUBJECT: Cook Inlet royalty reduction (CSHB 380(FIN))

TO: Representative Gene Therriault
Representative Mark Hanley
Co-chairs, House Finance Committee
Attn: Shar Smith, Committee Secretary

FROM: Richard A. Glover - *RAG*
Legislative Counsel

Enclosed is the CS you requested. Note that there are several changes in the CS that were not requested. The changes are made in order to correct errors in the \F version, which our office typed but did not review for legal problems. The bill has been corrected to conform to the drafting manual, and the title requires a correction. I also recommend deleting the language ", all of which are located within the Cook Inlet sedimentary basin, were discovered before January 1, 1988, and have been undeveloped or shut in from at least January 1, 1988, through December 31, 1997," since this language (which is merely a recitation of historical details) has no legal effect.

I would also recommend discussing the designation of the six specified fields for proper legal description with the Department of Natural Resources. The bill specifies these "fields" as eligible for royalty reduction, but I do not know how the lateral boundaries of the fields are determined. The department has much greater expertise in these matters, and the description in the bill may have sufficient plain meaning within the industry and normal usage by the department. However, the lateral limits of the fields may not be known under the geological definitions of "field," and if so, litigation may be necessary to determine the royalty due from a well that factually may or may not lie within the named locations, or be subject to the pooling or unitization agreements.

If I may be of further assistance, please advise.

RAG:jdr
98-207.jdr

Enclosure

HOUSE COMMITTEE REPORT

(11)

Date Referred to Committee: March 13, 1998

FURTHER REFERRALS:

Date of Committee Action: 3/18/98

The FINANCE Committee considered:

HB 380

HOUSE BILL NO. 380

REDUCE ROYALTY ON COOK INLET OIL & GAS

"An Act relating to a temporary reduction of royalty on oil and gas produced for sale from fields within the Cook Inlet sedimentary basin where production is commenced in fields that have been discovered and undeveloped or that have been shut in."

recommends it be replaced with the following committee substitute CS HB 380 (FIN) the same title a new title

additional referral to _____ Committee
 attached amendment(s)

ADOPTS: _____ Letter of Intent

ATTACHES NEW FISCAL NOTE(S): (Dept) _____ APPROVES PREVIOUS: (Dept/Date) _____
 fiscal note(s) _____ fiscal note(s) DNR 3/13/98

zero fiscal note(s) _____ zero fiscal note(s) _____

| SIGNING WITH RECOMMENDATIONS | DP | DNP | NR | AM |
|-------------------------------|----|-----|----|----|
| <i>[Signature]</i> Theriault | | | X | |
| <i>[Signature]</i> Kelly | | | X | |
| <i>[Signature]</i> G. Davis | X | | | |
| <i>[Signature]</i> Kohring | X | | | |
| <i>[Signature]</i> Milder | X | | | |
| <i>[Signature]</i> Gussendorf | | | | X |
| <i>[Signature]</i> Martin | | | X | |
| | | | | |
| | | | | |
| | | | | |

Co-CHAIR'S SIGNATURE *[Signature]*

FISCAL NOTE

STATE OF ALASKA
1998 LEGISLATIVE SESSION

Bill Version: CSHB 380 (O&G)
Publish Date: 3/13/98

Revision Date: _____ Dept Affected: Natural Resources
 Title: An Act relating to a temporary reduction of BRU: Resource Development
royalty on oil and gas produced ... from ... Cook Inlet ... Component: Oil & Gas Development
 Sponsor: Rep. Hodgins
 Requestor: (H) O & G Component Serial No. #439

Expenditures/Revenues (Thousands of Dollars)

| OPERATING EXPENDITURES | FY99 | FY00 | FY01 | FY02 | FY03 | FY04 |
|---------------------------------------|------------|------------|------------|------------|------------|------------|
| PERSONAL SERVICES | | | | | | |
| TRAVEL | | | | | | |
| CONTRACTUAL | | | | | | |
| SUPPLIES | | | | | | |
| EQUIPMENT | | | | | | |
| LAND & STRUCTURES | | | | | | |
| GRANTS, CLAIMS | | | | | | |
| MISCELLANEOUS | | | | | | |
| TOTAL OPERATING | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CAPITAL EXPENDITURES | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CHANGE IN REVENUES (fund code) | 0.0 | * | * | * | * | * |

FUND SOURCE (Thousands of Dollars)

| | | | | | | |
|--------------------------|------------|------------|------------|------------|------------|------------|
| 1002 Federal Receipts | | | | | | |
| 1003 GF Match | | | | | | |
| 1004 GF | | | | | | |
| 1005 GF/Program Receipts | | | | | | |
| 1037 GF/Mental Health | | | | | | |
| Other (Specify Type) | | | | | | |
| TOTAL | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

Estimate of any current year (FY98) cost: \$ none

POSITIONS

| | | | | | | |
|-----------|---|---|---|---|---|---|
| FULL-TIME | 0 | 0 | 0 | 0 | 0 | 0 |
| PART-TIME | 0 | 0 | 0 | 0 | 0 | 0 |
| TEMPORARY | 0 | 0 | 0 | 0 | 0 | 0 |

ANALYSIS: *(Attach a separate page if necessary)*

It is impossible to quantify the fiscal effect of this bill since some critical terms are not defined and no economic analysis has been provided.

Following on page 2 is an example of what we believe would be the fiscal impact of this bill on one particular project.

Prepared by: Ken Boyd, Director *Mico Buss for* Phone: 259-8800
 Division: Oil & Gas Date: 20-Feb-98
 Approved by Commissioner: *Mico Buss for John Stevens* Date: 2-20-98
 Agency: Natural Resources

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COMMITTEE COPY

The State and an oil company have recently negotiated the creation of the Redoubt Unit in Cook Inlet. This Unit includes several abandoned wells and contains "undeveloped" oil and thus clearly, in our view, meets the criteria of the bill. This unit was created with the understanding that royalties would be 12.5%. There was never any discussion of reducing royalties as a condition of forming the Unit (although the company could APPLY for royalty reduction under HB-207). The company never indicated that royalty relief would be necessary to develop the Unit. The fiscal consequence of HB380 on the Redoubt Unit is:

1) If we assume 500 bbl/day production per well, \$10/bbl oil price:

$500 \text{ bbl/day} \times \$10/\text{bbl} \times 12.5\% = \$625/\text{day} \times 365 \text{ days} \times 10 \text{ years} = \$2.28 \text{ million/well}$

$500 \text{ bbl/day} \times \$10/\text{bbl} \times 5\% = \$250/\text{day} \times 365 \text{ days} \times 10 \text{ years} = \$910 \text{ thousand/well}$

The State will receive \$1.37 million fewer royalty dollars at 500 bbl/day per well.

2) If we assume 1,000 bbl/day production per well, \$10/bbl oil price:

$1,000 \text{ bbl/day} \times \$10/\text{bbl} \times 12.5\% = \$1,250/\text{day} \times 365 \text{ days} \times 10 \text{ years} = \$4.56 \text{ million/well}$

$1,000 \text{ bbl/day} \times \$10/\text{bbl} \times 5\% = \$500/\text{day} \times 365 \text{ days} \times 10 \text{ years} = \1.8 million/well

The State will receive \$2.7 million fewer royalty dollars at 1,000 bbl/day per well.

Production per well will likely be somewhere between these two numbers, so the State will forfeit between \$1.37 million and \$2.7 million per well for just the Redoubt Unit.

Assuming (conservatively) that 10 wells are in production the State will "contribute" between \$14 and \$27 million to this project in the form of an unrequested royalty reduction.

Similar examples could be prepared for other fields. Estimates for reductions of royalty payments for gas are more difficult to prepare. But unless and until there are new markets for gas (and assuming the markets are not over-supplied) the 5% royalty gas will merely displace 12.5% royalty gas.

In general, for all production to which this bill applies, the State will receive $(12.5\% - 5\%) = 7.5\%$ fewer royalty dollars. This is a 60% royalty reduction given without any economic analysis or justification.

3/28/98

#1

78 passed 5/2

AMENDMENT

OFFERED IN THE HOUSE
TO: CSHB 380(O&G)
0-LS1503\F

Page 2, Line 3

After "the first"

Delete "35,000,000"

Insert "25,000,000"

FISCAL NOTE

STATE OF ALASKA
1998 LEGISLATIVE SESSION

Bill Version: CSHB 380 (O&G)
 Publish Date: 3/13/98

Revision Date: _____ Dept Affected: Natural Resources
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royalty on oil and gas produced ... from ... Cook Inlet ... Component: Oil & Gas Development
 Sponsor: Rep. Hodgins
 Requestor: (H) O & G Component Serial No. #439

(Thousands of Dollars)

| Expenditures/Revenues | FY99 | FY00 | FY01 | FY02 | FY03 | FY04 |
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| OPERATING EXPENDITURES | | | | | | |
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| LAND & STRUCTURES | | | | | | |
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| MISCELLANEOUS | | | | | | |
| TOTAL OPERATING | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
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| CHANGE IN REVENUES (fund code) | 0.0 | * | * | * | * | * |

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| Other (Specify Type) | | | | | | |
| TOTAL | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

Estimate of any current year (FY98) cost: \$ none

POSITIONS

| | | | | | | |
|-----------|---|---|---|---|---|---|
| FULL-TIME | 0 | 0 | 0 | 0 | 0 | 0 |
| PART-TIME | 0 | 0 | 0 | 0 | 0 | 0 |
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ANALYSIS:

(Attach a separate page if necessary)

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 Division: Oil & Gas Date: 20-Feb-98
 Approved by Commissioner: *Mico Bus for John Swaley* Date: 2-20-98
 Agency: Natural Resources

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DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

3601 "C" STREET, SUITE 1380
ANCHORAGE, ALASKA 99503-5948
PHONE: (907) 269-8800

March 11, 1998

Senator Rick Halford, Chairman
Senate Resources Committee
Alaska State Legislature
State Capitol
Juneau, Alaska 99601

Dear Senator Halford:

I would like to take this opportunity to offer some comments on SB256/HB 380 (bill) and to respond to the March 4 letter to you from James Eason. His letter misrepresents the division's position on the bill's fiscal effects and is somewhat "factually disadvantaged." Moreover, what is clear now that was not clear from the letter is that Mr. Eason is working for Forcenergy on the bill.

The bill's principal goal is not "to develop new sources of natural gas to help offset potential supply shortages which have been forecasted to occur in the next 10-11 years." As the representative of Marathon testified before both the Senate Resource Committee and the House Special Committee on Oil and Gas (committee), "[n]ew markets for uncommitted natural gas reserves are not available for the next several years, making it difficult to economically justify near term drilling expenditures [and] this Bill ... will [not] be enough to stimulate significant activity for natural gas development in the near future." Even Enstar acknowledges that it already has under contract enough gas to meet its demand through 2002. In the near future, the bill's only effect on the gas market will likely be the substitution of five percent royalty gas for 12.5 percent royalty gas. The picture that emerges strongly suggests that the bill's principal goal is to grant Forcenergy a royalty reduction for oil production from the Redoubt Unit, whether it is needed or not and without any economic or technical analysis.

About a year ago Forcenergy approached the division about forming a new unit, the Redoubt Unit. Two of the leases in the proposed unit would expire if they were not put into the unit and could be released in the next competitive lease sale. The division agreed to form the unit and extend the leases because the division believed, based on Forcenergy's representations, that Forcenergy would rapidly attempt to develop the leases under the existing lease terms, specifically the 12.5 percent royalty terms. Indeed, Forcenergy committed to shoot a 3-D seismic survey over the area and process it by the end of 1997, evaluate the data by the 1st quarter of this year, and drill a well by the end of 1999 or commit to construct a production platform by the end of 2001. The division always understood that Forcenergy could apply for royalty reduction under the statute amended by HB 207 where it would be required to show by "clear and convincing" evidence that "production ... would not be otherwise economically feasible."

It is disconcerting that Mr. Eason would be critical of the assumptions made in the division's fiscal note. First, Mr. Eason has recognized that making such a financial estimate "is difficult when all the information is on the table [and is] virtually impossible when neither reserves, nor the cost to produce those reserves are [available]." This latter situation is precisely what the division confronted in preparing the fiscal note and the reason for its caveat: "It is impossible to quantify the fiscal effect of this bill" Nevertheless, the division attempted, in good faith, to inform the legislature of the bill's possible financial consequences. Given the paucity of the data, the division stands by its fiscal note.

Next, by referring to a decline curve for the Hemlock Oil Pool, Mr. Eason criticizes the division's use of flat production. Again, the division was merely trying to give an idea of the magnitude of potential loss to the state. For this type of analysis, a flat decline curve over a specified range of production is perfectly acceptable. The division is well aware of how fields decline. Interestingly, Mr. Eason's depletion table is very misleading. It starts 10 years AFTER the start of production—in the first year of decline. The Hemlock's production graph shows that for the first 10 years there was NO production decline. The division can provide the exact numbers if you want them, but if the complete production history is considered, then the range of reduction is virtually identical to that presented in the division's fiscal note. Without better information, all anyone can do is speculate about the shape of a field's decline curve. What one can say with certainty, however, is that the bill creates an incentive to produce the field as rapidly as possible to minimize the decline curve in the field's early years.

Finally, Mr. Eason criticizes the fiscal note by selectively picking and choosing parts of the division's analysis. Page 3 of the letter starts: "If one adopts the division's highest production rate" What it should say is that: "The author of this letter has chosen to adopt the division's highest production rate and ignore the rest of the division's analysis." The fiscal note provides two ranges of production and suggests that Cook Inlet oil fields would often fit somewhere in this range. Again, the division stands by its fiscal note, fully recognizing the uncertainties in these types of analyses.

Mr. Eason's letter also attempts to rationalize the bill's terms by equating them to those of two other recent bills. First, he suggests that the bill's terms are consistent with the recent royalty reduction bill, HB 207. Both do have a five per cent royalty rate provision. But, the bill's provision is a five percent ceiling while HB 207's provision is a five percent floor. Under the bill, the royalty cannot be increased during the ten year holiday. Moreover, this bill guts HB 207's protections: (1) a clear showing of necessity; (2) protection of the state's interest; and (3) upside potential for the state. As Representative Rokeberg noted, this bill is just an end run around HB 207.

Next, Mr. Eason attempts to link this bill to the recent discovery royalty bill because neither provides for changing economic conditions. But, they cannot be equated. The discovery royalty bill is intended to reward companies who risk substantial dollars drilling rank wildcat exploration wells and then act diligently to bring that field into production. This bill rewards those who had the good fortune to own the leases in question at the time of the bill's passage for bringing known oil and gas accumulations into production. This bill gives a bigger reward (because it applies to all pools within a field as opposed to a pool within a field) for a longer time (because the ten year period runs from the date of first production rather than from the date of discovery) to those who take less risk. Something is wrong with this picture. Mr. Eason's comparison of the bill's terms with these other two bills' merely veils the arbitrariness of the bill's terms.

One of the key provisions in HB 207 is that royalty relief cannot be granted unless there is a clear and convincing showing that without the relief the oil or gas production "would not otherwise be economically feasible." The bill grants relief whether or not the field needs relief. Mr. Eason suggests that one should assume that the showing has been made because fields that were discovered 30 years ago and are still not developed must ("it seems axiomatic") need royalty reduction. Apparently, not all the fields that were discovered 30 years ago need relief since only the six fields in the Committee Substitute are permitted this relief, even if other fields may meet the same criteria. Furthermore, all six fields must need identical amounts of relief over the same amount of time since the bill provides no options. Although these fields may have been discovered 30 years ago, the leases that comprise the two oil fields (Redoubt and Pt. Starichkof) were recently issued. Forcenergy recently acquired the Redoubt leases and applied for the Redoubt Unit within the past year. Arco, Anadarko and Forcenergy bought Pt. Starichkof leases in the last few lease sales. If they did not think these prospects were profitable bearing a 12.5 percent royalty, then why buy the leases and why form the Redoubt Unit?

As I outlined in my March 2 letter to Representative Hodgins, the recent Phillips press release regarding their new discovery (Tyonck Deep) indicates that that field is economic and states "[e]ngineering studies have been initiated for design of pipeline and production facilities capable of processing 5,000 barrels of oil per day as early as mid-1999." Perhaps "leveraging additional exploration and development in the vicinity of new infrastructure" does not require a 60% royalty reduction.

Moreover, the notion that a known accumulation, which has not been developed for twenty to thirty years, is uneconomic has been refuted. Technological advances and cost saving measures have more than offset declining oil prices in real terms. On the Alaska North Slope, for example, the minimum economic field size continues to be reduced. Between 1991 and 1996, operating expenses were reduced from \$2.29 per barrel to \$1.54 per barrel (a 33% reduction), development well costs were reduced from \$3.0 million per well to \$2.0 million per well (a 33% reduction), and well hook-up costs were reduced from \$1.5 million per well to \$0.6 million per well (a 60% reduction). Between 1996 and 1997, development well costs were reduced further reduced from \$2.0 million to \$1.7 million (another 15% reduction in one year). These costs are in "dollars of the day," and considering inflation over this period, these reductions are, to quote Arco, "even more dramatic."

Although the division does not possess similar statistics for the Cook Inlet, industry has also been recently reducing costs in the Cook Inlet and expects to continue to reduce costs over, at least, the next several years. Moreover, 3-D seismic and extended reach drilling has enabled the industry to drill "smarter" wells giving more reductions. "Smarter" means fewer wells drilled with a greater precision than could have been achieved even five years ago. 3-D seismic not only provides the explorationist a clearer view of the subsurface, it provides the production manager a tool to drill more efficient development wells. 3-D seismic also assists in designing water floods and other production enhancing techniques to maximize benefit and minimize cost.

Given these technological advances and cost saving measures, one must question the need for additional incentives in the Cook Inlet. Today the Cook Inlet is a busy place (see enclosures) with a lot of drilling and seismic activity. We have had two successful recent lease sales and exploration activities are the highest since Arco's work at Sunfish five years ago. The division expects this pace to continue for the near term.

In addition to these two factors, this high level of activity can be attributed to a favorable business climate. This favorable climate exists, in large part, due to an ongoing series of

new legislation that has improved the state's stature in the world oil marketplace. Area-wide leasing and discovery royalty are two examples. It may be wise to give these new technologies, cost saving measures, and new programs a chance to work before committing the state to any additional, and potentially unnecessary, financial obligation.

If the legislature nevertheless believes that an incentive is warranted, the division urges the legislature to select terms that are not to use the Senate sponsor's word "arbitrary," and that provide for the "maximum benefit of [Alaska's] people" as the Alaska constitution requires. A bill that gives us away too much royalty does not benefit Alaska's citizens. It does not create Alaska jobs or provide local taxes since they would be created anyway. It increases profit for a company and revenues for the federal government at the state's expense.

If the legislature desires simple terms with certain relief, it should do so only after careful analysis. It is true, for example, that the federal Deepwater Royalty Relief Act has helped promote development in the Gulf of Mexico. But the terms were not adopted arbitrarily. They were only adopted after analysis of the costs and benefits to the federal government. The terms recognize that distance from the infrastructure and water depth increases costs and the act's royalty volume cap varies with depth. The forty million barrel cap in the committee substitute is a step in the right direction, but it does not recognize the significant difference in cost between onshore and offshore development in the Cook Inlet.

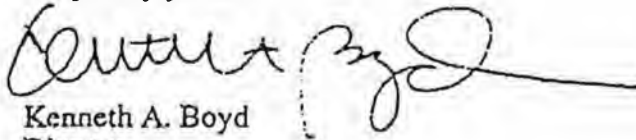
Moreover, it does not protect the state's interest if oil prices rise. The bill will either

1. not reduce costs enough to get Redoubt developed;
2. reduce costs, but Redoubt would have been developed anyway; or
3. reduce costs such that Redoubt could be developed when it would not have otherwise been developed

If the latter is the case, consider this. Based on today's oil prices, the proposed sixty percent reduction in royalty equates to about a ninety cent per barrel reduction in oil price. In essence, Forcenergy is telling the legislature that they could develop Redoubt, but only if oil prices went up ninety cents. If the legislature reduces the royalty, and oil prices rise ninety cents, should the royalty return to 12.5 percent? If oil prices increase \$1.80 over today's prices, should the state share in that upside? If oil prices rise from the current \$12 level to the \$22 level of just last year, should the state share in that upside?

I am available to answer any questions you or members of the Committee may have.

Very truly yours,



Kenneth A. Boyd
Director

Enclosures

cc: Senator Drue Pearce
Representative Mark Hodgins

Cook Inlet - Recent Activity

- State Lease Sale 85A-W (re-offer) set for late February.
 - Sale 85A was held in December 1996
 - Included over one million acres, drew \$3 million in bids
 - Joint DNR-Mental Health Lands Trust Sale
- North Middle Ground Shoal Unit established 1996.
- Redoubt Unit established, Forcenergy is operator.
- Forcenergy bought all of Stewart Petroleum assets.
- UNOCAL has proposed formation of Pioneer Unit.
- Growth Resources exploring for coalbed methane.
 - 3 shallow wells have permit-to-drills and are spudded
 - Locations are near Houston in south-central Alaska
- Ninilchik area 2D , Upper Cook Inlet offshore 3D and Swanson River 3D surveys completed in 1997.

Cook Inlet - Future Activity

- Forcenergy plans gas exploration well, Coffee Creek #1.
West of Pretty Creek Field on CIRI land
- Forcenergy plans drilling Boulder Shoal prospect.
Adjacent to West McArthur River Unit.
- Frontier Petroleum plans gas exploration well, Aegis #1.
Onshore west of Trading Bay Field
- Anadarko has proposed a well, Lone Creek #1.
Near Tyonek on Moquawkie (surface)/CIRI (subsurface) land
- Phillips plans more drilling for Tyonek Deep accumulation.
Formerly known as Sunfish
Located at a level below North Cook Inlet gas field
Results of latest delineation well non-commercial
- N Middle Ground Shoal 3D/2D survey planned for later in 1998



TONY KNOWLES, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

3601 "C" STREET, SUITE 1380
ANCHORAGE, ALASKA 99503-5948
PHONE: (907) 269-8800

March 19, 1998

Representative Mark Hanley
Representative Gene Therriault
Co-Chairs, House Finance Committee
Alaska State Legislature
State Capitol
Juneau, Alaska 99801

Gentlemen:

Several hearings have been held on HB 380/CSHB 380 (bill) in the House Special Committee on Oil and Gas. I presume you have the series of correspondence from us regarding the bill and we will try not to repeat all the arguments contained in that correspondence. Those letters will provide the committee with essential background information.

We cannot support the bill in its current form, which is not to say that we don't support continued—and increased—oil and gas activity in the Cook Inlet. We believe the combination of new technology (e.g. 3-D seismic) and recent legislation (e.g. Areawide Leasing) has led, and will continue to lead, to increased oil and gas activity in the Cook Inlet.

Our problems with the bill (as detailed in our previous correspondence) are several, but the two fundamental principles that the bill violates are:

The relief provided is not based on any economic evaluation of need.

It does not protect the State's upside potential if economic conditions change.

Both of these principles are provided for in current law (as recently amended by HB-207). Both of you, and a number of your committee members, were actively involved in the lengthy debate over HB-207. We doubt anyone will claim that HB-207 is a "perfect" piece of legislation. It is complicated and cumbersome, but it does embody the two principles above as well as providing for a rather lengthy public process.

"Develop, Conserve and Enhance Natural Resources for Present and Future Alaskans"

Representative Mark Hanley
Representative Gene Therriault
Co-Chairs, House Finance Committee
March 19, 1998
Page 2 of 3

Representative Mark Hodgins, Chairman of the Oil and Gas Committee, has asked the division to take a look at the bill and to suggest improvements. We are working with Chairman Hodgins on some preliminary ideas using data obtained from testimony. If requested by the committee, we will attempt to do further analysis, but can only do so if we are provided some additional information.

— To help us evaluate the economic "need" we request a copy of the report prepared for Forcenergy by Netherland, Sewell and Associates. Additionally, we will need to review the 3-D seismic data recently acquired over the Redoubt Unit. We have a number of questions already, but will assume some of them will be answered by these data. Absent any additional information we can see no reason to have a "cap" of more than 8.9 million barrels—the amount of "proven" oil reported to be in the Redoubt Shoal prospect—and a number we believe does not tell the whole story of this reservoir (see attached article from Petroleum News May/June 1996). While Forcenergy has reported the "proven" reserves number it has not mentioned the "probable" or "high" reserves numbers.

— If we can obtain suitable data and information, we will then try to devise a royalty system that embodies volume, value and time. A volume cap does not, by itself, protect the State's upside if oil prices should rise. The difficulty in developing this system is the disparity in the two oil fields permitted relief under this bill. One is offshore and one will (in large part) be reachable from onshore. The costs of development (and the economics of the companies doing the development) will be different.

Issues other than economics and money also need to be evaluated. Should the fields be assignable once this relief is granted? If we devise a royalty relief scheme for some company for a particular field can the company merely sell the field and walk away? Is the company that receives the relief compelled to perform? Will the "relief" dollars given by the State be invested in Alaska projects? Are local hire, local purchase or local manufacturing clauses to be part of the relief structure?

The current high level of oil and gas activity in Cook Inlet can be attributed to a favorable business climate and the use of new technology to reduce costs. This favorable climate exists, in large part, due to an ongoing series of new legislation that has improved the state's stature in the world oil marketplace. Areawide leasing and discovery royalty are two examples. Three-D seismic and extended reach drilling has enabled the industry to drill "smarter" wells which allow substantial reductions in costs. "Smarter" means fewer wells drilled with a greater precision than could have been achieved even five years ago. Three-D seismic not only provides the explorationist a clearer view of the subsurface, it provides the production manager a tool to drill more efficient development wells. Three-D seismic also assists in designing water floods and other production enhancing techniques to maximize benefit and minimize cost. It may be wise to

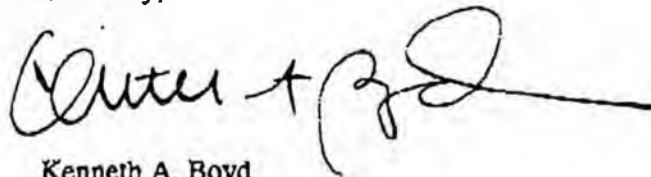
Representative Mark Hanley
Representative Gene Therriault
Co-Chairs, House Finance Committee
March 19, 1998
Page 3 of 3

give these new technologies, cost saving measures, and new programs a chance to work before committing the state to any additional, and potentially unnecessary, financial obligation.

If the legislature nevertheless believes that an incentive is warranted, the division urges the legislature to select terms that are not, to use the Senate sponsor's word "arbitrary," and that provide for the "maximum benefit of [Alaska's] people" as the Alaska constitution requires. A bill that gives away too much royalty does not benefit Alaska's citizens. It does not create Alaska jobs or provide local taxes since they would be created anyway. It increases profit for a company and revenues for the federal government at the state's expense.

If the legislature desires simple terms with certain relief, it should do so only after careful analysis.

Sincerely,

A handwritten signature in black ink, appearing to read "Ken + Boyd", written over a horizontal line.

Kenneth A. Boyd
Director

Enclosures

cc: Representative Mark Hodgins

COOK INLET REPORT

1. Patrick
2. Ken

LAYER

ARCO Cook Inlet

an aggressive independent from sound like an explorer who has st in the Cook Inlet. The comp- player, teaming up with North acquire a 33.333 percent work- royalty interest in four ARCO s Kenai Peninsula.

to discuss details. "We do have l Taylor, Anadarko's vice presi- ions. However, it appears Ana- plans for the Inlet. pportunities. This is not the last aid.

late leases — three offshore and grouped around tracts held by dy has announced plans to drill : immediate area discovered by

pany that likes to go in and get sit around kind of a group," Ken oil and gas division, said of

that we're not a sit around kind

ssive nature surfaced a few years ther large Outside independent, North Slope giant ARCO to ex- ective Colville Delta region just aruk field. That effort led to an 100 million barrels, a reserve er after this winter's drilling and re region appears ripe for devel-

r opportunities," Taylor said. and the economics are better. Alaska."

kes ARCO as a partner because nd use of new and evolving tech-

e said. "We match up very well

to be learning the ajor producer, prov- est leaseholder in Alaska the slope," Boyd said. "In t e Inlet and like what they see."

by Tyson, Contributing Writer

EXPLORATION

Analyst releases reserve estimates for Danco's Redoubt Shoals

At 38.1 million barrels, best case scenario will require Unocal's assistance and possibly royalty relief from the state

By Roy Tyson
Contributing Writer

Cook Inlet's undeveloped Redoubt Shoals most likely holds 38.1 million barrels of "proven" and "probable" crude reserves, concludes the reservoir analyst hired by independent Danco Exploration to appraise the offshore prospect.

Reserve estimates released to PNA by Houston based Netherland, Sewell and Associates, points to a much smaller reservoir than Danco's initial "reasonable" scenario of 250 million barrels. Nonetheless, the project appears do-able assuming investment capital can be rounded up and access gained to at least some of the region's existing facilities.

"I think that as long as there is infrastructure around the Cook Inlet, this prospect eventually will be drilled," said Frank Hicks, a reservoir engineer for the Texas firm.

However, project economics change depending on Netherland, Sewell's other crude reserve estimates for Redoubt Shoal, which include a low of 13.4 million barrels and a high of 154.9 million

barrels.

At the low end, which represents proven reserves based on engineering studies and existing geological data, the project is "marginal if not uneconomic," depending on facility costs and other factors, Hicks said.

Hicks said in the low-case scenario, contracts with other producers to use existing facilities and pipelines would be necessary to produce and transport the oil ashore from one satellite drilling platform.

It's also likely that on the low side, producing about 9,600 barrels of crude a day, Redoubt Shoals would need state royalty relief, he added.

"The proved case is very sensitive to the cost of facilities and wells," Hicks said.

At the high end of the reserve spectrum, which represents proven, probable and possible reserves, Redoubt Shoals becomes a robust project with 80 wells on three platforms yielding 33,000 barrels of oil a day. The crude also would be processed on the main platform and a pipeline constructed to transport the oil.

"We're all hoping that this is



Daniel Donkel

what it ends up being," Hicks said

The most likely reserve estimate of 38.1 million barrels of crude, while a respectable volume by Cook Inlet standards, still would require the use of existing pipelines and facilities to produce 9,100 barrels a day from two satellite drilling platforms, Hicks said.

However, he added, "this would be economic based on facilities and oil pricing. It's encouraging."

One Danco option calls for Redoubt Shoal oil to be piped to Unocal's nearby Dillon platform for processing and then to shore

see DANCO page 16

PETROLEUM NEWS

MAY/JUNE 1996

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Anchorage wants to buy Shell's interest in gas field

*Mayor will appoint a blue ribbon committee to review*By Kay Cashman
PNA Editor

Anchorage Mayor Rick Mystrom announced in mid-April that the municipal Assembly had approved an agreement to pursue the purchase of Shell Western E&P Inc.'s one-third interest in the Cook Inlet Beluga River gas field for \$125.1 million. All of Shell's Alaska oil and gas properties are for sale.

The signing of the agreement is the first step in a six-month public process, which will include public comment, two more Assembly votes and a review by the Alaska Public Utilities Commission. It will also take a public vote to sell revenue bonds to pay for the purchase. Failure to issue the bonds will result in forfeiture of the city's \$12.5 million deposit to Shell.

The mayor is expected to appoint a blue-ribbon committee within the next 10 days. It will review the proposed purchase and make recommendations on how, or if, to proceed with the purchase.

According to Mystrom, the municipal-

ity is concerned about the long-term predictable supply of clean burning natural gas for Municipal Light and Power. The utility's current contracts for gas expire in 2005. The purchase will assure ML&P, said the mayor, of a lower-cost, long-term, fuel supply, as well as stabilize or reduce consumer rates over the next 30 years. With the municipality owning its own fuel supply, industry predictions of increased natural gas costs would have little effect on ML&P customers, noted Mystrom.

George Wuerch one of two Assembly members opposed to the sale, said he doesn't think government belongs in the oil and gas business.

Wuerch said the entry of the municipality into Cook Inlet oil and gas arena "unbalances the playing field" because the city has access to tax-free bonding and does not have to pay property or income tax.

"What we'd be doing is leveraging our public benefits against private enterprise ... and claiming a degree of efficiency we probably wouldn't earn."

continued from page 13

DANCO

via a Unocal pipeline for refining at Tesoro's Nikiski plant.

Hicks said Redoubt Shoals oil also could be piped over to the west side of Cook Inlet for processing and shipment to the Drift River tank farm and terminal.

No matter which side of the Inlet, Redoubt Shoals oil likely will have to pass through some facility operated by Unocal, the Inlet's largest producer.

"I think that sooner or later, it would have to at least go through a Unocal pipeline," Hicks said. "We would have to get contracts that don't exist."

Danco already has approached Unocal about participating in a Redoubt Shoals project, an offer Unocal appears willing to

consider given the company's desire to keep its extensive processing and transportation network intact because of dwindling crude reserves.

"We have an infrastructure we would try to make available to Danco or anyone else," said Kevin Tabler, Unocal's Alaska land manager. "We have an interest in maintaining this infrastructure as long as we can."

Tabler also said Netherland, Sewell's reserve estimates for Redoubt Shoals "are in the ball park of possibilities" based on Unocal's own assessment of the prospect.

"They are as good a numbers as you can come up with," he added. "Redoubt Shoals is clearly one of the largest remaining known structures in the Inlet. "If the opportunity presents itself and it can compete (with other Unocal projects), we will consider it."

James E. Eason

Oil and Gas Operations, Management and Policy

8611 Leeper Circle • Anchorage, AK 99504-1209
Phone: (907) 337-3515 • Fax: (907) 333-9087

March 20, 1998

Senator Rick Halford, Chairman
Senate Resources Committee
Alaska State Legislature
State Capitol (MS 3100)
Juneau, Alaska 99801-1182

Dear Senator Halford:

I appreciate this opportunity to respond to Oil and Gas Division Director Ken Boyd's March 11, 1998 letter to you. In that letter, Ken submitted additional comments on behalf of the division regarding SB 256, and its companion bill, HB 380 ("the bill"), and he responded to several points raised in my earlier letter to you dated March 4, 1998. Given the potential for confusion regarding the contents of these various exchanges, I have enclosed copies of both letters to facilitate your review of those documents, as well as this response. As discussed later in this letter, I have also enclosed a copy of the Department of Natural Resources two page fiscal note, dated March 7, 1995, which was submitted in support of HB 207, Governor Knowles' royalty reduction bill during the 19th Legislative Session.

As you are probably aware, after three hearings, HB 380 passed out of the House Special Committee on Oil and Gas ("Oil and Gas Committee") on Thursday, March 12th, and is scheduled for its first hearing before the House Finance Committee this afternoon. Although Mr. Boyd testified on behalf of the administration at each of the hearings before the Oil and Gas Committee, he has declined, as yet, to confirm the administration's position on the proposed legislation. Nevertheless, the bill was amended by the Oil and Gas Committee to accommodate two concerns identified by Mr. Boyd.

First, in response to concerns regarding the bill's applicability, a list of six fields identified as meeting the bill's criteria, and thus, being potential candidates for royalty relief, was incorporated in CSHB 380 (O&G). Secondly, in response to concerns over protecting the state's interest in the event one or more of the candidate fields turns out to be larger than expected, a cap of 35 million barrels of oil and 35 billion cubic feet of gas was adopted by the committee. Any oil or gas production from a qualifying field which exceeds those amounts would pay royalty at the rate specified in the lease, or, if applicable, the unit agreement.

My goals, as well as those of my client, Forcenergy, are to assure that there is an opportunity for a full discussion of the bill's merits, to provide you and your colleagues in the legislature an accurate and timely response to your questions and concerns, and to help you build a solid record for your deliberations and decision—regardless of what that decision ultimately may be. In pursuing those goals, it has been, and continues to be our intent to be open, candid and direct with everyone involved regarding our support for the bill. As a result, I am concerned about the implications of the comments in the first and

third paragraphs of Mr. Boyd's March 11th letter. If one did not know better, it would appear from that letter that I have hidden my representation of Forcenergy in this matter, and that Forcenergy may not have lived up to its prior agreements with the state. Neither of these conclusions are supported by the record.

For example:

- I scheduled separate meetings, one here in Juneau with Commissioner Shively during the last week of January, and the other in Anchorage during the first week of February with Director Boyd and his deputy, Patrick Coughlin to discuss the bill. At those meetings, I explained the intent of the bill, acknowledged my involvement in its development and confirmed that I would be advocating its passage on Forcenergy's behalf.
- Prior to those meetings, on January 5, 1998, I registered with the Alaska Public Offices Commission to lobby on behalf of Forcenergy. That registration is a matter of public record.
- Before meeting with administrative or legislative officials to discuss the bill, Forcenergy's Vice President, Mr. Gary Carlson, registered with the Alaska Public Offices Commission, which also is a matter of public record.
- As you no doubt will remember, at my first meeting with you to discuss the bill—in the presence of Senator Ward, as I recall—I revealed my association with Forcenergy on this issue and discussed the basis for the company's support of the bill.
- I subsequently testified before the House Special Committee on Oil and Gas that my comments on the bill were being made on behalf of Forcenergy; and
- In each meeting which I have had with legislators and staff regarding the bill, I have made my representation of Forcenergy known.

Under these circumstances, I do not understand how it could be inferred that my association with Forcenergy only became clear after I drafted my March 4, 1998 letter to you. Nor do I understand the relevance of reciting Forcenergy's work commitments under the terms of the Redoubt Unit Agreement without acknowledging that, to date, the company has met each of those obligations. Failing to note that fact, leaves the mistaken impression that the state has received less than what it bargained for in approving the unit.

To the extent that the division based its decision to form the Redoubt Unit upon "Forcenergy's representations, that Forcenergy would rapidly attempt to develop the leases under the existing lease terms, specifically the 12.5 percent royalty terms...", I believe the record reflects that the division's decision was well founded. Forcenergy completed the promised 3-D seismic survey and interpretation on schedule, contracted for a review of alternative platform designs for use in exploring and delineating the Redoubt Field ahead of schedule, selected one of the alternatives for detailed design and is in the process of finalizing cost estimates to determine whether it will proceed with the project.

Contrary to Mr. Boyd's statement in the last paragraph of his March 11th letter, however, Forcenergy has not told the legislature "that they (Forcenergy) could develop Redoubt, but only if oil prices went up ninety cents." In fact, I have testified before the Oil and Gas Committee that none of the six fields potentially eligible for reduced royalty under the bill may, in fact, be developed—with or without the reduction contemplated under the bill. That was true then, and it remains true today.

It is also incorrect to assert that Forcenergy has committed to develop the Redoubt Shoal Field under the existing royalty structure. In its application to form the Redoubt Unit, Forcenergy did not commit to develop the Redoubt Field. Instead, it agreed to a number of pre-defined steps to determine whether commercial production was feasible, and it stipulated that, if it did not meet the prescribed schedule and milestones, it would relinquish the leases. Under these circumstances, it is impossible to conclude, as Mr. Boyd does, that the bill "...does not create Alaska jobs or provide local taxes since they would be created anyway." (emphasis added) Mr. Boyd's apparent certainty now that these fields will be developed contrasts with his reluctance to provide such assurances to the Oil and Gas Committee.

We can continue to debate the magnitude and the onset of production decline in undeveloped fields of unknown size. We can also hypothesize which lessee may develop which field when, and under what circumstances. However, doing so is not likely to be very constructive. What may be more helpful, in my view, is to have a better understanding of why the division's analysis of the fiscal impacts of this bill are so different from its earlier assessment of the fiscal impacts of HB 207, Governor Knowles royalty reduction legislation passed during the 19th Legislative Session.

In March of 1995, Director Boyd prepared the enclosed fiscal note. According to the division's analysis at that time, the fiscal impacts anticipated as a result of HB 207 were limited to operating expenditures for the salary, benefits and other expenses associated with the hiring of a new petroleum engineer to evaluate royalty reduction proposals. In addressing the effects of the legislation on the state's operating revenues, Director Boyd wrote:

"This legislation will effect state operating revenues in an unquantifiable manner (the Permanent Fund share is not affected by this legislation). This legislation gives the commissioner the authority to grant royalty reduction, which on its face, would seem to indicate a decrease in revenue. However, since the purpose of this legislation is to promote development of fields that would not otherwise be produced, the net effect on state revenues should be positive. As a result, of this legislation we are gaining new revenues based on this new production (albeit at a somewhat reduced rate from currently producing fields)." (emphasis added)

Since both HB 207 and this bill are intended to promote development of fields that would not otherwise be developed, only the division can reconcile the inconsistent approaches it has taken in estimating the fiscal impacts of the two bills. In doing so, however, it cannot rely upon its unsupported assertion that "This bill gives a bigger reward (because it applies to all pools within a field as opposed to a pool within a field)...", unless it can document that discovery pools in new fields will always contain less oil and gas than is believed to exist in the fields at issue. Nor can it say this bill "rewards those who had the good fortune to own the leases in question at the time of the bill's passage for bringing known oil and gas accumulations into production" without acknowledging the similar intended purposes of both HB 207 and the Northstar legislation.

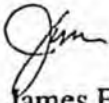
It is also indefensible to suggest that the announced development of the Tyonek Deep is evidence that leveraging additional exploration and development in the vicinity of new infrastructure "...does not require a 60% royalty reduction" without addressing the different factual circumstances involved. (emphasis added) On the one hand, the Tyonek Deep will be developed from an existing production platform in the North Cook Inlet gas field, one of the region's largest gas fields, with reserves estimated by the division to be in

excess of 2.2 trillion cubic feet of gas. On the other hand, should sufficient reserves be confirmed, development of the Redoubt Shoal field and the other candidate fields will provide new infrastructure from which adjacent exploration, and hopefully development, can occur. Rather than calling into question the positive impacts of extending infrastructure, development of the Tyonek Deep confirms the importance of infrastructure in leveraging new, incremental development.

Finally, any reconciliation of inconsistent fiscal analyses should address the division's prior willingness to assume the receipt of new revenues, based on new production under HB 207, while continuing to disregard the potential for new production revenues from this bill. I do not understand how the division can demonstrate the hypothetical "loss" of a portion of the state's royalty revenue unless it first acknowledges the value of "new" royalty revenues against which that loss is to be measured.

Thank you again for this opportunity to provide another perspective on these issues. I am available at your convenience to answer any questions which you or the members of your committee may have, and I would welcome the opportunity to do so.

Sincerely,



James E. Eason

Enclosures

cc: Senator Drue Pearce
Representative Mark Hodgins
Representative Gene Therriault
Representative Mark Hanley
Commissioner John Shively
Director Ken Boyd

1995 LEGISLATIVE SESSION

REPORTED OUT OF

(H) Publish Date: 3/8/95

Revision Date: Original SFC 5-11-95 Dept. Affected: Natural Resources
 Title: An Act relating to adjustments to royalty reserved for the state to encourage otherwise uneconomic production of oil and ...
 SRU: Resource Development
 Component: Oil & Gas Development
 Sponsor: House Rules Committee
 Requestor: Governor Knowles Component Serial No. 429

Expenditures/Revenues (Thousands of Dollars)

| OPERATING EXPENDITURES | FY96 | FY97 | FY98 | FY99 | FY00 | FY01 |
|------------------------|-------|-------|-------|-------|-------|-------|
| PERSONAL SERVICES | 90.5 | 94.0 | 97.5 | 101.2 | 105.0 | 108.9 |
| TRAVEL | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 |
| CONTRACTUAL | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 | 3.0 |
| SUPPLIES | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 | 5.0 |
| EQUIPMENT | | | | | | |
| LAND & STRUCTURES | | | | | | |
| GRANTS, CLAIMS | | | | | | |
| MISCELLANEOUS | | | | | | |
| TOTAL OPERATING | 105.5 | 109.0 | 112.5 | 116.2 | 120.0 | 123.9 |
| CAPITAL EXPENDITURES | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CHANGE IN REVENUES | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

FUND SOURCE (Thousands of Dollars)

| | | | | | | |
|--------------------------|-------|-------|-------|-------|-------|-------|
| 1002 Federal Receipts | | | | | | |
| 1003 GF Match | | | | | | |
| 1004 GF | 105.5 | 109.0 | 112.5 | 116.2 | 120.0 | 123.9 |
| 1005 GF/Program Receipts | | | | | | |
| 1006 GF/MHTIA | | | | | | |
| Other | | | | | | |
| TOTAL | 105.5 | 109.0 | 112.5 | 116.2 | 120.0 | 123.9 |

Estimate of any current year (FY95) cost: \$ None

POSITIONS

| | | | | | | |
|-----------|---|---|---|---|---|---|
| FULL-TIME | 1 | 1 | 1 | 1 | 1 | 1 |
| PART-TIME | 0 | 0 | 0 | 0 | 0 | 0 |
| TEMPORARY | 0 | 0 | 0 | 0 | 0 | 0 |

ANALYSIS:

(Attach a separate page if necessary)

SEE ATTACHED

Prepared by: Ken Boyd, Acting Director *[Signature]* Phone: 762-2547
 Division: Oil & Gas Date: 3-Mar-95
 Approved by Commissioner *[Signature]* Date: 3-7-95
 Agency: Natural Resources

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COMMITTEE COPY

ATTACHMENT FOR FISCAL NOTE - HB207
REDUCE ROYALTY SHARE/HOLD PERMANENT FUND "HARMLESS"

Implementation of this legislation will create an increased workload for the Division of Oil & Gas. We anticipate that some of the applications will be analyzed within the Division and many will require analysis by third parties (the bill provides that third-party costs will be paid for by the companies). Because of the extremely sensitive and confidential nature of the data a considerable amount of interaction between the third-party contractor and the state will be needed. Furthermore, the bill requires that applicants make a clear and convincing showing of the need for royalty reduction, so the Division will need to evaluate the economic, geological and engineering data submitted for compliance with the law prior to seeking the assistance of a third party.

Because this legislation contains provisions that may cause the terms of the application to vary over time, any approved application will need to be monitored on a continuing basis. We expect this program to have broad appeal, however, we cannot anticipate how many applications will be submitted or when they will be submitted.

An exempt Petroleum Engineer, Range 26A, will provide the broad background that will be needed to evaluate these proposals effectively. This position will need to be skilled not only in Petroleum Engineering, but will also need to have extensive knowledge of petroleum geology and petroleum economics. The salary cost of this position will be approximately \$90.6 the first year, including benefits. Additional, minor expenses such as travel, contractual and supplies will be required which we estimate will not exceed \$15.0. This position and the associated costs are our estimates of the funding needed to get the program started; if many applications are received, other positions may be required. We assume that each application will take between 4-6 employee-months to evaluate.

This legislation will effect state operating revenues in an unquantifiable manner (the Permanent Fund share is not affected by this legislation). This legislation gives the commissioner authority to grant royalty reduction which, on its face, would seem to indicate a decrease in revenue. However, since the purpose of this legislation is to promote development of fields that would not otherwise be produced, the net effect on state revenues should be positive. As a result of this legislation we are gaining new revenues based on this new production (albeit at a somewhat reduced rate from currently producing fields).

1

- ① (a) Training is limited to permittees and applicants. Most of our training is done for operators installers

Wastewater and water system operators allowed under (a)(5) are not "permittees or applicants"

domestic wastewater certified installers aren't

Neither are

Food Service employees

Pool + spa operators

Sanitary Surveyors

- ② (a) Fees are limited to activities surrounding
- certifications (refers to activities in (a)(b) and (a)(1)) and (a)(2)
 - inspections
 - training as mentioned ...
 - permit preparation and administration
 - plan review and approval

Registering pesticides allowed under (a)(5) doesn't involve any of those activities.

- ③ (g) does not allow the dept to charge a fee for conferring with 3rd parties.
- Refee for applying only to air and to solid waste (both only, hourly program fees) : water, air, sur

2

Rarely deal directly with an applicant.

We deal w/ consultants

engineers

hydrologists

attorneys

• Public Notice requirements in statute for certain

Permits -
46.03.110

Principles of democracy.

Allowed in the negotiated agreement - curious as to why?

④ "Actual direct costs"

same class employees are pd different

actual hourly rates

so everyone will want to use the new guy because he's cheapest

← directly engaged in performing the service

- How we do flat fees now

- Includes clerical time, which is "support"

- Not sure what is meant by "supervisory"

Some people directly engaged are

supervisors;

Program managers costs are not included

in our flat fee calculation. In SW, people

only pay if the manager gets deeply involved in the permitting

- Administrative - part of issuing a permit, conducting an inspection or giving an approval. Includes collecting the \$.

- Overhead - it is a cost of providing the service.

* - Effect on local government delegations

- Diner

- Food Service

In the case of Sanitary Surveys, we provide, privates provide,

why + affect on cost of both services.

5. Training our employees

- Well-trained state employees are a time saver for companies.

- Legislature's general view that training = junket

- Untrained state employees negotiating with well-trained employees from some of the most sophisticated companies in the state is like tying one hand behind the state's back. **IT DOES NOT SERVE THE PUBLIC INTEREST!**

6. Ban on hourly fees -

So a waste would go to flat fees in 2000, (Section 3) No reason to go ahead w/ ^{ISW being funded} ~~ISW being funded~~

- While ~~seated~~ has flat fees, in that program + m/inspection program, we will do after-hours (weekend, holiday) inspections at the request of the facility. Charge by the hour

- Also charge by the hour when someone submits a permit or plan + ^{all programs} withdraws it after we've started working on it but before its completed.

7. Pesticide fee levels = too low.

Have between 2,000 - 3,000 pesticides, so use 2,500. Don't have a good handle on restricted use v. unrestricted use.

4

but know the vast majority is
unrestricted. So say its

5-95% restricted/unrestricted

Bring in just under \$40.0 or.. is \$15.5
short of what we need.

Let us set registration fees in
regulation

— Beyond these substantive
concerns, also some issues
relative to drafting —

- language in (a)(3)
- (e): doesn't seem to
preclude a re-opener
clause. if something unexpected
comes up during the process -
that's important

James E. Eason

Oil and Gas Operations, Management and Policy

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March 11, 1998

Representative Mark Hodgins, Chairman
House Special Committee on Oil and Gas
Alaska State Legislature
State Capitol (MS) 3100
Juneau, Alaska 99801-1182

Dear Representative Hodgins:

I wanted to take the opportunity to reply to several concerns and/or requests for additional information made by members of the House Special Committee on Oil and Gas during the committee's hearing on H.B. 380 last Thursday, March 5, 1998. A listing of the additional information requested and concerns expressed is provided below:

- a list of the wells and pools involved in the six fields which would be candidates for royalty reduction under H.B. 380, a summary of the discovery history for each field and an estimate of each field's reserves;
- concern that stipulating a 10 year royalty reduction term could potentially lead to accelerated production of the field(s), and thus to waste of the resources;
- concern over the potential for "double dipping" of royalty reduction under both the provisions of H.B. 380 and AS 38.05.180(d)(4)(A), the current royalty reduction statute;
- concern over whether assignment of affected leases would be possible; and
- concern over the need to include a sliding scale formula based upon price variations to assure that lessees do not receive an unexpected windfall at the State's expense

Each of these issues is discussed below.

History of Each Field—Wells Drilled, Productive Intervals and Estimated Reserves¹

1. Falls Creek:

The Falls Creek gas field, is located on the Kenai Peninsula near Clam Gulch. There have been four wells drilled on or near the Falls Creek structure. The discovery well, Falls Creek No. 1, was completed in April 1961. The discovery well tested gas at a rate of 1.8 million cubic feet (mcf) per day from the Tyonek Formation at a depth of approximately 7,600 feet. A subsequent well drilled about four miles to the southwest of the initial well in 1966, the Falls Creek No. 2 well, was a dry hole. In 1973, Chevron drilled the 43-6 well

¹ Except for Redoubt Shoal field reserves, all reserve estimates are from the draft 1997 report entitled "Historical and Projected Oil and Gas Consumption", Alaska Department of Natural Resources, Division of Oil and Gas.

about 2,000 feet east of the Falls Creek No. 1 well. This well, which was located off structure, also was dry. In 1996, Marathon drilled the Corea Creek No. 1 well on the west flank of the Falls Creek structure. The Corea Creek well was plugged and abandoned. Gas reserves are estimated to be 12 billion cubic feet (bcf).

2. Nicolai Creek:

The Nicolai Creek gas field is located on the west side of Cook Inlet near the northwest corner of Trading Bay. The discovery well, Texaco's Nicolai Creek State No. 1-A well, discovered gas in both the Beluga and Tyonek Formations. A total of seven wells have been drilled in the area, with three of those wells being dry holes. Three of the seven wells encountered gas, and one well encountered oil. Estimated gas reserves are 2 billion cubic feet (bcf).

3. North Fork:

The North Fork gas field is located onshore, east of Anchor Point and north of Homer. Only one well has been drilled in the field, the Chevron North Fork No. 41-35 well, which was completed in 1965. The well tested gas from a zone in the Tyonek Formation. Other wells in the vicinity of the North Fork structure have been dry holes. The nearest existing gas pipeline is more than 50 miles away. Estimated gas reserves are 12 billion cubic feet (bcf).

4. Redoubt Shoal:

The Redoubt Shoal oil field is located offshore, to the east of the West Foreland and west of the Port of Nikiski. Six exploratory wells have been drilled in the unit area. Those wells include:

- Pan Am Redoubt Shoal St. 22064 No. 1 (June 1967), which was plugged and abandoned as a dry hole;
- Tenneco St. 36465 No. 1 (November 1967), which was plugged and abandoned as a dry hole with oil shows;
- Pan Am Redoubt Shoal St. 29690 No. 1 (December 1967), which recovered minor amounts of oil from the Hemlock Formation;
- Pan Am Redoubt Shoal Unit 29690 No. 2 (September 1968), which tested 1291 barrels of oil per day from the Hemlock Formation, and is the discovery well for the Redoubt Shoal field;
- Union Redoubt Bay Unit No. 1 (October 1976), which failed to recover significant quantities of oil although numerous drill stem tests were conducted in the well; and
- Mobil South McArthur River No. 1A (December 1982), which was plugged and abandoned as a dry hole.

The Division of Oil and Gas has not published oil reserves estimates for the Redoubt Shoal field. However, the engineering firm of Netherland, Sewell and Associates completed an independent assessment of the field in February of this year, using all available well data and the 3D seismic survey completed in the fall of 1997 to determine proven reserves for Securities and Exchange Commission reporting purposes. The firm's estimate of proven oil reserves at the Redoubt Shoal field is 8.9 million barrels.

5. Starichkof:

The Starichkof oil field is located offshore and about six miles north of Anchor Point. The discovery well, the Pennzoil Starichkof No. 1 well, was drilled in 1967. A second well drilled later that year two miles north of the discovery location, the Starichkof State Unit No. 1 well, was plugged and abandoned. The discovery well tested 57 barrels of oil per day.

6. West Foreland:

The West Foreland gas field is located on the shoreline of the West Foreland, west of the Port of Nikiski. The field was discovered in 1962 by the Pan Am West Foreland No. 1 well. Pan American Oil subsequently drilled the West Foreland Unit No. 1 well about four miles to the north and the West Foreland Unit No. 2 well about to the north without finding gas. Estimated gas reserves are 20 billion cubic feet (bcf).

The 10 Year Term and Its Potential to Cause Waste

Concern was expressed about the possibility that, given the limited period of eligibility, a company might produce a field too fast in order to increase its benefits from reduced royalty payments. Amending the bill to allow for extension of the 10 year period for this eventuality is not necessary. One of the Alaska Oil and Gas Conservation Commission's ("AOGCC's") primary responsibilities is monitoring development and production from the state's oil and gas fields to assure that wasteful operations do not occur. That independent agency's oversight will assure that field development plans are consistent with the goals of preventing waste and maximizing recovery of the resources.

Potential for "Double Dipping" of Royalty Reduction

Royalty reduction under the provisions of H.B. 380 would obviate the need for royalty reduction under AS 38.05.180(d)(4)(A) during the 10 year period of eligibility under the proposed bill. Thus, as a practical matter, there could be no "double dipping" during that period. If the royalty obligation was already five percent under H.B. 380, a reduction to five percent under AS 38.05.180(d)(4)(A) would not further reduce the royalty rate. As the bill is drafted, however, it is conceivable that a field eligible for royalty reduction under its provisions could produce for 10 years at the five percent royalty rate, and thereafter, could qualify for continued royalty reduction under the provisions of AS 38.05.180(d)(4)(A). The only circumstances where that could happen, however, are instances in which the commissioner of the Department of Natural Resources makes an affirmative finding, based on the merits and under the stringent conditions of H.B. 207, that continued reduction was both appropriate and in the state's best interests.

Assignment of Lease Interests in Candidate Fields

Passage of H.B. 380 will establish a short period to qualify for royalty reduction, with eligibility ending on December 31, 2003. If production from a candidate field has not begun by that time, lessees holding interests in the field forfeit the opportunity to qualify. Under its terms, the bill is designed to insure that lessees either diligently pursue development or lose the potential benefit of paying the reduced royalties. Under these circumstances, it is entirely possible that the incentive provided by H.B. 380 may be insufficient to promote development of some or all of the candidate fields by their current owners, yet may lead to assignments of lease interests to others who are willing to pursue development.

The Need for a Sliding Scale, Price-Based Formula or Price Cap

For the following reasons, amendment of H.B. 380 to provide for pre-determined caps on the volumes of oil and gas qualifying for reduced royalty is preferable to using a sliding scale, price-based formula or price caps for determining royalties:

- each of the six fields has remained undeveloped for 30+ years, through wide ranges of prices, suggesting that short term spikes in prices, in and of themselves, are insufficient to spur production;
- applying volume limits equally to all the fields is the simplest, most direct way of implementing the incentive;
- fluctuating prices could lead to frequent activation and deactivation of royalty reduction, which could negatively impact long-term planning and investment decisions critical to a field's development; while
- a simplified incentive program will facilitate lessees' planning for capital allocation and minimize administrative costs for both the State and the lessees.

Based on the results of prior exploration, none of the field's potentially benefiting from passage of H.B. 380 are likely to have unexpectedly large reserves. Both the reserve estimates of the Division of Oil and Gas and those of Netherland, Sewell and Associates support this conclusion. As further evidence of the perceptions of others, including former and current lessees, more than three decades have passed since these discoveries were made—without development having occurred. Under these circumstances, the simplest and most direct incentive has the greatest likelihood of producing the desired effects.

In closing, Mr. Chairman, I believe passage of H.B. 380 has the potential to re-energize Cook Inlet exploration and development, and to extend the productive life of older producing fields. It would also encourage participation by a broad range of interests, including major oil companies, independent oil companies and local individuals in the development of the shut-in resources. On behalf of Forcenergy, I appreciate the careful review and consideration which you and members of your committee have given the bill, and I urge your continued support in passing the bill from the committee.

Sincerely,



James E. Eason

cc: Senator Drue Pearce
Representative Mark Hodgins
Members of the House Special Committee on Oil and Gas
Commissioner John Shively, DNR
Director Ken Boyd, DO&G

OILWATCH ALASKA

PO Box 101555 Anchorage, AK 99510 ●● Ph: 907-277-8910 Email: oilwatch@alaska.net

DT: March 20, 1998

TO: House Finance Committee

Representative Mark Hanley, Chairman and Committee Members

Representatives Therriault, Mulder, Davis, Foster, Kelly, Kohring, Martin, Davies,
Grussendorf and Moses,

FR: Jim Sykes, Executive Director

RE: Comments on HB380

MAR 20 1998

PLEASE COPY TO ALL COMMITTEE MEMBERS. THANK YOU!

Honorable Chairman Hanley and Finance Committee Members,

As you face tough choices in determining our state budget, I urge you in the strongest terms to reject HB 380, which provides a special 60% reduction in royalties to six oilfields in Cook Inlet at a time when other similarly situated fields are seeing significant amounts of exploration and production activity under the existing royalty structure. Ballpark estimates of royalty losses to the state have ranged from \$14 million to \$27 million, but they could easily be higher. Before this kind of legislation goes forward there needs to be clear and convincing evidence that a royalty reduction is needed or desirable.

Prior to this legislation moving forward, prudent policy and business practice should demand that the State to take back a nonperforming well and offer it for *competitive bid*, (which has been done in the past). Such a process would determine whether or not other companies were interested in trying to make a profit under the existing royalty structure, since petroleum producers frequently sit on profitable fields if they figure to extract more concessions and profits. The rebid process would provide a better idea of real value without setting a terrible precedent that encourages lease holders threaten nondevelopment as an easy method to gain more concessions from the State.

If this HB380 royalty reduction were to pass, wouldn't a reasonable person expect the owners of the North Kenai field to question whether they shouldn't be given the same royalty break? It almost begs for litigation.

New technology has dramatically lowered lifting costs for the petroleum resources so that wells are smarter, fewer and better. The way the bill is currently structured, the 60% royalty reduction could be applied to all connected structures outside the zone of shut-in or undeveloped gas or oil and be applied to currently producing and higher quality structures. Department of Oil and Gas geophysicist Ken Boyd illustrated this concept as a stack of colored sponges representing an oilfield and a non-producing zone being just one sponge, yet the royalty could extend to the entire stack of sponges, or the connected structures. It seems difficult to justify giving out royalty reduction goodies to selected oil and gas field corporate owners while serious cuts are being contemplated that affect many Alaskan individuals.

Additional examination should be given to the recent unitization of Forcenergy holdings as the Redoubt Unit. It is doubtful that the Division of Oil and Gas would have approved the unit if it had been known that Forcenergy would come to the legislature for additional royalty relief. Perhaps the division would have released the two leases that were about to expire to be rebid, since there would be much higher interest from others in acquiring the leases with a lower royalty etc. Higher bonus bids would have undoubtedly been sought by the State.

Under the current HB380 legislation, people need to know if someone could re-assign a 5% lease to someone else, (creating additional potential profit to a leaseholder who might not want to develop). It is curious why the arbitrary type of window was chosen for the six oilfields cited in the bill, (discovery before January 1, 1998 and been undeveloped or shut in from January 1, 1988 through December 31, 1997, and begin producing before January 1, 2004).

HB380 begs a basic question of how we Alaskans decide to use our nonrenewable resources. In the case of Cook Inlet gas, a majority of Alaskans, one-third of a million people, depend on it for electricity and heat. At the present time, almost two-thirds of Cook Inlet Gas is exported--much of it to Japan. Less than one-third is used for residential gas and electric power generation. Current projections indicate that we will run out of Cook Inlet Gas around 2007 from the wells that are currently in production.

Should we risk Alaskans' energy security by exporting current levels of Cook Inlet gas? HB380 puts no restrictions on the use or export of our natural gas. The only restriction is to begin production from the identified fields by 2004, which coincidentally is the renewal date for export licenses currently held by Phillips and Marathon. This is currently a contentious regulatory issue before the federal Department of Fossil Energy, [FE Docket No. 96-99-LNG]. The federal Natural Gas Act prohibits exports that cause regional shortages [15 U.S.C. § 717b(a)(1994)]. Alaskans need to know whether HB380 affects assertions made before the U.S. Department of Energy Fossil Energy

Department that producers which are seeking to extend their export licenses are not able to actually meet their current gas contract obligations.

Southcentral Alaska's energy security could be guaranteed for an additional decade (to 2017) if current supplies were used within the region and not exported. HB380 puts no restrictions on the use or export of our natural gas. While technology is sometimes kind to us in getting more from a field, there are no guarantees. We cannot risk betting that generous estimates or technology will meet the needs of Southcentral Alaska while we effectively pay private industry to dig up our valuable oil and gas resources and cart them off to a foreign country.

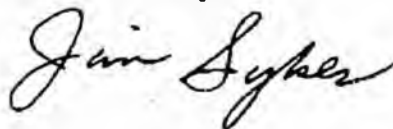
If there truly is some compelling need to create this oil and gas royalty break, we need to know what it is in the clearest terms. The State should then put non producing wells out to competitive bid. If the rebid results are not good and royalty break is still seen as a compelling need I suggest a different structure. The current bill could be amended to reduce the royalty break from 10 years to 5 years, and that the 7% benefit at the front end be added back following the sunset. Since industry will profit from a lower rate for 5 years it only seems fair that the state should recover what is reasonably due. Following the sunset, after 5 years, the royalty rate should rise to 15% for a period of ten years before decreasing back to the present 12%. That way the startup is encouraged and a reasonable royalty is recovered on the backside, similar to a concept being considered for development of North Slope gas.

Since oil and gas are expected to dramatically increase in value over the next short years, the current oil price dip notwithstanding, perhaps the State should demand royalty increases rather than reductions, or at least a plan that would increase the State's percentage along with the rise in profits.

Our constitution states in Article VIII, Section 2 that, "...the legislature shall provide for utilization, development, and conservation of all natural resources belonging to the State.. for the maximum benefit of its people." It's hard to see how this bill provides any benefit, let alone maximum benefit to the people of Alaska. Please reject HB380.

If you have questions on March 20, please call my cell phone 230-3081. Thank you.

Most sincerely,



Executive Director

TONY KNOWLES, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

3601 "C" STREET, SUITE 1380
ANCHORAGE, ALASKA 99503-5948
PHONE: (907) 269-8800

February 20, 1998

Senator Rick Halford
Chairman, Senate Resources Committee
Alaska State Legislature
State Capitol, Rm. 121
Juneau, AK 99801-1182

Dear Senator Halford:

The division has reviewed SB256 in preparation for a hearing in the Senate Resources Committee this afternoon. At this point we are not prepared to take a position on the bill. To help us develop our position, we have several questions about certain aspects of the bill.

The bill has no provision to account for changing economic (or other) conditions. For instance, if the price of oil were to increase, the relief would remain the same. In many committee hearings over the years we have discussed protecting the State's "upside" interests—in other words not giving more relief than necessary to make a project economic. This bill only provides for a reduction in royalty. There is no mechanism for the state to protect its interest should economic (or other) factors change.

There does not appear to be any economic analysis that leads to the terms of the royalty reduction described in the bill. Why have these particular terms (5%, 10 years etc.) been selected? Are the economic requirements of all companies so similar that the same level of relief is needed for each of them?

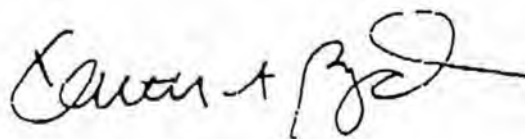
Under the provisions of HB207 (the royalty adjustment bill passed in 1995) any shut-in field is eligible for royalty relief upon a showing of economic need. If these fields need royalty relief to become economic, why not use HB207? After the ten-year term of SB206 is completed, can the company then apply under HB207?

Senator Rick Halford
February 20, 1998
Page 2 of 2

It is not clear to us which fields will qualify for the royalty reduction. I'm sure there will be some discussion about this in the committee hearings. The State has recently negotiated the Redoubt Unit Agreement with Forcenergy. The Agreement provides for the creation of the Unit based on a series of work commitments. At no time during our negotiations with Forcenergy was the issue of royalty reduction raised. This field appears to qualify for royalty reduction under the bill as it is currently drafted. Is a royalty reduction of 60% for 10 years needed to bring this field into production?

I hope that these questions will prove useful to the discussion. Once we have a clearer idea of the intent and rationale behind the bill, we may have some additional questions.

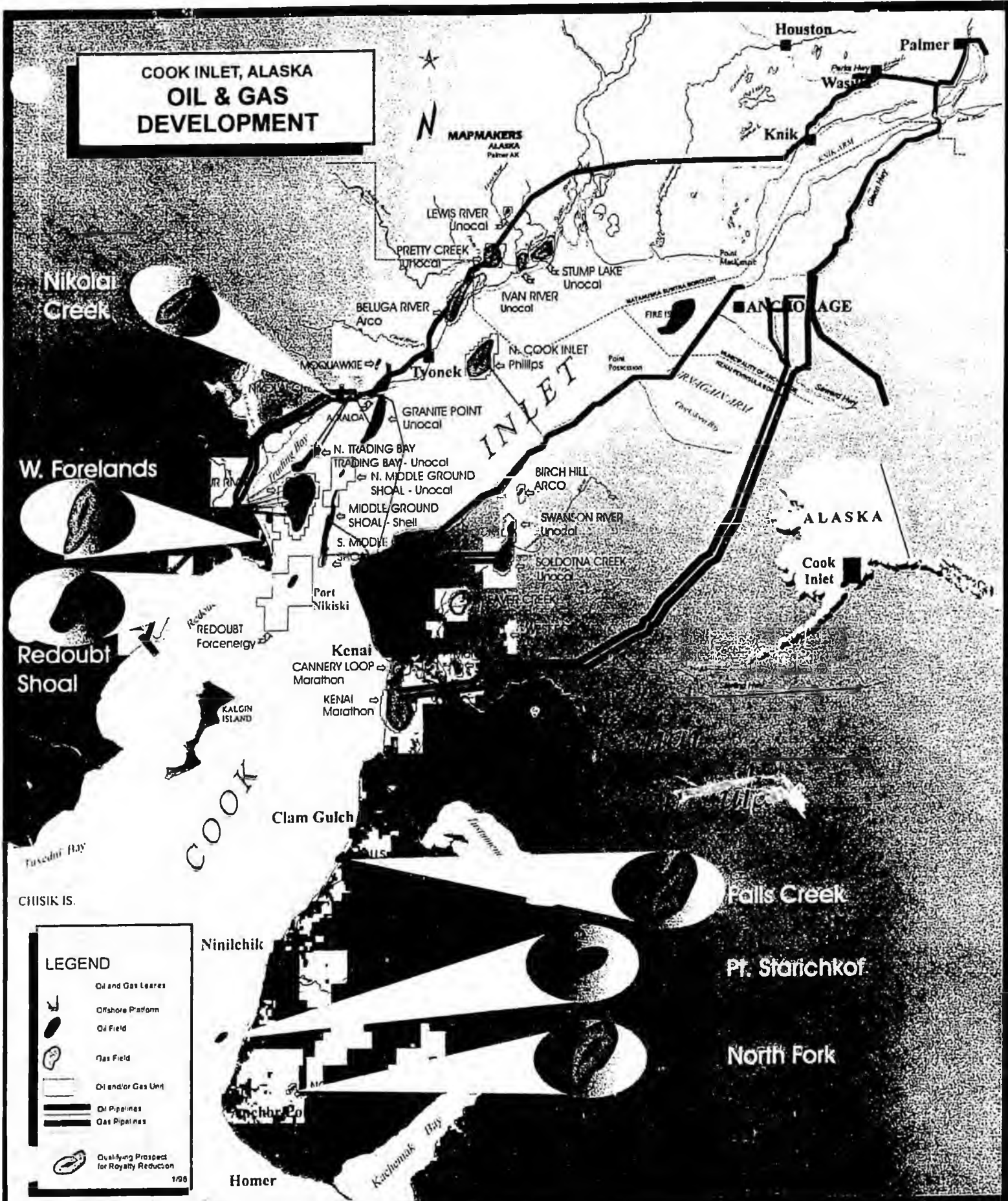
Sincerely,



Kenneth A. Boyd
Director

cc: Senator Drue Pearce
Representative Mark Hodgins
Commissioner John Shively

**COOK INLET, ALASKA
OIL & GAS
DEVELOPMENT**



LEGEND

- Oil and Gas Leases
- Offshore Platform
- Oil Field
- Gas Field
- Oil and/or Gas Unit
- Oil Pipelines
- Gas Pipelines
- Qualifying Prospect for Royalty Reduction

PROPOSED CS FOR HB 380 (O&G)

Section 1. AS 38.05.180 (f) is amended by adding a new paragraph to read:

(5) notwithstanding and in lieu of a requirement in the leasing method chosen of a minimum fixed royalty share, or the royalty provision of a lease, for leases unitized as described in (p) of this section, leases subject to an agreement described in (s) or (t) of this section, or interests unitized under AS 31.05, the lessee of all or part of an oil or gas field **identified in this section.** *[in the cook inlet sedimentary basin discovered before January 1, 1998, that has been undeveloped or shut in from January 1, 1988, through December 31, 1997, and that, before January 1, 2004, begins producing for sale previously undeveloped or shut in oil or gas,]* shall, **provided production for sale begins before January 1, 2004,** pay a royalty of five percent on *[all production of oil & gas]* **the first 40 million barrels of oil and the first 35 billion cubic feet of gas produced** for sale from that oil or gas field that occurs in the 10 years following the date on which the production for sale *[of previously undeveloped or shut in oil & gas]* commences *[from that field]*. **The fields eligible for royalty reduction pursuant to this section, all of which are located within the Cook Inlet sedimentary basin, were discovered before January 1, 1988, and have been undeveloped or shut in from at least January 1, 1988, through December 31, 1997, are:**

- 1) Falls Creek ;**
- 2) Nicolai Creek;**
- 3) North Fork;**
- 4) Point Starichkof;**
- 5) Redoubt Shoal; and**
- 6) West Foreland.**

New text underlined *[Deleted text bracketed]*

Analysis for Fiscal Note SB 256 2/23/98

It is impossible to quantify the fiscal effect of this bill since some critical terms are not defined and no economic analysis has been provided.

Following is an example of what we believe would be the fiscal impact of this bill on the particular projects shown on the sponsor's map. We provide some examples for typical oil and gas projects in Cook Inlet and extrapolate these to the various fields.

The State and an oil company have recently negotiated the creation of the Redoubt Unit in Cook Inlet. This Unit includes several abandoned wells and contains "undeveloped" oil and thus clearly, in our view, meets the criteria of the bill. This unit was created with the understanding that royalties would be 12.5%. There was never any discussion of reducing royalties as a condition of forming the Unit (although the company could APPLY for royalty reduction under HB-207). The company never indicated that royalty relief would be necessary to develop the Unit. The fiscal consequence of SB-256 on the Redoubt Unit is:

Assume 500-1,000 bbl/day production per well, \$10/bbl oil price.

500 bbl/day x \$10/bbl x 12.5% = \$625/day x 365 days x 10 years = \$2.28 million/well
500 bbl/day x \$10/bbl x 5% = \$250/day x 365 days x 10 years = \$910 thousand/well

The State will receive \$1.37 million fewer royalty dollars at 500 bbl/day per well.

1,000 bbl/day x \$10/bbl x 12.5% = \$1,250/day x 365 days x 10 years = \$4.56 million/well
1,000 bbl/day x \$10/bbl x 5% = \$500/day x 365 days x 10 years = \$1.8 million/well

The State will receive \$2.7 million fewer royalty dollars at 1,000 bbl/day per well.

Production per well will likely be somewhere between these two numbers, so the State will forfeit between \$1.37 million and \$2.7 million per well for just the Redoubt Unit.

Assuming (conservatively) that 10 wells are in production the State will "contribute" between \$14 and \$27 million to this project in the form of an unrequested royalty reduction.

Following the examples for oil, here are two similar analyses for gas using the following assumptions:

Two flow rates:

Case 1 1MMcf/d 1 million cubic feet per day = 1,000 mcf/d
Case 2 5MMcf/d 5 million cubic feet per day = 5,000 mcf/d

Gas price \$1.50/mcf This is the Cook Inlet average price

Case 1

1,000 mcf/d x 365 days x \$1.50/mcf x (.125 - .05) = \$41,062/year/well

In ten years = \$410,620/well

This is probably the minimum economic case.

Case 2:

$5,000 \text{ mcf/d} \times 365 \text{ days} \times \$1.50/\text{mcf} \times (.125 - .05) = \$205,312/\text{year}/\text{well}$

In ten years = \$2,053,120/well

This case would be typical of the North Fork, Falls Creek and West Forelands fields.

Assuming the 4 gas fields on the map are one-well fields then the state would forego about \$8 million (4 x \$2 million) in royalties over the ten year period of the royalty reduction.

Assuming the 2 oil fields on the map produce at a rate of 10,000bbl/day the state will forego about \$54 million in royalties over the ten year period of the royalty reduction.

Total for the fields on the map is \$62 million for the program.

THIS ASSUMES THAT NO OTHER FIELDS OTHER THAN THOSE SHOWN ON THE MAP QUALIFY FOR THE REDUCTION.

In general, for all production to which this bill applies, the State will receive (12.5% - 5%) = 7.5% fewer royalty dollars. This is a 60% royalty reduction given without any economic analysis or justification.

Oil and Gas Operations, Management and Policy
8611 Leeper Circle
Anchorage, Alaska 99504

Telephone (907) 337-3515
Facsimile (907) 333-9087

March 4, 1998

Senator Rick Halford, Chairman
Senate Resources Committee
Alaska State Legislature
State Capitol (MS) 3100
Juneau, Alaska 99801-1182

Dear Senator Halford:

I wanted to take this opportunity to reply to several concerns posed by Ken Boyd, Director of the Division of Oil and Gas ("division"), in his February 20, 1998 letter to you regarding S.B. 256. Mr. Boyd's concerns were related to 1) the lack of a provision in the bill to account for changing conditions to protect the State's "upside" interests, 2) the basis for the selection of the royalty rate and term of eligibility used in the bill—five percent for 10 years, 3) a question regarding whether or not all fields and all lessees were similarly situated with regard to economic need, and 4) his desire to clarify which fields are potential candidates for royalty reduction under the proposed legislation. In addition to addressing each of these concerns, I have provided some comments that might be helpful in your evaluation of the division's document entitled "Analysis for Fiscal Note S.B. 256 2/23/96".

Five percent was selected as the floor to provide consistency with the minimum royalty provisions of the state's current discovery royalty program, AS 38.05.180(f)(4), which was enacted in 1996. Five percent also was adopted as the floor by the legislature for royalty reduction under AS 38.05.180(j)(4)(A), the existing statute governing royalty reduction. A 10 year period was selected to provide a reasonable amount of time for royalty relief, on the presumption that production rates and ultimate recovery are likely to be relatively small compared with currently producing Cook Inlet oil and gas fields. The 10 year period is also consistent with the period of royalty reduction applicable under the State's current royalty reduction statute.

The economic requirements of all companies having interests in the fields which may be developed under the proposed legislation are not equal. However, based upon the fact that more than three decades have passed since those fields were discovered, without commercial development of the resources, suggests that, regardless of any individual company's specific economic requirements, royalty reduction may be required to encourage development of these fields. Given the paucity of information about the potential reserves in these fields, it is questionable that applicants could provide the information required under H.B. 207 [AS 38.05.180(j)(4)(A)] to persuade the Commissioner of Natural Resources that royalty reduction is appropriate, although it seems axiomatic that the passage of thirty years without development demonstrates the need for relief.

The fact that S.B. 256 contains no provision to accommodate changing economic conditions is not unique. For example, the legislature made the policy choice in enacting the current discovery royalty statute in 1996 that, in the interest of encouraging new exploration and development in Cook Inlet, a five percent royalty for a 10 year period was appropriate for all new discoveries, regardless of their size. S.B. 256 is intended to provide the same incentive for another class of fields, those which have been discovered, but have not been developed and produced because of their perceived economics.

As a matter of policy, if the legislature wants to limit potential benefits which a lessee might realize if its reserves turn out to be considerably higher than expected, a simple and straight-forward way of doing that would be to amend the bill to limit the volume of oil and gas to which relief would apply. Similarly, to alleviate concerns that the bill may be construed to apply to fields other than those for which it is intended, the bill could be amended to define an explicit list of candidate fields.

In reviewing the division's February 23rd analysis of its Fiscal Note for S.B. 256, you may want to consider the following points. Oil production rates decline over time. Therefore, projecting a constant production rate for 10 years, as the analysis does, overstates the volume, and thus the value, of the state's royalty share. As a result, by implication, the "loss" to the State if it receives a five percent royalty instead of a 12-1/2 percent royalty is also overstated. The rate of decline can vary for a variety of reasons, and the initiation of decline can be deferred by such initiatives as waterflooding, reinjection of produced gas and other measures—if there are sufficient reserves to justify the large capital investments required to do so. However, production decline cannot be avoided, and any estimate of production should reflect that reality.

The attached illustration reflects the decline curve for the Hemlock Oil Pool in the McArthur River Field.¹ During the early development of this field, five rigs were employed in drilling wells from three platforms to develop the oil reserves. In addition, waterflooding was initiated at the beginning of field life to prolong the production plateau—something that less economic fields may not be able to afford. As illustrated, since decline began in 1976, it has continued at a rate of about 16 percent per year, a rate which is a realistic minimum rate for Cook Inlet oil reservoirs. The table below demonstrates the effect of adjusting the division's assumed production profile for the two oil fields to reflect this conservative decline profile, assuming no secondary recovery.

| <u>Year</u> | <u>Volume (bbls)</u> | <u>Gross Value (\$)</u> | <u>5%</u> | <u>7.5%</u> |
|-------------|----------------------|-------------------------|-----------------|------------------|
| 1 | 3,650,000 | 36,500,000 | 1,825,000 | 2,737,500 |
| 2 | 3,066,000 | 30,660,000 | 1,533,000 | 2,299,500 |
| 3 | 2,575,440 | 25,754,400 | 1,287,720 | 1,931,581 |
| 4 | 2,163,373 | 21,633,730 | 1,081,686 | 1,622,530 |
| 5 | 1,817,233 | 18,172,330 | 908,617 | 1,362,925 |
| 6 | 1,526,476 | 15,264,760 | 763,238 | 1,144,857 |
| 7 | 1,282,240 | 12,822,400 | 641,120 | 961,680 |
| 8 | 1,077,082 | 10,770,820 | 538,541 | 807,812 |
| 9 | 904,749 | 9,047,490 | 452,375 | 678,562 |
| 10 | 759,989 | 7,599,890 | 379,995 | 569,992 |
| | <hr/> 18,822,582 | <hr/> 188,225,820 | <hr/> 9,411,292 | <hr/> 14,116,945 |

¹ Alaska Oil and Gas Conservation Commission, 1996 Annual Report, page 82.

If one adopts the division's highest assumed oil production rate—1,000 bbls/day—and the division's "conservative" number of 10 wells per field, but adjusts for a decline of 16 percent per year, a different picture emerges. The projected value of "foregone" royalties per field is about \$14.2 million, instead of the \$27 million estimated by the division. More importantly the table highlights something that is missing from the division's analysis—the \$9.4 million value of the five percent royalty received by the State, which, based upon the evidence of more than 30 years of non-development, might not otherwise occur.

The division's analysis also does not address the bill's potential for leveraging additional exploration and development in the vicinity of new infrastructure. That infrastructure could include roads, platforms, pipelines and associated facilities, all of which could effectively reduce the average cost of producing existing reserves, and extend the economic life of existing and new Cook Inlet production and transportation infrastructure. While these benefits may be hard to quantify, no one can seriously doubt their value. Nor, in my opinion, should they be discounted.

As I have said before, I believe S.B. 256 is an important bill which has the potential to re-energize Cook Inlet exploration and development, and to encourage the participation of a broader range of interests, including major oil companies, independent oil companies and local individuals in that development. I urge your careful consideration and support, as well as that of other members of the Resources Committee, for the bill.

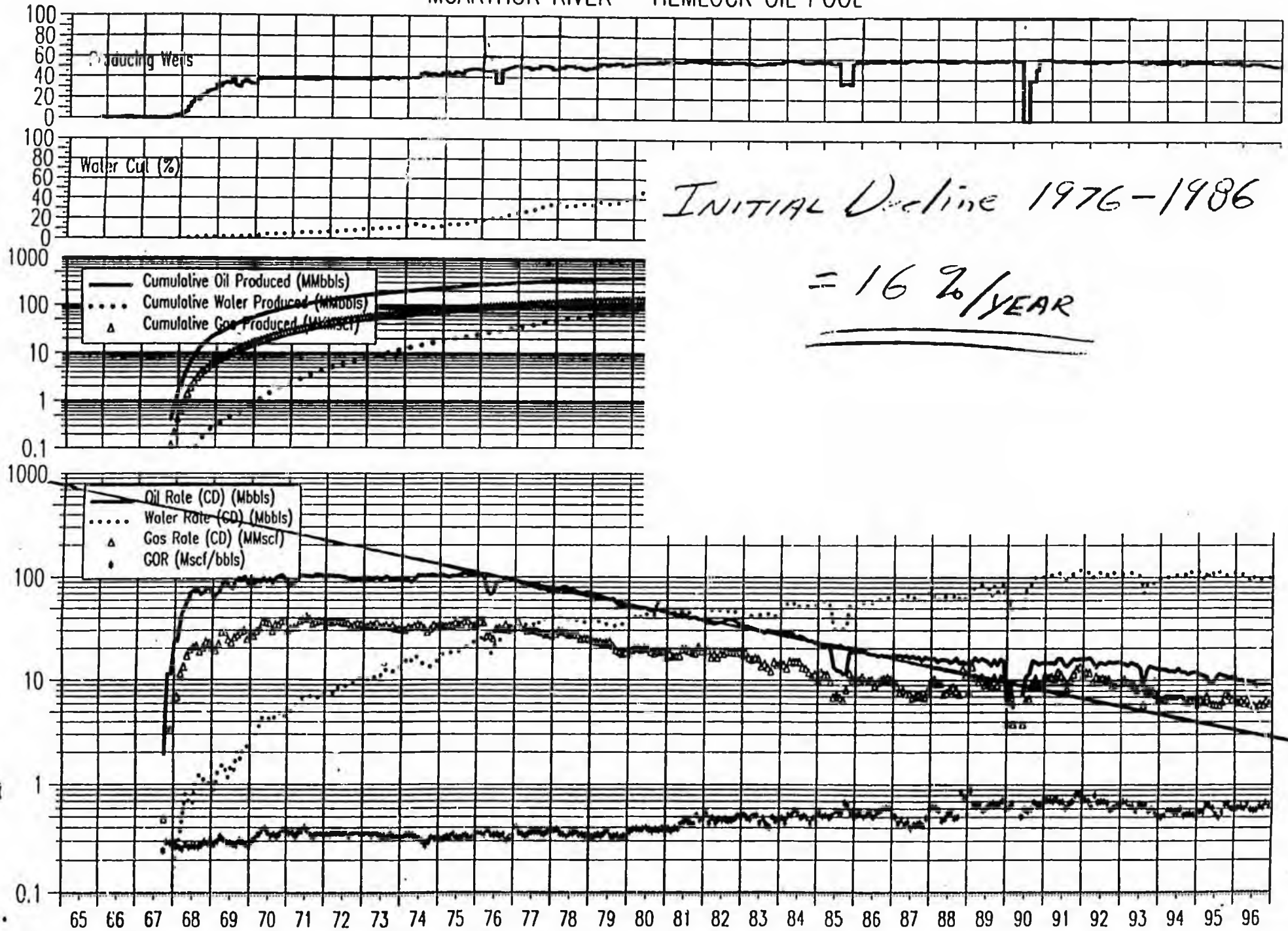
Sincerely,



James E. Eason

cc: Senator Drue Pearce
Representative Mark Hodgins
Commissioner John Shively
Director Ken Boyd

MCARTHUR RIVER - HEMLOCK OIL POOL



PATTON BOGGS, L.L.P.

VIA FACSIMILE
907.465.3884

March 12, 1998

The Honorable Gene Therriault
Co-Chair, House Finance Committee
Alaska State Legislature
State Capitol
Juneau, Alaska 99801

RE: HB 380, "An Act relating to a temporary reduction of royalty on oil and gas produced for sale from fields within the Cook Inlet sedimentary basin where production is commenced in fields that have been discovered and undeveloped or that have been shut in."

Dear Representative Therriault:

HB 380, "An Act relating to a temporary reduction of royalty on oil and gas produced for sale from fields within the Cook Inlet sedimentary basin where production is commenced in fields that have been discovered and undeveloped or that have been shut in," was passed out of the House Special Committee on Oil & Gas today, and now awaits a hearing before the House Finance Committee. I am writing today to encourage you to schedule HB 380 for a hearing in the House Finance Committee at the earliest possible date.

As Jim Eason mentioned to Sara Fisher-Goad when he and I met with her in Juneau last week, passage of Cook Inlet "royalty holiday" legislation this session is critical to encouraging the production of oil and gas from known fields within the Cook Inlet sedimentary basin which have never been developed, or have been shut in.

Under the terms of the proposed legislation, lessees owning leases overlying previously discovered oil or gas fields in the Cook Inlet basin which have remained undeveloped or shut in from at least January 1, 1988, through December 31, 1997, would have an incentive to develop those fields as rapidly as possible. The legislation would provide that, for the first 35 million barrels of oil and the first 35 billion cubic feet of gas produced from undeveloped or shut in fields brought into production before January 1, 2004, lessees would pay a reduced royalty of five percent, instead of the 12 1/2 percent specified in the lease, for a period of 10 years following the date on which oil or gas production begins.

March 12, 1998 K. Parker letter
Re: HB 380, Cook Inlet Royalty Holiday, p. 2

By establishing a short period of eligibility -- ending on December 31, 2003 -- HB 380 ensures that lessees diligently pursue development or forfeit the opportunity to pay reduced royalties. By limiting the period of reduced royalty payments from qualifying fields to 10 years following the beginning of production, the legislation provides a reasonable and measurable limit to the state's foregone royalties in exchange for oil and gas production that may otherwise not occur. The state's royalties from currently producing Cook Inlet oil and gas fields are not effected by HB 380.

Jim Eason and I are available to meet with you at your convenience to discuss this legislation, and we are prepared to return to Juneau to appear before the House Finance Committee and testify in support of the bill. I look forward to working with you and the members of the Finance Committee on this legislation.

Thank you for your continued support.

Sincerely,



Kyle W. Parker

cc: The Honorable Gail Phillips
Speaker of the House

The Honorable Mark Hodgins
Chair, House Oil & Gas



PATTON BOGGS, L.L.P.

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TO: The Honorable
Gene Therriault
907.465.4797
907.465.3884 (FAX)

FROM: Kyle W. Parker

DATE: March 12, 1998

PAGES: 3 (Including cover)

James E. Eason

Oil and Gas Operations, Management and Policy

8611 Leeper Circle • Anchorage, AK 99504-4209
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March 11, 1998

Representative Mark Hodgins, Chairman
House Special Committee on Oil and Gas
Alaska State Legislature
State Capitol (MS) 3100
Juneau, Alaska 99801-1182

Dear Representative Hodgins:

I wanted to take the opportunity to reply to several concerns and/or requests for additional information made by members of the House Special Committee on Oil and Gas during the committee's hearing on H.B. 380 last Thursday, March 5, 1998. A listing of the additional information requested and concerns expressed is provided below:

- a list of the wells and pools involved in the six fields which would be candidates for royalty reduction under H.B. 380, a summary of the discovery history for each field and an estimate of each field's reserves;
- concern that stipulating a 10 year royalty reduction term could potentially lead to accelerated production of the field(s), and thus to waste of the resources;
- concern over the potential for "double dipping" of royalty reduction under both the provisions of H.B. 380 and AS 38.05.180(d)(4)(A), the current royalty reduction statute;
- concern over whether assignment of affected leases would be possible; and
- concern over the need to include a sliding scale formula based upon price variations to assure that lessees do not receive an unexpected windfall at the State's expense

Each of these issues is discussed below.

History of Each Field—Wells Drilled, Productive Intervals and Estimated Reserves¹

1. Falls Creek:

The Falls Creek gas field, is located on the Kenai Peninsula near Clam Gulch. There have been four wells drilled on or near the Falls Creek structure. The discovery well, Falls Creek No. 1, was completed in April 1961. The discovery well tested gas at a rate of 1.8 million cubic feet (mcf) per day from the Tyonek Formation at a depth of approximately 7,600 feet. A subsequent well drilled about four miles to the southwest of the initial well in 1966, the Falls Creek No. 2 well, was a dry hole. In 1973, Chevron drilled the 43-6 well

¹ Except for Redoubt Shoal field reserves, all reserve estimates are from the draft 1997 report entitled "Historical and Projected Oil and Gas Consumption", Alaska Department of Natural Resources, Division of Oil and Gas.

about 2,000 feet east of the Falls Creek No. 1 well. This well, which was located off structure, also was dry. In 1996, Marathon drilled the Corea Creek No. 1 well on the west flank of the Falls Creek structure. The Corea Creek well was plugged and abandoned. Gas reserves are estimated to be 12 billion cubic feet (bcf).

2. Nicolai Creek:

The Nicolai Creek gas field is located on the west side of Cook Inlet near the northwest corner of Trading Bay. The discovery well, Texaco's Nicolai Creek State No. 1-A well, discovered gas in both the Beluga and Tyonek Formations. A total of seven wells have been drilled in the area, with three of those wells being dry holes. Three of the seven wells encountered gas, and one well encountered oil. Estimated gas reserves are 2 billion cubic feet (bcf).

3. North Fork:

The North Fork gas field is located onshore, east of Anchor Point and north of Homer. Only one well has been drilled in the field, the Chevron North Fork No. 41-35 well, which was completed in 1965. The well tested gas from a zone in the Tyonek Formation. Other wells in the vicinity of the North Fork structure have been dry holes. The nearest existing gas pipeline is more than 50 miles away. Estimated gas reserves are 12 billion cubic feet (bcf).

4. Redoubt Shoal:

The Redoubt Shoal oil field is located offshore, to the east of the West Foreland and west of the Port of Nikiski. Six exploratory wells have been drilled in the unit area. Those wells include:

- Pan Am Redoubt Shoal St. 22064 No. 1 (June 1967), which was plugged and abandoned as a dry hole;
- Tenneco St. 36465 No. 1 (November 1967), which was plugged and abandoned as a dry hole with oil shows;
- Pan Am Redoubt Shoal St. 29690 No. 1 (December 1967), which recovered minor amounts of oil from the Hemlock Formation;
- Pan Am Redoubt Shoal Unit 29690 No. 2 (September 1968), which tested 1291 barrels of oil per day from the Hemlock Formation, and is the discovery well for the Redoubt Shoal field;
- Union Redoubt Bay Unit No. 1 (October 1976), which failed to recover significant quantities of oil although numerous drill stem tests were conducted in the well; and
- Mobil South McArthur River No. 1A (December 1982), which was plugged and abandoned as a dry hole.

The Division of Oil and Gas has not published oil reserves estimates for the Redoubt Shoal field. However, the engineering firm of Netherland, Sewell and Associates completed an independent assessment of the field in February of this year, using all available well data and the 3D seismic survey completed in the fall of 1997 to determine proven reserves for Securities and Exchange Commission reporting purposes. The firm's estimate of proven oil reserves at the Redoubt Shoal field is 8.9 million barrels.

5. Starichkof:

The Starichkof oil field is located offshore and about six miles north of Anchor Point. The discovery well, the Pennzoil Starichkof No. 1 well, was drilled in 1967. A second well drilled later that year two miles north of the discovery location, the Starichkof State Unit No. 1 well, was plugged and abandoned. The discovery well tested 57 barrels of oil per day.

6. West Foreland:

The West Foreland gas field is located on the shoreline of the West Foreland, west of the Port of Nikiski. The field was discovered in 1962 by the Pan Am West Foreland No. 1 well. Pan American Oil subsequently drilled the West Foreland Unit No. 1 well about four miles to the north and the West Foreland Unit No. 2 well about to the north without finding gas. Estimated gas reserves are 20 billion cubic feet (bcf).

The 10 Year Term and Its Potential to Cause Waste

Concern was expressed about the possibility that, given the limited period of eligibility, a company might produce a field too fast in order to increase its benefits from reduced royalty payments. Amending the bill to allow for extension of the 10 year period for this eventuality is not necessary. One of the Alaska Oil and Gas Conservation Commission's ("AOGCC's") primary responsibilities is monitoring development and production from the state's oil and gas fields to assure that wasteful operations do not occur. That independent agency's oversight will assure that field development plans are consistent with the goals of preventing waste and maximizing recovery of the resources.

Potential for "Double Dipping" of Royalty Reduction

Royalty reduction under the provisions of H.B. 380 would obviate the need for royalty reduction under AS 38.05.180(d)(4)(A) during the 10 year period of eligibility under the proposed bill. Thus, as a practical matter, there could be no "double dipping" during that period. If the royalty obligation was already five percent under H.B. 380, a reduction to five percent under AS 38.05.180(d)(4)(A) would not further reduce the royalty rate. As the bill is drafted, however, it is conceivable that a field eligible for royalty reduction under its provisions could produce for 10 years at the five percent royalty rate, and thereafter, could qualify for continued royalty reduction under the provisions of AS 38.05.180(d)(4)(A). The only circumstances where that could happen, however, are instances in which the commissioner of the Department of Natural Resources makes an affirmative finding, based on the merits and under the stringent conditions of H.B. 207, that continued reduction was both appropriate and in the state's best interests.

Assignment of Lease Interests in Candidate Fields

Passage of H.B. 380 will establish a short period to qualify for royalty reduction, with eligibility ending on December 31, 2003. If production from a candidate field has not begun by that time, lessees holding interests in the field forfeit the opportunity to qualify. Under its terms, the bill is designed to insure that lessees either diligently pursue development or lose the potential benefit of paying the reduced royalties. Under these circumstances, it is entirely possible that the incentive provided by H.B. 380 may be insufficient to promote development of some or all of the candidate fields by their current owners, yet may lead to assignments of lease interests to others who are willing to pursue development.

The Need for a Sliding Scale, Price-Based Formula or Price Cap

For the following reasons, amendment of H.B. 380 to provide for pre-determined caps on the volumes of oil and gas qualifying for reduced royalty is preferable to using a sliding scale, price-based formula or price caps for determining royalties:

- each of the six fields has remained undeveloped for 30+ years, through wide ranges of prices, suggesting that short term spikes in prices, in and of themselves, are insufficient to spur production;
- applying volume limits equally to all the fields is the simplest, most direct way of implementing the incentive;
- fluctuating prices could lead to frequent activation and deactivation of royalty reduction, which could negatively impact long-term planning and investment decisions critical to a field's development; while
- a simplified incentive program will facilitate lessees' planning for capital allocation and minimize administrative costs for both the State and the lessees.

Based on the results of prior exploration, none of the field's potentially benefiting from passage of H.B. 380 are likely to have unexpectedly large reserves. Both the reserve estimates of the Division of Oil and Gas and those of Netherland, Sewell and Associates support this conclusion. As further evidence of the perceptions of others, including former and current lessees, more than three decades have passed since these discoveries were made—without development having occurred. Under these circumstances, the simplest and most direct incentive has the greatest likelihood of producing the desired effects.

In closing, Mr. Chairman, I believe passage of H.B. 380 has the potential to re-energize Cook Inlet exploration and development, and to extend the productive life of older producing fields. It would also encourage participation by a broad range of interests, including major oil companies, independent oil companies and local individuals in the development of the shut-in resources. On behalf of Forcenergy, I appreciate the careful review and consideration which you and members of your committee have given the bill, and I urge your continued support in passing the bill from the committee.

Sincerely,



James E. Eason

cc: Senator Drue Pearce
Representative Mark Hodgins
Members of the House Special Committee on Oil and Gas
Commissioner John Shively, DNR
Director Ken Boyd, DO&G

**OWNERSHIP OF SHUT-IN AND UNDEVELOPED
COOK INLET OIL AND GAS FIELDS
IDENTIFIED AS POTENTIALLY QUALIFYING
FOR TEMPORARY ROYALTY REDUCTION
UNDER THE PROVISIONS OF
SENATE BILL 256 / HOUSE BILL 380**

| <u>Field</u> | <u>Type</u> | <u>Discovered</u> | <u>Affected Lessees *</u> |
|----------------|-------------|-------------------|---|
| Falls Creek | Gas | 1961 | ARCO Alaska (50%); Cliff Burglin (22%); Other Private Individuals (28%) |
| Nicolai Creek | Gas | 1966 | UNOCAL (50%); Marathon (50%) |
| North Fork | Gas | 1965 | Gas-Pro Alaska (64.721%); ARCO Alaska (27.375%); and Marathon (7.904%) |
| Pt. Starichkof | Oil | 1967 | Mobil (25%); Pennzoil (25%); Placid (16.07143%); Rosewood Resources (4.726890%); Hunt Petroleum Corp. (4.201680); and Forcenergy Inc (25%) |
| Redoubt Shoal | Oil | 1968 | Forcenergy Inc (100%) |
| West Foreland | Gas | 1962 | Forcenergy Inc (100%) ** |

* For those fields which are within approved units—Falls Creek, Nicolai Creek, North Fork and Redoubt Shoal fields—includes both the identity of the Working Interest Owners (WIOs) and their respective ownership interests in the State of Alaska leases within the unit. For Pt. Starichkof Field, which is not utilized, WIOs and ownership interest percentages noted are for the lease upon which the discovery well was drilled. Additional delineation drilling in all fields may confirm reserves extending beneath adjacent leases. Accordingly, lessees in addition to those noted above may potentially be affected by expedited delineation and production of these fields.

** The discovery well for the West Foreland Field is located onshore on a federal lease now owned by Cook Inlet Region, Inc. However, there is evidence to suggest that the gas accumulation confirmed by the discovery well may extend offshore onto one or more leases owned by Forcenergy Inc.

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LEGISLATIVE TELECONFERENCE NETWORK SYSTEM
PARTICIPANT LIST (ALL PARTICIPANTS)
TCN:80585 SCHEDULED FOR:03/28/98 14:00 TO 16:30
PUBLIC HEARING HOUSE FINANCE

LTN1150
BY:ANC
FOR:ANC

LOCATION: ANCHORAGE

HB 380
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LEGISLATIVE TELECONFERENCE NETWORK SYSTEM
PARTICIPANT LIST (TESTIFIERS ONLY)
TCN:80585 SCHEDULED FOR:03/28/98 14:00 TO 16:30
PUBLIC HEARING HOUSE FINANCE

LTN1150
BY:JNU
FOR:ALL

LOCATION: ANCHORAGE

HB 380
HB 380

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