reservoir temperature. At depths of 5000 feet or less, the cold Arctic subsurface chills the oil to impractically low temperatures.

Moreover, in Schrader Bluff's case the heavy oil is entrained in unconsolidated sand. As the oil is lifted, sand comes with it, choking the well bore and fouling the well pump.

Heavy oil's specific gravity is close to water's; as a result, oil/water separation becomes especially difficult. Once separated, moreover, heavy oil's viscosity, and its relative paucity of more valuable lighter hydrocarbon fractions, makes heavy oil less valuable in the market.

Heavy oil wells are notoriously slow producers. And though heavy oil fields enjoy correspondingly long field lives, slow initial production rates considerably impair the investor's ability to recover its capital investment in a commercially reasonable time.

Schrader Bluff's heavy oil is thus triply disadvantaged: (1) it shares the unpleasant attributes of heavy oil generally; (2) the reservoir's shallow depth and unconsolidated sand impose yet additional engineering challenges; and (3) its development suffers all the economic handicaps facing Milne Point as a whole.

Even so, Alaska's North Slope lessees have invested hundreds of millions of dollars trying to make a go of this uncooperative resource.

D. Industry's Efforts to Develop ANS Heavy Oil.

The initial stab at ANS heavy oil came not at Milne Point, but rather at the adjacent Kuparuk River Unit, which is operated by Arco Alaska Inc. ("Arco"). The prize at Kuparuk River is potentially even greater than Milne Point's. While Schrader Bluff

might produce 300 million barrels of heavy oil, Kuparuk River's West Sak Sands could eventually produce two or more times that amount.

Beginning in September, 1984, Arco invested $135 million drilling 13 wells into the West Sak Sands, and building associated facilities, before abandoning that pilot project in December, 1986. About 1 million barrels were ultimately produced from that endeavor, which meant that the project's development costs were about $135/bbl.

It took industry five years to try again, this time at Schrader Bluff. At Milne Point's Tract 14, Conoco, Chevron and OXY invested about $126 million on 22 heavy oil wells and associated facilities. [10]/ The project's expected recovery of at least 13.5 million barrels translates into a 15-fold improvement in per barrel investment costs over Arco's West Sak effort--from $135/bbl. to $9.30/bbl.

The Tract 14 pilot was an exercise in ingenuity. To keep sand from the wellbore, the companies installed special gravel filters. To heat the oil as it rose through the permafrost zone, heat trace elements were wrapped to the production tubing. The reservoir was fractured to stimulate production, and an electric submersible pump was added downhole to lift the oil. *Chart 7.*

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[10]/ Conoco, Chevron and OXY brought considerable expertise to bear on the 1991 pilot project. OXY, in particular, has long been a leader in developing innovative lifting techniques for heavy oil, particularly in California, where OXY owns heavy oil properties.

Even so, development costs of $9.30/bbl. still made the exercise uneconomic, and initial flow rates from Tract 14 wells only averaged 275 bbls./day. And so, at the end of 1991, further development of Schrader Bluff stopped.

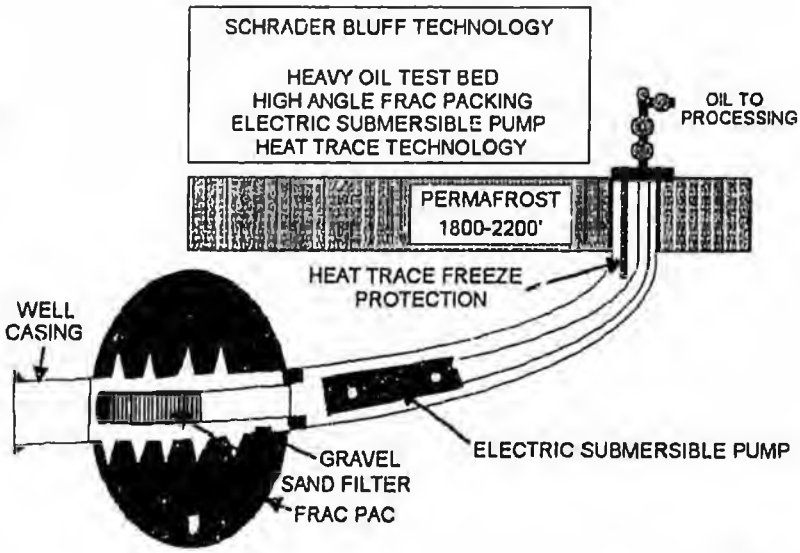

Chart 7

It resumed again in 1994 with BP's acquisition of majority ownership in the unit. One heavy oil well was drilled in 1994, and, in 1995, BP and OXY invested $15 million in six new wells, some well recompletions and additional technical study.

While evaluation of the 1995 drilling isn't complete, we do know that:

- *Advances in technology and better geologic information have made initial flow rates of 300-400 bbls./day practical; and*
- *Other, more conventional methods of stimulating heavy oil production are impractical. Conoco began water injection into Schrader Bluff wells in 1992, without proven success to date. Horizontal drilling, which improves lifting, has been tried at Schrader Bluff with mixed results. Steamflooding, a common recovery technique in the Lower 48, isn't feasible on the North Slope for environmental and practical reasons.*

Experience thus suggests that any dramatic technological breakthrough that would greatly improve ANS heavy oil well productivity is unlikely in the foreseeable future. Put simply, engineering, while it has brought full development of Schrader Bluff

near the brink, may also have reached the point of diminishing returns. What happens from here is largely an economic question.

And it's a question worth pursuing, given the considerable benefit, to both the public and private sectors, of realizing the fullest possible return on heavy oil development.

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III. The Consequences of Schrader Bluff Development

Ultimately, BP and OXY expect to recover at least 13.5 million barrels of heavy oil from the Tract 14 pilot project. Conversely, underlying Milne Point are about 300 million barrels of reasonably recoverable heavy oil. As one might expect, development of that resource would resonate throughout Alaska's economy.

A. The Parameters of Development.

DNR's Spring, 1995 production forecasts for Milne Point portray a unit peaking at 65,000 bbl./day in 1999, then sharply declining until the unit is abandoned in 2011. [11]/ As Chart 8 illustrates, with development of Schrader Bluff's heavy oil, the unit's profile looks different. [12]/

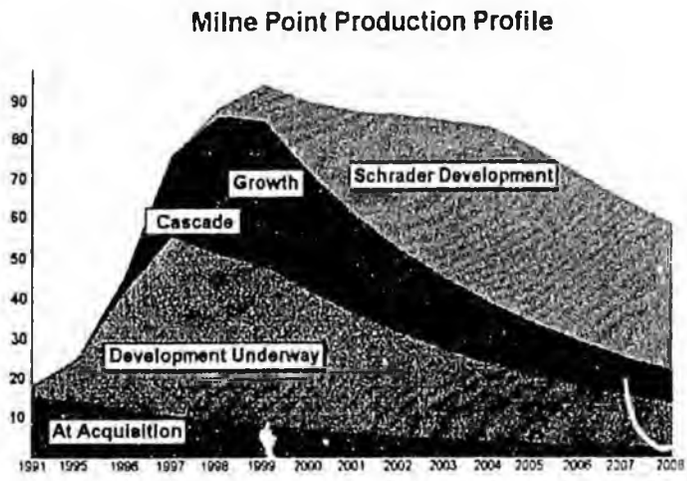

Chart 8

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[11]/ *Historical and Projected Oil and Gas Consumption,* March, 1995 at 6-7.

[12]/ The components of Milne Point production depicted in the chart include: (1) "At Acquisition." This component reflects Milne Point production existing when BP acquired majority ownership of the unit at the end of 1993; (2) "Development Underway" is principally comprised of additional Kuparuk formation production from the northwest corner of the unit; (3) "Cascade" refers to an accumulation lying to the southeast of the unit. Production from that lease will be routed through Milne Point's processing facilities; (4) "Growth" refers to a number of planned expansion projects; and (5) "Schrader Development," of course, refers to the unit's heavy oil resources. Without Schrader Bluff development, the companies project peak production in 1998-99 of about 80,000 bbls./day--a forecast more optimistic than DNR's projections. Milne Point's central processing facilities are being expanded to accomodate that increased production. Currently, the unit produces only 28,000 bbl./day--a limit dictated in part by the current capacity of the unit's processing facilities. On the other hand, the companies' forecasts do mirror DNR's projections of a sharp decline in unit production after 1999, absent development of Schrader Bluff.

If and when the project becomes commercially feasible, the Milne Point Unit business plan envisions that initial development of Schrader Bluff would involve drilling some 230 wells, and constructing new surface facilities and pads, over a nine-year development period, with a total capital cost of $550 million. Once producing, those wells would peak at 45,000 bbls./day, and production would decline only gradually, giving the field a 41-year life.

Over the 41-year period, production expenses would average $15 million annually, totalling $600 million over the field's life.

B. The Economic Impacts of Schrader Bluff Development.

1. Private Sector Employment

The University of Alaska Anchorage has authored an economic impact analysis of the initial development scenario in the Milne Point business plan. [13]/ Employing the impact methodology developed by Professor Scott Goldsmith, the analysis charted both the direct and indirect employment and fiscal consequences of Schrader Bluff development. Looking first at the development phase of the project, those impacts included:

- ***233 direct oil industry jobs created during the nine-year development phase.*** [14]/ *Of those jobs, 157 would be performed in Alaska, and 118 would be filled by Alaska residents;*

- ***142 indirect or spin-off Alaska private sector jobs, and an additional 62 jobs for Alaska industry vendors, created during the development phase alone;***

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[13]/ The analysis, entitled "*Heavy Oil Development: The Economic Impact,*" is available on request from either UAA or BP.

[14]/ For the development phase, the UAA report expresses its projections in "man-years of employment" for the entire nine year development phase. To translate that number into "jobs," the total man-years (in the case of direct industry jobs, 2098 man-years) was divided by nine.

- ***All tolled, 322 new private sector jobs filled by Alaska residents during the development phase, out of a total of 361 new private sector jobs performed in Alaska; and***

- ***An Alaska resident payroll of $171 million during the development phase, out of a total Alaska payroll of $206.5 million.*** [15]/ *Because Milne Point is a remote location, and because the jobs created by Schrader Bluff development are skilled, the average salary for each new direct oil industry job would be $100,000/yr.*

Because the core infrastructure is already in place at Milne Point, the impacts of development-related employment would begin to be felt within months of the companies' commitment to the endeavor. Potentially, if that commitment is made early enough in 1996, the resultant jobs and payroll during the development phase would fuel the Alaska economy from 1996 through 2004.

Enhanced production would then commence in 1997. From that year, and until the year 2037, the UAA analysis projects that, throughout the period, Alaska would experience:

- ***58 new long-term direct oil industry jobs in Alaska, of which 46 would be held by Alaska residents;***

- ***An additional 76 new indirect and vendor jobs created in Alaska;***

- ***All tolled, 134 new private sector jobs created in Alaska, of which 122 would be held by Alaska residents; and***

- ***A total Alaska resident, private sector payroll increase of $7.43 million/year, out of a total Alaska private sector payroll increase of $8.58 million/year.***

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[15]/ All dollar figures expressed in the UAA report are in constant 1995 dollars.

The private sector employment impacts forecast in the UAA report are summarized in Chart 9.

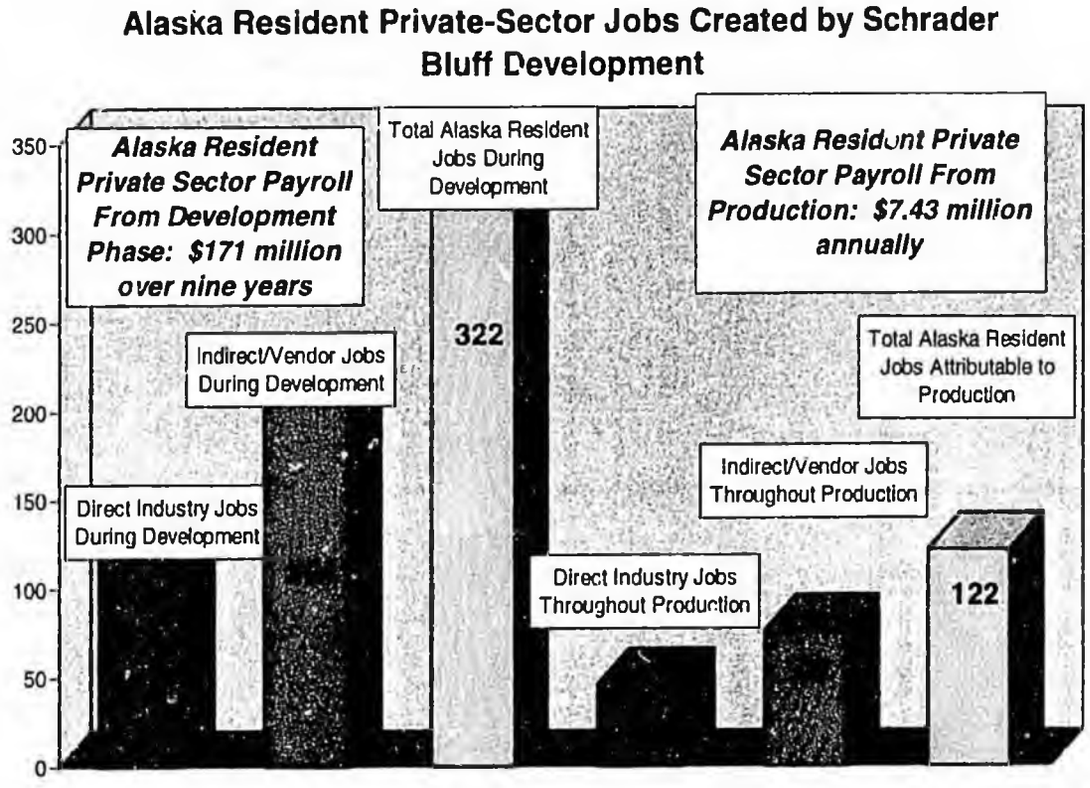

Chart 9

2. State Revenue Impacts

As Chart 2 indicates, the state can expect to receive $365 million more in royalties than DNR's Spring, 1995 production forecasts would yield--*if* the passage of HB 325 stimulates development of Schrader Bluff. [16]/ For its part, and as Chart 10 illustrates, UAA looked at the aggregate of royalty and tax revenues that the state could expect to receive from initial Schrader Bluff development. UAA projects that the state would receive $444 million in revenues, and a $348 million net return (after accounting

[16]/ Again, the $365 million figure is expressed in nominal dollars.

for increased government expenditures occasioned by the substantial increase in private sector employment), as a result of initial field development. [17]/

Chart 10

One element of that net gain warrants special attention. Schrader Bluff development would cause a proportional increase in TAPS pipeline throughput occasioned by up to 45,000 bbl./day of Schrader Bluff heavy oil travelling through it. Declining ANS production in the 21st century will cause upward pressure on per-barrel TAPS tariffs. As more Schrader Bluff oil passes through the TAPS line, the tariff on ***all*** ANS crude decreases, and the resultant wellhead value on ***all*** ANS crude increases.

That, in turn, results in higher state royalties on ***all*** ANS production. UAA estimates, in this regard, that if Schrader Bluff were developed, the state would earn between $65-$84 million in additional royalty income from ***all*** ANS production during Schrader Bluff's field life.

3. Public Sector Employment

UAA projects that the economic activity generated by Schrader Bluff development will occasion $97 million in public sector costs over the life of the field. To a large extent, that translates into new public sector jobs.

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[17]/ If TAPS pipeline throughput were lower than that scenario envisions, UAA's revenue and net revenue projections are, respectively, $425 million and $329 million.

UAA estimates that development will directly result in 27 additional state government jobs during the development phase, and an additional 10 state jobs lasting over the field's 41-year producing life. UAA also believes that second and subsequent rounds of public sector employment gains will be realized as the economic impact of the enterprise compounds itself. UAA concluded that 38 additional new public sector jobs--state and local--would be spawned by this multiplier effect during field development, while 15 additional new public sector jobs would be generated by the multiplier effect throughout 41 years of field production.

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IV. The Economics of Schrader Bluff Development.

A. The Rate of Return Necessary for Schrader Bluff Development.

$550 million--the capital necessary to develop Schrader Bluff--is a considerable investment. And as Arthur D. Little recently reminded the Oil & Gas Policy Council, "[c]ompanies will review and compare all opportunities available to them worldwide, [and] governments are competing on a global basis to attract risk investment." [18]/

The benchmark by which the attractiveness of Schrader Bluff investment will be measured is the "hurdle rate," which represents the minimal projected rate of return necessary to warrant consideration among the companies' investment options. That rate, in turn, is built on four components (Chart 11):

"Hurdle Rate" -- The Minimum Rate of Return Necessary to Justify Capital Investment

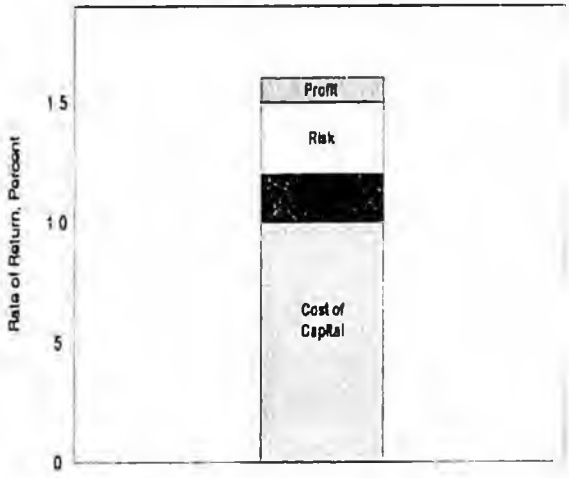

Chart 11

- ***The cost of capital.*** *Corporations acquire investment funds in one of two ways--borrowing, or attracting equity investment. The cost of capital is the weighted average of the company's bond interest rates and cost of equity;* [19]/

- ***Overhead.*** *Any new investment must bear its requisite share of the corporation's overall overhead costs, such as corporate management;*

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[18]/ *Little Report* at 9.

[19]/ Marino, *Handbook of Capital Expenditure Management* at 93 (1986). The cost of equity capital includes more than just dividends paid. The cost of capital for common stock, for example, consists of "the expected total return from dividend yield ***and capital gains.***" Block and Hirt, *Foundations of Financial Management,* App. 11A (1989); emphasis added.

- *Risk. "[I]n order for investors to take more risk they must be compensated by larger expected returns...U.S. Treasury bills may be considered a riskless asset. When viewed in this context, an investor must achieve an extra return above that obtainable from a Treasury bill in order to induce the assumption of more risk." ;* [20]/ *and*

- *Profit. No enterprise invests without the expectation of some profit.*

In today's market, and as Chart 11 suggests, these four "hurdle rate" components combine to require at least a 15% projected rate of return from any new investment--a benchmark validated by the *Little Report:*

> *Companies will generally consider any field uneconomic if the gross project value is negative at a discount rate of about 15%.*
>
> ...
>
> *[Oil] companies generally look for a rate of return of about 15%...Projects with lower returns usually do not generate enough profits to encourage companies to commit time and resources to their development.*

Little Report at 120, 122.

Passing the hurdle rate does not guarantee investment capital because, as Arthur D. Little reminded us, any investment must still compete with often lucrative worldwide opportunities. The hurdle rate is a qualifying time, not a checkered flag--it is only enough to warrant the prospect's consideration by corporate policy-makers.

The hurdle rate is therefore a conservative measure of Schrader Bluff's prospects, and also a conservative measure of the effectiveness of any development incentive.

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[20]/ *Foundations of Financial Management*, op. cit. n. 19; *see also In the Matter of the Filing of Revised Tariffs by Cook Inlet Pipeline Co.*, Alaska Public Utilities Commission, January 14, 1985 at 26 (additional rate of return allowed because of risk that oil prices may drop in the future).

B. Schrader Bluff's Projected Rate of Return.

To forecast the likely rate of return from Schrader Bluff development, OXY seems the fairest candidate since, unlike other North Slope producers, OXY's revenues from Schrader Bluff production will come solely from wellhead revenues--OXY does not share in significant downstream pipeline, tanker or refinery profits.

For its presentation to the Oil & Gas Policy Council in June, 1995, OXY projected its rate of return from something of a best case. For example, initial flow rates from the Tract 14 pilot project have averaged only 275 bbls./day. The five best of those 21 wells managed initial rates of between 300-600 bbls./day, and OXY's projections assumed initial flow rates equal to the average of ***only those five best producing wells.***

In other words, OXY assumed that the technological innovation and better geologic data gained through five years of experimentation at Schrader Bluff would yield the highest plausible reward.

To those production forecasts were applied:

- *Projected oil prices drawn from the Department of Revenue's Spring, 1995 base case revenue forecasts;* [21]/
- *Well costs equal to the average costs of Tract 14's 21 wells;*
- *The existing 12.5% state royalty, and historically-based tax payments;*
- *Projected operating expenses taken from the unit's 1995 estimates; and*
- *Facilities costs from the operator's 1995-1997 business plan.*

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[21]/ As noted previously, the Fall, 1995 Department of Revenue long-range price forecasts are virtually identical to the Spring, 1995 forecasts. *See n. 5, ante.*

The results are depicted in Chart 12. In short, the projections show a:

- ***12.8% projected rate of return.*** *The projection thus falls materially short of the 15% hurdle rate;*

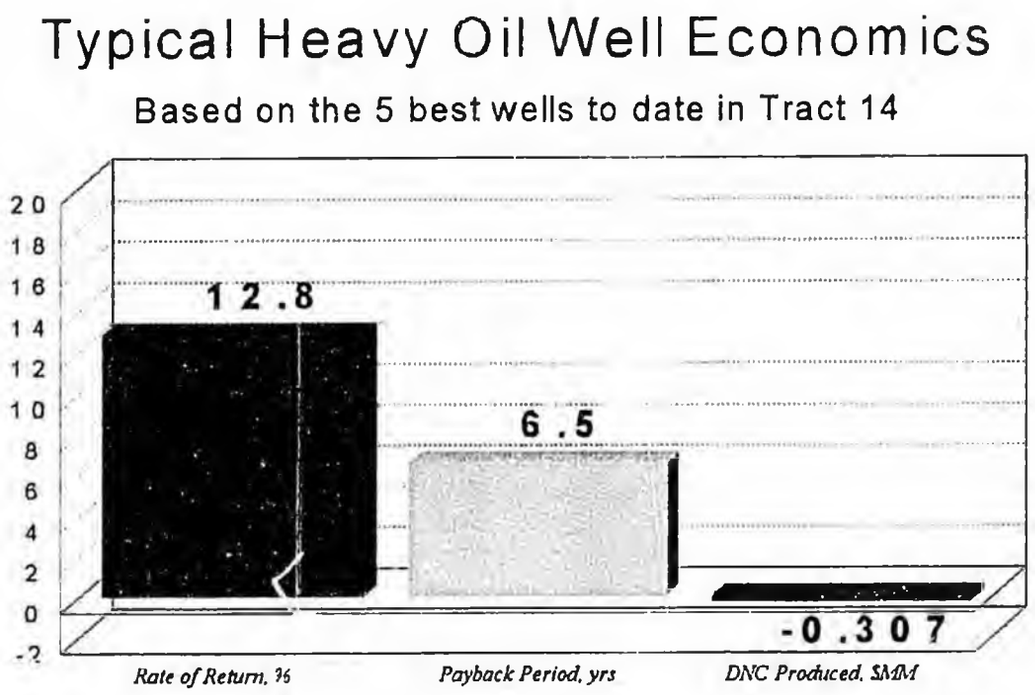

Chart 12

- ***6.5-year payout period.*** *Five years is a commercially reasonable time for project payout. The extended payout period is a function, of course, of the inadequate rate of return; and*

- ***Negative discounted cash flow at 15%.*** *As Arthur D. Little observed, "[c]ompanies will generally consider any field uneconomic if the gross project value is negative at a discount rate of about 15%."*

The numbers shouldn't be surprising. As we've seen, the state itself has long felt that development of Schrader Bluff is unlikely. And, despite:

⇒ Arco's investment of $135 million in the Kuparuk River Unit's West Sak sands;

⇒ Conoco's and OXY's investment of $126 million in the Tract 14 pilot project; and

⇒ BP's investment of an additional $15 million in pilot drilling, recompletions and technical studies in 1995,

the only heavy oil produced today on the North Slope flows from those limited experimental endeavors. Schrader Bluff heavy oil sits beneath a convenient unit infrastructure. And, as Chart 8 illustrates, full Schrader Bluff development is integral to prolonging the entire unit's economic life. There seems, in sum, no good reason for not developing that field, save for its inability to cross the hurdle rate threshold.

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V. Legislation to Improve the Economics of Developing Alaska's Heavy Oil Resource

A. The Criteria for Legislation.

Development of Alaska's heavy oil resource is a shared challenge. For its part, the private sector has invested nearly $270 million over the past decade in a determined effort to increase production and reduce production costs.

For its part, the state will affect heavy oil investment decisions most directly through the royalty structure that it imposes. In tailoring that structure to optimize the public's return on heavy oil development, there are seven criteria that should shape the outcome:

- ***Specificity.*** *As Section II(C)-(D) discussed, ANS heavy oil development presents unique challenges that are best met by a royalty structure tailored to the peculiarities of the resource. Revisiting general state royalty policy in order to spur heavy oil development may yield a result that is overbroad or insufficient, or which risks unintended consequences elsewhere.*

  For example, last year the legislature rewrote Alaska's general policy on oil and gas royalty relief. Ch. 85, SLA 1995; HB 207. From a statewide perspective, the legislation set a positive tone for encouraging public/industry partnerships in developing Alaska's marginal reserves. However, the heavy oil initiative that may best suit development of that resource--a five-year royalty suspension--would be impossible under that legislation. HB 207 requires a minimum 5% royalty for every year of production from new fields, [22] */ and a new field is eligible for relief only if there has been no commercial production from that field.* [23]*/*

  Both of these limitations may make considerable sense generally. However, with respect to heavy oil especially, the

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[22]/ AS 38.05.180(j)(4)(A).

[23]/ AS 38.05.180(j)(1)(A)(ii). As we have seen, about 3,000 bbls./day of heavy oil are produced and sold from Schrader Bluff's Tract 14 pilot project.

minimum royalty requirement of HB 207 fails to account for the fact that heavy oil wells invariably: (1) have low initial production rates; but (2) produce for an unusually long time. Thus, the state may--and in this case apparently will--benefit more from a royalty structure that assesses 12.5%-20% royalties commencing in the sixth year of production, than from a structure that imposes, say, a 5% royalty throughout field life. See Section V(C)(6-7), post. [24]/

- ***Relevancy.*** *The task here is to materially improve the projected rate of return from the considerable capital investment necessary to develop ANS heavy oil reserves. Some royalty initiatives are aimed at lowering operating costs in order to prolong or renew production from declining wells.* [25]/ *Here, the targets are quite different: (1) improving the return on new investment; and (2) reducing the period for recovering that investment to a commercially reasonable one.*

- ***Certainty.*** *Companies are unlikely to make serious investment decisions on the mere possibility of a favorable royalty structure. A royalty structure established by operation of law, rather than one dependent on the uncertain outcome of an administrative proceeding, is considerably more likely to favorably influence investment choices.*

- ***Immediacy.*** *There is a window of opportunity for development of ANS heavy oil reserves--one that will last only so long as: (1) the current infrastructure at Milne Point and Kuparuk River remains operational; and (2) the TAPS line is able to carry heavy oil at reasonable per-barrel tariffs.*

  DNR has projected, as recently as March, 1995, that Milne Point will be abandoned in 2011. That does not mean, however, that Alaska has 15 years to debate heavy oil. For example, integral to the ultimate economic viability of heavy oil development is the assumption that, over a considerable portion of heavy oil field life, production costs can be shared

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[24]/ The relationship of HB 207 to the issues raised by this paper is discussed further in Appendix A.

[25]/ This, for example, is the purpose behind BLM's proposed heavy oil royalty regulations. Those regulations, which would establish a sliding-scale royalty for heavy oil wells, are intended 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." 60 *Federal Register* at 18081 (April 10, 1995).

with other, conventional oil production from the same unit. And, as discussed in Section I, ante, the current momentum that has driven the 1994-95 pilot drilling and technical studies at Milne Point risks being lost if the project's economic prospects remain discouraging;

◊ ***Credibility.*** *Simply put, Alaska should look to initiatives that have proven successful in spurring capital investment in marginal fields in other oil producing jurisdictions.*

◊ ***Sufficiency.*** *No one can guarantee the impact of any development initiative. On the other hand, if it is apparent that a given proposal would leave project economics below the competitive threshold, there is nothing gained by the exercise--and perhaps considerable to lose.*

◊ ***Necessity.*** *The state should entertain economic incentives only if it concludes that the initiative will yield the state, and the public, a net economic benefit. Inherent in that philosophy is the proposition that the state should do no more than is reasonably necessary to induce the targeted activity. The state, in short, should not leave money on the table.*

B. The Proposed Initiative--A Five-Year Royalty Suspension on New Heavy Oil Wells.

This paper, and HB 325, propose that the state suspend royalties, for the first five years of production, on the first 500 barrels of heavy oil produced from each new heavy oil well drilled on Alaska's North Slope after June 30, 1996.

The essential attributes of the proposal include:

◊ ***The Five-Year Suspension.*** *The suspension would be applied separately for each new heavy oil well drilled. When each well achieved five years' production, full lease royalties--at either 12.5% or 20%--would apply to all future production from that well.*

Because new heavy oil wells would be drilled over a nine-year development period, there would thus be no sudden shift from royalty-free to royalty-burdened production. Rather, field royalties would be phased in beginning in the sixth year of development, as Chart 13 illustrates.

ADDITIONAL PRODUCTION FROM HEAVY OIL
BY
DEVELOPMENT YEAR

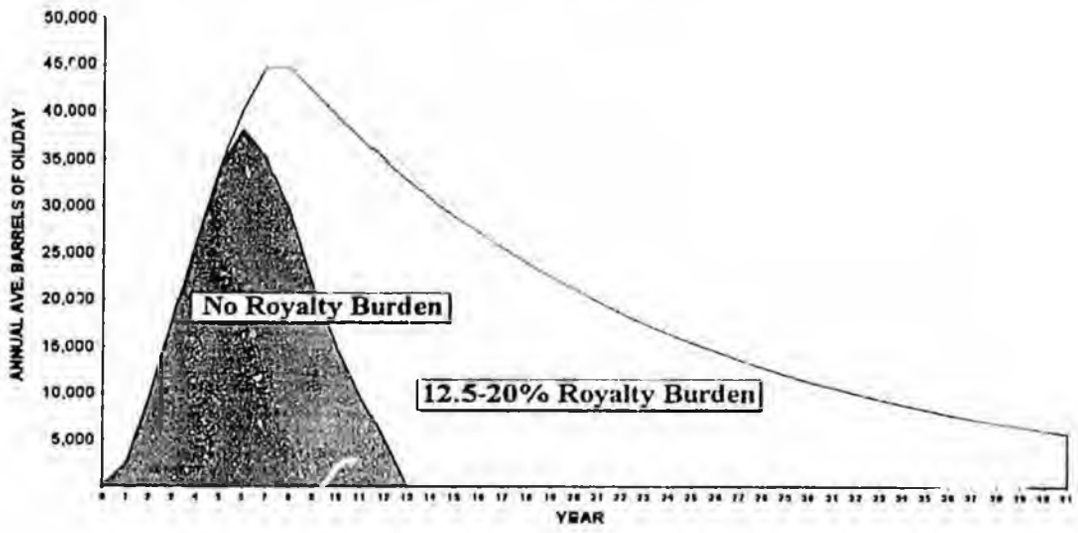

Chart 13

The five-year limitation coincides with the period that most investors consider the longest reasonable time to recover capital costs.

◊ ***The 500 bbls./day limitation.*** *500 barrels per day is as good a working definition as any of a marginal Alaska North Slope oil well. If a new ANS heavy oil well is able to achieve production in excess of that ceiling, that additional production would be subject to full lease royalties.*

ANS experience suggests that new heavy oil wells probably won't reach this ceiling. Even initial production rates from Schrader Bluff's Tract 14 wells averaged only 275 bbls./day, and the five best Tract 14 wells--on which OXY's economic forecast, discussed in Section IV, was premised--averaged about 430/bbls./day.

◊ ***The Limitation to New Wells.*** *The purpose of this initiative is to encourage additional development of ANS heavy oil reserves. As a result, the proposal does not affect production from any now-existing well; nor does it affect even new production from other formations such as Kuparuk or Sag River.*

◊ ***The Geographic Limitation to the North Slope.*** *The economic and technical conditions on which the proposal is based are unique to Alaska's North Slope.*

C. Application of the Seven Criteria to the Proposed Royalty Suspension.

Among any number of possible royalty structures, the five-year royalty suspension seems to best satisfy each of the seven criteria discussed in subsection (A):

1. The Specificity Criterion

The technical and economic challenges facing development of ANS heavy oil are unique, and by confining the proposal's scope to new heavy oil wells on the North Slope, legislation can be carefully tailored to those pecularities.

Through that kind of specificity, the proposal addresses one of the drawbacks of Alaska's fiscal system noted in Arthur D. Little's report to the Oil & Gas Policy Council. Alaska, until now, has maintained a one-size-fits-all royalty structure. On the one hand, Little found that this system has been good to companies producing large, profitable fields--indeed, Alaska ranks in the top quarter of oil producing jurisdictions worldwide in that respect. *Little Report* at 150.

On the other hand, Alaska's uniform system ranks poorly in encouraging investment in marginal fields. *Id.*

Little's findings prove the obvious: when setting statewide policy, the legislative and executive branches are inevitably driven by the policy's impact on large fields such as Prudhoe Bay. The specific proposal envisioned in this paper avoids that, and enables Alaska to take a more surgical approach to royalty policy.

2. The Relevancy Criterion

According to Arthur D. Little, Alaska's fiscal regime "is not fiscally efficient," and in fact ranks 48th out of 101 fiscal systems studied worldwide in its impact on field

rate of return. *Little Report* at 10, 150. "The Alaskan terms," moreover, "do not provide any incentive for the development of marginal fields." *Id.* at 172.

The reason is this: Alaska demands money up-front, before the field recovers its capital investment, irrespective of the impact of that demand on the field's ability to recover its investment within a commercially reasonable time. *Id.* at 91 ("A single royalty rate," Little concluded, "can make marginal fields uneconomic to develop.")

By suspending royalties at the outset of production, rather than spreading a reduced royalty over the field's life, the proposal targets the critical capital recovery period, which Little found Alaska to have heretofore ignored.

Moreover, and as Chart 13, *ante,* illustrates, given the typical production profile of a heavy oil well, targeting initial capital recovery, instead of spreading relief over field life, benefits the state as well. Because production will be initially low, but sustained over an extraordinarily long period with an unusually gradual decline rate, the state can expect to receive full lease royalties for a majority of total well production.

3. The Certainty Criterion

The proposal requires no application or agency review. The suspension is imposed by operation of law upon the occurrence of objectively-measured events.

4. The Immediacy Criterion

The suspension will be immediately available for any new heavy oil well drilled on the North Slope after June 30, 1996. And, at least at Schrader Bluff, industry is capable of responding to the initiative quickly. Because the infrastructure necessary for additional Schrader Bluff development is in place, additional heavy oil drilling could begin within months of the proposal's enactment.

5. The Credibility Criterion.

Royalty suspensions, Arthur D. Little concluded, "will encourage field development," and are "particularly effective for marginal fields" when they are tied to specific amounts of production. *Little Report* at 192. As the following table indicates, production tax and royalty suspensions have served as a principal tool for oil producing jurisdictions seeking to encourage investment in marginal properties: [26]/

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[26]/ Most oil producing states do not themselves own significant oil-producing property, and thus the production or severance tax is the principal source of those states' take. As a result, suspensions enacted in other states generally apply to the severance tax, rather than to privately-collected royalties.

Production Tax and Royalty Suspensions in Other Jurisdictions

Jurisdiction	*Investment Targeted*	*Length of Suspension*
United States	*Gulf of Mexico deep-water wells*	*Variable, depending on water depth*
Texas	*High-cost gas wells*	*10 years*
Utah	*Wildcat wells*	*First 12 months*
Utah	*Development wells*	*First 6 months*
Oklahoma	*Horizontal wells*	*Until payout*
Oklahoma	*Enhanced oil recovery projects*	*Until payout*
Montana	*Horizontal wells*	*First 18 months*
Mississippi	*Discovery wells*	*First 5 years*
Mississippi	*Re-activated wells*	*First 3 years*
Kansas	*Tertiary projects and shallow wells*	*Life of the project*
Kansas	*Discovery wells*	*First 12 years*
Arkansas	*Discovery wells*	*First 5 years*

According to the Texas Railroad Commission, its 10-year production tax suspension for high-cost gas wells netted that state, for the period 1989-93:

- *A 400% increase in the number of high-cost gas wells drilled annually in Texas above the number drilled annually before enactment of the incentive;*
- *$4.122 billion more in natural gas produced in the state over the period;*
- *$240 million in additional sales tax revenues generated over the period;*
- *104,000 new additional employment years created over the period; and*

- *$12 billion in additional economic value generated for the state of Texas over the period.* [27]/

As originally enacted, the Texas incentive was to expire in 1996. Based on its fiscal track record, the Texas legislature renewed the incentive this past year for an additional six years.

6-7. The Sufficiency and Necessity Criteria

As Chart 14 indicates, the five-year, 500 bbls./day royalty suspension moves Schrader Bluff's rate of return from the 12.8% projected by OXY to 15.9%.

The Effect of Royalty Suspension on Schrader Bluff Development Decisions

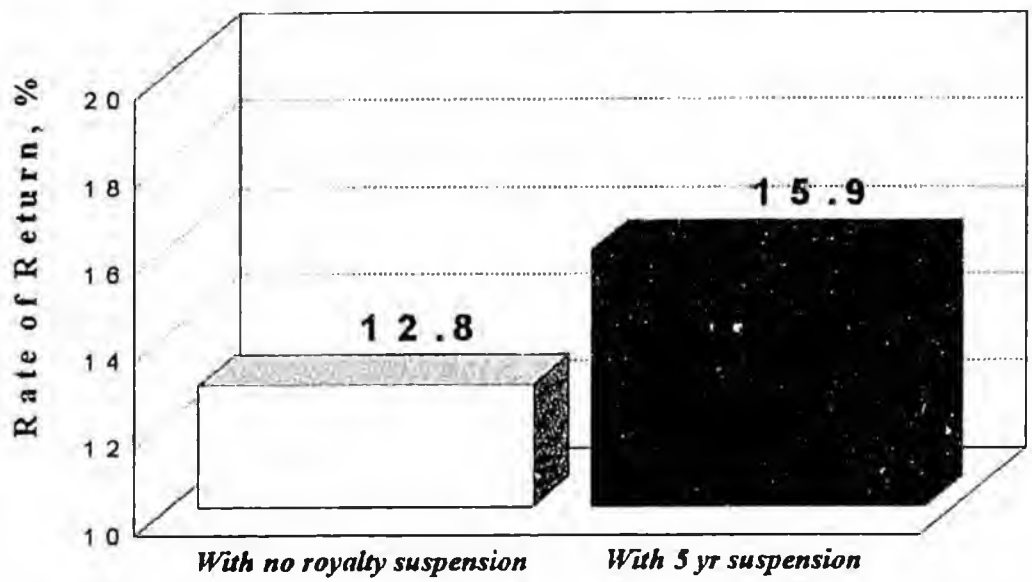

Chart 14

[27]/ *Source*: Texas Railroad Commission, "*Extension of Tax Incentive for the Production of Certain High Cost Gas,*" undated (1994).

Chart 15 shows that the suspension proposal also reduces the capital recovery period close to a commercially reasonable five years.

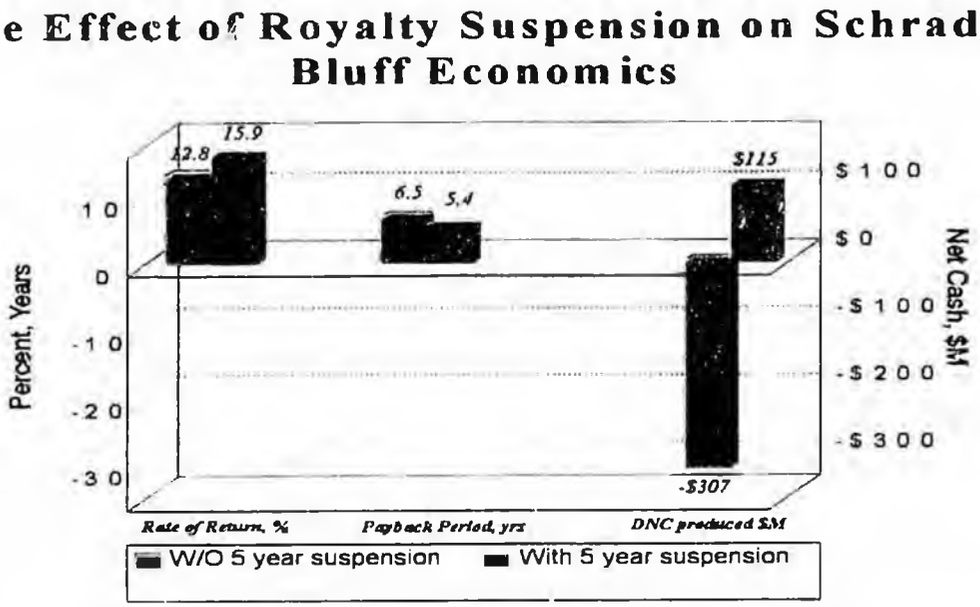

Chart 15

The five-year suspension thus seems ***sufficient*** to at least make Schrader Bluff development competitive with other industy investment opportunities. It appears to put that endeavor over the hurdle rate--an accomplishment that, as discussed *ante*, does not guarantee funding, but does lift the usually fatal burden of bearing below-hurdle rate economics.

It does so, however, by the thinnest of margins, suggesting that the proposal satisfies the ***necessity*** criteria as well. That's perhaps best illustrated by the $115,000 positive net discounted cash flow projected on Chart 15, which is presented on a per-well basis. With each new heavy oil well costing perhaps $2 million, that $115,000 translates into slightly more than a 5% profit for any given well.

The suspension proposal's fit with the necessity criteria--that is, with the concept that the state should leave nothing on the table--can be seen in three other ways:

*1. **Built-in safeguards.*** The proposal's 500 bbls./day ceiling, for example, protects the state in the event that an engineering breakthrough enables heavy oil producers to pull more oil through new ANS heavy oil wells. If any technologically-driven windfall occurs during the suspension period, the state will receive full lease royalties from the added production.

Moreover, and by the very nature of the suspension proposal, the state is better assured a full share of any increased profits caused by either technology or unanticipated oil price increases. With full lease royalties commencing in each well's sixth year of production, the state's risk of losing its full share of any unanticipated profits ends after five years. Conversely, simply reducing the lessee's royalties over the life of the field--to, say, 5%--would expose the state to that risk for over 40 years. And, the consequence of that difference is magnified by the fact that both oil prices and the state of technology are more predictable in the short run than over a four-decade period.

Similarly, if enhanced recovery techniques ultimately allow more total production than is now estimated, the state would enjoy full lease royalties from that increased production, since it would occur later in field life.

2. Comparison to Other Incentives. As Chart 16 shows, a 5% royalty reduction on new heavy oil wells, extending over the life of each well, would also push Schrader Bluff development over the hurdle rate. On a nominal dollar basis, however, the state's royalties over the life of the field would be considerably less. Because of their low initial production rates and slow decline rates, heavy oil wells are better suited, from a landlord's perspective, to a finite royalty suspension at the outset of production than to a reduced royalty over the life of the field.

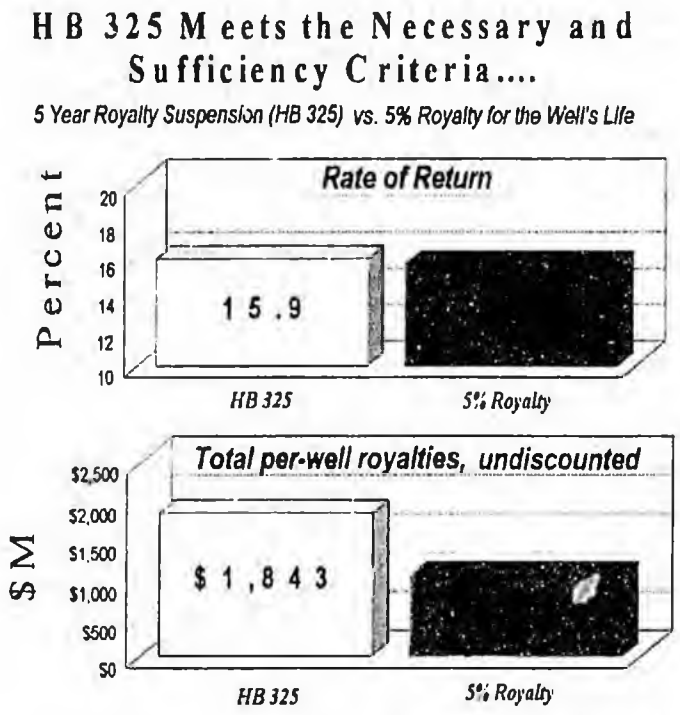

Chart 16

3. Return to the State. This paper began with Chart 2, which compared: (1) the $60 million in royalties that the state could expect to receive from the limited Schrader Bluff production forecast by DNR in the Spring of 1995; to (2) the $425 million in royalties that the state could receive from development of Schrader Bluff under the unit's business plan, even with a five-year royalty suspension.

The suspension proposal would thus seem to meet the essential test of a successful partnership--considerable net benefit to both partners.

For its part, industry has already contributed about $270 million to that partnership through the Schrader Bluff and West Sak pilot projects. And most recently, BP won a $1.6 million U.S. Department of Energy Grant--to which BP will add $9 million--to further refine heavy oil recovery technology.

Moreover, if development occurs, BP and OXY will contribute another $550 million capital investment, and on a project basis won't recover that investment for at least seven years. Thus, the state, which will begin receiving full lease royalties on initial wells at the beginning of the project's sixth year, will see a positive net cash flow from its heavy oil partnership sooner than will its industry partners.

VI. Conclusion

Some decision about Alaska's heavy oil reserves will be made this year--since, as we've seen, even a decision to do nothing carries its own risks, and ought to be a conscious choice, if that's the choice made. Indeed, waiting-to-see may present the highest stakes of all, since it is the only alternative that risks losing the entire resource.

Governor Knowles has provided a critical catalyst for this debate--a debate that, given the magnitude of the resource, warrants legislative involvement. And that discourse is likely to yield the best possible answer if it remains guided by three overriding issues:

- ◊ *Are Alaska's heavy oil reserves likely to be developed in the near future even without any stimulus on the state's part?*
- ◊ *If not, then do the benefits of immediate development, and the risk of waiting, warrant a special state/industry partnership to develop those resources now? and*
- ◊ *If immediate development is in the public interest, what form of royalty structure will best meet the seven criteria discussed in this paper?*

Irrespective of the outcome, the fact that the State of Alaska is about to have such a business-like discussion, as discussions between potential partners should be, sends an encouraging signal about the direction of Alaska's economic climate into the next century.

Appendix A: Some Questions About the Heavy Oil Five-Year Royalty Suspension Proposal

Q: Why don't companies with heavy oil reserves simply use the process established last year in HB 207 (Ch. 85, SLA 1995).

HB 207 authorized discretionary royalty relief in three instances: (1) for new marginal fields: (2) to restore shut-in production; and (3) to prolong the economic life of older fields. A new field is eligible for relief only if "the field or pool has not previously produced oil or gas for sale." AS 38.05.180(j)(1)(C). About 3,000 bbls./day are produced from Schrader Bluff's Tract 14 pilot project. Schrader Bluff would thus be ineligible for "new marginal field" relief, and the remaining bases for relief under HB 207 are simply inapplicable.

For its part, Arco did produce and sell oil from its West Sak Sands pilot project at the Kuparuk River Unit, but has since abandoned that production. Arco, therefore, might be eligible for relief under HB 207 "to reestablish production of shut-in oil."

However, HB 207 imposes another barrier. As the white paper explains, a five-year royalty suspension at the outset of production seems better suited--from both industry's and the state's perspective--to spur additional heavy oil development than a reduced royalty over field life. HB 207, however, requires a minimum 3-5% royalty throughout the life of the field. AS 38.05.180(j)(4). Royalty suspensions, then, are categorically excluded under that legislation.

Of course, HB 207 could be amended. It shouldn't be, for these reasons:

1. As a general statement of state royalty policy, HB 207 sets a proactive tone for future state/industry cooperation in sustaining Alaska's oil and gas industry into the 21st century. It was landmark legislation in that respect--creative royalty management has long been discussed in Juneau, but there hadn't been much concrete action. HB 207 is an accomplishment that does not need revisiting;

2. On the other hand, HB 207 did not purport to solve every development challenge facing the state and the oil industry. That is why, for example, Governor Knowles charged his Oil & Gas Policy Council to address additional royalty management issues after the law had passed. Specifically, the state made a conscious choice, last session, to address heavy oil development separately through the Council and the responsible legislative committees; and

3. As discussed in the white paper, ANS heavy oil development presents unique economic and technical issues that are best addressed on their own. The terms and limitations in a general law such as HB 207 are sensible as a statewide rule--given the

myriad circumstances they will govern. However, and as Arthur D. Little suggested to the Oil & Gas Policy Council, one-size-fits-all policies, which were necessarily developed with larger fields in mind, may actually impair development of smaller or unusual fields. The peculiar challenges facing ANS heavy oil development are ample proof of that.

Lastly, resorting to discretionary agency relief would satisfy neither the certainty nor immediacy criteria that, as the white paper explains, are critical to stimulating heavy oil development during the current window of opportunity presented by existing unit infrastructures, reasonable TAPS pipeline tariffs, and the momentum occasioned by the Tract 14 pilot project and BP's 1994-5 drilling program.

Q. Milne Point already pays no severance tax because of the economic limit factor. Isn't royalty relief asking too much?

Arthur D. Little, in his report to the Oil & Gas Policy Council, concluded that Alaska's royalty structure was "fiscally inefficient," and particularly harmful to marginal fields, because it demanded high payments before a field could recover its capital investment.

For its part, Alaska's severance tax cures that problem, and becomes sensitive to field productivity, through the ELF. However, in the case of marginal endeavors such as ANS heavy oil development, the progressive policies of the severance tax are undermined by a regressive royalty policy. That fact argues for consistency between the two fiscal regimes. The current inconsistency is a problem, then, but for reasons other than the question suggests.

The white paper shows that, even with application of the ELF, development of Alaska's heavy oil reserves is unlikely to occur unless the state revisits its royalty structure for that resource--a fact corroborated by: (1) the industry's inability to develop the resource, despite investing $270 million in pilot drilling; and (2) DNR's oil production projections. Whether royalty restructuring is "too much" of a price to pay to develop that resource is, of course, the ultimate question. Given, however, that:

(1) the state is likely to receive only $60 million in royalties from Schrader Bluff production if DNR's production estimates prove true; while

(2) the state may receive $425 million in royalties if the royalty suspension proposal is enacted, and development of Schrader Bluff's reserves resultantly occurs,

it would seem that the state would not be paying much of a price at all.

Q: OXY received a royalty reduction through a 1994 settlement agreement that restricted its right to apply for additional reductions from DNR. Isn't OXY's support of a royalty suspension an end-run around that agreement?

The 1994 settlement agreement returned OXY's Milne Point royalties to the same rate that the state had promised when OXY's predecessors acquired an interest in the Milne Point leases by competitive bid in 1969. The lease royalty rate was, and for OXY is now again, 12.5%.

Several years after acquiring those leases, Conoco (which was then the unit operator) and the other unit participants applied to DNR to form the Milne Point Unit. The state, however, informed the companies that it would not approve the unit agreement, and would allow the Milne Point leases to lapse, unless the companies agreed to increase the royalty on eight unit leases from 12.5% to 20%.

In late 1985, after oil prices had collapsed, the companies applied to DNR to reduce the unit's royalties. At the time, DNR believed that Milne Point warranted relief, especially given the unusually high 20% royalty that some unit production now bore, but also felt that that it was legally precluded from granting relief until the unit had produced oil for two years.

In January, 1987, the Milne Point Unit was shut-in--DNR having concurred that continued operation of the unit posed an unwarranted economic hardship.

Production resumed in April, 1989, and when two years' total production had been achieved in February, 1990, Conoco and OXY again applied for a reduced royalty. In two separate decisions issued on April 21 and 22, 1991, DNR denied those applications. Conoco and OXY then appealed those denials to Alaska Superior Court. [1]

The litigation lasted for over three years. In December, 1993, and after an unsuccessful eight-year effort to reach a royalty agreement with the state, Conoco sold its interest in Milne Point to BP Exploration (Alaska) Inc., as did Chevron.

OXY maintained its minority 8.81% interest in the unit, and in July, 1994 the litigation settled. OXY's royalties were returned to the same 12.5% rate that Alaska had promised OXY's predecessors back in 1969, when the leases were issued. The settlement, however, was personal to OXY. BP remained obligated--and remains obliged today--to pay a 20% royalty on its majority share of production from the eight affected leases.

Section 5.3 of the settlement agreement also restricted OXY's ability to apply to DNR for royalty reductions. That clause reads:

---

[1] *Conoco Inc. v. State of Alaska, Department of Natural Resources*, 1JU-91-797Civ.; *OXY USA Inc. v. State of Alaska, Department of Natural Resources*, 1JU-91-798Civ.

> *Notwithstanding paragraph 18(h)(8) of the MPU Agreement and any otherwise applicable law, OXY cannot apply for any reduced royalty: (1) for any of the [eight 20% leases]...during the remaining life of the MPU; or (2) for any other liquid hydrocarbon production from the MPU, for five years from the effective date of this agreement.*

By both its terms and intent, the agreement does not attempt to limit the legislature's authority to set state royalty policy. Rather, this clause was inserted after both parties agreed that neither wished to reenact the 4 1/2 years of [illegible]ly administrative proceedings, and subsequent litigation, consumed by these discr[illegible]nary royalty reduction applications.

*And in any event, the question is academic, because if HB 325 is enacted, the state will still enjoy the full benefit of its bargain. The proposal would apply **only** to new heavy oil wells drilled after June 30, 1996. DNR's production projections have, as recently as March, 1995, assumed that future Schrader Bluff production will be limited to the unit's pre-existing Tract 14 pilot project. Thus, HB 325 would not affect any production that DNR believed would occur when it entered into the settlement agreement in 1994. [2]/*

In the scheme of things, this question is tangential to the heavy oil debate--after all, OXY owns but an 8.81% interest in one heavy oil field. Moreover, one needs to remember that the initiative for this discussion came not from OXY, but from the state itself. OXY was invited to participate in the debate over state oil policy initiated by the introduction of HB 207 and creation of the Oil & Gas Policy Council, and it has always been forthcoming on this count in its discussions with both the administration and the legislature. OXY, like anyone, is subject to new laws, and it welcomes the opportunity to exercise its right to participate in public debate over oil and gas legislation.

---

[2]/ Indeed, when the settlement agreement was entered into, DNR was not only projecting that no further development of Schrader Bluff would occur beyond the Tract 14 pilot project--it had concluded that the Milne Point Unit as a whole would be abandoned in the year 2006. DNR, *Historical and Projected Oil and Gas Consumption,* February, 1994 at 6-7.

Q: How can we be assured that, if this initiative passes, our heavy oil reserves will actually be developed?

As the white paper explains, improving Schrader Bluff's economic outlook will not guarantee a positive investment decision. It will only allow Schrader Bluff to compete with other investment opportunities. Actual funding is always a function of available budget funds, the quality of competing prospects, and other variables.

Industry, however, does have a considerable stake in following through. First, it has already invested about $270 million in heavy oil pilot projects--an investment it would plainly like to recoup. Second, lessees with heavy oil reserves do feel some sense of urgency. They know that, given the right economic climate, ANS heavy oil reserves are more valuable now than perhaps they'll ever be. There is an existing on-site infrastructure now; transportation costs are tolerable; and the momentum spawned by the Tract 14 pilot project and BP's recent drilling provides a stimulus to additional development that may well evaporate in a climate of disinterest.

Successful development of North Slope heavy oil is dependent on industry's ability to increase production rates and lower production costs, and the state's interest in crafting a workable royalty structure. Section II of the white paper explains how industry is meeting its obligations in that respect, and by enactment of an effective royalty initiative, the state would have done all it can. In that event, heavy oil would not be lightly disregarded by industry.

Finally, one should remember that the royalty suspension would apply solely to new heavy oil wells drilled after June 30, 1996. If Schrader Bluff or other ANS heavy oil reserves aren't developed, the state loses nothing.

Q: Why isn't this just another industry giveaway?

Bear in mind, in this respect, that the state "gives" nothing unless industry contributes to the partnership by heavily investing in heavy oil development.

But, yes, if the state concludes that Schrader Bluff and the Kuparuk River Unit's West Sak sands will likely be developed ***while*** *existing unit infrastructures remain operational;* ***while*** *TAPS tariffs remain reasonable; and* ***while*** *existing development momentum perseveres, then the royalty suspension proposal is a giveaway, and the state shouldn't do it.*

Q: If OXY owns only an 8.81% interest in Schrader Bluff, why is it so interested in all of this?

To begin with, heavy oil is something of a cause celebre for OXY. It is a nationwide leader in developing creative methods for lifting heavy oil.

And Milne Point is OXY's core asset in Alaska. OXY is the only original Milne Point participant remaining, and its perseverance over 15 difficult years reflects a stubborn commitment to realizing that unit's full potential.

And frankly, that is all to Alaska's advantage. The gene pool of Alaska's oil industry is shrinking, and that's unhealthy. Conoco gave up on Alaska in 1993, and other companies have considerably reduced their Alaska presence, laying off hundreds of Alaska employees over the past several years. The energetic participation of new, independent companies in Alaska's economy should be encouraged--both for its own sake, and to send a clear message that Alaska welcomes active, involved newcomers.

9-LS1122\R.5
Chenoweth
2/9/96

AMENDMENT #1 Adopted

OFFERED IN THE HOUSE BY REPRESENTATIVE BROWN

TO: CSHB 325(O&G)

Mud

Page 1, line 10, after "baseline.":

Insert "When an exemption from payment of royalty is obtained on the production of heavy oil under this subsection, for a period of 20 years after the last day on which a royalty payment exemption is allowed under this subsection a lessee may not claim or obtain the benefit of an adjustment of royalty on the production of oil under contract or any other provision of law authorizing a royalty modification."

HOUSE COMMITTEE REPORT

(11)

Date Referred to Committee: February 7, 1996 **FURTHER REFERRALS:**

Date of Committee Action: 3/22/96

The FINANCE 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 CS HB 325 (Fin) [ ] the same title [ ] a new title

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

ADOPTS: _____ Letter of Intent

ATTACHES NEW FISCAL NOTE(s): (Dept)

[X] fiscal note(s) Rev

_____

[ ] zero fiscal note(s) _____

_____

APPROVES PREVIOUS: (Dept/Date)

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

_____

[ ] zero fiscal note(s) _____

_____

SIGNING WITH RECOMMENDATIONS		DP	DNP	NR	AM
Richard Foster	Foster	X			
Pete Kelly	Kelly			X	
Mark Hanley	Hanley			X	
Helen Nutchen	Mulder	X			
Jean Parnell	Parnell			X	
Eric Kohring	Kohring	X			
Irene Merriault	Merriault			X	
Mike Navarre	Navarre				X
Jay Fordyce	Brown		X		

CHAIR'S SIGNATURE Mark Hanley Richard Foster

Hanley Foster

FISCAL NOTE

BILL NO: CSHB 325

1996 LEGISLATIVE SESSION

Revision Date:

Dept. Affected: Revenue

Title: Royalty Suspension: N. Slope Heavy Oil

BRU: Revenue Operations

Component: Oil and Gas Audit

Sponsor: Representative Green

Requester: (H) Finance

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 ( )	0.0	0 - (300.0)	0 - (2,000)	0 - (7,000)	0 - (13,000)	0 - (19,000)

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: (907) 276-1363

Division: Oil and Gas Audit Date: February 13, 1996

Approved by Commissioner: Wilson F. Condon Date: February 13, 1996

Agency: Department of Revenue

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Analysis of Bill/Program Effects

This revised fiscal note is prepared to illustrate more specifically the potential revenue impacts of the bill. To a large extent the revenue outcome of any legislation which is designed to promote a particular economic activity is uncertain. This revised fiscal note presents two alternative outcomes for heavy oil royalty holiday as applied to the Schrader Bluffs using the Department of Revenue Fall 1995 forecast production, wellhead price and well assumptions. This analysis does not include the West Sak heavyoil production from the Kuparuk unit which in the Fall Forecast is assumed to begin in a small way (.012 million bbl/day) in FY 2003.

	Scenario #1 Holiday Ensures Large Scale Heavy Oil Development Which would Otherwise Not Occur	Scenario #2 Development Would Have Occurred Without Holiday
	Incremental Royalty Impact (Millions $)	Incremental Royalty Impact (Millions $)
1997	0	0
1998	0	-0.3
1999	0	-2
2000	0	-7
2001	0	-13
2002	0	-19
2003	1	-22
2004	2	-25
2005	7	-21
2006	12	-15
2007	19	-10
2008	19	-7
2009	23	-3
2010	25	-1

Clearly if the holiday is needed to attract the investment, the payoff to the State is long term since no significant added royalty income will flow into the treasury until well into the next decade. At the same time Scenario #2 could be characterized a potential revenue loss scenario and effectively puts a price tag on the likely subsidy to Schrader heavy oil production using the Department of Revenue production assumptions.

Note neither of these scenarios is based on the maximum potential oil production scenarios presented in industry documents during testimony on this legislation.

Adopted

9-LS1122\R.5
Chenoweth
2/9/96

AMENDMENT 7

OFFERED IN THE HOUSE BY REPRESENTATIVE BROWN

TO: CSHB 325(O&G)

Page 1, line 10, after "baseline.":

Insert "When an exemption from payment of royalty is obtained on the production of heavy oil under this subsection, for a period of 20 years after the last day on which a royalty payment exemption is allowed under this subsection a lessee may not claim or obtain the benefit of an adjustment of royalty on the production of oil under contract or any other provision of law authorizing a royalty modification."

The Honorable Mark Hanley
Alaska State Representative
March 22, 1996
Page 2

I further suggest two "housekeeping" amendments:

Adopted Amendment 4

Page 2, line 10

delete "finished goods"
insert "industrial commodities"

Page 2, line 22 Conceptual Amendment # 5 Amended Adopted

insert after the word "performed":
"at least once monthly"
Wells above 19.°/o API Gravity

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

Jack
Call me
Louanne
6814

CS FOR HOUSE BILL NO. 325(O&G)

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINETEENTH LEGISLATURE - SECOND SESSION

BY THE HOUSE SPECIAL COMMITTEE ON OIL AND GAS

Offered: 1/24/96
Referred: Resources, Finance

Sponsor(s): REPRESENTATIVE GREEN

A BILL

FOR AN ACT ENTITLED

"An Act authorizing exemption from payment of royalty for initial production of a portion of the heavy oil produced from wells on the Arctic Slope; and providing for an effective date."

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

*** Section 1.** AS 38.05.180 is amended by adding a new subsection to read:

(dd) Notwithstanding any other provision of this section or any provision in a lease, unit agreement, or other agreement between a lessee and the state that establishes an obligation to pay royalty on production, royalty is not payable, under the conditions and to the extent described in this subsection, for the production of heavy oil that is removed or sold from a lease or leases located north of the Umiat baseline. [ ] As follows.

[For purposes of this subsection, "heavy oil" means oil having a weighted average equal to or less than 20 degrees API gravity as the term "API gravity" is defined in AS 43.55.900. Under this subsection, the exemption from payment of royalty applies

(A) [(1)] only to the portion of the value at the wellhead, net of eligible field

lessee's reportable royalty before any [ ] cost deduction

Alaska State Legislature

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DEPT. OF NATURAL RESOURCES
DEPT. OF COMMERCE & ECONOMIC DEVELOPMENT
DEPT. OF ENVIRONMENTAL CONSERVATION

Representative Joe Green

District 10

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.

CORRECTION

THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
ASSURE LEGIBILITY OR PAGINATION

CS FOR HOUSE BILL NO. 325(O&G)

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINETEENTH LEGISLATURE - SECOND SESSION

BY THE HOUSE SPECIAL COMMITTEE ON OIL AND GAS

Offered: 1/24/96
Referred: Resources, Finance

Sponsor(s): REPRESENTATIVE GREEN

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(A) [(1)] only to the portion of the value at the wellhead, net of eligible field

lessee's royalty before any [illegible]

cost deductions, as calculated for the month of production, for the first 500 barrels of daily production of heavy oil from the well, that, for the period beginning on

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

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

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

(C) (3) only to heavy oil produced during the first 1,825 days of well operation after the start of production of oil from the well, as reported to the Alaska Oil and Gas Conservation Commission; and

(D) (4) for a well only if the lessee

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

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

* **Sec. 2.** This Act takes effect immediately under AS 01.10.070(c).

Alaska State Legislature

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

Representative Joe Green

District 19

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.

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

Mr. Edward J. Behm
OXY USA Inc.

Confidential

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/bol 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

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.

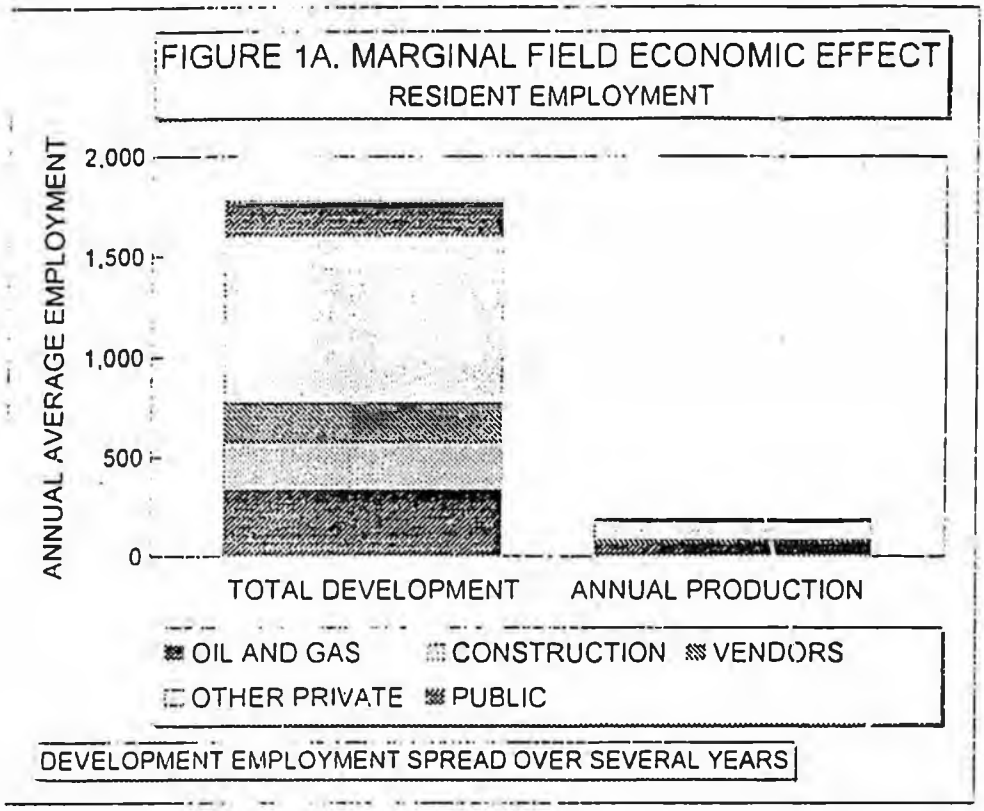


FIGURE 1A. MARGINAL FIELD ECONOMIC EFFECT
RESIDENT EMPLOYMENT
ANNUAL AVERAGE EMPLOYMENT
2,000
1,500
1,000
500
0
TOTAL DEVELOPMENT
ANNUAL PRODUCTION
OIL AND GAS
CONSTRUCTION
VENDORS
OTHER PRIVATE
PUBLIC
DEVELOPMENT EMPLOYMENT SPREAD OVER SEVERAL YEARS

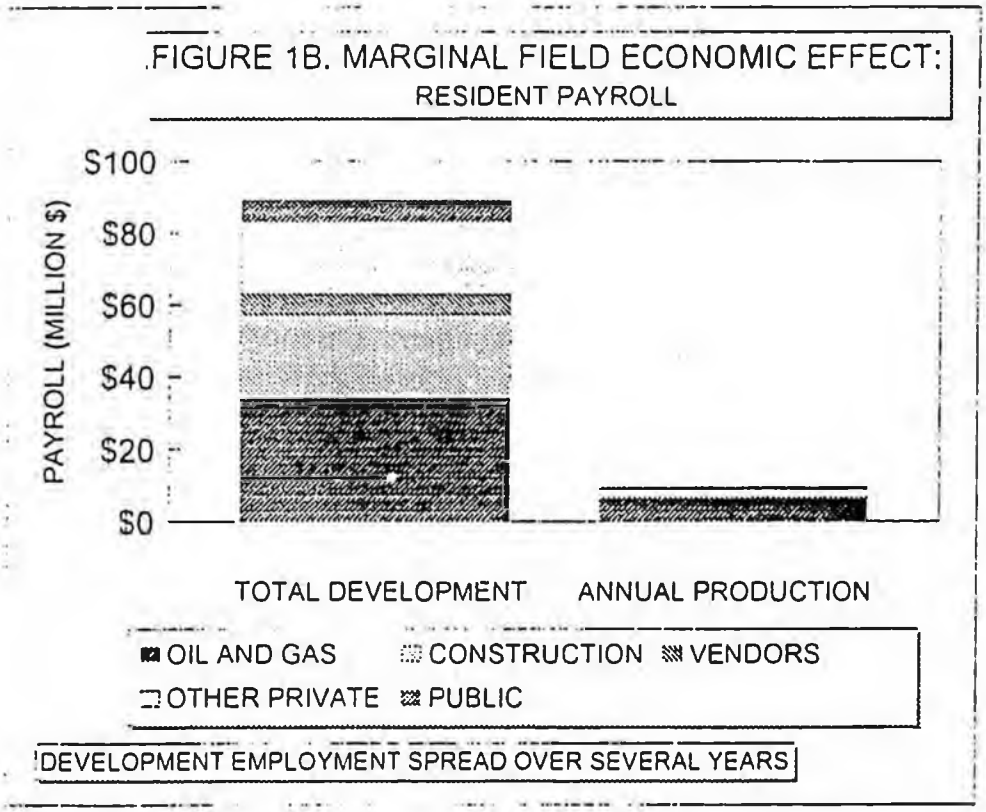
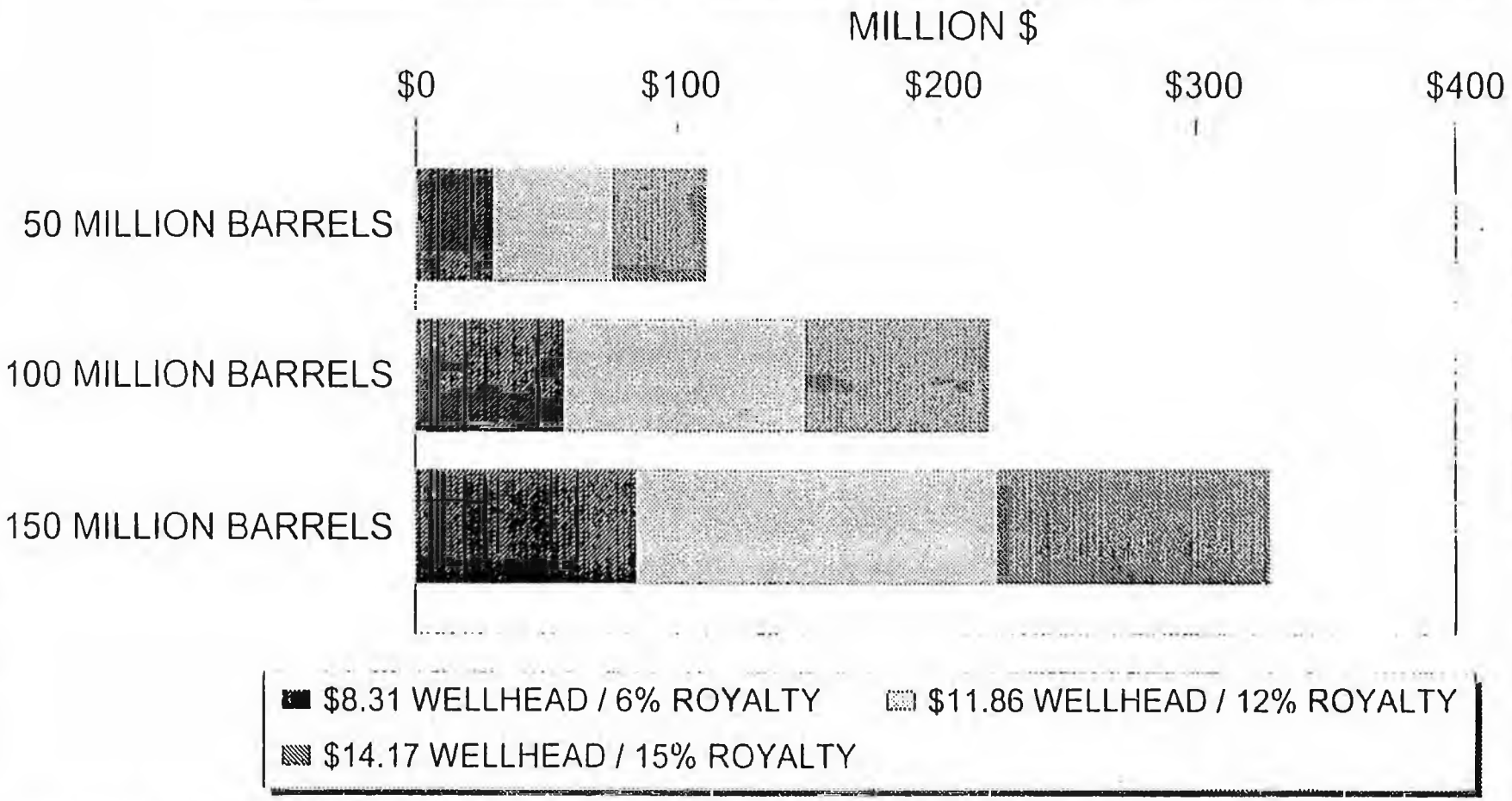


FIGURE 1B. MARGINAL FIELD ECONOMIC EFFECT:
RESIDENT PAYROLL
PAYROLL (MILLION $)
$100
$80
$60
$40
$20
$0
TOTAL DEVELOPMENT
ANNUAL PRODUCTION
OIL AND GAS
CONSTRUCTION
VENDORS
OTHER PRIVATE
PUBLIC
DEVELOPMENT EMPLOYMENT SPREAD OVER SEVERAL YEARS

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

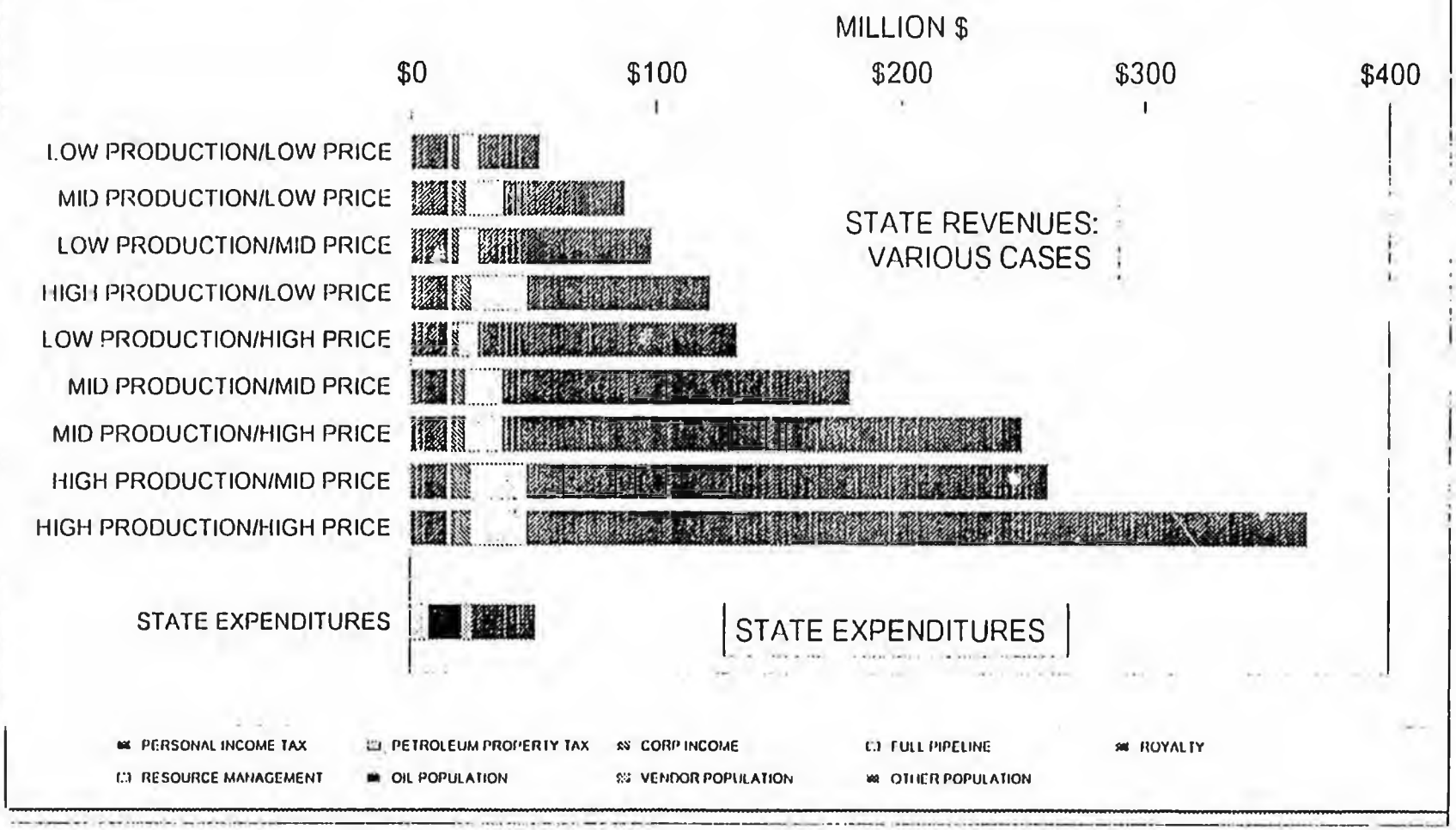
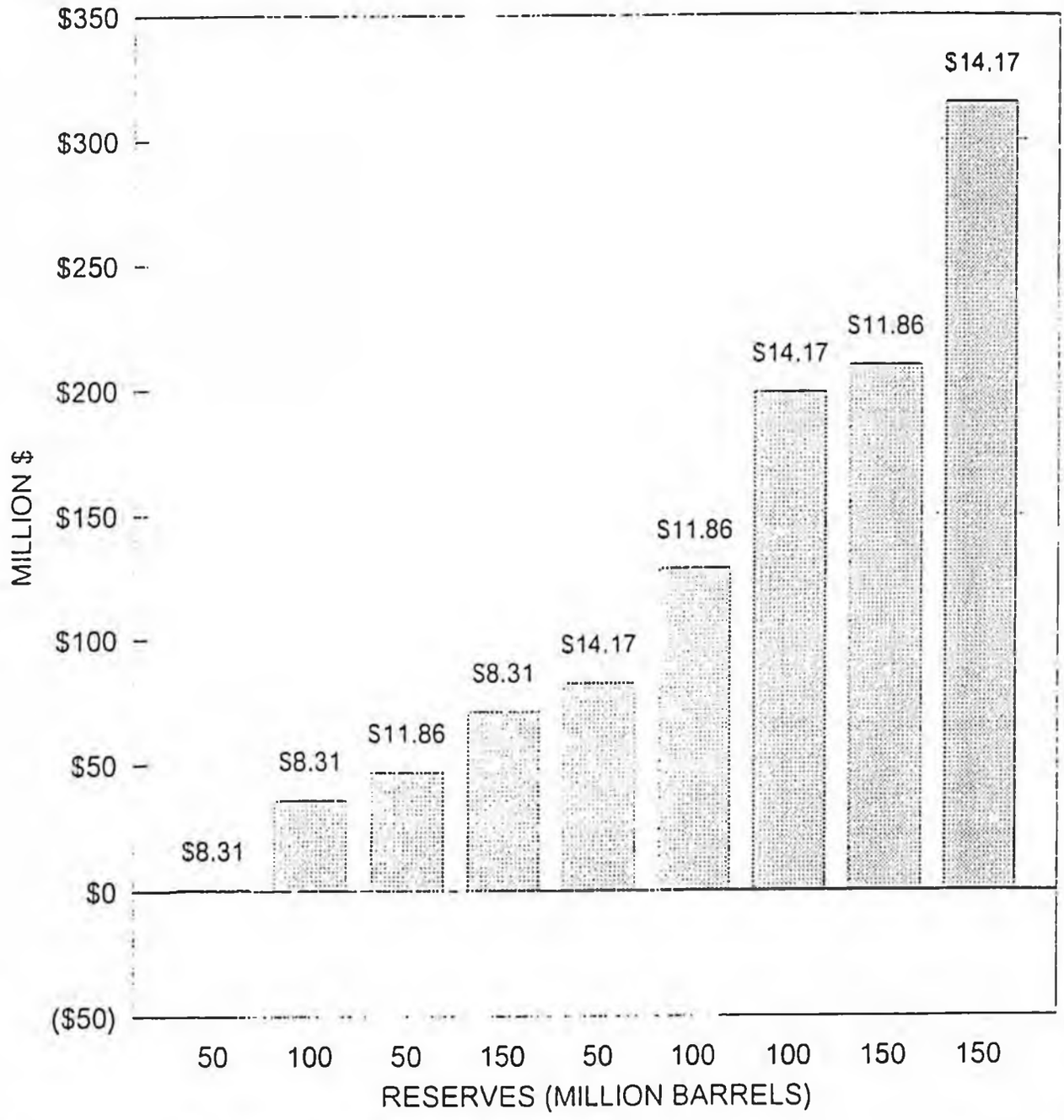


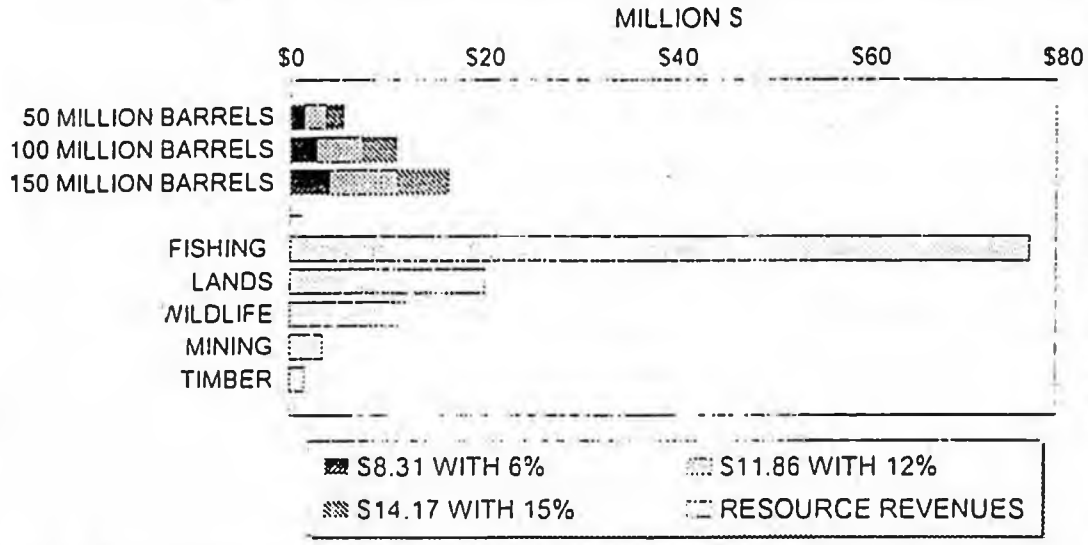
FIGURE 4. STATE REVENUE "DIVIDEND"

VARIATION IN RESERVES, PRICE, AND ROYALTY RATE



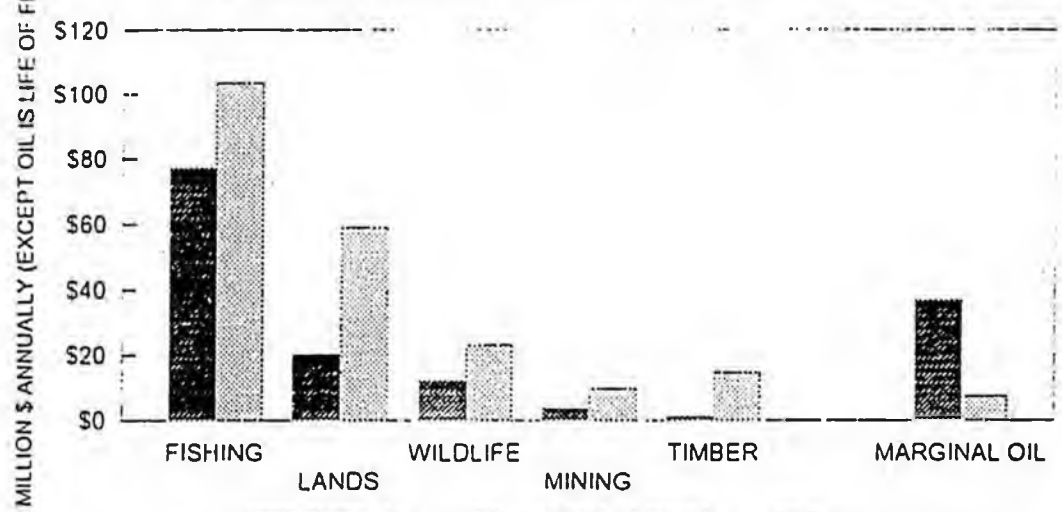
REVENUES IN EXCESS OF AMOUNT NEEDED TO PROVIDE NEW PUBLIC SERVICES

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

DENALI

Doyon buys Kantishna roadhouse

BUSINESS • D-1

TOP 10 UPSETS

No. 4 Colorado 24, No. 24 Kansas 40
No. 7 Michigan 13, No. 25 Northwestern 19
No. 8 Texas A&M 7, Texas Tech 14
No. 9 Virginia 17, North Carolina 22

SPORTS • C-1

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FAIRBANKS

Daily News-Miner

The Voice of Interior Alaska

VOL. XCIII, No. 272 • FAIRBANKS, ALASKA, SUNDAY, OCTOBER 8, 1995 • $1.5

West Sak's oil powerful magnet

Giant field draws money, but not profits

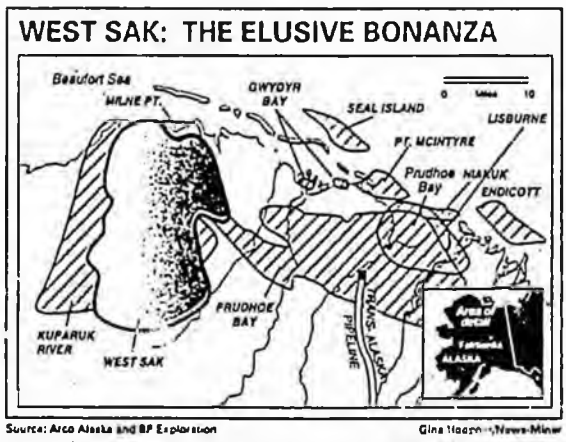
By BRIAN O'DONOGHUE
Staff Writer

Like mythic knights tugging on the sword in the stone, North Slope oil producers keep reaching, without payoff, for the tantalizing rewards locked in the shallow sands of Alaska's West Sak.

"There's a couple billion barrels of that heavy oil in place. That's a pretty big target," said Al Hastings, who worked for Conoco during that producer's costly pilot project tapping the gigantic field of thick, cold crude.

BP Exploration recently estimated West Sak might contain as much as 16 billion barrels of heavy oil. This July Arco executive Scott Kerr told a congressional committee the formation's "oil-in-place exceeds 10 billion barrels, which makes it larger than the Kuparuk field but smaller than Prudhoe Bay."

The staggering size of West Sak, and the similar Ugnu sands, has caused some environmentalists to view the North Slope's heavy oil formations as sleeping giants, whose development could offset Prudhoe's declining production. Those opposed to permitting exploration inside the Arctic National Wildlife Refuge point to West Sak's proven reservoir as a ready alternative source of oil needed to keep the trans-Alaska pipeline in business.



Source: Arco Alaska and BP Exploration — Gina Hoorn/News-Miner

But producers, who've already lost hundreds of millions on West Sak, and state experts say the costs and technological problems associated with the Slope's heavy oil formations make recovery prospects speculative at best. "Even under our most optimistic scenario," Kerr said, "we anticipate oil reserves in the range of a half billion barrels—a significant number but substantially less than the giant fields to which West Sak is often compared."

Alaska's oil and gas division shares that cautious assessment.

"We look at it as a big resource but not a big proven reserve," said division petroleum expert Bill Van Dyke. "It's a lot of oil and there is some production, but the individual wells just don't produce at a very high rate."

Money down the hole

Beginning in 1981 Arco spent nine years and some $200 million sinking 13 wells into West Sak. The company pumped more than a million barrels of oil, before admitting defeat, Kerr told the Senate Natural Resources Committee.

"The pilot project was a technical success but an economic failure," he said. "The cost... was too high to continue production from even the best part of the West Sak formation. The pilot was abandoned in 1986 and production never resumed."

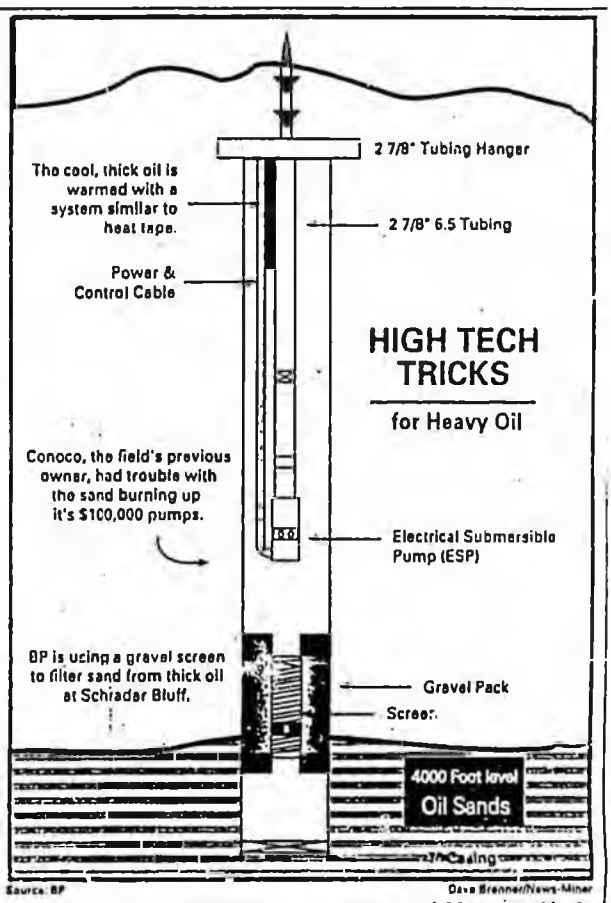
By all accounts, the best commercial prospects reside in the eastern portions of West Sak's 300-square-mile field, where the oily sands rest 4,000 to 4,500 feet below the surface, or about 3,000 feet above Kuparuk. Conoco and, more recently, BP Exploration, have attempted to cash in on the heavy oil using their Milne Point facility to sink wells into the section of the field known as Schrader Bluff.

"It's deeper in the ground, so the temperature is a little warmer," BP's field asset manager, Howard Mayson, said of the heavy oil accessible through Milne's wells. "So it flows a little easier."

But any advantage is relative, Mayson said. Even in BP's sweet corner, West Sak's heavy oil "flows 40 times worse than Prudhoe Bay."

Conoco's $126 million Schrader Bluff investment started pumping in 1991. At its height, the project's 22 wells

See OIL, Page A-7



Source: BP — Dave Brenner/News-Miner

Dividend time: when dreams become reality

By ROSANNE PAGANO
Associated Press Writer

ANCHORAGE—The calendar says autumn but for Alaskans it's the windfall time of year, when permanent fund dividends arrive and—if you're Ambler writer Nick Jans—visions of Visqueen dance through your head.

"Basically, my dividend check defrayed the packing and loading costs for the air charter that all my building supplies came in on," said Jans, a magazine columnist and nature book author who teaches school during the day, writes at night and builds his new house in between.

The charter itself cost $13,000, Jans said. The home, with its tongue-and-groove flooring, cutaway loft and view of the Kobuk River headwaters, ought to be ready by Thanksgiving. "This," he says, "is a real house."

The annual dividend—which this year totals $990—is the stuff Alaska's dreams are made on.

State surveys show that about half of us use the check, paid every year since 1980, to cover day-to-day bills. Nearly two-thirds say they'll save some, while nearly one-in-four Alaskans say they spend, spend, spend it all.

Among the spenders: Explorers Norman and Carolyn Muegge Vaughan, who are chipping away at debt from their antarctic treks. Among the savers: U.S. Sen. Ted Stevens, whose family puts their checks toward a college fund for 14-year-old daughter, Lilly.

"My dividend is going right into the dog barn," said top-ranking Iditarod Trail musher DeeDee Jonrowe.

The building at Jonrowe's Willow kennel is a just-finished two-story affair, with an apartment for her dog handler above and a warm sleeping area for her team below.

"I'm so excited," Jonrowe said at the prospect of being able to keep her arthritic dogs comfy in the 24-foot-by-24-foot insulated barn. "Last year, I had as many as six dogs in the garage part of the house. This year, I built them their own building."

A bit of basking is what former Anchorage school board member Theresa Obermeyer has in mind with her family's six checks—one each for her and her husband, Tom, and their four children, aged 9 to 13.

Obermeyer says last year she parlayed the dividends into MarkAir travel coupons, but the move made her somewhat unpop-

See DREAMS, Page A-7

INSIDE

Alaska A-2

Supply of pumpkins

Great pumpkin

OIL: Giant West Sak draws money

Continued from Page A-1

added a grand total of 3,300 barrels a day to the company's Milne Point production. The effort was undermined by a costly series of equipment breakdowns. The worst problems arose with the submersible pumps inserted at the bottom of the well shafts to force the thick oil to the surface.

"Conoco's pumps were lasting from one day to a couple of months," said Bruce Policky, exploitation manager of BP Exploration, which bought out Conoco's Milne Point investment in 1993. "Sand would come in, just plug up the pump, and the motor would burn out."

Each of the long narrow 150 horsepower pumps is "worth the better part of $100,000," according to Mayson. The dollar-value of that loss is magnified by the difficulty of inserting replacements deep in the well. "So that's why you want them to last as long as you can."

Conoco's appetite for West Sak oil was curbed by the continuing pump failures. "We needed about a two-year-pump run to keep costs down for a chance at being economic," recalled Hastings, who now serves as oil and gas director for CIRI, a regional for-profit native corporation.

Schrader Bluff chief John Dillon is one of several Conoco employees who stayed on with BP when the field changed hands. "We've had the benefit of all of their mistakes," he said. "It's all part of the learning curve."

BP's team has managed to boost Milne's heavy oil production to about 4,000 barrels a day, with individual wells now averaging about 200 barrels daily, or less than one-third the output of most Kuparuk wells. A mixture of new and old tricks is evident in BP's current West Sak effort.

A warming device, similar to heat tape, prevents freeze ups as the thick oil passes through some 2,000 feet of permafrost. Gravel filters inserted at the bottom of each well restrain the sands like a coffee filter.

"We haven't had a (pump) failure since we've been running the field," Mayson said. "We have two wells where the pumps are approaching five years. We'd like to see five year runs be the rule of the day."

Individual well output has shown improvement from blasting water down into the formation, a technique known as Fracpack, which penetrates and opens a pathway for the oil's retrieval, Policky said. "All of that sand fractures and creates an interstate highway back to the well."

Schrader Bluff's operators are considering other innovations, including injection of bacteria, Dillon said. "The idea is to put friendly bugs down into wells and see if we can change some of the oil qualities."

Bugs in the goo

The slope's heavy oil isn't just colder than the crude presently filling the pipeline. Even at room temperature, West Sak oil is thick and viscous, less gassy and possessing fewer so-called lighter petroleum ends. These qualities are due, in part, to a bio-degradation process, which Dillon attributes to "bugs" naturally present in West Sak's shallow formation. "The lighter ends of the oil are being attacked by bacteria. Essentially the bugs are eating and enjoying themselves at your expense."

Not only is heavy oil more difficult to extract, it yields less gasoline and other premium products, reducing its value to Slope producer's by about 60-cents-a-barrel. "More of it ends up as heating oil," Mayson said.

Given the investment disincentives, some lawmakers are talking about cutting producers a break on Alaska's heavy-oil. Rep. Joe Green, R-Anchorage, has introduced legislation to declare a "royalty holiday" qualifying wells.

"There's a significant reserve of heavy oil if we can make it more profitable," Green said. "There might be more interest from producers if they knew they could recoup their investment faster, say, in a 4-5 year period."

Green's bill is scheduled for a hearing later this month.

The state's natural resources chief, John Shively, said heavy oil formations are suited to the royalty adjustments lawmakers authorized last session.

"We developed the royalty incentive bill with things like West Sak in mind," Shively said. "It's a well-delineated pool, where you could look at the economics and make a decision. Developing technology might allow the state to capture the up side as well, the commissioner noted, referring to the provisions for raising royalties if a marginal field becomes a money maker.

Richard Fineberg, an independent North Slope environmental and oil policy analyst, contends that producers downplayed West Sak's potential in their recent congressional testimony to strengthen arguments that ANWR oil is needed to shore up the viability of the trans-Alaska pipeline.

"Given all the problems it (West Sak) faces, Arco first said prices had to be $35 per barrel," Fineberg noted. "Then it was $25. Now at $20 they're looking at it again. Why do we presume they can't overcome the barriers?"

Journalist Debbie Miller, who covers North Slope oil issues and opposes ANWR development, urged Congress to heed the bullish assessment from Occidental, one of BP's Schrader Bluff partners.

"The West Sak formation is a sleeping giant," Miller told Sen. Frank Murkowski's committee. "If the reason for invading the refuge is to find oil, we've already found it near Prudhoe Bay."

Arco is weighing a new West Sak pilot project, spokesman Ronnie Chappell said last week. "No decision's been made. We're at the point in our planning cycle where people are putting forward their projects for next year's spending."

But Mayson cautions that no one, including BP, has proven that money can be made on West Sak oil.

"Arco and Conoco spent more than $120 million apiece. Essentially they lost that money and we haven't made a go of it yet," Mayson said. "In early 1997 we'll come to the decision point on whether or not we can make the case for the next level of production.

"I personally think that if we don't make a go of it, major companies will go cold on West Sak for the next decade."

DREAMS

Continued from Page A-1

ular when the airline quit flying in Alaska. "This year, I want to go to Hawaii," she said. "That really sounds fun."

Sitka-based detective novel writer John Straley has sun on his mind, too, but wouldn't dare move from rainy Southeast and risk losing the inspiration for his books.

Straley, who's lived in Sitka since 1977 and has received every dividend issued from Alaska's oil-wealth savings account, says this year he's investing in ultra-bright lights that ward off dark thoughts brought on by Alaska's dark winters.

Usually, the family's checks go into general income. "This year, I'm going to buy lamps," said Straley, who's at work on a second book for Bantam publishing. "If that doesn't work, I just might get a whole collection of aloha shirts and shorts and walk around town in them. I always get gloomy in wintertime."

In Juneau, Susan Knowles says family rules don't change just because her husband was elected governor. This year's checks will once again go into an education savings account for the couple's three children.

"There's usually a bit of discussion," Knowles said Friday as she recalled the wheedling she and Gov. Tony Knowles wade through each year when the children report how their friends are allowed to spend $50, or $100, or $200 out of their dividend.

PUMPKIN: S

Continued from Page A-1

pollen, bees took a long break from the heat, and heat-stressed flowers didn't want to open, Eastburn explained. The result was fewer pumpkins, or small ones that were easily devoured by fungi.

A killing frost Sept. 23 did in a lot of the late-setting fruit, he added.

There's one bit of comfort, he noted. The canning pumpkins used for Thanksgiving pies are a different species and weren't hit as hard.

In other big pumpkin states such as Pennsylvania and New York, the large growers who invested in irrigation made it through the summer, averting an out-and-out shortage. Still, pumpkins are generally smaller and more expensive, because of the lower yields and higher production costs.

"I know from some of the things I've seen on the national level that they are evidently in short supply across the country," said Bill Troxell, executive secretary of the Pennsylvania Vegetable Growers Association. "We certainly aren't going to have any

Advisers see Alaska's oil output rising

Legislature's consultants say marginal North Slope fields likely to offset decline after 2000

By IAN MADER
The Associated Press

JUNEAU — The legislature's oil consultant gave lawmakers a surprisingly bullish report Wednesday about Alaska's oil-producing potential during the coming decade.

Massachusetts-based Cambridge Energy Research Associates told lawmakers it would be possible for Alaska to produce more oil in 2005 than today.

State oil economist Chuck Logsdon said the report probably took into account a trend toward greater tax and royalty relief for oil companies.

But industry critics said the forecast may show that royalty giveaways proposed by Gov. Tony Knowles and many lawmakers are not needed to make marginal Alaska oil fields feasible.

■ **SURPRISES UNLIKELY:** Analysts predict stable North Slope crude prices for the year. **D-1**

Cambridge indicated Alaska's current decline in production likely would be offset by new production potential between 2000 and 2010 from North Slope oil fields currently deemed marginal, such as Badami Bay and West Sac.

In a presentation to House and Senate finance committees, Cambridge oil expert Ann-Louise Hittle showed lawmakers graphs indicating a surge in potential North Slope production starting in 2002. Production would peak in 2005 at a rate somewhat higher than this year, before beginning another decline.

"All the graphs I've ever seen have lines just going straight down. This one goes down and then up," said Sen. Tim Kelly, R-Anchorage, who saw the graphs but not the presentation. "It's certainly good news for Alaska."

Hittle said company forecasts involve assessments of world oil supply and demand, and technological advances.

Please see Back Page, OIL

OIL: Legislature's consultant gives bright view of future production

Continued from Page A-1

After checking with Cambridge officials, Hittle declined to tell a reporter whether the forecast took into account proposed changes in Alaska's royalty structure, or whether the production likely would become profitable even without such royalty breaks.

"I do not want to get involved in politics," Hittle said. "I don't want to answer your question."

Oil companies, the Knowles administration and many state lawmakers currently agree that companies need royalty breaks in order to make production possible at several Alaska oil fields.

Royalty, now usually at 12.5 percent, is the oil that companies must turn over to the state in return for producing here, in addition to excise and income taxes.

Bills introduced by Knowles and amended by lawmakers would give the natural resources commissioner wide authority to temporarily or permanently reduce royalty, on a case-by-case basis, as low as zero.

What the state sacrifices in revenue it would gain by guaranteeing oil-industry jobs for Alaskans, Knowles says.

Rep. David Finkelstein, D-Anchorage, said the Cambridge forecast was good news for Alaska, but that it increased his skepticism about aspects of the royalty legislation.

"It makes it doubly clear to me that we don't need to allow royalty reduction to go down to zero, ever."

Oil companies, the Knowles administration and many state lawmakers agree that companies need royalty breaks in order to make production possible at several Alaska oil fields.

Richard Fineberg, oil adviser to former Gov. Steve Cowper and a critic of the royalty proposals, said Cambridge may not have considered royalty changes in its forecast.

"In the past they have tended to not factor in current Alaska political dialogue," Fineberg said.

Fineberg has testified that Alaska oil production — which gives the state about 85 percent of its annual revenues — is not in as severe a decline as is traditionally assumed. He maintains oil companies exaggerate their need for royalty reduction.

"The wolves cry only when they think they can frighten you and get rewards out of that fright," Fineberg said. "Here, the legislature's own consultant is coming in with forecasts that are even more optimistic than mine. It's forecasts like this that lead us to want to see a substantive case being made for royalty relief, rather than rhetoric."

On one chart in the Cambridge report, total Alaska production potential is pegged at 1.71 million barrels per day this year, 1.35 million in 2000 and 1.73 million in 2005.

Another chart indicates in a footnote that production figures for 2005 assume development of Badami Bay, West Sak, North Star, Gwydyr Bay, Point Thompson, Hammerhead, Tern Island and Colville Delta fields.

Production and infrastructure at Badami would be a key to developing many other fields on the list, Hittle told lawmakers.

BP Exploration (Alaska) Inc., majority owner of Badami, has so far been unsuccessful in its attempts to get royalty breaks it says would be needed to make that field workable. Company spokesman Jim Palmer said a royalty break would be just one of many factors that must fall in place before the field could begin producing.

"If this stuff's going to come on, why do you need the incentives? Well, to say that this is going to come on regardless of other variables would be absurd," Palmer said. "It's more complicated than that."

Logsdon, the state oil economist, said Cambridge probably did not consider specific bills before the legislature. But he said the company likely would have assumed there would be some tax and royalty breaks for oil companies in coming years.

"When they forecast, it's mostly trend extrapolation. If the trend is governments reviewing changes on the tax side — well, that's going on everywhere," Logsdon said.

b

(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) [✓] 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 Joseph Green

HOUSE COMMITTEE REPORT

(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(OTG) [ ] 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
Ted Ogan	✓			
Vic Kohring	✓			
Eldon Mulligan	X			
Jerry Sanders			✓	
Norman Rokeberg	X			
Janet Mackie		X		
Bettie Davis by Shirley Gatto	X			

CHAIR'S SIGNATURE Norman Kohring 1-23-96

HOUSE SPECIAL COMMITTEE ON OIL & GAS

January 23, 1996, 9:00 a.m.

Tape 1, Side A

REP. ROKEBERG: Present are Norman Rokeberg chairman, Representative Gary Davis, Representative Bill Williams, Representative Scott Ogan, and Bettye are you on line, can you hear us?

REP. B. DAVIS: Yes I am.

REP. ROKEBERG: Representative Bettye Davis at the Anchorage LIO and thanks for being here Bettye.

REP. B. DAVIS: You bet.

REP. ROKEBERG: We have a quorum of the Oil and Gas Committee that is present.

REP. BRICE: Mr. Chair I'd like to be recognized as being here as well.

REP. ROKEBERG: I'm sorry, my apologies Tom. Mr. Tom Brice is also here. Good. I need new glasses. Tom I didn't get that right, right.

REP. BRICE: I'll let it go this time.

REP. ROKEBERG: Right, sorry to -- on the calendar today we have House Bill 325 authorizing suspension of payment of a portion of royalty due the state for initial production of heavy oil from wells on the Arctic Slope. On teleconference today we have Representative Bettye Davis and hopefully Chuck Logsdon from the Department of Revenue and Mr. Ken Boyd of the -- Director of Oil -- the Oil and Gas Division.

[THIS PORTION NOT REQUESTED]

Tape 1, Side B

REP. ROKEBERG: . . . The Chair recognizes the attendance of Representative Finkelstein at 10:05. Good morning Dave. Thank you Mr. Phillipi. Bev Ward did you have short statement?

MS. WARD: Actually Mr. Chairman we hadn't planned to read it aloud. It is the same testimony that we gave in November and we made copies for the Representatives of that. We still support the bill with small changes (indiscernible).

REP. ROKEBERG: Thank you very much. Mr. Ken Boyd, the Director of Oil and Gas, are you online sir?

(Via teleconference)

MR. BOYD: Yes Mr. Chairman.

REP. ROKEBERG: Would you please proceed with your testimony, sir?

MR. BOYD: Yes, Mr. Chairman. For the record my name is Ken Boyd. I'm the Director, Division of Oil and Gas. Now Mr. Chairman I was going to do a voice check to you. Am I coming through loud and clear, too loud and clear, or what?

REP. ROKEBERG: No it's pretty good, a little choppy but we can hear you.

MR. BOYD: All right, again we'll move a little bit closer to the mike. With me is (indiscernible - cuts out).....

REP. ROKEBERG: That's too loud.

MR. BOYD: . . . . . with the Department of Law, Bill Van Dyke, Petroleum Manager and Mike Kotowski who is the Unit

Manager. Both Bill and Mike are petroleum engineers with the Division of Oil and Gas.

Mr. Chairman, we just have a couple of comments. The committee needs to realize that this bill will result in -- in no royalty for five years per well and there will be no taxes. The bill doesn't provide for any clear and convincing showing or any economic analysis. If you recall last year in the debate with HB 207 we spent a lot of time talking about the standards we needed to grant royalty relief and one of the things we talked about a lot was to be able to -- the need really to show -- to have a clear and convincing showing that a company needs this royalty relief.

The presentation by OXY and -- and -- and BP does not provide an economic analysis It does provide some numbers and some assumptions I presume. I don't know that these assumptions would be the same for any other operator on the North Slope. And even if you make the assumption that this is need then there's no basis for the term selected to cure this assumed need. The $15 netback, the 5 year term, the $500 barrels are all picked but with no -- no basis selected. And it also would assume that, I presume, that the economics for all the companies are the same for every field. Having said that there are some unintended consequences, I think, here. Do these same assumptions hold that the heavy oil lake of Prudhoe Bay, the heavy oil of the Kuparuk field, and West Sak, heavy oil of Bedombi (ph), and Point Thompson. These fields also

contain heavy oil and this bill the way it's crafted applies to all those fields, yet you've heard testimony from no one on anything except Schrader bluff. There is clearly no assurance that the companies will do anything at all at least at Schrader bluff. There certainly is no assurance that they'll do anything after five years. There's no assurance that additional royalty relief wouldn't be sought after the fifth year. In short, Mr. Chairman, the administration's position is we believe HB 207 is a better vehicle to craft royalty reductions. You can do a clear and convincing and detailed economic analysis to determine need. I am not saying there isn't a need or that it isn't a valuable tool. There is nothing (indiscernible) to do. I'm just -- all I'm saying is that we -- you've picked a bunch of assumptions and made a bunch of assumptions with no basis. So the Department's and administration's position is we believe that HB 207 remains the -- the -- the tool to use for royalty reductions. Thank you Mr. Chairman. Mr. Chairman, I think as far as I -- just one more thing. If you want some more specifics we talked about what is a well and to side track accounts and dates. I don't know that the assurance of somebody testimony -- testifying, one company gives us much assurance that in fact side tracks, or multilaterals or other wells are not in fact separate wells. So I just wanted to add that. We have some other assumptions in our bill analysis. I won't get into the details but we're here to answer any questions the committee might have.

REP. ROKEBERG: Does anybody else on your phone hook up, Mr. Boyd, that wants to testify from your Department?

MR. BOYD: No, Mr. Chairman. We'll -- we'll be available to answer any questions but somebody else may have something to say at that time.

REP. ROKEBERG: Are there questions of Mr. Boyd? Representative Finkelstein.

REP. FINKELSTEIN: Thank you, Mr. Chairman. Mr. Boyd I'm -- I'm not as confident as I wasn't at the November hearing, I was out of town. The -- in the -- in the discussions you've had about this has anyone pointed out any provisions of the royalty reduction law we have in place now that won't adequately address these situations? I realize there's a floor in some cases but other than that minor difference is there anything else out there that has been pointed out that would -- would arguably keep the royalty reduction provision from being used?

MR. BOYD: Mr. Chairman, Representative Finkelstein, the floor is right. I mean we believe the 3 percent floor -- you know -- at the maximum, it depends on how you look at it as a whole. The other provisions that would not work at least -- for OXY and only OXY would -- would be the provision under the settlement of the royalty reductions that I believe Mr. Benton referred to earlier, he said there would be no -- no effect. Well the effect would be that this bill -- (indiscernible) after this bill they would not be able to use HB 207. Our

leases that were changed from 20 percent to 12 and a half and I think that was 7, these -- the bill as presented here, of course gets rid of that provision and they would be able to use it. So I guess the one piece that they wouldn't -- wouldn't be able to use would be to use bi-oxydental on those (indiscernible).

REP. FINKELSTEIN: Thank you Mr. Chairman.

REP. ROKEBERG: Other questions of Mr. Boyd? Mr. Boyd the fiscal note you provided, could you walk us through your methodology on that? I'll get it out here. Let's see here, this is the one that you're estimating a per well change in revenues of $228,000 per well per year.

MR. BOYD: Yes, Mr. Chairman. What we did was take the 500 barrel per day maximum multiply it by 12-1/2 percent royalty rate multiply it times a net factor of $10 a barrel multiplied by 365 days a year. It's just a -- a benchmark. It -- it just --- it just sets a number that shows what the royalty -- what's the royalty --- what's the royalty the state would not collect per well over that period of time.

REP. ROKEBERG: But if there are no wells are drilled here we're not losing anything, is that correct?

MR. BOYD: That's correct.

REP. ROKEBERG: So this isn't even the half a loaf we're talking about under 207, this is a zip loaf or something? Would that be a fair analysis?

MR. BOYD: I have no guarantee and you have received no guarantee that any wells would be drilled no matter what you do under any bill or any provision of anything.

REP. ROKEBERG: Do -- Representative Williams?

REP. WILLIAMS: Yeah what did you call -- first I'd like to get either something written from your office on your reasons about why 207 would go along with this to take care of heavy oil.

MR. BOYD: Mr. Chairman, Representative Williams, I beg your pardon if I've interrupted you but you're breaking up.

REP. ROKEBERG: Speak up Bill.

REP. WILLIAMS: I would first of all like something written from your office stating why 207 would -- how 207 would affect the -- the heavy oil. I have a question and answer about heavy oil that the five-year royalty suspension from -- in the white paper which I haven't had a chance to study. As far as saying that after five years or during the five years that the -- we will be able to assure -- be assured that ARCO, or BP, or any oil company out there that would like to come in, there's no -- there's no guarantee in -- in anything. Well I guess the old saying the only guarantee we have is taxes and death, what type of guarantee are you talking about?

MR. BOYD: Mr. Chairman and Representative Williams I talk to you about no guarantee either. I'm saying that HB 207 says that we can to allow for production that would not economic -- otherwise be economically feasible and it goes on,

it doesn't limit it to heavy oil or not to heavy oil It just allows the commissioner to make that determination based on a real economic analysis. If at the end of the day we may craft something that still doesn't provide them any need or we may provide them the need and they still may not develop it. I mean they said here if you had this bill which they claim will give them the relief they seek that they still may not develop the field.

REP. WILLIAMS: They're not -- is -- they are not developing the field today?

MR. BOYD: But they are working on the field today, Representative Williams. I mean they are drilling wells and they are making production what I'm saying is under 207 if they see the need all 207 does is remember from the long -- the long years we've had is -- is a mechanism for the state to look at the numbers on which their assumptions are based and then craft some sort (indiscernible - speakerphone covered by paper)

REP. WILLIAMS: Would you -- will you be able to get me something written on your reasons why the -- 207 would affect -- would work in this area?

MR. BOYD: I can do it Representative Williams.

REP. WILLIAMS: Okay and I guess going back to BP's paper here, The Risk of Project Development Delay, would 207 affect any of this -- this area? Do you have BP's explana -- paper in front of you? It's a . . . . .

MR. BOYD: I do Representative Williams.

REP. WILLIAMS: Okay, the last page of Risk of Project Development Delay, would . . . . .

MR. BOYD: The last page?

REP. WILLIAMS: Yes. And on top of it it has the Risk of Project Development Delay. Would 207 delay anything in this area from -- according to their operating. . . . .

MR. BOYD: Mr. Chair and Representative Williams, I mean there would be the application process and the analysis process which takes time.

REP. WILLIAMS: How -- how much time?

MR. BOYD: It's hard to say. It depends on how clear and convincing their argument is right out of the box, whether we use consultants, perhaps, to come in and -- you know --- time is money here. With more people doing analysis, we have a limited staff, I would say 3 to 6 months, and that's a guess.

REP. ROKEBERG: Further questions? Representative Finkelstein.

REP. FINKELSTEIN: Thank you Mr. Chairman. Mr. Boyd, what's the entire history of applications from the industry under either the old royalty reduction provisions or the new ones for reductions for these type of fields?

MR. BOYD: Mr. Chairman and Representative Finkelstein I don't have that exact -- that information in front of me. As I recall there were several applications in Cook Inlet, Texaco, Marathon comes to mind.

REP. FINKELSTEIN: For the . . . . .

MR. BOYD: Beg your pardon, Mr. Chairman, stand by. I have some

REP. FINKELSTEIN: Well could I -- I'll make the question simpler. How about for North Slope fields what's -- how many times have the companies applied for royalty reduction under the old provisions or the new provisions?

MR. BOYD: Well Mr. Chairman, Representative Finkelstein, just one, the Conoco/Oxy application of some years ago.

REP. FINKELSTEIN: And -- and no one has applied under the new provisions yet to see how they will work and what the time frame will be?

MR. BOYD: Mr. Chairman, Representative Finkelstein, that's correct nobody has applied.

REP. FINKELSTEIN: Okay, thank you Mr. Chairman.

REP. ROKEBERG: Mr. Boyd, the follow up on that question. As I recall of the -- of the -- actually few but several royalty reduction applications made under section (j) that there was never any -- the state has never granted any kind of a royalty reduction under the prior statutory regime, is that correct?

MR. BOYD: No, Mr. Chairman. We -- the royalty reduction was granted under the settlement actually on the -- I'm going to say seven leases are -- I'll say seven leases that Oxy has the reduction was to 20 percent and 12 percent with the provisions then they would not apply for -- again for a royalty reduction.

REP. ROKEBERG: Well I -- but even in Cook Inlet there was never a grant of royalty reduction is that correct?

MR. BOYD: There was never an application. I was mistaken, there was an application and then it was withdrawn.

REP. ROKEBERG: Withdrawn, that's correct. And -- and the victims of the other one are sitting here. Thank you very much. Any other questions? Representative Finkelstein.

REP. FINKELSTEIN: Thank you Mr. Chairman. But just to point out again we spent hours and hours debating those issues here, revised the law and we've now got new provisions that no applications have ever been submitted under. I just want to make sure that's the case.

REP. ROKEBERG: Well Mr. Boyd the way this statute is written it -- it is not discretionary on the part of the commissioner or does not require the Governor's approval, is that correct?

MR. BOYD: Mr. Chairman are you talking about HB 325?

REP. ROKEBERG: That's correct.

MR. BOYD: As far as I can tell, no.

REP. ROKEBERG: It's self-executing therefore your department nor even a company that would be -- come under the guise of this particular statute would not have to expend any money to review an application is that correct?

MR. BOYD: Mr. Chairman only the -- the administrative costs -- you know -- the way you have it crafted now with the -- the adding in the PTI index and some of those things but I

mean it's -- it -- I'd have to say it's a minor administrative cost.

REP. ROKEBERG: Yeah this is really basically self-executing. You know when you say -- you know -- you care to venture a guess what a six -- 3 to 6 month review of a 207 application would cost just your department?

MR. BOYD: No, Mr. Chairman, I can't do that. I don't know the answer to that.

REP. ROKEBERG: Okay.

MR. BOYD: I don't know also what effect it would have on the state though if you did not do that sort of economic analysis.

REP. ROKEBERG: And further the analysis of the -- well the testimony today showed that the state stood to -- to gain some $350 million in otherwise foregone royalties from this particular scheme. Would you buy into that type of analysis whether the numbers are exactly right but aren't the long-range potentials for further royalty revenues to the state greater under this particular bill than no bill at all?

MR. BOYD: Mr. Chairman, there are absolutely no way for me to answer that question.

REP. ROKEBERG: Any other questions of Mr. Boyd? Representative Finkelstein.

REP. FINKELSTEIN: Thank you Mr. Chairman. Just to get the theme behind this wasn't -- and I think Mr. Boyd you were one of the proponents of this theme last year, wasn't the theme

last year sort of when all these same questions came up that it's the ability of the administration with discretion under law to make these kinds of decisions. That every time I and others propose limitations on that discretion on the royalty reduction bill the response was no, that's better left to each situation, negotiations necessary and that that's what we have a Department of Natural Resources and a Division of Oil and Gas for? Wasn't that the theme last year and isn't that a little contradictory to what we're doing today?

MR. BOYD: Representative Finkelstein, I certainly hope not. What I'm saying is that it is specific in each instance and here is an instance. And I think its proper now that this be done. I don't think we've ever testified to anything different under HB 207.

REP. FINKELSTEIN: Well -- well my argument is just it seems to me we're losing the ability that the legislature took on last year -- the legislature gave the department to make these kind of decisions that just sort of trust the department, we'll make good decisions which was the theme last year is now being lost in sort of turn it all over -- will eliminate any administrative discretion.

MR. BOYD: Mr. Chairman, Representative Finkelstein, I think that's absolutely true.

REP. FINKELSTEIN: Thank you Mr. Chairman.

REP. ROKEBERG: Thank you. Next we'd like to hear from Mr. Chuck Logsdon. Chuck are you on line there sir?

MR. LOGSDON: Yes, I'm here, Mr. Chairman.

REP. ROKEBERG: Well go ahead and give us your testimony, look forward to it please.

MR. LOGSDON: Okay. Really -- I didn't really have much to add what's been stated by Mr. Boyd of DNR. Our fiscal note is really done quite simply. It's based on what we were assuming in the fall of '94 -- fall '95 forecast for production and royalties from the straight or lost production. The production assumptions that we used bear as closely as possible the current development plans of the industry and they're based on direct communications with the involved developers and public statements and we do have access to some proprietary data. The negative fiscal note really just reflects what would happen if we were to redo the forecast with those same development plans what the heavy oil would be exempt from royalties. And that's what the revenue in fact issue is based upon. That's really all I have to say about the bill, Mr. Chairman, and I can be available to answer any questions, obviously.

REP. ROKEBERG: So your -- your note -- fiscal note of a negative 50 some million dollars is really prospective and based on the development plans that were provided by BP. Is that correct?

MR. LOGSDON: I can expect it -- that we were -- that we had the ability to obtain that kind of information, yes.

REP. ROKEBERG: And the -- but they don't include potential development of 230 additional wells over a period of 7 to 9 years on the -- just the Schrader bluff alone. Is that -- that correct, you didn't take that into account?

MR. LOGSDON: That's correct.

REP. ROKEBERG: Now you've heard testimony here today that the -- the prospective revenues of some $60 million should be as much as $425 if this legislation went forward and the field investment did take place as contemplated in the Schrader bluff area. Do you -- would you agree that that would be at least a -- a fair analysis of the potential revenue gains in the future if this amount of development took place?

MR. LOGSDON: I really haven't had the opportunity to evaluate that -- the -- those -- those assumptions and I -- it would be, I think, premature of me to comment on whether or not that number is accurate until we have a chance to look at the assumptions.

REP. ROKEBERG: Well I understand that but just in the terms of it conceptually don't we know our priority that that's going to happen, that we're going to gain more here if in fact they go ahead with their development?

MR. LOGSDON: Well -- you know -- I mean the issues is, of course, fraught with uncertainty and oil prices would probably be the main driver of the whole induction decision anyway and just try to estimate the revenue you would -- you would have to have some consensus about where you thought oil

prices were going. And I -- I believe that this is just one of those unanswerable type questions. It makes this kind of analysis question so very difficult. Certainly you could come up with a scenario which would underpin that -- that number see, just as you suggested but whether would be my own personal best guess or whether it fell in within the range. I don't know that that's -- that -- I -- I have just -- am unprepared to answer that.

REP. ROKEBERG: Other questions? Representative Finkelstein?

REP. FINKELSTEIN: Thank you Mr. Chairman. I -- I know too that your question requires the assumption that HB 207's provisions don't work because if they do work then -- then there would be some return to the state under the status quo. Mr. Logsdon on a broader economic analysis one of the arguments that's being made is even if there's no return to the state and even if we will make less than we will under the royalty reduction provisions in current law that somehow this will be good because it's going to bring about all this activity and even in the short term, we're going to make money somehow because we're going to have more activity going on. Have -- does your department get involved at all -- I suppose -- suppose that you don't, on looking at what other benefits are out there? Because obviously you don't make any money on income tax, obviously we don't make any money on sales tax, isn't in the bigger sense this new generated activity if there

is no income to the state from any royalties or taxes isn't it a net loss in pub -- public services provided?

MR. LOGSDON: Mr. Chairman, Representative Finkelstein, I actually we are very tightly focused on strictly the petroleum revenue issue. Obviously the study that was done by Doctor Goldsmith and others have made estimates of what heavy oil development could mean in terms of their overall economic impact. I -- we have just not -- we have not looked at that generally speaking -- we're -- that the focus has been very tightly on the impact on the petroleum revenue side.

REP. FINKELSTEIN: Thank you Mr. Chairman.

REP. ROKEBERG: Mr. Logsdon in the committee substitute, I'm not sure you had an opportunity to look at that, but it sets forward a well-head price of $15 which is I believe the reported royalty value type of a number. Could -- would you care to comment on that as a circuit breaker price for suspension of the -- any -- any royalty exemption and you -- would you agree that that would be a -- a fair price to use?

MR. LOGSDON: Mr. Chairman, I -- I believe that it is that kind of modification that would be appropriate to preserve a blanket five-year type royalty holiday for any production and -- and I also believe that it's -- you know -- it's possible that these sorts of royalty modifications should -- could be accomplished under the -- through the Department of Natural Resources but certainly that -- that would be a step in a direction that would truncate the risk the state would have for

instance in a case of a price slide which occurred for a lengthy period of time during the five-year holiday.

REP. ROKEBERG: And do you think the $15 -- does that relate to like the federal $24 WTI price and could that be a pretty fair comparison.

MR. LOGSDON: Compared to -- what is it -- what's the federal government's cap again?

REP. ROKEBERG: $24 WTI.

MR. LOGSDON: Okay, well let's see -- that would take us to -- actually it would be -- that would actually be a probably in -- in the ball park considering the -- the quality of the heavy oil and the additional transportation costs to -- to move it to the pipeline and the entire pipeline tariff, that's probably in the ball park of the number that's somewhat consistent with the federal cap.

REP. ROKEBERG: And just one last thing, there -- there's a difference between the fall forecast for '95 and the spring forecast, particularly relates to the -- the peripheral smaller fields including Schrader bluff as pointed out for the committee members on page 3 of the white paper. Would you care to comment on the different methodology used?

MR. LOGSDON: I -- as far -- I -- I don't have the -- I don't have that white paper in front of me, as far as I know the -- the difference between the spring and the fall would be a function of any adjustments made in -- in the development schedule for the Schrader bluffs is a result of our

investigation into the development planning for that -- that particular field.

REP. ROKEBERG: Very good. Further questions of Mr. Logsdon? Hearing none, thank you very much sir, appreciate your testimony.

[END OF REQUESTED PORTION]

What is "heavy oil"?

- Low gravity
- Thick
- Produces slowly over a long period of time
- Disadvantaged in market place
- Capital intensive
- A focus of current debate on oil and gas incentives

Previous Heavy Oil Development

ARCO/West Sak Project

- *Spent $135 Million on 13 wells and facilities*
- *Average producing rate = 250 BOPD per well*
- *Expected Recovery = 1 million barrels*
- *Total Investment = $135/Barrel*
- *Uneconomical*

Source: SPE 30289, "Milne Point Schrader Bluff: Finding the Keys to Two Billion Barrels", 6/95

Previous Heavy Oil Experience

Conoco/Tract 14

- ***Spent a minimum of $126 Million on 22 wells, pads, etc.***
- ***Average producing rate = 275 BOPD per well***
- ***Expected Recovery = 13.5 Million Barrels***
- ***Total Investment = $9.30/BBL***
- ***Uneconomical***

Source: SPE 30289, "Milne Point Schrader Bluff: Finding the Keys to Two Billion Barrels", 6/95. Reserves determined from decline curve analysis.

Suspension Incentives in Other Jurisdictions

- Texas
  - high-cost gas (10 year exemption)
- Utah
  - wildcat wells (first 12 months)
  - development wells (first 6 months)
- Oklahoma
  - horizontal wells (until payout)
  - enhanced oil recovery projects (until payout)
- Montana
  - horizontal wells (first 18 months)
- Mississippi
  - discovery wells (first 5 years)
  - re-activated wells (first 3 years)
- Kansas
  - tertiary projects (for life of project)
  - shallow wells (for life of project)
  - discovery wells (first 12 years)
- Arkansas
  - discovery wells (first 5 years)

SPE 30289

Milne Point Schrader Bluff: Finding the Keys to Two Billion Barrels

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This paper was prepared for presentation at the International Heavy Oil Symposium held in Calgary, Alberta, Canada, 19-21 June 1995.

ABSTRACT

Milne Point, North Slope Alaska, contains in excess of 2 billion barrels original oil in place (OOIP) in the shallow, Late Cretaceous, Schrader Bluff Formation. This resource is part of a larger accumulation in excess of 26 billion barrels OOIP overlying many of the deeper producing fields. A small waterflood pilot presently produces 3300 barrels of oil per day (BOPD) of 19 API oil from 2650 acres in Milne Point. Initial average well productivity's of 350 BOPD, low by North Slope standards, coupled with current cost, performance, and fiscal conditions, render the resource uneconomic. A multi-pronged approach dealing with well productivity, drilling and facility costs, and development incentives is underway to save this resource from abandonment. Technological and contractual innovations are considered keys to success. Which keys fit the lock will determine the development of billions of barrels of recoverable oil.

Illustrations at end of paper

INTRODUCTION

Milne Point is located approximately twelve miles west of Prudhoe Bay on the North Slope of Alaska (Figure No. 1). BPXA acquired Milne Point from the majority owners, CONOCO and Chevron, and began operating the field on 1 January, 1994. Occidental Petroleum continues to maintain a minority working interest in the field. The field currently produces 28,000 BOPD primarily from the Kuparuk Formation, one of the main North Slope reservoirs. The Schrader Bluff accumulation overlies this deeper horizon. BPXA has initiated a significant challenge to commercialize this Schrader Bluff reservoir following earlier attempts by CONOCO at Milne and by ARCO to the south and west of Milne, in the reservoir interval known informally as West Sak.

THE RESOURCE

The shallow Schrader Bluff/West Sak/Ugnu reservoirs overlie the main reservoirs at the Kuparuk River, Milne Point, and Prudhoe Bay fields. With 26 billion barrels of oil in place, these shallow pools are larger than the North Slope's Prudhoe Bay. The Milne Point portion of this resource(Figure No. 2), the subject of this paper, consists of a stacked sequence of

reservoirs with variable oil water contacts and variable API gravities, covering over 32,000 acres (50 square miles). This challenging reservoir is one of the largest undeveloped accumulations in North America, and with even modest recoveries, reserves must be considered substantial.

SHALLOW SAND NORTH SLOPE HISTORY

The Schrader Bluff discovery well at Milne Point, Kavearak Point 32-25, was drilled by Standard Oil of California with partners, Mobil and Phillips in mid-1969. Although a deeper horizon was tested, the shallower intervals were only logged. Additional drilling concentrated on the deeper horizons, but the accumulations were considered uneconomic until the CONOCO partnership crystallized and committed to development in the early 1980's. Milne Point #1 was the first to test the shallower interval, yielding 125 BOPD of 19 degree API oil by drill stem test. The partnership developed the deeper Kuparuk Formation starting in 1985, leaving the Schrader Buff until later.

Arco's West Sak pilot at the Kuparuk River Unit attempted to produce from roughly the stratigraphic equivalent of Milne Point's Schrader Bluff. Commencing production in September 1984, an estimated $135 million was invested in 13 wells and processing facilities. Significant additional investments were made in reservoir studies and project design. The production wells averaged 120 BOPD without stimulation and about 250 BOPD after fracture stimulation. About 0.8 MM barrels were recovered before the pilot was abandoned in December 1986. Difficult reservoir fluid properties (high oil viscosity), unconsolidated sands, and low completion efficiency contributed to the project's low productivity.

CONOCO's Schrader Bluff pilot at the Milne Point commenced production in March 1991. The pilot was producing about 3,300 BOPD at the end of 1993 when BP acquired the Milne Point Unit. At this point, the 12 producers averaged 275 BOPD/well of 19 degree API gravity crude and about 3 MM barrels had been recovered. Approximately $126 million ha been invested in 22 wells, four pads, roac power lines, and pipelines. As with the We Sak pilot, this project lost money and failed meet key development hurdles for commerci viability: sufficient well productivity at low capit costs.

RESERVOIR CHARACTERISTICS

The Schrader Bluff consists of Late Cretaceou near shore marine sand sequences, informal referred to as the "N" and "O" sands. Th individual reservoir units are predominantl very fine to fine grained, moderately sorte unconsolidated quartz sands with varyir amounts of accessory minerals, mainly roc fragments, mica and glauconite. The reservc units are amalgamations of storm deposi redistributed, for the most part, below wav base. Bioturbation, and burrows are common some intervals whereas, others display fine laminated bedding, suggesting more rap sedimentation. Calcareous interbeds a locally common, often associated wi concentrations of bivalve debris.

The upper "N" sands consist of multip reservoir layers varying in thickness between and 15 feet, with permeabilities rangir between 5 millidarcies to 5 darcies. The lowe "O" sands consist of two main sand bodies tha although are finer grained than the "N" sands are generally more massive and competen These sands are more continuous ar correlative across the North Slope than th thinner, more discontinuous "N" interval. Th "O" sands thickness varies between 10 to 35 with permeabilities between 10 millidarcies ar 1 darcy. The average porosity in all sand uni varies between 25 to 28 percent.

The formation dips gently north-northeast at rate of approximately 170 ft per mile. Th resulting monocline is broken by numerou faults of variable displacement, most of whic trend north-northeast and progressive downdrop the reservoir to the northeas Depths range from 3500 feet - 4500 feet. Fault generally producing offsets between 20-15 feet compartmentalize the reservoir to son