ALASKA LEGISLATURE COMMITTEE FILES 1995-1996 8672

8966 SENATE RESOURCES

stated that if Congress wanted to impose such a requirement, "it could have easily so provided. It did not." Id. at 62.

Likewise, had the legislature intended to reward only production, it could have easily awarded a reduced royalty to the first producer in the structure like the Territorial legislature did. But, it did not. I will not equate discovery with production.

As explained in detail in the Decision, the G-1 well did not make the first discovery of oil and gas in the SOS structure.[3] Conoco knew not only of the existence of oil bearing structure, but also the supergiant size of the accumulation, before it drilled. It did not bear any exploratory risk.

Even if Conoco's argument was correct, it would not be entitled to discovery royalty because previous wells demonstrated commercial quantities.

The G-1 well was hardly the first well into the SOS that yielded "acceptable evidence" of commercial quantities in the discovery zone. As explained in the Decision, many wells, including Conoco's own A-1, B-2, A-3, and N-1B wells, drilled and tested earlier in the SOS yielded that evidence. I find that the flow rates from potential tests in several of Conoco's earlier wells yielded acceptable evidence that oil could "be produced in commercial quantities." Furthermore, Arco's pilot program in the SOS structure demonstrated that the structure was currently commercial,

---

[3] Conoco cites two other discovery royalty applications in support of its idea that "first discovery" is different from "first encounter." Neither of the cited cases assist Conoco. It is true that Point McIntyre No. 3 was certified despite the fact that earlier wells had penetrated the structure. However, it is clear that merely penetrating the structure does not constitute a first discovery. In the case of Point McIntyre, the operators of the wells making those earlier penetrations (the Point McIntyre No. 1 and No. 2 wells) failed to acquire sufficient evidence of a discovery before abandoning the wells as dry holes. Such corroborative data might have included open-hole logs, tests, or core data from the discovery intervals. This sharply contrasts with the circumstances extant with Conoco's knowledge regarding the SOS, where over a billion barrels of oil were known to exist from prior exploratory drilling.

In the case of the Sag Delta No. 3 well, it encountered no productive interval at all.

albeit only marginal. See DeRuiter, Nash & Wyrick, Solubility and Displacement Behavior of Carbon Dioxide and Hydrocarbon Gases with a Viscous Crude Oil, SPE 20523 (1990).[3]

Conoco argues the failure of any previous owner to undertake commercial development demonstrates that the previous wells did not discovery commercial quantities. First, the fact that no earlier lessee applied for certification is irrelevant. Br. at 7-8. The issue is not whether others could have qualified, but whether Conoco does. Second, the other's failure to develop in not surprising, given that the owners' decision to develop the underlying more economic Kuparuk structure first for their own internal reasons.

Even under Conoco's interpretation of "discovery" any benefit from discovery royalty would have expired before the drilling of the G-1 well.

I have previously stated my opinion that the first encounter well is the discovery well. Even if I accepted Conoco's argument that the first well to produce was the discovery well, the first encounter would nevertheless start the running of the ten year reduced royalty period.

Both regulations 11 AAC 83.200 & 210 refer to the first encounter of oil and gas. 11 AAC 83.210 states

> to establish priority as to the time and date of discovery, an operator must furnish the committee with a sworn statement and substantiating evidence acceptable to the committee that oil or gas has been encountered in sufficient showing to cause a reasonable and prudent operator to conduct further operations in an effort to complete a well in the discovery zone so that the well can be tested for potential oil or gas production in commercial quantities. The statement must include the time and date of first discovery . . .

[3] Conoco misunderstands the commerciality test as defined in the regulations. Conoco would require actual commercial development as the only method of satisfying the commercial quantities test. Br. 5. The regulations only require a potential test which would in the future lead to one additional well with a reasonable profit if a market existed. 11 AAC 83.205. No actual development is required.

It is clear that "first discovery" refers to first encounter in this regulation.

Regulation 11 AAC 83.215 states that "the date of commencement of the 10 year-5 percent discovery royalty term shall be the first of the next month after the established date of initial discovery." It is clear that "initial discovery" in this regulation refers to the same event referred to in 11 AAC 83.210 as "first discovery," namely first encounter of the discovery zone. 11 AAC 83.215 bases the date of initiation of the 10 year reduced royalty on this date, which is distinct from the date in which a well establishes oil in commercial quantities. Both the division and the industry have consistently accepted that the ten year period begins to run from the date of first encounter, not confirmation or establishment of commercial quantities. See Niakuk, supra at 5. Therefore, even if I were to accept Conoco's claim that the G-1 well established commercial quantities in the SOS structure (which I do not), the date of commencement of reduced royalty would be controlled by the date of first encounter. Indisputably the date of first encounter or initial discovery of the SOS occurred more than ten years prior to the drilling of the G-1 well and subsequent initiation of SOS production ADL 25906. Therefore, none of the production from this lease would be entitled to a reduced royalty.

Conclusion

The discovery royalty expressly rewards the one who makes a "first discovery," not the one who is "first into production." I know the difference between discovery and production. Conoco knew when it drilled the G-1 well what the structure was, and, to a high degree of precision, the quantity and quality of the oil accumulation that would be encountered. Conoco faced not the risks of a dry exploration hole, but the economic risks associated with taking someone else's discovery into production. It is not my role as lease manager on behalf of the citizens of the state to transform the discovery incentive into solely a production incentive. Therefore, I affirm the Decision of the director.

Harold C Heinze

Harold C. Heinze
Commissioner

ENCLOSURE 28

MONTHLY SAVINGS ATTRIBUTABLE TO THE DISCOVERY ROYALTY PROVISION

Example Month: JULY 1994

Field	Savings
Niakuk/Lisburne	$198,768.00
Point McIntyre	$534,118.00
North Prudhoe Bay	$ 51,587.00
TOTAL	$784,473.00

SB
113

INITIAL SECTIONAL SUMMARY

3/8/95 by Kreitzer, Committee Aide

SB 113: "An Act authorizing a reduction in coal, oil and gas royalty for the producers of those minerals used in certain projects."

Section 1.: Adds the royalty reduction provision into the exploration licensing program passed by the Eighteenth Legislature (SB 150).

Section 2.: Amends the coal leasing provisions to include the royalty reduction for coal mining, production and sale or delivery for qualifying projects.

Section 3.: Adds a new subsection in the coal leasing provisions which would allow the commissioner the discretion to reduce the royalty due the state. The royalty may be calculated on either the amount or the value of the coal. The royalty may be reduced up to 50%. Qualifications for the royalty reduction:

a) coal must be used as an energy resource by the general public

b) coal must be used in a facility owned or operated by a municipality or village in the state and not more than 50 miles from the production site of the coal.

Section 4.: Adds the royalty reduction provision to the oil and gas leasing provisions.

Section 5.: Amends the oil and gas leasing provisions to include the royalty reduction.

Section 6.: Adds a new subsection in the oil and gas leasing provisions which would allow the commissioner the discretion to reduce the royalty due the state. The royalty may be calculated on either the amount or the value of the oil or gas. The royalty may be reduced up to 50%. Qualifications for the royalty reduction:

a) oil or gas must be used as an energy resource by the general public

b) oil or gas must be used in a facility owned or operated by a municipality or village in the state and not more than 50 miles from the production site of the oil or gas.

c) the facility may not be connected to an existing pipeline.

SENATE BILL NO. 113

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINETEENTH LEGISLATURE - FIRST SESSION

BY THE SENATE RESOURCES COMMITTEE

Introduced: 3/7/95
Referred: RES, FIN

A BILL

FOR AN ACT ENTITLED

"An Act authorizing a reduction in coal, oil, and gas royalty for the producers of those minerals used in certain projects."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

*** Section 1.** AS 38.05.134 is amended to read:

Sec. 38.05.134. CONVERSION TO LEASE. If the licensee requests and the commissioner determines that the work commitment obligation set out in an oil and gas exploration license issued under AS 38.05.132 has been met, the commissioner shall convert to one or more oil and gas leases all or part, as the licensee may indicate, of the area described in the exploration license that remains after the relinquishments, removals, or deletions required by AS 38.05.132(d)(2). A lease issued under this section

(1) is subject to the acreage limitations imposed by AS 38.05.140(c);

(2) is subject to AS 38.05.180(j) - (m), (o) - (u), and (x) - (z);

(3) must be conditioned upon a royalty in amount or value of not less

than 12.5 percent of production**, except that a lessee who, proceeding under AS 38.05.131 - 38.05.134, produces oil or gas that is used in a project that qualifies under AS 38.05.180(dd) is entitled to the reduction in royalty authorized by that subsection**;

(4) must include an annual rent of $3 per acre or fraction of an acre initially paid to the state at inception of the lease and payable annually after that until the income to the state from royalty under that lease exceeds the rental income to the state under that lease for that year; and

(5) is subject to other conditions and obligations that are specified in the lease.

* **Sec. 2.** AS 38.05.150(d) is amended to read:

(d) For the privilege of mining or extracting the coal in the land covered by the lease, the lessee shall pay to the state the royalties specified in the lease. The royalties shall be fixed before offering the lease, **except that a lessee who produces coal and sells or delivers it to a project that qualifies under (f) of this section shall pay the royalty determined under that subsection,** and shall be effective for a period of not more than 20 years. The royalties shall be not less than five cents a ton of 2,000 pounds. The lessee shall also pay an annual rental, payable at the date of the lease and annually thereafter, on the land or coal deposits covered by the lease, at a rate fixed by the commissioner before offering the lease. The annual rental shall be effective for a period of not more than 20 years. The annual rental shall be not less than 25 cents an acre for the first year of the lease, not less than 50 cents an acre for the second year, third year, fourth year and fifth year, and not less than $1 an acre for each year thereafter during the continuance of the lease. The rental for each year shall be credited against the royalties as they accrue for that year. Each lease shall provide that the annual rental payment is subject to adjustment at intervals of no more than 20 years and adjustments shall be based on the current rates for properties similarly situated.

* **Sec. 3.** AS 38.05.150 is amended by adding a new subsection to read:

(f) For coal produced from a lease and sold or delivered for use in a project that qualifies under this subsection, the commissioner may reduce the royalty on the amount or value of the coal produced and delivered to the project, not to exceed a reduction of 50 percent in the royalty rate, as the commissioner may determine. Sale of coal for a project qualifies for a royalty reduction under this subsection if the commissioner determines that

(1) the sale or delivery of the coal for which the reduction in the royalty is sought is to a facility that converts the coal for use as an energy resource by the general public; and

(2) the facility to which the coal is sold and delivered is

(A) owned or operated by

(i) a municipality; or

(ii) a village, as that term is defined in AS 46.03.900; and

(B) located in the state and not more than 50 miles from the point of production of the coal.

* Sec. 4. AS 38.05.180(f) is amended to read:

(f) Except as provided by AS 38.05.131 - 38.05.134, 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** [. 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 [. 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 [. FOLLOWING] a pre-sale analysis, the commissioner may choose at least one of the following leasing methods:

(A) [(1)] 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) [(2)] 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;

(C) [(3)] 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) [(4)] a fixed cash bonus with the share of the net profit derived from the lease reserved to the state as the bid variable;

(E) [(5)] 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) [(6)] 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) [(7)] 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, a lessee who produces oil or gas and sells or delivers it to a project that qualifies under (dd) of this section shall pay the royalty determined under that subsection.

* Sec. 5. AS 38.05.180(w) is amended to read:

(w) Notwithstanding any other provisions of this section, land that [WHICH] has been offered for lease within the previous five years and that [WHICH] received no bids at competitive sale or for which no bid was accepted may be, at the discretion of the commissioner, immediately offered for lease, under regulations adopted by the commissioner, upon terms appearing most advantageous to the state; however, noncompetitive leasing is prohibited. The commissioner shall establish a royalty determined to be in the public interest but not less than <u>12.5</u> [12 1/2] percent**<u>, subject to reduction under (dd) of this section</u>**. A lease must provide for payment to the state or rental but need not adhere to the rental schedule in (n) of this section nor to the 5,760-acres-per-lease limitation in (m) of this section. The lease term may not exceed 10 years, except as provided in (o) of this section.

*** Sec. 6.** AS 38.05.180 is amended by adding a new subsection to read:

(dd) For oil or gas produced from a lease and sold or delivered for use in a project that qualifies under this subsection, the commissioner may reduce the royalty on the amount or value of oil or gas produced and delivered to the project, not to exceed a reduction of 50 percent in the royalty rate, as the commissioner may determine. Sale of oil or gas for a project qualifies for a royalty reduction under this subsection if the commissioner determines that

(1) the sale or delivery of the oil or gas for which the reduction in the royalty is sought is to a facility that converts the oil and gas for use as an energy resource by the general public; and

(2) the facility to which the oil or gas is sold and delivered is

[illegible]

(A) owned or operated by

(i) a municipality; or

(ii) a village, as that term is defined in AS 46.03.900;

(B) located in the state and not more than 50 miles from the point of production of the oil or gas; and

(C) not connected to a pipeline that exists on the effective date of this Act and, in the judgment of the commissioner, could not be connected to a pipeline that existed on the effective date of this Act because the law does not permit the connection or because the connection would not be economically feasible.

Mapco, a company that all interior Alaskans are familiar with is building a 400 mile, 12 inch pipeline which will carry 185,000 barrels per day from mid-continent U.S. to Hobbs, New Mexico, a city of 29,000 people. The cost of the pipeline is estimated at 99 milion dollars.

Why wouldn't it be a great money maker for a smaller company like Mapco to bulid a 400 mile oil pipeline to Fairbanks or interior Alaska. A 24 inch pipeline would carry up to 400,000 barrels per day within the already designated 6 mile pipeline corridor. At an estimated cost of 500 million dollars, the pipeline owner could charge 2 dollars per barrel to transport the oil from the North Slope to Interior Alaska and pay for the pipeline in two years and have money left over.

There are many sound reasons for building such a line. A smaller shorter line could service the already discovered oil fields that are non-economic for the present owners to produce profitably.

There is no excess capacity in the present line to accomodate additional discoveries. Pressure could be taken off the Taps line so that many much needed repairs could be made. The oil could flow to the interior from where it could be distributed to nearly every other part of the state.

The pipeline would provide inexpersive efficient power for all present businesses, as well as other industries that could operate profitably with a plentiful supply of cheap energy.

If the Taps line had to be shut down for any of a multitude of reasons, Alaskans would have an emergency source of fuel. This would certainly be a consideration for the military installations in all of Alaska.

Another shorter pipeline is needed that is not as complex and would not have to contend with as many natural obstacles like river crossings, mountain ranges, and wetlands. It would also encourage competition in leasing, exploration, and production. Construction, development, exploration and engineering would generate thousands of Alaskan jobs.

A gas line to the interior would also make good sense. Instead of illegaly wasting billions of cubic feet of gas per day on the North Slope by flaring, a gas line to the interior could solve many of our energy and pollution problems. Natural gas would make year round farming in the interior possible and profitable. A natural gas supply to the Big Delta area could go a long way to bringing in industries that would help replace the loss of military personoll due to the shutting down of Fort Greely.

For many uses, natural gas would replace more expensive and less efficient fuels. Natural gas is already in use as an energy source for pump stations along the pipeline. There is no question about its feasibility or economy. Because natural gas is a much cleaner burning fuel, its affect on the environment would be very positive.

Natural gas could also be diverted to towns and villages along the corridor and solve their heating and power problems once and for all. It would also provide jobs for the local residents.

Both an oil line and a natural gas line to the interior would make goood economic sense. They would bring millions of dollars profit to the companies that would own them. They would add thousands of jobs. Both are affordable. If a mid sized company like Mapco can build a 400 mile oil pipeline to a limited market like Hobbs, New Mexico for under 100 million dollars, why can't the same be done in Alaska? Its ironic that Mapco earns the money in Alaska so that it can build a 400 mile pipeline in the lower forty eight.

If either or both of these lines are built, it would allow our three monopolistic oil companies, as well as Alyeska to leave Alaska with a clear conscious and invest their money in other parts of the world where the returns, according to them would be greater.

Request for Proposals (RFP)
DOE 96-R-001
Rural Alaska Intertie Study

The Department of Community and Regional Affairs, Division of Energy, is requesting proposals from qualified firms for a study to identify and evaluate opportunities from qualified firms for a study to identify and evaluate opportunities for electric transmission interties in rural Alaska.

Proposal documents are available during normal working hours beginning July 26, 1995 at the following address: Division of Energy, 333 W. 4th Avenue, Suite 206, Anchorage, AK 99501-2341, Phone (907) 269-4695, Fax: (907) 269-4685, Attn: Marlys Hagen.

Proposals must be received by the Division of Energy not later than 4:30 p.m., Anchorage time on August 23, 1995. Late proposals will not be accepted.

The State of Alaska complies with Title II of the Americans with Disabilities Act. Individuals with disabilities who may need auxiliary aids, services, and/or special modifications to respond to this Request for Proposals should contact Marlys Hagen at 269-4695, or 269-4555 TTY, or 1-800-930-4555 no later than August 14, 1995 to make the necessary arrangements.
Pub: July 26 - 30, 1995

SB

114

INITIAL SECTIONAL SUMMARY

3/8/95 by Kreitzer, Committee Aide

SB 114: "An Act relating to high cost marginal oil wells."

Section 1.:

Sec. 31.05.200 Amends the Oil and Gas Conservation Act to give the Oil and Gas Conservation Commission the authority to establish procedures for certifying producing wells as high cost marginal oil wells based on a formula of production.

Sec. 31.05.210 Outlines the amount of credit allowed for a high cost marginal oil well and what the credit may be applied against.

Sec. 31.05.290 Defines terms used in this new section.

Alaska State Legislature

Official Business

State Capitol
Juneau AK 99801

SENATE RESOURCES COMMITTEE

*expected to be present

*Chairman: Senator Loren Leman
*Vice Chairman: Senator Drue Pearce
*Senator Steve Frank
*Senator Rick Halford
*Senator Robin Taylor
*Senator Georgianna Lincoln
*Senator Lyman Hoffman

Teleconference Sites: ANC

AGENDA
3:30 to 5:00 p.m.
Wednesday, February 7, 1996

SB 114: High Cost Marginal Wells — Teleconferenced
SENATE RESOURCES COMMITTEE, Sponsor

Expected Witnesses:
Senator Leman to present Committee Substitute LS0845\G
Ken Boyd, Department of Natural Resources

NEXT MEETING:

Meeting Canceled for Friday, Feb. 9

Monday, February 12:
Leg Approve Perm'nt Recreat'nl Restrict'n (Senator Pearce)

ADJOURN

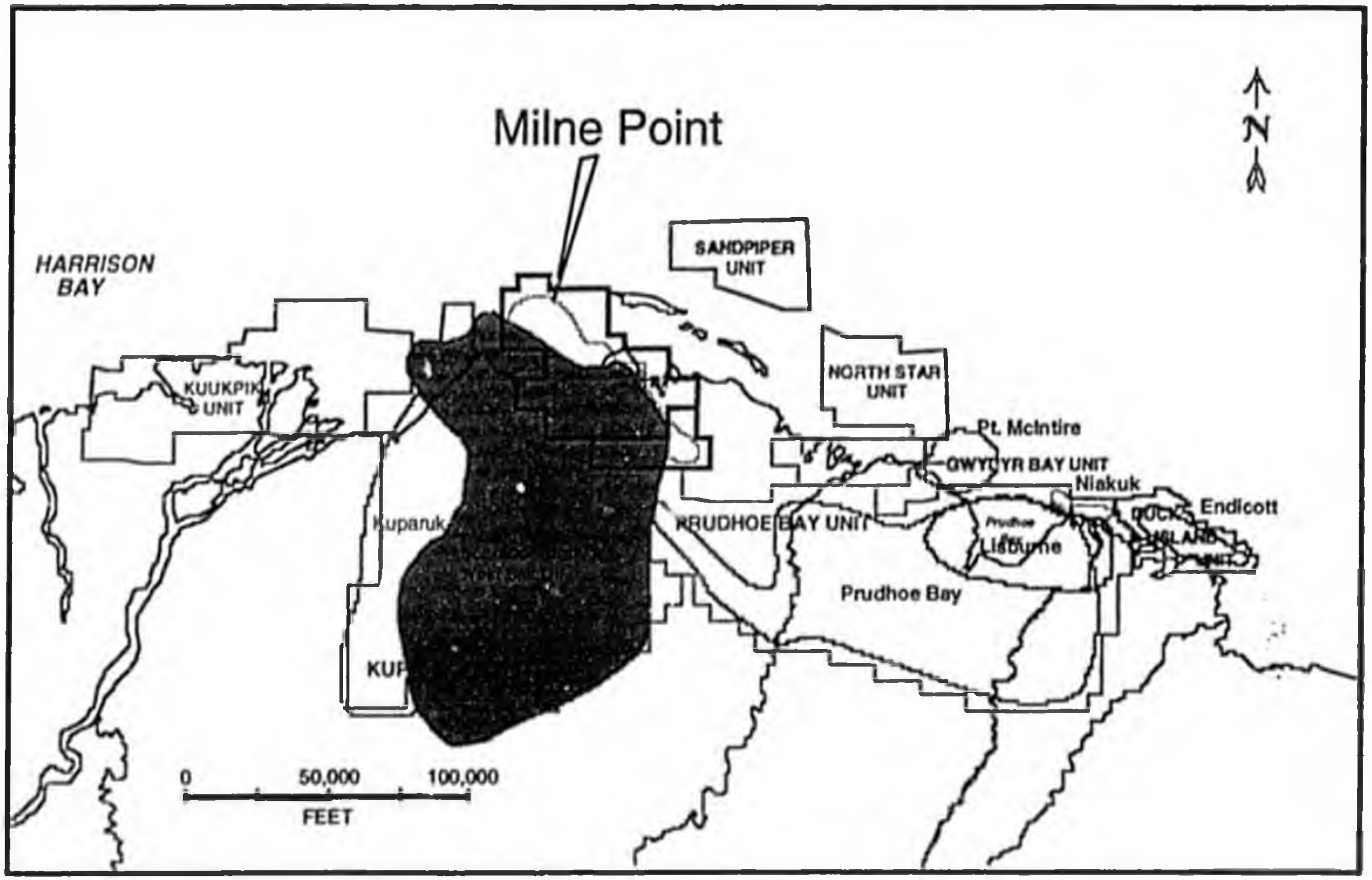
Heavy Oil Potential at Milne Point

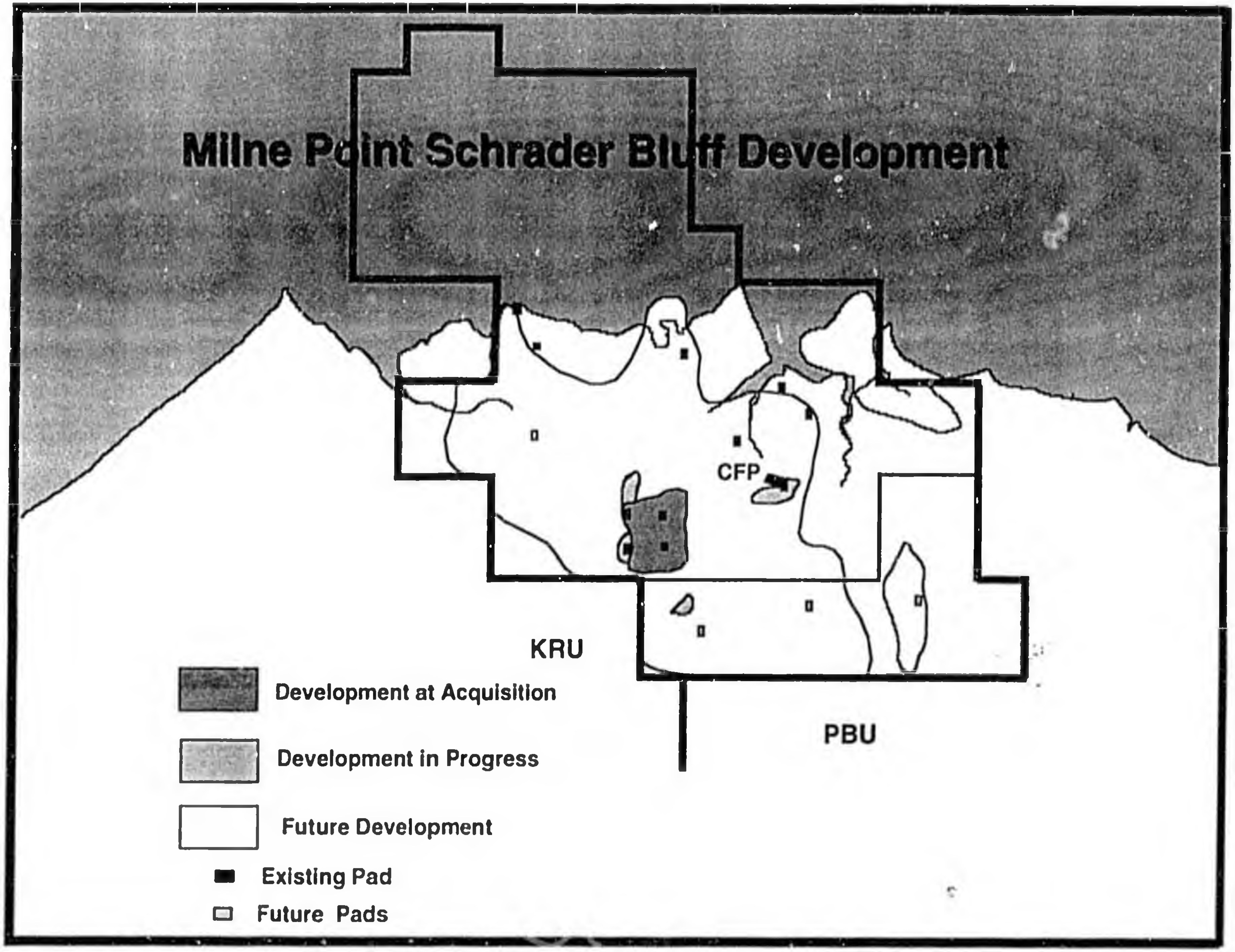
Presentation by BP Exploration (Alaska) Inc

before the House Oil and Gas Committee

November 14, 1995

North Slope Fields





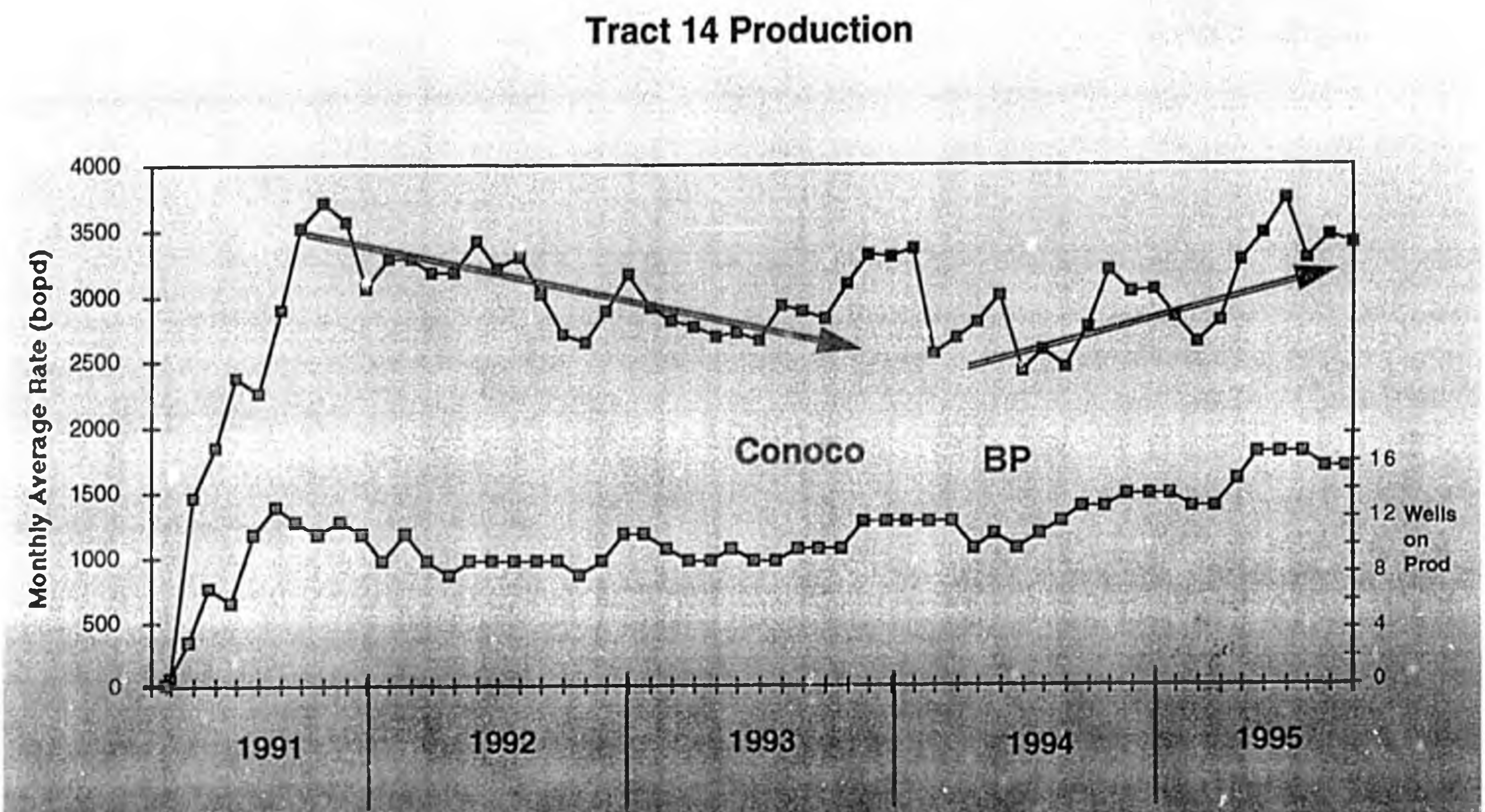
Milne Point Schrader Bluff Development
CFP
KRU
PBU
Development at Acquisition
Development in Progress
Future Development
Existing Pad
Future Pads

MPU Heavy Oil - History

West Sak at MPU: (Schrader Bluff)

- First production from pilot project in 1991.
- 16 producers and 5 injectors drilled.
- Low average initial well rate ~ 350bpd.
- Not commercially competitive.
- Development stopped in '91.

Significant technical and commercial hurdles remain to be overcome


Tract 14 Production
Monthly Average Rate (bopd)
4000
3500
3000
2500
2000
1500
1000
500
0
Conoco
BP
16
12 Wells on Prod
8
4
0
1991
1992
1993
1994
1995

MPU Schrader Bluff - Potential Program

1994

Drill Test Well

1995

Drill six "Test Wells"

?? - 1998 - ??

Potential Development

Circa 200 to 300 Wells

60,000 bpd Production

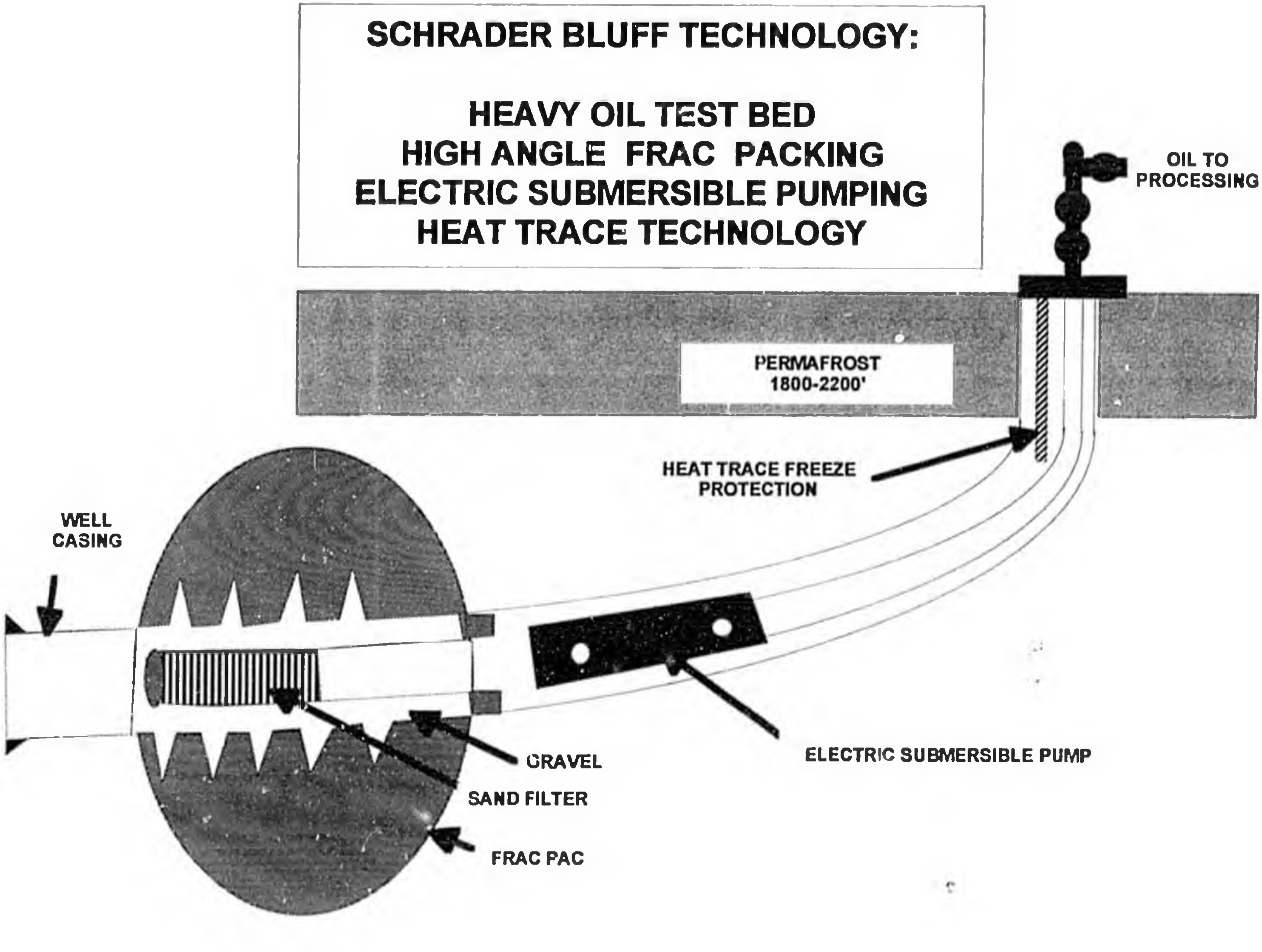
Key Decisions

Determine viability and scope for '95 wells. Demonstrate increased rate and reduce costs.

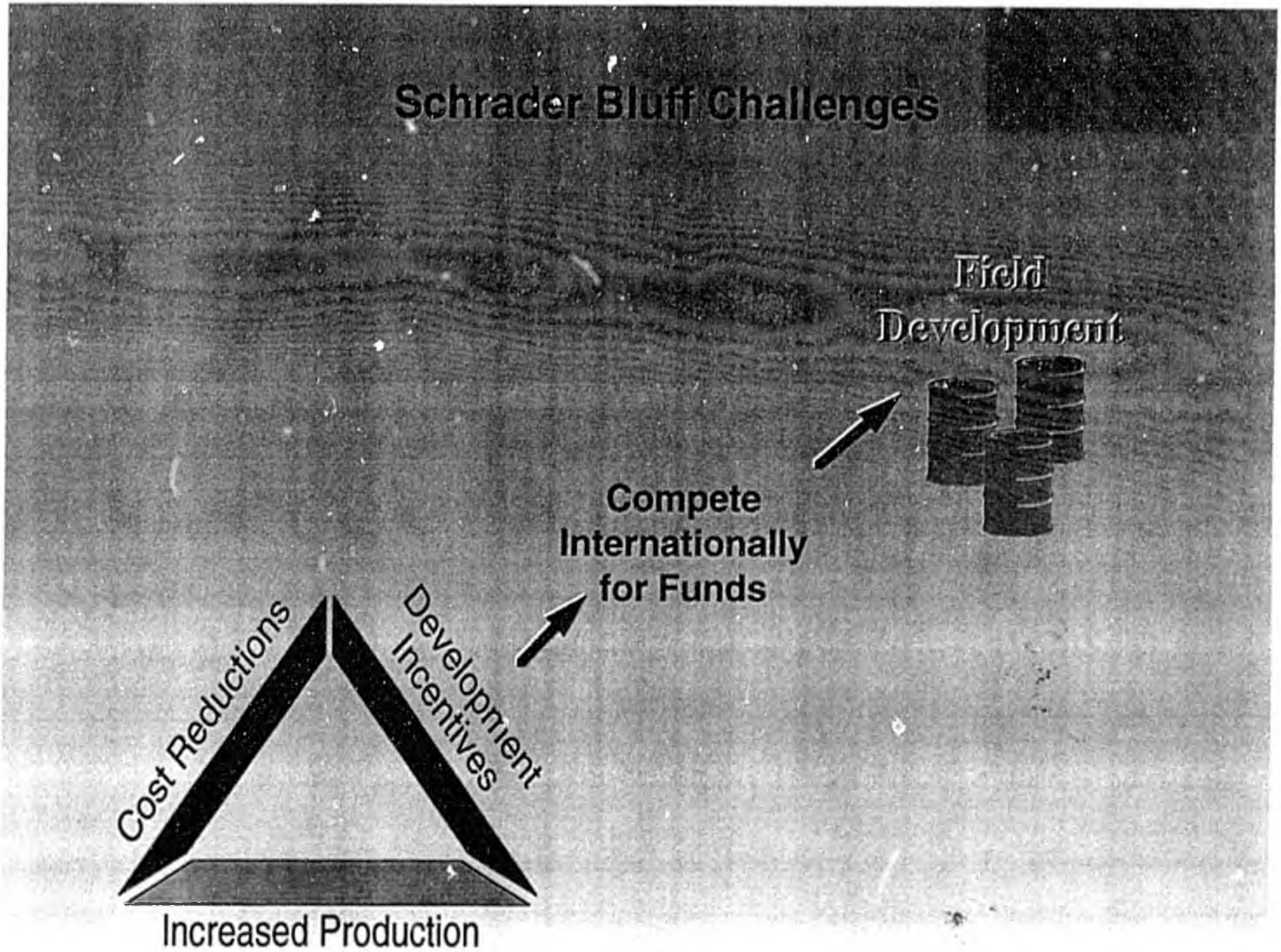
Establish viability of larger scale development.

1995 Schrader Bluff Development

- Objectives
  - Reduce capital requirements and operating costs
  - Increased initia[illegible]oduction rates from new wells
  - Reduce development uncertainty
- Progress - 1995 spend $13,000,000 to $15,000,000
  - Six wells drilled but not yet completed or on production
  - Three wells recompleted
  - Reservoir and facility technical studies initiated
- Results
  - Drilling cost reduction demonstrated
  - Improved submersible pump life realized
  - Completion costs, well performance and technical study results not yet available

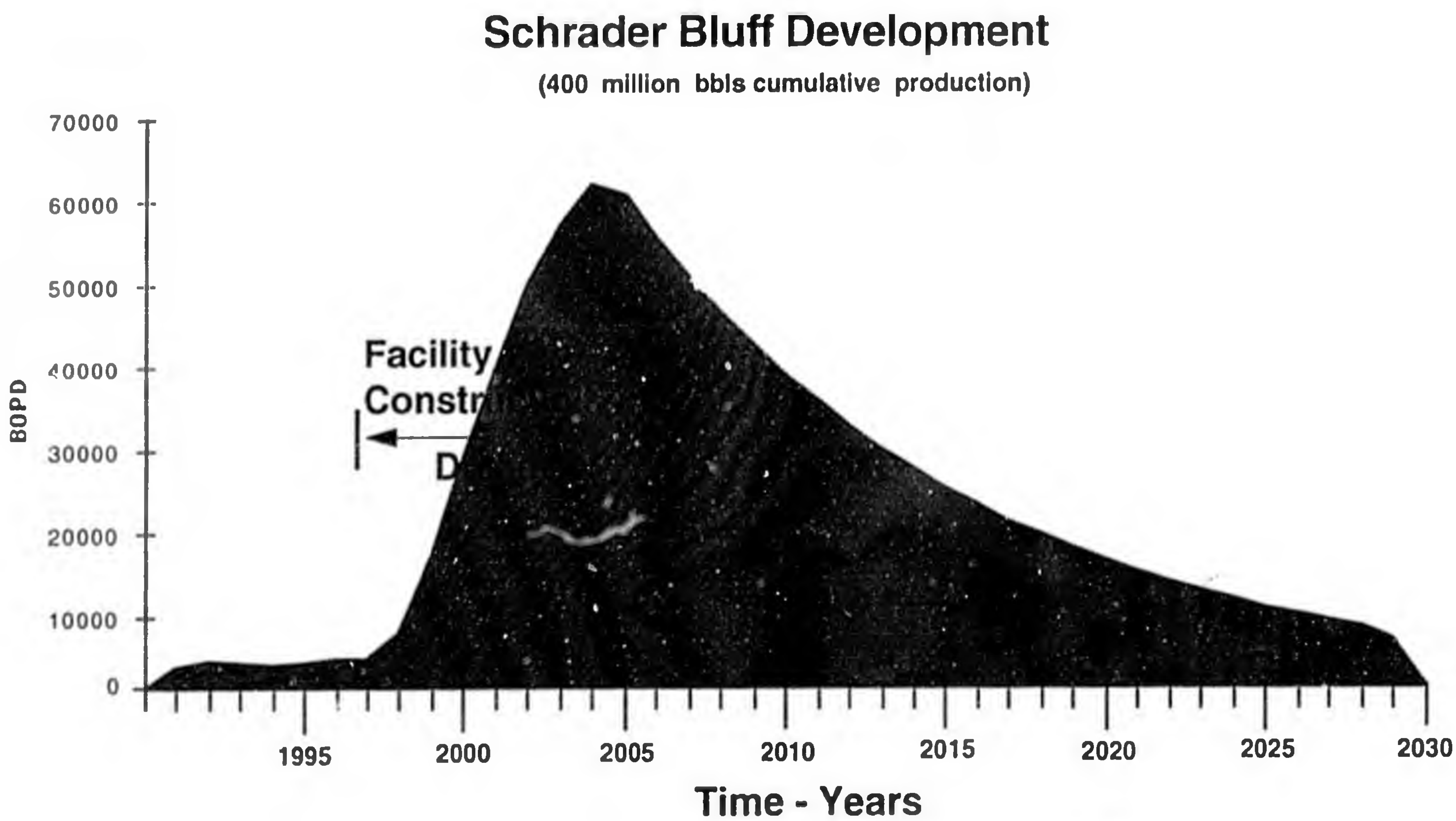


SCHRADER BLUFF TECHNOLOGY:
HEAVY OIL TEST BED
HIGH ANGLE FRAC PACKING
ELECTRIC SUBMERSIBLE PUMPING
HEAT TRACE TECHNOLOGY
OIL TO PROCESSING
PERMAFROST 1800-2200'
HEAT TRACE FREEZE PROTECTION
WELL CASING
GRAVEL
SAND FILTER
FRAC PAC
ELECTRIC SUBMERSIBLE PUMP


Schrader Bluff Challenges
Field Development
Compete Internationally for Funds
Cost Reductions
Development Incentives
Increased Production

The "Prize" at Milne Point

- 2+ Billion barrels of oil in place
- Potential ultimate recovery - 200 to 800 million barrels
- Expansion to adjacent fields



Schrader Bluff Development
(400 million bbls cumulative production)
70000
60000
50000
40000
30000
20000
10000
0
BOPD
Facility
Constr
D
1995
2000
2005
2010
2015
2020
2025
2030
Time - Years

[illegible]

- Ultimate impact on investment decision [illegible]
- Investment incentive will:
  - Improve economics
  - Reduce uncertainty
  - Provide positive signal to industry
  - Potentially accelerate development
- Time lag from incentive to start of investment is potentially short

The "Risk" of Delay

- Ultimate recovery placed at risk
- Project is less economic
- Current development momentum is lost
- Economic benefits deferred / value lost

Previously under CS SB 114 (version F):

Certificates were good for one year.

API Gravity less than 15 degrees

Credit may be applied to suspend obligation to pay royalty on first 100 bbls daily production.

Credit can't be combined with any other program.

NOW UNDER CS SB 114 (version G):

Certificates good for five years.

API Gravity 20 degrees

Exemption from royalty payments for the first 300 bbls daily production.

Drilling must take place on or after July 1, 1996 and before July 1, 2006.

Ed

Law Offices of

SI..PSON, TILLINGHAST, SORENSEN & LORENSEN, P.C.

One Sealaska Plaza, Suite 300 Juneau, Alaska 99801
Telephone: (907) 586-1400 Telecopier: (907) 586-3065

E. Budd Simpson
Jonathan K. Tillinghast
Stephen F. Sorensen
Ronald W. Lorensen

Leslie Longenbaugh
L. Merrill Lowden
Daniel H. Inouye

FAX COVER SHEET

Date:	2/2/96	From:	Jon Tillinghast
Fax #:		Client:	BP/OXY
# of Pages (Including Cover):	12	Case #:	840.2

Please Deliver To: Rick Foppiano & Ed Behm 915-685-5754

Message:

IF YOU DO NOT RECEIVE THE NUMBER OF PAGES LISTED ABOVE, PLEASE CALL Barb AS SOON AS POSSIBLE AT (907) 586-1400.

Revised 10/24/95

February 2, 1996

The Honorable Joe Green
Alaska State House of Representatives
State Capitol, Room 24
Juneau, Alaska 99801-1182

Re: Application of HB 207 to Heavy Oil
Our File No.: 840.2

Dear Representative Green:

OXY USA Inc. ("OXY") has asked us to respond to Division of Oil and Gas Director Kenneth Boyd's January 30, 1996 letter to Representative Bill Williams regarding the possible use of HB 207 to accomplish the goals of HB 325.

To begin with, OXY very much agrees with Mr. Boyd that HB 325 furthers the "primary purpose" of HB 207. OXY, in fact, entered the debate over heavy oil only in response to Governor Knowles' invitation to the private sector to explore new partnerships to develop Alaska's untapped energy resources.

However, HB 207 was never intended as the sole, nor even the principal vehicle for accomplishing that goal. Before each of the several legislative committees that considered HB 207 last session, DNR Commissioner John Shively stressed that HB 207 was only a tentative beginning, and that more concrete initiatives would follow. As Commissioner Shively explained to the Senate Resources Committee:

> *There are a variety of ideas about how to provide the oil industry with the incentive to develop marginal oil fields. HB 207 was a compromise effort that can be implemented this year, as opposed to other ideas that can be studied by the Governor's Oil and Gas Policy Commission [sic].*

Minutes, Senate Resources Committee, April 22, 1995 at 8. Commissioner Shively made the same point to your committee:

> *[Shively] said the Administration believes there are a number of things which can be done, both in the state's best interest and in the oil industry's best interest, to help encourage greater oil development. He noted part of that may be done now but the bulk of that will be done through the study the Governor's Oil and Gas Policy Council will be conducting over the next several years.*

Minutes, House Resources Committee, March 32, 1995 at 3; emphasis added. As Commissioner Shively explained to the House Oil and Gas Committee, HB 207 was simply a quick first step from a new administration:

> *[Shively] said, he thinks there are other roads, and some other additional legislation. He stated it was his decision, at this point, given the newness of the Administration, that this is something we can do this year. However, the Governor has appointed the Oil and Gas Policy Council, and one of their responsibilities is to look at other methods of providing incentives for oil development, and for a healthy oil industry. He then stated they consider this to be just the first step.*

Minutes, House Oil and Gas Committee, March 9, 1995 at 4. [1]

Heavy oil, in particular, was excluded from the HB 207 debate. Last April, OXY sought the advice of both the Administration, and the legislature, on the most appropriate vehicle for addressing heavy oil incentives. At the time, both felt that HB 207 was the wrong vehicle for that endeavor, and that the heavy oil issue should instead be treated separately, over the interim, through the Oil and Gas Policy Council and the appropriate legislative committees.

OXY appreciates the Administration's interest in encouraging heavy oil development, through HB 207 or any other means. That interest reenforces DNR's long-

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[1] Similarly, Commissioner Shively told the Senate Finance Committee that:

> *A number of ideas have been proposed to provide incentives for development of marginal fields in Alaska. Early in this administration, the proposed royalty incentive was determined to be 'something we could do this year' while the oil and gas policy commission [sic] examines other methods of 'making the state more competitive, internationally.'"*

Minutes, Senate Finance Committee, May 8, 1995.

held view that, under the existing fiscal environment, heavy oil development isn't likely to occur. [2]/ The effort, unfortunately, is procrustean. [3]/ The goals of HB 325 can't be forced into HB 207's structure for three reasons:

I. Schrader Bluff is ineligible under HB 207

Mr. Boyd is correct that HB 207 does not authorize royalty relief in all circumstances, but rather under only three tightly-defined circumstances. Mr. Boyd argues that the second of those circumstances--the "Declining Field" circumstance set out in AS 38.05.180(j)(1)(B)--might be made to fit Schrader Bluff. [4]/

The "Declining Field" clause in HB 207 was intended to apply to older fields that are reaching their economic limit because production is declining, and per-barrel costs are correspondingly rising. It is, in short, the Cook Inlet clause, and was never intended to apply to stimulate initial development of new fields that had experienced only pilot drilling.

The limitations of that clause, and its inapplicability to Schrader Bluff, are apparent from three different angles:

a. The language of the clause. By its terms, the clause allows royalty relief only: (1)to "prolong the life" of an oil field; and (2) "as costs per barrel...increase."

The purpose of HB 325 is not to "prolong" Schrader Bluff's field life, for at the moment (and save for a pilot project) there is nothing to prolong. HB 325's purpose, rather, is to encourage *initial development* of an essentially untapped field. [5]/

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[2]/ As our white paper, *An Opportunity to Develop Alaska's Heavy Oil Resources*, explains, DNR's Spring, 1994 production forecasts concluded that the entire Milne Point Unit (inclusive of Schrader Bluff) would be abandoned in 2006, while that agency's Spring, 1995 forecasts predicted unit abandonment in 2011. Neither forecast assumed any heavy oil development, save for the minor production flowing from the Tract 14 pilot project. Some projected heavy oil development first appeared in the Department of Revenue's Fall, 1995 forecasts because of methodology changes that were unrelated to the actual likelihood of Schrader Bluff development.

[3]/ Procrustes, you'll recall, was the villainous son of Poseidon who forced travelers to fit into his wooden bed by stretching them on a rack, or cutting off their limbs.

[4]/ Mr. Boyd briefly argues that the third circumstance--where royalty relief may be granted to "reestablish production of shut-in oil"--might also be availing. There is no shut-in production at Schrader Bluff, and, through the Tract 14 pilot wells, the field produces and sells 3,000 bbls./day.

[5]/ Indeed, one would think that, if any of HB 207's three bases for royalty relief were applicable to Schrader Bluff, it would be what Mr. Boyd calls the "New Pool" clause of AS 38.05.180(j)(1)(A). However, Mr. Boyd concedes that this basis is unavailable because it excludes any field which has "previously produced oil or gas for sale." The statute thus fails to account for new fields from which some production has occured from test or pilot drilling. Whether that omission was intentional or inadvertent, it's still nonetheless fatal to Schrader Bluff's eligibility under HB 207.

Moreover, "costs per barrel" are not increasing at Schrader Bluff, as they are in Cook Inlet where constant operating expenses are being spread over fewer and fewer barrels. To the contrary, one essential goal of BP's and OXY's pilot efforts has been to reduce per barrel costs, and, as BP has testified before your committee, continued *decreases* in per barrel costs are as essential to field development as an effective legislative incentive.

b. *HB 207's legislative history.* Commissioner Shively explained to the Senate Finance Committee that the "Declining Field" clause was only intended to cover "fields that are declining or about to be shut in." [6] The clause, the Commissioner added, addressed only fields "that might be abandoned" (*id.*), and DNR's position paper on HB 207 made it clear that the clause was aimed only at providing relief at the end of a field's life. The clause, the agency said, covered:

> *Oil and gas fields whose economic life may be prolonged in light of increasing costs in the later stages of production.*

"CS for HB 207(FIN)AM QUESTIONS AND ANSWERS," (herinafter "*DNR Paper*") undated at 1. These were what the agency called "mature producing fields," [7] or what Chair Rokeburg more directly described as "old uneconomic fields...e.g. Cook Inlet." [8]

The administration and the legislature knew what the "Declining Field" clause encompassed. The clause was directed at Cook Inlet fields, and not initial development of ANS heavy oil reserves.

c. *Prior DNR precedent.* HB 207 added only one category of fields eligible for royalty relief--Mr. Boyd's "New Pools," the most frequently cited example being the Badami Field. As DNR consistently reminded the legislature:

> *The current law allows the commissioner to grant royalty reduction to prolong the economic life of a field or to reestablish shut-in production.*

DNR Paper at 1. Indeed, DNR often cited its pre-existing authority under the Declining Field clause as a defense to claims that HB 207 gave the agency excessive discretion. Granting royalty relief under the Declining Field clause, Commissioner Shively told the House Oil and Gas Committee, "is really not something new to the office." [9] Indeed,

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[6] *Minutes, Senate Finance Committee*, May 8, 1995.
[7] *Id.* at 3.
[8] *Memorandum, Chairman Rokeburg to Members of Senate Finance Committee*, May 5, 1995 at 2.
[9] *Minutes, House Oil and Gas Committee*, March 9, 1995 at 4.

and as Mr. Boyd explained to the Senate Finance Committee, the Conoco royalty relief application had been decided under that clause. [10]/

The Conoco decision, in which Conoco and OXY were denied any adjustment to the special royalty surcharge imposed on some Milne Point production at the time the Milne Point Unit was formed, concluded that relief could not be granted under the Declining Field clause until near the very end of field life. Until then, projections about field economics would be dependent on projections of future oil prices, and the inherent uncertainities in forecasting the future price of oil made it *impossible* for Conoco to make the requisite "clear" showing of entitlement to relief. Said the hearing officer:

> *It is impossible to ascertain whether royalty relief granted after three years of production in a field with an estimated field life of twenty-five to twenty-eight years would compensate for, and be commensurate with, increasing costs in the later stages of production decline. Given the volatility of future oil prices and the remoteness of late stage costs, the department should not conclude that this standard would be met by granting the requested royalty reduction [under the Declining Field clause] at this time.*
>
> *It is very difficult, if not impossible, to provide such ['clear'] evidence here, since the Milne Point field is in the very early stages of production.* [11]/

The Declining Field clause, DNR ruled, was available only to Cook Inlet fields, where but a few production years remained. Younger fields were ineligible. And given that:

(1) the Declining Field clause, according to DNR, simply transferred intact into HB 207:

(2) the former standard of requiring a "clear" showing was replaced by HB 207 with an even more stringent "clear and convincing showing" requirement; [12]/ and

(3) Schrader Bluff's potential future field life of perhaps 41 years in nearly twice as long as the Kuparuk Formation field life at issue in the Conoco decision,

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[10]/ *Minutes, Senate Finance Committee*, May 8, 1995.
[11]/ *Recommended Decision of the Commissioner of Natural Resources Regarding the Conoco Application for Royalty Reduction on ADL 47433, 47434, 47437, 47438, and 28231 (Kuparuk Participating Area, Milne Point Unit)* (hereinafter "*Conoco Decision*"), December 28, 1990 at 15-16.
[12]/ AS 38.05.180(j)(2).

Mr. Boyd's suggestion that the future development of ANS heavy oil ought to be adjudicated under the Declining Field clause does not give ground for optimism.

II. HB 207 Does Not Allow Royalty Suspensions

Mr. Boyd has suggested an amendment to HB 207 that might obviate Schrader Bluff's eligibility problem, though even that amendment would fail to cure the seemingly insurmountable barrier imposed by the Conoco decision. The Conoco decision aside, however, amending HB 207's eligibility requirements would not lessen any of the other difficulties inherent in relying on that discretionary statute.

The first of these remaining problems is HB 207's mandatory 3% royalty floor for Declining Fields. AS 38.05.180(j)(4)(B).

As our white paper explains (*see n.* 2, ante) Heavy oil fields are materially different from the kinds of fields considered in the debate over HB 207. Their initial production rates are low; however, production declines quite gradually thereafter, and the field enjoys a remarkably long life--in Schrader Bluff's case, an estimated 41-years.

Thus, the white paper demonstrates, the State of Alaska would likely earn considerably more royalty income from a five-year royalty suspension at the outset production (which is what HB 325 envisions) than from a reduced royalty spread over the life of the field (as HB 207 envisions).

Indeed, the white paper estimates that the State of Alaska ***would lose about $800,000 per well*** if it imposed a 5% field royalty under HB 207 rather than enacting HB 325. *Id.* at 39, Chart 16.

As the white paper also discusses, Arthur D. Little, in its report to the Oil and Gas Policy Council, faulted Alaska for insisting on a one-size-fits-all royalty policy that is insensitive to the peculiarities of particular marginal fields. HB 207's royalty floor may make sense as a general proposition, but it disserves both the public's and industry's interest in developing heavy oil. In this respect, then, HB 207 proves Arthur D. Little's point, and it also underscores the wisdom of Commissioner Shively's repeated cautions to the legislature that HB 207 was never intended to address every oil and gas incentive issue.

III. HB 207 Addresses Only Lease-Based Royalty Relief

HB 207 only authorizes royalty relief for leases and unitized interests. AS 38.05.180(j)(1). It does not envision royalty relief targeted to individual wells.

HB 325, conversely, purposefully targets only individual new heavy oil wells. In so doing, it denies any incentive to production from pre-existing heavy oil wells, or production from other oil-bearing formations in the unit. In this way, it ensures that incentives are offered only when they serve the bill's primary purpose--to encourage new heavy oil drilling.

Also, HB 325's five-year suspension limit applies on a per well basis, so that the state can begin receiving royalties early in the field's development. And it imposes its 500/bbl./day cap on a per well basis, because individual well production rates are the best measure of whether the heavy oil property as a whole requires the incentive.

HB 207's lease-based approach does not seem suited to the kind of targeted relief, and targeted safeguards, contained in HB 325.

IV. HB 207 Is Burdened By an Unrealistic Economic Test

In the Conoco decision, the hearing officer ruled that an oil company should invest in a prospective oil and gas development, and needs no incentive, if it projects a rate of return from that venture at least equal to the then-current yield on a risk-free 90-day U.S. Treasury bill. *Conoco Decision* at 10.

OXY thought this an unreasonable standard. If an investor can earn the same rate of return from: (1) a risk-laden oil venture; or (2) a T-bill, why would that investor not simply purchase the T-bills?

This standard was imposed by a prior administration. However, nothing in HB 207 expressly altered that standard. And unless and until DNR reconsiders the matter, this standard remains a formidable obstacle to any worthwhile development incentive.

V. HB 207 Fails to Achieve Three Other Goals of HB 325

Our white paper lists seven criteria for any effective heavy oil incentive. HB 207 fails each of these three:

a. Immediacy. As BP has testified before your committee, there is a window of opportunity for developing ANS heavy oil that, as experience has shown, may pass quickly. Mr. Boyd has testified that DNR could complete an HB 207 application for heavy oil in as few as three months. However, given that:

(1) Alaska's only prior royalty reduction proceeding required 15 months to complete; and

(2) HB 207's process is considerably more complex than prior law's, [13]/

[13]/ Among the steps required by HB 207 are: (1) preparation of preliminary and final findings; (2) a mandatory 30-day public comment period; (3) possible selection of an independent consultant; (3) preparation and agency review of the consultant's report; (4) agency audits; (5) possible legislative committee review; and (6) gubernatorial review.

we believe that one year is a more realistic minimum;

(b) Certainty. As you know, HB 207 accords DNR considerable discretion. Indeed, no matter how compelling the applicant's economic case, DNR remains free to deny or limit relief under an open-ended "public interest" standard. AS 38.05.180(l)(3)(A). As a result, no prudent investor would commit capital on the assumption that adequate relief under HB 207 would be granted. To the contrary, any investment decision made in 1996 would necessarily assume that relief would ultimately be denied; and

(c) Credibility. Our white paper argues that any heavy oil incentive should draw on successful experience in other oil producing jurisdictions. The Arthur D. Little report called royalty suspensions a tried and successful tool to stimulate investment in marginal fields, and the white paper lists the United States, and seven producing states, as jurisdictions that have employed royalty and tax suspension to do just that. In Texas alone, a high-cost gas well tax suspension resulted in a 400% increase in gas wells drilled an 104,000 new additional employment years over the suspension's four-year history. *Id.* at 35.

Conversely, Alaska's local history on discretionary royalty reductions is less encouraging. There has been only one such completed proceeding, and after nearly four years of agency and court proceedings, the principal applicant--Conoco--sold its interest in Milne Point and left the state.

Besides its certainty, HB 325, in contrast to HB 207, benefits from its simplicity. As we've seen, the only prior completed royalty reduction proceeding in Alaska consumed 15 months. As would be the case with HB 207, each individual lessee was required to present a complete, lessee-specific economic case. Even though it owns but an 8.81% interest in Milne Point, OXY was forced to bear six-figure fees and costs associated with the application, as well as a considerable disruption of company operations.

Independent companies with smaller interests in Alaska, or with only prospective interests in the state, will not be attracted to Alaska by potentially complex administrative proceedings with uncertain outcomes. Once again, Arthur D. Little's admonition is pertinent. Alaska, for too long, has built its royalty policies around large, profitable fields run by large interest holders. As a result, the gene pool of Alaska's oil industry continues to shrink, and reliance on HB 207 to spur ANS heavy oil development would do nothing to reverse that trend.

VI. HB 325 Enhances the Legislature's Role in Setting State Royalty Policy

HB 325 reflects the belief that, *where it is possible to do so*, the legislature itself should set royalty policy. That wasn't possible with HB 207, since its broad scope encompassed to many varying situations to admit to direct legislative management.

HB 325, on the other hand, focuses only on a known and well-understood development challenge. It well admits to a reassertion of legislative involvement in this sphere, if the legislature chooses to take that opportunity. In part, that's because there seems something of a consensus that ANS heavy oil is unlikely to be developed without an effective incentive. [14]/ A better opportunity for direct legislative involvement is, in our view, unlikely to present itself.

* * *

On behalf of OXY, let me extend our thanks for the consideration that I know you, and the House Resources Committee members, will give to the thoughts expressed in this letter. If you or any committee member have any further questions, please don't hesitate to contact me.

Sincerely,

SIMPSON, TILLINGHAST, SORENSEN & LORENSEN

Jon K. Tillinghast

[14]/ For years, the departments of Natural Resources and Revenue took that position, and nothing has changed since the Spring of 1995 when that view was last articulated. For their part, companies such as BP, OXY, Arco and Conoco have invested over $270 million in ANS heavy oil pilot projects over the past decade. If, for example, Schrader Bluff could be economically developed without changes in the state's fiscal structure, its owners would have plainly seized the opportunity to recover that investment a long time ago. Our white paper discusses the technical, logistic and economic hurdles associated with heavy oil development in detail, and we've heard no one suggest that the case was overstated.

Ken

TONY KNOWLES, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

3601 "C" STREET, SUITE 1380
ANCHORAGE, ALASKA 99503-5948
PHONE: (907) 269-8784

January 30, 1996

The Honorable Bill Williams
Alaska State Representative
State Capitol, Room 128
Juneau, Alaska 99801-1182

Dear Representative Williams

You asked whether HB 207 passed last session, could be used to grant royalty relief for the production of "heavy oil." The division's short answer is yes. Nevertheless, because of the concerns expressed in the hearing on January 24 about the applicability of HB 207 to heavy oil production, the administration would support an amendment to HB 207 to provide explicitly that it applies to heavy oil production.

Subject to several provisions designed to protect the state's interests, HB 207 grants authority to the commissioner of the Department of Natural Resources to modify the existing royalty rate "to allow for production that would not otherwise be economically feasible" for any one of three types of oil or gas pools. In essence, the three are:

1. To allow production from an oil or gas pool that has been delineated, but has not previously produced ("New Pool")
2. To prolong the economic life of an oil or gas pool as costs per barrel or barrel equivalent increase ("Declining Pool")
3. To reestablish production from a shut-in oil or gas pool ("Shut-in Pool").

For purposes of HB 207, heavy oil production is no different from any other type of oil production. In other words, HB 207 would apply whether the oil production consisted of heavy, medium, or light production. If a company wished to produce heavy oil from a Shut-in Pool, it could be granted royalty relief under HB 207. For example, heavy oil production from ARCO's portion of the Schrader Bluff pool (which ARCO calls West Sak) that has been shut-in could be granted royalty relief. The same would be true for heavy oil production from a Declining Field or New Field.

Oxy and BP have a specific concern about whether heavy oil production from the Schrader Bluff pool within the Milne Point Unit could qualify under HB 207. Again the issue is not whether heavy oil production could qualify; rather it is whether the Schrader Bluff pool fits within one of the three types of pools listed in HB 207.

In the division's opinion, the Schrader Bluff pool does not meet the definition of a New Pool because the Schrader Bluff production has been sold. Arguably, the Schrader Bluff pool meets the definition of a Shut-in Pool. The Arco portion of the Schrader Bluff pool is currently shut-in. The Tract 14 pilot project for production from the Oxy and BP portion was shut-in from 1992 to 1994. If the production remains uneconomic, as the companies asserted in their testimony and the pilot project was stopped, the Schrader Bluff pool would clearly qualify as a Shut-in Pool.

The most applicable definition to the Schrader Bluff pool is the Declining Pool definition, number 2 above. First, granting royalty relief could "prolong the economic life of" the Schrader Bluff pool production. Second, the costs per barrel increase with heavy oil production. Most importantly, granting relief, assuming it was justified, would be consistent with HB 207's primary purpose "to allow for production that would not be otherwise be economically feasible." It appears that HB 207 could be applied to heavy oil production from the Milne Point Unit.

Nevertheless, some of the companies and representatives have expressed concern about the applicability of HB 207 to heavy oil production from the Milne Point Unit. To alleviate any concern about HB 207's applicability to the Milne Point Unit, the administration would support an amendment to HB 207 to make heavy oil explicitly included within the purview of HB 207. This could be accomplished by amending the language in AS 38.05.180(j)(1)(B) to read as follows:

> (B) to prolong the economic life of an oil or gas field or pool as costs per barrel or barrel equivalent increase **or to allow for the production from an oil pool containing heavy oil, defined as production with American Petroleum Institute weighted average gravity of 20 degrees or less**; or

Such an amendment is preferable to HB 325 because it would subject any relief to the protection of the state's interests afforded by HB 207. Specifically, it would require a complete and thorough economic analysis of heavy oil royalty relief, which is lacking in HB 325. Indeed, no state agency has been given the detailed backup data that presumably supports the economic assertions contained in the white paper prepared by BP and Oxy. HB 207 would also provide for public and legislative comment before any relief is granted. Finally, it would allow any relief granted to be conditioned to change if the bases upon which the relief is granted change.

By passing HB 207, the legislature adopted a consistent policy that would treat all players fairly and equally. HB 207 allows for "fiscally efficient" royalty terms. HB 325 is not fiscally efficient because it is not sensitive to profitability. It reduces the state's royalty without a showing of necessity by the companies or a guarantee of anything in return to the state for granting relief. Despite the companies' contrary protestations, they can have certainty of relief under HB 207 before making any investment.

Undeniably, HB 207 is not as administratively simple as HB 325 because it requires a complete review. The long debate over HB 207 last session convinced me that although both the legislature and the governor want expedited development of Alaska's oil and gas resources, they want this done with proper scrutiny. This scrutiny, clearly present in HB 207, is lacking in HB 325.

I hope this information is helpful to you. If you have any further questions, please feel free to call me.

Sincerely,

Kenneth A. Boyd
Director

9-LS0845\G
Chenoweth
2/6/96

CS FOR SENATE BILL NO. 114(RES)

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINETEENTH LEGISLATURE - SECOND SESSION

BY THE SENATE RESOURCES COMMITTEE

Offered:
Referred:

Sponsor(s): SENATE RESOURCES COMMITTEE

A BILL

FOR AN ACT ENTITLED

"An Act relating to high cost marginal oil wells on the North Slope, and authorizing an exemption from payment of royalty for initial production of a portion of the heavy oil produced from certified high cost marginal oil wells on the North Slope; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* **Section 1.** AS 31.05.030 is amended by adding a new subsection to read:

(i) The commission shall regulate and certify high cost marginal oil wells under AS 31.05.200 - 31.05.299. The authority granted by this subsection expires July 1, 2011.

* **Sec. 2.** AS 31.05 is amended by adding new sections to read:

ARTICLE 4. HIGH COST MARGINAL OIL WELLS.

Sec. 31.05.200. COMMISSION TO CERTIFY HIGH COST MARGINAL OIL WELLS. (a) The commission shall, by regulation, establish procedures under which a lessee of oil and gas rights on state land may apply to the commission and obtain from the commission a certificate under AS 31.05.210 that an oil well is a high cost marginal oil well.

(b) To obtain the certificate authorized by (a) of this section, a producer shall

(1) make application to the commission on a form provided by the commission; and

(2) provide to the commission the production or well data that the commission may require to determine whether the well qualifies for certification as a high cost marginal oil well.

Sec. 31.05.210. CERTIFICATION AS A HIGH COST MARGINAL OIL WELL. The commission shall grant the certificate authorized by AS 31.05.200 if the lessee demonstrates that the oil well for which the certificate is sought is a high cost marginal oil well for a field or pool and that

(1) actual drilling of the well began on or after July 1, 1996;

(2) the weighted average API gravity of oil produced from the well is less than 20 degrees API; and

(3) the well is located north of the Umiat baseline.

Sec. 31.05.220. DURATION OF CERTIFICATES. (a) Unless earlier revoked under (b) of this section, a certificate issued by the commission under AS 31.05.210 is valid for five years.

(b) After notice to a lessee holding a certificate and opportunity for hearing, the commission shall revoke a certificate if the commission determines that the oil well fails to meet the criteria established for certification in AS 31.05.210.

Sec. 31.05.230. EFFECT OF HIGH COST MARGINAL OIL WELL CERTIFICATE. A lessee holding a certificate issued under AS 31.05.210 may claim the benefit of suspension of royalty payments under AS 38.05.180(dd). The suspension of payment of royalty under AS 38.05.180(dd) is available only for the duration of the certificate under AS 31.05.220.

Sec. 31.05.299. DEFINITION. In AS 31.05.200 - 31.05.299, "certificate" means the certificate of a well as a high cost marginal oil well under AS 31.05.210.

* **Sec. 3.** AS 38.05.180 is amended by adding a new subsection to read:

(dd) Notwithstanding any other provision of this section or any provision in a lease, unit agreement, or other agreement between a lessee and the state that establishes an obligation to pay royalty on production, a producer who holds a certificate from the Alaska Oil and Gas Conservation Commission under AS 31.05.200 - 31.05.299 is not obligated to pay royalty under the conditions and to the extent described in this subsection, for the production of heavy oil from a well that is certified under AS 31.05.200 - 31.05.299 as a high cost marginal oil well. For purposes of this subsection, "heavy oil" means oil having a weighted average equal to or less than 20 degrees API gravity as the term "API gravity" is defined in AS 43.55.900. Under this subsection, the exemption from payment of royalty applies

(1) only to the portion of the value at the wellhead, net of eligible field cost deductions, as calculated for the month of production, for the first 300 barrels of daily production of heavy oil from the well, that, for the period beginning on

(A) the effective date of this section and until December 31, 1996, does not exceed $15 per barrel; and

(B) the first day of the calendar year during each calendar year beginning January 1, 1997, does not exceed the amount specified under (A) of this paragraph as adjusted for inflation or deflation; in making the adjustment, the department shall, not later than February 15 of each calendar year, calculate and apply to the amount set out in (A) of this paragraph a change in the dollar amount to the extent of the change in the producer price index for finished goods compiled by the United States Department of Labor; the index for January 1996 is the reference base index;

(2) only if the actual drilling of the well from which the heavy oil is produced began on or after July 1, 1996, and before July 1, 2006;

(3) only to heavy oil produced during the period in which the producer holds a valid certificate issued by the Alaska Oil and Gas Conservation Commission under AS 31.05.200 - 31.05.299; and

(4) for a well only if the lessee

(A) submits with its royalty report for the first month for which the exemption from royalty payment under (1) - (3) of this subsection is claimed and with subsequent royalty reports at quarterly intervals for so long as the exemption continues, oil gravity test results performed during the period for which the royalty report is filed demonstrating that the oil tested is heavy oil; the report must be in accordance with the standards for measurement and testing set out in the regulations of the Alaska Oil and Gas Conservation Commission; and

(B) maintains, for a period of at least two years after the last day of the royalty payment exemption authorized by this subsection, records of production that show the actual date that drilling of the well started, the daily production from the well, and the API degree gravity data, and allows the department to inspect the records during regular business hours.

* Sec. 4. This Act takes effect immediately under AS 01.10.070(c).

9-LS0845\F
Chenoweth
5/9/95

CS FOR SENATE BILL NO. 114(RES)

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINETEENTH LEGISLATURE - FIRST SESSION

BY THE SENATE RESOURCES COMMITTEE

Offered:
Referred:

Sponsor(s): SENATE RESOURCES COMMITTEE

A BILL

FOR AN ACT ENTITLED

"An Act relating to high cost marginal oil wells."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. AS 31.05.030 is amended by adding a new subsection to read:

(i) The commission shall regulate and certify high cost marginal oil wells under AS 31.05.200 - 31.05.299.

* Sec. 2. AS 31.05 is amended by adding new sections to read:

ARTICLE 4. HIGH COST MARGINAL OIL WELLS.

Sec. 31.05.200. COMMISSION TO CERTIFY HIGH COST MARGINAL OIL WELLS. (a) The commission shall, by regulation, establish procedures under which a lessee of oil and gas rights on state land may apply to the commission and obtain from the commission a certificate under AS 31.05.210 or 31.05.220 that an oil well is a high cost marginal oil well.

(b) To obtain the certificate authorized by (a) of this section, a producer shall

(1) make application to the commission on a form provided by the commission; and

(2) provide to the commission the production or well data that the commission may require to determine whether the well qualifies for certification as a high cost marginal oil well.

Sec. 31.05.210. CERTIFICATION AS PRODUCING WELL. The commission shall grant the certificate authorized by AS 31.05.200 if the lessee demonstrates that the well for which the certification is sought is a producing well and that

(1) the well produces oil at a maximum average production of not more than 100 barrels of oil per day;

(2) the percentage of water produced from the well is not less than 70 percent; and

(3) for the period for which the certificate is valid, the well is in production for at least 20 days.

Sec. 31.05.220. CERTIFICATION AS A NORTH SLOPE TEST OR DEVELOPMENT WELL. The commission shall grant the certificate authorized by AS 31.05.200 if the lessee demonstrates that the oil well for which the certificate is sought is a North Slope test or development well for a field or pool and that

(1) actual drilling of the well began on or after July 1, 1995;

(2) the weighted average API gravity of oil produced from the well is less than 15 degrees API; and

(3) the well is located north of the Umiat baseline.

Sec. 31.05.230. DURATION OF CERTIFICATES. (a) Unless earlier revoked under this subsection, a certificate issued by the commission under AS 31.05.210 is valid for one month. After notice to a lessee holding a certificate and opportunity for hearing, the commission shall revoke a certificate if the commission determines that the oil well fails to meet the criteria established for certification in AS 31.05.210.

(b) A certificate issued by the commission under AS 31.05.220 is valid for one year.

Sec. 31.05.240. HIGH COST MARGINAL PRODUCING WELL CREDIT. (a) A lessee holding a certificate issued under AS 31.05.210 obtains a high cost marginal producing well credit. The amount of the credit authorized by this subsection

(1) is equal to $0.25 per barrel of production from a well for which the

credit is given; and

(2) may not exceed the lower of the following:

(A) $125,000 per well; or

(B) $500,000 per lessee.

(b) A credit extended under (a) of this section

(1) may be applied against

(A) an oil or gas rental or royalty payment payable to the state;

(B) taxes payable under AS 43.20 or AS 43.55; and

(C) oil and gas bonus payments due the state under AS 38.05.180(f);

(2) must be used within one year after the certificate is granted under AS 31.05.210; and

(3) may be assigned by the lessee to another person.

Sec. 31.05.250. HIGH COST MARGINAL NORTH SLOPE TEST OR DEVELOPMENT WELL CREDIT. (a) A lessee holding a certificate issued under AS 31.05.220 obtains a high cost marginal North Slope test or development well credit.

(b) Except as provided by AS 31.05.260(b), notwithstanding any provision of AS 38.05.180 or any provision in a lease, unit agreement, or other agreement between a lessee and the state that establishes an obligation to pay royalty on the production of oil, the credit authorized by (a) of this section may be applied to suspend the obligation to pay a royalty on the amount or value of the production removed or sold from the well for the production of the first 100 barrels of daily production from the well.

(c) The suspension of payment of royalty under (b) of this section is available only for the duration of the certificate under AS 31.05.220(b).

Sec. 31.05.260. LIMITATION ON USE OF WELL CREDITS. (a) The credit for a high cost marginal North Slope test or development well obtained under AS 31.05.250 may not be applied in combination with the high cost marginal producing well credit obtained under AS 31.05.240.

(b) The credit for a high cost marginal North Slope test or development well obtained under AS 31.05.250 may not be taken against production for which the rate of royalty has been reduced under AS 38.05.180(j).

Sec. 31.05.299. DEFINITIONS. In AS 31.05.200 - 31.05.299,

(1) "barrel" has the meaning given in AS 46.04.900;

(2) "certificate" means the certificate of a well as a high cost marginal oil well, whether applicable to a producing well under AS 31.05.210 or to a North Slope test o. development well under AS 31.05.220;

(3) "credit" means

(A) the high cost marginal producing well credit authorized by AS 31.05.240; and

(B) the high cost marginal North Slope test or development well credit authorized by AS 31.05.250.

* Sec. 3. If this Act takes effect after July 1, 1995, AS 31.05.220(1), added by sec. 2 of this Act, is retroactive to July 1, 1995, and applies to oil wells whose actual drilling began on or after that date.

HIGH COST MARGINAL WELLS AND THE ALASKA SEVERANCE TAX

Testimony prepared by Charles Logsdon for presentation to Senate Resources Committee
March 17, 1995

THE SEVERANCE TAX IS LEVIED ON ALL BARRELS OF OIL PRODUCED IN THE STATE OF ALASKA. THE TAX IS CALCULATED ON A FIELD BASIS BY MULTIPLYING THE BARRELS PRODUCED OF NON-ROYALTY OIL IN THAT FIELD BY THE WELLHEAD PRICE BY THE TAX RATE (EITHER 15% OR 12.25% — 1st 5 yrs DEPENDING ON THE AGE OF THE FIELD) BY THE ECONOMIC LIMIT FACTOR (ELF).

THE ELF IS CALCULATED FOR EACH FIELD AND CAN HAVE A VALUE FROM 0.0 TO ALMOST 1.0. THE ELF IS THUS A PERCENTAGE REDUCTION IN THE SEVERANCE TAX. THAT IS, IF ELF IS 0.0 THEN THE SEVERANCE TAX IS 0.0 AND IF THE ELF IS NEARLY 1.0 THERE IS ALMOST NO REDUCTION IN THE SEVERANCE TAX..

ANOTHER WAY OF LOOKING AT THE ELF IS TO THINK OF IT AS A PERCENTAGE REDUCTION IN THE BARRELS SUBJECT TO THE TAX RATE. IT COULD ALSO BE THOUGHT OF AS A PERCENTAGE REDUCTION IN THE TAX RATE APPLIED ON ALL BARRELS.

AS WE SHALL SEE, THE ELF PROVIDES CONSIDERABLE TAX RELIEF TO MARGINAL WELLS AND TO SMALL OIL FIELDS

WHAT IS THE ELF?

THE ELF IS A FACTOR WHICH REDUCES THE SEVERANCE TAX RATE AS BOTH PER WELL AND OVERALL FIELD WIDE PRODUCTION DECLINES. SIMPLY STATED THE BIGGER THE FIELD AND THE BETTER THE WELLS, THE HIGHER THE TAX (CHART ONE AND CHART TWO)

THE ELF FORMULA--THE THEORY (CHART THREE)

ELF = (1-300/WP)^((150,000/TP)^1.5333)

WP IS THE AVERAGE PRODUCTION PER WELL IN AN OIL FIELD AND TP IS THE DAILY PRODUCTION FROM THE FIELD

WHAT THE HECK DOES THIS MEAN?

BREAK THE FORMULA INTO TWO PARTS BY LOOKING AT THE TERMS IN PARENTHESIS.

THE FIRST TERMS IN PARENTHESES ESTABLISH WHAT I WILL CALL THE WELL PRODUCTION TAX ALLOWANCE.

FIRST, NOTICE THAT EACH WELL IN A FIELD GETS 300 BBL/DAY TAX FREE. THAT IS, IF YOU PLUG 300 INTO THE FORMULA THAT THE RESULT IS 1-300/300

OR 1 MINUS 1 WHICH IS ZERO. ALSO NOTICE THAT PLUGGING ANY WELL PRODUCTION ABOVE 300 GIVES A POSITIVE ELF AND AS A RESULT TAXES ARE DUE.

FURTHER, WELL PRODUCTION ABOVE 300 BBL/DAY IS SCALED PROPORTIONATELY TO THE 300 BBL/DAY TAXING LIMIT. THAT IS, AS WELL PRODUCTION INCREASES THE THE WELL PRODUCTIVITY ALLOWANCE BEGINS TO APPROACH A VALUE OF 1.0.

THE SECOND SET OF TERMS IS REPRESENTED BY THE EXPONENT. THIS IS THE FIELD SIZE FACTOR WHICH IS USED TO MODIFY THE WELL PRODUCTIVITY ALLOWANCE.

<u>AN EXAMPLE</u> (CHART FOUR)
ASSUME A FIELD WITH WELLS WHICH AVERAGE 1000 BBL/DAY PLUGGING INTO THE FIRST PART OF THE FORMULA THIS GIVES A FRACTION OF 700/1000 OR 70%. THIS ESTABLISHES A WELL PRODUCTIVITY BASE OF A 70% REDUCTION IN TAX RATE OR A 70% REDUCTION IN TAXED BARRELS.

THE EXPONENTS WHICH THEN ADJUST THIS BASE ARE THE FIELD SIZE FACTOR . THE EFFECT OF FIELD SIZE ON THE BASE CAN BE THOUGHT OF AS A TEETER TOTTER WHERE THE 70% IS THE FULCRUM. FIELD SIZES GREATER THAN 150,000 BBL/DAY PUSH THE RATE ABOVE THE 70% ESTABLISHED BY THE 1000 BBL/DAY WELL RATE. CONVERSELY FIELD SIZES LOWER THAN 150,000 BBL/DAY PUSH DOWN THE RATE BELOW THE 70% BASE.

LOOK AT THE GRAPH AND NOTE THAT THE EFFECT OF THE FIELD SIZE FACTOR ON OUR 1000 BBL/DAY WELL OIL FIELD IS TO PUSH THE TAX RATE UP VERY QUICKLY TOWARD 1.0 UNTIL SOMEWHERE AROUND 250,000 BBL/DAY THEN THE RATE INCREASE TENDS TO FLATTEN VERY CLOSE TO 1.0.

<u>THE ELF TRACK RECORD</u>
1. ONLY 5 OF ROUGHLY 21 PRODUCING ALASKAN OIL FIELDS PAY ANY OIL SEVERANCE TAX. (CHART TWO AGAIN)

2. THE OVERALL AVERAGE ELF HAS FALLEN BY ONE PERCENTAGE POINT SINCE 1990--FROM .92 TO .91. THIS RESULTED IN A TAX SAVINGS IN 1994 OF $9.4 MILLION COMPARED TO THE RATE IN EFFECT IN 1990.

<u>ELF AND THE FUTURE</u> (CHART FIVE)

THE ELF SHRINKS AS PRODUCTION FROM OUR DEPLETING OIL FIELDS DECLINES. WE WILL CONTINUE TO GET A SHRINKING PIECE OF A SHRINKING PIE.

Considerable Tax Relief To Marginal Wells

- 300 FREE Barrels for "Every" Well
- Tax Benefits to Small Fields
- Most Fields in Alaska Pay "$0" Severance Tax

Alaska Severance Tax Summary Table

FIELD	TOTAL PRODUCTION (TP) MM bbl/day	WELL PRODUCTION (WP) bbl/day	ELF	Effective TAX RATE %	TAX PAID $Million
Prudhoe	0.9630	1518	0.985719	14.79	462
Kuparuk	0.3055	882	0.863817	12.96	116
Pt McIntyre	0.1028	6021	0.904659	11.08	36
Endicott	0.0929	2608	0.750042	11.25	28
Lisburne	0.0191	618	0	0	0
Milne	0.0155	448	0	0	0
Niakuk	0.0123	2383	0.001918	.02	0
Schrader	0.0028	263	0	0	0
N Prudhoe	0.0021	3340	0	0	0
West Beach	0.0016	3929	0	0	0
Sag Delta	0.0010	542	0	0	0
Cook Inlet	0.0590	135	0	0	0

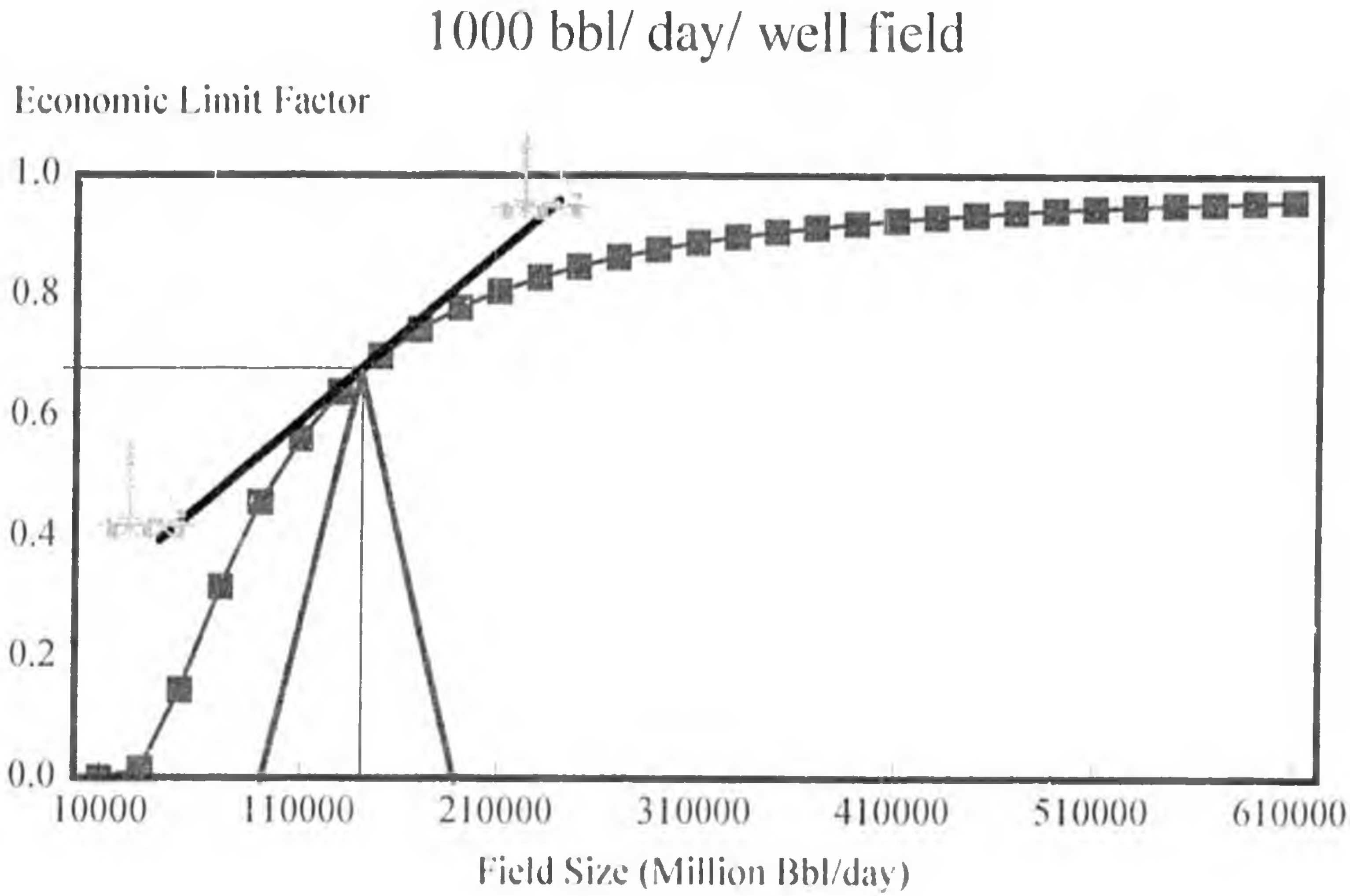
Economic Limit Factor

$$\text{ELF} = \overbrace{(1 - 300 / WP)}^{\textit{well production allowance}} \wedge \overbrace{((150{,}000 / TP) \wedge 1.5333))}^{\textit{field size adjustment}}$$

WP is the average production per well in an oil field

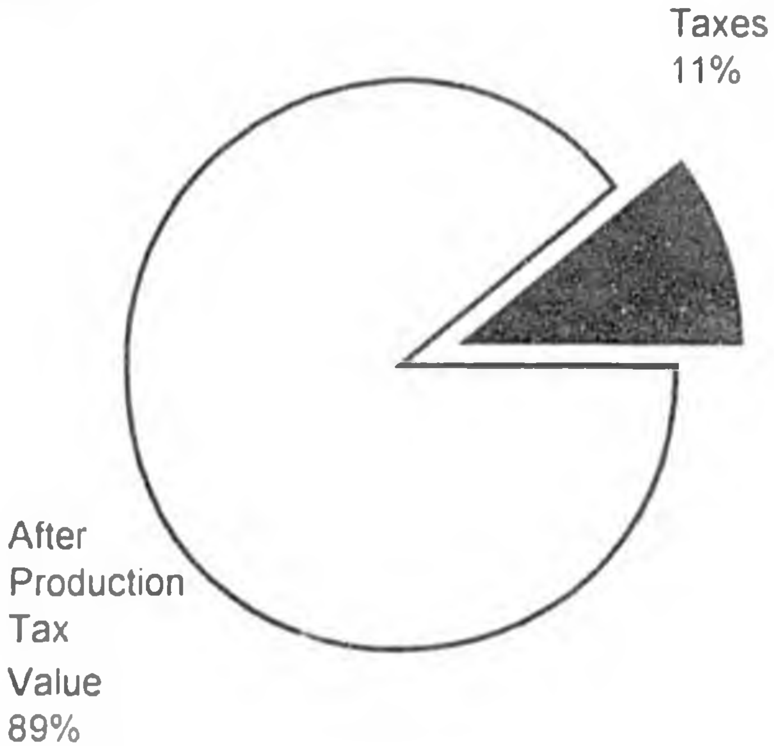
TP is the total daily production from the field

FIELD SIZE AND ELF

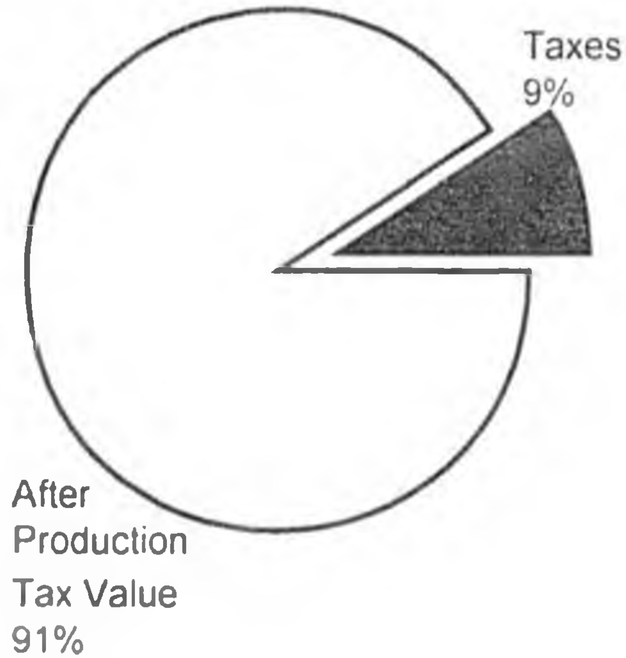


SHRINKING PIECE OF SHRINKING PIE

1994



2005



FISCAL NOTE

STATE OF ALASKA
1995 LEGISLATIVE SESSION

BILL NO. SB 114

Revision Date:
Title: High Cost Marginal Oil Wells
Sponsor: (S) RES
Requester: (S) RES

Dept. Affected: Revenue
BRU: Revenue Operations
Component: O&G Audit/ I&E Audit
COMPONENT SERIAL NO. 115 / 113

Expenditures/Revenues (Thousands of Dollars)

OPERATING EXPENDITURES	FY 96	FY 97	FY 98	FY 99	FY 00	FY 01
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						
CHANGE IN REVENUES (GF)	(94.6)	(98.6)	(104.7)	(107.2)	(108.5)	(108.6)

FUND SOURCE (Thousands of Dollars)

FUND SOURCE	FY 96	FY 97	FY 98	FY 99	FY 00	FY 01
1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1006 GF/MHTIA						
Other						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY95) cost: $ 0.0

POSITIONS

POSITIONS	FY 96	FY 97	FY 98	FY 99	FY 00	FY 01
FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

This bill would allow qualified low productivity oil wells a tax credit of up to $2.00/bbl but limited to 50% of the taxes payable under AS 43.55 (petroleum production tax) on production from the well, $1million per well and $5 million per producer. Tax credits could be applied against corportion income taxes (AS 43.20); production taxes (AS 43.55); and oil and gas rental, bonus and royalty payments.

The revenue impact is based on currently producing well data. It is assumed that the hazardous release surcharge contained under 43.55 is creditable. No allowance is made for old wells being turned on that weren't producing in 1993 hence no royalty offset is included.

Other than the hazardous release, 5 wells in 1993 paid severance tax, their average rate of production was 50 bbl/day.

Given the high cost of drilling wells, it is unlikely that new wells would be drilled to take advantage of the credit. Since the Economic Limit Factor already has served to reduce the severance tax to zero on our oldest fields in Cook Inlet and on the small fields on the North Slope, the net impact of the credit on oil field investment activity will be imperceptible.

Prepared by: Robert Baratko
Division: Administrative Services Division
Phone: 465-2312
Date: 3/16/95

Approved by Commissioner: Deborah Vogt
Agency: Department of Revenue
Date: 3/16/95

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SB 114 Fiscal Note

North Slope
Assume:
1. 10 wells producing 190,000bbls/yr
2. 5 wells pay zero severance tax
3. 2 wells in Kuparuk and 3 wells in Prudhoe Bay
4. All 10 wells pay hazardous release

Cook Inlet
Assume:
1. 41 wells producing 697644 bbl/yr
2. All wells pay zero severance tax
3. All wells pay hazardous release

	Prudhoe Sev Tax per Bbl	Prudhoe Well Prod bbl/d	Prudhoe Wells	Prudhoe Credit	Kuparuk Sev Tax per Bbl	Kuparuk Well Prod bbl/d	Kuparuk Wells	Kuparuk Credit	Other Wells Cook North Slope	Other Wells Prod bbl/d	Other Credits	Total Credits
1996	1.61	50	3	44621.25	1.33	50	2	24820	46	50	25185	94626.25
1997	1.71	50	3	47358.75	1.4	50	2	26097.5	46	50	25185	98641.25
1998	1.89	50	3	52286.25	1.46	50	2	27192.5	46	50	25185	104663.8
1999	1.99	50	3	55023.75	1.45	50	2	27010	46	50	25185	107218.8
2000	2.07	50	3	57213.75	1.4	50	2	26097.5	46	50	25185	108496.3
2001	2.14	50	3	59130	1.3	50	2	24272.5	46	50	25185	108587.5

FISCAL NOTE

STATE OF ALASKA | **BILL NO. SB114**
1995 LEGISLATIVE SESSION

Revision Date:	Original	Dept Affected:	Natural Resources
Title:	An Act relating to high cost marginal oil wells	BRU:	Resource Development
		Component:	Oil & Gas Development
Sponsor:	Senate Resources		
Requestor:		Component Serial No.	439

Expenditures/Revenues (Thousands of Dollars)

OPERATING EXPENDITURES	FY96	FY97	FY98	FY99	FY00	FY01
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
CHANGE IN REVENUES ( )		(1,000.0)	(1,000.0)	(1,000.0)	(1,000.0)	(1,000.0)

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1006 GF/MHTIA						
Other						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY95) cost: $

POSITIONS

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

ANALYSIS: (Attach a separate page if necessary)

The majority of the impact of this bill would fall on the Alaska Oil and Gas Conservation Commission and the Dept. of Revenue. The impact on DNR would be a small amount of relatively routine accounting work in the Royalty accounting section i.e. entering any royalty deductions from Royalties, Bonuses and/or Rents.

Section 31.050210 allows for a credit against either taxes or royalties, which would impact revenues to the state and reduce contributions to the permanent fund.

Prepared by:	Ken Boyd, Acting Director	Phone:	762-2547
Division:	Oil & Gas	Date:	14-Mar-95
Approved by Commissioner:	[signature] for John Shively	Date:	3-14-95
Agency:	Natural Resources		

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FISCAL NOTE

STATE OF ALASKA **BILL NO.** SB 114
1995 LEGISLATIVE SESSION

Revision Date:
Title: " An Act relating to high cost marginal oil wells."
Sponsor: The Senate Resources Committee
Requestor:

Dept. Affected: Administration
BRU: AK Oil and Gas Conservation Commission
Component: AK Oil and Gas Conservation Commission
COMPONENT SERIAL NO. 2010

Expenditures/Revenues (Thousands of Dollars)

OPERATING EXPENDITURES	FY 96	FY 97	FY 98	FY 99	FY 00	FY 01
PERSONAL SERVICES	9.3	9.3	9.3	9.3	9.3	9.3
TRAVEL	0.0	0.0	0.0	0.0	0.0	0.0
CONTRACTUAL	0.5	0.0	0.0	0.0	0.0	0.0
SUPPLIES	1.9	0.0	0.0	0.0	0.0	0.0
EQUIPMENT	9.3	0.0	0.0	0.0	0.0	0.0
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	21.0	9.3	9.3	9.3	9.3	9.3
CAPITAL EXPENDITURES						
CHANGE IN REVENUES ( )						

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF	21.0	9.3	9.3	9.3	9.3	9.3
1005 GF/Program Receipts						
1006 GF/MHTIA						
Other						
Total	21.0	9.3	9.3	9.3	9.3	9.3

Estimate of current year (FY 95) cost: $ 0.0

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

Assumptions: Determination of high cost marginal well (HCMW) is fairly straightforward using previously submitted and easily interpreted production data. No economic analysis of cost data is required. Report to Department of Revenue requires only notice of qualifying wells and itemization of production data for previous six months. Wells are recertified every six months.

(Continued)

Prepared by: David W. Johnston, Chairman
Division: Alaska Oil and Gas Conservation Commission
Phone:
Date:

Approved by Commissioner: Mark Boyer MarkBoyer
Agency: Department of Administration
Date: 3/16/95

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FISCAL NOTE

STATE OF ALASKA
1995 LEGISLATIVE SESSION

BILL NO. SB 114

ANALYSIS: (continued)

Summary:

a) Personal Services--The program will require reclassification of one Natural Resource Technician to a Natural Resource Officer. Position will review applications for HCMW, analyze production and certify wells.

b) Contractual--The program will require minimal funding for advertising and public hearings.

c) Supplies--The program will require funding for software and forms.

d) Equipment--The program will require funding for computer equipment.

Economic Impact: Bill should prolong producing life of qualifying wells for several years. Also, some currently shut-in wells may be returned to production. Based on 1994 production data, cost to state is estimated to be less than $5 million per year. Cost could rise if significant numbers of shut-in wells are returned to production. Future costs will increase as more wells qualify for HCMW standing as production declines in existing fields.

Cost of program is offset by royalty oil gained by the state, which would be lost if marginal production is shut-in.

Cautionary note: If tax credits are extended but withdrawn in later years, the HCMW then existing will be immediately plugged and abandoned. The resulting economic downturn would be more dramatic than if the wells are gradually plugged and abandoned in the absence of incentives.

Impact on Local Government: Principle beneficiary of the bill is the Kenai Peninsula and surrounding Cook Inlet area were most HCMWs are located. Bill will contribute to local employment and tax base. Significant additional benefits could be realized if new production is developed from currently shut-in wells.

SB

128

FISCAL NOTE

STATE OF ALASKA
1996 LEGISLATIVE SESSION

BILL NO. SSSB 128

Revision Date:
Title: Nonresident hunt, sport fish, trap fees
Sponsor: Senator Donley
Requester: Senate Resources

Dept. Affected: Fish and Game
BRU: Wildlife Conservation
Component: Wildlife Conservation
COMPONENT SERIAL NO. 473

Expenditures/Revenues (Thousands of Dollars)

OPERATING EXPENDITURES	FY 97	FY 98	FY 99	FY 00	FY 01	FY 02
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
CHANGE IN REVENUES (1024)	(276.0)	(1,696.8)	(1,696.8)	(1,696.8)	(1,696.8)	(1,696.8)

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
1024 Fish/Game Fund	(276.0)	(1,696.8)	(1,696.8)	(1,696.8)	(1,696.8)	(1,696.8)
TOTAL	(276.0)	(1,696.8)	(1,696.8)	(1,696.8)	(1,696.8)	(1,696.8)

Estimate of any current year (FY96) cost: $ 0.0

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)

This bill is expected to result in a permanent annual loss of $1,696.8 in hunting/trapping revenues to the Fish and Game Fund beginning in FY98. See page 2 for fiscal analysis.

Prepared by: Phil Koehl, Wildlife Biologist PK
Division: Wildlife Conservation
Phone: 465-6198
Date: 1/13/96
Approved by Commissioner: Frank Rue Geron Bruce for
Agency: Department of Fish and Game
Date: 1/15/96

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Rev 11/95) 96fiscal.xls/OBR

Bill Number **SSSB 128**
Title: **Nonresident hunt, sport fish, trap fees**

Assumptions used for license revenue caluculations:

- Effective date of bill will be 1/1/97 rather than 1/1/96.
- Revenue calculations are based on 1995 license year statistics.
- Approximately 80% of nonresident and 100% of nonresident alien license purchase sales occur in the first half of the fiscal year, thus accounting for reduced revenue losses for FY97.
- Annual license/tag sales to nonresidents and nonresident aliens fluctuate, but there is no long-term up or down sales trend.
- No nonresidents will purchase trapping licenses with the proposed rates and reduction of the licensing period from 1 year to 30 days.
- License sales to nonresidents and nonresident aliens are projected to decline by 40-50% and tag sales to nonresidents and nonresident aliens are projected to decline from 50-83%, depending on species. Based on a survey of nonresident hunters (Alaska Voters, Alaska Hunters, and Alaska Nonresident Hunters: Their Wildlife Related Trip Characteristics and Economics, by McCollum and Miller, November 1994), up to 40 percent of nonresidents and 50 percent of nonresident aliens indicated that they would not be willing to pay as much for their trip as the amounts proposed in SSSB 128. The percentage of hunters who indicated an unwillingness to hunt in Alaska varies by big game species targeted and ranges from 50% for nonresidents hunting caribou to 83% for nonresident aliens hunting sheep and elk.

Projected revenue losses to wildlife component of Fish and Game Fund:

Resident hunting and trapping licenses	131.1
Nonresident hunting licenses	229.1
Nonresident trapping licenses	6.5
Nonresident alien hunting licenses	15.8
Nonresident big game tags	1151.0
Nonresident alien big game tags	163.3
Total Revenue Losses	**$1,696.8**

FISCAL NOTE

STATE OF ALASKA
1996 LEGISLATIVE SESSION

BILL NO. SSSB 128

Revision Date:
Dept. Affected: Fish and Game
Title: Nonresident hunt, sport fish, trap fees
BRU: Sport Fish
Component: Sport Fish
Sponsor: Senator Donley
Requester: Senate Resources
COMPONENT SERIAL NO. 464

Expenditures/Revenues (Thousands of Dollars)

OPERATING EXPENDITURES	FY 97	FY 98	FY 99	FY 100	FY 01	FY 02
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0
CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
CHANGE IN REVENUES (1024)	543.0	2,215.3	2,259.6	2,304.8	2,350.9	2,397.9

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Fish and Game Fund 1024	543.0	2,215.3	2,259.6	2,304.8	2,350.9	2,397.9
TOTAL	543.0	2,215.3	2,259.6	2,304.8	2,350.9	2,397.9

Estimate of any current year (FY96) cost: $ 0.0

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)

See attached page for assumptions.

Prepared by: Irvin Brock
Phone: 465-6185
Division: Sport Fish
Date: 1/12/96
Approved by Commissioner: Frank Rue Geron Bruce for
Date: 1/15/96
Agency: Fish and Game

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FISCAL NOTE Continuation Page 2 of 2
Bill Number SSSB 128
Title: Nonresident hunt, sport fish, trap fees

Assumptions used for license revenue calculations:

- Effective date of bill will be 1/1/97 rather than 1/1/96.
- Revenue calculations are based on 1995 license sales statistics.
- Approximately 25% of sport fish license sales occur in the first half of a given calendar year (based on 3 year average 1993-1995) With this in mind, FY 97 revenues are only 25% of calculated total for calendar year.
- Annual license sales growth is estimated at 2% for revenue projections.
- Residents will purchase combination licenses out of convenience rather than for cost savings, therefore same number of combination licenses will be purchased in the future.
- Nonresidents who currently purchase an annual license will be forced to purchase a series of 14 day licenses. 50% will purchase two while the remaining 50% will purchase one 14 day license.
- Those nonresidents who currently purchase 14, 3, and 1 day licenses will continue to do so.
- The number of nonresident hunters will be reduced by 50% upon enactment of this bill (pers. comm. w/Wildlife Division).
- Of remaining nonresident hunters, 50% will purchase two 14 day sport fish licenses while the other 50% will purchase only one.
- Those nonresident hunters who currently purchase 14 day sport fish licenses will continue to do so.
- Of those nonresidents who currently purchase an annual nonresident king salmon stamp, 50% will purchase two 14 day stamps while the remaining 50% will purchase only one stamp.
- Those nonresidents who currently purchase 3 and 1 day king salmon stamps will continue to do so.

Sport Fish License and King Salmon Stamp Sales Comparison

DESCRIPTION	# SOLD 1995	REVENUE 1995	# SOLD 1997	REVENUE 1997	REVENUE NET (+/-)
Resident Sport Fishing	119995	1799.9	119995	1799.9	0
Resident Sport Fish & Hunt *	341	512.1	34141	448.1	(64.0)
Resident SF, Hunt & Trap *	4714	70.7	4714	64.3	(6.4)
Nonresident Sport Fish	22497	1124.8	N/A	0	(1124.8)
Nonresident 14 day Sport Fish	80377	2411.3	115762	4630.5	2219.2
Nonresident 3 day Sport Fish	58083	871.2	58083	1161.7	290.5
Nonresident 1 day Sport Fish	61704	617.0	61704	617.0	0
Nonresident Hunt and Sport Fish *	1050	52.5	N/A	0	(52.5)
Nonresident Hunt and 14 day SF *	1702	51.1	N/A	0	(51.1)
Nonresident King Salmon Stamp	32994	1154.8	N/A	0	(1154.8)
Nonresident 14 day KS Stamp	N/A	0	49491	1979.6	1979.6
Nonresident 3 day KS Stamp	27230	408.4	27230	544.6	136.2
Nonresident 1 day KS Stamp	31832	318.3	31832	318.3	0
Totals	476319**	7592.2	474952**	9764.1	2171.9

* Sport Fish portion only.
** Numbers are different due to loss of 1376 nonresident hunters and rounding.

THE SEAL OF THE STATE OF ALASKA

Official Business

COMMITTEE:

SENATE RESOURCES

DATE: 1/24/96

SIGN-IN

Subject of meeting:

SB 128 Nonresident Hunt, Sport Fish, Trap Fees

PLEASE PRINT!

NAME	ADDRESS (MAILING) & (ZIP)	PHONE	REPRESENTING	DO YOU WANT TO TESTIFY?
Wayne Regelin	PO Box 25526 Juneau 99801		Fish & Game	Y

9-LS0843\G
Utermohle
2/9/96

CS FOR SPONSOR SUBSTITUTE FOR SENATE BILL NO. 128( )

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINETEENTH LEGISLATURE - SECOND SESSION

BY

Offered:
Referred:

Sponsor(s): SENATOR DONLEY

A BILL

FOR AN ACT ENTITLED

"An Act reducing certain resident sport fishing, hunting, and trapping license fees, increasing certain nonresident sport fishing, hunting, and trapping license fees, and relating to nonresident sport fishing, hunting, and trapping licenses; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. AS 16.05.340(a)(3) is amended to read:

(3) Resident hunting and trapping license . . . . <u>35</u> [40]

* Sec. 2. AS 16.05.340(a)(5) is amended to read:

(5) Resident hunting and sport fishing license . . . . <u>35</u> [40]

* Sec. 3. AS 16.05.340(a)(6) is amended to read:

(6) Resident hunting, trapping, and sport fishing license . . . <u>50</u> [55];

(A) however, the fee is $5 for an applicant who

(i) is receiving or has received assistance during the preceding six months under any state or federal welfare program to aid

the indigent; [,] or

(ii) has an annual family gross income of less than $8,200 for the year preceding application;

(B) a person paying $5 for a resident hunting, trapping, and sport fishing license must provide proof of eligibility under this paragraph when requested by the departments.

* Sec. 4. AS 16.05.340(a)(7) is amended to read:

(7) Nonresident [SPECIAL] sport fishing license - valid for the period inscribed on the license

(A) For 14-day license $60

(B) For seven-day license 40

(C) [$30 (B)] For three-day license .... 20 [15]

(D) [(C)] For one-day license 10

A nonresident who, for the preceding six consecutive months, has maintained a permanent place of abode in the state and who has continually maintained a voting residence in the state may receive a nonresident sport fishing license valid for six months or until the end of the calendar year, whichever is less, for $60.

* Sec. 5. AS 16.05.340(a)(9) is amended to read:

(9) Nonresident hunting license - valid for the 30-day period inscribed on the license .... 100 [85]

A nonresident may not take a big game animal without previously purchasing a numbered, nontransferable, appropriate tag, issued under (15) of this subsection. The tag must be affixed to the animal immediately upon capture and must remain affixed until the animal is prepared for storage, consumed, or exported. A tag issued but not used for an animal may be used to satisfy the tagging requirement for an animal of any other species for which the tag fee is of equal or less value.

* Sec. 6. AS 16.05.340(a)(11) is amended to read:

(11) Nonresident [HUNTING AND] trapping license - valid for the 30-day period inscribed on the license .... $500 [$250]

* Sec. 7. AS 16.05.340(a)(19) is amended to read:

(19) Nonresident small game hunting license - valid for the 30-day

period inscribed on the license . . . . 25 [20]

* Sec. 8. AS 16.05.340(a)(20) is amended to read:

(20) Nonresident alien hunting license - valid for the 30-day period inscribed on the license . . . . 500 [300]

A nonresident alien may not take a big game animal without previously purchasing a numbered, nontransferable, appropriate tag, issued under (21) of this subsection. The tag must be affixed to the animal immediately upon capture and must remain affixed until the animal is prepared for storage, consumed, or exported. A tag issued but not used for an animal may be used to satisfy the tagging requirement for an animal of any other species for which the tag fee is of equal or less value.

* Sec. 9. AS 16.05.340(a)(24) is amended to read:

(24) Nonresident anadromous king salmon tag - valid for the period inscribed on the tag

(A) for a one-day tag $10

(B) for a three-day tag . . . . 20 [15]

(C) for a seven-day tag 40

(D) for a 14-day [OR ANNUAL] tag . . . . 60 [35].

A nonresident may not engage in sport fishing for anadromous king salmon without having a valid anadromous king salmon tag in the person's actual possession, unless that person is under the age of 16.

Members [HOWEVER, MEMBERS] of the military service on active duty who are permanently stationed in the state, and their dependents, who do not qualify as residents under AS 16.05.940, may obtain an annual nonresident military anadromous king salmon tag for $20.

A nonresident who, for the preceding six consecutive months, has maintained a permanent place of abode in the state and who continually maintained a voting residence in the state may receive a nonresident anadromous king salmon tag valid for six months or until the end of the calendar year, whichever is less, for $60.

* Sec. 10. AS 16.05.350 is amended to read:

Sec. 16.05.350. EXPIRATION OF LICENSES AND TAGS. (a) Licenses and tags required under AS 16.05.330 - 16.05.430, except biennial licenses, the nonresident [SPECIAL] sport fishing license, **the nonresident hunting license, the nonresident alien hunting license, the nonresident trapping license, the nonresident small game hunting license,** the resident trapping license, the [ONE, THREE, OR 14-DAY] nonresident anadromous king salmon tag, and the waterfowl conservation tag, expire at the close of December 31 following issuance.

(b) Biennial licenses expire after December 31 of the year following the year of issuance.

(c) The resident trapping license expires at the close of September 30 of the year following the year in which the license is issued.

(d) The waterfowl conservation tag expires at the close of January 31 of the year following the year of issue of the tag.

* Sec. 11. AS 16.05.340(a)(8) and 16.05.340(a)(10) are repealed.

* Sec. 12. This Act takes effect January 1, 1997.

SPONSOR SUBSTITUTE FOR SENATE BILL NO. 128

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINETEENTH LEGISLATURE - FIRST SESSION

BY SENATOR DONLEY

Introduced: 3/28/95
Referred: RES, FIN

A BILL

FOR AN ACT ENTITLED

"An Act reducing certain resident sport fishing, hunting, and trapping license fees, increasing certain nonresident sport fishing, hunting, and trapping license fees, and relating to nonresident sport fishing, hunting, and trapping licenses; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

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(3) Resident hunting and trapping license . . . . 35 [40]

* **Sec. 2.** AS 16.05.340(a)(5) is amended to read:

(5) Resident hunting and sport fishing license . . . . 35 [40]

* **Sec. 3.** AS 16.05.340(a)(6) is amended to read:

(6) Resident hunting, trapping, and sport fishing license . . . 50 [55];

(A) however, the fee is $5 for an applicant who

(i) is receiving or has received assistance during the preceding six months under any state or federal welfare program to aid

the indigent; [,] or

(ii) has an annual family gross income of less than $8,200 for the year preceding application;

(B) a person paying $5 for a resident hunting, trapping, and sport fishing license must provide proof of eligibility under this paragraph when requested by the departments.

* Sec. 4. AS 16.05.340(a)(7) is amended to read:

(7) Nonresident [SPECIAL] sport fishing license - valid for the period inscribed on the license

(A) For 14-day license . . . . **$40** [$ 30]

(B) For three-day license . . . . **20** [15]

(C) For one-day license 10

* Sec. 5. AS 16.05.340(a)(9) is amended to read:

(9) Nonresident hunting license **- valid for the 30-day period inscribed on the license** . . . . **100** [85] **A nonresident may not take a big game animal without previously purchasing a numbered, nontransferable, appropriate tag, issued under (15) of this subsection. The tag must be affixed to the animal immediately upon capture and must remain affixed until the animal is prepared for storage, consumed, or exported. A tag issued but not used for an animal may be used to satisfy the tagging requirement for an animal of any other species for which the tag fee is of equal or less value.**

* Sec. 6. AS 16.05.340(a)(11) is amended to read:

(11) Nonresident [HUNTING AND] trapping license **- valid for the 30-day period inscribed on the license** . . . . **$500** [$250]

* Sec. 7. AS 16.05.340(a)(15) is amended to read:

(15) Nonresident big game tags

(A) Bear, black, each . . . . **250** [225]

(B) Bear, brown or grizzly, each . . . . **1,000** [500]

(C) Bison, each . . . . **750** [450]

(D) Caribou, each . . . . **500** [325]

(E) Deer, each . . . . **200** [150]

(F) Elk, each . . . . 500 [300]

(G) Goat, each . . . . 500 [300]

(H) Moose, each . . . . 750 [400]

(I) Sheep, each . . . . 1,000 [425]

(J) Wolf, each . . . . 250 [175]

(K) Wolverine, each . . . . 250 [175]

(L) Musk oxen, each . . . . 1,500 [1,100]

* Sec. 8. AS 16.05.340(a)(19) is amended to read:

(19) Nonresident small game hunting license **- valid for the 30-day period inscribed on the license** . . . . 25 [20]

* Sec. 9. AS 16.05.340(a)(20) is amended to read:

(20) Nonresident alien hunting license **- valid for the 30-day period inscribed on the license** . . . . 500 [300]

A nonresident alien may not take a big game animal without previously purchasing a numbered, nontransferable, appropriate tag, issued under (21) of this subsection. The tag must be affixed to the animal immediately upon capture and must remain affixed until the animal is prepared for storage, consumed, or exported. A tag issued but not used for an animal may be used to satisfy the tagging requirement for an animal of any other species for which the tag fee is of equal or less value.

* Sec. 10. AS 16.05.340(a)(21) is amended to read:

(21) Nonresident alien big game tags

(A) Bear, black, each . . . . $500 [$300]

(B) Bear, brown or grizzly, each . . . . 1,500 [650]

(C) Bison, each . . . . 1,000 [650]

(D) Caribou, each . . . . 750 [425]

(E) Deer, each . . . . 300 [200]

(F) Elk, each . . . . 750 [400]

(G) Goat, each . . . . 750 [400]

(H) Moose, each . . . . 750 [500]

(I) Musk oxen, each . . . . 2,000 [1,500]

(J) Sheep, each . . . . 1,500 [550]

(K) Wolf, each . . . . 500 [250]

(L) Wolverine, each . . . . 500 [250]

* Sec. 11. AS 16.05.340(a)(24) is amended to read:

(24) Nonresident anadromous king salmon tag - valid for the period inscribed on the tag

(A) for a one-day tag $10

(B) for a three-day tag . . . . 20 [15]

(C) for a 14-day [OR ANNUAL] tag . . . . 40 [35].

A nonresident may not engage in sport fishing for anadromous king salmon without having a valid anadromous king salmon tag in the person's actual possession, unless that person is under the age of 16. However, members of the military service on active duty who are permanently stationed in the state, and their dependents, who do not qualify as residents under AS 16.05.940, may obtain an annual nonresident military anadromous king salmon tag for $20.

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(c) The resident trapping license expires at the close of September 30 of the year following the year in which the license is issued.

(d) The waterfowl conservation tag expires at the close of January 31 of the year following the year of issue of the tag.

* Sec. 13. AS 16.05.340(a)(8) and 16.05.340(a)(10) are repealed.

* Sec. 14. This Act takes effect January 1, 1996.

SPONSOR SUBSTITUTE FOR SENATE BILL NO. 128

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINETEENTH LEGISLATURE - FIRST SESSION

BY SENATOR DONLEY

Introduced: 3/28/95
Referred: RES, FIN

A BILL

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* Sec. 3. AS 16.05.340(a)(6) is amended to read:

(6) Resident hunting, trapping, and sport fishing license . . . <u>50</u> [55];

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