degree. This coupled with stratigraphic discontinuities, can hydraulically isolate individual reservoir units.

The fracture gradient is between 0.66-0.70 psi/ft with an overburden stress gradient of 0.85 psi/ft. The estimated net confining stress is between 1000 to 1300 psi.

OIL CHARACTERISTICS

The Schrader Bluff Pool is understaturated by about 500 psi and correspondingly has no gas cap. The initial average reservoir pressure is 1750 psig at 4000 ft true vertical depth subsea with an average reservoir temperature of 81°F. These pressures are only slightly higher than the local hydrostatic pressures. Currently, the average reservoir pressure is between 1400 to 1750 psi depending on producing fault block.

The hydrocarbon quality varies between the N and O sands, the deeper O sand containing a better-quality crude than the N sand. The N sand oil gravities range from 14° to 19° API with viscosities between 40 and 140 centipoise(cp). The oil gravities and viscosities improve in the O sands, oil gravities typically falling between 18° to 21.5° API with viscosities from 30 to 45 cp. Figure No. 3 shows the anticipated API gravity variations across the Schrader Bluff formation.

In general, the PVT properties of the Schrader Bluff hydrocarbons bear a resemblance to conventional heavy oil systems, namely:

- low API gravities (14-22°),
- low gas oil ratio(GOR)(100-200 scf/stb),
- low oil formation volume factor (about 1.04-1.08 rbbl/stb),
- high average viscosity (30 to 70 cp at original conditions).

The live oils of the Schrader Bluff are dominated by the C7+ fractions (67 mole percent on average). This corresponds to an exceedingly small amount of C2-C6 intermediate hydrocarbons and suggests high bio-degradation. The hydrocarbons contain no hydrogen sulfide, and very little quantities of carbon dioxide or nitrogen. The gas composition is primarily methane. The formation water contains approximately 27,000 ppm total dissolved solids, with an average salinity of 20,000 ppm NaCl equivalent.

In common with fluid systems from shallow and soft sands, the Schrader Bluff hydrocarbon properties exhibit significant variations across sand bodies. This variance is seen vertically, from sand to sand, and laterally within one sand as it is traced down dip. The mapped variance is poorly understood at this time.

PRESENT DEVELOPMENT

A localized Tract 14 pilot project was initiated in 1991, developing approximately 2560 acres (Figure No. 2). Roads, pipelines and general facilities to support 4 pads were constructed and presently support 23 deviated wells (Figure No. 4). A limited waterflood was initiated in March 1992 The reservoir is currently developed on a spacing that varies from 160 acre to 80 acres. It is anticipated that development will be ultimately be equal to, or less than, 80 acres.

RESERVOIR / FIELD PERFORMANCE

Drilling

Drilling and completion costs comprise one of the major cost levers being aggressively worked. Historical drilling and completion costs averaged $2.3 MM per well. Changes in the casing program have resulted in significant cost reductions. Current drill and completion costs average $1.6 MM, a 30 percent savings. Work is underway to reduce these costs further.

Completions

Typical completion design includes 2 7/8" tubing with an electrical submersible pump (ESP) and a wellbore heat trace system preventing freezing in the permafrost section of the wellbore. (Figure No. 5). Sand control methods are required to insure long ESP run lives. Wells where O-sands have not been controlled have produced varying quantities of sand, leading to premature ESP failures.

Gravel packs, pre-packed screens, and frac-packed sand control techniques have been

employed to determine the most cost effective and least damaging completion. The future challenge is to improve frac-packing technology and reduce completion costs.

Offtake History

Commercial production from Schrader Bluff began in March 1991. Waterflood was initiated in March 1992 in four different fault blocks when several production wells were converted to water injectors and two additional injectors were drilled. There are twenty three (23) wells in Tract 14 region; 2 horizontal producers, 15 active conventional producers, of which 4 are shut-in because of ESP failures, 5 injectors and 1 well that was never completed due to faulted section.

Initial production averaged approximately 350 BOPD. The initial gas oil ratio averaged 180 scf/stb with watercuts generally less than 1 percent. Currently, the average production rate is 200 BOPD per well with an average GOR of 450 scf/stb. The watercut has increased to 14 percent. The most productive wells of the field have cumulative volumes of 0.5 MMstbo. Cumulative production to date is approximately 4.1 MMstbo representing approximately 1.4 percent of original oil in place within the Tract 14 region. The field decline rate is 6 percent per year (Figure No. 6).

Completion designs limit reservoir surveillance activities. Therefore, alternative data acquisition methods are used. For example, RFT pressures are obtained in the Schrader Bluff from wells drilled to the deeper Kuparuk formation. This pressure information provides valuable data for monitoring depletion in the different sands.

Reserves

Reservoir volumetric analysis quantifying oil in place, as complex as it might be, is one of the more straight forward estimations regarding the Schrader Bluff. Actual reservoir connectivity due to stratigraphy and sedimentology, as well as structural compartmentalization, complicate the picture. Therefore, sweep efficiency will be highly variable and in some areas, ineffective. Additional efforts are focused on quantifying the effects of three drive mechanisms providing energy to the reservoir: solution gas, compaction, and water drives. Initial performance is attributed to solution gas drive, followed by contributions from compaction and water support. The ultimate necessity and timing of waterflood support is considered key to large-scale planning.

Milne Point's Schrader Bluff contains more than 2 billion barrels of oil. The Schrader Bluff, over the entire North Slope, contains more than 16 billion barrels. An additional 10 billion barrels resides in the informally named Ugnu sands overlying the Schrader Bluff. The oils in this unit have progressively lower API gravities corresponding to increased bio-degradation. The associated higher viscosities, coupled with the lower temperatures as one approaches the permafrost at 1500-2000 feet, renders recoveries from this resource more problematic.

Assuming waterflood support, and limiting production to existing producers, modeling indicates recoveries exceeding 16 percent. Applying these recoveries to original oil in place yields greater than 320 MMstbo with fieldwide development. This first generation model will be replaced with a more refined simulator being developed to assist in reservoir evaluation, planning and maintenance.

EOR Recoveries

The reservoir and oil characteristics of the Schrader Bluff make it a prime candidate for various enhanced oil recovery (EOR) projects. Among the methods that have passed initial screening are Air Injection (In-situ Combustion), various floods, such as CO2 or natural gas liquid projects, and to a lesser degree, steam flooding. Each of these methods has its own advantages and disadvantages, with varying probabilities of success. Several methods might ultimately be employed in different parts of the field, depending upon local reservoir and oil character.

Scoping models of these processes yield possible incremental recoveries from 12-40 percent over those recovered by waterflood.

These models indicate that air injection yields the highest recoveries, although capital costs for compressors, facilities, and re-completions are anticipated to be significant. Extremely tight environmental compliance on the North Slope is another significant consideration in what processes ultimately move from modeling to field testing.

CHALLENGES

Presently, the Schrader Bluff and the total shallow oil accumulation of 26 billion barrels in the greater North Slope area, do not favorably compete for international development funds. Contributing factors are: elevated North Slope facility and drilling costs; costs associated with environmental protection, presently inflexible fiscal terms; all coupled with production rates, low by North Slope standards. The combination yields net rates of return and paybacks that are unattractive under current economic conditions.

Assuming constant economic factors such as royalty rates, and oil prices, main challenges to unlocking large-scale development include:

1) driving down front end capital costs associated with drilling and facilities to levels, comparable with Canadian and northern tier Lower 48 operations, through design, operational innovations, and judicious contractual agreements,
2) accelerating initial production and modifying decline curves on a per well basis through innovative completion techniques and reservoir management,
3) maximizing ultimate recovery through reservoir management and to a lessor degree, enhanced oil recovery methods.

If such challenges can be met, the keys to success will have been found.

Costs

Cost savings have already been realized in many areas including: casing programs, well head hardware, hydraulic fracture designs, analysis of hole sizing, facilities design, piggybacking on existing facility designs, utilizing surplus equipment from other North Slope assets, pad design, fit for purpose rigs, logging costs, workover costs, and investigation of coil tubing completions.

In addition, general operating and overhead costs are prime targets for reduction. As an example, the workover cost of replacing a failed ESP, universally utilized at Milne Point, has been reduced by half. Furthermore, costs are expected to be reduced to one third of the original costs within the year. The frequency of ESP replacement, a significant operating expense, has also seen improvement with expected runlives increasing from 3 to 5 years.

Well Productivities

Well productivities are primarily keyed to net pay, oil viscosity, completion design, and ESP runlives. Whereas, net pay and oil viscosity are variables somewhat beyond control, gains have been made in completion design, and all operational aspects of ESP's.

Recent innovative hydraulic fracture designs involving pumping large volumes in short time frames, achieving wide fracture width with minimal propagation, have yielded the highest productivity index to date. These rates, while pushing the envelope of existing equipment, have the potential of increasing initial production rates by a factor of 2 to 3.

Environmental Considerations

Operations on the North Slope of Alaska are not "business as usual" when it comes to environmental concerns. In these times of heightened awareness, Milne Point is located in a place where this awareness is focused. Alaska contains a high percentage of our protected lands within the United States. Over 50 % of the total acreage devoted to Parks or Refuges fall within Alaska, and with this high concentration, goes a heightened responsibility. As stewards of the environment in which we work, we must be diligent in our protection of this resource. This stewardship comes with a cost, however, and this cost is substantial.

Due to land ownership, lease conditions, and legislation, the North Slope is regulated by three layers of government, the North Slope Borough, the State of Alaska, and the United States government. As a result, regulations must be followed, studies conducted, reports filed and permits obtained for each of these entities.

The nature of the tundra wetlands and its associated flora and fauna drives many aspects of operations, all to minimize impact: facility design, waste disposal, drill pad site selection, road construction, and timing of operations with regard to temperature and wildlife cycle. These costs are necessary for doing business in a responsible manner. But, the costs are considerable and put an additional economic burden upon any successful development. Being fully committed to our environmental responsibilities, and simultaneously striving to find keys to unlocking this resource, crystallizes an environmental challenge: finding ways to fully protect the environment by reducing the foot print, and thereby, reducing overall costs.

PRESENT DEVELOPMENT PLANS

The 1995 Schrader Bluff program includes drilling as many as 5 wells from the existing Milne Point pad infrastructure to achieve higher production rates at lower drilling and completion costs. Non-conventional wells and large scale frac-packs are two examples of technologies under consideration to improve production rates. In addition, drilling and completion methods and costs are being challenged and alternative drilling fluids are being evaluated to minimize completion and formation damage.

In conjunction with this drilling program, a comprehensive reservoir and fluid study is underway to more fully understand performance. This work is fully cross-disciplinary and interlinks at many levels. (Figure No. 7) As well as integrating existing data, conventional core and downhole fluid samples are being taken to further this analysis. Much of this data will be the basis for a fullfield simulator being constructed to assist in reservoir management and evaluation.

Development scenarios for collection and processing facilities are being evaluated. The aim is to efficiently collect production from potentially hundreds of new wells, while increasing facility capacity to process the flowstreams. Several alternatives are under consideration, including debottlenecking the central processing plant and 'partial processing' of produced fluids at well pads.

The desire to minimize surface impact by centralized pad design dovetails with cost reduction. However, this drives up drilling costs and complicates field development, and maintenance, as it requires highly deviated wells. As the iterations involving development strategy, facility design and drilling costs are far from unique, choosing the final solution will be a challenge in its own right.

EOR processes are being screened and scoping analyses will be conducted to evaluate incremental recoveries. However, primary and secondary recovery, coupled with cost, are the main Schrader Bluff economic drivers. Enhanced oil recovery is not considered a key to unlocking the Schrader Bluff resource. As presented in this paper, the keys are closer at hand.

ACKNOWLEDGMENTS

The authors wish to acknowledge Occidental Petroleum for granting permission to publish this material. Thanks go to the previous staff of CONOCO who saw the potential of the Schrader Bluff resource and went forward with the initial pilot project. Similarly, those within BP who have seen the potential and can see the path towards realization are acknowledged. Thanks also go to Craig Smalley, BP-Sunbury, for assistance rendered.

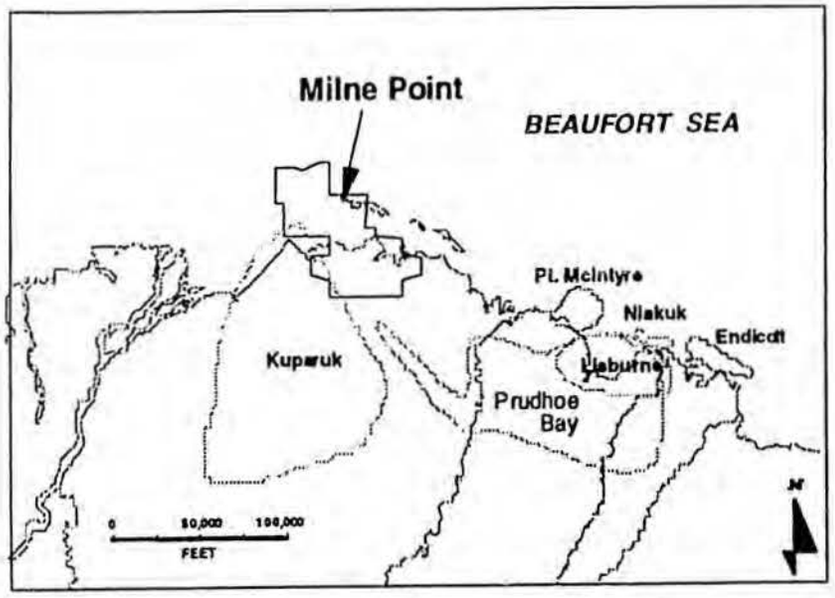


Figure 1 - Map of the North Slope of Alaska

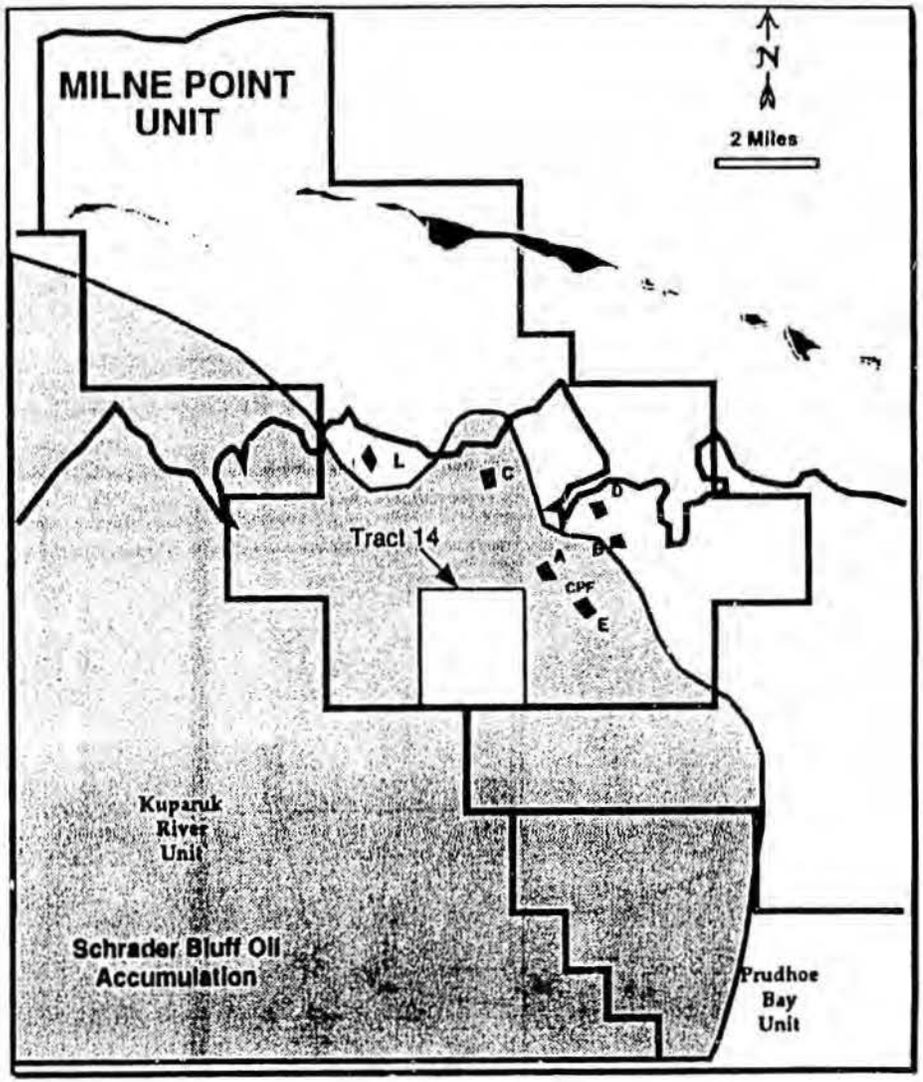


Figure 2 - Schrader Bluff Oil Accumulation

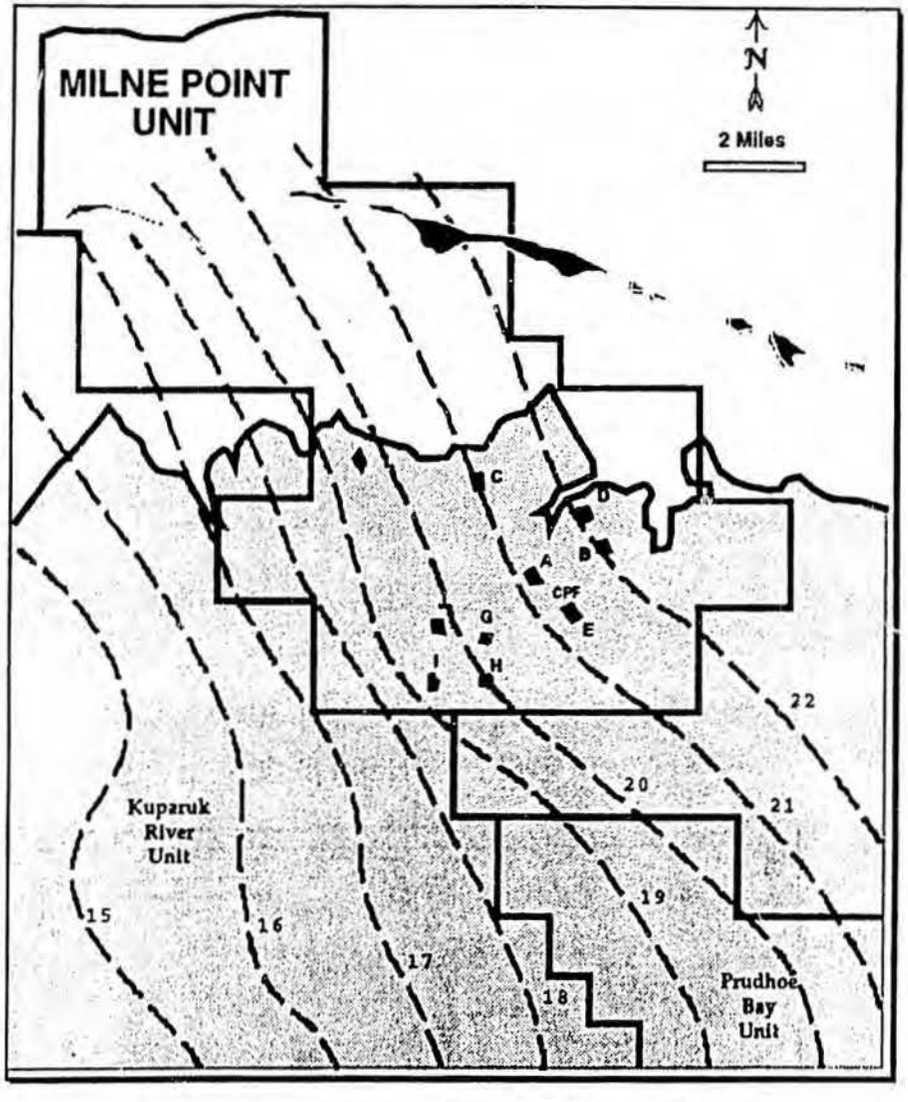


Figure 3 - Schrader Bluff API Gravity Map

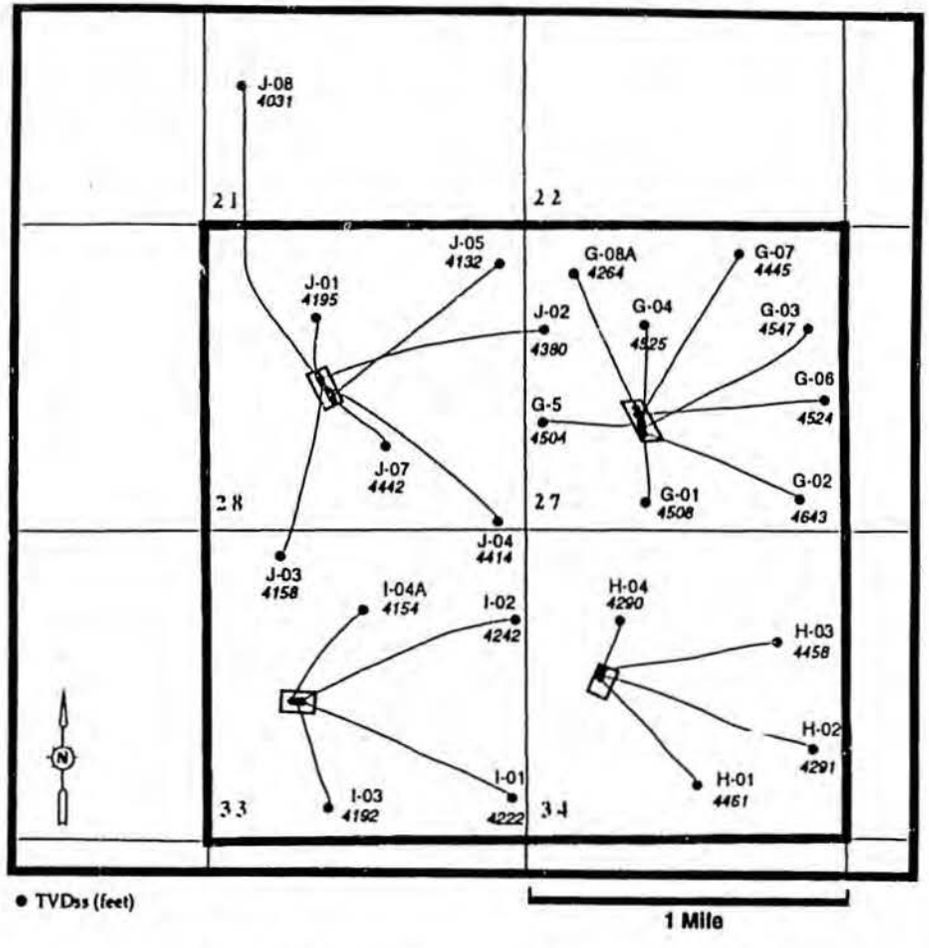


Figure 4 - Tract 14 Well Location Map

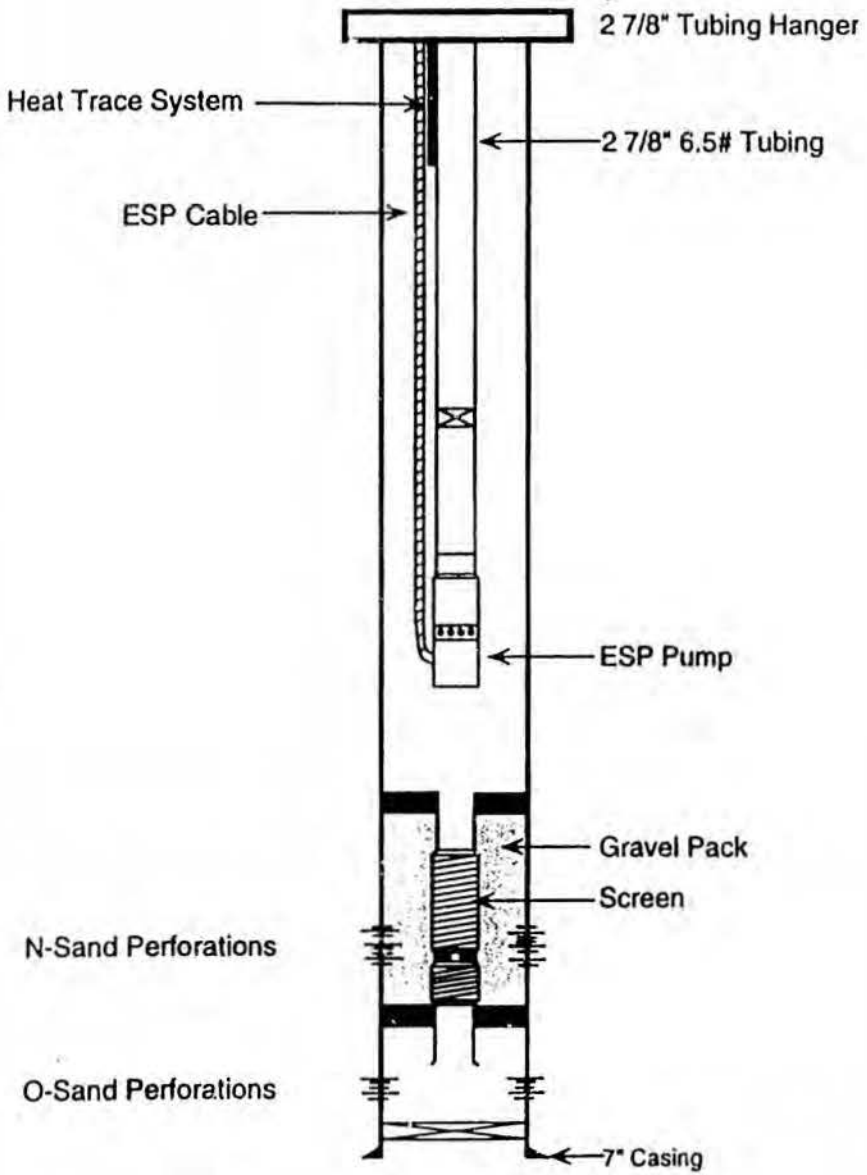


Figure 5 - Generic Schrader Bluff Completion

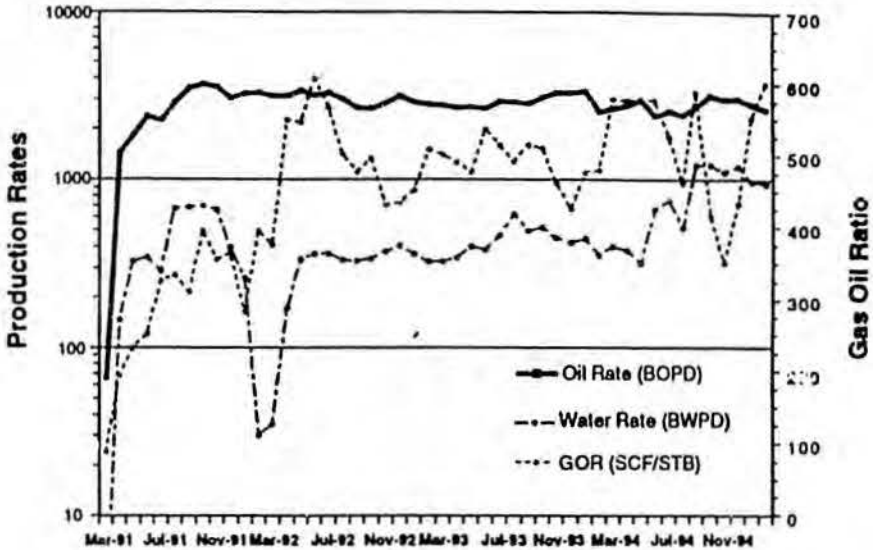


Figure 6 - Monthly Average Production History

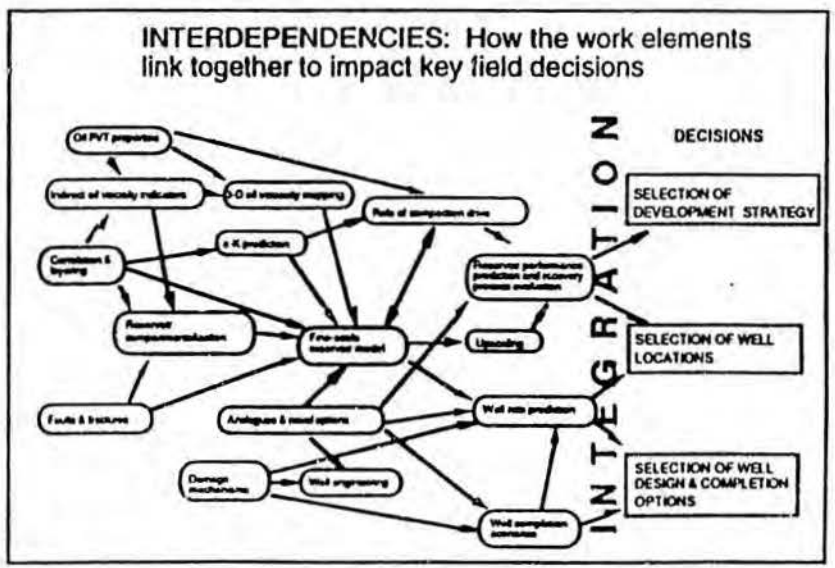


Figure 7 - Work Program Interdependencies

ATTORNEYS AT LAW

SIMPSON, TILLINGHAST, SORENSEN & LORENSEN

A PROFESSIONAL CORPORATION

LESLIE LONGENBAUGH
RONALD W. LORENSEN
L. MERRILL LOWDEN
E. BUDD SIMPSON
STEPHEN F. SORENSEN
JON K. TILLINGHAST

ONE SEALASKA PLAZA, SUITE 300
JUNEAU, ALASKA 99801

PHONE (907) 586-1400
FAX (907) 586-3065

January 16, 1996

Ms. Shirley Armstrong
Office of Rep. Norman Rokeburg
Room 110, State Capitol
Juneau, Alaska 99801

Re: Enclosed Price Ceiling Examples
Our File No.: 840.1

Dear Shirley:

Enclosed are the BLM and IRS incentive price ceiling examples that I mentioned to Rep. Rokeburg yesterday, and that he requested. I've marked the ceiling language in blue pen.

Sincerely,

SIMPSON, TILLINGHAST, SORENSEN & LORENSEN

Jon K. Tillinghast

LEVEL 1 - 1 OF 3 DOCUMENTS

FEDERAL REGISTER
Vol 60, No 116

Proposed Rules

DEPARTMENT OF THE INTERIOR (DOI)
Bureau of Land Management (BLM)

43 CFR Part 3100

[WO-610-4110-02 1A]
RIN 1004-AC26

Promotion of Development, Reduction of Royalty on Heavy Oil

60 FR 31663

DATE Friday, June 16, 1995

ACTION Notice of proposed rulemaking, notice of reopening of comment period

SUMMARY On April 10, 1995, the Bureau of Land Management (BLM) published in the
Federal Register (60 FR 18081) a notice of proposed rulemaking to amend the regulations related to the waiver, suspension, or reduction of rental, royalty, or minimum royalty on "heavy oil" (crude oil with a gravity of less than 20 degrees) The notice allowed a comment period of 60 days, closing on June 9, 1995

The Department of Energy (DOE) is currently developing new information on the potential impacts of the proposed rule DOE is focusing particularly on the effects of raising the qualifying crude oil gravity to more than 20 degrees In order to allow all interested parties sufficient time to review the new DOE information, BLM is reopening the comment period for an additional 30 days. Information on the DOE findings is available from Dr John Bebout, at the address shown below under FOR FURTHER INFORMATION CONTACT

DATES Comments should be submitted by July 17, 1995 Comments received or postmarked after the above date may not be considered in the decisionmaking process on the final rule

ADDRESSES Comments should be sent to Director (140), Bureau of Land Management,

Room 5555, 1849 C Street, NW., Washington, DC 20240. Comments can also be sent to internet:WO140@attmail.com. Please include "attn: AC26" and your name and return address in your internet message. Comments will be available for public review at the above address during regular business hours (7:45 a.m. to 4:15 p.m.), Monday through Friday.

FOR FURTHER INFORMATION CONTACT: Dr. John W. Bebout, Bureau of Land Management (310), 1849 C Street, NW., Washington, DC 20240, (202) 452-0340.

Micheal A. Ferguson,

Acting Assistant Director, Resource Use and Protection.

60 FR 31663

[FR Doc 95-14785 Filed 6-15-95, 8:45 am]

BILLING CODE 4130-84-P

LEVEL 1 - 2 OF 3 DOCUMENTS

FEDERAL REGISTER
Vol 60, No 68

Proposed Rules

DEPARTMENT OF THE INTERIOR (DOI)
Bureau of Land Management (BLM)

43 CFR Part 3100

[WO-610-00-4110-2411]
RIN 1004-AC26

Promotion of Development, Reduction of Royalty on Heavy Oil

60 FR 18081

DATE Monday, April 10, 1995

ACTION Proposed rule

To view the next page, type np* TRANSMIT
To view a specific page, transmit p* and the page number, e g p*1

SUMMARY The Bureau of Land Management (BLM) is issuing this proposed rule to amend the regulations relating to the waiver, suspension, or reduction of rental, royalty, or minimum royalty This amendment would establish the conditions under which the operators of properties that produce "heavy oil" (crude oil with a gravity of less than 20 degrees) can obtain a reduction in the royalty rate This action is being taken to encourage the operators of Federal heavy oil leases to place marginal or uneconomical shut-in oil wells back in production, provide an economic incentive to implement enhanced oil recovery projects, and delay the plugging of these wells until the maximum amount of economically recoverable oil can be obtained from the reservoir or field The BLM believes that this amendment will result in substantial additional revenue for the States and Federal Government, increase the cumulative amount of domestic oil production from existing wells, increase the percentage of oil recovery from presently developed reservoirs, minimize the necessity of drilling new wells with their additional environmental impacts, assist in reducing the national balance of trade deficit, and help promote stability in the jobs and

services related to the domestic oil industry

DATES Comments should be submitted by June 9, 1995 Comments postmarked after this date may not be considered as part of the decisionmaking process in issuance of a final rule

ADDRESSES Comments should be sent to Director (140), Bureau of Land Management, Room 5555, Main Interior Building, 1849 C Street, N W , Washington, D C 20240 Comments will be available for public review in Room 5555 at the above address during regular business hours (7 45 a m to 4 15 p m), Monday through Friday

60 FR 18081, *

FOR FURTHER INFORMATION CONTACT Dr John W Bebout, Bureau of Land Management,
(202) 452-0340

SUPPLEMENTARY INFORMATION Existing section 3103 4-1 of Title 43, Code of Federal Regulations, provides two forms of Federal oil and gas royalty reduction on a case-by-case basis upon application, and for stripper wells In order to encourage the greatest ultimate recovery of oil or gas and in the interest of conservation, the Secretary, upon a determination that it is necessary to promote development, or that a lease cannot be successfully operated under the terms provided therein, may reduce the royalty on an entire leasehold or any portion thereof The provision concerning stripper well properties allows royalty reduction for properties that produce an average of less than 15 barrels of oil per eligible well per well-day

The Bureau of Land Management (BLM) has reason to believe that additional royalty relief for producers of heavy crude oil may be necessary to maintain current levels of development, promote investment in enhanced recovery efforts, and encourage maximum recovery of the resource, thus warranting royalty reduction under Section 39 of the Mineral Leasing Act (30 U S C 209)

Fluctuating oil prices, combined with high production costs, have resulted in an uncertain economic future for producers of low gravity crude oil As recently as last January, California producers of heavy crude were spending between $ 9 and $ 10 to produce a barrel of crude oil that was typically selling for between $ 8 50 and $ 9 per barrel (from data provided by the Conservation Commission of California Oil and Gas Producers) When depreciation, depletion, and amortization costs were considered, nearly 69% of the state's production was uneconomic and more than 13,000 industry and industry-related jobs were at risk (California Independent Petroleum Association)

Heavy crude oil prices have recently risen to the point that the immediate crisis in California has passed Many of the heavy oil properties remain only marginally economic, however, and are vulnerable to future down-turns in oil prices As many as two-thirds of the marginal properties could be lost during a period of sustained low oil prices (National Petroleum Council Committee on Marginal Wells/Executive Summary-Draft) The danger in losing these wells is that, although production from individual wells may be small, their collective loss would be significant The United States would lose the opportunity to take advantage of new technologies being developed by the Department of Energy (DOE) and industry, and the remaining recoverable reserves would be lost

This proposed rule would preserve the contribution of marginal producers of heavy crude oil to the national reserve base. As a result of this relief, more wells should stay on line (even in periods of depressed oil prices), fewer recoverable reserves should be lost, and there will be less adverse economic impact on States and local communities.

The DOE has modeled the BLM's proposed royalty rate reduction for heavy crude oil. It is DOE's conclusion that the proposal will benefit all producers of heavy oil while remaining revenue neutral to all oil producing States except California (California contains the majority of the nation's heavy oil reserves). Assuming a West Texas Intermediate Crude oil price of $ 20 per barrel-a price consistent with recent oil markets-the proposal can be expected to increase recoverable reserves in California by around 72 percent, from 132.8 million barrels to 228.5 million barrels.

60 FR 18081 *

A provision of the proposed rule provides for the termination of individual royalty reductions should the average price of West Texas Intermediate Crude oil rise to a level greater than $ 24 per barrel for a period of at least 6 consecutive months. This provision is intended to ensure that [*18082] royalty relief is only provided during periods of low market prices.

The proposed rule establishes a sliding scale royalty rate for qualifying heavy-oil-producing properties. The sliding scale is intended to somewhat offset the reduced prices paid for oil as oil gravity decreases. The reduced royalty rate applies to qualifying heavy oil properties rather than individual wells, because production is normally not measured for individual oil wells, and is based on the average gravity of the oil weighted by the production of heavy oil from each well within the property. A weighted average gravity is used to prevent gravity manipulation by selectively producing wells on a property with heavier gravity crude. Using a weighted average of oil gravity encourages maximum recovery from all wells within a property by removing the economic advantage of selective production.

The rule provides that either the operator (as defined at 43 CFR 3100.0-5) or the payor (as defined at 30 CFR 208.2) must calculate the weighted average gravity of the oil-measured on the American Petroleum Institute (API) scale-produced from a property every 12 months to determine the appropriate royalty rate. In no case, however, would the royalty rate exceed the rate established by the terms of the lease.

The section amended by this proposed rule also provides for royalty rate reductions for stripper oil wells. Many provisions of this proposed rule are essentially the same as the provisions of the existing regulations that pertain to stripper wells, except that references to "stripper well" have been replaced with "heavy oil well." The similarity between the existing provisions pertaining to stripper wells and the provisions of this proposed rule could allow for some restructuring of section 43 CFR 3103.4-1 to reduce the overall regulatory text and to increase clarity. The public is invited to comment on whether reorganizing 43 CFR 3103.4-1 should be considered in preparing the final heavy oil royalty reduction rule.

The principal author of this proposed rule is Dr. John W. Bebout, Senior Technical Specialist, Fluids Group, assisted by the Regulatory Management Team, Bureau of Land Management.

It is hereby determined that this rule does not constitute a major Federal action significantly affecting the quality of the human environment and that no

detailed statement pursuant to Section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)) is required.

This rule has been reviewed under Executive Order 12866.

The BLM has determined that this rule will not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 et seq.). This is because the proposed royalty rate reduction is voluntary, requires no additional paperwork, and applies to all operators regardless of size. Additionally, the BLM has determined, under Executive Order 12630, that the rulemaking will not cause a taking of private property.

60 FR 18081, *18082

The BLM has certified that these regulations meet the applicable standards provided in sections 2(a) and 2(b)(2) of Executive Order 12778

The information collection requirements of this rule have been approved by the Office of Management and Budget under 44 U S C 3501 et seq and assigned clearance numbers 1010-0090 and 1004-0145

List of Subjects for 43 CFR Part 3100

Land Management Bureau, Public Lands-mineral resources, Oil and gas production, Mineral royalties

On March 30, 1995, an outdated version of this proposed rule was published in the Federal Register (60 FR 16424) by mistake That proposed rule publication is hereby withdrawn, and this version is published in its place

For the reasons stated in the preamble, and under the authorities cited below, Part 3100, Group 3100, Subchapter C, Chapter II of Title 43 of the Code of Federal Regulations is proposed to be amended as set forth below

PART 3100--OIL AND GAS LEASING

1 The authority citation for part 3100 continues to read as follows

Authority 30 U S C 181, et seq , 30 U S C 351-359

Subpart 3103--Fees, Rentals and Royalty

2 Section 3103 4-1 is amended by revising paragraph (b)(1), redesignating paragraph (e) as paragraph (g), and adding new paragraphs (e) and (f) to read as follows

@ 3103 4-1 -- Waiver, suspension, or reduction of rental, royalty or minimum royalty

* * * * *

(b)(1) An application for the benefits under paragraph (a) of this section on other than stripper oil well leases or heavy oil properties must be filed by the operator payor in the proper BLM office It must contain the serial number of the leases, the names of the record title holders, operating rights owners

(sublessees), and operators for each lease, the description of lands by legal subdivision and a description of the relief requested

* * * * *

(e)(1) A heavy oil well property is any Federal lease or portion thereof segregated for royalty purposes, a communitization area, or a unit participating area, operated by the same operator, that produces crude oil with a weighted average gravity of less than 20 degrees as measured on the American Petroleum Institute (API) scale

(2) An oil completion is a completion from which the energy equivalent of the oil produced exceeds the energy equivalent of the gas produced (including the

entrained liquefiable hydrocarbons) or any completion producing oil and less than 60 MCF of gas per day

(f) Heavy oil well property royalty rate reductions will be administered according to the following requirements and procedures

(1) The Bureau of Land Management requires no specific application form for the benefits under paragraph (a) of this section for heavy oil well properties However, the operator/payor must notify, in writing, the proper BLM office that it is seeking a heavy oil royalty rate reduction The letter must contain the serial number of the affected leases (or, as appropriate, the communitization agreement number or the unit agreement name), the names of the operators for each lease, the calculated new royalty rate as determined under paragraph (f)(2) of this section, and copies of the Purchaser's Statements (sales receipts) to document the weighted average API gravity for a property

(2) The operator must determine the weighted average API gravity for a property by averaging (adjusted to rate of production) the API gravities reported on the operator's Purchaser's Statement for the last 3 calendar months preceding the operator's written notice of intent to seek a royalty rate reduction, during each of which at least one sale was held This is shown in the following 3 illustrations

(i) If a property has oil sales every month prior to requesting the royalty rate reduction in October of 1994, the operator must submit Purchaser's Statements for July, August, and September of 1994.

(ii) If a property has sales only every 6 months, during the months of March and September, prior to requesting the rate reduction in October of 1994, the [*18083] operator must submit Purchaser's Statements for the months of September 1993, and March and September 1994, and

(iii) If a property has multiple sales each month, the operator must submit Purchaser's Statements for every sale for the 3 entire calendar months immediately preceding the request for a rate reduction

(3) The following equation must be used by the operator/payor for calculating the weighted average API gravity for a heavy oil well property

$$\frac{(V[1]xG[1])+(V[2]xG[2])+(V[n]xG[n])}{V[1]+V[2]+V[n]} = \text{Weighted Average API gravity for a property}$$

Where

V[1] = Average Production (bbls) of Well #1 over the last 3 calendar months of sales

V[2] = Average Production (bbls) of Well #2 over the last 3 calendar months of sales

V[n] = Average Production (bbls) of each additional well (V[3], V[4], etc.) over the last 3 calendar months of sales

G[1] = Average Gravity (degrees) of oil produced from Well #1 over the last 3

calendar months of sales

G[2] = Average Gravity (degrees) of oil produced from Well #2 over the last 3 calendar months of sales

G[n] = Average Gravity (degrees) of each additional well (G[3], G[4], etc.) over the last 3 calendar months of sales

Example Lease "A" has 3 wells producing at the following average rates over 3 sales months with the following associated average gravities Well #1, 4,000 bbls, 13 degrees API, Well #2, 6000 bbls, 21 degrees API, Well #3, 2,000 bbls, 14 degrees API Using the equation above-

(4,000 x 13) + (6,000 x 21) + (2,000 x 14) 17.2 Weighted Average
---------- =
(4,000 + 6,000 + 2,000) API gravity for property

(4) For those properties subject to a communitization agreement or a unit participating area, the weighted average API oil gravity for the lands dedicated to that specific communitization agreement or unit participating area must be determined in the manner prescribed in paragraph (f)(3) of this section and assigned to all property subject to Federal royalties in the communitization agreement or unit participating area

(5) The operator payor must use the following procedures in order to obtain a royalty rate reduction under this section

(i) Qualifying royalty rate determination

(A) The operator/payor must calculate the weighted average API gravity for the property proposed for the royalty rate reduction in order to verify that the property qualifies as a heavy oil well property

(B) Properties that have removed or sold oil less than 3 times in their productive life may still qualify for this royalty rate reduction However, no further reductions will be granted until the property has a sales history of at least 3 production months (see paragraph (f)(5)(iii) of this section)

(ii) Calculating the qualifying royalty rate If the Federal leases or portions thereof (e.g., communitization or unit agreements) qualify as heavy oil property, the operator/payor must use the weighted average API gravity rounded down to the nearest whole degree (e.g., 11.7 degrees API becomes 11

degrees), and determine the appropriate royalty rate from the following table

Royalty Rate Reduction
for Heavy Oil

Weighted average API gravity (degrees)	Royalty rate (percent)
6	0.5
7	1.4
8	2.2
9	3.1

60 FR 18081, *18083

10	3 9
11	4 8
12	5 6
13	6 5
14	7 4
15	8 2
16	9 1
17	9 9
18	10 8
19	11 6
20	12 5

Start declining @ 20° - 5°.
HR 6.99 start @ 25° - 5°.
API 19 → Royalty
11.6
4.52
BLM
A644

(iii) New royalty rate effective date The new royalty rate will be effective on the first day of production 2 months after BLM receives notification by the operator payor The rate will apply to all oil production from the property for the next 12 months If the API oil gravity is 20 degrees or greater, the royalty rate will be the rate in the lease terms

(iv) Royalty rate determinations in subsequent years (A) At the end of each 12-month period, beginning on the first day of the calendar month the royalty rate reduction went into effect, the operator payor must determine the weighted average API oil gravity for the property for that period The operator/payor must then determine the royalty rate for the following year using the table in paragraph (f)(5)(ii) of this section

(B) The operator/payor must compare the newly determined royalty rate to the initial qualifying royalty rate The operator/payor must notify BLM of its determinations under this paragraph and paragraph (A) of this @ 3103 1-4(f)(5)(iv) The new royalty rate will not become effective until the first day of the second month after BLM receives notification, and will remain effective for 12 calendar months Notification must include copies of the Purchaser's Statements (sales receipts) and be mailed to the proper BLM office If the operator does not notify the BLM of the new royalty rate within 60 days after the end of the subject 12-month period, the royalty rate for the heavy oil well property will return to the rate in the lease terms.

(v) Prohibition Any heavy oil property reporting an API average oil gravity determined by BLM to have resulted from any manipulation of normal production or adulteration of oil sold from the property will not receive the benefit of a royalty rate reduction under this paragraph (f)

(vi) Certification The operator/payor must use the applicable royalty rate when submitting the required royalty [*18084] reports/payments to the

Minerals Management Service (MMS). In submitting royalty reports/payments using a royalty rate reduction authorized by this paragraph (f), the operator/payor must certify that the API oil gravity for the initial and subsequent 12-month periods was not subject to manipulation or adulteration and the royalty rate was determined in accordance with the requirements and procedures of this paragraph (f).

(vii) Agency action. If an operator/payor incorrectly calculates the royalty rate, the BLM will determine the correct rate and notify the operator/payor in writing. Any additional royalties due are payable immediately upon receipt of this notice. The BLM will assess late payment or underpayment charges in accordance with 30 CFR 218.102. The BLM will terminate a royalty rate reduction for a property if BLM determines that the API oil gravity was

manipulated or adulterated by the operator/payor Terminations of royalty rate reductions for individual properties will be effective on the effective date of the royalty rate reduction resulting from a manipulated or adulterated API oil gravity so that the termination will be retroactive to the effective date of the improper reduction The operator/payor must pay the difference in royalty resulting from the retroactive application of the non-manipulated rate The BLM will assess late payment or underpayment charges in accordance with 30 CFR 218 102

(6) The BLM may suspend or terminate all royalty reductions granted under this paragraph (f) upon 6 month's notice in the Federal Register when BLM determines that-

(i) The average oil price remains above $ 24 per barrel over a period of 6 consecutive months (based on the West Texas Intermediate Crude average posted prices and adjusted for inflation using the implicit price deflator for gross national product with 1991 as the base year), or

(ii) After September 10, 1997, the royalty rate reductions authorized by this paragraph (f) have not been effective in reducing the loss of otherwise recoverable reserves. This will be determined by evaluating the expected versus the actual abandonment rate, the number of enhanced recovery projects, and the amount of operator reinvestment that can be attributed to this rule

OK seven years not enough time capital investment otherwise can't be documented.

(7) The heavy oil well property royalty rate reduction applies to all Federal oil produced from a heavy oil property

(8) If the lease royalty rate is lower than the benefits provided in this heavy oil well property royalty rate reduction program, the lease rate prevails

(9) If the property qualifies for a stripper well property royalty rate reduction, as well as a heavy oil well property reduction, the lower of the two rates applies

(10) The operator/payor must separately calculate the royalty for gas production (including condensate produced in association with gas) for oil completions using the lease royalty rate

(11) The minimum royalty provisions of @ 3103 3-2 will continue to apply

* * * * *

Dated April 4, 1995

Bob Armstrong,

Assistant Secretary of the Interior

[FR Doc 95-8702 Filed 4-7-95, 8 45 am]

BILLING CODE 4310-84-P

LEVEL 1 - 3 OF 3 DOCUMENTS

FEDERAL REGISTER
Vol 60, No 61

Proposed Rules

DEPARTMENT OF THE INTERIOR (DOI)
Bureau of Land Management (BLM)

43 CFR Part 3100

[WO-610-00-4110-2411]
RIN 1004-AC26

Promotion of Development, Reduction of Royalty on Heavy Oil

60 FR 16424

DATE Thursday, March 30, 1995

ACTION Proposed rule

To view the next page, type np* TRANSMIT
To view a specific page, transmit p* and the page number, e g p*1

SUMMARY The Bureau of Land Management (BLM) is issuing this proposed rule to amend the regulations relating to the waiver, suspension, or reduction of rental, royalty, or minimum royalty This amendment would establish the conditions under which the operators of properties that produce "heavy oil" (crude oil with a gravity of less than 20 degrees) can obtain a reduction in the royalty rate This action is being taken to encourage the operators of Federal heavy oil leases to place marginal or uneconomical shut-in oil wells back in production, provide an economic incentive to implement enhanced oil recovery projects, and delay the plugging of these wells until the maximum amount of economically recoverable oil can be obtained from the reservoir or field. The BLM believes that this amendment will result in substantial additional revenue for the States and Federal Government, increase the cumulative amount of domestic oil production from existing wells, increase the percentage of oil recovery from presently developed reservoirs, minimize the necessity of drilling new wells with their additional environmental impacts, assist in reducing the national balance of trade deficit, and help promote stability in the jobs and

services related to the domestic oil industry

DATES Comments should be submitted by May 30, 1995 Comments postmarked after this date may not be considered as part of the decisionmaking process in issuance of a final rule

ADDRESSES Comments should be sent to Director (140), Bureau of Land Management, Room 5555, Main Interior Building, 1849 C Street, N W , Washington, D C 20240 Comments will be available for public review in Room 5555 at the above address during regular business hours (7 45 a m to 4 15 p m), Monday through Friday

60 FR 16424 *

FOR FURTHER INFORMATION CONTACT: Dr. John W. Bebout, Bureau of Land Management,
(202) 452-0340 [*16425]

SUPPLEMENTARY INFORMATION: Existing section 3103.4-1 of Title 43, Code of Federal Regulations, provides two forms of Federal oil and gas royalty reduction on a case-by-case basis upon application, and for stripper wells. In order to encourage the greatest ultimate recovery of oil or gas and in the interest of conservation, the Secretary, upon a determination that it is necessary to promote development, or that a lease cannot be successfully operated under the terms provided therein, may reduce the royalty on an entire leasehold or any portion thereof. The provision concerning stripper well properties allows royalty reduction for properties that produce an average of less than 15 barrels of oil per eligible well per well-day.

The Bureau of Land Management (BLM) has reason to believe that additional royalty relief for producers of heavy crude oil may be necessary to maintain current levels of development, promote investment in enhanced recovery efforts, and encourage maximum recovery of the resource, thus warranting royalty reduction under Section 39 of the Mineral Leasing Act (30 U.S.C. 209).

Fluctuating oil prices, combined with high production costs, have resulted in an uncertain economic future for producers of low gravity crude oil. As recently as last January, California producers of heavy crude were spending between $9 and $10 to produce a barrel of crude oil that was typically selling for between $8.50 and $9 per barrel (from data provided by the Conservation Commission of California Oil and Gas Producers). When depreciation, depletion, and amortization costs were considered, nearly 90% of the state's production was uneconomic and more than 13,000 industry and industry-related jobs were at risk (California Independent Petroleum Association).

Heavy crude oil prices have recently risen to the point that the immediate crisis in California has passed. Many of the heavy oil properties remain only marginally economic, however, and are vulnerable to future down-turns in oil prices. As many as two-thirds of the marginal properties could be lost during a period of sustained low oil prices (National Petroleum Council Committee on Marginal Wells/Executive Summary-Draft). The danger in losing these wells is that, although production from individual wells may be small, their collective loss would be significant. The United States would lose the opportunity to take advantage of new technologies being developed by the Department of Energy (DOE) and industry, and the remaining recoverable reserves would be lost.

This proposed rule would preserve the contribution of marginal producers of heavy crude oil to the national reserve base. As a result of this relief, more wells should stay on line (even in periods of depressed oil prices), fewer recoverable reserves should be lost, and there will be less adverse economic impact on States and local communities.

The DOE has modeled the BLM's proposed royalty rate reduction for heavy crude oil. It is DOE's conclusion that the proposal will benefit all producers of heavy oil while remaining revenue neutral to all oil producing States except California (California contains the majority of the nation's heavy oil reserves). Assuming a West Texas Intermediate Crude oil price of $ 20 per barrel-a price consistent with recent oil markets-the proposal can be expected to increase recoverable reserves in California by around 72 percent, from 132.8 million barrels to 228.5 million barrels. The increase in recoverable reserves

will ultimately result in a 35 percent increase in Federal revenues (royalties and individual and corporate taxes) and a 49 percent increase in California State revenues

A provision of the proposed rule provides for the termination of individual royalty reductions should the average price of West Texas Intermediate Crude oil rise to a level greater than $ 28 per barrel for a period of at least 6 consecutive months This provision is intended to ensure that royalty relief is only provided during periods of low market prices

The proposed rule establishes a sliding scale royalty rate for qualifying heavy-oil-producing properties The sliding scale is intended to somewhat offset the reduced prices paid for oil as oil gravity decreases The reduced royalty rate applies to qualifying heavy oil properties rather than individual wells, because production is normally not measured for individual oil wells, and is based on the average gravity of the oil weighted by the production of heavy oil from each well within the property A weighted average gravity is used to prevent gravity manipulation by selectively producing wells on a property with heavier gravity crude Using a weighted average of oil gravity encourages maximum recovery from all wells within a property by removing the economic advantage of selective production

The rule provides that either the operator (as defined at 43 CFR 3100 0-5) or the payor (as defined at 30 CFR 208 2) must calculate the weighted average gravity of the oil-measured on the American Petroleum Institute (API) scale-produced from a property every 12 months to determine the appropriate royalty rate The royalty rate for years subsequent to the initial 12 month period will be the lesser of the newly calculated royalty rate or the royalty rate determined for the initial year This provision is necessary to avoid discouraging additional investment in enhanced recovery and workovers that may have the collateral effect of increasing the gravity of the oil produced from the property In no case, however, would the royalty rate exceed the rate established by the terms of the lease

The section amended by this proposed rule also provides for royalty rate reductions for stripper oil wells Many provisions of this proposed rule are essentially the same as the provisions of the existing regulations that pertain to stripper wells, except that references to "stripper well" have been replaced with "heavy oil well " The similarity between the existing provisions pertaining to stripper wells and the provisions of this proposed rule could allow for some restructuring of section 43 CFR 3103 4-1 to reduce the overall regulatory text and to increase clarity The public is invited to comment on whether

reorganizing 43 CFR 3[illegible]3 4-1 should be considered in preparing the final heavy oil royalty reduction rule

The principal author of this proposed rule is Dr John W Bebout, Senior Technical Specialist, Division of Fluid Minerals, assisted by the staff of the Division of Legislation and Regulatory Management, Bureau of Land Management

It is hereby determined that this rule does not constitute a major Federal action significantly affecting the quality of the human environment and that no detailed statement pursuant to Section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U S C 4332(2)(C)) is required

This rule has been reviewed under Executive Order 12866

The BLM has determined that this rule will not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 et seq.) This is because the proposed royalty rate reduction is voluntary, requires no additional paperwork, and applies to all operators regardless of size. Additionally the BLM has determined, under Executive Order 12630, that the rulemaking will not cause a taking of private property. [*16426]

The BLM has certified that these regulations meet the applicable standards provided in sections 2(a) and 2(b)(2) of Executive Order 12778

The information collection requirements of this rule have been approved by the Office of Management and Budget under 44 U.S.C. 3501 et seq. and assigned clearance numbers 1010-0090 and 1004-0145

List of Subjects for 43 CFR Part 3100

Land Management Bureau, Public Lands-mineral resources, Oil and gas production, Mineral royalties

For the reasons stated in the preamble, and under the authorities cited below, Part 3100, Group 3100, Subchapter C, Chapter II of Title 43 of the Code of Federal Regulations is proposed to be amended as set forth below

PART 3100--OIL AND GAS LEASING

1. The authority citation for part 3100 continues to read as follows

Authority: 30 U.S.C. 181, et seq., 30 U.S.C. 351-359

Subpart 3103--Fees, Rentals and Royalty

2. Section 3103.4-1 is amended by revising paragraph (b)(1), redesignating paragraph (e) as paragraph (g), and adding new paragraphs (e) and (f) to read as follows

§ 3103.4-1 -- Waiver, suspension, or reduction of rental, royalty or minimum royalty

* * * * *

(b)(1) An application for the above benefits on other than stripper oil well leases or heavy oil properties must be filed by the operator payor in the proper BLM office. It must contain the serial number of the leases, the names of the record title holders, operating rights owners (sublessees), and operators for each lease, the description of lands by legal subdivision and a description of the relief requested.

* * * * *

(e)(1) A heavy oil well property is any Federal lease or portion thereof segregated for royalty purposes, a communitization area, or a unit

participating area, operated by the same operator, that produces crude oil with a weighted average gravity of less than 20 degrees as measured on the American Petroleum Institute (API) scale

(2) An oil completion is a completion from which the energy equivalent of the oil produced exceeds the energy equivalent of the gas produced (including the entrained liquefiable hydrocarbons) or any completion producing oil and less than 60 MCF of gas per day

(f) Heavy oil well property royalty rate reductions will be administered according to the following requirements and procedures

(1) The Bureau of Land Management requires no specific application form for the benefits under paragraph (a) of this section for heavy oil well properties. However, the operator payor must notify, in writing, the proper BLM office that it is seeking a heavy oil royalty rate reduction. The letter must contain the serial number of the affected leases (or, as appropriate, the communitization agreement number or the unit agreement name), the names of the operators for each lease, the calculated new royalty rate as determined under paragraph (f)(2) of this section, and copies of the Purchaser's Statements (sales receipts) to document the weighted average API gravity for a property

(2) The operator must determine the weighted average API gravity for a property by averaging (adjusted to rate of production) the API gravities reported on the operator's Purchaser's Statement for the last 3 calendar months preceding the operator's written notice of intent to seek a royalty rate reduction, during each of which at least one sale was held. This is shown in the following 3 illustrations

(i) If a property has oil sales every month prior to requesting the royalty rate reduction in October of 1994, the operator must submit Purchaser's Statements for July, August, and September of 1994;

(ii) If a property has sales only every 6 months, during the months of March and September, prior to requesting the rate reduction in October of 1994, the operator must submit Purchaser's Statements for the months of September 1993, and March and September 1994, and

(iii) If a property has multiple sales each month, the operator must submit Purchaser's Statements for every sale for the 3 entire calendar months immediately preceding the request for a rate reduction

(3) The following equation must be used by the operator/ payor for calculating the weighted average API gravity for a heavy oil well property

$$\frac{(V[1]XG[1])-V[2]XG[2])-(V[n]XG[n])}{V[1]-V[2]\cdot V[n]} = \text{Weighted Average API gravity for a property}$$

Where

V[1]=Average Production (bbls) of Well #1 over the last 3 calendar months of sales

V[2]=Average Production (bbls) of Well #2 over the last 3 calendar months of

sales

V[n]=Average Production (bbls) of each additional well (V[3], V[4], etc.) over the last 3 calendar months of sales

G[1]=Average Gravity (degrees) of oil produced from Well #1 over the last 3 calendar months of sales

G[2]=Average Gravity (degrees) of oil produced from Well #2 over the last 3 calendar months of sales

G[n]=Average Gravity (degrees) of each additional well (G[3], G[4], etc.) over the last 3 calendar months of sales

Example Lease "A" has 3 wells producing at the following average rates over 3 sales months with the following associated average gravities: Well #1, 4,000 bbls, 13 degrees API, Well #2, 6000 bbls, 21 degrees API, Well #3, 2,000 bbls, 14 degrees API. Using the equation above-

$$\frac{(4{,}000\times 13)+(6{,}000\times 21)+(2{,}000\times 14)}{(4{,}000+6{,}000+2{,}000)} = 17.2$$

Weighted Average API gravity for property

(4) For those properties subject to a communitization agreement or a unit participating area, the weighted average API oil gravity for the lands dedicated to that specific communitization agreement or unit participating area must be determined in the manner prescribed in paragraph (f)(3) of this section and assigned to all property [*16427] subject to Federal royalties in the communitization agreement or unit participating area

(5) The operator/payor must use the following procedures in order to obtain a royalty rate reduction under this section

(i) Qualifying royalty rate determination

(A) The operator/payor must calculate the weighted average API gravity for the property proposed for the royalty rate reduction in order to verify that the property qualifies as a heavy oil well property

(B) Properties that have removed or sold oil less than 3 times in their productive life may still qualify for this royalty rate reduction. However, no further reductions will be granted until the property has a sales history of at

least 3 production months (see paragraph (f)(5)(iii) of this section)

(ii) Calculating the qualifying royalty rate. If the Federal leases or portions thereof (e.g., communitization or unit agreements) qualify as heavy oil property, the operator/payor must use the weighted average API gravity rounded down to the nearest whole degree (e.g., 11.7 degrees API becomes 11 degrees), and determine the appropriate royalty rate from the following table

Weighted Average API Gravity	Royalty Rate Reduction for Heavy Oil	Royalty

60 FR 16424, *16427

average API gravity (degrees)	rate (percent)
6	0.5
7	1.4
8	2.2
9	3.1
10	3.9
11	4.8
12	5.6
13	6.5
14	7.4
15	8.2
16	9.1
17	9.9
18	10.8
19	11.6
20	12.5

(iii) New royalty rate effective date The new royalty rate will be effective on the first day of production 2 months after BLM receives notification by the operator/payor. The rate will apply to all oil production from the property for the next 12 months If the API oil gravity is 20 degrees or greater, the royalty rate will be the rate in the lease terms.

(iv) Royalty rate determinations in subsequent years

(A) At the end of each 12-month period, beginning on the first day of the calendar month the royalty rate reduction went into effect, the operator/payor must determine the weighted average API oil gravity for the property for that period The operator/payor must then determine the royalty rate for the following year using the table in paragraph (f)(5)(ii) of this section.

(B) The operator/payor must compare the newly determined royalty rate to the initial qualifying royalty rate The operator/payor must notify BLM of its determinations under this paragraph and paragraph (A) of this @ 3103 1-4(f)(5)(iv) The lower of the two rates will be used for the new 12-month period The new royalty rate will not become effective until the first day of the second month after BLM receives notification, and will remain effective for 12 calendar months Notification must include copies of the Purchaser's Statements (sales receipts) and be mailed to the proper BLM office. If the operator does not notify the BLM of the new royalty rate within 60 days after

the end of the subject 12-month period, the royalty rate for the heavy oil well property will remain at the previous royalty rate until the next 12-month anniversary

(C) The royalty rate will never exceed the heavy oil property royalty rate calculated during the first qualifying period unless and until BLM terminates all heavy oil royalty rate reductions under paragraph (f)(6) (i) or (ii) of this section

(v) Prohibition Any heavy oil property reporting an API average oil gravity determined by BLM to have resulted from any manipulation of normal production or adulteration of oil sold from the property will not receive the benefit of a royalty rate reduction under this paragraph (f)

(vi) Certification The operator/payor must use the applicable royalty rate when submitting the required royalty reports/payments to the Minerals Management Service (MMS) In submitting royalty reports/payments using a royalty rate reduction authorized by this paragraph (f), the operator/payor must certify that the API oil gravity for the initial and subsequent 12-month periods was not subject to manipulation or adulteration and the royalty rate was determined in accordance with the requirements and procedures of this paragraph (f)

(vii) Agency action If an operator/payor incorrectly calculates the royalty rate, the BLM will determine the correct rate and notify the operator/payor in writing Any additional royalties due are payable immediately upon receipt of this notice The BLM will assess late payment or underpayment charges in accordance with 30 CFR 218 102 The BLM will terminate a royalty rate reduction for a property if BLM determines that the API oil gravity was manipulated or adulterated by the operator/payor Terminations of royalty rate reductions for individual properties will be effective on the effective date of the royalty rate reduction resulting from a manipulated or adulterated API oil gravity so that the termination will be retroactive to the effective date of the improper reduction. The operator/payor must pay the difference in royalty resulting from the retroactive application of the non-manipulated rate. The BLM will assess late payment or underpayment charges in accordance with 30 CFR 218 102

(6) The BLM may suspend or terminate all royalty reductions granted under this paragraph (f) upon 6 month's notice in the Federal Register when BLM determines that-

(i) The average oil price remains above $ 28 per barrel over a period of 6 consecutive months (based on the West Texas Intermediate Crude average posted prices and adjusted for inflation using the implicit price deflator for gross national product with 1991 as the base year), or

(ii) After September 10, 1997, the royalty rate reductions authorized by this paragraph (f) have not been not effective in reducing the loss of otherwise recoverable reserves resulting from wells being shut in or abandoned.

(7) The heavy oil well property royalty rate reduction applies to all Federal oil produced from a heavy oil property

(8) If the lease royalty rate is lower than the benefits provided in this heavy oil well property royalty rate reduction program, the lease rate prevails.

(9) If the property qualifies for a stripper well property royalty rate reduction, as well as a heavy oil well property reduction, the lower of the two rates applies

(10) The operator payor must separately calculate the royalty for gas production (including condensate produced in association with gas) for oil completions using the lease royalty rate

(11) The minimum royalty provisions of @ 3103 3-2 will continue to apply

* * * * *

the effective date of this regulation, of a petition to reinstate a lease under §3108.2-3 of this title; and

(f) Each succeeding time a specific lease is reinstated under §3108.2-3 of this title, the annual rental on that lease shall increase by an additional $5 per acre or fraction thereof for leases that were originally issued noncompetitively and by an additional $10 per acre or fraction thereof for leases that were originally issued competitively.

[53 FR 17353, May 16, 1988 and 53 FR 22837, June 17, 1988]

§3103.3 Royalties.

§3103.3-1 Royalty on production.

(a) Royalty on production shall be payable only on the mineral interest owned by the United States. Royalty shall be paid in amount or value of the production removed or sold as follows:

(1) 12½ percent on all leases, including exchange and renewal leases and leases issued in lieu of unpatented oil placer mining claims under §3108.2-4 of this title, issued after December 22, 1987, except:

(i) Leases issued after December 22, 1987, resulting from offers to lease or bids filed on or before December 22, 1987, which are subject to the rates in effect on December 22, 1987; and

(ii) Leases issued on or before December 22, 1987, which are subject to the rates contained in the lease or in regulations at the time of issuance;

(2) 16⅔ percent on noncompetitive leases reinstated under §3108.2-3 of this title plus an additional 2 percentage-point increase added for each succeeding reinstatement;

(3) Not less than 4 percentage points above the rate used for royalty determination contained in the lease that is reinstated or in force at the time of issuance of the lease that is reinstated for competitive leases, plus an additional 2 percentage-point increase added for each succeeding reinstatement.

(b) Leases that qualify under specific provisions of the Act of August 8, 1946 (30 U.S.C. 226c) may apply for a limitation of a 12½ percent royalty rate.

(c) The average production per well per day for oil and gas shall be determined pursuant to 43 CFR 3162.7-4.

(d) Payment of a royalty on the helium component of gas shall not convey the right to extract the helium. Applications for the right to extract helium shall be made under part 16 of this title.

[53 FR 22838, June 17, 1988]

§3103.3-2 Minimum royalties.

(a) A minimum royalty shall be payable at the expiration of each lease year beginning on or after a discovery of oil or gas in paying quantities on the lands leased, except that on unitized leases the minimum royalty shall be payable only on the participating acreage, at the following rates:

(1) On leases issued on or after August 8, 1946, and on those issued prior thereto if the lessee files an election under section 15 of the Act of August 8, 1946, a minimum royalty of $1 per acre or fraction thereof in lieu of rental, except as provided in paragraph (a)(2) of this section; and

(2) On leases issued from offers filed after December 22, 1987, and on competitive leases issued from successful bids placed at oral auctions conducted after December 22, 1987, a minimum royalty in lieu of rental of not less than the amount of rental which otherwise would be required for that lease year.

(b) Minimum royalties shall not be prorated for any lands in which the United States owns a fractional interest but shall be payable on the full acreage of the lease.

(c) Minimum royalties and rentals on non-participating acreage shall be payable to the Service.

(d) The minimum royalty provisions of this section shall be applicable to leases reinstated under §3108.2-3 of this title and leases issued under §3108.2-4 of this title.

[49 FR 33682, July 22, 1983, as amended at 49 FR 11687, Mar. 27, 1984; 49 FR 30446, July 30, 1984; 53 FR 22839, June 17, 1988]

§3103.4 Promotion of development.

§3103.4-1 Waiver, suspension or reduction of rental, royalty or minimum royalty.

(a) In order to encourage the greatest ultimate recovery of oil or gas and in the interest of conservation, the Secretary, upon a determination that it is necessary to promote development or that the leases cannot be successfully operated under the terms provided therein, may waive, suspend or reduce the rental or minimum royalty or reduce the royalty on an entire leasehold, or any portion thereof.

(b)(1) An application for the above benefits on other than stripper oil well properties shall be filed in the proper BLM office. It shall contain the serial numbers of the leases, the names of the record title holders, operating rights owners (subleassees), and operators for each lease, the description of lands by legal subdivision and a description of the relief requested.

(2) Each application shall show the number, location and status of each well drilled, a tabulated statement for each month covering a period of not less than 6 months prior to the date of filing the application of the aggregate amount of oil or gas subject to royalty, the number of wells counted as producing each month and the average production per well per day.

(3) Every application shall contain a detailed statement of expenses and costs of operating the entire lease, the income from the sale of any production and all facts tending to show whether the wells can be successfully operated upon the fixed royalty or rental. Where the application is for a reduction in royalty, full information shall be furnished as to whether overriding royalties, payments out of production, or similar interests are paid to others than the United States, the amounts so paid and efforts made to reduce them. The applicant shall also file agreements of the holders to a reduction of all other royalties or similar payments from the leasehold to an aggregate not in excess of one-half the royalties due the United States.

(c)(1) A stripper well property is any Federal lease or portion thereof segregated for royalty purposes, a communitization agreement, or a participating area of a unit agreement, operated by the same operator, that produces an average of less than 15 barrels of oil per eligible well per well-day for the qualifying period.

(2) An eligible well is an oil well that produces or an injection well that injects and is integral to production for any period of time during the qualifying or subsequent 12-month period.

(3) An oil completion is a completion from which the energy equivalent of the oil produced exceeds the energy equivalent of the gas produced (including the entrained liquid hydrocarbons) or any completion producing oil and less than 60 MCF of gas per day.

(4) An injection well is a well that injects a fluid for secondary or enhanced oil recovery, including reservoir pressure maintenance operations.

(d) Stripper oil well property royalty rate reduction shall be administered according to the following requirements and procedures.

(1) An application for the benefits under paragraph (a) of this section for stripper oil well properties is not required.

(2) Total oil production (regardless of disposition) for the subject period from the eligible wells on the property is totaled and then divided by the total number of well days or portions of days, both producing and injection days, as reported on Form MMS-3160 or MMS-4054 for the eligible wells to determine the property average daily production rate. For those properties in communitization agreements and participating areas of unit agreements that have allocated (not actual) production, the production rate for all eligible well(s) in that specific communitization agreement or participating area is determined and shall be assigned to that allocated property in that communitization agreement or participating area.

(3) Procedures to be used by operator:

(i) Qualifying determination.

(A) Calculate an average daily production rate for the property in order to verify that the property qualifies as a stripper property.

(B) The initial qualifying period for producing properties is the period August 1, 1990, through July 31, 1991. For

the properties that were shut-in for 12 consecutive months or longer, the qualifying period is the 12-month production period immediately prior to the shut-in. If the property does not qualify during the initial qualifying period, it may later qualify due to production decline. In those cases, the 12-month qualifying period will be the first consecutive 12-month period beginning after August 31, 1990, during which the property qualifies.

(ii) Qualifying royalty rate calculation. If the property qualifies, use the production rate rounded down to the next whole number (e.g., 6.7 becomes 6) for the qualifying period, and apply the following formula to determine the maximum royalty rate for oil production from the Federal leases for the life of the program.

Royalty Rate (%) = 0.5 + (0.8 × the average daily production rate)

The formula-calculated royalty rate shall apply to all oil production (except condensate) from the property for the first 12 months. The rate shall be effective the first day of the production month after the Minerals Management Service (MMS) receives notification. If the production rate is 15 barrels or greater, the royalty rate will be the rate in the lease terms.

(iii) Outyears royalty rate calculations.

(A) At the end of each 12-month period, the property average daily production rate shall be determined for that period. A royalty rate shall then be calculated using the formula in paragraph (d)(3)(ii) of this section.

(B) The new calculated royalty rate shall be compared to the qualifying period royalty rate. The lower of the two rates shall be used for the current period provided that the operator notifies the MMS of the new royalty rate. The new royalty rate shall not become effective until the first day of the month after the MMS receives notification. Notification shall be received on Form MMS-4377 and mailed to Minerals Management Service, P.O. Box 17110, Denver, CO 80217. If the operator does not notify the MMS of the new royalty rate within 60 days after the end of the subject 12-month period, the royalty rate for the property shall revert back to the royalty rate established as the qualifying period royalty rate, effective at the beginning of the current 12-month period.

(C) The royalty rate shall never exceed the calculated qualifying royalty rate for the life of this program.

(iv) Prohibition. For the qualifying period and any subsequent 12-month period, the production rate shall be the result of routine operational and economic factors for that period and for that property and not the result of production manipulation for the purpose of obtaining a lower royalty rate. A production rate that is determined to have resulted from production manipulation will not receive the benefit of a royalty rate reduction.

(v) Certification. The applicable royalty rate shall be used by the operator/payor when submitting the required royalty reports/payments to MMS. By submitting royalty reports/payments using the royalty rate reduction benefits of this program, the operator certifies that the production rate for the qualifying and subsequent 12-month period was not subject to manipulation for the purpose of obtaining the benefit of a royalty rate reduction, and the royalty rate was calculated in accordance with the instructions and procedures in these regulations.

(vi) Agency action. If a royalty rate is improperly calculated, the MMS will calculate the correct rate and inform the operator/payors. Any additional royalties due are payable immediately upon notification. Late payment or underpayment charges will be assessed in accordance with 30 CFR 218.102. The BLM may terminate a royalty rate reduction if it is determined that the production rate was manipulated by the operator for the purpose of receiving a royalty rate reduction. Terminations of royalty rate reductions will be effective on the effective date of the royalty rate reduction resulting from the manipulated production rate (i.e., the termination will be retroactive to the effective date of the improper reduction). The operator/payor shall pay the difference in royalty resulting from the retroactive application of the unmanipulated rate. Late payment or underpayment charges will be assessed in accordance with 30 CFR 218.102.

(4) The royalty rate reduction provision for stripper well properties shall be effective as of October 1, 1992. If the oil price, adjusted for inflation by BLM and MMS, using the implicit price deflator for gross national product with 1991 as the base year, remains on average above $28 per barrel, based on West Texas Intermediate crude average posted price for a period of 6 consecutive months, the benefits of the royalty rate reduction under this section may be terminated upon 6 months' notice, published in the FEDERAL REGISTER.

(5) The Secretary will evaluate the effectiveness of the stripper well royalty reduction program and may at any time after September 10, 1997, terminate any or all royalty reductions granted under this section upon 6 months notice.

(6) The stripper well property royalty rate reduction benefits shall apply to all oil produced from the property.

(7) The royalty for gas production (including liquids produced in association with gas) for oil completions shall be calculated separately using the lease royalty rate.

(8) If the lease royalty rate is lower than the benefits provided in this stripper oil property royalty rate reduction program, the lease rate prevails.

(9) The minimum royalty provisions of §3103.3-2 apply.

(10) Examples.

§ 1.43–3 *Certification.*

(a) Petroleum engineer's certification of a project.
(1) In general.
(2) Timing of certification.
(3) Content of certification.
(b) Operator's continued certification of a project.
(1) In general.
(2) Timing of certification.
(3) Content of certification.
(c) Notice of project termination.
(1) In general.
(2) Timing of notice.
(3) Content of notice.
(d) Failure to submit certification.
(e) Effective date.

§ 1.43–4 *Qualified enhanced oil recovery costs.*

(a) Qualifying costs.
(1) In general.
(2) Costs paid or incurred for an asset which is used to implement more than one qualified enhanced oil recovery project or for other activities.
(b) Costs defined.
(1) Qualified tertiary injectant expenses.
(2) Intangible drilling and development costs.
(3) Tangible property costs.
(4) Examples.
(c) Primary purpose.
(1) In general.
(2) Tertiary injectant costs.
(3) Intangible drilling and development costs.
(4) Tangible property costs.
(5) Offshore drilling platforms.
(6) Examples.
(d) Costs paid or incurred prior to first injection.
(1) In general.
(2) First injection after filing of return for taxable year costs are allowable.
(3) First injection more than 36 months after close of taxable year costs are paid or incurred.
(4) Injections in volumes less than the volumes specified in the project plan.
(5) Examples.
(e) Other rules.
(1) Anti-abuse rule.
(2) Costs paid or incurred to acquire a project.
(3) Examples.

§ 1.43–5 *At-risk limitation. [Reserved]*

§ 1.43–6 *Election out of section 43.*

(a) Election to have the credit not apply.
(1) In general.
(2) Time for making the election.
(3) Manner of making the election.
(b) Election by partnerships and S corporations.

§ 1.43–7 *Effective date of regulations.*

[T.D. 8448, 57 FR 54923, Nov. 23, 1992]

§ 1.43–1 The enhanced oil recovery credit—general rules.

(a) *Claiming the credit—(1) In general.* The enhanced oil recovery credit ("credit") is a component of the section 38 general business credit. A taxpayer that owns an operating mineral interest (as defined in §1.614–2(b)) in a property may claim the credit for qualified enhanced oil recovery costs (as described in §1.43–4) paid or incurred by the taxpayer in connection with a qualified enhanced oil recovery project (as described in §1.43–2) undertaken with respect to the property. A taxpayer that does not own an operating mineral interest in a property may not claim the credit. To the extent a credit included in the current year business credit under section 38(b) is unused under section 38, the credit is carried back or forward under the section 39 business credit carryback and carryforward rules.

(2) *Examples.* The following examples illustrate the principles of this paragraph (a).

Example 1. Credit for operating mineral interest owner. In 1992, A, the owner of an operating mineral interest in a property, begins a qualified enhanced oil recovery project using cyclic steam. B, who owns no interest in the property, purchases and places in service a steam generator. B sells A steam, which A uses as a tertiary injectant described in section 193. Because A owns an operating mineral interest in the property with respect to which the project is undertaken, A may claim a credit for the cost of the steam. Although B owns the steam generator used to produce steam for the project, B may not claim a credit for B's costs because B does not own an operating mineral interest in the property.

Example 2. Credit for operating mineral interest owner. C and D are partners in CD, a partnership that owns an operating mineral interest in a property. In 1992, CD begins a qualified enhanced oil recovery project using cyclic steam. D purchases a steam generator and sells steam to CD. Because CD owns an operating mineral interest in the property with respect to which the project is undertaken, CD may claim a credit for the cost of the steam. Although D owns the steam generator used to produce steam for the project, D may not claim a credit for the costs of the steam generator because D paid these costs

in a capacity other than that of an operating mineral interest owner.

(b) *Amount of the credit.* A taxpayer's credit is an amount equal to 15 percent of the taxpayer's qualified enhanced oil recovery costs for the taxable year, reduced by the phase-out amount, if any, determined under paragraph (c) of this section.

(c) *Phase-out of the credit as crude oil prices increase—(1) In general.* The amount of the credit (determined without regard to this paragraph (c)) for any taxable year is reduced by an amount which bears the same ratio to the amount of the credit (determined without regard to this paragraph (c)) as—

(i) The amount by which the reference price determined under section 29(d)(2)(C) for the calendar year immediately preceding the calendar year in which the taxable year begins exceeds $28 (as adjusted under paragraph (c)(2) of this section); bears to

(ii) $6.

(2) *Inflation adjustment—(i) In general.* For any taxable year beginning in a calendar year after 1991, an amount equal to $28 multiplied by the inflation adjustment factor is substituted for the $28 amount under paragraph (c)(1)(i) of this section.

(ii) *Inflation adjustment factor.* For purposes of this paragraph (c), the inflation adjustment factor for any calendar year is a fraction, the numerator of which is the GNP implicit price deflator for the preceding calendar year and the denominator of which is the GNP implicit price deflator for 1990. The "GNP implicit price deflator" is the first revision of the implicit price deflator for the gross national product as computed and published by the Secretary of Commerce. As early as practicable, the inflation adjustment factor for each calendar year will be published by the Internal Revenue Service in the Internal Revenue Bulletin.

(3) *Examples.* The following examples illustrate the principles of this paragraph (c).

Example 1. Reference price exceeds $28. In 1993, E, the owner of an operating mineral interest in a property, incurs $100 of qualified enhanced oil recovery costs. The reference price for 1991 determined under section 29(d)(2)(C) is $30 and the inflation adjustment factor for 1992 is 1. E's credit for 1992 determined without regard to the phase-out for crude oil price increases is $15 ($100 × 15%). In determining E's credit, the credit is reduced by $5 ($15 × (($30 − ($28 × 1))/$6)). Accordingly, E's credit for 1992 is $10 ($15 − $5).

Example 2. Inflation adjustment. In 1993, F, the owner of an operating mineral interest in a property, incurs $100 of qualified enhanced oil recovery costs. The 1992 reference price is $34, and the 1993 inflation adjustment factor is 1.10. F's credit for 1993 determined without regard to the phase-out for crude oil price increases is $15 ($100 × 15%). In determining F's credit, $30.80 (1.10 × $28) is substituted for $28, and the credit is reduced by $6 ($15 × (($34 − $30.80)/$6)). Accordingly, F's credit for 1993 is $7 ($15 − $8).

(d) *Reduction of associated deductions—(1) In general.* Any deduction allowable under chapter 1 for an expenditure taken into account in computing the amount of the credit determined under paragraph (b) of this section is reduced by the amount of the credit attributable to the expenditure.

(2) *Certain deductions by an integrated oil company.* For purposes of determining the intangible drilling and development costs that an integrated oil company must capitalize under section 291(b), the amount allowable as a deduction under section 263(c) is the deduction allowable after paragraph (d)(1) of this section is applied. See §1.43–4(b)(2) (extent to which integrated oil company intangible drilling and development costs are qualified enhanced oil recovery costs).

(e) *Basis adjustment.* For purposes of subtitle A, the increase in the basis of property which would (but for this paragraph (e)) result from an expenditure with respect to the property is reduced by the amount of the credit determined under paragraph (b) of this section attributable to the expenditure.

(f) *Passthrough entity basis adjustment—(1) Partners' interests in a partnership.* To the extent a partnership expenditure is not deductible under paragraph (d)(1) of this section or does not increase the basis of property under paragraph (e) of this section, the expenditure is treated as an expenditure described in section 705(a)(2)(B) (concerning decreases to basis of partnership interests). Thus, the adjusted bases of the partners' interests in the

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

February 9, 1996

Mr. John Morgan
BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612

Mr. Edward K. Behm
OXY USA Inc.
6 Desta Drive, Suite 6000
P.O. Box 50250
Midland, Texas 79710-0250

Dear Sirs:

BP Exploration (Alaska) Inc. ("BP") and OXY USA Inc. ("OXY") have made representations to the House of Representatives in support of HB 325 concerning the feasibility of heavy oil development in the Milne Point Unit, Schrader Bluff Participating Area in both a "white paper" dated January 22, 1996, and in testimony to the House Subcommittee on Oil and Gas, the House Resources Committee and the House Finance Committee. Further, BP and OXY offered to make detailed back-up data available to the Division of Oil and Gas. As a result, the Division has been asked by members of the Alaska State Legislature to review the economics of heavy oil development at the Milne Point Unit in order to evaluate the provisions of HB 325. On February 8, 1996, the Division received from OXY a summary sheet titled "Critical Assumptions." More information is needed to provide background to the bottomline figures presented so far, similar to the information OXY previously provided for its prior Milne Point Unit royalty reduction request and the information BP provided to assist the Division in evaluating BP's economics for another field.

In order to perform the requested review, the Division will need detailed and comprehensive data from BP and OXY supporting the analyses that both companies have previously presented. This data must cover both the full Schrader Bluff pool development and, because the proposed legislation is currently structured on a per-well basis, the per-well economics of the Schrader Bluff pool. In both cases, the companies should provide the incremental company economics that are projected to accrue to the project through facility sharing arrangements, pipeline tariffs, tax benefits, etc. We recognize that each company's economic assessment is different, and so each company should provide its own analysis of these impacts.

Mr. John Morgan
BP Exploration (Alaska) Inc.
February 9, 1996

Mr. Edward J. Behm
OXY USA Inc.

Per-well economics. The "Critical Assumptions" sheet provides a summary guide to the kind and detail of information required by the Division. Supporting data necessary includes:

1. Production and Revenues: the historical data for each Schrader Bluff well, including initial production rates, decline rates and per-well reserves, plus all back-up data supporting the chart presented in BP's Finance Committee presentation on February 8, 1996 ("BP's Presentation") entitled "Schrader Bluff Typical Well Production Rate vs Time (years)."

2. Drilling and equipment costs: historical data for each Schrader Bluff well, plus an analysis of the cost reduction trends including any documents supporting the statement made in BP's Presentation that the 1995 Schrader Bluff development program has demonstrated that drilling costs have been reduced, that completion costs have remained constant, and that ESP life has been improved. Provide the results of the well performance and technical study referred to in BP's Presentation as soon as it is available.

3. Supporting data for the dry hole cost assumption of 86.80% of producing well costs and for the 90% success rate assumption.

4. Back-up data and analysis for the $0.72/bbl associated facility cost, including an explanation of the calculation used. This component should be also thoroughly documented in the Schrader Bluff development economics.

5. Complete detail and analysis for the $2.20/bbl operating expense estimate and a detailed explanation of the $0.50/bbl for fixed per-well operating expense. The operating expenses should also be thoroughly documented in the Schrader Bluff pool development economics. Forecasts of both this component and item 4 above must be supported by historical (actual) data.

6. Complete detail and analysis for OXY's calculation of 0.6% severance tax and 8.0% property tax percentages calculated on revenue, including an explanation of why revenue was used instead of the oil value and property assessment. If BP has different values, please provide those values plus the supporting detail.

Schrader Bluff pool development. It is the Division's understanding that the decision to develop the Schrader Bluff is not made on a well-by-well basis. For example, Mr. Policky testified that development of the Schrader Bluff pool would require upgrading of the central production facility serving all horizons in the unit. BP and OXY should each provide the Division with the complete analysis of the whole project, including any documentation describing the "full development scenario" of 350-400 wells presented in OXY's Critical Assumption sheet versus any documentation describing the 230 well

Mr. John Morgan
BP Exploration (Alaska) Inc.
February 9, 1996

Mr. Edward J. Behm
OXY USA Inc.

development scenario represented in the BP's Presentation in a chart titled "Additional Production from Heavy Oil by Development Year." Included in this information should be the same kind of analysis that would be presented to corporate decisionmakers who would ultimately commit resources to the development of the Schrader Bluff pool. Additionally, please provide the economic analysis of facility expansion and the way that such capital expenditures are to be allocated to Schrader Bluff production. Potential areas of risk should be identified and an explanation of how they were incorporated into the assessment.

Other Information Needed.

1. Any BP documents prepared for the purpose of seeking financial approval and commitment to acquire its interest in the Milne Point Unit including any *pro forma* finance memoranda.

2. Copies of all AFEs (both accepted and rejected) for any capital expenditures relating to the Schrader Bluff pool including the $15MM expenditures for the recent 6 new wells, well completions, and additional technical study.

3. Internal documents that explain the company's approval and sanction process for a major investment, including economic hurdle parameters, IRR, NPV, PW, any other financial criteria required by the company's evaluation, corporate, federal and state income tax rates, cost of capital, and Schrader Bluff contribution to company incremental economics. NOTE: BP has already provided all but the Schrader Bluff contribution to company incremental economics and need not duplicate information provided.

4. From OXY, an EXCEL-type spreadsheet (on disk to speed analysis) detailing how the 12.8 and 15.9 rates of return, the 6.5 and 5.4 year pay back periods, the $115M net discounted cash flow, negative $307M discounted cash flows, and the total per-well royalties undiscounted of $1843M and $1,040M were calculated in the white paper. Please provide a calculation of the total per-well royalties using the fifteen percent discount rate that OXY used for its own internal analysis.

From BP, all documents supporting Mr. Policky's testimony to the House Finance Committee that BP's rate of return varies 2-3% higher than OXY's rate of return, and an EXCEL-type spreadsheet (on disk to speed analysis) of the calculation of the rate of return.

5. BP's 1995-1997 Business Plan dated 9/30/94 and any other BP or OXY Business Plan related to Schrader Bluff pool development.

6. Provide BP and OXY's actual marine transportation cost per barrel and a description of the differences between BP and OXY's transportation costs.

Mr. John Morgan
BP Exploration (Alaska) Inc.
February 9, 1996

Mr. Edward J. Behm
OXY USA Inc.

7. The Arthur D. Little study cited in the BP/OXY white paper states that a TAPS owner has a $1.00/bbl advantage over a non-TAPS owner . If either BP or OXY does not agree with that proposition please provide the relevant calculation along with the supporting documentation.

8. Mr. Policky testified on February 8, 1996, to the House Finance Committee that currently the Milne Point Unit CPF is running at capacity at 25MBD with Kuparuk production; that they intend to add 40MBD in the next few weeks for Kuparuk production; that they intend to add 10MBD capacity in 1997 for Cascade/Kuparuk production; and that they would then need to add an additional 15MBD capacity for Schrader Bluff production. Please provide a detailed schedule of production versus capacity for the MPU CPF specifically explaining the capacity schedule as it relates to the production curve for the 230 well development scenario that shows a peak of 45MBD. If not detailed above already, please provide a detailed capital investment schedule for the two Schrader Bluff pool development scenarios.

If you wish the Division to maintain any of the information submitted as confidential, please mark each page "confidential," submit such information in a sealed envelope separate from non-confidential information, and provide a statement describing the authority under which the Division may maintain the information confidential. If you have any questions about the analyses or data to be provided, please address them in writing to Kevin Banks, Petroleum Economist, Division of Oil and Gas, 3601 C Street, Suite 1380, Anchorage, Alaska, 99503-5948. Because we are dealing with the Legislature in a public forum, any communications should be made in writing.

Very truly yours,

Kenneth A. Boyd
Director, Division of Oil and Gas

cc: Commissioner John Shively, Department of Natural Resources
Representative Mark Hanley, Co-Chair, House Finance Committee,
Alaska State Legislature
Jim Palmer, BP Exploration (Alaska) Inc.

I USE COMMITTEE REPOI

(7)

Date Referred: April 28, 1995 FURTHER REFERRALS: Resources, Finance

Date of Committee Action: 1/23/96

The HOUSE SPECIAL COMMITTEE ON OIL AND GAS Committee considered: HB 325

HOUSE BILL NO. 325 ROYALTY SUSPENSION: N. SLOPE HEAVY OIL

"An Act authorizing suspension of payment of a portion of the royalty due the state for initial production of heavy oil from wells on the Arctic Slope."

recommends it be replaced with the following committee substitute CSHB325(O&G) [ ] the same title [X] a new title

[ ] additional referral to _____ Committee
[ ] attached amendment(s)

ADOPTS: _____ Letter of Intent

ATTACHES NEW FISCAL NOTE(s): (Dept) APPROVES PREVIOUS: (Dept/Date)

[X] fiscal note(s) (1) DNR (2) DOR [ ] fiscal note(s) _____

[ ] zero fiscal note(s) _____ [ ] zero fiscal note(s) _____

SIGNING WITH RECOMMENDATIONS	DP	DNP	NR	AM
Scott Ogan	✓			
Norman Rokeberg	✓			
Eldon Mulligan	X			
Peggy Wilson			✓	
Norman Rokeberg and Scott Ogan	X			
Bettie Davies by Shirley Gatto	X	X		

CHAIR'S SIGNATURE Norman Rokeberg 1-23-96

D

(9)

HOUSE COMMITTEE REPORT

2/7/96

Finance

Date Referred to Committee: January 24, 1996 **FURTHER REFERRALS:**

Date of Committee Action: 2/7/96

The RESOURCES Committee considered: **HB 325**

HOUSE BILL NO. 325 **ROYALTY SUSPENSION: N. SLOPE HEAVY OIL**

"An Act authorizing suspension of payment of a portion of the royalty due the state for initial production of heavy oil from wells on the Arctic Slope."

recommends it be replaced with the following committee substitute CSHB 325 (O+G) [ ] the same title [X] a new title

[ ] additional referral to _____ Committee
[ ] attached amendment(s)

ADOPTS: _____ Letter of Intent

ATTACHES NEW FISCAL NOTE(s): (Dept) APPROVES PREVIOUS: (Dept/Date)

[ ] fiscal note(s) (2) [X] fiscal note(s) REV, DNR 1/24/96

[ ] zero fiscal note(s) [ ] zero fiscal note(s)

SIGNING WITH RECOMMENDATIONS	DP	DNP	NR	AM
Nicholia				X
DAVIES				X
Williams	✓			
Green	✓			
Austerman	✓			
Kott	✓			
Ogan	✓			
	(5)			(2)

Co-CHAIR'S SIGNATURE _____ Green

BP EXPLORATION

James A. Palmer
Director
External Affairs
Alaska

BP Exploration (Alaska) Inc
900 East Benson Boulevard
P O Box 196612
Anchorage, Alaska 99519-6612
(907) 564-5435

November 10, 1995

Representative Joseph Green
Alaska State Legislature
716 W. Fourth Avenue, Suite 350
Anchorage, Alaska 99501-2133

Dear Representative Green

Earlier this year, BP Exploration (Alaska) commissioned a study on the economic impacts of marginal oil field development in Alaska. Conducted by the Institute of Social and Economic Research, the results of the study were presented to the State of Alaska Oil and Gas Policy on June 5, 1995.

Although specific marginal fields would have differing degrees of economic and public sector impacts, the general conclusion about the significance of developing marginal oil fields is important to note.

> "Marginal oil field development in Alaska can generate jobs and income for Alaska workers, sales for Alaska businesses, and an increase in the state tax base more than sufficient to offset any additional costs to government from resource management and public service requirements from population increase."

Additionally, when compared to the state's natural resource revenues and management expenditures of fishing, lands, wildlife, mining and timber, the marginal oil field is the only case where resource management costs are covered by the revenues generated, and the substantial revenues are available to contribute to the general costs of the government (see Figure 5B in attached summary).

As you know, the oil industry faces a variety of competitive challenges it must overcome in order to attract the funds it needs to survive and grow in Alaska. Together with the state, we've begun to take our first tangible steps toward overcoming our competitive disadvantages by working together. This includes efforts such as last year's legislation that encourages development of new, economically marginal oil fields.

This study is another step in the cooperative process. I thought you would appreciate receiving a copy of the executive summary for your initial examination. If you would like a copy of the entire report, please feel free to give me a call at 564-5435.

Sincerely,

James A. Palmer
Director, External Affairs
Alaska

encl:

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

EXECUTIVE SUMMARY

Marginal oil field development in Alaska can generate jobs and income for Alaska workers, sales for Alaska businesses, and an increase in the state tax base more than sufficient to offset any additional costs to government from resource management and public service requirements from population increase.

This conclusion is based on an analysis using existing information about the economy and public sector combined with a description of a hypothetical marginal oil field. In reality, each marginal field would have different characteristics, and the actual economic and public sector effects would differ from the description in this study. However, given the economics of field development, this study demonstrates that the general conclusions are consistent with a broad range of assumptions about both field characteristics and the economy.

The purpose of this study is to provide a framework for analysis of the economic effects of new, small marginal oil fields which may be typical of new petroleum industry activity in Alaska. The analysis is generic and hopefully will lead to more detailed and specific studies where appropriate. Some of the information used to develop the parameters for the analysis come from the ongoing study of the Badami oil field on the North Slope. Since that project is only in the earliest stages of its evolution, it would be inappropriate to interpret this analysis as a study of the Badami prospect.

The study examines a hypothetical marginal oil field on the North Slope with anticipated recoverable reserves of 100 million barrels of oil. We assume a total development budget of $320 million, most of which would be spent in a two-year period during which the initial wells would be drilled, the pipeline constructed, the modules fabricated and put into place, and the operating facility built. Production would subsequently continue over a 20-year period at a cost of $320 million. In the early production years, the drilling of wells would continue and after year 5, the drilling activity would switch to workovers of the existing wells. The purpose of these development and production cost figures is to calculate economic effects, and they should not be interpreted as reflecting the actual costs associated with any particular field.

Although some expenditures, in particular module fabrication and equipment for the modules and pipeline, would be purchased outside the state, much of the work would be carried out onsite during both field development and production. These tasks include site preparation, pipeline and module installation, and well drilling; and all have a large labor component. During production the operation of the field and drilling would continue around the clock so the number of workers employed would be 4

times the number of jobs to be done onsite. The development and production jobs would require highly trained and skilled workers so wages would be high and some specialized jobs would, of necessity, be filled by workers from Outside. Based on current experience, the share of jobs going to residents would be high, but some workers would choose to live outside the state.

Other costs associated with field development and production would generate sales, employment, and payrolls for Alaska vendors providing supplies, equipment, and services to the owner company, the oil service companies doing the contract drilling and other work, the construction contractors, etc. A large portion of the economic effect of marginal field development would come from the recirculation within the economy of the high payrolls paid the North Slope workers. These payrolls would generate sales, jobs, and tax base in the communities where the Slope workers live.

Figure 1 shows the size and composition of Alaska employment and payroll which the development and production of the field would generate after subtracting onsite jobs likely to be filled by nonresidents. Field development would be spread over several years, so the number of annual average jobs produced in the peak year would be about 500 with a payroll of $25 million. As the figure shows, the majority of those jobs would be offsite in vendor businesses, in the communities where the workers reside, and in the public sector. During production the number of jobs would fall to under 250 for an average year, and the pattern again is that most of the jobs would be offsite. However, in both the development and production phases, the payrolls are concentrated onsite.

The actual economic impact in a real situation would depend on the development and production plan as well as the resident share of employment and purchase of other inputs. But once the field size has been estimated, the budget and with it the economic effect would be constrained within a narrowly defined range. Basically the budget must be economically feasible, and the economic effect would flow from that budget. While the economic effects are clearly defined once the development strategy has been identified, the revenues that the field would generate are much less so since they are sensitive to actual, rather than anticipated, production, wellhead price, and the tax and royalty rates in place.

The range of variation of state revenues from production, primarily royalties but also the state share of the property tax and the corporate income tax, in response to variation in these parameters is shown in Figure 2. For example, if over its life the field were to produce 150 million barrels, the wellhead averages $8.31 (1995 $) and the royalty rate is 6%, production revenues would be $84 million. For the range from low to high price, production, and royalty, the range of production revenues is $29 to $328 million.

Two other sources of revenue, from the "full pipeline effect" and the payrolls generated by the new jobs, are less volatile and significant. Adding production from a marginal field to the existing throughput of the Alyeska pipeline marginally reduces

the tariff on existing throughput and increases its wellhead value. This "full pipeline effect" would increase severance tax and royalty revenues from production from all North Slope fields. The payroll generated by the marginal field activity represents a tax base which could be tapped to pay some of the state government costs imposed by the new workers and their families. Although the state currently has no vehicle to allow these workers to pay for some of the public services they receive, the tax capacity represented by their payroll should be included as a potential revenue source.

The costs to state government from marginal field development consist of management costs such as environmental monitoring, tax auditing, etc., and more importantly the costs of providing services for the families of the new workers both onsite and in Alaska's urban centers. These costs can be divided into those which support oil industry families, vendor families, and other private and public workers in the urban centers. The public management costs are about $7 million, and the population-related costs are about $4.4 million, totaling about $51 million.

These public sector costs are contrasted with the range of revenues which the field could produce over its life in Figure 3. Subtracting the costs from the revenues yields a range for the state revenue "dividend" (Figure 4), which is the tax base generated by the marginal field over and above the amount necessary to pay for the costs of state government imposed by the field. The "dividend" ranges from $1 to $300 million depending upon production, price, and royalty rate.

Figure 5A shows the range of production revenues introduced as Figure 2, converted to an annual equivalent. It contrasts the potential range of revenues for the marginal field with the total annual revenues to the state generated by other natural resources based on a recent analysis of the sources of state revenues prepared by Legislative Research in 1993. The range for the marginal oil field is clearly consistent with the total revenues to the state from most other natural resources.

Finally, Figure 5B compares the state's natural resource revenues from various resources with the state's resource management expenditures for those same natural resources. The marginal oil field is the only case where resource management costs are covered by the revenues generated, and the substantial revenues are available to contribute to the general costs of government.

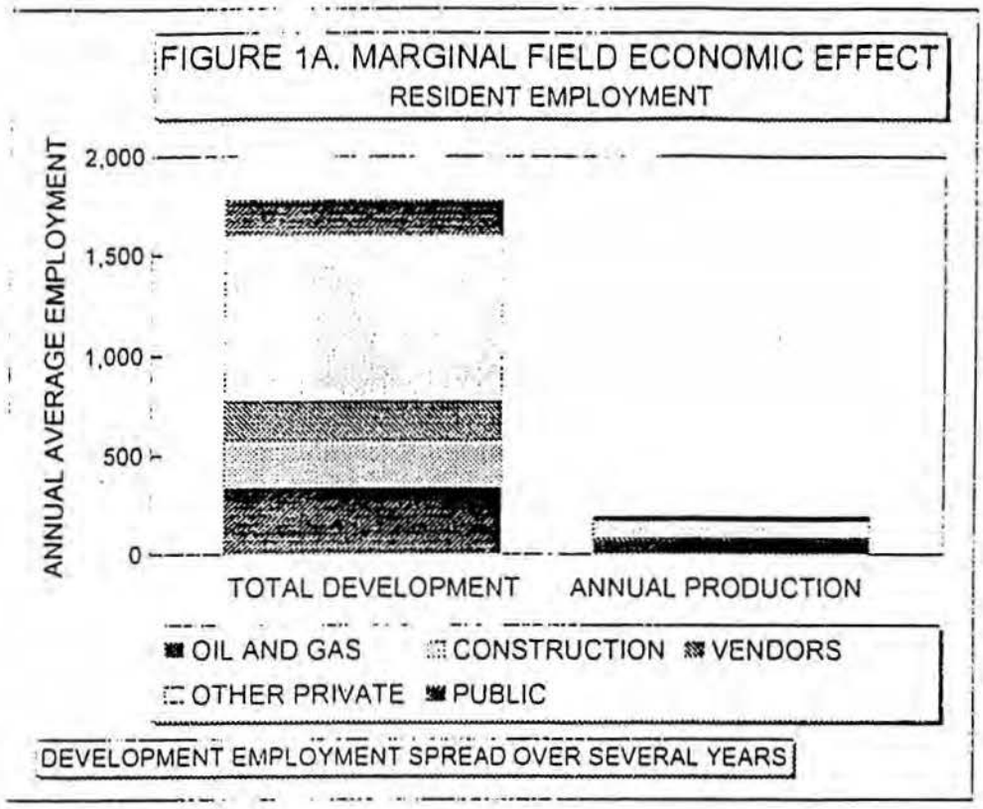


FIGURE 1A. MARGINAL FIELD ECONOMIC EFFECT
RESIDENT EMPLOYMENT
ANNUAL AVERAGE EMPLOYMENT
2,000
1,500
1,000
500
0
TOTAL DEVELOPMENT
ANNUAL PRODUCTION
OIL AND GAS
CONSTRUCTION
VENDORS
OTHER PRIVATE
PUBLIC
DEVELOPMENT EMPLOYMENT SPREAD OVER SEVERAL YEARS

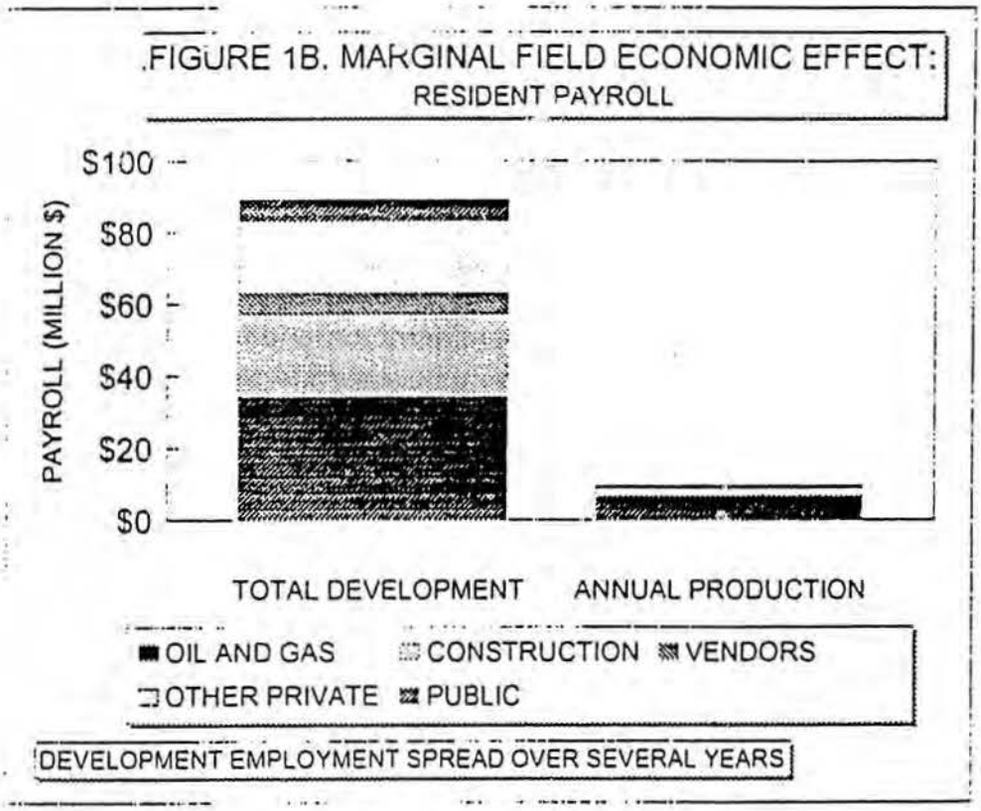
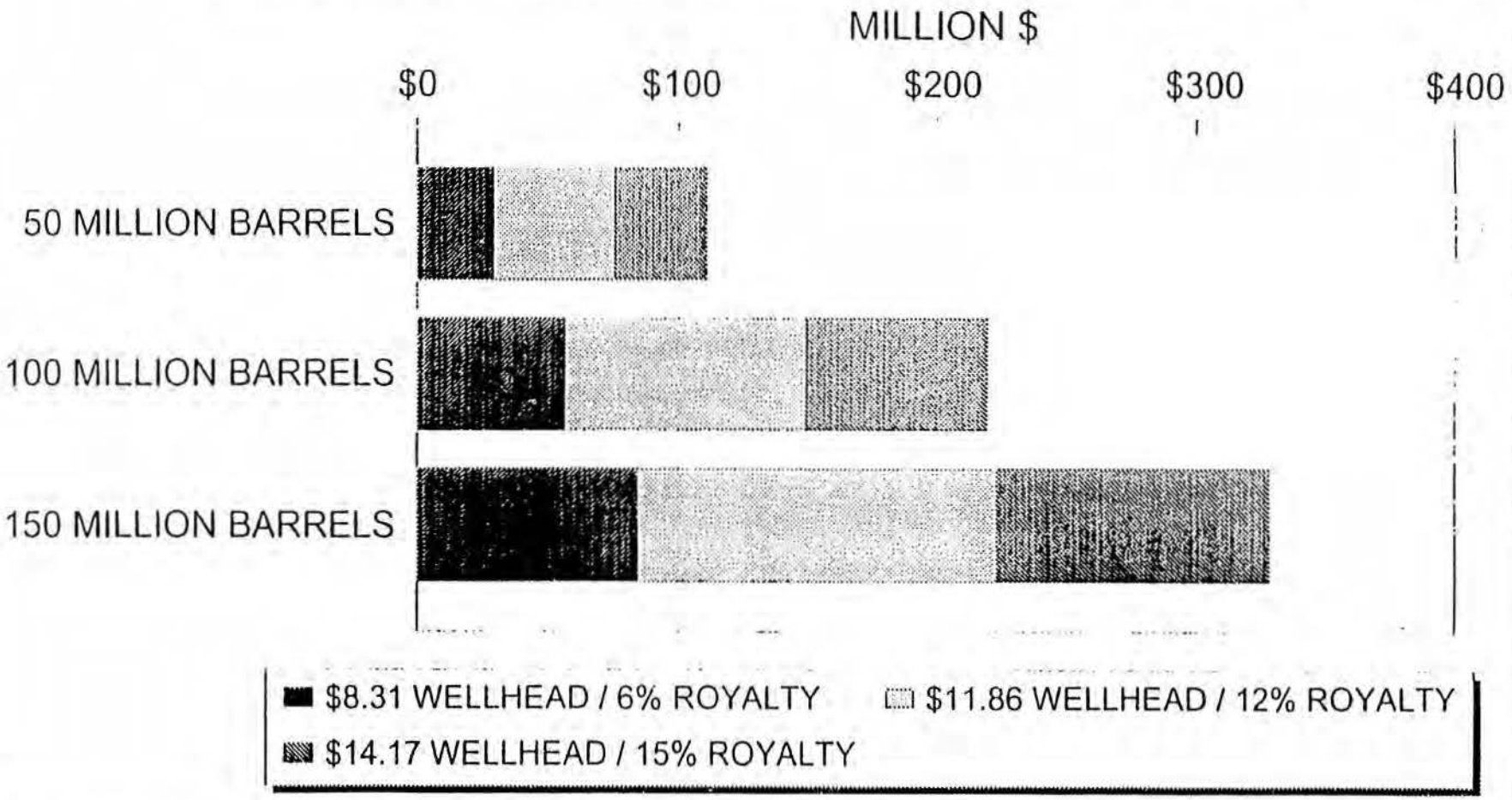


FIGURE 1B. MARGINAL FIELD ECONOMIC EFFECT:
RESIDENT PAYROLL
PAYROLL (MILLION $)
$100
$80
$60
$40
$20
$0
TOTAL DEVELOPMENT
ANNUAL PRODUCTION
OIL AND GAS
CONSTRUCTION
VENDORS
OTHER PRIVATE
PUBLIC
DEVELOPMENT EMPLOYMENT SPREAD OVER SEVERAL YEARS

FIGURE 2. MARGINAL FIELD PRODUCTION REVENUES

SENSITIVITY TO PRODUCTION, WELLHEAD PRICE, AND ROYALTY RATE



REVENUES OVER THE LIFE OF THE FIELD

FIGURE 3. STATE REVENUES AND EXPENDITURES: LIFE OF THE FIELD

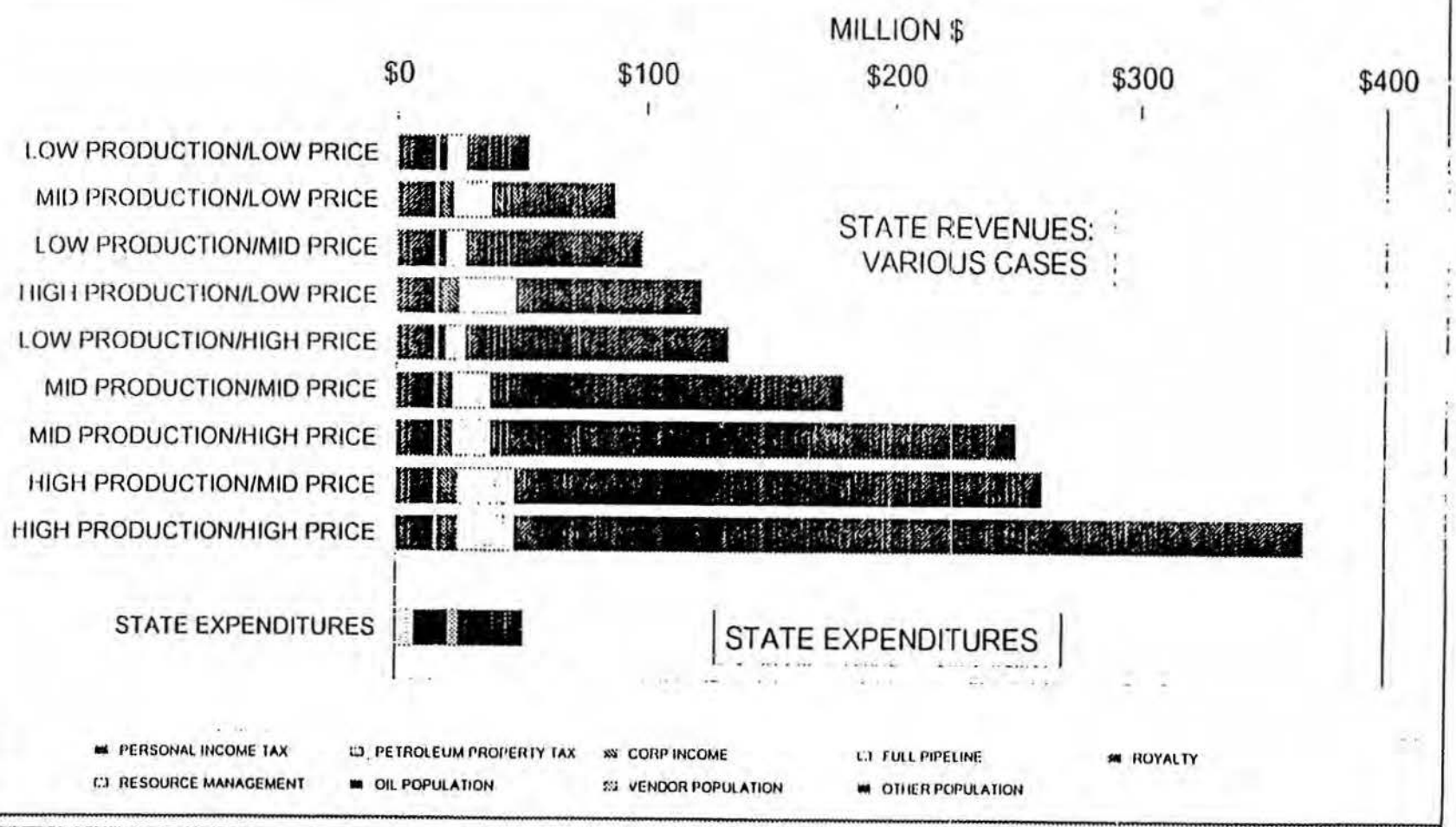
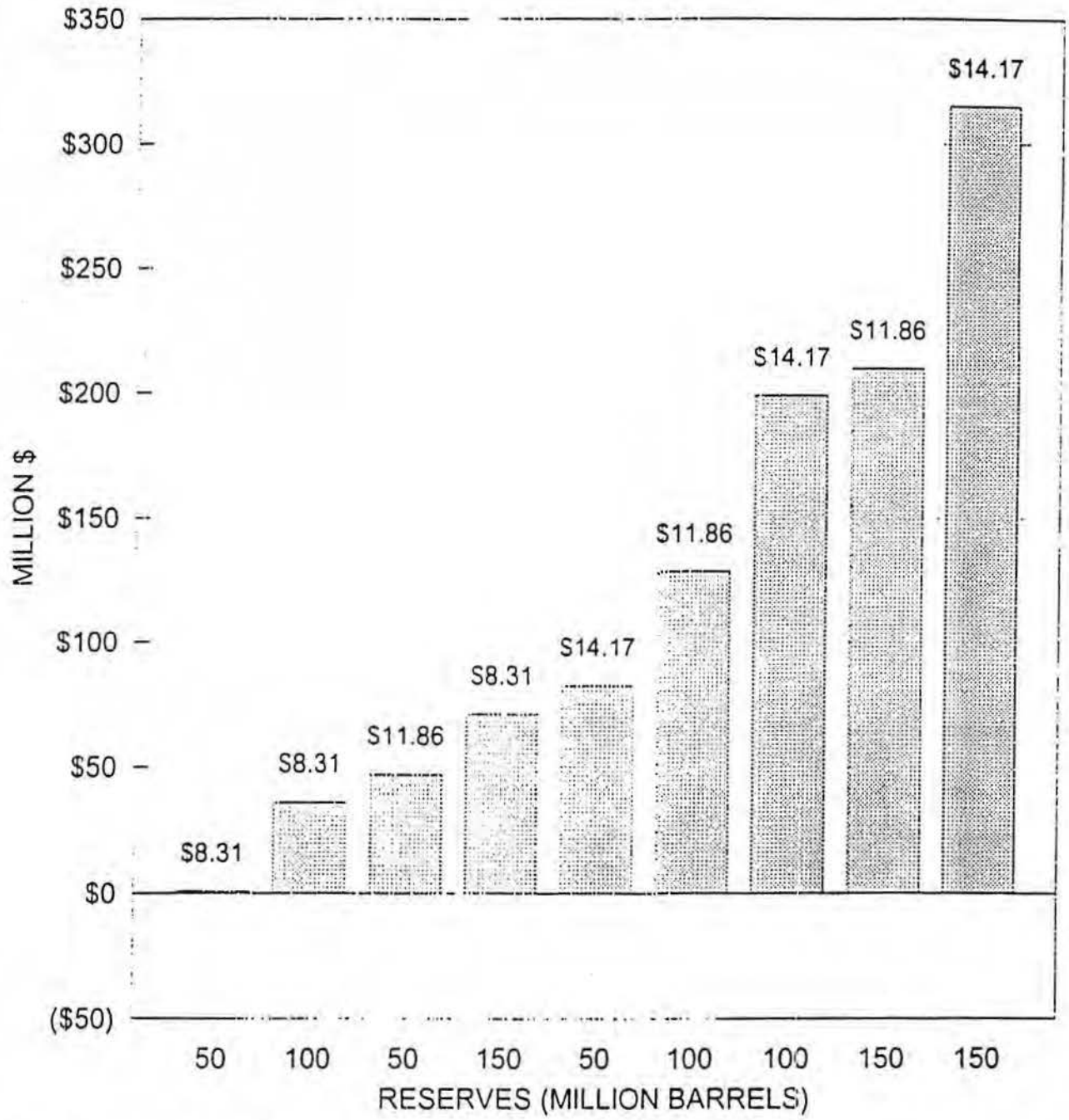


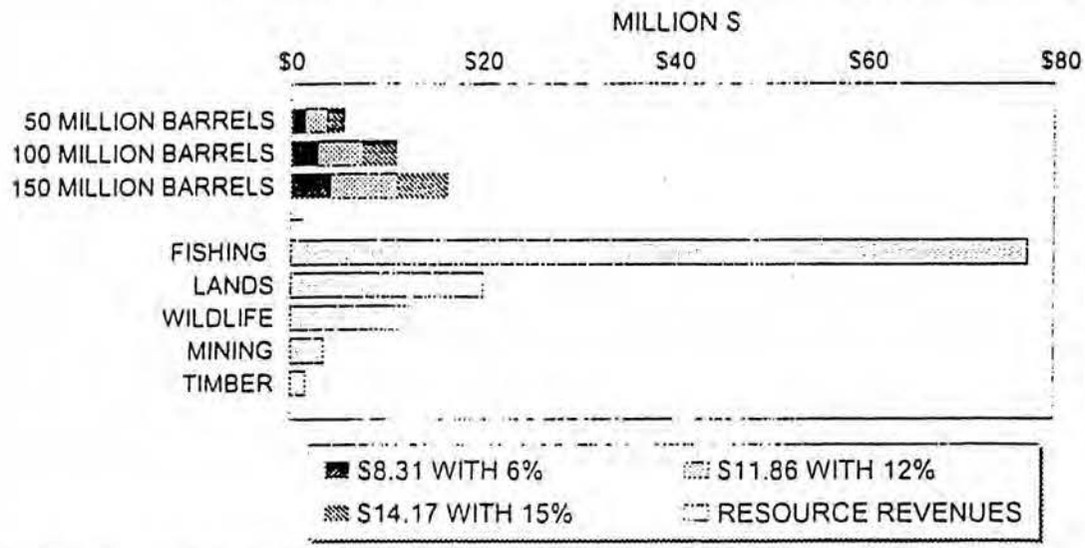
FIGURE 4. STATE REVENUE "DIVIDEND"

VARIATION IN RESERVES, PRICE, AND ROYALTY RATE



REVENUES IN EXCESS OF AMOUNT NEEDED TO PROVIDE NEW PUBLIC SERVICES

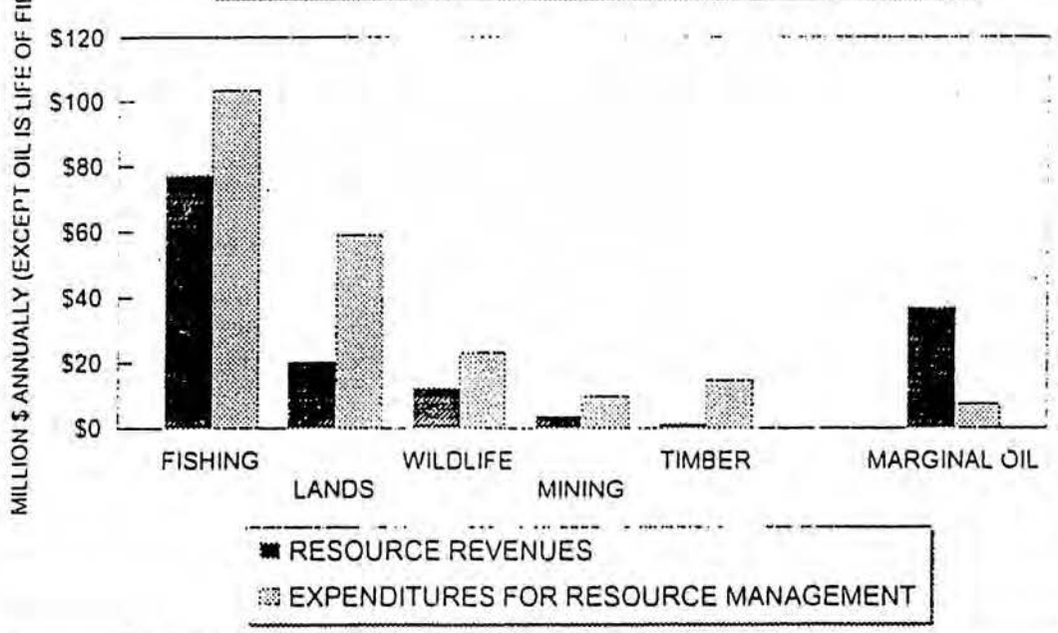
FIGURE 5A. ANNUAL MARGINAL FIELD PRODUCTION REVENUES
COMPARISON TO TOTAL REVENUES FROM OTHER RESOURCES



SOURCE FOR OTHER RESOURCES: LEGISLATIVE RESEARCH 1993

FIGURE 5B. STATE OF ALASKA

NATURAL RESOURCE REVENUES AND EXPENDITURES



SOURCE: LEGISLATIVE RESEARCH, 1993,
EXCEPT MARGINAL OIL IS LOWEST REVENUE CASE FROM TEXT NET OF INCOME AND SALES TAX RE

CALIFORNIA INDEPENDENT PETROLEUM ~~ASSOCIATION~~

Main Office: 1112 "I" Street, Suite 350, Sacramento, CA 95814 • 916-447-1177 • Fax 916-447-1144
Environmental Affairs Office: 5201 Truxtun Avenue, #119, Bakersfield, CA 93309 • 805-633-3119 • Fax 805-633-3191

June 21, 1995

JUL 05 1995

Representative Joe Green
Alaska State Legislature
Alaska State Capitol
Juneau, Alaska 99801

RE: CIPA Support for HB 325, the "Heavy Oil Royalty Suspension" Bill

Dear Representative Green:

The California Independent Petroleum Association (CIPA) wishes to express its strong support for HB 325, provided that Congress lifts the ban on the export of Alaskan North Slope crude oil which appears likely to happen soon. CIPA represents over 550 production, exploration and service companies operating in California.

This measure proposes a simple yet effective incentive for independent producers, including those in California, to invest in heavy oil projects in Alaska. As you know, approximately two-thirds of California's oil production is heavy oil and this state's producers know only too well the difficult investment climate for heavy oil and the large role incentives can play in stimulating such activity.

Simplifying the process of obtaining incenvtives is critical for the independent producer because of limited manpower resources. And in order to be an effective inducement to increase activity, the incentive must significantly affect an independent's economics. HB 325 appears to accomplish both of these goals.

Please do not hesitate to contact me at (916) 447-1185 if I may be of assistance in your deliberations on this proposal.

Sincerely,

Daniel P. Kramer
Executive Director

STATE OF ALASKA
1996 LEGISLATIVE SESSION

FISCAL NOTE

BILL NO: HB325

Revision Date:
Dept. Affected: Revenue
Title: Royalty Suspension: N. Slope Heavy Oil
BRU: Revenue Operations
Component: Oil and Gas Audit
Sponsor: Representative Green
Requestor: H (O&G) Committee
COMPONENT SERIAL NO. 115

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						
CHANGE IN REVENUES ( )	**-1,800.0**	**-2,400.0**	**-5,700.0**	**-11,000.0**	**-12,000.0**	**-24,500.0**

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other						
TOTAL	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

Estimate of any current year (FY96) cost $

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

(See Attached Analysis)

Prepared by: Chuck Logsdon
Phone: 276-1363 ext. 265
Division: Oil & Gas Audit
Date: 1/19/96
Approved by Commissioner:
Date: 1/19/96
Agency: Department of Revenue

PREPARER TO PROVIDE ALL DISTRIBUTION COPIES TO GOVERNOR'S LEGISLATIVE OFFICE
For further distribution information call the Governor's Legislative Office

I:LEG:HB325.XLS

Analysis of Bill/Program Effects

This bill has two main parts. The first addresses the ability of the Commissioner of the Department of Natural Resources to modify the payment of royalty on leases, and the second suspends the royalty obligation for wells producing less than 500 barrels a day of Alaska North Slope (ANS) heavy oil for five years of production.

The Department of Revenue Fall 1995 forecast assumptions for Alaska North Slope heavy oil production, wells, and revenues FY 1997 to FY 2002 is contained in the following table:

	Production	Wells	Severance Tax	Royalties
1997	3000 bb/d	14	0	$1800 thousand
1998	4000	16	0	2400
1999	5700	22	0	5700
2000	11100	42	0	11000
2001	18100	65	0	12000
2002	24500	85	0	24500

The bill would effectively reduce projected heavy oil royalties to zero.

Alaska State Legislature

WHILE IN SESSION
CAPITOL BUILDING
JUNEAU, ALASKA 99801-1182
[illegible]
[illegible] FAX

INTERIM ADDRESS
[illegible] WEST 4th AVENUE
ANCHORAGE, ALASKA 99501
[illegible]
[illegible] FAX

CO-CHAIR, RESOURCES COMMITTEE
VICE CHAIR, JUDICIARY COMMITTEE
MEMBER, STATE AFFAIRS COMMITTEE

FINANCE SUBCOMMITTEES:
DEPT. OF NATURAL RESOURCES
DEPT. OF COMMERCE & ECONOMIC DEVELOPMENT
DEPT. OF ENVIRONMENTAL CONSERVATION

Representative Joe Green

District 12

Sponsor Statement

HB 325 - Heavy Oil Royalty Holiday

HB 325 allows the producers of heavy oil to forgo the payment of royalty to the state on the first 500 barrels of heavy oil produced each day, for a period of five years. The heavy oil considered in this bill is a thick, tar-like hydrocarbon that is more difficult to produce than the lighter, more conventional oil and gas. The purpose of suspending the royalty is to encourage the lessees of heavy oil deposits to do field research and hopefully develop the maximum amount of recoverable oil in a timely manner.

HB 325 requires no application, the suspension is automatic. In order to receive the suspension the producer must simply submit documentation to DNR certifying that the oil produced meets the definition of "heavy oil" and monitor the production rate to satisfy the requirements in the bill.

HB 325 sends a message to potential investors world-wide that the 19th Alaska Legislature supports the development of heavy oil.

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

March 22, 1996

The Honorable Mark Hanley
Alaska State Representative
State Capitol, Room 507
Juneau, Alaska 99801-1182
MAIL STOP 3101
FAX 1-907-465-2418

Dear Representative Hanley:

I received the proposed amendments from your office on March 19. These amendments do two things (other than "housekeeping").

First, they clarify that only new grass roots wells are eligible for royalty relief, and, further, they describe what types of other "well operations" will not be considered for relief. As with any list, it is impossible to contemplate every variation of well type or well operation (nor can it envision future technology). Nonetheless, I believe this gives a pretty clear message as to what the legislative intent is. This intent is further clarified by the new "initial production" language you inserted. I suggest the following amendment to round out the concepts you propose:

Adopted

Page 2, after line 30 #2

insert "(E) for purposes of calculating the first 500 barrels per day of production from a well, production from dual completions and other forms of multiple completions in a well is to be added together and counted as production from a single well."

Second, they clarify that "field cost" deductions will not be allowed from any royalty free production of heavy oil. The bill does not define "field costs." I suggest the following amendment to clarify what I believe your intent is:

Adopted

Page 2, after line 30 #3

insert "(F) for purposes of defining field costs in this subparagraph, field costs include ~~the~~ those ~~costs~~ outlined in AS 38.05.180(f)."

Lease or Unit expenses

The bill appears to suggest "reported royalty" will be the actual royalty. This needs further clarification, and I will work with the legislature to come up with more appropriate language.

3/22/96
ATTACHMENT 2

I further suggest two "housekeeping" amendments:

Adopted

Page 2, line 10 Am 4

delete "finished goods"
insert "industrial commodities"

Page 2, line 22 Am 5 Adopted

insert after the word "performed": concep
"at least once monthly"
19 or greater

I continue to have concerns with the overall approach taken in the legislation and the proposed 500 b/d, $15/b and 10 year open window trigger points. I still believe that HB-207 is the proper vehicle to determine both the need for, and level of, royalty relief. Heavy oil has an important role to play in the future on the north slope. Hopefully we can continue to discuss our differences and reach a common understanding.

Sincerely,

Kenneth A. Boyd
Director

032296mh.kb

ATTORNEYS AT LAW
SIMPSON, TILLINGHAST, SORENSEN & LORENSEN
A PROFESSIONAL CORPORATION

LESLIE LONGENBAUGH
RONALD W. LORENSEN
L. MERRILL LOWDEN
E. BUDD SIMPSON
STEPHEN F. SORENSEN
JON K. TILLINGHAST

ONE SEALASKA PLAZA, SUITE 300
JUNEAU, ALASKA 99801
PHONE (907) 586-1400
FAX (907) 586-3065

February 22, 1996

The Honorable Mark Hanley
Alaska State Representative
Co-Chair House Finance Committee
State Capitol, Room 507
Juneau, Alaska 99801-1182

Re: HB 325; Royalty floor
Our file: 553.7

Dear Representative Hanley:

The purpose of this letter is to share OXY USA Inc.'s ("OXY") views on the option of creating a royalty floor in HB 325. Under this option, royalties would not be suspended for a period of 5 years; rather, royalties during an initial development period would be reduced to 2 or 3 percent. As the attached chart indicates, if the committee's desire is still to craft an effective incentive--that is, one that appears calculated to push heavy oil development over the 15 percent hurdle-rate threshold--then:

(1) with a 2 percent "floor," the incentive period would need to be extended to six years from the initial drilling of each new well; and

(2) with a 3 percent "floor," the incentive period would be eight years.

OXY believes that a royalty floor would make HB 325 a materially less effective incentive without yielding any corresponding revenue benefits to the state. For these reasons, we would oppose its inclusion in the legislation. To explain:

1. A floor's impact on the bill's effectiveness as an incentive. The purpose of HB 325 is to spur capital investment in new heavy oil drilling by: (a) improving each well's rate of return; and (b) reducing the capital recovery period to a commercially reasonable term. Either a 2%/6-year, or 3%/8-year, "floor" would yield the same rate of return as a 5-year suspension--as the attached graph illustrates. However, by extracting royalty payments at the outset of production, a floor would impair initial cash flow and resultantly prolong capital recovery. As you know, even a five-year royalty

suspension yields a 5.4 year projected capital recovery period--still longer than the commercial five-year standards. *See White Paper*, p. 37. Any material adverse impact on that already-marginal recovery period could adversely affect investment decisions.

Moreover, a floor would increase the investor's risk to declining oil prices. With the bill's $15/bbl. ceiling, the state is protected from high-side risk. However, if oil prices fall, the resultant losses to the operator would be aggravated by the need to pay a royalty on gross production value. The increased risk occasioned by a royalty floor during the capital recovery period will undoubtedly be considered by investment decision-makers.

For these reasons, jurisdictions seeking to encourage new capital investment (as opposed to prolonging an exiting field's economic life) have uniformly chose to suspend payment obligations at the outset of development, rather than spread reduced payments over a longer period. *See White Paper*, p. 35. [1]/ Indeed, the Arther D. Little Report specially mentioned royalty suspensions as an effective vehicle for encouraging investment in marginal fields. *Id.* at 34. In sum, a royalty suspension would be consistent with precedent and prevailing wisdom. The approach envisioned by a "floor" would not be.

2. **A floor's impact on state revenues.** On a nominal dollar basis, the royalty suspension maximizes state revenues from heavy oil development. [2]/ This is because heavy oil wells: (a) have low initial production rates; (b) decline very slowly; and (c) have unusually long lives. Indeed, in the White Paper OXY showed that, for these reasons, the state would receive $800,000 more in royalties for each well under a royalty suspension than from a five-percent royalty over the life of the field. *White Paper*, p. 39.

As a result, it is in the state's interest to front-load the incentive, and have it expire at the earliest possible time.

HB 207 requires a 3-5% royalty floor. That is because that law's drafters had in mind more conventional oil fields with perhaps a 20-year field life, and a 20% annual production decline. In these more typical situations, the state does have a clear interest in capturing a share of initial action. Conversely, with a 41-year field life, and only a 10% annual production decline rate, the state gains nothing, and at some point actually loses revenues, by dragging out an incentive simply for the purpose of capturing a share of initial production.

If you have further questions on this matter, please do not hesitate to ask.

---

[1]/ It's true that most of these other incentives suspend a state's severance tax, rather than royalties. However, and as the White Paper explains, this is only because oil production in other states generally occurs on private land, and therefore the severance tax forms the principal government "take" from oil production.

[2]/ It remains our understanding that the State of Alaska generally predicates its economic analyses on nominal dollars.

Sincerely,

SIMPSON, TILLINGHAST,
SORENSEN & LORENSEN

Jon K. Tillinghast

cc: Rep. Joe Green
Rep. Norman Rokeburg
Members, House Finance Committee

JKT:tg

ATTORNEYS AT LAW
SIMPSON, TILLINGHAST, SORENSEN & LORENSEN
A PROFESSIONAL CORPORATION

LESLIE LONGENBAUGH
RONALD W. LORENSEN
L. MERRILL LOWDEN
E. BUDD SIMPSON
STEPHEN F. SORENSEN
JON K. TILLINGHAST

ONE SEALASKA PLAZA, SUITE 300
JUNEAU, ALASKA 99801
PHONE (907) 586-1400
FAX (907) 586-3065

FEB 02 1996

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. In summary, we are confident that HB 207, as it currently exists, cannot be used to fashion an effective ANS heavy oil incentive. To cure the problems associated with HB 207, as it applies to ANS heavy oil, we believe that last year's law would need to be amended to substitute the process and substance of HB 325 for the discretionary procedures set out in HB 207.

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. Commisioner 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

---

[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.

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 re-enforces DNR's long-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 six 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 conditions. 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]/

---

[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

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 is 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; emphasis added. 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.

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 Declining Field clause pre-dated HB 207:

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

---

any field that 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.

[6]/ *Minutes, Senate Finance Committee*, May 8, 1995.

[7]/ *Id.* at 3.

[8]/ *Memorandum, Chair Rokeburg to Members of Senate Finance Committee*, May 5, 1995 at 2.

DNR Paper at 1; emphasis added. 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, and as Mr. Boyd explained to the Senate Finance Committee, the Conoco/OXY 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, any prognosis about field economics would be dependent on projections of future oil prices, and the inherent uncertainties 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, was simply transferred into HB 207:

---

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

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

(3) Schrader Bluff's potential 41-year field life is nearly twice as long as the Kuparuk Formation field life at issue in the Conoco decision,

Mr. Boyd's suggestion that the future development of ANS heavy oil 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. However, amending HB 207's eligibility requirements would not lessen any of the other difficulties inherent in relying on that statute.

The first of these other 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 then declines quite gradually thereafter, and the field enjoys a remarkably long life--in Schrader Bluff's case, an estimated 41-years.

Thus, and as the white paper demonstrates, the State of Alaska would likely earn considerably more royalty income from a five-year royalty suspension at the outset of 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 pecularities 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.

---

[12] / AS 38.05.180(j)(2).

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 that may be owned by several lessees.

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 concluded 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, the Conoco/OXY Milne Point proceeding, required 15 months to complete simply at the agency level; and

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

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(j)(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, and 104,000 additional employment years, over the suspension's four-year history. *Id.* at 35.

Conversely, Alaska's discretionary royalty reduction history is less encouraging. There has been only one such completed process, 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 before the agency. As would be the case with HB 207, each individual lessee was required to present a complete, lessee-specific economic case. Even though it owned 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 our state by potentially complex administrative proceedings with uncertain outcomes. Once again, Arthur D. Little's

---

[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.

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 too many varying situations to admit of direct legislative management.

HB 325, on the other hand, focuses only on a single, well-understood development challenge. As a result, it invites 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.

cc: Senator Loren Leman
Representative Norman Rokeburg
The Hon. John Shively
Mr. Kenneth A. Boyd
Members, House Resources Committee

Alaska Environmental Lobby, Inc.
P.O. Box 22151 Juneau, Alaska 99802
Phone: 907-463-3366
Fax: 907-463-3312

HB 325 Royalty Holiday on Heavy Oil

Alaska's Constitution requires that the State and its officers maximize the value of state resources. It is the obligation of the Administration and the Legislature to support the constitution and maximize the value of Alaska's resources consistent with the public interest, for the maximum benefit of its people, not corporations who do business here.

Major changes to existing leases and royalty agreements should be negotiated in public. The supporting data for decisions should be public. As shareholders, Alaskans each have the right and responsibility to pay close attention to the decisions made by our "board of directors" (the Legislature) Our democratic system demands that the public has access to the basic information about the decision effecting us. Without this it will be impossible for anyone to ever know if the constitutional obligation to maximize the value of the state's resources has been fulfilled. Legitimate decision will always be able to withstand public scrutiny.

It is rarely good public policy to craft laws that favor one company over another. But, it is worse to, in the guise of solving the problem of a small independent oil producer, with out ownership of TAPS, or shipping give away the farm. If HB 325 is designed to help OXY petroleum only, then craft it so narrowly that only they benefit. If, the problem is a broader application, make sure the State's best interest is served.

Retroactive changes to leases are unfair advantages to individual companies, harming competition, and possibly neglecting the State's best interest.

To accommodate the economic difficulties of developing heavy crude the State should never forgo the royalty completely. With some royalty being paid, there is a formal relationship and interest in the health of the well by the owner (State) and the producer (lease holder).

In many businesses, (film, music, TV) royalty negotiations are standard. There are many models of shared risk at the investment level, but, over the life of the project all royalties are paid. Benefit now, pay later, but, you should come back and pay.

As the chairman of House Oil and Gas said on 1/23/96, "....(it's) self executing". But, I urge you not to shoot Alaska in it's future earnings.

Alaska Onshore/Near Shore

Field Size (mmb)	Appraisal Wells			Development Cost ($/bbl)	First Oil (Years)	Production Profile		Operating Costs			
	Number**	Cost/Well ($mm)	Duration (Years)			Peak Offtake (%)	Field Life (Years)	Total ($/bbl)	Variable ($/bbl)	Fixed ($/bbl)	Tariff ($/bbl)*
10*	1	10	2	6.0	4	14	12	6.6	3.2	3.4	3.0
25*	1	10	2	4.7	4	14	12	5.1	2.4	2.7	3.0
50*	2	10	2	3.4	4	13	12	4.0	1.8	2.2	3.0
125	3	10	3	2.8	4	12	15	3.1	1.4	1.7	3.0
250	4	10	3	2.5	5	11	20	2.5	1.1	1.4	3.0
500	5	10	3	2.1	5	10	22	2.1	1.0	1.1	3.0

* TAPS tariff only shown, $2.0/bbl for TAPS owner

4.0 → 11.1

4.8 → 12.1

Alaska State Legislature

WHILE IN SESSION:
CAPITOL BUILDING
JUNEAU, ALASKA 99801-1182
(907) 465-4931
(907) 465-4316 FAX

INTERIM ADDRESS:
716 WEST 4TH AVENUE
ANCHORAGE, ALASKA 99501
(907) 258-8198
(907) 258-8171 FAX

CO-CHAIR, RESOURCES COMMITTEE
VICE CHAIR, JUDICIARY COMMITTEE
MEMBER, STATE AFFAIRS COMMITTEE

FINANCE SUBCOMMITTEES:
DEPT. OF NATURAL RESOURCES
DEPT. OF COMMERCE & ECONOMIC DEVELOPMENT
DEPT. OF ENVIRONMENTAL CONSERVATION

Representative Joe Green

District 10

February 2, 1996

Mr. Ken Boyd, Director
Division of Oil & Gas
Department of Natural Resources
3601 "C" Street, Suite 1380
Anchorage, Alaska 99503

Mr. Boyd,

Thank you for the copy of your letter responding to Representative Bill Williams' questions about the applicability of AS 38.05.180 (j) in reducing the royalty for heavy oil.

I appreciate the position you and Commissioner Shively share on heavy oil incentives, and as well, I appreciate the proposed amendment language offered; however, I feel that neither AS 38.05.180(j), nor the proposed amendment achieves the goal I set when I introduced HB 325.

As I stated after your testimony on HB 325 last Friday, the incentives offered in HB 325 are not discretionary. I believe this is the most important aspect of the bill. To allow DNR to have discretionary authority to grant the royalty reduction would introduce an unacceptable degree of uncertainty. As you well know, in the eyes of investors, uncertainty equals risk, and risk is the major element we are attempting to diminish.

The committee substitute offered by the Oil & Gas Committee adequately protects the state with a limited window of opportunity, and a production and price ceiling above which the full royalty applies. The issue of a minimum royalty has been discussed, and it may be possible to discuss this issue further, as an amendment to HB 325, or as a modification to AS 38.05.180(j).

I remain open to proposals to amend AS 38.05.180 (j) to clarify that it can be used to adequately reduce the risk of producing heavy oil to interested potential developers. However, at this time I still feel that the certainty of an automatic royalty reduction is necessary and therefore cannot support discretionary uncertainty in HB 325.

Sincerely,

Representative Joe Green, Co-Chairman
House Resources Committee

TONY KNOWLES, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

3601 "C" STREET, SUITE 1330
ANCHORAGE, ALASKA 99503-5948
PHONE: (907) 269-8784

DIVISION OF OIL AND GAS

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