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256

Alaska State Legislature



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Drue Pearce

SPONSOR STATEMENT SB 256

Sponsored by Senator Drue Pearce
Co-chair Senate Finance Committee

Senate Bill 256 is intended to encourage the expedited production of oil and gas from known, but undeveloped or shut-in fields within the Cook Inlet sedimentary basin. A principal goal of the legislation is to develop new sources of natural gas to help offset potential supply shortages which have been forecasted by some to occur within the next 10-11 years. New gas reserves developed as a result of the proposed legislation not only would defer those shortages, but could be instrumental in maintaining reliable and economically priced gas supplies for Southcentral consumers, including residential and commercial users.

In addition to possibly stimulating the development of several known undeveloped fields, many of which were discovered more than 30 years ago, Senate Bill 256 has the potential to leverage additional exploration and development in the vicinity of new infrastructure, including pipelines and associated facilities, required to develop those known fields. Any new oil and gas production resulting from the development of these fields will in turn reduce the average cost of producing existing reserves, and extend the economic life of both existing and new Cook Inlet production and transportation infrastructure.

Senate Bill 256 provides the legislature a simple, effective means of responding to several disturbing trends associated with Cook Inlet oil and gas production, including:

- the approaching depletion of many of Cook Inlet's producing gas fields, including the Kenai Field, the area's largest and oldest producing gas field, which is more than 88 percent depleted, and
- the resulting potential for near term gas shortages which would lead to rapid price increases for all consumers and threaten the continued viability of important industrial projects such as UNOCAL's fertilizer manufacturing plant and the Phillips/Marathon LNG Export facilities at Nikiski, both of which provide substantial employment opportunities and vital revenues for Southcentral Alaska communities,

- continued decline of oil production, from a historical high of more than 82 million barrels per year in 1970 to less than 14.6 million barrels per year in 1996,
- the associated declines in employment related to the oil and gas industry, as well as state and local taxes and royalties from Cook Inlet production,
- the advanced depletion of Cook Inlet's principal producing oil fields, most of which now are more than 90 percent depleted.

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 oil and 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.

By establishing a short period of eligibility—ending on December 31, 2003—Senate Bill 256 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 Senate Bill 256.

FISCAL NOTE

STATE OF ALASKA
1998 LEGISLATIVE SESSION

BILL NO. SB256

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: Senator Pearce
 Requestor: Senate Resources 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
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CHANGE IN REVENUES (fund code)	0.0	?	?	?	?	?
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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 *Ken Boyd for* Phone: 269-8800
 Division: Oil & Gas Date: 13-Feb-98
 Approved by Commissioner: *Ken Boyd for John King* Date: 2-16-98
 Agency: Natural Resources

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SB256 Fiscal Analysis continued...

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:

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.

STATE OF ALASKA

TONY KNOWLES, GOVERNOR

FEB 25 1998

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,

A handwritten signature in cursive script, appearing to read "Ken + Boyd", written in dark ink.

Kenneth A. Boyd
Director

cc: Senator Drue Pearce
Representative Mark Hodgins
Commissioner John Shively

**ALASKA SENATE RESOURCES COMMITTEE
PUBLIC COMMENT ON SB256
MARATHON OIL COMPANY
February 20, 1998**

Good afternoon Chairman Halford and members of the Senate Resources Committee. My name is John Miesse and I am here today representing Marathon Oil Company. As most of you know, Marathon has been an operator in the Cook Inlet Area for over 30 years. We appreciate your interest and support of the oil and gas industry in the Cook Inlet area. I'd like to take a few moments to comment on Senate Bill 256, which is intended to provide an incentive for oil and gas development in Cook Inlet from fields that have previously been undeveloped or shut-in.

Marathon supports Senate Bill 256 and believes that in the long term, this incentive will have a positive economic impact on the State of Alaska and the local communities. I would like to point out however, that we believe this Bill would have a more immediate impact on undeveloped or shut-in oil fields because of the readily available market for this product. The ultimate incentive for adding additional reserve capacity, whether it be oil or natural gas, is the availability of ready and stable markets. While such a market is certainly available for new oil reserves in the Cook Inlet area, the same cannot be said for natural gas. New markets for uncommitted

natural gas reserves are not available for the next several years, making it difficult to economically justify near term drilling expenditures. Although this Bill will provide some economic benefit to the industry, we don't believe by itself, will be enough to stimulate significant activity for natural gas development in the near future.

I would now like to ask the committee to consider points of clarification that we believe are needed in Senate Bill 256. It is our understanding that the intent of this legislation is to provide the temporary relief to fields that have been undeveloped "or" shut-in. We would like clarification on the definition of undeveloped. Specifically we would like to know if a field that has produced periodically over the last few years, but requires additional drilling to fully develop the field, would be eligible for the temporary royalty relief. Also we would like to clarify that royalty relief would apply to either a re-entry of an existing well or a new well needed to recover undeveloped reserves. Again, we understand the intent of the proposed legislation is to address these scenarios, but we would appreciate the Department's review to make sure the language is explicit.

In closing, many of the oil and gas producing states enacted similar incentives for oil and gas development in the early 1990's. These states have found the programs to be beneficial to all stakeholders involved and have maintained those programs. We believe incentive programs such as Senate Bill 256 will also lead to economic gain for our communities and the State, but we recognize

that market availability is probably the overriding incentive for our industry to look for new oil or gas reserves. Therefore, we believe you will see a more immediate impact on the undeveloped oil fields in the Cook Inlet area as a result of this proposed incentive.

Thank you for the opportunity to share these comments with you today. I will be glad to answer any questions you might have.

TESTIMONY
OF
MR. GARY E. CARLSON, VICE PRESIDENT
FORCENERGY INC
SENATE RESOURCES COMMITTEE
FEBRUARY 20, 1998

Mr. Chairman, and members of the Committee, for the record my name is Gary E. Carlson. I am Vice President of Forcenergy Inc and manager of Forcenergy's Alaska division. Forcenergy is an independent oil and gas company that is a relative newcomer to Alaska oil and gas exploration and development. We have only been here for about fifteen months, so some members of the Committee may not be too familiar with who we are and what we have accomplished to date.

I would like to take a few moments to review some of our recent accomplishments and ongoing projects, because I believe they reflect a commitment of resources and revenue to finding new reserves, prolonging Cook Inlet's existing oil and gas production and employing new technology both to locate and to develop smaller and more economically challenging oil and gas accumulation. Don't get me wrong, we would love to find a substantial resource, but we can't count on it.

Forcenergy's financial commitments in Alaska to date total more than \$180 million. This includes acquisitions, seismic projects, and drilling.

- We purchased Marathon Oil Company's crude oil properties in Cook Inlet, as well as its interests in the Prudhoe Bay Field on the North Slope;
- purchased Marathon Oil Company's interest in the Cook Inlet Pipeline System, thus providing Forcenergy with an ownership interest in the established Cook Inlet oil and gas transportation infrastructure;
- purchased new Cook Inlet leases in competitive oil and gas lease sales held by both the State of Alaska and the federal Minerals Management Services;

- purchased the leases overlying the Redoubt Shoal Field, a field which was discovered in 1968, but which has remained undeveloped since that time;
- purchased Stewart Petroleum's West McArthur River Unit property, and are continuing operations in that field to enhance oil production and to establish new reserves;
- purchased leases held by Trading Bay Energy;
- committed to spend \$30 million for a joint account with Unocal for acquisitions, wells, and seismic; and in turn received access to their extensive database.

We opened an office currently staffed with 22 Forcenergy employees. Eighteen of these employees were already Alaska residents; 3 are reruns (like myself), and one was recruited from out of state. We also make liberal use of local contractors and consultants. Since early spring of 1997, we have contracted seismic crews; in the Inlet until ice drove us out for the season, and on frozen ground onshore. This includes two state-of-the-art 3D surveys. Our total expenditures to date for seismic activities approximates \$10 million.

Currently, we are drilling our second and third wells in the area. Two of the three wells are on state acreage.

Collectively, these actions reflect Forcenergy's long-term commitment to Alaska, as well as its belief that Cook Inlet continues to provide opportunities for additional discoveries and development – particularly for companies that are innovative, technically adept and willing to accept the challenge and risk of exploring for smaller and smaller accumulations. That optimism is tempered, however, by the realization that, as production from the area's producing oil and gas fields declines, new production must be found and brought to market as quickly as possible if we are to maintain the area's infrastructure.

We believe that Cook Inlet's shut-in oil and gas fields can play a key role in deferring production decline and in spurring new exploration and development. Accordingly, we are supportive of the proposed legislation, and believe that it can provide an effective incentive for encouraging production from Cook Inlet's shut-in and undeveloped fields, many of which were discovered more than thirty years ago. We are also encouraged by your consideration of this legislation which, if passed, will further level the playing field in Cook Inlet. By applying equally to fields in which there is diverse ownership interests, including independents like ourselves, majors such as ARCO, Phillips and Marathon, and small local companies such as Gas Pro and individual Alaskans; the proposed legislation will serve to encourage broader participation in the development and production of the fields eligible for royalty reduction under Senate Bill 256.

In addition to possibly stimulating the development of several known, undeveloped oil and gas fields, Senate Bill 256 also has the potential to leverage additional exploration and development in the vicinity of new infrastructure, including pipelines and associated facilities, required to develop those fields. Any new oil and gas production resulting from the development of these fields will in turn reduce the average cost of producing existing reserves, and will extend the economic life of both existing and new Cook Inlet production and transportation infrastructure.

We believe that Senate Bill 256 represents a straight forward, effective means of responding to several disturbing trends associated with Cook Inlet oil and gas production, including: 1) the continued decline of oil production, from a historical high of more than 82 million barrels per year in 1970 to less than 14.6 million barrels per year in 1996; 2) the associated decline in employment related to the oil and gas industry, as well as declining state and local taxes and royalties from Cook Inlet production; 3) the advanced depletion of Cook Inlet's principal producing oil fields, most of which now are more than 90% depleted; and 4) the approaching depletion of many of Cook Inlet's producing gas fields.

The proposed legislation provides an incentive for 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, to develop those fields as rapidly as possible. In return, for new oil or gas production from those fields begun before January 1, 2004, lessees would pay a reduced royalty of 5%, instead of the 12-½% specified in the lease, for a period of 10 years following the date on which production begins. By its terms, however, Senate Bill 256 assures that the State stands to gain also.

By establishing a short period of eligibility – ending on December 31, 2003 – Senate Bill 256 ensures that lessees diligently pursue development of those fields 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. Both the State and all Cook Inlet lessees stand to gain from extensions to existing infrastructure which may result from the development of fields which are eligible under Senate Bill 256.

In closing, Forcenergy supports Senate Bill 256, and urges the members of the Committee to support its passage. This concludes my prepared testimony, but I will be happy to answer any questions that the members of the Committee may have.



ENSTAR Natural Gas Company
A DIVISION OF SEAGULL ENERGY CORPORATION
3000 Spenard Road
P.O. Box 190268
Anchorage, Alaska 99519-0268
(907) 264-3681

Richard F. Barnes
President

February 19, 1998

Senate Resources Committee
Alaska State Legislature

Dear Senators:

Re: SB 256

ENSTAR Natural Gas favors passage of Senate Bill 256. We are concerned about ensuring an adequate gas supply for the 97,000 homes and businesses that we serve in Southcentral Alaska. We are working with Cook Inlet producers to try to develop new supplies. In a modest way, this bill may help make more gas available.

Small gas fields can be expensive to develop and are typically difficult to operate. By reducing the royalty burden on these marginal properties, some leaseholders may choose to develop fields that otherwise would be left shut-in. We presume that the same holds true for marginal oil properties.

Reserves attributable to shut-in gas fields are not large. If all of those presently identified were made available for our customers' use, they would represent about 13 months of gas consumption.

While additional gas production encouraged by SB 256 will help the area's supply situation, we believe that serious shortages may occur within the next ten years. We hope to work with the legislature to develop secure gas supplies to meet local Alaskan needs.

Very truly yours,

A handwritten signature in cursive script that reads "R. F. Barnes".

offered for oil and gas leasing during the calendar year in which the proposed program is made available to the legislature and the following four calendar years.

(c) Except as provided in (d) and (w) of this section, an oil and gas lease sale may not be held unless it was included in the proposed leasing programs submitted to the legislature during the two calendar years preceding the year in which the sale is held. A lease sale may not be held before the date it is scheduled in the proposed oil and gas leasing program.

(d) The commissioner

(1) may annually offer oil and gas leases of the acreage described in AS 38.05.035(e)(6)(G);

(2) may issue oil and gas leases in an area that has not been included in a leasing program prepared, in accordance with (b) of this section if the land to be leased

(A) was previously subject to a valid state or federal oil and gas lease;

(B) is contiguous to land already under state, federal or private lease and the commissioner makes a written finding, after hearing, that leasing of the land would result in a substantial probability of early evaluation and development of the land to be leased;

(C) is adjacent to land owned or controlled by another party on which a discovery of commercial quantities of oil or gas has been made, and the commissioner finds, after hearing, that there is a reasonable probability that the land to be leased contains oil or gas in communication with the oil or gas discovered on the land of the other party;

(D) is adjacent to land included in the federal five-year Outer Continental Shelf leasing program under 43 U.S.C. 1344, and the commissioner makes a written finding, after hearing, that coordinated or simultaneous leasing with the federal government is in the public interest; or

(E) is the subject of an oil and gas exploration license issued under AS 38.05.131 — 38.05.134.

(e) Simultaneously with submission of the leasing program required under (b) of this section, the commissioner shall prepare and notify the legislature of the availability of a report containing the following:

(1) the schedule of all lease sales held during the preceding calendar year, the bidding method or methods utilized, and an analysis of the results of the bidding;

(2) if determined, a description of the bidding methods to be used for all lease sales to be held during the current and next two succeeding calendar years;

(3) the reasons a particular bidding method has been selected.

(f) Except as provided by AS 38.05.131 — 38.05.134 and 38.05.177, the commissioner may issue oil and gas leases on state land to the highest responsible qualified bidder as follows:

(1) the commissioner shall issue an oil and gas lease to the successful bidder determined by competitive bidding under regulations adopted by the commissioner; bidding may be by sealed bid or according to any other bidding procedure the commissioner determines is in the best interests of the state;

(2) whenever, under any of the leasing methods listed in this subsection, a royalty share is reserved to the state, it shall be delivered in pipeline quality and free of all lease or unit expenses, including but not limited to separation, cleaning, dehydration, gathering, salt water disposal, and preparation for transportation off the lease or unit area;

(3) following a pre-sale analysis, the commissioner may choose at least one of the following leasing methods:

(A) a cash bonus bid with a fixed royalty share reserved to the state of not less than 12.5 percent in amount or value of the production removed or sold from the lease;

(B) a cash bonus bid with a fixed royalty share reserved to the state of not less than 12.5 percent in amount or value of the production removed or sold from the lease and a fixed share of the net profit derived from the lease of not less than 30 percent reserved to the state;

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(C) a fixed cash bonus with a royalty share reserved to the state as the bid variable but no less than 12.5 percent in amount or value of the production removed or sold from the lease;

(D) a fixed cash bonus with the share of the net profit derived from the lease reserved to the state as the bid variable;

(E) a fixed cash bonus with a fixed royalty share reserved to the state of not less than 12.5 percent in amount or value of the production removed or sold from the lease with the share of the net profit derived from the lease reserved to the state as the bid variable;

(F) a cash bonus bid with a fixed royalty share reserved to the state based on a sliding scale according to the volume of production or other factor but in no event less than 12.5 percent in amount or value of the production removed or sold from the lease;

(G) a fixed cash bonus with a royalty share reserved to the state based on a sliding scale according to the volume of production or other factor as the bid variable but not less than 12.5 percent in amount or value of the production removed or sold from the lease;

(4) notwithstanding a requirement in the leasing method chosen of a minimum fixed royalty share, on and after March 3, 1997, the lessee under a lease issued in the Cook Inlet sedimentary basin who is the first to file with the commissioner a nonconfidential sworn statement claiming to be the first to have drilled a well discovering oil or gas in a previously undiscovered oil or gas pool and who is certified by the commissioner within one year of completion of that discovery well to have drilled a well in that pool that is capable of producing in paying quantities shall pay a royalty of five percent on all production of oil or gas from that pool attributable to that lease for a period of 10 years following the date of discovery of that pool, and thereafter the royalty payable on all production of oil or gas from the pool attributable to that lease shall be determined and payable as specified in the lease; for purposes of this paragraph, the reduced royalty authorized by this paragraph is subject to the following:

(A) only one reduction of royalty authorized by this paragraph may be allowed on each lease that qualifies for reduction of royalty under this paragraph;

(B) if, under this paragraph, application is made for a royalty reduction for a lease that was entered into before March 3, 1997, the commissioner may approve the application only if, on that date, the lease was a nonproducing lease that was not committed to a unit approved by the commissioner under (m) of this section, that is not part of a unit under (p) or (q) of this section, and that has not been made part of a unit under AS 31.05;

(C) if application for a royalty reduction is made under this paragraph for a lease on which a discovery royalty was claimed or may be claimed under the discovery royalty provisions of former AS 38.05.180(a) in effect before May 6, 1969, the commissioner shall disallow the application under this paragraph unless the applicant waives the right to claim the right to a reduced royalty under the discovery royalty provisions of former AS 38.05.180(a) in effect before May 6, 1969; and

(D) the commissioner shall adopt regulations setting out the standards, criteria, and definitions of terms that apply to implement the filing of applications for, and the review and certification of, discovery oil and gas royalty certifications under this paragraph.

(g) The share of the net profit derived from a lease reserved to the state under (f) of this section is royalty sale proceeds for the purposes of the Alaska permanent fund under AS 37.13.010.

(h) The commissioner may include terms in any oil and gas lease imposing a minimum work commitment on the lessee. These terms shall be made public before the sale, and may include appropriate penalty provisions to take effect in the event the lessee does not fulfill the minimum work commitment. If it is demonstrated that a lease has been proven unproductive by actions of adjacent lease holders, the commissioner may set aside a work commitment. The commissioner may waive for a period not to exceed one two-year period any term of a minimum work commitment if the commissioner makes a written finding either that conditions preventing drilling or exploration were beyond the lessee's

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**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**

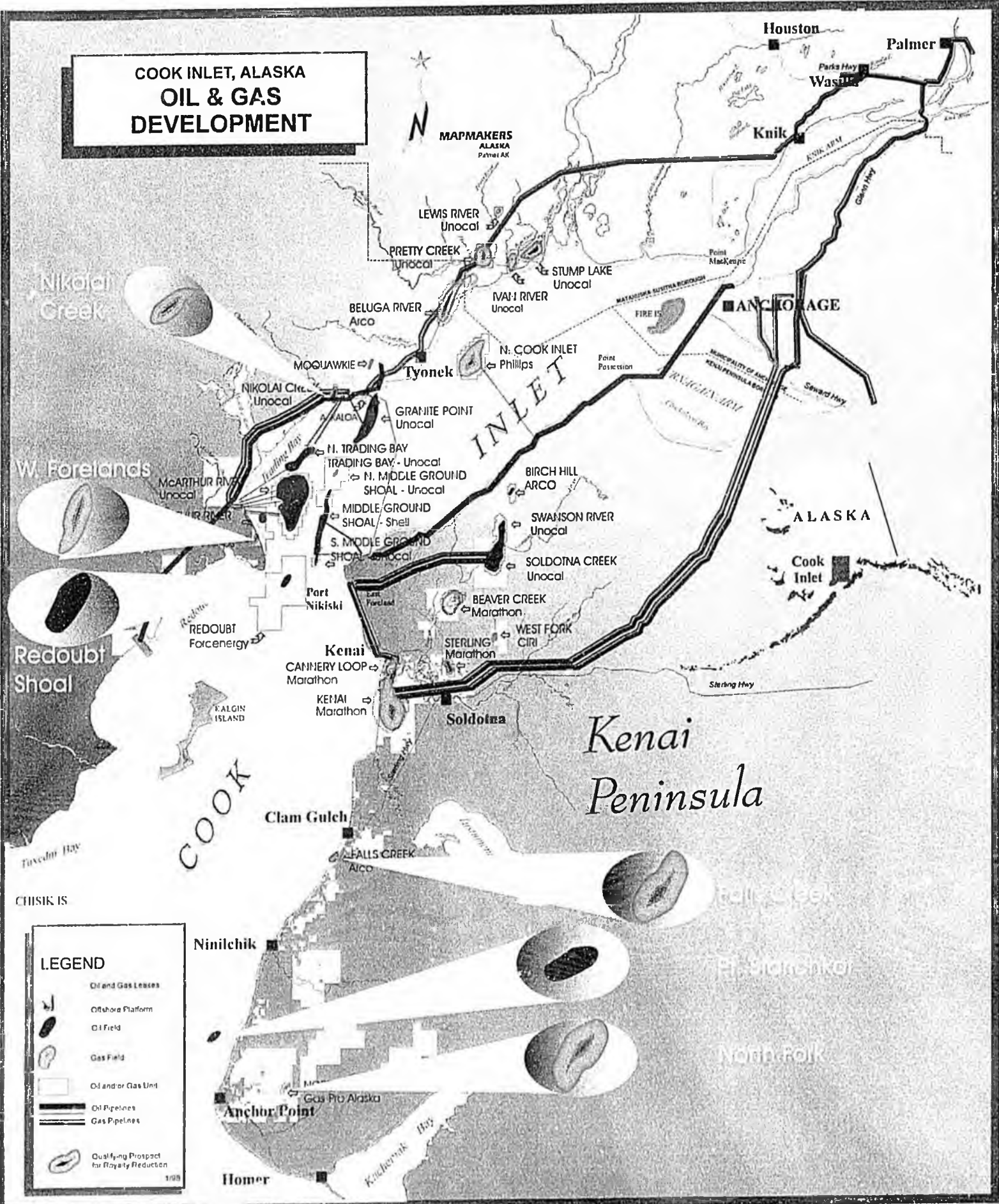
<u>Field</u>	<u>Type</u>	<u>Discovered</u>	<u>Affected Lessees</u> *
Falls Creek	Gas	1961	ARCO Alaska (50%); Cliff Burglin (22%); Other Private Individuals (28%)
Nicolai Creek	Gas	1966	UNOCAL (50%); Marathon (50%)
North Fork	Gas	1965	Gas-Pro Alaska (64.721%); ARCO Alaska (27.375%); and Marathon (7.904%)
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 (70%); UNOCAL(30%) **
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 unitized, 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.

** Forcenergy Inc currently holds 100% Working Interest in the Redoubt Unit. However, under the terms of an agreement between the companies, UNOCAL has the option, which it is expected to exercise, to acquire a 30% Working Interest in the unit.

*** The discovery well for the West Foreland Field is located onshore on a federal lease held by Phillips Petroleum Company. 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.

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

Kornbrath—ANALYSIS OF HISTORICAL OIL AND GAS LEASE SALE AND EXPLORATION DATA FOR ALASKA—DGGG Report of Investigations 95-11

Report of Investigations 95-11

**ANALYSIS OF HISTORICAL OIL AND GAS LEASE SALE
AND EXPLORATION DATA FOR ALASKA**

by

Richard W. Kornbrath



Published by

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES

DIVISION OF GEOLOGICAL & GEOPHYSICAL SURVEYS
IN COOPERATION WITH THE DIVISION OF OIL & GAS

1995

Table 9. Complete listing of all Alaska discoveries

No.	Field/accumulation	Discovery date	Fluid type(s)	Status	No.	Field/accumulation	Discovery date	Fluid type(s)	Status
Northern Alaska					Cook Inlet				
1	Prudhoe Bay	1967	Oil, Gas	P	40	Swanson River	1957	Oil, Gas	P
2	Lisburne	1967	Oil, Gas	P	41	Middle Ground Shoal	1962	Oil, Gas	P
3	Kuparuk River	1969	Oil, Gas	P	42	Granite Point	1965	Oil, Gas	P
4	Milne Point	1969	Oil, Gas	P	43	Trading Bay	1965	Oil, Gas	P
5	Prud. Bay - West Beach	1976	Oil, Gas	P	44	McArthur River	1965	Oil, Gas	P
6	Prud. Bay - N. PB St.	1970	Oil, Gas	P	45	Beaver Creek	1965	Oil, Gas	P
7	Endicott	1978	Oil, Gas	P	46	West McArthur River	1991	Oil, Gas	P
8	Niakuk	1985	Oil	P	47	Kenai	1959	Gas	P
9	Point McIntyre	1988	Oil, Gas	P	48	West Fork	1960	Gas	P
10	South Barrow	1949	Gas	P	49	North Cook Inlet	1962	Gas	P
11	East Barrow	1974	Gas	P	50	Beluga River	1962	Gas	P
12	Walakpa	1980	Gas	P	51	Ivan River	1966	Gas	P
13	West Sak	1969	Oil	UD	52	Lewis River	1975	Gas	P
14	Point Thomson	1977	Oil, Gas	UD	53	Stump Lake	1978	Gas	P
15	Northstar/Seal Island	1984	Oil	UD	54	Pretty Creek	1979	Gas	P
16	Flaxman Island	1975	Oil	UD	55	Cannery Loop	1979	Gas	P
17	Umiat	1946	Oil	UD	56	Katalla (Gulf of Alaska)	1902	Oil	ABND
18	Fish Creek	1949	Oil	UD	57	Redoubt Shoal	1968	Oil	UD
19	Simpson	1950	Oil	UD	58	Sunfish	1991	Oil	UD
20	Mikkelson	1978	Oil	UD	59	Sterling	1961	Gas	SI
21	Gwydyr Bay	1981	Oil	UD	60	Falls Creek	1961	Gas	UD
22	Tem Island	1983	Oil	UD	61	West Foreland	1962	Gas	UD
23	Hemi Springs	1984	Oil	UD	62	North Fork	1965	Gas	UD
24	Colville Delta	1985	Oil	UD	63	Nicolai Creek	1966	Gas	SI
25	Hammerhead	1986	Oil	UD	64	Birch Hill	1967	Gas	UD
26	Sandpiper Island	1986	Oil	UD	65	Moquawkie	1965	Gas	SI
27	Badami	1990	Oil	UD	66	Albatross/Kalooa	1968	Gas	UD
28	Kuvlum	1992	Oil	UD	67	N. Middle Ground Shoal	1964	Gas	UD
29	Fiord (Colville Delta)	1992	Oil	UD	<p style="text-align: center;">Abbreviations</p> <p style="text-align: center;">P = producing UD = undeveloped ABND = abandoned SI = shut in = discovered prior to competitive leasing, 12/59</p>				
30	Kalubik (Colville Delta)	1992	Oil	UD					
31	Cascade	1993	Oil	UD					
32	Sourdough	1994	n/a	UD					
33	Meade	1950	Gas	UD					
34	Wolf Creek	1951	Gas	UD					
35	Gubik	1951	Gas	UD					
36	Square Lake	1952	Gas	UD					
37	East Umiat	1963	Gas	UD					
38	Kavik	1969	Gas	UD					
39	Kemik	1972	Gas	UD					

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 99801

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 (Tyonek 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. Areawide 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.

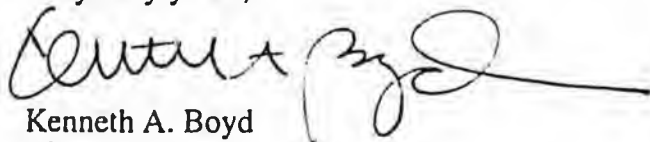
Moreover, it does not protect the state's interest if oil prices rise. The bill will either:

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



ENSTAR Natural Gas Company
A DIVISION OF SEAGULL ENERGY CORPORATION
3000 Spenard Road
P.O. Box 190288
Anchorage, Alaska 99519-0288
(907) 264-3681

Richard F. Barnes
President

December 5, 1997

Anchorage Caucus
Alaska State Legislature

We would like to have the Anchorage Caucus pass a resolution supporting the sale of State royalty gas from Cook Inlet to supply the needs of local users.

We are concerned about ensuring an adequate natural gas supply for Alaskans. We are working with Cook Inlet producers to try to develop new supplies. Along with these reserves that may be developed, we want to contract to purchase the state's Cook Inlet royalty gas. The state's share will not solve all of our supply shortfall, but it will take us part way there, with the balance coming from new sources.

The red lines on the map (first slide) show the location of our high-pressure transmission pipelines. Distribution mains and service lines branch out from this system. In all, we have about 5,000 miles of pipelines extending from as far south as Kalifornski Beach on the Kenai Peninsula to the Houston High School, north of Wasilla. From this system we deliver natural gas at 97,000 locations. We serve over half of the homes and businesses in the entire state. Because of widespread use, your constituents have a very large stake in the security of gas supplies to meet their heating needs.

The next slide shows annual use of gas produced from fields located in and around Cook Inlet. Two industrial plants on the Kenai Peninsula use the majority of production: the LNG plant owned by Phillips and Marathon and the ammonia/urea plant owned by Unocal. Power use is for Chugach Electric, ML&P and the military bases. Gas utility is for gas purchased by ENSTAR for its customers and gas transported by ENSTAR for direct users or third-party marketers. Field operations include gas for lifting, processing, pumping and compressing oil and gas. Note that the total produced in 1996 was 225.4 billion cubic feet. I will compare this production rate to what is left and what has been discovered over the past 30 years.

The next slide shows how much gas is left in Cook Inlet and who controls the gas. The total reserve number is from Alaska Division of Oil and Gas estimates. Phillips and Marathon argued in their export license extension application that there might be 10% more reserves than the state's number. Our consultants believe that the state's estimate may be high. From a big-picture view, it probably doesn't matter that much as to who has the best number. At the end of 1997, the state's number would be around 3,000 Bcf. A 10% difference, or 300 Bcf, would extend supplies only about 16 months at the 225 Bcf per year rate (previous slide). As a separate issue, you know we are questioning the wisdom approving

the LNG extension (2004-2009) at this time because of the proven reserve situation. I hope you can understand why we have taken this unpleasant position in light of projected reserves crashing during that period. The primary point here is to underscore the unsustainable rate of gas production compared to what is left in known reservoirs.

The next slide shows what rate-of-production from proven gas supplies is implied. After 2004, the annual amount that needs to be produced exceeds what you can reasonably expect to produce from known reservoirs.

Some say that there is lots of gas in Cook Inlet and that all we have to do is drill for it and it will be found. We hope that turns out to be the case; however, the data does not support that contention. The next slide shows annual exploration wells drilled and the resulting new fields discovered. From 1957 to 1965 there were great drilling successes in the basin. Most gas being produced today still comes from the very large fields discovered during this time period. However, those large fields are depleting at a rapid rate. From 1966 through 1996, another 146 exploratory wells were drilled, but with limited success.

The next slide shows what the 146 exploratory wells produced in the way of new gas and oil fields. West Forelands (Stewart Petroleum) and Sunfish (ARCO/Phillips) oil discoveries – both small fields. And, three modest gas fields: Cannery Loop, Stump Lake and Ivan River. In this 30-year effort approximately 210 Bcf of gas was discovered in new fields, which amounts to less than one year of current production (225Bcf). The last gas field was discovered in 1979, 18 years ago.

Another way of expressing past exploration versus production is that we are producing gas at 30 times the rate that we are discovering new supplies.

The next slide shows ENSTAR's projected purchases as the total of the stacked bars. The blue is gas produced from the Beluga gas field (Chevron, ARCO and ML&P). The red is from Marathon. The green and yellow totals are gas supplies that we need to obtain. The green shows the effect that obtaining state royalty in kind gas would have on our supply situation. As you can see, the state's share alone would not supply all of our needs, but it would provide a meaningful layer to our supply needs. Our shortfall is projected to begin in 2002. We have four years left at full supply.

The last slide shows how a pipeline spur from an export gas pipeline could bring significant supplies of gas to Cook Inlet users. It would be a good, long-term fix for our area. However, we cannot stand by while waiting for the owners of the North Slope gas to decide that the timing is right to commit gas to export. For now, we must work with what is closer at hand. It would be imprudent to bet on speculative discoveries and construction of the North Slope gas pipeline to keep the heat on for half the state's population.

We believe that the Cook Inlet royalty gas should be committed to local users at this time. We are offering to pay to the state a price that is at least as much as the producers are now paying for the value of royalty gas taken for their purposes, or the same amount as ENSTAR pays its suppliers, whichever is higher. Currently, ENSTAR pays its suppliers more than the state receives from the producers in royalty payments. So, there would be no subsidy by the state and probably no increased cost to consumers.

December 5, 1997

We hope that the Anchorage Caucus can support our effort. We re-sell gas at the same price we pay at the wellhead. Our operating margins come from use of the pipeline system. And because we have a very efficient system, our rates are among the lowest in the country. We would appreciate your support in keeping this benefit working for Alaskans.

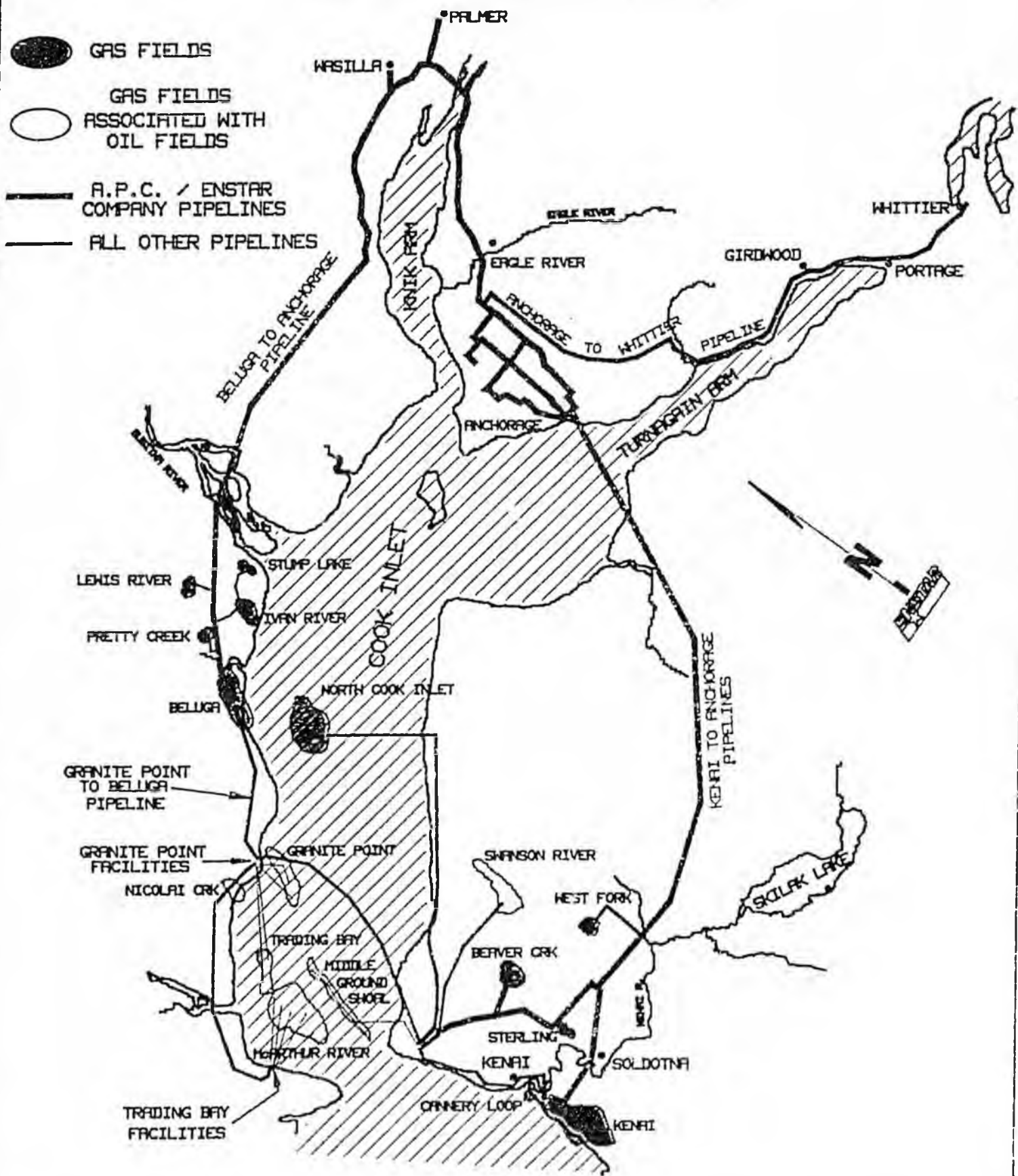
Please let me know if you have questions.

Very truly yours,



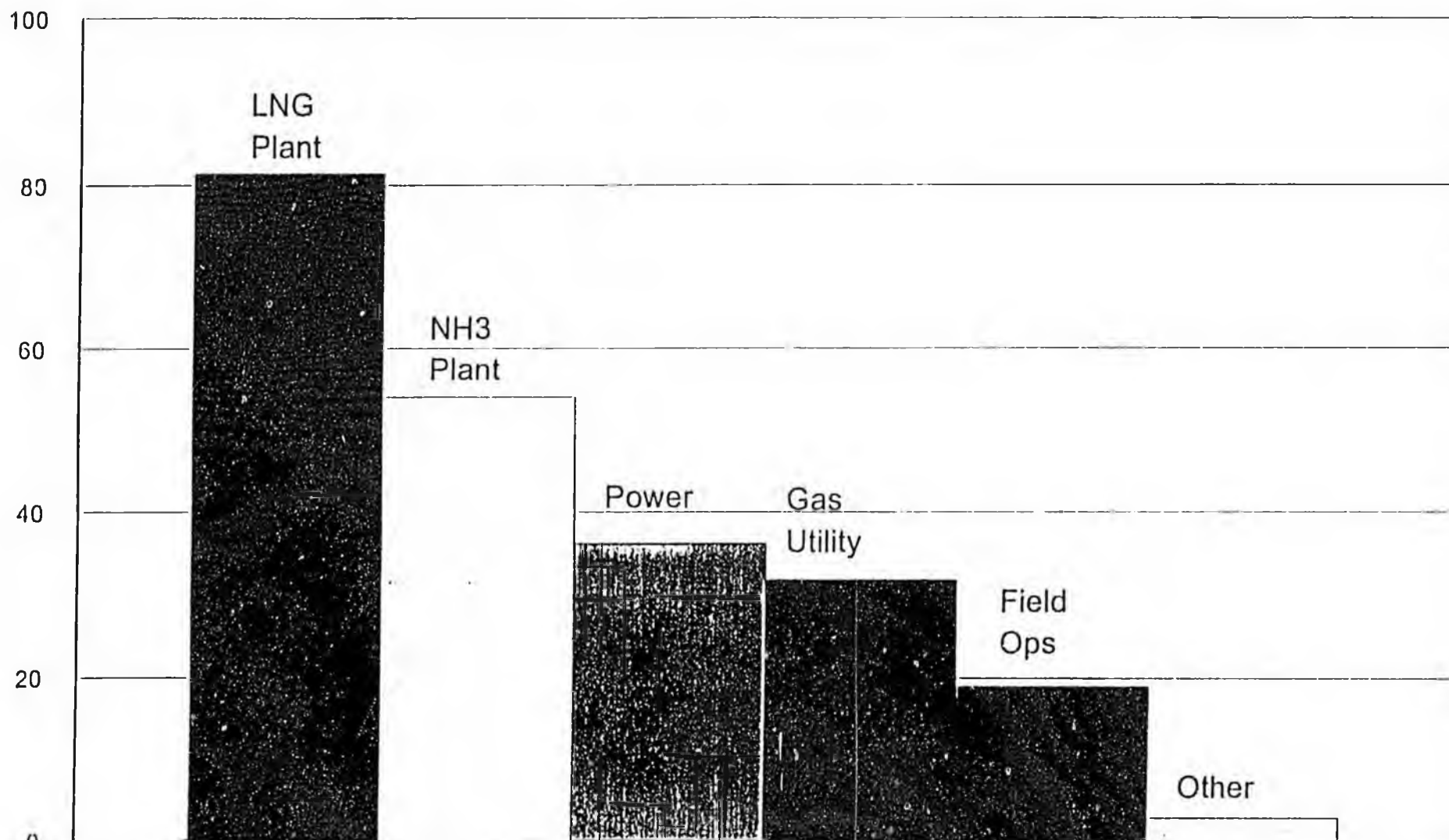
Encs.

ALASKA PIPELINE COMPANY / ENSTAR NATURAL GAS COMPANY GAS TRANSMISSION SYSTEM



1996 End Use of Cook Inlet Gas Production

Annual Volume (Bcf)

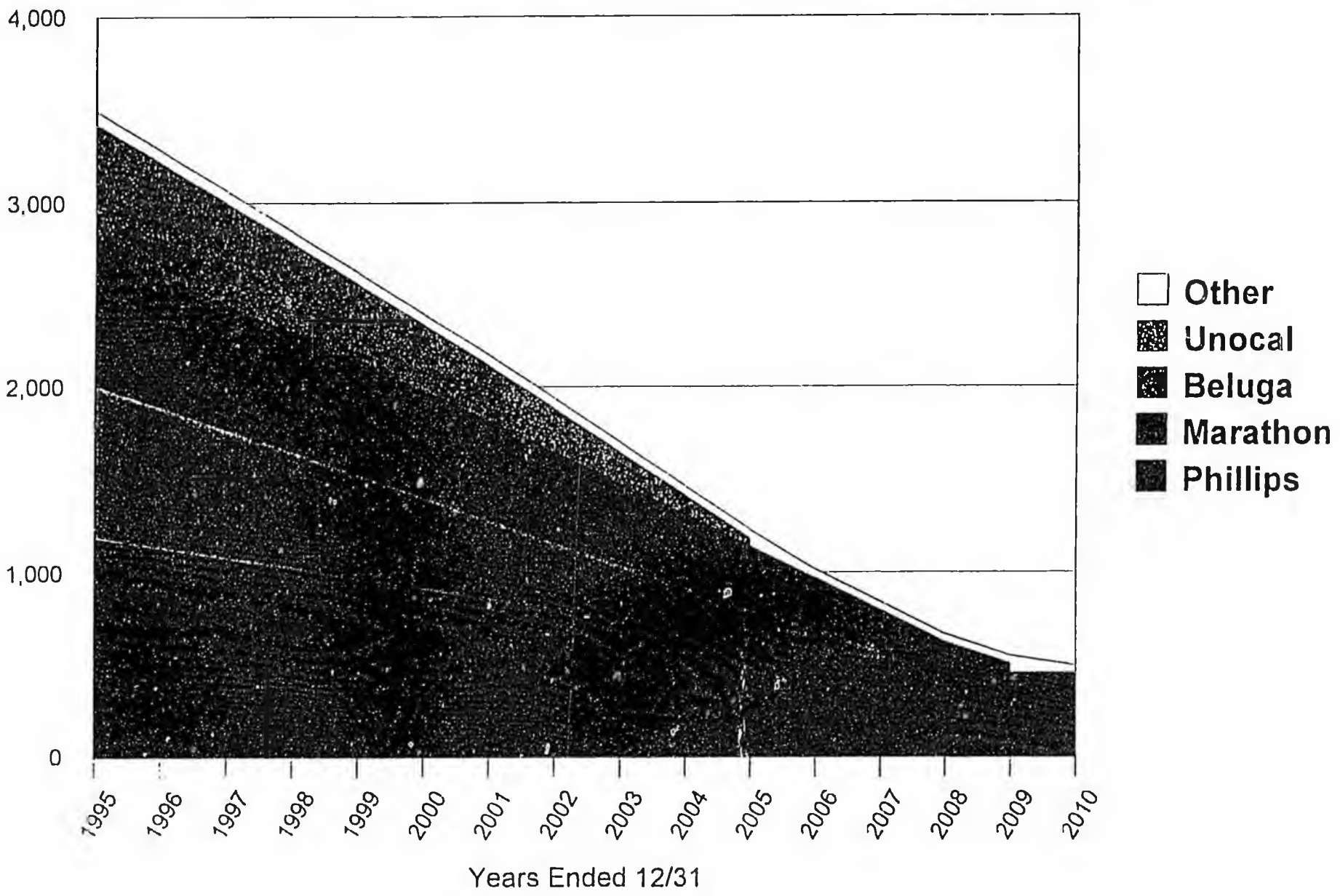


Total Use 225.4 Bcf

Source: AK Dept. of Natural Resources 4/97 Report

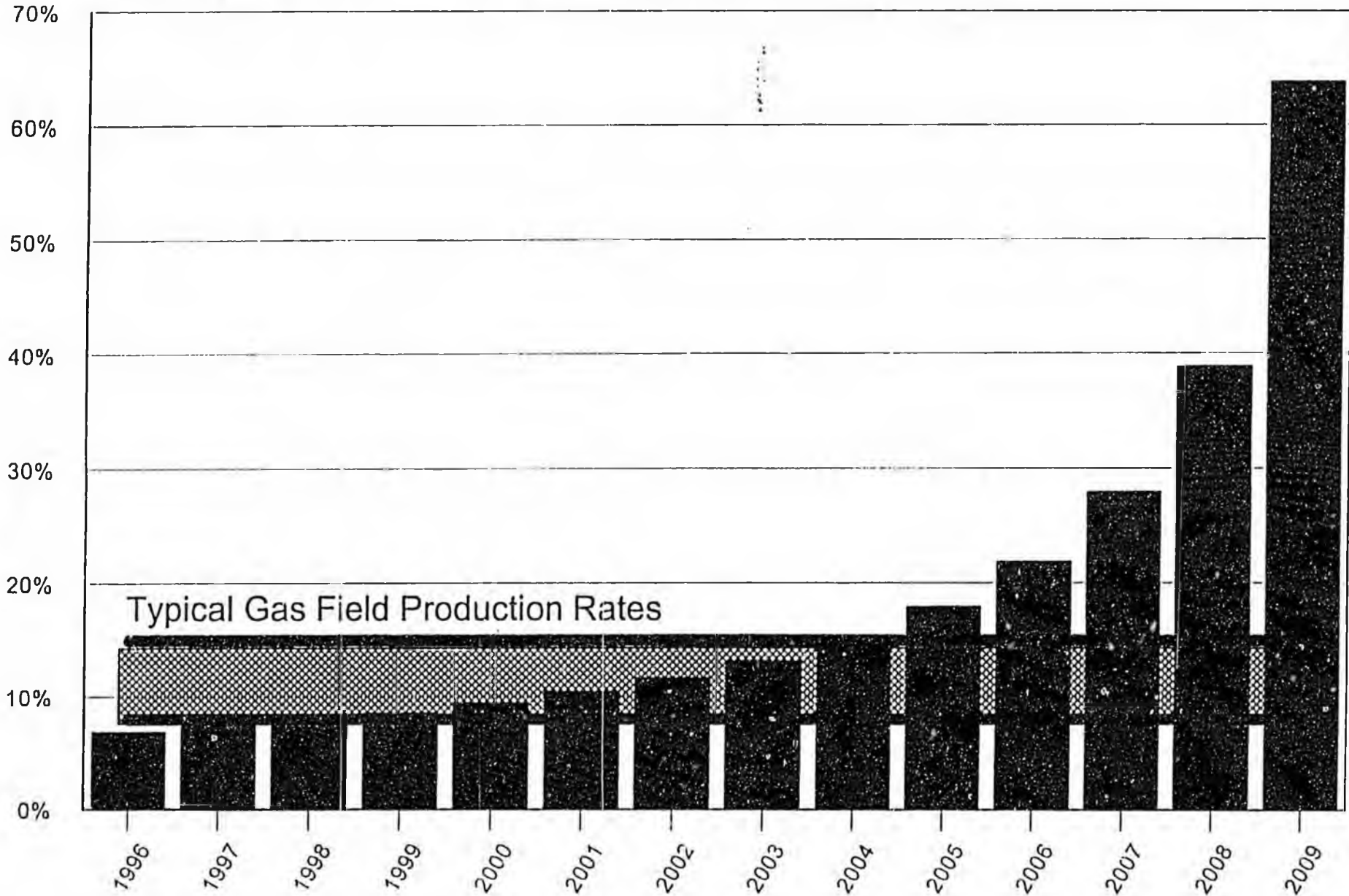
Estimated Remaining Cook Inlet Gas Reserves (In Bcf)

Assumes LNG Contract Extension. Based on Alaska DNR 1/97 Report.



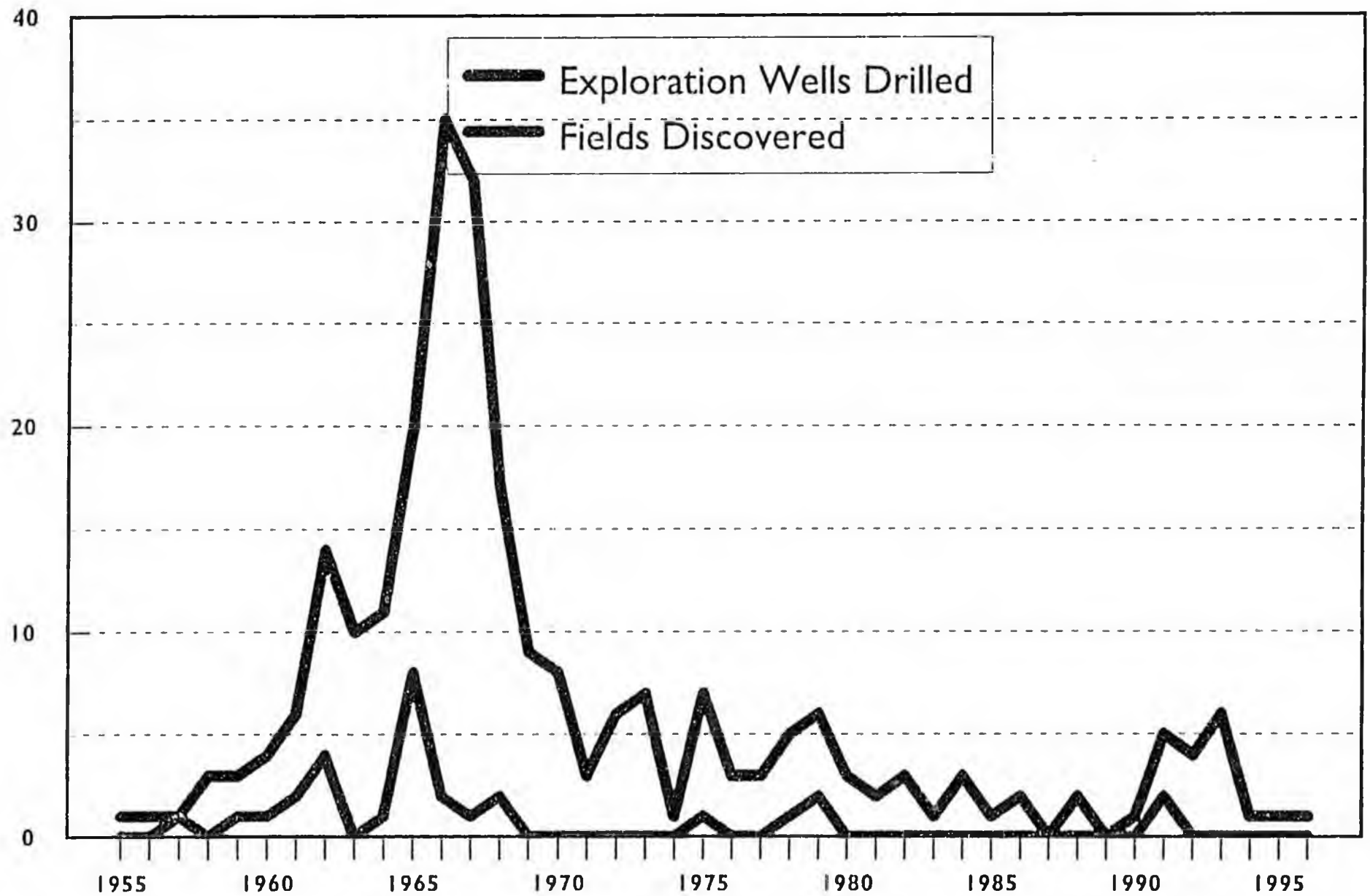
Production Rate as a Percentage of Remaining Reserves

Assumes Annual Production at 1996 Levels (225 Bcf per Year)



Cook Inlet Exploration Results

Oil and Natural Gas

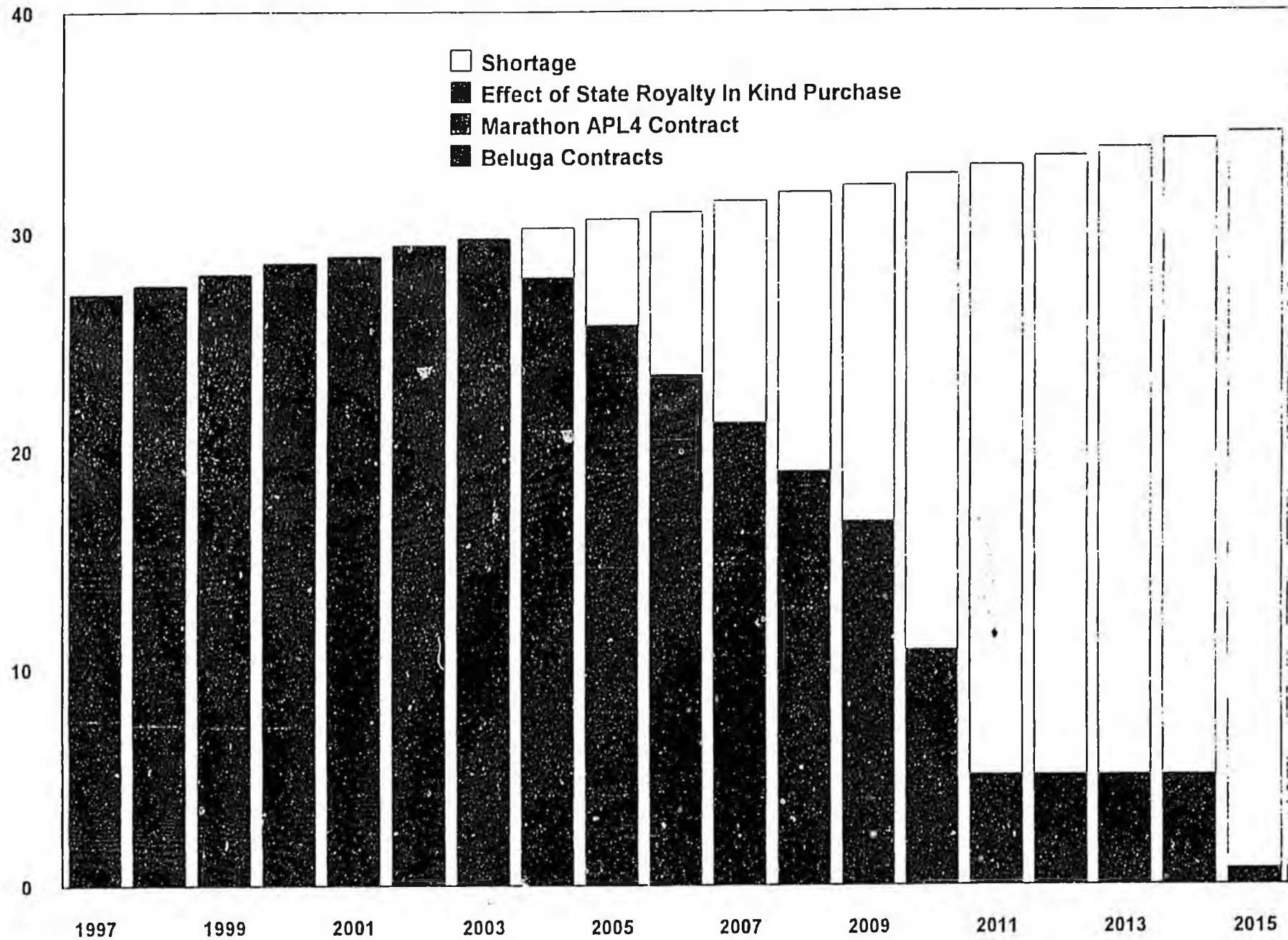


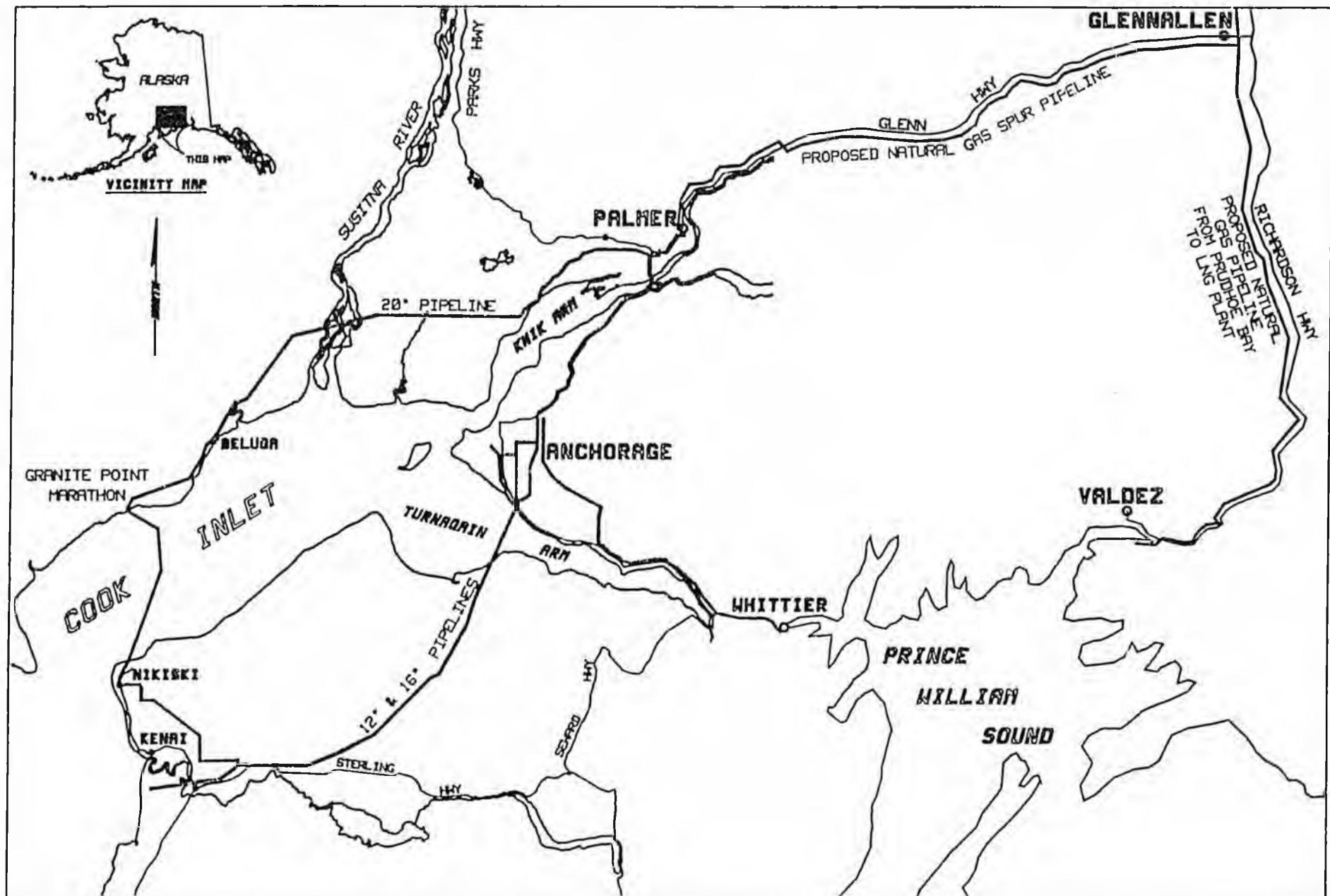
Cook Inlet Discoveries 1966-1996

Exploration Wells Drilled	Commercial Success Rate	Commercial Oil Fields Discovered	Commercial Gas Fields Discovered
146	3.42%	2	3
		West Forelands Sunfish	Cannery Loop Stump Lake Ivan River (210 Bcf)

Last Commercial Natural Gas Field Discovered in 1979

Projected ENSTAR Gas Purchases in Bcf





Proposed resolution
Anchorage Caucus
Alaska Legislature

COOK INLET ROYALTY GAS CONTRACT

WHEREAS, approximately one-half of Alaska's population and over half of Alaska's businesses are located in Southcentral Alaska, and

WHEREAS, this large segment of Alaska's population and commercial activity depends on affordable natural gas produced from Cook Inlet for its basic energy needs, and

WHEREAS, the State of Alaska owns approximately one-eighth of the gas produced from state leases located in the Cook Inlet area, and

WHEREAS, the State has the right to take royalty gas in kind rather than accept payment for royalty gas taken by producers, and

WHEREAS, meeting local needs is a State priority use of natural gas, and

WHEREAS, use of royalty gas could play an important role in meeting a portion of future local needs,

NOW, THEREFORE, IT IS RESOLVED, that the Anchorage Caucus of the Alaska Legislature requests that the Governor, acting through the Commissioner of Natural Resources, negotiate a State royalty gas sales contract with ENSTAR Natural Gas and Alaska Pipeline Company, the utilities that are certificated by the Alaska Public Utilities Commission to serve Anchorage and the surrounding Southcentral Alaska communities, and

FURTHER RESOLVED, that the administration submit to the legislature an executed contract for approval in the 1998 legislative session.



Alaska Pipeline Company
A SUBSIDIARY OF SEAGULL ENERGY CORPORATION
3000 Spruce Leaf Road
P.O. Box 10016
Anchorage, Alaska 99519-0288
(907) 277-5551

Richard F. Barnes
President

November 4, 1997

Honorable Dave Donley
Co-Chair
Anchorage Caucus
Alaska Legislature

Dear Senator Donley:

Following up on our previous conversation, I have attached a draft resolution for the Anchorage Caucus' consideration. I would greatly appreciate your distributing this draft at your November 5th meeting and taking action on this matter at the earliest appropriate time.

Over the past two weeks, we have met with numerous members of the Anchorage Caucus and intend to fully brief each member.

As we discussed, a state royalty gas contract with ENSTAR would prove to be a win-win situation: ensuring that Southcentral consumers would enjoy a secure source of energy at an affordable cost while providing the State of Alaska with more revenue than it otherwise would receive from the producers.

Thank you for your interest in this issue that affects our 96,000 customers. We look forward to working with you to make this addition to our gas supply possible.

Very truly yours,

A handwritten signature in cursive script that reads "R. F. Barnes".

Attachment

Unocal Alaska Resources
Unocal Corporation
909 West 9th Avenue, P.O. Box 196247
Anchorage, Alaska 99519-6247
Telephone (907) 263-7600
Facsimile (907) 263-7698

UNOCAL 76

RECEIVED
DEC 08 1997

Ans'd.....

Kevin A. Tabler, Manager
Land/Government Affairs

December 8, 1997

Senator Dave Donley
Co-Chair Anchorage Caucus
716 West 4th Avenue, Suite 430
Anchorage, AK 99501-2133

Re: Anchorage Caucus Meeting
December 10, 1997
Executive Summary of Submittal

Dear Senator:

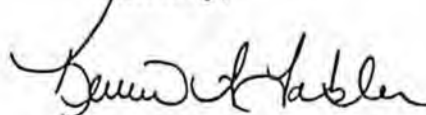
In response to your notification of the December 10, 1997, Anchorage Caucus meeting, Union Oil Company of California (Unocal) submits the attached analysis of State of Alaska Royalty In Kind Gas Sales to Enstar. This summary of the attached, highlights the salient points of our analysis and is provided for your review and use at the December 10, meeting:

- There is considerable debate on the adequacy of Cook Inlet gas reserves to meet demand in Southcentral Alaska.
- ENSTAR is seeking to contract for gas supplies to cover a supply shortfall commencing 2002
- ENSTAR seems unable to reach agreement on the purchase of additional gas supplies from any of the current Cook Inlet producers.
- State Royalty Gas should be reserved for domestic users in times of shortage.
- Unocal supports State sales of Royalty Gas to domestic users, e.g. ENSTAR, ML&P, Chugach Electric, Homer Electric and Unocal's Kenai Plant.

The attached document provides a more detailed discussion of the issues and Unocal's reasons for support of ENSTAR's proposal.

Thank you for the opportunity to participate in the December 10, 1997, meeting.

Sincerely,

A handwritten signature in cursive script, appearing to read "Kevin A. Tabler".

Kevin A. Tabler

cc: Anchorage Caucus
w/attachment

UNION OIL COMPANY OF CALIFORNIA

In Support of a Sale of State Royalty Gas to ENSTAR

We appreciate this opportunity to be heard today and to present Unocal's view on the future of Cook Inlet gas supply and deliverability for Southcentral Alaska. We will present Unocal's views in support of a sale of State Royalty gas to ENSTAR.

Unocal

Unocal's activity in Alaska started in the early 1900's, when we began selling petroleum products throughout the Territory. We have participated in every major lease offering and explored in geologic basins statewide. Our early exploration successes were located in and around the Cook Inlet. It is the area we know best and one in which we have concentrated our efforts. For the last seven years, we have consolidated and restructured our Alaskan operations to take advantage of our strength as the lowest cost producer in Cook Inlet. We have, through purchase and exchange of properties, positioned ourselves to have the most cost effective operation possible. Most recently, the consolidation of our organizations under a single management structure for upstream oil and gas operations and our downstream fertilizer plant has created a fully integrated Alaskan operation. We have a clear understanding of the Cook Inlet gas market and have focused our attention on future gas supplies and deliverability. Unocal is uniquely positioned to help facilitate a long-term solution to the energy needs of Southcentral Alaska. We are also actively searching for new gas reserves in this very mature gas province.

Unocal is both a producer and consumer of natural gas in the Cook Inlet. We operate properties that produce 250 mmscf/d of natural gas, representing 45% of the production in the area. The Unocal-owned share of this production is dedicated and supplied to

Unocal's Agricultural Products Plant in Nikiski on the Kenai Peninsula (Unocal's "Kenai Plant").

We employ 630 Alaskans and provide indirect employment for numerous full-time contract personnel, service companies and suppliers, making us the largest private employer and taxpayer on the Kenai Peninsula.

Introduction

We would like to share with you our knowledge and experience of the Cook Inlet gas business, as well as our vision of the future for Cook Inlet gas supplies. We will give you: a brief history of Cook Inlet gas exploration and production; Unocal's view of the reserves picture and the ability of producers to supply the gas markets; the outlook as we eventually move toward a time of shortfall in winter gas deliverability and how we can best meet that challenge; and, of course, an explanation as to how we believe we can meet our long-term needs when Cook Inlet gas reserves are depleted.

Additionally, we will present to you Unocal's thoughts on the role of the Cook Inlet gas producers, the role of the State of Alaska and the role North Slope gas will play in the future. Central to the question of gas supply for Southcentral Alaska is the disposition of the State's royalty share of natural gas production -- both from the Cook Inlet and ultimately from the North Slope.

Reserves & Deliverability

More than 8 trillion cubic feet of natural gas has been discovered in Cook Inlet. Over 90% of this gas is, or was, in fields discovered more than 30 years ago. Today, Unocal estimates remaining Cook Inlet gas reserves to be about 3.2 trillion cubic feet.

Estimates in the industry vary from 3.2 to 3.6 trillion cubic feet. With annual

consumption at 220 billion cubic feet, differences in reserves estimates equate to no more than 2 years of gas supply.

Simple arithmetic could lead us to think that there is sufficient gas to supply current users for between 15 and 17 years. However, such a simple analysis ignores a more important issue, the one of "deliverability". The critical question is -- "Can the remaining Cook Inlet reserves be produced at high enough rates to meet the peak winter demand on any one day?" Deliverability is determined by the ability of the pressure in the existing gas reservoirs (together with the wells, production facilities, compressor stations and the pipelines) to supply natural gas at the rates required by the consumers.

To further understand the importance of deliverability, one must also understand at what times of the year consumers need this gas.

There are three major groups of users or consumers of natural gas in Southcentral Alaska: utilities such as ENSTAR and Chugach Electric; in-state manufacturing plants such as Unocal's Nikiski Plant; and LNG exporters, i.e. the Phillips/Marathon LNG Plant. The utilities are the only users whose gas consumption changes substantially through the year. Demand is high during the cold, dark winter months and low during summer months. Other users require gas to be delivered at more or less constant rates. So, though utilities may only consume 30% of all gas produced in any one year, they draw up to 50% of the production in the winter, but little more than 10 or 15% of the production in the summer. The ability of producers to meet these swings in demand hinges on "deliverability".

A simply analogy for a "deliverability shortfall" might be: there are a lot of hungry people, an adequate supply of wheat; but you can't make bread fast enough to feed them.

Unocal's Deliverability Forecast

Unocal's forecasts suggest that even with timely capital investments and accelerated development of known reserves in the Cook Inlet, there will be a shortage of deliverability within 7 or 8 years. It will then be necessary for the producers and users to invest in and use, storage or "peak-shaving" facilities. As a result, gas prices for periods of high demand, in the winter months, will be higher than prices today.

Storage and peak-shaving are common practices in gas markets of the Lower 48. Alaska has in the past enjoyed the luxury of a large deliverability surplus. This may soon come to an end.

It might surprise you to know that the Cook Inlet gas market has actually been benefiting from gas storage since 1986. The Unocal-operated Swanson River Oil Field is currently producing gas that was originally injected in a time of market surplus to enhance oil recovery in the field. This "stored" gas is now being produced. Thus, the Cook Inlet gas market has, for some time, been consuming more gas than is produced from the original gas reservoirs of the Cook Inlet.

While the industry can manage the deliverability shortfall for a period of time, there will ultimately be a supply shortfall. This will occur when storage operations are unable to offset the deliverability shortfall. Based on Unocal's reserves projections, this would happen by about the year 2006.

Current Reserves Commitments

Unocal's analysis of the commitments of gas reserves to the gas users can be summarized as follows (remember that I previously mentioned there were only three gas markets in Cook Inlet):

Utilities – ML&P and Chugach appear to have gas supplies to cover their markets through the year 2010, though the adequacy of those supplies may be in question. ENSTAR has a need for new supplies and, more importantly, deliverability, starting in the year 2002.

In-state manufacturing - Unocal has sufficient supplies to sustain its Kenai Plant through the year 2006.

LNG Export - the LNG exporters have sufficient supplies through the term of their current export license (which expires in 2004), and for some period thereafter.

Managing Our Way To The Future

The future can be managed, but it is going to require active participation and cooperation on the part of the State of Alaska, all producers and consumers. In developing a long-term strategy for meeting the natural gas needs of Southcentral Alaska, we should think in terms of both reserves and deliverability. We must manage the initial deliverability shortfall problem first and then, ultimately, the supply shortfall.

Action by the State of Alaska

The State of Alaska clearly puts a priority on gas supplies to domestic users and, in particular, on gas supplies to the utilities. The priority for use of the State's Royalty-In-Kind gas is: first, domestic utilities (ENSTAR, Chugach, etc.); second, in-state manufacturing (e.g. Unocal's Nikiski Plant); and last, exports such as the Phillips/Marathon LNG Plant. Domestic users must have a reliable gas supply and it would be prudent for the State to divert Royalty-In-Kind gas to these users.

With the importance of utilities, "guaranteed" gas supplies are needed. Utilities cannot be asked to simply hope for future exploration success. ENSTAR and others should be guaranteed supplies from the State's Royalty-In-Kind gas.

Alaska's natural gas consumers look to the State to monitor supply and demand, and to regulate where necessary to ensure the adequacy of domestic supplies of natural gas.

Action by ENSTAR

ENSTAR must, of course, access gas supplies for its customers before it can avail itself of a storage service. Our understanding is that discussions are underway with certain producers to acquire a reliable supply of gas. These producers must satisfy ENSTAR's need for a long-term, stable supply and at a competitive price.

In the absence of being offered an assured gas supply to fill its needs as of the year 2002, ENSTAR has asked the State of Alaska to enter in to an agreement to sell the State's Royalty share of Cook Inlet natural gas production.

If the State of Alaska supplies Royalty gas to ENSTAR, then it will be necessary for ENSTAR to store or "park" that gas so that it may be used at times of high demand. Such a storage or "parking" service is available from Unocal.

Action by Unocal

Unocal is taking action to help manage the future. However, its actions alone will not solve the inevitable Cook Inlet supply and deliverability problems. A storage and peak-shaving gas service is needed to address the imminent deliverability shortfall. Unocal has recognized and positioned itself to satisfy this essential requirement. Unocal has the reservoirs, the facilities and the practical experience to quickly develop this capability for Cook Inlet. As a first step, we are already discussing storage services with ENSTAR. Commitment to a storage and/or peaking service will require significant

investment. It is not yet clear whether the utility markets can absorb the costs of such a project for the short-term fix that would be achieved before an overall supply shortage appears in about 2006. Unocal's Kenai Plant's steady, base load demand for gas allows Unocal to provide a "parking" service for Royalty gas purchased now by utilities, in anticipation of a long-term need. Investment in further wells, facilities and pipelines would allow Unocal to redeliver "parked" gas at times of high demand.

The second step in Unocal's plan is to add gas reserves. To help prolong the life of the Kenai Plant, a domestic user of gas, Unocal will be exploring for additional gas reserves. This explains Unocal's aggressive lease acquisitions in the State of Alaska's Lease Sale 85A. We believe that though exploration is unlikely to result in discovery of major new gas fields, modest reserves additions may be made and will play a part in the interim supply picture. However, continual State lease sale litigation restricts access and delays evaluation of any remaining natural gas potential in the Cook Inlet area. Nor should we fool ourselves, Cook Inlet is a mature hydrocarbon province and modest natural gas reserves additions alone will not solve the supply shortfall and deliverability problems. The attached map shows the historical exploration and development drilling activity in the Cook Inlet.

A third step is also underway. Consumers such as Unocal's Kenai Plant must ensure that natural gas is used efficiently and conserved where possible. Unocal is actively pursuing several major projects to improve energy conservation.

In the long run, a large supply of affordable gas will be required to meet the energy needs of Southcentral Alaska. With the domestic needs of this geographic area growing and the majority of the population located there, the only logical and identifiable source of gas is on the North Slope. We see TAGS pipeline owners and the North Slope producers as the major, long-term suppliers of gas to Southcentral Alaska.

The only questions are: "When will North Slope gas be available in Southcentral Alaska?" and "What must the State, Cook Inlet producers, and consumers and users do to manage limited gas reserves and deliverability until North Slope gas arrives?"

In conclusion, it is important that everyone understands the gas market in Cook Inlet is changing. Picture, if you will, three stages in a process: starting with ample reserves and supply; then moving down the line to a period of deliverability shortfall; finally, arriving at a supply shortfall. In Cook Inlet, we are rapidly moving from the ample reserves stage to the deliverability shortfall stage. We know this to be true, because for a brief period of time in January of this year, Murphy's Law took over, and a combination of extremely cold weather and mechanical failure ultimately led to litigation that centers on the deliverability issue.

Unocal stands ready, willing and able to help facilitate a workable, long-term plan for the natural gas needs of Southcentral Alaska. But, it will require the cooperation of all to succeed.

As new supplies of natural gas are uncertain, Unocal supports the reservation of the State's Royalty gas for domestic use, with utilities such as ENSTAR having the highest priority in seeking supply.

James E. Eason

Oil and Gas Operations, Management and Policy

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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

Oil and Gas Operations, Management and Policy
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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	1,077,982	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
	18,822,582	188,225,820	9,411,292	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

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.

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

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

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

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

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

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 10,000 bbl/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.

02/20/98
16:01:59

LEGISLATIVE TELECONFERENCE NETWORK SYSTEM
PARTICIPANT LIST (ALL PARTICIPANTS)
TCN:80311 SCHEDULED FOR:02/20/98 15:30 TO 17:00
PUBLIC HEARING SENATE RESOURCES

LTN1150
BY:ANC
FOR:ANC

LOCATION: ANCHORAGE

SB 286	MR	CHARLES	MCKEE		TESTIFY
SB 256	MR	KEN	BOYD	DIV OIL & GAS	TESTIFY
SB 256	MR	KEVIN	TABLER	UNOCAL	TESTIFY
SB 256	MR	JOHN	MIESSE	MARATHON	TESTIFY
SB 256	MR	PATRICK	COUGHLIN	ANSWER QUESTION	TESTIFY

02/20/98 15:30:59 LEGISLATIVE TELECONFERENCE NETWORK SYSTEM
MESSAGE FROM: LIOCJEN IN ANCHORAGE

LTN1120
JNU

RE TCN: 80311 SCHEDULED FOR:02/20/98 15:30 TO 17:00
SPONSOR: SENATE RESOURCES PURPOSE: PUBLIC HEARING

MESSAGE TEXT: KAREN COWART IS ON LINE (OFFNET CALLER) *SB 256*