

SCOMM

96:11

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

Expenditures/Revenues:

(Thousands of Dollars)

OPERATING EXPENDITURES	FY 97	FY 98	FY 99	FY 00	FY 01	FY 02
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0

CAPITAL EXPENDITURES						
-----------------------------	--	--	--	--	--	--

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

FUND SOURCE

(Thousands of Dollars)

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

Estimate of any current year (FY96) cost \$ _____

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

(See Attached Analysis)

Prepared by: Chuck Logsdon
 Division: Oil & Gas Audit
 Approved by Commissioner: [Signature]
 Agency: Department of Revenue

Phone: 276-1363 ext. 265
 Date: 1/19/96
 Date: 1/19/96

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Analysis of Bill/Program Effects

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

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

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

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

FISCAL NOTE

STATE OF ALASKA

BILL NO. HB325

1996 LEGISLATIVE SESSION

Revision Date: Original Dept Affected Natural Resources
 Title: An Act authorizing suspension of payment BRU: Resource Development
of a portion of the royalty due the state for initial production... Component: Oil & Gas Development
 Sponsor: Representative Green
 Requestor: _____ Component Serial No. 439

Expenditures/Revenues	(Thousands of Dollars)					
OPERATING EXPENDITURES	FY97	FY98	FY99	FY00	FY01	FY02
PERSONAL SERVICES						
TRAVEL						
CONTRACTUAL						
SUPPLIES						
EQUIPMENT						
LAND & STRUCTURES						
GRANTS, CLAIMS						
MISCELLANEOUS						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0

CAPITAL EXPENDITURES	0.0	0.0	0.0	0.0	0.0	0.0
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CHANGE IN REVENUES (1004)	(228.0/well)	(228.0/well)	(228.0/well)	(228.0/well)	(228.0/well)	(228.0/well)
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FUND SOURCE	(Thousands of Dollars)					
1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1006 GF/MHTIA						
Other						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY96) cost: \$ none

POSITIONS

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

ANALYSIS: (Attach a separate page if necessary)

It is not possible at this time to accurately predict the number of new wells that will be drilled that will qualify for the proposed royalty reduction. Nor is it possible to accurately predict the timing of the drilling of any of these new wells. For each new well that is drilled, if it produces at a rate of 500 barrels per day and oil is valued for royalty purposes at \$10 per barrel, then the annual royalty reduction will be \$228,000 for each of the first five years of well life. Assuming that the well produces at the 500 b/d rate for five years and oil prices stay flat, the total royalty reduction would amount to \$1.14 million per well – close to the cost to drill the well. For a new demonstration project equal in size and scope to the existing Milne Point Schrader Bluff heavy oil project, the royalty reduction would range from \$1.5 million per year at current well rates to \$3.7 million per year at well rates of 500 b/d/well.

Long term production behavior also is unknown for these wells. It is suspected that the wells will produce at a fairly constant rate for at least five years then production decline will begin. Behavior of the Milne Point Schrader Bluff wells is being analyzed to see if any production trends are evident to date.

Prepared by: Ken Boyd, Director Phone: 269-8800
 Division: Oil & Gas Date: 18-Jan-96
 Approved by Commissioner: [Signature] Date: 18-Jan-96
 Agency: Natural Resources

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(Thousands of Dollars)

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Estimate of any current year (FY96) cost \$ _____

POSITIONS:

FULL-TIME						
PART-TIME						
TEMPORARY						

ANALYSIS: (Attach a separate page if necessary)

(See Attached Analysis)

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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

CS HB 325 (046)

[] 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
<i>Scott Ogan</i>	Ogan	✓			
<i>John Rokeberg</i>	Rokeberg	✓			
<i>William S. Williams</i>	Williams	X			
<i>G. Davis</i>	G. Davis			✓	
<i>Brice</i>	Brice	X			
<i>Engelstein</i>	Engelstein		X		
<i>Bette Davis by Shirley Loring</i>		X			

CHAIR'S SIGNATURE

Norm Rokeberg

1-23-96



HOUSE SPECIAL COMMITTEE ON OIL
AND GAS

DATE: January 23, 1996

[REDACTED]

SIGN - IN

PLEASE PRINT!
NAME

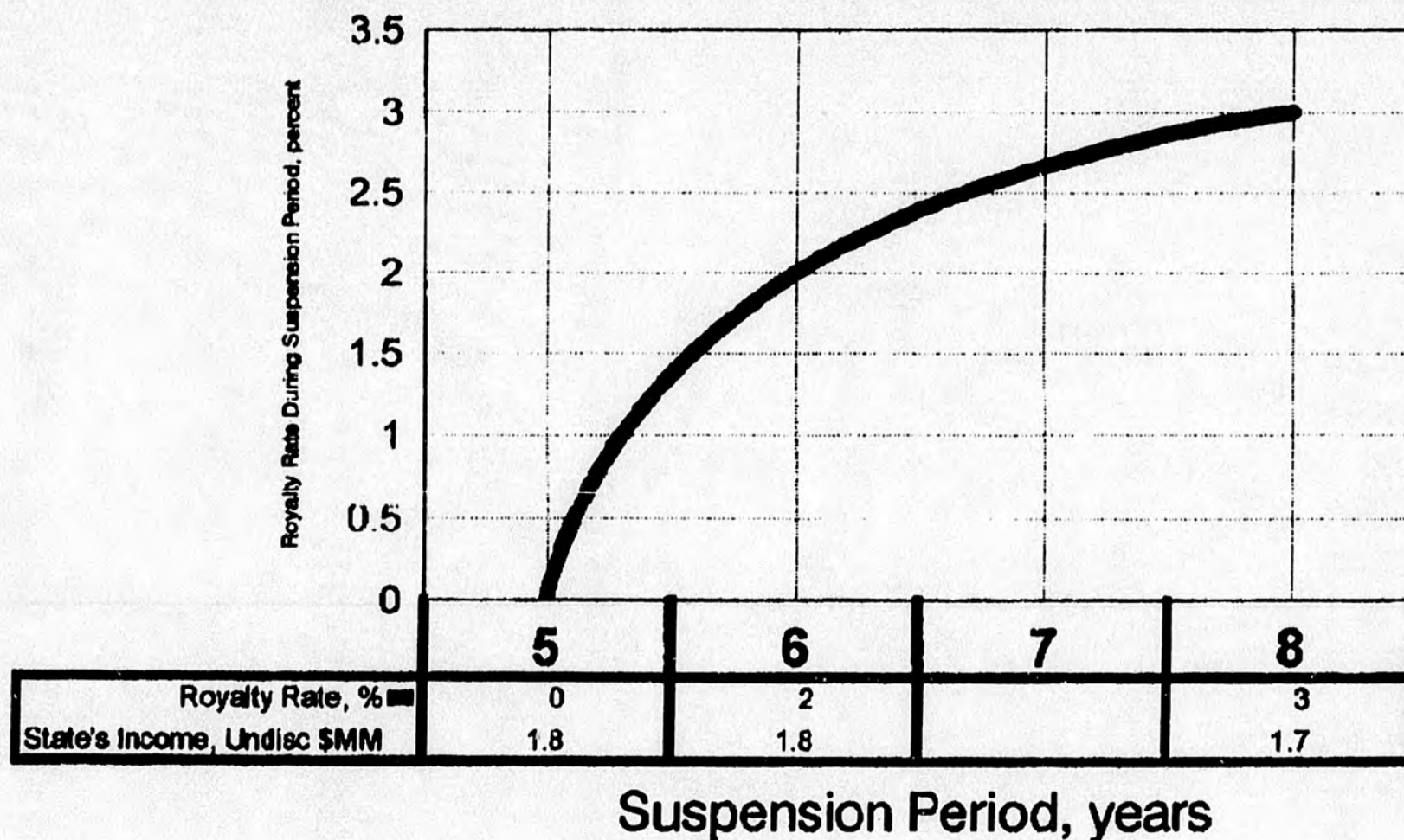
PHONE

REPRESENTING

DO YOU WANT TO TESTIFY?

[illegible]

What combination of minimum royalty rate and suspension period yields a 15.9% ROR?



OXY per-well economics. January 19, 1996

**MARGINAL OIL FIELD DEVELOPMENT:
THE ECONOMIC IMPACT**

prepared for

BP Exploration (Alaska) Inc.

for presentation to

The State of Alaska Oil and Gas Policy Council

prepared by

**Oliver Scott Goldsmith
Professor of Economics**

**Institute of Social and Economic Research
University of Alaska Anchorage
3211 Providence Drive
Anchorage, Alaska 99508**

June 5, 1995

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

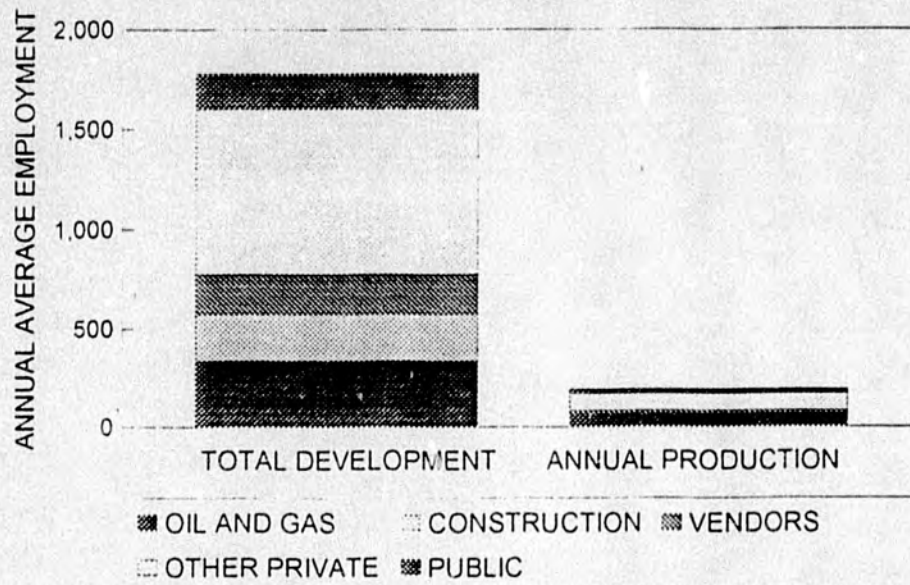


FIGURE 1B. MARGINAL FIELD ECONOMIC EFFECT:
RESIDENT PAYROLL

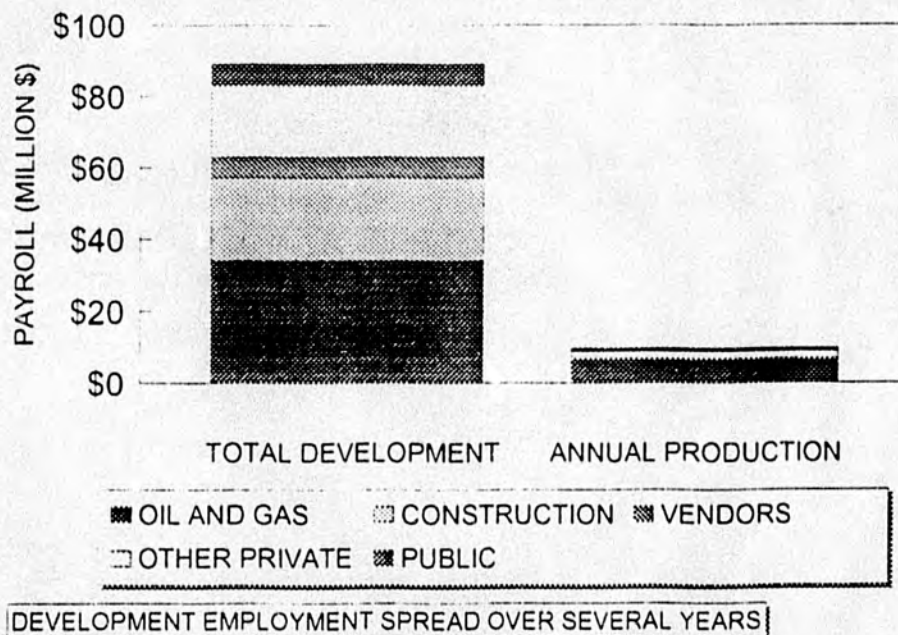
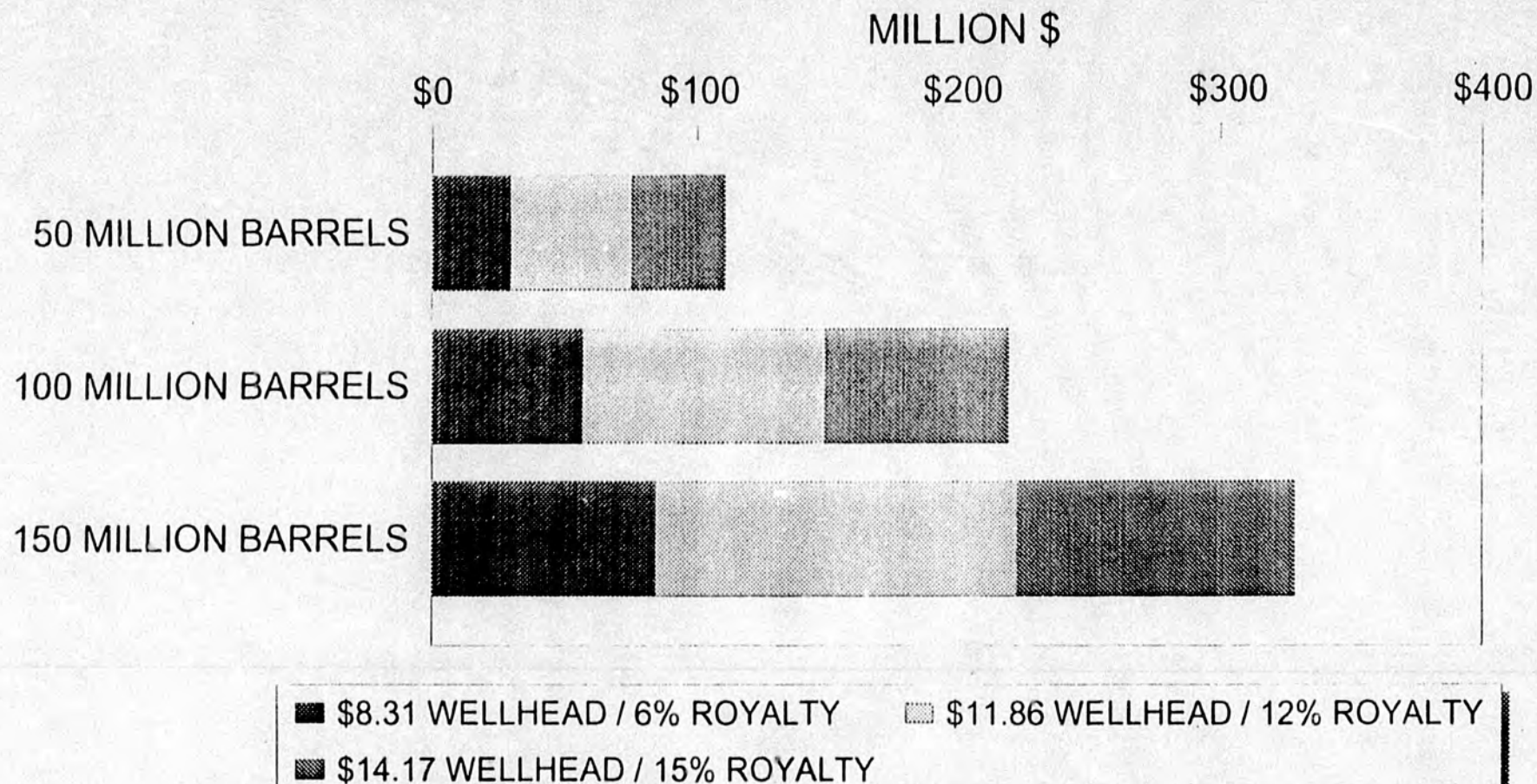
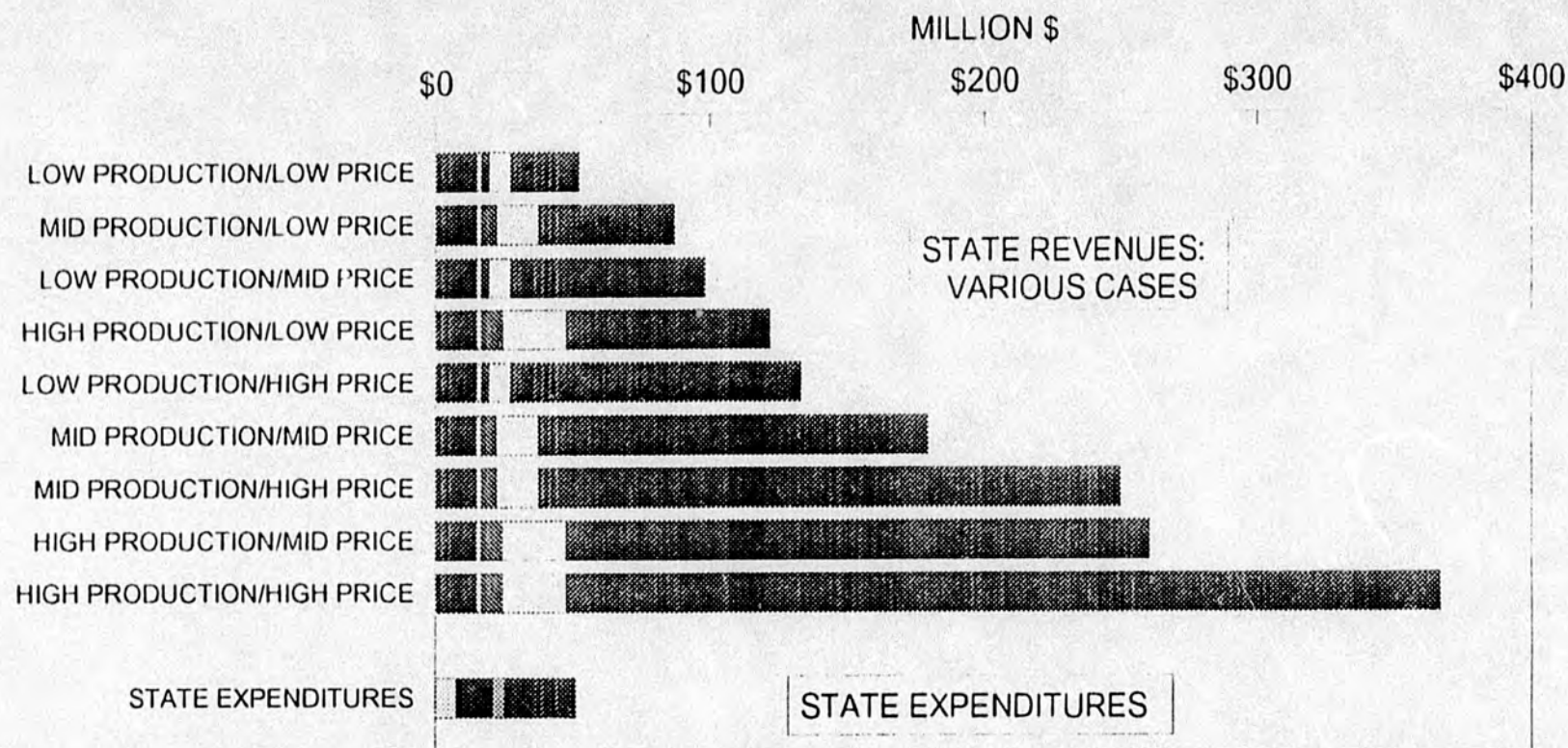


FIGURE 2. MARGINAL FIELD PRODUCTION REVENUES
 SENSITIVITY TO PRODUCTION, WELLHEAD PRICE, AND ROYALTY RATE



REVENUES OVER THE LIFE OF THE FIELD

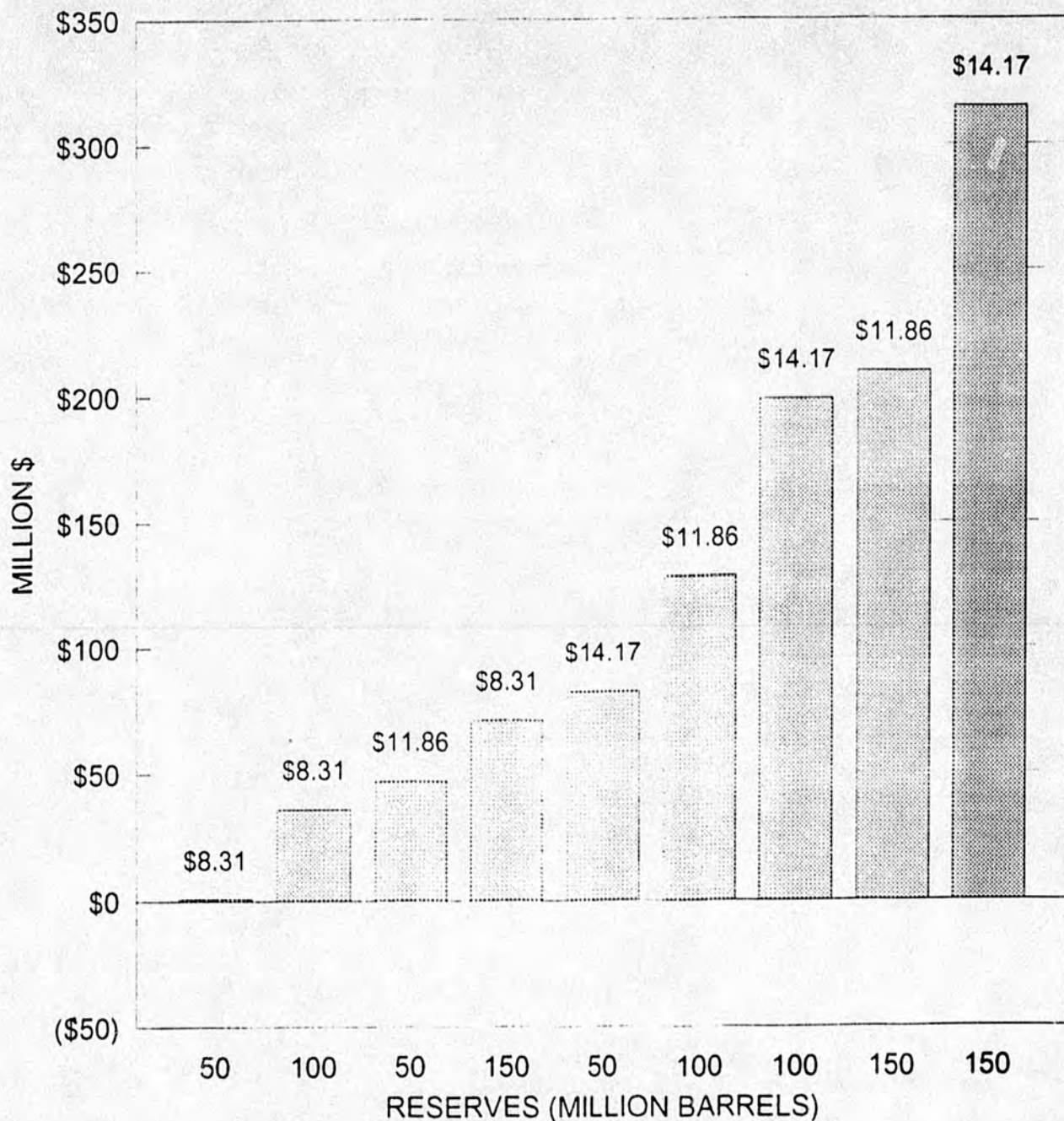
FIGURE 3. STATE REVENUES AND EXPENDITURES: LIFE OF THE FIELD



■ PERSONAL INCOME TAX ■ PETROLEUM PROPERTY TAX ■ CORP INCOME ■ FULL PIPELINE ■ ROYALTY
 ■ RESOURCE MANAGEMENT ■ OIL POPULATION ■ VENDOR POPULATION ■ OTHER POPULATION

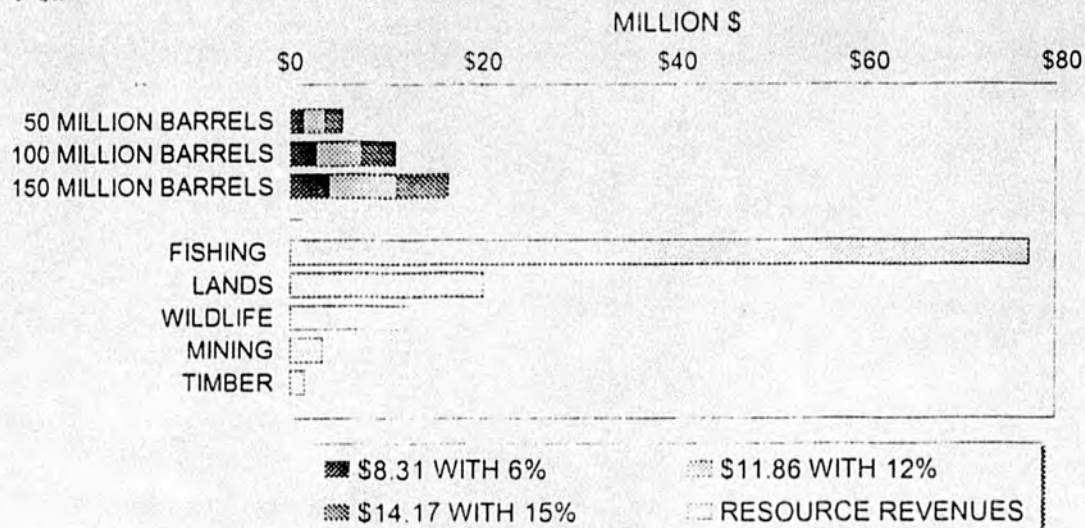
FIGURE 4. STATE REVENUE "DIVIDEND"

VARIATION IN RESERVES, PRICE, AND ROYALTY RATE



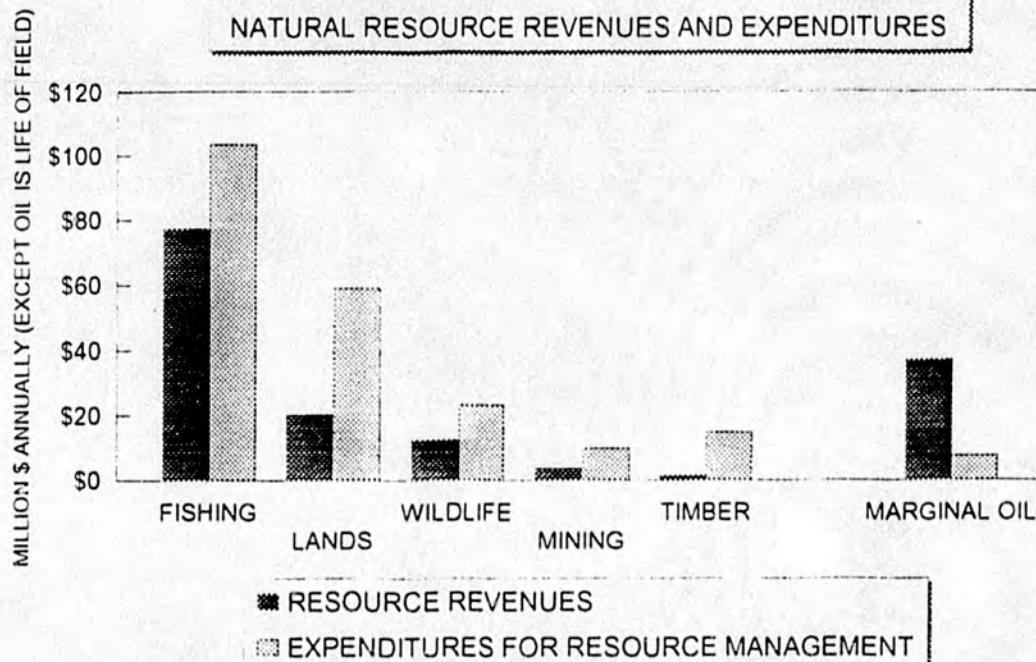
REVENUES IN EXCESS OF AMOUNT NEEDED
TO PROVIDE NEW PUBLIC SERVICES

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

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

INTRODUCTION

Since the characteristics of each marginal North Slope oil field are unique, we estimate the economic impact of a marginal field based upon the assumptions of a generic field in the current economic environment. We assume an initial period of field development followed by 20 years of production under constant conditions of employment and oil flow. To simplify the analysis, we consider a typical year midway through the production phase. Although we have chosen 2005 for this purpose, all dollar values should be interpreted as 1995 dollars.

The employment and payroll impacts depend primarily on the development and production plan for the field as well as the residence of the workers employed onsite and in supporting roles. Large numbers of highly paid workers are required during the development of the field. A portion of these workers must be employed onsite for drilling, site preparation, and fabrication of pipelines and other facilities. Employment associated with module construction is more likely to be located outside the state in lower cost locations with better access to the equipment and specialized labor required for this purpose. Once all the facilities are in place, the number of jobs required to operate and maintain the field is quite small.

Total employment and payroll depend on both the activities onsite and the activity of suppliers to the industry, such as transportation and wholesaling. The payrolls paid to resident workers in these industries will be spent in state and generate employment in the support industries of trade, finance, and services as well as smaller amounts of employment in construction, communications, transportation, and utilities. Furthermore, as the households of the new workers move into the state, they will require public services which in turn generate additional jobs in state and local government.

The public expenditure requirements generated by the marginal field are sensitive to the marginal cost of providing public services to another Alaska resident and the number of new Alaska residents generated by the new jobs. Nonresident workers require little in terms of government services like education which make up the bulk of the state budget. Likewise, to the extent that the jobs are filled by current Alaskans and no new migrants move into the state looking for work, the marginal cost of public services is also minimized.

Unlike employment, payroll, and public expenditure requirements, which are fairly well-determined by the development plan for the field, state revenues are very sensitive to field size, the wellhead price of oil, and the tax and royalty structure in place. Assuming that the marginal field will not be subject to the severance tax, the largest source of revenue is the royalty payment to the state with the corporate

income and state property taxes generating small additional revenues which are not as price- or production sensitive.

Two other sources of revenue are important. Production from the marginal field will increase the flow through the ALYESKA pipeline and marginally reduce the tariff faced by all the production on the North Slope. This will raise the wellhead price which will in turn increase severance taxes and royalties on all North Slope production. The size of this "full pipeline effect" depends on the percent increase in throughput from the marginal field development.

Alaska currently has neither a state personal income tax nor a statewide general sales tax. Consequently, when measuring the revenue burden faced by any new industrial development in Alaska, the payroll tax base generated by the new activity is generally not considered as a potential source of revenues to offset the public sector costs which the development would generate. However, this is clearly an increase in the tax base which would be available to pay at least some of the public sector costs which the new population associated with the development would require. Furthermore, there is some likelihood that in future years the state will impose one or both of these taxes to offset some of the revenue loss from the decline in petroleum revenues. Consequently, we include the potential revenues from both a state personal income tax and a state general sales tax in the calculation of revenues available from the marginal development. It is, of course, a policy decision whether the state would avail itself of these sources of revenue.

Using conservative assumptions which produce an upper bound estimate of the public sector costs of marginal field development combined with conservative assumptions which produce modest estimates of revenues available from the field, we conclude that the marginal field would produce a fiscal "dividend" under all but the most pessimistic assumptions regarding the lifetime production from the field.

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

DEVELOPMENT EXPENDITURES (Table 1)

The budget for development of a marginal field depends upon the development plan which will vary from case to case, based on many technical and economic factors. The development plan is contingent upon some estimate of recoverable reserves, but actual field performance will only become clear after production begins. Consequently, a large share of the total cost of the field will be determined at the time the decision is made to proceed with development. Furthermore, since the development cost has a fixed component, the size of the development budget will not necessarily vary proportionally with the estimated size of the field.

A primary consideration is that the sum of the development and operating costs of the field be low enough on a per-barrel basis to justify investment in the field. This is not a study of the economic viability of marginal field development, but we have chosen the size of the development budget in Table 1 combined with the production budget in Table 2 to be generally consistent with economic viability for a field with recoverable reserves of 100 million barrels on the North Slope.

The budget in Table 1 has six primary elements which are relatively self-evident. The development phase of the project would primarily occur over a two-year period, but the drilling of production wells would extend for several years into the production phase of the life of the field. Consequently, the estimate of 762 Alaska man years of labor would be spread out over time rather than occurring all in a single year. Pipeline installation would occur over a period of a few months. The equipment required for the modules (including their fabrication), pipeline, and other facilities would of necessity all be fabricated outside the state. Facility construction would occur onsite, and like the other onsite tasks would have a large labor component. Engineering would, in this hypothetical case, be conducted mostly outside the state. Company management is split between Alaska and headquarters outside of the state.

Of the total man years of labor required for this development, about half would occur in Alaska and half outside the state. The instate wage bill for this labor is high — \$76 million — because the jobs are skilled, remote, and require long hours. Consequently, we assume an average wage above the average for the industry as a whole since at least half the current jobs in the oil and gas industry are located in urban Alaska where there are many office-type jobs.

TABLE 1: MARGINAL FIELD ANALYSIS: DEVELOPMENT PHASE TOTAL EXPENDITURES

	SUM			DRILLING			PIPELINE INSTALLATION			EQUIPMENT			FACILITY CONSTRUCTION			ENGINEERING			COMPANY MANAGEMENT		
	TOTAL	ALASKA	OUTSIDE	TOTAL	ALASKA	OUTSIDE	TOTAL	ALASKA	OUTSIDE	TOTAL	ALASKA	OUTSIDE	TOTAL	ALASKA	OUTSIDE	TOTAL	ALASKA	OUTSIDE	TOTAL	ALASKA	OUTSIDE
EXPENDITURE (MILLION \$)	\$320	\$159	\$161	\$128	\$85	\$43	\$48	\$37	\$11	\$90	\$0	\$90	\$32.0	\$28.4	\$3.6	\$16.0	\$4.0	\$12.0	\$6.4	\$4.8	\$1.6
LABOR	\$147	\$99	\$48	\$51.2	\$51.2	\$0.0	\$24.0	\$24.0	\$0.0	\$36.0	\$0.0	\$36.0	\$16.0	\$16.0	\$0.0	\$14.4	\$3.6	\$10.8	\$5.8	\$4.3	\$1.4
EQUIPMENT	\$60	\$20	\$41	\$25.6	\$12.8	\$12.8	\$7.2	\$3.6	\$3.6	\$22.5	\$0.0	\$22.5	\$4.8	\$3.1	\$1.7	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
SUPPLIES	\$60	\$14	\$46	\$32.0	\$8.0	\$24.0	\$7.2	\$1.8	\$5.4	\$13.5	\$0.0	\$13.5	\$4.8	\$2.9	\$1.9	\$1.6	\$0.4	\$1.2	\$0.6	\$0.5	\$0.2
SERVICES	\$38	\$20	\$19	\$12.8	\$9.6	\$3.2	\$7.2	\$5.4	\$1.8	\$13.5	\$0.0	\$13.5	\$4.8	\$4.8	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
TRANSPORT	\$15	\$7	\$8	\$6.4	\$3.2	\$3.2	\$2.4	\$2.4	\$0.0	\$4.5	\$0.0	\$4.5	\$1.6	\$1.6	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
OTHER	\$0	\$0	\$0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0	\$0.0
EMPLOYEES (MAN YEARS)	1,443	762	680	394	394	0	185	185	0	554	0	554	123	123	0	138	28	111	49	33	16
AVG PAYROLL (THOUSAND \$) (A)					\$100	\$60		\$100	\$50		\$100	\$50		\$100	\$50		\$100	\$75		\$100	\$70
TOTAL PAYROLL (MILLION \$)	\$113.4	\$76.2	\$37.1	\$39.4	\$39.4	\$0.0	\$18.5	\$18.5	\$0.0	\$27.7	\$0.0	\$27.7	\$12.3	\$12.3	\$0.0	\$11.1	\$2.8	\$8.3	\$4.4	\$3.3	\$1.1

DISTRIBUTION OF TOTAL FIELD DEVELOPMENT COST AS FOLLOWS

DRILLING	40%
PIPELINE INSTALLATION	15%
EQUIPMENT	33% INCLUDES MODULE SUPPLIES AND FABRICATION AS WELL AS PIPE
FACILITY CONSTRUCTION	5%
ENGINEERING	5%
MANAGEMENT	2%

(A) AVERAGE ANNUAL ALASKA PAYROLL (000\$) REMOTE SITE CONSTRUCTION \$100
OIL AND GAS \$100

THIS IS ABOVE THE AVERAGE FOR THE INDUSTRY BECAUSE THE JOBS ARE REMOTE SITE AND HIGHLY TECHNICAL

LABOR COST/PAYROLL RATIO 1.3

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

PRODUCTION EXPENDITURES (Table 2)

Production in an oil field typically occurs at a declining rate. We assume a 20-year production life, describe a typical year within that period, and multiply by 20 to cover the entire life of the field. During the first five years of production, the drilling of new wells budgeted in the development budget will continue. Subsequent to that, a smaller crew will operate a rig for workovers as long as the field produces. This production budget includes only the workover drilling expenses, and the average annual expenditure for this is shown in the table.

The main expenditures during production are the onsite employment associated with field operation and the crews for manning the workover rig. In addition, a small amount of headquarters employment has been allocated to the project.

The 75 employees required to operate the field are double the number that are onsite at any time and four times the number of actual jobs. This field is designed to operate with a very small level of employment, but it does operate around the clock so four employees are necessary for each job. This is necessary given the high cost of labor combined with the constraints on the economic viability of the project. Over 20 years the \$16 million annual production budget cumulates to a \$320 million budget which is identical to the development budget.

Labor is the largest expense during the production phase, and it must occur onsite either in the operation of the field or the reworking of wells. Other expenses represent a combination of purchases for goods and services instate such as transportation, food, and water, and out of state such as drilling mud and equipment.

Because of the technical nature of the work and the long hours, the average annual wage is higher than the industry average.

TABLE 2: MARGINAL FIELD ANALYSIS: PRODUCTION PHASE ANNUAL AVERAGE EXPENDITURES

	SUM			ON SITE FIELD OPERATION			WORKOVER DRILLING (B)			HEADQUARTERS		
	TOTAL	ALASKA	OUTSIDE	TOTAL	ALASKA	OUTSIDE	TOTAL	ALASKA	OUTSIDE	TOTAL	ALASKA	OUTSIDE
EXPENDITURE (MILLION \$)	\$16.0	\$14.5	\$1.5	\$8.1	\$7.1	\$1.0	\$6.8	\$6.3	\$0.5	\$1.1	\$1.1	\$0.0
LABOR	\$9.8	\$9.8	\$0.0	\$5.2	\$5.2		\$3.9	\$3.9		\$0.7	\$0.7	
EQUIPMENT	\$2.0	\$1.0	\$1.0	\$1.0	\$0.0	\$1.0	\$1.0	\$1.0		\$0.0		
SUPPLIES	\$2.0	\$1.5	\$0.5	\$1.0	\$1.0		\$1.0	\$0.5	\$0.5	\$0.0		
SERVICES	\$1.2	\$1.2	\$0.0	\$0.4	\$0.4		\$0.4	\$0.4		\$0.4	\$0.4	
TRANSPORT	\$1.0	\$1.0	\$0.0	\$0.5	\$0.5		\$0.5	\$0.5		\$0.0		
OTHER	\$0.0	\$0.0	\$0.0	\$0.0			\$0.0			\$0.0		
EMPLOYEES (MAN YEARS)	75	75	0	40	40	0	30	30	0	5	5	0
AVG PAYROLL (THOUSAND \$) (A)					\$100	\$60		\$100	\$50		\$100	\$50
TOTAL PAYROLL (MILLION \$)	\$7.5	\$7.5	\$0.0	\$4.0	\$4.0	\$0.0	\$3.0	\$3.0	\$0.0	\$0.5	\$0.5	\$0.0

SINCE PRODUCTION AND DRILLING CONTINUE AROUND THE CLOCK, EACH JOB REQUIRES 4 EMPLOYEES. WITH A 12 HOUR SHIFT AND WEEKLY ROTATION THERE WILL BE TWO SHIFTS "ON SITE" AT ANY GIVEN TIME.

(A) AVERAGE ANNUAL ALASKA PAYROLL (000\$) OIL AND GAS \$100
THIS IS ABOVE THE AVERAGE FOR THE INDUSTRY BECAUSE THE JOBS ARE REMOTE SITE AND HIGHLY TECHNICAL

LABOR COST/PAYROLL RATIO 1.3

(B) WORKOVER DRILLING COMMENCES IN YEAR 6 OF FIELD OPERATIONS AND CONTINUES THROUGH YEAR 20
THESE FIGURES REPRESENT THE TOTAL LIFETIME COST OF WORKOVER DRILLING DIVIDED BY THE 20 YEAR FIELD LIFE

THIS AVERAGING REPRESENTS A FIVE YEAR PERIOD WITH ONLY PRODUCTION RELATED EMPLOYMENT (DURING WHICH DEVELOPMENT DRILLING CONTINUES) FOLLOWED BY A FIFTEEN YEAR PERIOD WITH PRODUCTION RELATED EMPLOYMENT AND WORKOVER DRILLING

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

PETROLEUM REVENUES FROM MARGINAL FIELD PRODUCTION (Table 3)

The amount of state revenues collected over the life of the marginal field is very sensitive to the total oil produced from the field, the wellhead price of oil, and the royalty rate. For the range of assumptions discussed below, the range of lifetime revenues is from a low of \$29 million to a high of \$328 million.

We consider revenues from three sources: royalties, corporate income tax, and state property tax. We assume the severance tax rate on the marginal field will be zero due to its small size.

Royalties depend on the wellhead price, and we consider three price levels, based on the Alaska Department of Revenue (ADOR) Spring 1995 Petroleum Revenue Projections. We take the ADOR low, medium, and high Alaska North Slope (ANS) prices projected for 2005, deflate them to 1995 dollars, and subtract \$1 as a pipeline charge from the marginal field to the proximity of pump station 1 of the TAPS pipeline. The resulting net marginal field wellhead prices are \$8.31, \$11.86, and \$14.17. Royalties are calculated assuming 6% for the low price, 12% for the mid case, and 15% for the high case. Finally, we consider production levels of 50, 100, and 150 million barrels over a 20-year lifetime for the field.

We calculate the corporate income tax rate based on a cents-per-barrel amount. The average corporate income tax per barrel for Alaska production since 1986 has been \$.19. We arbitrarily assume the cents-per-barrel tax on the marginal field will be \$.05 per barrel.

We calculate the state property tax based on an initial value of capital in place of half the total cost of development. Although the state property tax rate is 20 mills, the North Slope Borough currently receives 18.77 mills of the total collected. We assume the same sharing of the property tax on this marginal field, so the annual state collection is \$80,000.

TABLE 3: MARGINAL FIELD ANALYSIS: PRODUCTION AND DIRECT PETROLEUM REVENUES

WELLHEAD PRICE DETERMINATION	LOW	MID	HIGH
ANS WELLHEAD PRICE IN 2005 (A)	\$11.53	\$17.47	\$23.62
DEFLATE TO 1995 \$ (B)	\$9.31	\$12.86	\$15.17
TRANSPORT DIFFERENTIAL (C)	\$1.00	\$1.00	\$1.00
NET MARGINAL FIELD WELLHEAD	\$8.31	\$11.86	\$14.17
ROYALTY RATE	6%	12%	15%

		LOW RESERVES 50 MILLION BARRELS						MEDIUM RESERVES 100 MILLION BARRELS						HIGH RESERVES 150 MILLION BARRELS					
		ANNUAL			20 YEAR FIELD LIFE			ANNUAL			20 YEAR FIELD LIFE			ANNUAL			20 YEAR FIELD LIFE		
WELLHEAD PRICE		\$8.31	\$11.86	\$14.17	\$8.31	\$11.86	\$14.17	\$8.31	\$11.86	\$14.17	\$8.31	\$11.86	\$14.17	\$8.31	\$11.86	\$14.17	\$8.31	\$11.86	\$14.17
PRODUCTION	MILLION BARRELS	2.5	2.5	2.5	50	50	50	5	5	5	100	100	100	7.5	7.5	7.5	150	150	150
WELLHEAD VALUE	MILLION \$	\$21	\$30	\$35	\$415	\$593	\$709	\$42	\$59	\$71	\$831	\$1196	\$1417	\$62	\$89	\$106	\$1246	\$1778	\$2126
ROYALTIES	MILLION \$	\$1.25	\$3.56	\$5.31	\$24.93	\$71.13	\$106.29	\$2.49	\$7.11	\$10.63	\$49.86	\$142.26	\$212.19	\$3.74	\$10.67	\$15.94	\$74.79	\$213.39	\$318.88
SEVERANCE (D)	"	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
INCOME (E)	"	\$0.13	\$0.13	\$0.13	\$2.50	\$2.50	\$2.50	\$0.25	\$0.25	\$0.25	\$5.00	\$5.00	\$5.00	\$0.38	\$0.38	\$0.38	\$7.50	\$7.50	\$7.50
PROPERTY (F)	"	\$0.10	\$0.10	\$0.10	\$1.97	\$1.97	\$1.97	\$0.10	\$0.10	\$0.10	\$1.97	\$1.97	\$1.97	\$0.10	\$0.10	\$0.10	\$1.97	\$1.97	\$1.97
TOTAL DIRECT REVENUES		\$1.47	\$3.78	\$5.54	\$29.40	\$75.60	\$110.76	\$2.84	\$7.46	\$10.98	\$56.83	\$149.23	\$219.55	\$4.21	\$11.14	\$16.42	\$84.26	\$222.86	\$328.35

(A) ADOR SPRING 1995 REVENUE SOURCES

(B) DEFLATION FACTORS BASE 0.736
 LOW 0.807
 HIGH 0.642

ADOR SPRING 1995 REVENUE SOURCES

(C) AUTHOR ASSUMPTION

(D) SEVERANCE TAX RATE 0.00%

(E) CORPORATE INCOME TAX ON PETROLEUM

FY	DAILY PRODUCTION	CORP TAX	TAX PER BARREL
86	1.847	\$133.90	\$0.20
87	1.896	\$120.40	\$0.17
88	2.048	\$158.00	\$0.21
89	2.003	\$166.00	\$0.23
90	1.888	\$117.20	\$0.17
91	1.839	\$185.10	\$0.28
92	1.833	\$165.50	\$0.25
93	1.728	\$105.70	\$0.17
94	1.639	\$17.80	\$0.03

NET OF SETTLEMENT

AVG \$0.19

ASSUME \$0.05 TAX PER BARREL

SOURCE: ADOR SPRING 1995 REVENUE SOURCES

(F) PROPERTY TAX BASED ON

HALF COST OF FIELD DEVELOPMENT \$160.00
 TAX RATE 2.00%
 LEVELIZED TO REFLECT DEPRECIATION OF VALUE \$1.60
 STATE SHARE OF TAXES COLLECTED 6%
 ANNUAL STATE COLLECTION \$0.10

STATE SHARE OF TAXES COLLECTED BASED ON NORTH SLOPE BOROUGH
 MILL RATE OF 18.77 FROM ALASKA TAXABLE 1992

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

PETROLEUM REVENUES FROM HIGHER NORTH SLOPE WELLHEAD (Table 4)

If the development of a marginal field increases production on the North Slope, throughput of the ALYESKA pipeline will increase. Because the pipeline tariff includes a fixed cost component, the tariff will fall, the wellhead value of all production on the North Slope will increase, and royalties and severance taxes based on wellhead value will increase.

We consider the size of the revenues from the "Full Pipeline Effect" under different assumptions about marginal field production, wellhead price, pipeline tariff, and volume of ALYESKA throughput. The revenues from this effect are most sensitive to field production but not to wellhead price, tariff, or volume of throughput. The lifetime revenues range from \$7.8 million for a 50 million barrel field, \$15.6 million for a 100 million barrel field, to \$23.2 million for a 150 million barrel field.

We use the range of pipeline tariffs for 2005 published by the ADOR in their Petroleum Revenue Projection Forecast as well as the range of North Slope production rates for the same year.

Only a portion of the Alyeska tariff is based on the volume of throughput. The tariff agreement allows the operators to recover an operating cost, a profit on each barrel, and an offset for increased tax liability on the additional profit from higher production. The sum of these three factors is assumed to be \$1.22 per barrel. Since the tariff for the average barrel is estimated to be over \$2.00, there is a slight reduction of about \$.01 in the average tariff with the increase in throughput.

This raises the average wellhead by about \$.01 per barrel. We assume that the average barrel produced on the North Slope pays a combined severance tax and royalty rate of 18% of the wellhead value.

TABLE 4: MARGINAL FIELD ANALYSIS: REVENUES FROM HIGHER WELLHEAD

	LOW RESERVES 50 MILLION BARRELS				MEDIUM RESERVES 100 MILLION BARRELS				HIGH RESERVES 150 MILLION BARRELS			
DAILY MARGINAL PRODUCTION	6 849	6 849	6 849	6 849	13 699	13 699	13 699	13 699	20 548	20 548	20 548	20 548
PIPELINE TARIFF IN 2005 (A)	\$2 65	\$2 65	\$3 03	\$3 03	\$2 65	\$2 65	\$3 03	\$3 03	\$2 65	\$2 65	\$3 03	\$3 03
DEFLATE TO 1995 \$ (B)	\$2 10	\$2 10	\$2 23	\$2 23	\$2 10	\$2 10	\$2 23	\$2 23	\$2 10	\$2 10	\$2 23	\$2 23
DAILY TAPS THRUPUT (C)	950 000	1 300 000	950 000	1 300 000	950 000	1 300 000	950 000	1 300 000	950 000	1 300 000	950 000	1 300 000
CHARGES (MILLION \$)	\$727	\$995	\$773	\$1 058	\$727	\$995	\$773	\$1 058	\$727	\$995	\$773	\$1 058
AUGMENTED DAILY THRUPUT	956 849	1 306 849	956 849	1 306 849	963 699	1 313 699	963 699	1 313 699	970 548	1 320 548	970 548	1 320 548
ADDITIONAL CHARGES (D)	\$3 05	\$3 05	\$3 05	\$3 05	\$6 10	\$6 10	\$6 10	\$6 10	\$9 15	\$9 15	\$9 15	\$9 15
AUGMENTED THRUPUT TARIFF	\$2 09	\$2 09	\$2 22	\$2 22	\$2 08	\$2 09	\$2 22	\$2 22	\$2 08	\$2 08	\$2 21	\$2 21
REDUCTION IN TARIFF-- INCREASE IN WELLHEAD	\$0 01	\$0 00	\$0 01	\$0 01	\$0 01	\$0 01	\$0 01	\$0 01	\$0 02	\$0 01	\$0 02	\$0 02
INCREASE IN WELLHEAD VALUES (MILLION \$)	\$2 18	\$2 18	\$2 51	\$2 51	\$4 32	\$4 34	\$4 96	\$5 00	\$6 44	\$6 48	\$7 41	\$7 45
BLENDED TAX / ROYALTY RATE (E)	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%	18%
INDIRECT INCREASE IN REVENUE (MILLION \$)												
ANNUAL	\$0 39	\$0 39	\$0 45	\$0 45	\$0 78	\$0 78	\$0 90	\$0 90	\$1 16	\$1 17	\$1 33	\$1 34
20 YEAR FIELD LIFE	\$7 84	\$7 85	\$9 02	\$9 04	\$15 56	\$15 62	\$17 91	\$17 98	\$23 18	\$23 31	\$26 68	\$26 83

(A) LOW PROJECTED TARIFF FOR 2005 \$2 73
HIGH PROJECTED TARIFF FOR 2005 \$3 03
ADOR, SPRING 1995 REVENUE SOURCES

(B) SEE DIRECT REVENUE SHEET FOR MID CASE DEFLATION FACTOR

(C) ANS PETROLEUM PRODUCTION PROJECTION FOR 2005 963,000 BARRELS / DAY LOW
ADOR, SPRING 1995 REVENUE SOURCES 1,292,000 BARRELS / DAY HIGH

(D) TARIFF INCLUDES FIXED PROFIT PER BARREL @ \$0 54
AND VARIABLE OPERATING COST @ \$0 32
AND TAX ALLOWANCE @ \$0 36
TOTAL \$1 22

BASED ON CONVERSATIONS WITH ADOR PERSONNEL

(E) ASSUME 12% ROYALTY AND 6% SEVERANCE TAX

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

OIL-RELATED EMPLOYMENT (Table 5)

The most important source of new jobs to the economy comes from development and production of the field. Subsequent tables identify additional employment effects.

Oil-related employment is divided into three categories for both the development and production phases of marginal field life. The first category is the **DIRECT** employment in the oil and gas and construction industries involved with field development or production. Second is the **VENDOR** employment associated with providing the goods and services to the oil and construction sectors for development and production. This employment is in the transportation, wholesale trade, and business services sectors. The third is **INDIRECT** and **INDUCED** employment which consists of the private sector jobs throughout the economy stimulated by the multiplier effect of the development and production of the field.

The **VENDOR** and **INDIRECT** and **INDUCED** employment are calculated using the Alaska input-Output model based on the **DIRECT EMPLOYMENT** and instate purchases by the oil and construction industries in the development and production of the field. Alaska payrolls are calculated the same way.

We assume that a portion of **DIRECT** employment is nonresident, based on information provided by BP Exploration (Alaska), Inc., from their records and information from their contractors. We assume that all other employees are residents. Nonresident payroll is assumed to have a small impact on economic activity in Alaska. We assume 20% of nonresident payroll is spent in Alaska on the same market basket as resident payroll.

Total jobs (annual average) to Alaska residents from field development are 1,482. Since field development would take more than one year, these jobs would be spread over several years. Total jobs to Alaska residents from production are estimated at 157 for each of the 20 years of production. Total Alaska payroll from development is \$79.2 million, and total payroll from production is \$8.47 million annually.

TABLE 5: MARGINAL FIELD ANALYSIS: OIL RELATED EMPLOYMENT

	TOTAL DEVELOPMENT	ANNUAL PRODUCTION
EXPENDITURE IN ALASKA (MILLION \$)		
LABOR	\$99	\$10
EQUIPMENT	\$20	\$1
SUPPLIES	\$14	\$2
SERVICES	\$20	\$1
TRANSPORT	\$7	\$1
OTHER	\$0	\$0
DIRECT JOBS IN AK (MAN YEARS)	762	75
CONSTRUCTION	308	0
OIL AND GAS	455	75
JOBS HELD BY ALASKA RESIDENTS (A)	572	60
CONSTRUCTION	231	0
OIL AND GAS	341	60
DIRECT PAYROLL IN ALASKA (MILLION \$) (B)	\$76.25	\$7.54
CONSTRUCTION	\$30.77	\$0.00
OIL AND GAS	\$45.48	\$7.54
PAYROLL TO ALASKA RESIDENTS	\$57.18	\$6.03
CONSTRUCTION	\$23.08	\$0.00
OIL AND GAS	\$34.11	\$6.03
ITEM: NON-RESIDENT PAYROLL SPENT IN AK (C)	\$3.81	\$0.30
VENDOR JOBS IN ALASKA (D)	201	21
INDIRECT AND INDUCED JOBS IN ALASKA (D)	709	76
TOTAL JOBS	1,672	172
TOTAL JOBS TO ALASKA RESIDENTS	1,482	157
VENDOR PAYROLL (MILLION \$) (D)	\$5.86	\$0.71
INDIRECT AND INDUCED PAYROLL (D)	\$16.12	\$1.73
TOTAL PAYROLL	\$98.23	\$9.98
TOTAL PAYROLL TO ALASKA RESIDENTS	\$79.17	\$8.47
(A) RESIDENT SHARES OF DIRECT JOBS		
CONSTRUCTION	75%	80%
OIL AND GAS	75%	80%
(B) AVERAGE PAYROLL FROM ADOL	REMOTE SITE CONSTRUCTION	\$100
	OIL AND GAS	\$100
(C) PORTION OF NON-RESIDENT PAYROLL SPENT IN AK	20%	20%
(D) FROM ALASKA INPUT-OUTPUT MODEL		

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

OIL-RELATED POPULATION (Table 6)

The jobs produced by the development and production from the marginal field could be filled either by currently unemployed residents or by new residents who would migrate to the state. In either case it is likely that population would increase through immigration to reestablish the equilibrium unemployment rate in the labor market. (In some cases, particularly in rural parts of the state, job creation might not stimulate immigration, but we do not consider this case.)

The population response will depend upon the characteristics of the households of the workers who take these jobs. Based on data from the Census, we find that households with an oil industry or construction industry worker tend to be slightly larger than the average household because they are more likely to be a traditional household of husband and wife. For this reason they have a larger average number of children as well as adults, and also a larger number of workers per household. We assume the new Alaskan households have characteristics similar to those already here in terms of size, number of school-aged children per household, and employed persons per household. We assume that the number of people aged 65 and over in these households is zero.

Since the average household has more than one employed person, two new households can supply one worker to fill one of the other jobs created by the development and production from the marginal field. We assume that the mix of occupations within these households matches the newly created jobs so that the new migrant household workers are not constrained in their employment opportunities.

Using these assumptions, we calculate that the economic activity surrounding the development of the marginal field will generate a population increase of 2,762 (which will be allocated over the period of field development), and the production of the field will generate a population increase of 293 annually.

TABLE 6: MARGINAL FIELD ANALYSIS: OIL RELATED POPULATION

	TOTAL DEVELOPMENT				ANNUAL PRODUCTION			
	TOTAL	DIRECT	VENDOR	INDIRECT INDUCED	TOTAL	DIRECT	VENDOR	INDIRECT INDUCED
RESIDENT JOBS	1,482	572	201	709	157	60	21	76
HOUSEHOLD SIZE (A)		3.07	3.07	2.75		3.07	3.07	2.75
ADULTS / HH (B)		2.04	2.04	1.72		2.04	2.04	1.72
SCHOOL AGED KIDS / HH (C)		0.69	0.69	0.61		0.69	0.69	0.61
JOBS PER HH (D)		1.72	1.72	1.41		1.72	1.72	1.41
HOUSEHOLDS	952	332	117	503	101	35	12	54
ADULTS	1,782	678	238	865	189	72	25	93
SCHOOL AGED KIDS	617	229	81	307	65	24	8	33
POP	2,762	1,021	359	1,383	293	108	37	148

ASSUME ALL INDIRECT AND INDUCED JOBS HELD BY RESIDENTS

- (A) 1990 CENSUS PUBLIC USE SAMPLE
- (B) POPULATION 18 TO 64 IN HOUSEHOLDS, 1990 CENSUS PUBLIC USE SAMPLE
- (C) POPULATION 5 TO 17 IN HOUSEHOLDS, 1990 CENSUS PUBLIC USE SAMPLE
- (D) JOBS PER HOUSEHOLD IS RATIO OF JOBS PER HH TO EMPLOYEES PER HH MULTIPLIED BY THE INDUSTRY SPECIFIC EMPLOYEES PER HOUSEHOLD FROM 1990 CENSUS PUBLIC USE SAMPLE

OIL AND GAS	0.9639	1.79	1.73
CONSTRUCTION	0.9639	1.87	1.80
ALL OTHER	0.9639	1.46	1.41

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

STATE GOVERNMENT COSTS OF OIL-RELATED POPULATION (Table 7)

The population increase induced by the economic activity in the development and production from the marginal field will require public services from state government. The cost of these services will depend upon the characteristics of the new households. Based on an analysis of the 1990 state budget (Table 13), we calculated an annual general fund operating cost per adult in a household without unemployment to be \$2,980 and the annual cost per school-aged child to be \$5,240. We assume that the cost of state government per child below the age of five is zero and that none of the induced population is over the age of 65. We assume that the capital cost of state government to the new population is 20% of the operating cost.

Since the increase in employment will induce an increase in population not only to fill the jobs but also to reestablish the unemployment rate, we assume a slight increase in the unemployed population through immigration. The adult portion of this population has a larger public service requirement than the new employed population since they will require use of the safety net (welfare, job training, medicaid, etc.), so their per capita operating cost is estimated at \$5,530 per adult.

Only about two-thirds of the state budget is funded out of the state general fund, with the rest financed by federal transfers, program receipts, etc. We assume that the sources of funds for this portion of the budget will automatically increase with the increase in population and will not result in a deficit requiring a contribution from the general fund.

Based on these assumptions we calculate the cost to state government imposed by the increase in population associated with the development and production from the marginal field. It is \$11.3 million for field development and \$1.2 annually for field production. Over the 20-year life of the field, this accumulates to \$24 million.

TABLE 7: MARGINAL FIELD ANALYSIS: PUBLIC EXPENDITURE REQUIREMENTS

		TOTAL DEVELOPMENT				ANNUAL PRODUCTION			
		TOTAL	DIRECT	VENDOR	INDIRECT INDUCED	TOTAL	TOTAL	TOTAL	TOTAL
HOUSEHOLDS ASSOCIATED WITH OIL ACTIVITY		952	332	117	503	101	35	12	54
ADULTS		1,752	678	238	865	189	72	25	93
SCHOOL AGED KIDS		617	229	81	307	65	24	8	33
POPULATION		2,762	1,021	359	1,383	293	108	37	148
NEW RESIDENTS REQUIRING PUBLIC SERVICES									
HOUSEHOLDS OF WORKERS	ADULTS	1,752	678	238	865	189	72	25	93
	S A KIDS	617	229	81	307	65	24	8	33
UNEMPLOYED (A)	ADULTS	125	47	17	61	13	5	2	6
	S A KIDS	43	16	6	21	5	2	1	2
TOTAL	ADULTS	1,906	726	255	925	202	77	27	99
	S A KIDS	660	245	86	328	70	26	9	35
PER CAPITA COST OF STATE OPERATING SERVICES (GENERAL FUND) (B)									
EMPLOYED	ADULTS	\$2,980	\$2,980	\$2,980		\$2,980	\$2,980	\$2,980	
	S A KIDS	\$5,240	\$5,240	\$5,240		\$5,240	\$5,240	\$5,240	
UNEMPLOYED	ADULTS	\$5,530	\$5,530	\$5,530		\$5,530	\$5,530	\$5,530	
	S A KIDS	\$5,240	\$5,240	\$5,240		\$5,240	\$5,240	\$5,240	
TOTAL COST OF STATE OPERATING SERVICES (MILLION \$)		\$9.46	\$3.57	\$1.25	\$4.63	\$1.00	\$0.38	\$0.13	\$0.50
EMPLOYED	ADULTS	\$5.31	\$2.02	\$0.71	\$2.58	\$0.56	\$0.21	\$0.07	\$0.28
	S A KIDS	\$3.23	\$1.20	\$0.42	\$1.61	\$0.34	\$0.13	\$0.04	\$0.17
UNEMPLOYED	ADULTS	\$0.69	\$0.26	\$0.09	\$0.33	\$0.07	\$0.03	\$0.01	\$0.04
	S A KIDS	\$0.23	\$0.08	\$0.03	\$0.11	\$0.02	\$0.01	\$0.00	\$0.01
PER CAPITA COST OF STATE CAPITAL SERVICES (GENERAL FUND)									
EMPLOYED	ADULTS	\$596	\$596	\$596		\$596	\$596	\$596	
	S A KIDS	\$1,048	\$1,048	\$1,048		\$1,048	\$1,048	\$1,048	
UNEMPLOYED	ADULTS	\$596	\$596	\$596		\$596	\$596	\$596	
	S A KIDS	\$1,048	\$1,048	\$1,048		\$1,048	\$1,048	\$1,048	
TOTAL COST OF STATE CAPITAL SERVICES (MILLION \$)		\$1.83	\$0.69	\$0.24	\$0.90	\$0.19	\$0.07	\$0.03	\$0.10
EMPLOYED	ADULTS	\$1.06	\$0.40	\$0.14	\$0.52	\$0.11	\$0.04	\$0.01	\$0.06
	S A KIDS	\$0.65	\$0.24	\$0.08	\$0.32	\$0.07	\$0.03	\$0.01	\$0.03
UNEMPLOYED	ADULTS	\$0.07	\$0.03	\$0.01	\$0.04	\$0.01	\$0.00	\$0.00	\$0.00
	S A KIDS	\$0.05	\$0.02	\$0.01	\$0.02	\$0.00	\$0.00	\$0.00	\$0.00
TOTAL COST OF STATE SERVICES									
ANNUAL	OPERATING CAPITAL TOTAL					\$1.00	\$0.38	\$0.13	\$0.50
						\$0.19	\$0.07	\$0.03	\$0.10
						\$1.20	\$0.45	\$0.16	\$0.59
LIFE OF PROJECT	OPERATING CAPITAL TOTAL	\$9.46	\$3.57	\$1.25	\$4.63	\$20.08	\$7.53	\$2.62	\$9.93
		\$1.83	\$0.69	\$0.24	\$0.90	\$3.88	\$1.45	\$0.51	\$1.92
		\$11.28	\$4.26	\$1.50	\$5.53	\$23.96	\$8.98	\$3.13	\$11.85

- (A) RATIO OF UNEMPLOYED NEW RESIDENTS TO EMPLOYED SOURCE: ADOL 7%
- (B) PER CAPITA ANALYSIS USES 1990 BUDGET--SEE TABLE 13
- (C) PER CAPITA ANNUAL CAPITAL COST ASSUMED TO BE 20% OF OPERATING COST
THIS IS ROUGHLY BASED ON THE HISTORICAL RATIO OF DEBT SERVICE AND CAPITAL BUDGETS TO THE OPERATING BUDGET
- NEW RESIDENT SHARE OF EMPLOYED POPULATION 100%
IF THE CURRENTLY RESIDENT UNEMPLOYED FILLED SOME OF THE JOBS THEN THE COST TO THE PUBLIC SECTOR WOULD BE MUCH LOWER
ALSO IF THE JOBS WERE FILLED BY RESIDENTS WHO WOULD OTHERWISE LEAVE THE STATE THE COST WOULD BE LOWER IF THEIR LEAVING CREATED EXCESS CAPACITY IN THE PUBLIC CAPITAL STOCK
- ASSUME NON-GENERAL FUND REVENUES COVER NON-GENERAL FUND EXPENDITURES
THIS IS PRIMARILY FEDERAL FUNDS

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

STATE GOVERNMENT-RELATED EMPLOYMENT (Table 8)

The delivery of the state public services associated with the costs calculated in the previous table will require the hiring of additional state employees and the contracting of construction firms to build the required public facilities. We estimate state government employment to meet this demand to be 79 during the development phase of the project and 8 annually during production. Construction employment is 9 and 1, respectively.

This public sector employment will also generate jobs in the private sector through the multiplier effect as public employees spend their paychecks and as state government purchases the services of private firms and procures supplies from private firms. Using the Alaska Input-Output model, we calculate that these multiplier effects generate 35 private sector jobs during field development and 4 jobs annually during production.

These additional jobs will have a population impact, and the new population from this source will increase the demand for public services. We assume that the ratio of population to employment for calculating the population impact is the same as the population as a whole, and that the public service requirements of this new population is at a cost equal to the average for the entire population.

Using these assumptions we calculate that the 123 jobs associated with state service delivery (79 public and 44 private) during the development phase of the field generate a population increase of 229, which has its own public service requirement of \$1.1 million. The 13 jobs associated with state service delivery (8 public and 5 private) annually during production generate a population increase of 25, with a public service requirement of \$.12 million annually.

TABLE 8: MARGINAL FIELD ANALYSIS: STATE GOVERNMENT JOBS

	TOTAL DEVELOPMENT	ANNUAL PRODUCTION
STATE GOVERNMENT EXPENDITURES (MILLION \$) RELATED TO TABLE 6 POPULATION		
OPERATING	\$9.46	\$1.00
CAPITAL	\$1.83	\$0.19
DIRECT JOBS IN AK (MAN YEARS) (A)	90	10
STATE GOVERNMENT	79	8
CONSTRUCTION	11	1
JOBS HELD BY ALASKA RESIDENTS (B)	88	9
STATE GOVERNMENT	79	8
CONSTRUCTION	9	1
DIRECT PAYROLL IN ALASKA (MILLION \$) (C)	\$3.60	\$0.36
STATE GOVERNMENT	\$3.12	\$0.33
CONSTRUCTION	\$0.48	\$0.05
PAYROLL TO ALASKA RESIDENTS	\$3.53	\$0.37
STATE GOVERNMENT	\$3.12	\$0.33
CONSTRUCTION	\$0.41	\$0.04
ITEM: NON-RESIDENT PAYROLL SPENT IN AK (D)	\$0.01	\$0.00
INDIRECT AND INDUCED JOBS IN ALASKA (E)	35	4
TOTAL JOBS	125	14
TOTAL JOBS TO ALASKA RESIDENTS	123	13
INDIRECT & INDUCED PAYROLL (MILLION \$) (E)	\$0.78	\$0.08
TOTAL PAYROLL	\$4.38	\$0.46
TOTAL PAYROLL TO ALASKA RESIDENTS	\$4.31	\$0.46
POPULATION INDUCED BY THESE JOBS (F)	229	25
STATE EXPENDITURES REQUIRED FOR THIS POPULATION (G)	\$1.10	\$0.12
RELATED STATE EMPLOYMENT	9	1
(A) DIRECT EMPLOYMENT PER \$1 MILLION OF SPENDING	STATE OPERATIONS CONSTRUCTION	8.33 6
(B) RESIDENT SHARE OF EMPLOYMENT	STATE OPERATIONS CONSTRUCTION	100% 85%
(C) ANNUAL AVERAGE PAYROLL	STATE OPERATIONS NON REMOTE SITE CONSTRUCTION	539.6 544.0
(D) SHARE OF NON-RESIDENT PAYROLL SPENT IN ALASKA		20%
(E) FROM ALASKA INPUT-OUTPUT MODEL		
(F) POPULATION TO EMPLOYMENT RATIO SEE TABLE 9 NOTES	1.86	
(G) STATE EXPENDITURES PER CAPITA SEE TABLE 9 NOTES	\$4.800	
(H) EMPLOYMENT CALCULATED USING FACTOR FROM NOTE (A)		

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

ADDITIONAL MULTIPLIER EFFECTS: EMPLOYMENT, POPULATION, AND STATE GOVERNMENT COSTS (Table 9)

The method we have used to estimate the employment, population, and state government costs associated with marginal oil field development has captured most but not all of the effects. In this section we estimate the additional effects associated with three factors.

The first (Part A) recognizes the fact that the increase in state employment in response to oil field development and production population will itself produce a requirement for state employment because state government employees themselves are consumers of state government services. In fact, each round of employment generated by the economic multiplier produces an additional requirement for public services. The "third-round jobs" shown here are the public sector jobs necessary to provide services to the new population calculated in the previous table — 229 for development and 25 annually for production. Fourth- and subsequent-round jobs are those produced by the multiplier effect of these third-round jobs — most occurring in the private sector.

The second (Part B) recognizes the fact that the population increase will require additional local government activity. Since a large share of local government revenues come from state government transfers and the main local sources of local government revenues are the property and sales taxes, we have assumed that locally generated government revenues will increase proportional to the increase in population so that there will be no local deficit. There will be an employment effect, however.

We assume that the increase in local government activity is the same magnitude as the increase in state government employment. The "second-round" employment figures are similar to the state government employment figures from Table 8. Subsequent rounds reflect the multiplier effect of local government spending in the economy.

Finally, because of the economic multiplier, there is an "interaction effect" between state spending and local spending as the third effect (Part C). New state employees will require new local government services, and new local government employees will require new state government services. The "third-round" interactions effects are twice the third round from Part A.

The total of these effects is 175 additional jobs during development and 19 jobs annually during production added in the public and private sectors. This represents additional population of 327 and 35, respectively, and additional state expenditures of \$1.57 million during development and \$.017 million annually during production.

TABLE 9: MARGINAL FIELD ANALYSIS: ADDITIONAL JOBS & PUBLIC SPENDING

	TOTAL DEVELOPMENT	ANNUAL PRODUCTION
A. JOBS CREATED BY STATE PUBLIC SECTOR REQUIREMENTS OF NEW POPULATION GENERATED BY STATE SPENDING (TABLE 8)		
THIRD ROUND JOBS	9.17	1.00
FOURTH ROUND JOBS (A)	2.75	0.30
FIFTH ROUND JOBS	0.83	0.09
SIXTH ROUND JOBS	0.25	0.03
SEVENTH ROUND JOBS	0.07	0.01
TOTAL ADDITIONAL JOBS	13	1
TOTAL ADDITIONAL PAYROLL (B)	\$0.42	\$0.05
POPULATION (C)	24	3
STATE EXPENDITURES (D)	\$0.12	\$0.01
B. JOBS FROM THE PROVISION OF LOCAL GOVERNMENT SERVICES		
LOCAL GENERATED JOBS EQUAL TO TABLE 8	123.10	13.35
THIRD ROUND JOBS (SIMILAR TO PART A)	9.17	1.00
FOURTH ROUND JOBS	2.75	0.30
FIFTH ROUND JOBS	0.83	0.09
SIXTH ROUND JOBS	0.25	0.03
SEVENTH ROUND JOBS	0.07	0.01
TOTAL ADDITIONAL JOBS	136	15
TOTAL ADDITIONAL PAYROLL (B)	\$4.35	\$0.47
POPULATION (C)	254	28
STATE EXPENDITURES (D)	\$1.22	\$0.13
C. INTERACTION EFFECTS		
THIRD ROUND JOBS	18.35	1.99
FOURTH ROUND JOBS	5.50	0.60
FIFTH ROUND JOBS	1.65	0.18
SIXTH ROUND JOBS	0.50	0.05
SEVENTH ROUND JOBS	0.15	0.02
TOTAL ADDITIONAL JOBS	26	3
TOTAL ADDITIONAL PAYROLL (B)	\$0.83	\$0.09
POPULATION (C)	49	5
STATE EXPENDITURES (D)	\$0.23	\$0.03
SUM		
TOTAL ADDITIONAL JOBS	175	19
TOTAL ADDITIONAL PAYROLL	\$5.60	\$0.61
POPULATION	327	35
STATE EXPENDITURES	\$1.57	\$0.17
(A) ASSUME 0.3 ADDITIONAL JOBS CREATED IN EACH SUBSEQUENT ROUND OF THE MULTIPLIER EFFECT		
(B) AVERAGE ANNUAL PAYROLL (000\$) FROM ADOL	\$31.0	
(C) RATIO OF POPULATION TO EMPLOYMENT FROM TABLE 6	1.86	
(D) STATE EXPENDITURES PER CAPITA FROM ANALYSIS OF 1990 BUDGET--TABLE 12	\$4.800	

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

TOTAL EMPLOYMENT, POPULATION, AND PAYROLL IMPACTS (Table 10)

This table sums the employment, payroll, and population effects from earlier tables to produce the total economic effects of marginal field development and production.

Total resident employment attributable to the development of the marginal oil field from all sources is estimated to be 1,780. Of this total, 572 are directly associated with the establishment of the new field and represent jobs in the oil and construction sectors employed at the site; 201 jobs are associated with vendor sales to the oil and construction sectors. The remainder are elsewhere in the private and public sectors of the economy.

Total resident employment attributable to the annual production of the marginal oil field from all sources is estimated to be 190. Of this total, 60 are directly associated with on-site production. An additional 21 are associated with vendor sales to the oil sector. The remainder are elsewhere in the private and public sectors of the economy.

The total population increase from development is 3,319 and from annual production, 354. Since the development phase occurs over several years, the population increase in any year would be much less.

Total resident payroll is \$89 million for development and \$9.5 million annually for production. The average annual payroll is \$50 thousand, considerably above the average for all industries in the state.

TABLE 10: MARGINAL FIELD ANALYSIS: TOTAL JOBS IMPACT

	<u>TOTAL DEVELOPMENT</u>	<u>ANNUAL PRODUCTION</u>
OIL PATCH JOBS: TABLE 5		
DIRECT	572	60
VENDORS	201	21
INDIRECT AND INDUCED	709	76
TOTAL ALASKA RESIDENTS	1,482	157
NON-RESIDENTS	191	15
STATE SUPPORT OF OIL PATCH INDUCED POPULATION: TABLE 8		
STATE GOVERNMENT AND STATE FUNDED CONSTRUCTION	88	9
INDIRECT AND INDUCED	35	4
TOTAL ALASKA RESIDENTS	123	13
NON-RESIDENTS	2	0
OTHER JOBS: TABLE 9		
TOTAL ALASKA RESIDENTS	175	19
NON-RESIDENTS	0	0
TOTAL RESIDENT JOBS CREATED	1,780	190
NON-RESIDENTS	192	15
TOTAL POPULATION INCREASE	3,319	354
OIL PATCH JOBS	2,762	293
STATE SUPPORT	229	25
OTHER	327	35
TOTAL PAYROLL INCREASE (MILLION \$)	\$89.07	\$9.53
OIL PATCH JOBS	\$79.17	\$8.47
STATE SUPPORT	\$4.31	\$0.46
OTHER	\$5.60	\$0.61
AVERAGE PAYROLL (000\$)	\$50.03	\$50.26

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

POTENTIAL REVENUES FROM NEW PAYROLL TAX BASE (Table 11)

Alaska, unlike other states, has neither a statewide personal income tax nor a statewide sales tax for collecting a portion of the revenues required to pay for the state services provided to residents. The payroll generated by the marginal field development and production represents an increase in revenue-producing capacity for the state since it is an addition to the potential income and sales tax base.

In the average state, 4.8% of personal income is collected by the state in some combination of personal income tax and general sales tax. We can calculate the taxes which would be collected from the payroll generated by marginal oil development and production if this average tax rate were applied.

Potential tax collections during development would be \$4.87 million, of which \$.86 million would be from nonresidents. Potential tax collections annually during production would be \$.50 million, of which \$.06 million would be from nonresidents. Over the life of the field, the revenues from this source could be \$14.8 million.

TABLE 11: MARGINAL FIELD ANALYSIS: POTENTIAL REVENUES FROM NEW TAX

	TOTAL DEVELOPMENT	ANNUAL PRODUCTION	TOTAL PRODUCTION	SUM
TOTAL PAYROLL--TAX BASE--(MILLION \$)				
OIL RELATED EMPLOYMENT				
RESIDENT	\$79.17	\$8.47	\$169.40	\$248.56
NON-RESIDENT	\$19.06	\$1.51	\$30.15	\$49.22
PUBLIC EXPENDITURE RELATED				
RESIDENT	\$4.31	\$0.46	\$9.13	\$13.44
NON-RESIDENT	\$0.07	\$0.01	\$0.15	\$0.23
OTHER MULTIPLIER EFFECTS				
RESIDENT	\$5.60	\$0.61	\$12.15	\$17.75
NON-RESIDENT	\$0.00	\$0.00	\$0.00	\$0.00
TOTAL				
RESIDENT	\$89.07	\$9.53	\$190.67	\$279.75
NON-RESIDENT	\$19.13	\$1.52	\$30.31	\$49.44
POTENTIAL REVENUES (MILLION \$)	\$4.87	\$0.50	\$9.94	\$14.81
PERSONAL INCOME TAX	\$2.38	\$0.24	\$4.86	\$7.24
RESIDENT	\$1.96	\$0.21	\$4.19	\$6.15
NON-RESIDENT	\$0.42	\$0.03	\$0.67	\$1.09
STATE SALES TAX	\$2.49	\$0.25	\$5.08	\$7.57
RESIDENT	\$2.05	\$0.22	\$4.39	\$6.43
NON-RESIDENT	\$0.44	\$0.03	\$0.70	\$1.14

FOR THE US AS A WHOLE STATE PERSONAL INCOME TAXES AND STATE
GENERAL SALES TAXES COMPRISE 4.5% OF PERSONAL INCOME
SOURCE: SIGNIFICANT FEATURES OF FISCAL FEDERALISM. ADVISORY
COMMISSION ON INTERGOVERNMENTAL RELATIONS, SEPTEMBER 1992.
PAGE 168.

PERSONAL INCOME TAX RATE 2.20%

STATE SALES TAX RATE 2.30%

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

SUMMARY: STATE GOVERNMENT REVENUES AND COSTS (Table 12)

The total costs associated with providing state services in support of the marginal oil field are \$51.11 million. Of this total \$7.4 million is the estimated cost of management by state government. The larger portion is the cost of providing services to the population induced by the activity. These costs are estimated at \$13.96 million during the development of the field and \$1.49 million each year during the 20-year life of the field. These figures for population-required services include not only the oil and construction industry workers and their families, at a cost of \$13.3 million, but all the population induced in all sectors of the economy.

Variation in this estimate would result from different assumptions about the cost to state government per person and the total population induced by the change in employment. The employment level itself is largely set by the choice of development and production plan for the field. We have been conservative in our assumptions about the additional cost of government services for additional population by assuming that most of the cost of government varies with the size of the population. Furthermore, we have assumed that all new employment will result in additional population. This results in a high estimate of the requirement for additional government services.

In spite of this conservatism, the revenues generated by the marginal oil field exceed the costs to state government in all cases except the low price, low royalty, and low production case when they are equal.

Of the five sources of revenues, the royalties, potential personal taxes, and "full pipeline effect" contribute most of the revenues. The corporate income tax and state-wide property tax make only a small contribution to revenues. Personal taxes are independent of the level of production or price of oil since they are determined by the employment generated by development and production. The "full pipeline effect" depends most importantly on the total production from the marginal field. The royalties are the most sensitive source of revenue, depending importantly on the level of production, the wellhead price, and the royalty rate.

For all but the lowest level of production, price, and royalty rate, there is a state revenue "dividend" calculated as the difference between revenues collected and revenues needed to pay for new costs of government. The size of the dividend reaches \$300 million using assumptions of high production, high wellhead price, and high royalty rate.

TABLE 12: MARGINAL FIELD ANALYSIS: SUMMARY PUBLIC REVENUES AND EXPENDITURES

	TOTAL DEVELOPMENT	ANNUAL PRODUCTION	TOTAL PRODUCTION	SUM	CUMULATIVE TOTAL
STATE EXPENDITURE REQUIREMENTS FROM MARGINAL FIELD (MILLION \$)					
RESOURCE MANAGEMENT: 100 MILLION BARREL FIELD (A)			\$7.40	\$7.40	\$7.40
STATE SPENDING FOR NEW POPULATION					
OIL INDUSTRY	\$4.26	\$0.45	\$8.98	\$13.24	\$20.84
VENDORS	\$1.50	\$0.16	\$3.13	\$4.63	\$25.27
INDIRECT AND INDUCED RELATED TO OIL FIELD	\$5.53	\$0.59	\$11.85	\$17.38	\$42.65
RELATED TO PUBLIC SPENDING	\$2.67	\$0.29	\$5.79	\$8.47	\$51.11
TOTAL SPENDING FOR NEW POPULATION	\$13.96	\$1.49	\$20.78	\$43.71	
TOTAL STATE SPENDING					\$51.11
REVENUES PROVIDED (MILLION \$)					
STATE REVENUES FROM MARGINAL OIL PRODUCTION--ROYALTIES, INCOME & PROPERTY TAX					
RESERVES (MILLION BARRELS)	WELLHEAD	ROYALTY			
50	\$8.31	6%	\$1.47	\$29.40	\$29.40
100	\$8.31	6%	\$2.94	\$56.83	\$56.83
50	\$11.86	12%	\$3.78	\$75.60	\$75.60
150	\$8.31	6%	\$4.21	\$84.26	\$84.26
50	\$14.17	15%	\$5.54	\$110.76	\$110.76
100	\$11.86	12%	\$7.46	\$149.23	\$149.23
100	\$14.17	15%	\$10.98	\$219.55	\$219.55
150	\$11.86	12%	\$11.14	\$222.86	\$222.86
150	\$14.17	15%	\$16.42	\$326.35	\$326.35
STATE REVENUES FROM HIGHER WELLHEAD VALUE					
50			\$0.39	\$7.84	\$7.84
100			\$0.78	\$15.56	\$15.56
150			\$1.16	\$23.18	\$23.18
POTENTIAL REVENUES FROM INCOME AND SALES TAX	\$4.87	\$0.50	\$9.94	\$14.81	
TOTAL STATE REVENUES					
RESERVES (MILLION BARRELS)	WELLHEAD	ROYALTY			
50	\$8.31	6%	\$4.87	\$2.06	\$47.18
100	\$8.31	6%	\$4.87	\$4.12	\$82.33
50	\$11.86	12%	\$4.87	\$4.67	\$93.38
150	\$8.31	6%	\$4.87	\$5.87	\$117.38
50	\$14.17	15%	\$4.87	\$6.43	\$128.54
100	\$11.86	12%	\$4.87	\$8.74	\$174.74
100	\$14.17	15%	\$4.87	\$12.25	\$245.06
150	\$11.86	12%	\$4.87	\$12.80	\$255.99
150	\$14.17	15%	\$4.87	\$18.07	\$361.47
STATE REVENUE DIVIDEND--REVENUES MINUS EXPENDITURES					
RESERVES (MILLION BARRELS)	WELLHEAD	ROYALTY			
50	\$8.31	6%			\$0.94
100	\$8.31	6%			\$38.09
50	\$11.86	12%			\$47.14
150	\$8.31	6%			\$71.14
50	\$14.17	15%			\$82.30
100	\$11.86	12%			\$128.50
100	\$14.17	15%			\$198.82
150	\$11.86	12%			\$209.74
150	\$14.17	15%			\$315.23
(A) TOTAL EXPENDITURES FOR MANAGEMENT OF OIL AND GAS IN FY 1992					
			\$49.50 MILLION		
DEPT OF LAW			\$26.80		
NATURAL RESOURCES			\$7.90		
ENVIRONMENTAL CONSERVATION			\$5.70		
REVENUE			\$4.60		
FISH AND GAME			\$2.10		
GOVERNOR'S OFFICE			\$1.70		
LABOR & COMMUNITY AND REGIONAL AFFAIRS			\$0.70		
ANNUAL PRODUCTION (MILLION BARRELS)			689,045		
OIL AND GAS MANAGEMENT EXPENSE PER BARREL			\$0.07		
SOURCE: LEGISLATIVE RESEARCH AGENCY RESEARCH REQUEST 93-102 & ADOR SPRING 1995 REVENUE SOURCES					

MARGINAL OIL FIELD DEVELOPMENT: THE ECONOMIC IMPACT

STATE GOVERNMENT EXPENDITURE ANALYSIS (Table 13)

To estimate the per capita cost to state government of new population, we analyzed each item in the 1990 state operating budget and put each one into one of seven categories based on its characteristics. The first category is general expenditures serving the adult population of the state. The second category is the expenditures specifically to serve the educational needs of the school-aged population. The third is the services provided specifically to seniors (senior supplement). The fourth is expenditures specifically for the management of Alaska public resources. The fifth is for activities which are clearly not population sensitive such as operation and maintenance of the Governor's mansion. The sixth is the activities that are clearly targeting the rural population like the power cost equalization program. The seventh is those activities that are targeting the unemployed or underemployed such as job training programs.

The sum in each category was then divided by the population served to arrive at a per-client figure for the category of service. We assumed that the population under 5 required no public services independent of their parents. All adults require one unit of general adult services. In addition, some individuals require a supplement — for seniors, rural, or safety net.

The allocation to categories other than general adult was only done if it was clear that such an allocation was appropriate. Consequently, we have been conservative in estimating the cost of state government for an average adult, and a more detailed analysis would result in a lower figure since more programs would be moved into the special categories.

These figures are used in the analysis in Table 7.

TABLE 13: MARGINAL FIELD ANALYSIS: STATE PER CAPITA EXPENDITURES

	DISTRIBUTION OF ACTIVITIES							
	avg over pop	general adult 18+	school aged child	senior supplement	safety net supplement	rural supplement	resource management	pure public & misc
TOTAL \$	\$3,008,406	\$1,620,534	\$693,315	\$102,009	\$286,458	\$55,535	\$190,278	\$80,277
PERCENT OF TOTAL		53.87%	23.05%	3.39%	9.52%	1.85%	6.32%	2.00%
GENERAL FUND \$	\$2,192,101	\$1,133,320	\$618,402	\$92,799	\$141,070	\$38,520	\$126,980	\$41,010
PERCENT OF TOTAL		51.70%	28.21%	4.23%	6.44%	1.76%	5.79%	1.87%
TOTAL FTE EMPLOYMENT	18,131	15,042	146	545	545	62	1,621	171
PERCENT OF TOTAL		82.96%	0.80%	3.01%	3.00%	0.34%	8.94%	0.94%
POPULATION GROUP SERVE	553,600	380,609	118,008	22,459	55,360			
GENERAL FUND SPENDING PER PERSON SERVED (000\$)	\$3.96	\$2.98	\$5.24	\$4.13	\$2.55			

SOURCE: 1990 STATE OPERATING BUDGET ANALYSIS USING
STATE OF ALASKA BEARS SYSTEM.

**MARGINAL OIL FIELD DEVELOPMENT:
THE ECONOMIC IMPACT**

APPENDIX A. STATE GOVERNMENT PROGRAM ANALYSIS DETAIL

1990 ALASKA GENERAL FUND EXPENDITURES
SOURCE: STATE OF ALASKA BEARS SYSTEM

DISTRIBUTION OF ACTIVITIES

		general adult GF	child GF	senior GF	resource GF	pure public misc GF	rural GF	safety net GF
TOTAL \$	\$3 008 406	1 620 534	693 315	102 009	190 278	60 277	55 535	286 453
PERCENT OF TOTAL		53.87%	23.05%	3.39%	6.32%	2.00%	1.85%	9.52%
GENERAL FUND \$	\$2 192 101	\$1 133 320	\$618 402	\$92 799	\$126 980	\$41 010	\$38 520	\$141 070
PERCENT OF TOTAL		51.70%	28.21%	4.23%	5.79%	1.87%	1.76%	6.44%
TOTAL FTE EMPLOYMENT	18 131	15 042	146	545	1 621	171	62	545
PERCENT OF TOTAL		82.96%	0.80%	3.01%	8.94%	0.94%	0.34%	3.00%

COMPONENT SERIAL NUMBER	BRU NAME	COMPONENT NAME
Office of the Governor		
1	Commissions/Special Offices	Human Rights Commission
3	Commissions/Special Offices	Equal Employment Opportunity
5	Commissions/Special Offices	Alaska Womens Commission
6	Executive Operations	Executive Office
9	Executive Operations	Governor's House
10	Executive Operations	Contingency Fund
11	Executive Operations	Lieutenant Governor
13	Executive Operations	Office of International Trade
797	Executive Operations	Arctic National Wildlife Refuge
1173	Executive Operations	High Seas Salmon Interception
15	Office of Management & Budget	Policy
16	Office of Management & Budget	Budget Review
17	Office of Management & Budget	Division of Audit and Management Services
18	Office of Management & Budget	Governmental Coordination
21	Elective Operations	Elections
22	Elective Operations	General and Primary Elections
23	Elective Operations	Elections Data Processing
Department of Administration		
26	Longevity Bonus	Grants
27	Longevity Bonus	Administration
28	Pioneers Homes	Sitka
29	Pioneers Homes	Fairbanks
30	Pioneers Homes	Palmer
31	Pioneers Homes	Anchorage
32	Pioneers Homes	Ketchikan
33	Pioneers Homes	Juneau
34	Pioneers Homes	Central Office
35	Pioneers Homes	Pioneers Homes Advisory Board
36	Older Alaskans Commission	Older Alaskan Services
38	Public Defender	First Judicial District
39	Public Defender	Second Judicial District
40	Public Defender	Third Judicial District
41	Public Defender	Fourth Judicial District
42	Public Defender	Administration and Support
43	Office of Public Advocacy	Office of Public Advocacy
45	Office of the Commissioner	Office of the Commissioner
46	Administrative Services	Administrative Services
47	Administrative Services	Municipal Grants
55	CIP Direct Charge Positions	CIP Direct Charge Positions
56	Personnel	Personnel
57	Personnel	Productivity Improvement Center
58	Labor Relations	Labor Relations
59	Finance	Finance
60	General Services	Purchasing
61	General Services	Property Management
62	General Services	Central Duplicating and Mail
64	Retirement and Benefits	Retirement and Benefits
964	Retirement and Benefits	Elected Public Officers Retirement System Benefits
66	Labor Relations Agency	Labor Relations Agency
70	Alaska Public Offices Commission	Alaska Public Offices Commission
71	Risk Management	Risk Management
72	Information Services	Computer Services
74	Information Services	Telecommunications Services
75	Information Services	Rural Alaska Television Network
77	Public Broadcasting Commission	Public Broadcasting Commission
79	Leasing and Facilities	Administration
81	Leasing and Facilities	Leases
83	Retirement Incentive Program	Retirement Incentive Program
Department of Law		
84	Consumer Protection	Consumer Protection
85	Prosecution	First Judicial District
86	Prosecution	Second Judicial District
87	Prosecution	Third Judicial District
88	Prosecution	Fourth Judicial District
89	Prosecution	Criminal Justice Litigation
90	Prosecution	Criminal Appeals and Special Prosecution
91	Prosecution	Data and Word Processing

1990 ALASKA GENERAL FUND EXPENDITURES
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PERCENT OF TOTAL		82.96%	0.80%	3.01%	8.94%	0.94%	0.34%	3.00%

COMPONENT SERIAL NUMBER	BRU NAME	COMPONENT NAME
93	Legal Services	Operations
94	Legal Services	Antitrust
95	Legal Services	Administration and Support
97	Oil and Gas Special Projects	Oil and Gas Operations
98	Oil and Gas Special Projects	Data and Word Processing
99	Oil and Gas Litigation	Oil and Gas Litigation
1175	Exxon Valdez Litigation	Exxon Valdez Litigation
Department of Revenue		
111	Child Support Enforcement	Child Support Enforcement
100	Alcohol Beverage Control Board	Alcohol Beverage Control Board
103	Shared Taxes	Amusement and Gaming Tax
104	Shared Taxes	Aviation Fuel Tax
105	Shared Taxes	Electric and Telephone Cooperative Tax
106	Shared Taxes	Liquor License Tax
107	Shared Taxes	Fisheries Tax
108	Municipal Bond Bank Authority	Municipal Bond Bank Authority
109	Permanent Fund Corporation	Permanent Fund Corporation
110	Alaska Housing Finance Corporation	Alaska Housing Finance Corporation
1009	Science and Technology	Science and Technology
113	Revenue Operations	Income and Excise Audit
115	Revenue Operations	Oil and Gas Audit
121	Revenue Operations	Treasury Management
123	Administration and Support	Commissioner's Office
982	Administration and Support	Oil and Gas Tax Case Review
125	Administration and Support	Administrative Services
981	Permanent Fund Dividend	Permanent Fund Dividend
Department of Education		
141	K-12 Support	Foundation Program
145	K-12 Support	Student Lunch Program
146	K-12 Support	Cigarette Tax Distribution
147	K-12 Support	Tuition Students
148	K-12 Support	Boarding Home Grants
150	K-12 Support	Youth in Detention
151	K-12 Support	Schools for the Handicapped
144	K-12 Support	Pupil Transportation
153	School Debt Reimbursement	School Debt Reimbursement
155	Ed Finance & Support Services	District Support Services
156	Ed Finance & Support Services	CIP Overhead and Associated Costs
159	Data Management & Processing	Data Processing
1018	Data Management & Processing	Data Management
165	Education Program Support	Community Schools
166	Education Program Support	Special and Supplemental Services
171	Education Program Support	Basic Education and Instructional Improvement
172	Education Program Support	Correspondence Study-State
173	Education Program Support	Education Special Projects
1029	Education Program Support	Instructional Technology Support
1033	Education Program Support	Director's Office
177	Adult and Vocational Education	Adult Basic Education
178	Adult and Vocational Education	Employment Training Grants
179	Adult and Vocational Education	Federal Vocational Education Grants
180	Adult and Vocational Education	Adult and Vocational Education Administration
181	Adult and Vocational Education	Alaska Career Information System
182	Adult and Vocational Education	Rural School Vocational Education Program
183	Adult and Vocational Education	Vocational Education Special Projects
184	Retirement Incentive Program (RI)	Retirement Incentive Program
189	Executive Administration	Executive Administration
157	Executive Administration	Department Administrative Services
158	Executive Administration	Department Overhead Expenses
190	Commissions and Boards	Professional Teaching Practice
192	Commissions and Boards	Alaska State Council on the Arts
195	Kotzebue Technical Center	Kotzebue Technical Center Operations Grant
196	Alaska Vocational Technical Center	Alaska Vocational Technical Center Operations
198	MI Edgecumbe Boarding School	Instruction Program
199	MI Edgecumbe Boarding School	Residential Program
976	MI Edgecumbe Boarding School	Private and Federal Grants
200	Vocational Rehabilitation	Counseling and Placement
975	Vocational Rehabilitation	Federal Training Grant
201	Vocational Rehabilitation	Services to Clients

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COMPONENT SERIAL NUMBER	BRU NAME	COMPONENT NAME		
202	Vocational Rehabilitation	Vocational Rehabilitation Administration		
203	Vocational Rehabilitation	Independent Living Rehabilitation		
204	Vocational Rehabilitation	Specialized Facilities		
205	Vocational Rehabilitation	Services for the Blind and Deaf		
206	Vocational Rehabilitation	Disability Determination		
207	Vocational Rehabilitation	Supported Work		
208	Alaska State Library	Library Operations		
209	Alaska State Library	Blue Book	1	5
977	Alaska State Library	Archives		
210	Alaska State Museums	Museum Operations	1	5
211	Alaska State Museums	Specific Cultural Programs	1	5
212	Alaska Postsecondary Education	Program Administration		
213	Alaska Postsecondary Education	Student Loan Operations		
214	Alaska Postsecondary Education	Western Interstate Commission For Higher Education		
215	Alaska Postsecondary Education	Western Interstate Commission for Higher Education		
953	Alaska Postsecondary Education	WAMI Medical Education		
216	Student Financial Aid	Federal Student Aid		
954	Alaska Postsecondary Education	Governor's Council on Vocational and Career Educat		
217	Alaska Postsecondary Education	Data and Word Processing		
218	Student Loan Corporation	Student Loan Program		
Department of Health & Social Services				
220	Assistance Payments	Aid to Families with Dependent Children	1	7
222	Assistance Payments	Adult Public Assistance	1	7
221	Assistance Payments	General Relief Assistance	1	7
223	Assistance Payments	Old Age Assistance-Alaska Longevity Bonus (A	3	
224	Assistance Payments	Post Mortem Examinations		
225	Permanent Fund Dividend Hold H	Permanent Fund Dividend Hold Harmless	1	7
226	Energy Assistance Program	Energy Assistance Program	1	6
229	Medical Assistance	Medicaid Non-Facility	1	7
230	Medical Assistance	Medicaid-Facilities	1	7
960	Medical Assistance	Indian Health Service	1	6
966	Medical Assistance	Medicaid Permanent Fund Dividend Hold Harm	1	7
231	Medical Assistance	Alaska Longevity Bonus Hold Harmless	3	
232	Medical Assistance	General Relief Medical	1	7
967	Medical Assistance	Medicaid State Programs	1	7
233	Public Assistance Administration	Public Assistance Administration	1	7
234	Public Assistance Administration	Quality Control	1	7
236	Public Assistance Administration	Eligibility Determination	1	7
237	Public Assistance Administration	Fraud Investigation	1	7
238	Public Assistance Administration	Alaska Work Programs	1	7
240	Public Assistance Administration	Public Assistance Data Processing	1	7
241	Medical Rate Commission	Medical Rate Commission	1	5
242	Medical Assistance Administratio	Medical Assistance Central Administration	1	7
243	Medical Assistance Administratio	Claims Processing	1	7
244	Medical Assistance Administratio	Medical Care Advisory Committee	1	7
245	Medical Assistance Administratio	Certification and Licensing	1	7
248	Purchased Services	Preventive Services		
249	Purchased Services	Adult Services		
250	Purchased Services	Early Intervention Services		
252	Purchased Services	Foster Care		
253	Purchased Services	Residential Child Care		
254	Family Services	Southcentral Region		
255	Family Services	Northern Region		
256	Family Services	Northwestern Region		
257	Family Services	Western Region		
258	Family Services	Southeastern Region		
259	Family Services	Central Office, Family and Youth Services		
263	Social Services Block Grant Offse	Social Services Block Grant Offset		
264	Youth Services	McLaughlin Youth Center		
265	Youth Services	Fairbanks Youth Facility		
266	Youth Services	Nome Youth Facility		
267	Youth Services	Johnson Youth Center		
268	Youth Services	Bethel Youth Facility		
269	Youth Services	Probation Services		
270	Manilaq	Manilaq Eligibility Determination and Staff Dev	1	6
271	Manilaq	Manilaq Social Services	1	6
272	Manilaq	Manilaq Public Health Services	1	6
273	Manilaq	Manilaq Alcohol and Drug Abuse Services	1	6
274	Manilaq	Manilaq Mental Health/Developmental Disabilit	1	6

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COMPONENT SERIAL NUMBER	BRU NAME	COMPONENT NAME
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275	Manilaq	Manilaq Senior Center	1	6
276	Norton Sound	Norton Sound Social Services	1	6
277	Norton Sound	Norton Sound Public Health Services	1	6
278	Norton Sound	Norton Sound Alcohol and Drug Abuse Service	1	6
279	Norton Sound	Norton Sound Mental Health and Development	1	6
280	Norton Sound	Norton Sound Sanitation	1	6
1004	Southeast Alaska Regional Health	Southeast Alaska Regional Health Corporation	1	6
1005	Southeast Alaska Regional Health	Southeast Alaska Regional Health Corporation	1	6
281	Kawerak Social Services	Kawerak Social Services	1	6
282	Tanana Chiefs Conference	Tanana Chiefs Conference Public Health Serv	1	6
283	Tanana Chiefs Conference	Tanana Chiefs Conference Alcohol and Drug A	1	6
284	Tanana Chiefs Conference	Tanana Chiefs Conference Mental Health Servi	1	6
285	Tlingit-Haida Social Services	Tlingit-Haida Social Services	1	6
286	Anchorage Social Services Block	Anchorage Social Services Block Grant		
287	Fairbanks Social Services Block	Fairbanks Social Services Block Grant		
978	Yukon-Kuskokwim Health Corpor	Yukon-Kuskokwim Public Health Services	1	6
979	Yukon-Kuskokwim Health Corp	Yukon-Kuskokwim Alcohol/Drug Services	1	6
980	Yukon-Kuskokwim Health Corpor	Yukon-Kuskokwim Mental Health Services	1	6
288	State Health Services	Nursing		
1013	State Health Services	Women, Infants and Children		
290	State Health Services	Maternal, Child, and Family Health		
291	State Health Services	Laboratory Services		
292	State Health Services	Public Health Administrative Services		
296	State Health Services	Epidemiology		
297	State Health Services	Emergency Medical Services (EMS) Training and Lice		
952	State Health Services	AIDS Services		
961	State Health Services	Bureau of Vital Statistics		
298	Health Grants	Infant Learning Program Grants		
299	Health Grants	Community Health Grants		
300	Health Grants	Emergency Medical Services Grants		
301	Health Grants	Health Promotion		
302	Alcohol and Drug Abuse Services	Administration		
303	Alcohol and Drug Abuse Services	Drug Abuse Grants		
304	Alcohol and Drug Abuse Services	Alcohol Abuse Grants		
305	Alcohol and Drug Abuse Services	Alcohol Safety Action Program (ASAP)		
307	Community Mental Health Grants	Community Mental Health Grants		
800	Community Mental Health Grants	Services to the Chronically Mentally Ill		
1014	Community Mental Health Grants	Designated Evaluation and Treatment		
309	Community Developmental Disab	Community Developmental Disabilities Grants		
310	Institutions and Administration	Mental Health Administration		
311	Institutions and Administration	Alaska Psychiatric Institute		
313	Institutions and Administration	Harborview Development Center		
316	Institutions and Administration	Alaska Youth Initiative		
317	Administrative Services	Commissioner's Office		
318	Administrative Services	Audit		
319	Administrative Services	Personnel and Payroll		
320	Administrative Services	Budget and Finance		
321	Administrative Services	Governor's Council/Handicapped and Gifted	1	5
322	Administrative Services	Data and Word Processing		
323	Administrative Services	Planning and Development		
325	Administrative Services	Facilities/CIP Costs		
1189	Administrative Services	Office of Prevention		
951	Administrative Services	Alaska Mental Health Board	1	5
326	Retirement Incentive Program	Retirement Incentive Program		

Department of Labor

328	Employment Security	Employment Services		
329	Employment Security	Unemployment Insurance		
331	Employment Security	Alaska Work Programs	1	7
332	Employment Security	Youth Employment Services	1	7
333	Employment Security	Governor's Committee on Employment of People With		
334	Data Processing	Data Processing		
335	Administrative Services	Management Services		
336	Administrative Services	Labor Market Information	1	7
337	Administrative Services	Resident Hire		
340	Office of the Commissioner	Commissioner's Office		
343	Fishermen's Fund	Fishermen's Fund	1	4
344	Workers' Compensation	Workers' Compensation		
345	Labor Standards and Safety	Wage and Hour Administration		
346	Labor Standards and Safety	Mechanical Inspection		

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970	Labor Standards and Safety	Occupational Safety and Health
1006	Labor Standards and Safety	Employment Preference Enforcement

Department of Commerce & Economic Development

349	Measurement Standards	Operations						
351	Banking, Securities, and Corporat	Financial Institutions						
352	Banking, Securities, and Corporat	Corporations						
354	Insurance	Operations						
356	Occupational Licensing	Administration						
357	Occupational Licensing	Licensing Boards						
358	Occupational Licensing	Investigations						
1027	Commissioner/Administrative Ser	Commissioner's Office						
1028	Commissioner/Administrative Ser	Administrative Services						
364	Alaska Public Utilities Commissio	Operations			4			
368	Oil and Gas Conservation Commi	Operations	1		4			
370	Alaska Energy Authority	Administration						
371	Alaska Energy Authority	Plant Operation and Maintenance						
372	Alaska Energy Authority	CIP Positions						
373	Alaska Energy Authority	Power Cost Equalization Administration	1					
965	Alaska Energy Authority	Power Cost Equalization Grants	1				6	6
801	Business Development	Business Development						
383	Investments	Investments						
387	Fisheries Enhancement Tax Rece	Fisheries Enhancement Tax Receipts	1		4			
1017	Tourism	Tourism Development	1		4			
1026	Tourism	Alaska Tourism Marketing Council	1		4			
390	Alaska Industrial Development an	Operations						
391	Alaska Industrial Development an	Capital Improvement Position Costs						
393	Alaska Seafood Marketing Institut	Alaska Seafood Marketing Institute	1		4			
1003	Alaska Housing Market Council	Alaska Housing Market Council	1			5		
1182	Amateur Sports Authority	Amateur Sports Authority						

Department of Military & Veterans Affairs

407	Disaster Planning & Control	Emergency Management Assistance						
408	Disaster Planning & Control	State Emergency Management Programs						
410	Disaster Planning & Control	Federal Emergency Management Programs						
413	Disaster Planning & Control	Federal Community Assistance						
414	Alaska National Guard	Office of Adjutant General	1			5		
415	Alaska National Guard	Army Guard Facilities Maintenance	1			5		
416	Alaska National Guard	Air Guard Facilities Maintenance	1			5		
836	Alaska National Guard	State Active Duty	1			5		
419	Alaska National Guard Benefits	Alaska National Guard Benefits	1			5		
962	Alaska National Guard Benefits	Retention Benefits Formula	1			5		
420	Alaska National Guard Benefits	Retirement Benefits	1			5		
421	Veterans' Affairs	Veterans' Services						
963	Veterans Affairs	Death Gratuity						
422	Disaster Relief Fund	Disaster Relief Fund						

Department of Natural Resources

423	Management and Administration	Commissioner's Office						
424	Management and Administration	Administrative Services						
42C	Management and Administration	Grants						
427	Management and Administration	Information Resource Management						
802	Management and Administration	Recorder's Office/Uniform Commercial Code						
429	Management and Administration	Data Processing/Direct Charge CIP						
430	Management and Administration	Commissions						
431	Land and Water Management	Land and Water Management	1		4			
433	Land and Water Management	Survey/Direct Charge CIP	1		4			
435	Forest Management	Forest Management	1		4			
439	Petroleum Management	Petroleum Management	1		4			
442	Mining Management	Mining Management/Operations	1		4			
1031	Geological Management	Geological Management	1		4			
437	Statewide Fire Suppression Progr	Fire Suppression	1		4			
451	Parks & Recreation Management	Historic Resource Management						
452	Parks & Recreation Management	Parks Management						
454	Parks & Recreation Management	Parks/Direct Charge/Overhead CIP						
455	Agricultural Management	Agricultural Management	1		4			
456	Agricultural Management	Agriculture/Direct Charge CIP	1		4			

Department of Fish & Game

459	Commercial Fisheries	Commercial Fisheries	1		4			
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COMPONENT SERIAL NUMBER	BRU NAME	COMPONENT NAME
461	Commercial Fisheries	Special Projects
464	Sport Fisheries	Sport Fisheries
465	Sport Fish	Special Projects
467	F R E D	F R E D
468	F R E D	Special Projects
473	Wildlife Conservation	Wildlife Conservation
474	Wildlife Conservation	Special Projects
475	Wildlife Conservation	Capital Improvement Position Costs
477	Administration and Support	Office of the Commissioner
478	Administration and Support	Public Communications
479	Administration and Support	Administrative Services
481	Retirement Incentive Program	Retirement Incentive Program
482	Boards of Fisheries and Game	Boards Services
483	Subsistence	Subsistence
484	Subsistence	Special Projects
486	Habitat	Habitat
487	Habitat	Special Projects
471	Commercial Fisheries Entry Com	Program Administration
Department of Public Safety		
490	Fish and Wildlife Protection	Enforcement and Investigative Services Unit
491	Fish and Wildlife Protection	Director's Office
492	Fish and Wildlife Protection	Aircraft Section
493	Fish and Wildlife Protection	Marine Enforcement
494	Fire Prevention	Fire Prevention Operations
496	Fire Prevention	Fire Service Training
498	Highway Safety Planning Agency	Highway Safety Planning Operations
827	Highway Safety Planning Agency	Commercial Vehicle Safety
499	Highway Safety Planning Agency	Federal Grants
500	Motor Vehicles	Driver Services
501	Motor Vehicles	Vehicle Services
502	Motor Vehicles	Field Services
503	Motor Vehicles	Administration
799	Alaska State Troopers	Detachments
1001	Alaska State Troopers	Special Projects
830	Alaska State Troopers	Criminal Investigations Bureau
508	Alaska State Troopers	Director's Office
831	Alaska State Troopers	Judicial Services-Anchorage
512	Alaska State Troopers	Prisoner Transportation
513	Alaska State Troopers	Search and Rescue
515	Alaska State Troopers	Rural Trooper Housing
798	Alaska State Troopers	Narcotics Task Force
516	Village Public Safety Officer Progr	Contracts
517	Village Public Safety Officer Progr	Support
518	Village Public Safety Officer Progr	Administration
519	Alaska Police Standards Council	Alaska Police Standards Council
520	Violent Crimes Compensation Bo	Violent Crimes Compensation Board
521	Domestic Violence and Sexual As	Domestic Violence and Sexual Assault
522	DPS Statewide Support	Contract Jails
523	DPS Statewide Support	Commissioners Office
524	DPS Statewide Support	Training Academy
525	DPS Statewide Support	Administrative Services
526	DPS Statewide Support	Civil Air Patrol
527	DPS Statewide Support	Laboratory Services
528	DPS Statewide Support	Alaska Public Safety Information Network
837	DPS Statewide Support	Building Security and Maintenance
Department of Transportation/Public Facilities		
530	Office of the Commissioner	Commissioner's Office
532	DBE/External Equal Employment	Disadvantaged Business Enterprise and External Equ
972	DBE/External Equal Employment	Unbudgeted RSA's (EEO Payroll Suspense)
534	Statewide Internal Review	Statewide Internal Review
536	Internal Review	Unbudgeted RSA's Audit P R Suspense
537	Statewide Administrative Services	Administrative Services
957	Statewide Administrative Services	Statewide Leasing/Property Management
539	Statewide Administrative Services	State Equipment Fleet
540	Statewide Information Systems	Statewide Information Systems
542	State Plans Programs and Budge	Plans Programs and Budget
545	State Plans Programs and Budge	Unbudgeted RSA's (HPR Payroll Suspense)
543	State Plans Programs and Budge	Statewide Aviation Planning

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1217	State Plans, Programs and Budge	Aviation Planning Payroll Suspense RSA
546	Statewide Research	Statewide Research
974	Statewide Research	Unbudgeted RSA's (HPR Payroll Suspense)
547	Statewide Engineering and Opera	Engineering and Operations Standards
1216	Statewide Engineering and Opera	Engineering & Operations Payroll Suspense RSA
549	Statewide Engineering and Opera	CIP Program
553	Central Region Administrative Ser	Administrative Services
556	Central Region Administrative Ser	Leasing and Property Management
557	Central Region Planning	Central Region Planning
560	Central Region Planning	Unbudgeted RSA's
561	Central Region Design and Const	Engineering Management
1215	Central Region Design and Const	Engineering Management Payroll Suspense RSA
563	Central Region Design and Const	CIP Program
570	Northern Region Administrative S	Interior District Administrative Services
571	Northern Region Administrative S	Western District Administrative Services
572	Northern Region Administrative S	Southcentral District Administrative Services
573	Northern Region Administrative S	Data and Word Processing
577	Northern Region Administrative S	Airport Leasing and Property Management
578	Northern Region Planning	Northern Region Planning
580	Northern Region Planning	Unbudgeted RSA'S, HPR P R SUS
581	Northern Region Design and Con	Engineering Management
1218	Northern Region Design and Con	Engineering Management Payroll Suspense RSA
583	Northern Region Design and Con	CIP Program
594	Southeast Region Administrative	Southeast Region Administrative Services
597	Southeast Region Planning	Southeast Region Planning
973	Southeast Region Planning	Unbudgeted RSA's (Payroll Suspense)
599	Southeast Region Design and Co	Engineering Management
1219	Southeast Region Design and Co	Engineering Management Payroll Suspense RSA
601	Southeast Region Design and Co	CIP Program
607	International Airports	Director of International Airports
608	Anchorage International Airport	Field Maintenance
609	Anchorage International Airport	Building Maintenance
610	Anchorage International Airport	Security
611	Anchorage International Airport	Custodial
612	Anchorage International Airport	Equipment Maintenance
613	Anchorage International Airport	Administration
614	Anchorage International Airport	Data and Word Processing
615	Fairbanks International Airport	Field Maintenance
616	Fairbanks International Airport	Building Maintenance
617	Fairbanks International Airport	Security
618	Fairbanks International Airport	Custodial
619	Fairbanks International Airport	Administration
564	Central Region Maintenance and	Highways and Aviation
565	Central Region Maintenance and	Traffic Signal Management
566	Central Region Maintenance and	Facilities
567	Central Region Maintenance and	Administration
554	Central Region Maintenance and	State Equipment Fleet
584	Interior District Maintenance and	Highways and Aviation
585	Interior District Maintenance and	Facilities
833	Interior District Maintenance and	Dillon Highway and Aviation
834	Interior District Maintenance and	Dillon Facilities
586	Interior District Maintenance and	Administration
574	Interior District Maintenance and	State Equipment Fleet
587	Western District Maintenance and	Highways and Aviation
588	Western District Maintenance and	Facilities
589	Western District Maintenance and	Administration
575	Western District Maintenance and	State Equipment Fleet
590	Southcentral District Maintenance	Highways and Aviation
591	Southcentral District Maintenance	Facilities
592	Southcentral District Maintenance	Administration
576	Southcentral District Maintenance	State Equipment Fleet
603	Southeast Region Maintenance a	Highways and Aviation
604	Southeast Region Maintenance a	Facilities
605	Southeast Region Maintenance a	Administration
596	Southeast Region Maintenance a	State Equipment Fleet
621	Marine Management	Administration
625	Marine Management	Customer Services Management
623	Marine Engineering	Engineering Management
624	Marine Engineering	CIP Program
629	Marine Operations	Vessel Operations Management

1990 ALASKA GENERAL FUND EXPENDITURES
SOURCE: STATE OF ALASKA BEARS SYSTEM

DISTRIBUTION OF ACTIVITIES

		general adult GF	child GF	senior GF	resource GF	pure public misc GF	rural GF	safety net GF
TOTAL \$	\$1 008 406	1 620 534	693 315	102 009	190 278	60 277	55 535	286 458
PERCENT OF TOTAL		53.87%	23.05%	3.39%	6.32%	2.00%	1.85%	9.52%
GENERAL FUND \$	\$2 192 101	\$1 133 320	\$618 402	\$92 799	\$126 980	\$41 010	\$38 520	\$141 070
PERCENT OF TOTAL		51.70%	28.21%	4.23%	5.79%	1.87%	1.76%	6.44%
TOTAL FTE EMPLOYMENT	18 131	15 042	146	545	1 621	171	62	545
PERCENT OF TOTAL		82.96%	0.80%	3.01%	8.94%	0.94%	0.34%	3.00%

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COMPONENT SERIAL NUMBER	BRU NAME	COMPONENT NAME
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626	Marine Operations	Southeast Shore Operations
630	Marine Operations	Southeast Vessel Operations
627	Marine Operations	Southwest Shore Operations
631	Marine Operations	Southwest Vessel Operations
632	Retirement Incentive Program	Retirement Incentive Program

Department of Environmental Conservation

633	Administration	Office of the Commissioner
635	Administration	Administrative Services
637	Facility Construction and Operatio	Facility Construction and Operations
638	Facility Construction and Operatio	Village Safe Water and Construction Grants Program
639	Environmental Quality	Environmental Quality Director
643	Environmental Quality	Monitoring and Laboratory Support
1016	Environmental Quality	Environmental Quality Projects
646	Environmental Health	Environmental Health Director
647	Environmental Health	Animal Health and Dairy Industry
648	Environmental Health	Meat and Poultry Inspection
649	Environmental Health	Seafood Industry
650	Environmental Health	Sanitation
651	Environmental Health	Palmer Laboratory

Department of Community & Regional Affairs

683	Administration and Support	Office of the Commissioner	
684	Administration and Support	Administrative Services	
686	Administration and Support	Data and Word Processing	
671	Administration and Support	Designated Grants	
653	Senior Citizens/Disabled Veteran	Homeowners' Property Tax Exemption	1
654	Senior Citizens/Disabled Veteran	Renters' Equivalency Rebate	1
666	Community Assistance Grants	National Forest Receipts	
668	Community Assistance Grants	Organizational Grants	
689	Municipal Revenue Sharing	State Revenue Sharing	
690	Municipal Revenue Sharing	Municipal Assistance	
672	Local Government Assistance	Training and Development	
673	Local Government Assistance	State Assessor	
674	Local Government Assistance	Local Boundary Commission	
676	Local Government Assistance	Statewide Assistance	
680	Local Government Assistance	ANCSA Plan of Survey	
681	Local Government Assistance	Municipal Lands Trustee	
658	Child Assistance	Child Care	
659	Child Assistance	Head Start Grants	
660	Employment Training/Rural Devel	Training/Energy Field Offices	
661	Employment Training/Rural Devel	Youth Programs	
662	Employment Training/Rural Devel	Governor's Training Program	
663	Employment Training/Rural Devel	Worker Adjustment Assistance	1
1012	Employment Training/Rural Devel	State Employment and Training	1
1178	Statewide Service Delivery	Statewide Service Delivery	
677	Energy Programs	Energy Conservation	
678	Energy Programs	Weatherization CIP	
682	Community Development	Block Grants CIP	
667	Community Development	Rural Development Grants	
687	Housing Assistance	Housing Loan Administration	
688	Housing Assistance	Housing Construction Development	

Department of Corrections

694	Administration and Support	Commissioner's Office
695	Administration and Support	Parole Board
696	Administration and Support	Facility Capital Improvement Unit
697	Administration and Support	Administrative Services
698	Administration and Support	Data and Word Processing
700	Statewide Operations	Statewide Programs
1015	Statewide Operations	Classification and Transportation
701	Statewide Operations	Correctional Industries Administration
702	Statewide Operations	Correctional Industries Product Cost
703	Statewide Operations	Training Unit
704	Statewide Operations	Out-of-State Contractual
705	Statewide Operations	Major Medical
706	Statewide Operations	Northern Director's Office
707	Statewide Operations	Fairbanks Correctional Center
708	Statewide Operations	Anvil Mountain Correctional Center
709	Statewide Operations	Yukon-Kuskokwim Correctional Center

1990 ALASKA GENERAL FUND EXPENDITURES
SOURCE: STATE OF ALASKA BEARS SYSTEM

DISTRIBUTION OF ACTIVITIES

		general adult GF	child GF	senior GF	resource GF	pure public misc GF	rural GF	safety net GF
TOTAL \$	\$3,008,406	1,620,534	693,315	102,009	190,278	60,277	55,535	286,458
PERCENT OF TOTAL		53.87%	23.05%	3.39%	6.32%	2.00%	1.85%	9.52%
GENERAL FUND \$	\$2,192,101	\$1,133,320	\$618,402	\$92,799	\$126,980	\$41,010	\$38,520	\$141,070
PERCENT OF TOTAL		51.70%	28.21%	4.23%	5.79%	1.87%	1.76%	6.44%
TOTAL FTE EMPLOYMENT	18,131	15,042	146	545	1,621	171	62	545
PERCENT OF TOTAL		82.96%	0.80%	3.01%	8.94%	0.94%	0.34%	3.00%

COMPONENT SERIAL NUMBER	BRU NAME	COMPONENT NAME
710	Statewide Operations	Northern Region Probation
711	Statewide Operations	Southcentral Director's Office
712	Statewide Operations	Palmer Correctional Center
713	Statewide Operations	Matanuska-Susitna Correctional Center
714	Statewide Operations	Combined Hilland Mountain Correctional Center
716	Statewide Operations	Cook Inlet Correctional Center
718	Statewide Operations	Anchorage Annex Correctional Center
720	Statewide Operations	Wildwood Correctional Center
722	Statewide Operations	Spring Creek Correctional Center
723	Statewide Operations	Southcentral Region Probation
724	Statewide Operations	Southeast Director's Office
725	Statewide Operations	Lemon Creek Correctional Center
726	Statewide Operations	Ketchikan Correctional Center
727	Statewide Operations	Southeast Region Probation
University of Alaska		
730	Statewide Programs and Services	Statewide Services
734	Statewide Programs and Services	Statewide Networks
732	Statewide Programs and Services	Statewide CIP Overhead Positions and Costs
1002	Statewide Vocational Technical P	Statewide Vocational Technical Programs
753	University of Alaska Anchorage	UAA/Anchorage Campus
756	University of Alaska Anchorage	UAA/Kenai College
757	University of Alaska Anchorage	UAA/Kodiak College
758	University of Alaska Anchorage	UAA/Matanuska-Susitna College
759	University of Alaska Anchorage	Prince William Sound Community College
761	University of Alaska Anchorage	UAA/Alaska Center For International Business
794	University of Alaska Anchorage	UAA/Organized Research
821	University of Alaska Anchorage	UAA/Mining and Petroleum Training Service
741	University of Alaska Fairbanks	UAF/Fairbanks Campus
956	University of Alaska Fairbanks	UAF/Rural College
751	University of Alaska Fairbanks	School of Fisheries and Ocean Science
750	University of Alaska Fairbanks	Fairbanks Organized Research
745	University of Alaska Fairbanks	UAF/Cooperative Extension Service
744	University of Alaska Fairbanks	UAF/Rural College/Chukchi Campus
746	University of Alaska Fairbanks	UAF/Rural College/Kuskokwim Campus
747	University of Alaska Fairbanks	UAF/Rural College/Northwest Campus
762	University of Alaska Southeast	UAS/Juneau Campus
764	University of Alaska Southeast	UAS/Sitka Campus
765	University of Alaska Southeast	UAS/Ketchikan Campus
Alaska Court System		
767	Alaska Court System	Appellate Courts
768	Alaska Court System	Trial Courts
769	Alaska Court System	Administration and Support
770	Commission on Judicial Conduct	Commission on Judicial Conduct
771	Judicial Council	Judicial Council
Legislature		
773	Budget and Audit Committee	Legislative Audit
774	Budget and Audit Committee	Legislative Finance
775	Budget and Audit Committee	Committee Expenses
776	Legislative Council	Salaries and Allowances
778	Legislative Council	Executive Administration
779	Legislative Council	Public Services
780	Legislative Council	Administrative Services
781	Legislative Council	Legal Services
782	Legislative Council	Session Expenses
783	Legislative Council	Council and Subcommittees
784	Legislative Council	Office Space Rental
1174	Legislative Council	Legislative Research Agency
796	Legislative Operating Budget	Legislative Operating Budget
790	Ombudsman	Ombudsman
Debt Service & Misc Programs		
792	Debt Service	General Obligation
793	Debt Service	International Airports
950	Debt Service	State Lease-Purchase Facilities

ARCO Alaska, Inc
Testimony
Re: HB-325

Mr. Chairman, for the record, my name is George Findling. I am the Manager of Government Relations for ARCO Alaska, Incorporated. I have resided in Alaska for over 11 years.

Thank you for the opportunity to testify HB-325. To summarize, while the provisions of HB-235 would create significant value in a West Sak development effort and while there is real merit for Alaska to incentivize heavy oil development, we can not say at this time that the provisions of HB-325 will create enough value to move the West Sak accumulation from unattractive to attractive for development. Let me elaborate with a background on ARCO's view for removing disincentives and our development status for West Sak, the heavy oil accumulation which lies above the Kuparuk horizon.

You may recall that last year ARCO testified that modifications to unrealized state revenues from oil should be used to stimulate investment and development that is not otherwise competitive under current conditions. As an another guideline, we also have strongly believed that because of the impending fiscal crisis, the rules for current revenue sources should not be changed: we believe that existing revenue sources should not be impacted. As a slight caveat, we have seen the benefits of tax credits for exploration drilling in other oil provinces and could see value in similar, modest programs in Alaska even though they would draw upon currently available general funds.

Turning back to heavy oil developments, such as West Sak, royalty is the primary potential state revenue stream which can be used to stimulate investment. This is because: 1) severance tax receipts will be essentially zero because of low well rates; 2) there are few, new, additional facilities which will increase ad valorem tax base; and 3) state income tax is not levied at the field level.

ARCO is working to bring West Sak oil into production. In the mid-1980's, our field work demonstrated a technique that could be used to complete wells and produce oil at modest rates. Despite these advances, the West Sak accumulation is currently not competitive for investment dollars when compared to other world wide opportunities. Numerous, closely spaced wells and lack of facility capacity make capital costs relatively high.

Low well rates, high operating costs and uncertain overall recovery rates raise the ongoing cost structure of the bulk of West Sak to unacceptably high levels.

Since the West Sak reservoir quality, indicated mainly by seam thickness, varies over the field, we would expect to develop first in the best areas, then move to the lesser areas of reservoir quality. In this scenario, you can imagine that production slowly builds up over time as the field development expands to new areas and cost reduction techniques are refined. Now, remember, the "best" West Sak is not as good in terms of current cost structure as the "worst" Kuparuk. So one key to West Sak is to make its cost structure effective enough to compete for facility usage against Kuparuk and other resources.

ARCO is trying to find ways to reduce this cost structure and make a significant amount of West Sak competitive. We are currently doing a strategic and technical "rethink" which we hope will lead to new, and innovative development approaches. In essence, we hope that a limited field program in 1996 and 1997 will be the first step in a phased commercialization which will include incremental improvements in technology and operating costs. The details of a program are not yet developed, but I can say that we will be trying to find ways to reduce our cost structure substantially at each step so that development can proceed to the next step.

Our current view is that we need to work through at least the 1996 cost reduction program to specifically know when royalty modifications will be needed to make the then next phase of development attractive for investment.

Our generic analyses to date show that royalty reductions can provide major improvements in the economics of a marginal heavy oil field. However, again, these improvements are making a negative situation only look less negative.

To summarize, whether some type of royalty reduction is sufficient to make the then next phase of the West Sak field attractive for investment is problematic at this time; but it will likely be better quantified after our 1996 cost reduction program.

Mr. Chairman, thank you for the opportunity to testify and I would be happy to take your questions.

***An Opportunity to Develop
Alaska's Heavy Oil Resources...***

**BP Exploration (Alaska) Inc.
OXY USA Inc.**

January 22, 1996

An Opportunity to Develop Alaska's Heavy Oil Resources...

I. Summary

Underlying the Milne Point and Kuparuk River units on Alaska's North Slope is a series of shallow, heavy oil sands that form the largest proven, undeveloped oil field in the United States. If development of those sands were economic, a billion or more barrels of oil could be recovered.

Beneath the Milne Point Unit alone, in the Schrader Bluff Formation, there are about 300 million barrels of recoverable heavy oil.^{1/} Initial development of that resource would entail drilling some 230 wells over a nine-year, labor-intensive development period, with peak production reaching at least 45,000 barrels per day. According to the University of Alaska, that activity would spawn:

- ◇ Capital development expenditures of \$550 million, of which 61%, or about \$333 million, would be spent in Alaska;

^{1/} See Bidinger and Dillon, *Milne Point Schrader Bluff: Finding the Keys to Two Billion Barrels*, SPE 30289 (available through BP Exploration (Alaska) Inc.). The Schrader Bluff sands, in relation both to other heavy oil sands at Milne Point and the West Sak Sands at the Kuparuk River Unit, are depicted in Chart 1.

Shallow Oil Sands Nomenclature

AGE	TYPE LOG MILNE POINT UNIT	TERMINOLOGY		
		Informal Milne Point Unit	Informal Kuparuk Unit	Formal North Slope GPI FORMATION
TERTIARY		K Sands	UPPER	SAGAVAN- IRKTOK
		L Sands	UGNU SANDS	
		M Sands	LOWER	PRINCE CREEK
		N Sands		SCHRADER BLUFF
CRETACEOUS		O Sands	WEST SAK SANDS	

Chart 1

- ◇ *Production expenditures of \$601 million spread over a 41-year field life, of which 85%, or about \$511 million, would be spent in Alaska;*
- ◇ *Around 360 new high-paying jobs during the development phase, and 134 new high-paying jobs during the 41-year production phase. 75-80% of those jobs would be filled by Alaska residents, resulting in additional Alaska resident payroll of \$171 million throughout the development phase, and \$7.4 million annually during the production phase; and*
- ◇ *65 new public sector jobs created during the development stage as a result of this increased economic activity, and 25 new public sector jobs created during the 41-year production phase.*^{2/}

And that, UAA projects, would flow solely from initial development of Schrader Bluff alone. All tolled, there are nearly 26 billion barrels of heavy oil underlying existing North Slope units--making ANS heavy oil a resource comparable to Prudhoe Bay. Successful initial development of Schrader Bluff could well result in technology transfers to other heavy oil lessees, and development of additional heavy oil deposits on the North Slope.

For the time being, however, and save for some minimal production from a Schrader Bluff pilot project, Alaska's heavy oil resources aren't being developed. Heavy oil is a thick and uncooperative substance, and its production poses a challenge to industry and governments worldwide.^{3/} For its part, Alaska's oil industry has

^{2/} University of Alaska Anchorage, School of Public Affairs and Institute of Social and Economic Research, *"Heavy Oil Development: The Economic Impact,"* December, 1995.

^{3/} Because heavy oil fields are "less attractive," Arthur D. Little recently told the Governor's Oil & Gas Policy Council, "changes in [government] fiscal terms may be necessary." Arthur D. Little/John Gault, *"Review of International Competitiveness of Alaska's Fiscal System,"* Preliminary Report for the State of Alaska, Department of Revenue, September, 1995 (*"Little Report"*) at 138. Guatemala, for example, imposes a lower royalty on heavier oil, according to a sliding scale based on the oil's viscosity. Ecuador does the same thing. *Id.* at 139-40. The U.S.

invested nearly \$270 million in the past decade tackling the technical barriers to lifting heavy oil from the cold, unconsolidated sands of the North Slope.

From an engineer's viewpoint, that pioneer effort succeeded. Complex and innovative completion technology was developed that can pull heavy oil from those sands at a sustained rate. But from an investor's eye, the pilot projects remain unconvincing. Initial flow rates from Schrader Bluff heavy oil wells have averaged only 275 barrels per day--far below the economic margin in this hostile working environment. ^{4/}

As a result, additional Schrader Bluff development is not expected to yield the minimal rate of return necessary to justify the requisite capital investment. Indeed, over the past several years, and through the Spring of 1995, the state itself has largely written the resource off--at least for the foreseeable future. The Alaska Department of Natural Resources' March, 1995 oil production forecasts, for example, concluded that Milne Point would produce no more heavy oil over the next 20 years than that currently lifted from the unit's small pilot project. ^{5/}

Department of Interior, Bureau of Land Management, has also proposed reduced royalties for heavy oil production, again on a sliding scale basis. 60 *Federal Register* 18081 (April 10, 1995).

^{4/} By comparison, initial production rates from individual Prudhoe Bay wells reached 25,000 bbls./day. Even initial production of lighter oil from Milne Point's Kuparuk formation--which observers uniformly acknowledge to be at the ANS margin--averaged 862 bbl./day.

^{5/} DNR, *Historical and Projected Oil and Gas Consumption*, March, 1995 at 6-7. The same conclusion was reached in the Spring, 1995 Department of Revenue ("DOR") forecasts. DOR, *Revenue Sources Book*, Spring, 1995 at Table 24 (base case).

The Fall, 1995 DOR forecasts use a different approach for predicting future revenues from undeveloped ANS resources. Those Fall, 1995 forecasts include considerably more near-term production from a variety of speculative projects such as North Star, Schrader Bluff, Mikkelson Bay and Colville River Delta than did the Spring, 1995 DOR projections, although even here Schrader Bluff production isn't projected to peak, at 45,000 bbls./day, until 2005. *Revenue Sources*, Fall, 1995, Table 22. The forecasts' Schrader Bluff figures begin with the unit's business plan projections for Schrader Bluff development discussed in Section III(A), *post*, then risk-discount those projections by about 25%. (cont'd)

That discouraging forecast, however, needn't necessarily be, and this paper proposes a special royalty structure for new ANS heavy oil development that may materially change project economics. The proposal was developed in response to the invitation extended to Alaska's private sector by Governor Knowles and his Oil & Gas Policy Council to explore new partnerships to guide Alaska's economy into the 21st century.

The proposal, embodied in HB 325, would suspend royalties for the first five years of production from any new ANS heavy oil well drilled after June 30, 1996. When the suspension ended, royalties would return to the full lease rate.^{6/} The suspension would apply only to the first 500 bbls./day of production from each well.

The Fall forecasts' methodology reflects the assumption that some development from various problematic ANS resources will likely occur, and that by spreading that *regional* prognosis over several prospects on a risk-discounted basis, the forecasts can paint a rough picture of plausible future production from the region as a whole without staking that projection on the fate of any one particular field. *Id.*, see p. 19. Indeed, the forecasts do not purport to conclude that development of any single marginal prospect will or will not be economic.

Inclusion of Schrader Bluff in that mix of regional possibilities is encouraging, since it seemingly reflects a growing recognition that, with an improved economic environment, ANS heavy oil is a potentially developable resource. That recognition, in part, may be attributable to the considerable attention that heavy oil received in the Summer of 1995, both before the Oil & Gas Policy Council and the legislature.

On the other hand, nothing occurred between the Spring and Fall of 1995 to warrant an about-face in the state's longstanding belief that, *under the fiscal status quo*, ANS heavy oil development will likely not happen in the foreseeable future. No technological or production breakthroughs occurred between the Spring and Fall forecasts, and the Fall, 1995 DOR projections' "long range price forecast is almost identical to last spring's." *Revenue Sources*, Fall, 1995, cover letter at 1.

For all these reasons, the Fall, 1995 DOR forecasts shouldn't be viewed as heralding any reversal in the state's outlook for Schrader Bluff development in the absence of some change in the fiscal environment.

^{6/} At Milne Point, for example, BP Exploration (Alaska) Inc., which owns 91.19% of Milne Point, would pay 12.5% on production assigned to some leases, and 20% on production assigned to others. OXY USA Inc., which owns the remaining 8.81% of the unit, would pay 12.5% on its share of production.

Any partnership should benefit each partner equally, and this proposal was tailored to accomplish that goal. For example:

From the state's perspective:

- ◇ *Given the unusually long life of heavy oil fields--in Schrader Bluff's case, an estimated 41 years--the state benefits more from incentives granted only for a finite period at the outset of production, rather than from more gradual incentives granted over the life of the field;*
- ◇ *The cost of administering the incentive is negligible;*
- ◇ *Suspensions have proven to be an effective tool in other oil producing jurisdictions to spur development of marginal fields. The state would be treading on proven ground;*
- ◇ *Only new heavy oil wells would benefit from the incentive, and for years now the state has assumed that no new heavy oil development will occur in the foreseeable future. As a result, the revenues contemplated by the state's various royalty agreements would be unimpaired;*
- ◇ *The short period of the incentive minimizes the state's exposure to unanticipated oil price increases or technological breakthroughs that might make heavy oil development more profitable. The state's window of exposure would be five years for each well, rather than over a 41-year field life; and*
- ◇ *By fashioning a specific incentive targeted to a single important resource, the state needn't re-invent overall state royalty policy or risk unintended consequences elsewhere.*

Conversely, from the investor's perspective:

- ◇ *The incentive is targeted at the initial years of production, and is therefore especially effective in allowing recovery of the lessee's capital investment in a reasonable period of time;*
- ◇ *The incentive would be available immediately;*
- ◇ *Because the incentive is granted by operation of law, its availability is certain, and serious investment decisions can be made in reliance on it; and*

- ◇ *Available economic and technical information suggests that this incentive will, in fact, materially improve the attractiveness of investing in ANS heavy oil development.*

Alaska's heavy oil reserves are an important public asset, and there are no risk-free options for managing it. One possibility, of course, is to wait things out, hoping for some unexpected, sustained oil price increase, or some technological advance, that would make heavy oil development attractive without any incentives. However:

- ◇ *As Arthur D. Little recently warned the Oil & Gas Policy Council, a "wait and see" strategy runs its own risks, since at some point the Trans Alaska Pipeline will no longer be available at a reasonable per-barrel tariff, if at all;*
- ◇ *In the case of ANS heavy oil, that risk is compounded by the fact that, even with incentives, heavy oil development may be economic only because it can share an existing infrastructure at Milne Point and Kuparuk River. In this respect, DNR's February, 1994 production forecasts predicted that Milne Point would be abandoned in 2006, while that agency's 1995 projections pegged the unit's abandonment date at 2011; ^{7/} and*
- ◇ *History has proven that progress in tackling the challenge of ANS heavy oil development is very much a child of momentum. Discouraging results have, time and again, led to years of inactivity as interest inevitably turns to more cooperative resources. See Section II(D), post. Putting ANS heavy oil on the public back burner may leave it there far longer than decision-makers intended.*

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^{7/} DNR, *Historical and Projected Oil and Gas Consumption*, February, 1994 at 6-7; March, 1995 at 6-7.

It's time to make a decision about Alaska's heavy oil. Even if the ultimate choice is to wait and see, the debate initiated by Governor Knowles will at least assure that the decision is purposeful.

The issue raised by this paper is how to optimize the public's return on a significant asset. It is not about trading jobs for royalties. As this paper will explain, and as Chart 2 illustrates, the underlying

Two Paths for Schrader Bluff

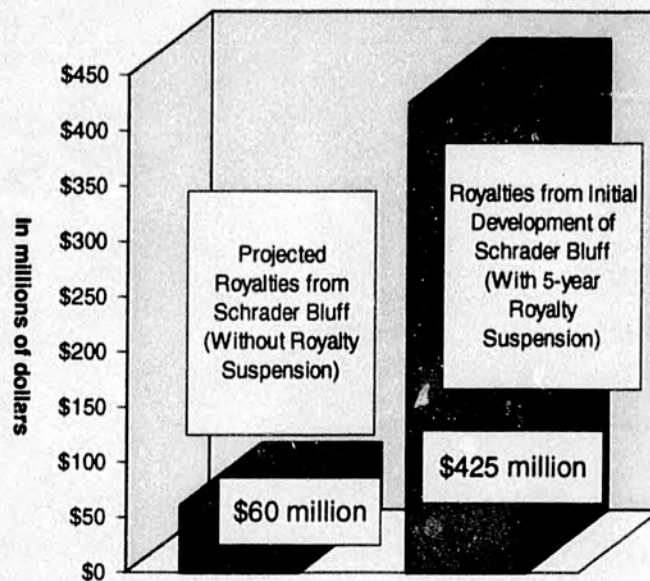


Chart 2. ^{8/}

premise of this proposal is that the state will receive more royalties from heavy oil development by adopting the incentive than by maintaining the *status quo*. Indeed, if the state's policy-makers conclude otherwise, there is little sense doing what this paper proposes.

^{8/} Source: Applicable royalty rates were applied to: (1) DNR's Spring, 1995 production forecasts for Schrader Bluff, discussed *ante*; then to (2) lessee projections of likely future production from initial Schrader Bluff development. Projected oil prices were taken from the Alaska Department of Revenue's Spring, 1995 *Revenue Sources Book's* base case. Dollars expressed are nominal.

Every management option available to the state carries its own mix of risk and potential reward. We believe that a careful balancing of those options will lead decision-makers to look carefully at the kind of tailored incentive contained in HB 325.

////////////////////

II. Background: Milne Point and Heavy Oil

A. An Overview of the Milne Point Unit.

The Milne Point Unit lies 12 miles west of Prudhoe Bay. *Chart 3.*

The unit was developed in the 1980's by Conoco Inc., Chevron and OXY USA Inc. ("OXY"). In late

1993, Conoco and Chevron sold their interest in the unit to BP Exploration (Alaska) Inc. ("BP"), and today 91.19% of the unit is owned by BP, and the remaining 8.81% by

Production Formations at Milne Point

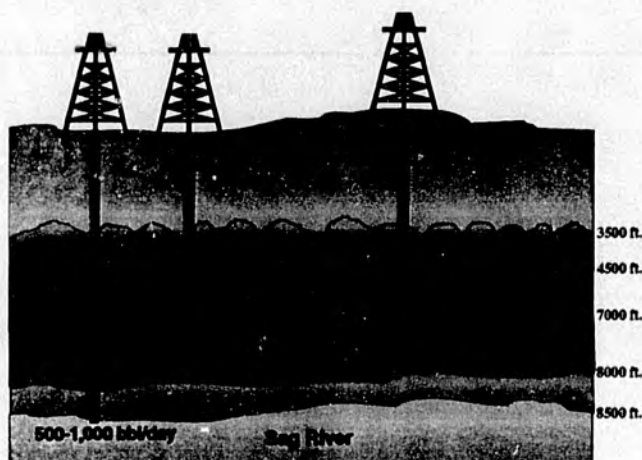
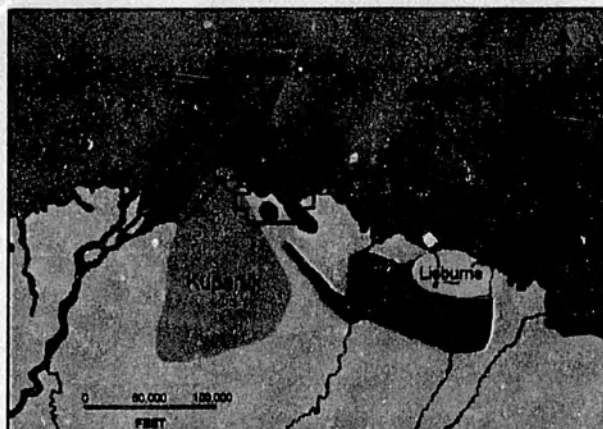


Chart 4

With an American Petroleum Institute ("API") gravity of 22-24 degrees, Kuparuk oil's quality is slightly heavier than other principal ANS crudes;



North Slope Fields and Milne Unit Outline

Chart 3

OXY.

Milne Point produces 28,000 barrels of oil daily from three formations (*Chart 4*):

Kuparuk (24,000 bbl./day).

Kuparuk production has been the unit's mainstay since production commenced in November, 1985.

Sag River (500-1000 bbls./day). In 1995, an initial long, horizontal well was drilled into this deepest of Milne Point formations. The well has produced only 500-1000 bbl./day because of the extraordinary amount of water produced from the formation. The API gravity of Sag River oil is about 35 degrees; and

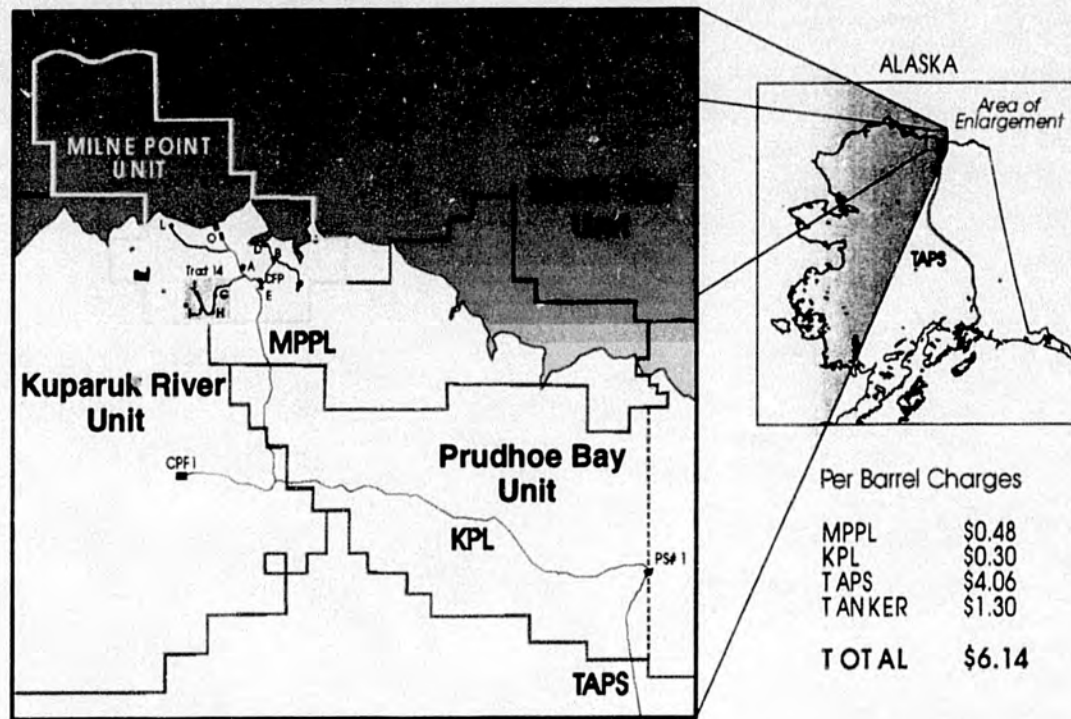
Schrader Bluff (3,000 bbl./day). Current production from this formation's heavy oil reserves comes from a pilot project initiated in 1990. The API gravity of Schrader Bluff oil ranges from 14-20 degrees. The companies' efforts to overcome the roadblocks to development of this resource are discussed in subsection (D), *post*.

B. The Unit's Economic Setting.

In-and-of itself, development of Schrader Bluff's heavy oil is a marginal proposition. Compounding the challenge is the fact that the unit from which that oil would be produced has been plagued by economic difficulties since its inception, including:

- Ø ***Low Production Rates.*** When Prudhoe Bay began production, its wells yielded up to 25,000 bbls./day. Initial rates from Milne Point's most productive formation--the Kuparuk--averaged only 862 bbl./day, and daily well production has declined at an annual rate of 15-20% ever since. Milne Point, in fact, has the lowest per well production rates of any major unit on the North Slope;
- Ø ***High Royalties.*** Because of a special royalty surcharge imposed on eight Milne Point leases at the time of unit formation (see Appendix A), BP pays a 20% royalty on its 91.19% interest in those eight leases. Virtually all other ANS production, including OXY's share of Milne Point production, is subject to a 12.5% royalty;
- Ø ***High Transportation Costs.*** As Chart 5 illustrates, Milne Point oil must travel through three pipelines to reach tidewater at Valdez, and resultantly pays the highest

Getting Heavy Oil to Market is Expensive



A-96
Chart 5

transportation costs on the North Slope. BP shares in those pipelines revenues; however, and except for an 8.81% interest in the Milne Point pipeline, OXY does not. Any income that OXY earns from its North Slope endeavors must come from Milne Point wellhead revenues; and

*Ø **Production Challenges.** Even Kuparuk Formation production has required costly waterflooding from the outset of production.*

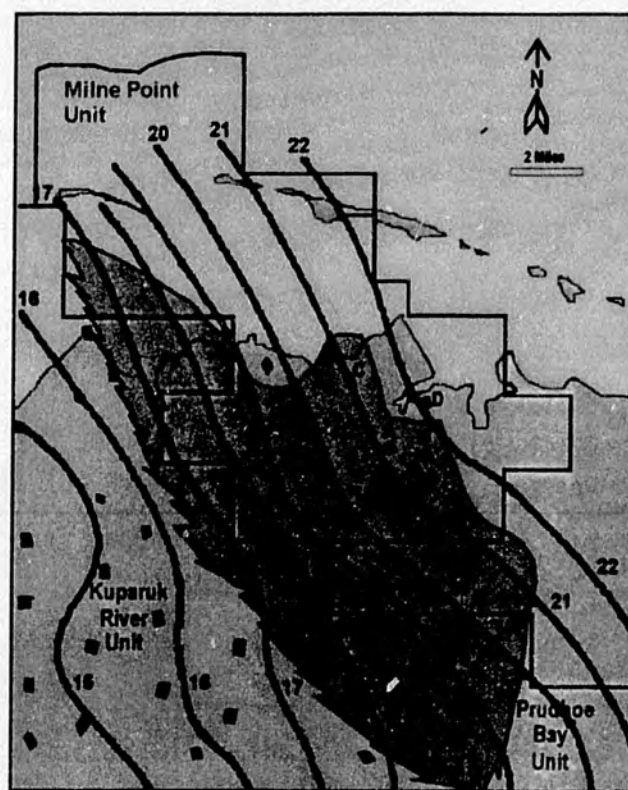
It is within this economic environment that BP and OXY have faced the challenge of developing the unit's heavy oil resources.

C. The Difficulties of Producing Heavy Oil.

The thickness, or viscosity, of crude oil is related to its gravity--the lower the gravity number, the heavier and thicker the oil. Outside of Milne Point, Alaska's currently-produced crudes range from 22-30 degrees at Prudhoe Bay to 25-35 degrees at Cook Inlet.

"Heavy oil" is generally defined as crude oil with an API gravity of 20 degrees or less.⁹ / As Chart 6 shows, the North Slope's heavy oil resources range from less than 14 degrees in the Kuparuk River Unit to 20 degrees in the southeast corner of the Milne Point Unit.

Thick as it is, heavy oil stubbornly resists lifting, and both downhole stimulation and mechanical lifting techniques are invariably needed to bring the oil to the surface. Compounding the problem on the North Slope is



SCHRADER BLUFF
O Sand
API Gravities

Chart 6

⁹/ For example, the Internal Revenue Code allows companies to claim a favorable percentage depletion allowance for "heavy oil" production, which the code defines to include oil with an API gravity of 20 degrees or less. 26 U.S.C. §613A(c)(6)(F). And, the U.S. Department of Interior, Bureau of Land Management, employs a 20-degree threshold for its pending heavy oil royalty relief proposal. 60 *Federal Register* 31663 (June 16, 1995).

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.*

^{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

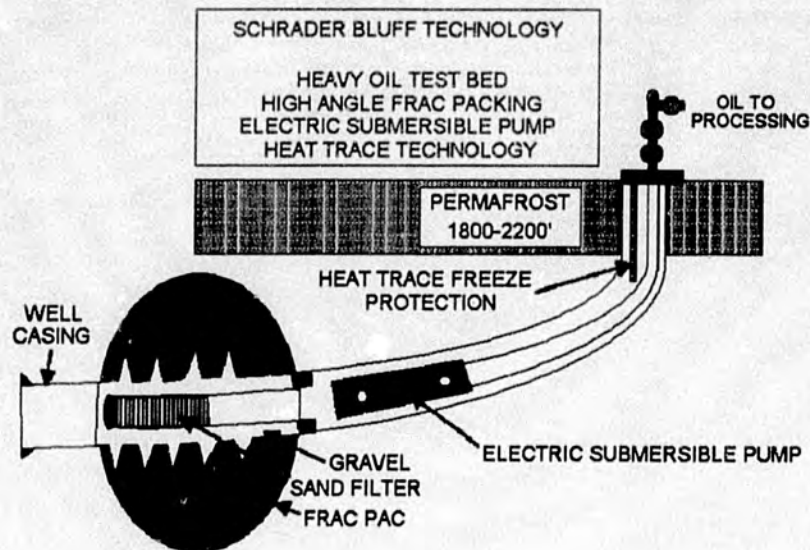


Chart 7

bbls./day. And so, at the end of 1991, further development of Schrader Bluff stopped.

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:

- Ø *Advances in technology and better geologic information have made initial flow rates of 300-400 bbls./day practical; and*
- Ø *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/}

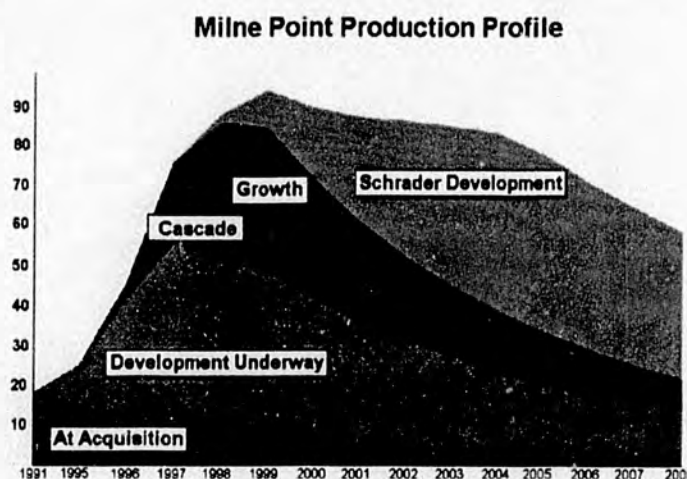


Chart 8

^{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 accommodate 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:

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

^{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.

Ø *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*

Ø *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:

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

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

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

Ø *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.*

^{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.

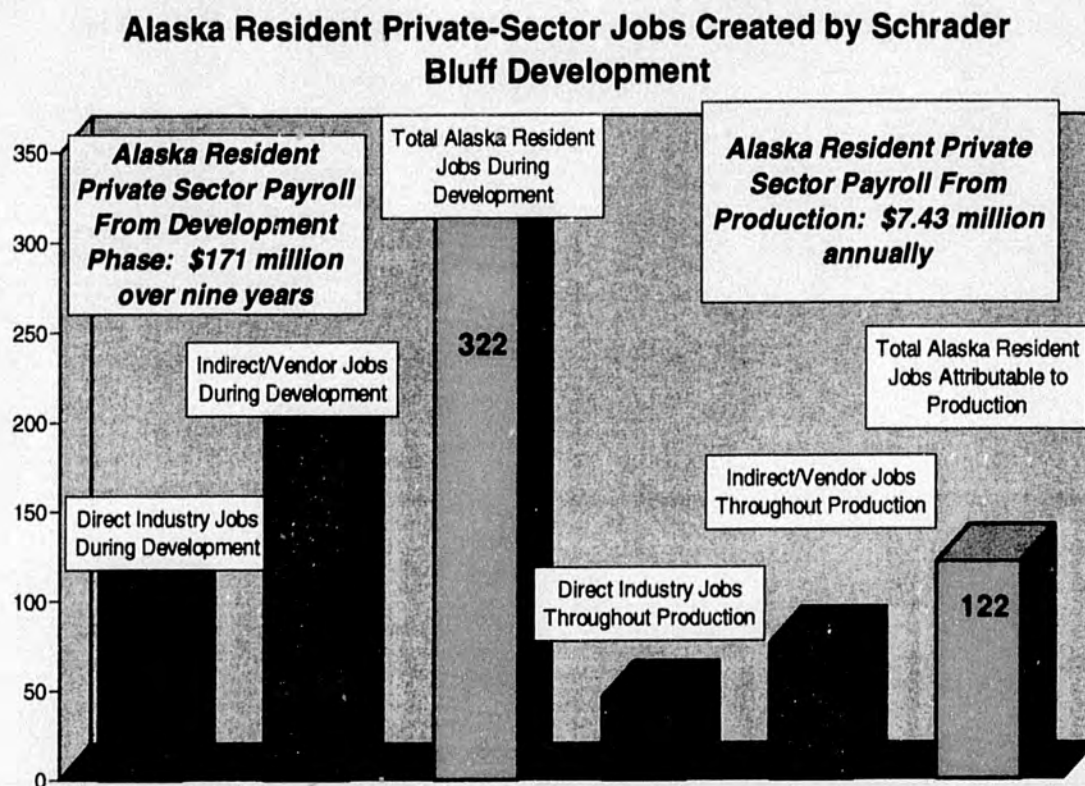


Chart 9

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/}

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



Chart 10

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.

^{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

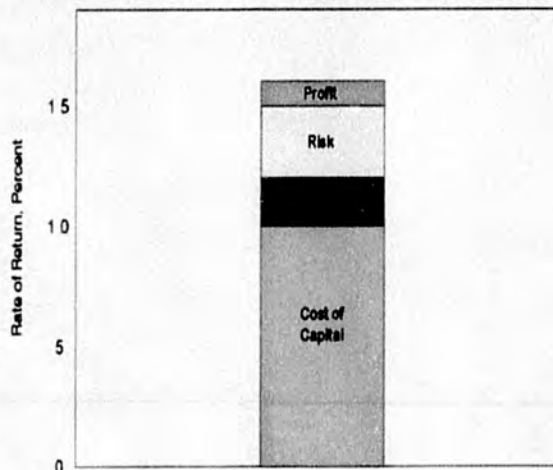


Chart 11

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

^{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.

Ø *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

Ø *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.

^{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:

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

^{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:

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

Typical Heavy Oil Well Economics

Based on the 5 best wells to date in Tract 14

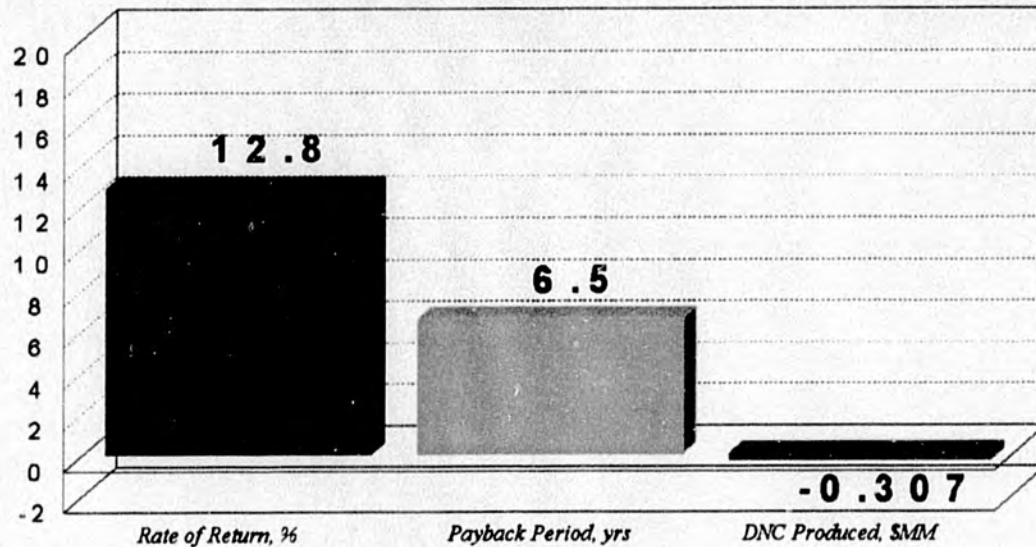


Chart 12

- Ø **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
- Ø **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:

- Ø *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

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/}

- Ø *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.
- Ø *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.
- Ø *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

^{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

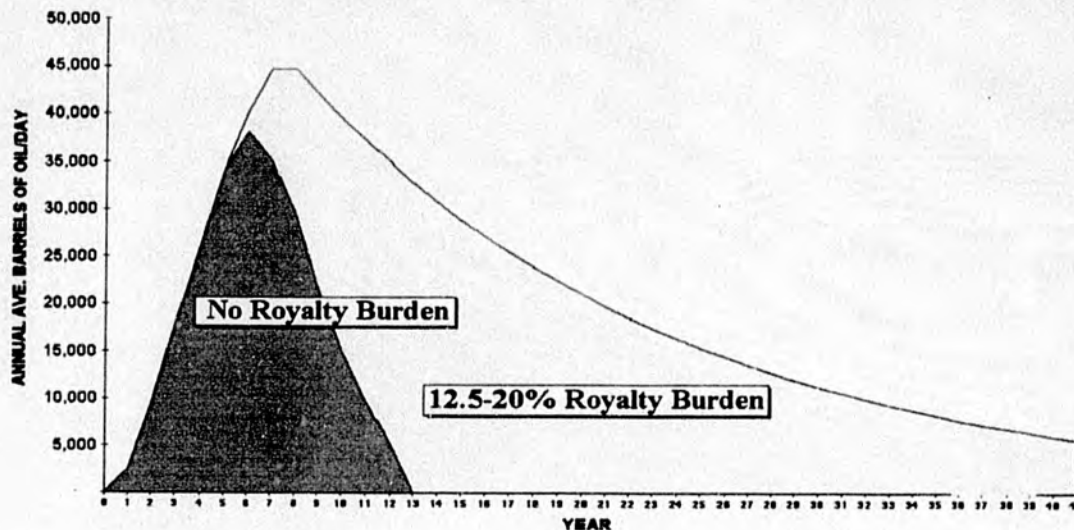


Chart 13

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 peculiarities.

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/}

////////////////////

^{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

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

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:

- Ø *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;*
- Ø *\$4.122 billion more in natural gas produced in the state over the period;*
- Ø *\$240 million in additional sales tax revenues generated over the period;*
- Ø *104,000 new additional employment years created over the period; and*

Ø \$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

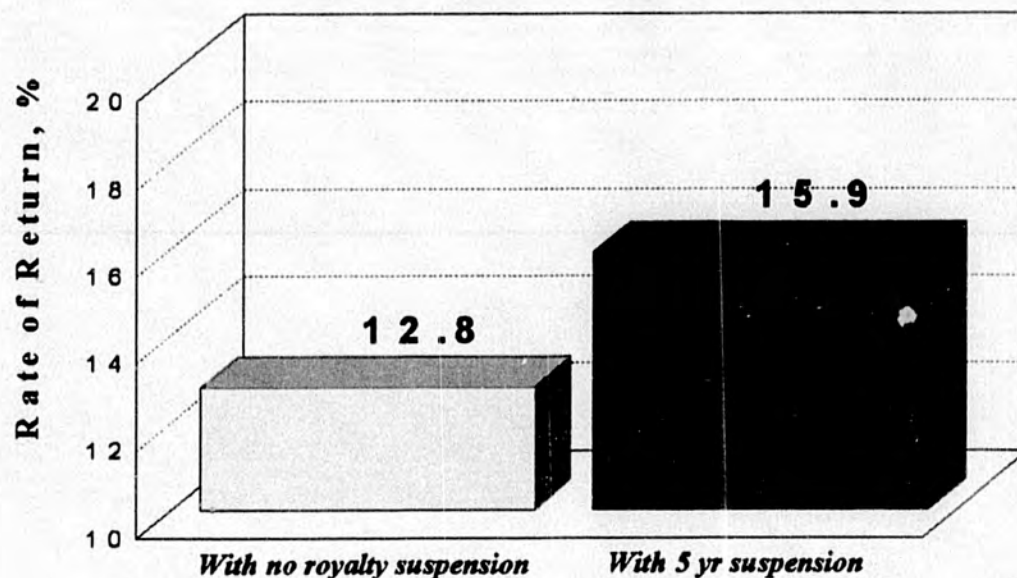


Chart 14

^{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.

The Effect of Royalty Suspension on Schrader Bluff Economics

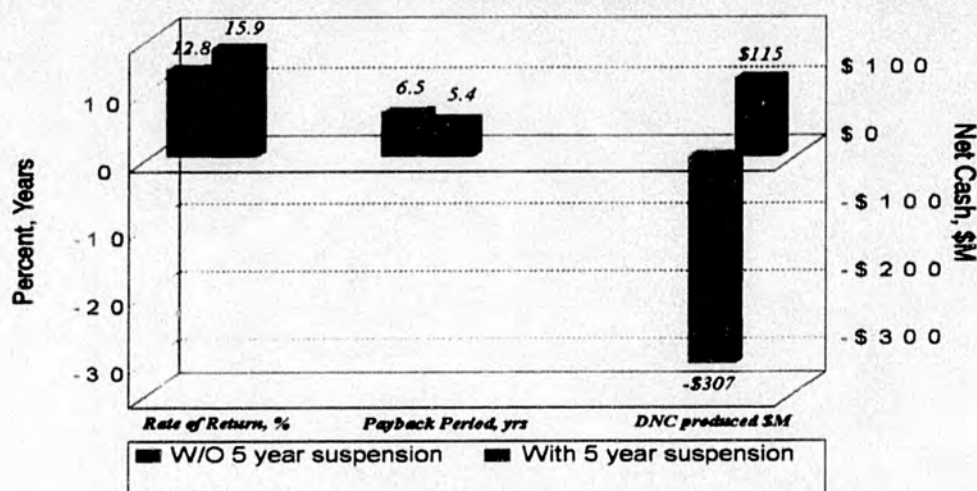


Chart 15

The five-year suspension thus seems *sufficient* to at least make Schrader Bluff development competitive with other industry 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.

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.

HB 325 Meets the Necessary and Sufficiency Criteria....

5 Year Royalty Suspension (HB 325) vs. 5% Royalty for the Well's Life

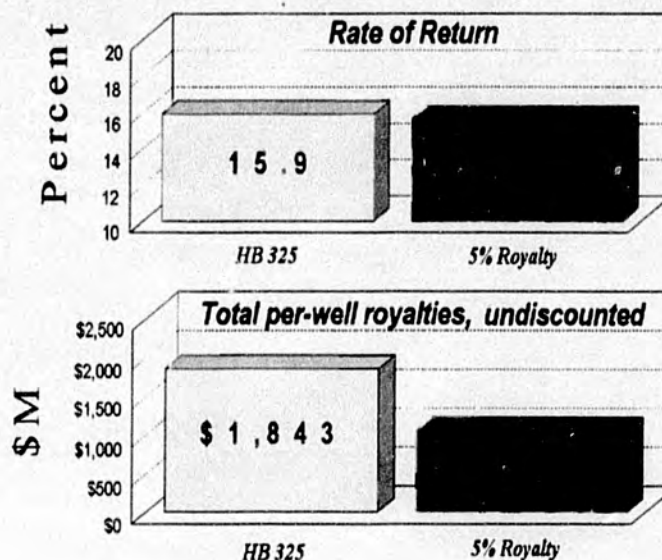


Chart 16

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 costly administrative proceedings, and subsequent litigation, consumed by these discretionary 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.

Unlocking the Heavy Oil Potential on Alaska's North Slope

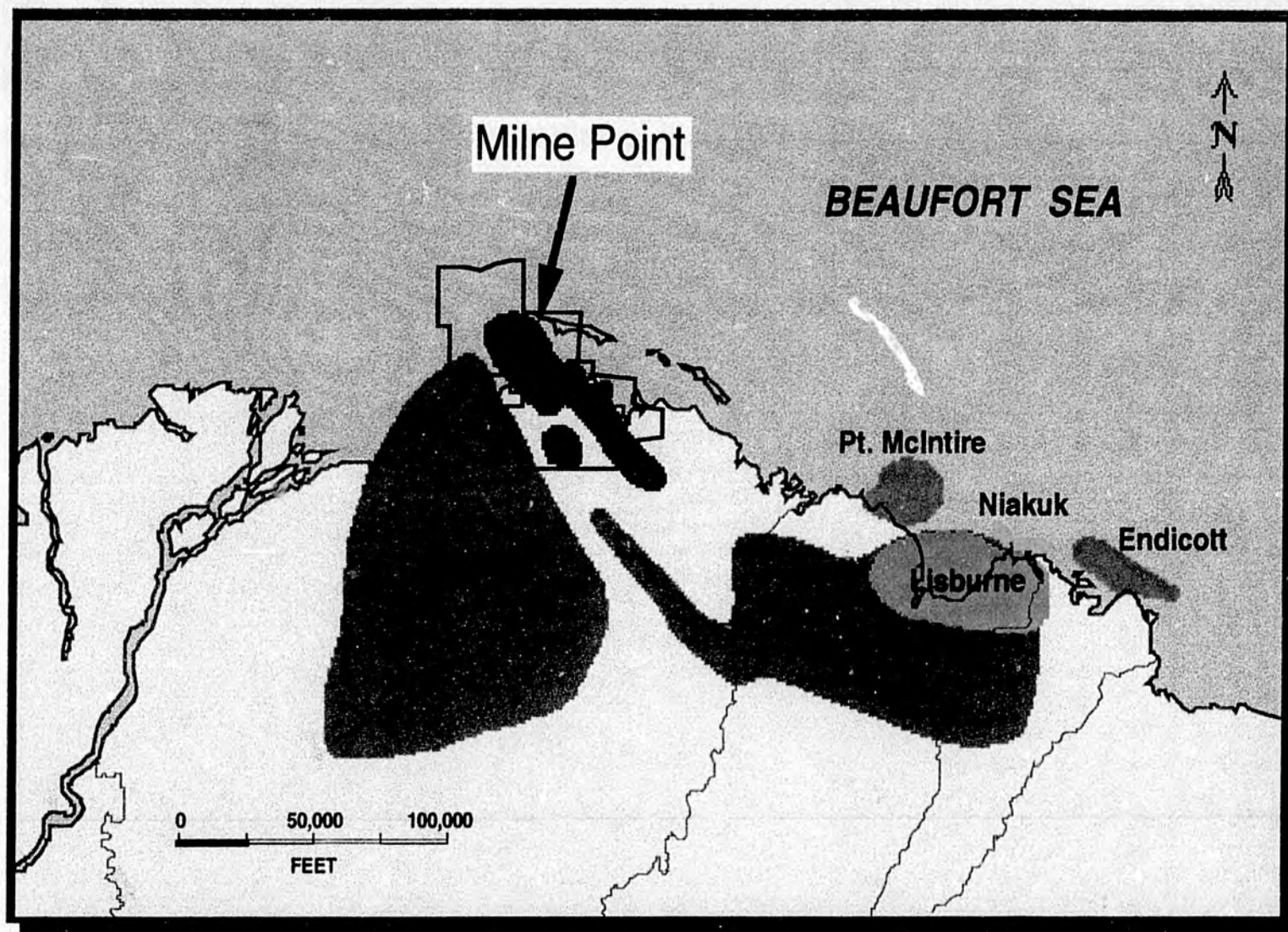
**Presentation by Occidental Oil and Gas Corporation before
the House Oil & Gas Committee on November 14, 1995**



BACKGROUND INFORMATION

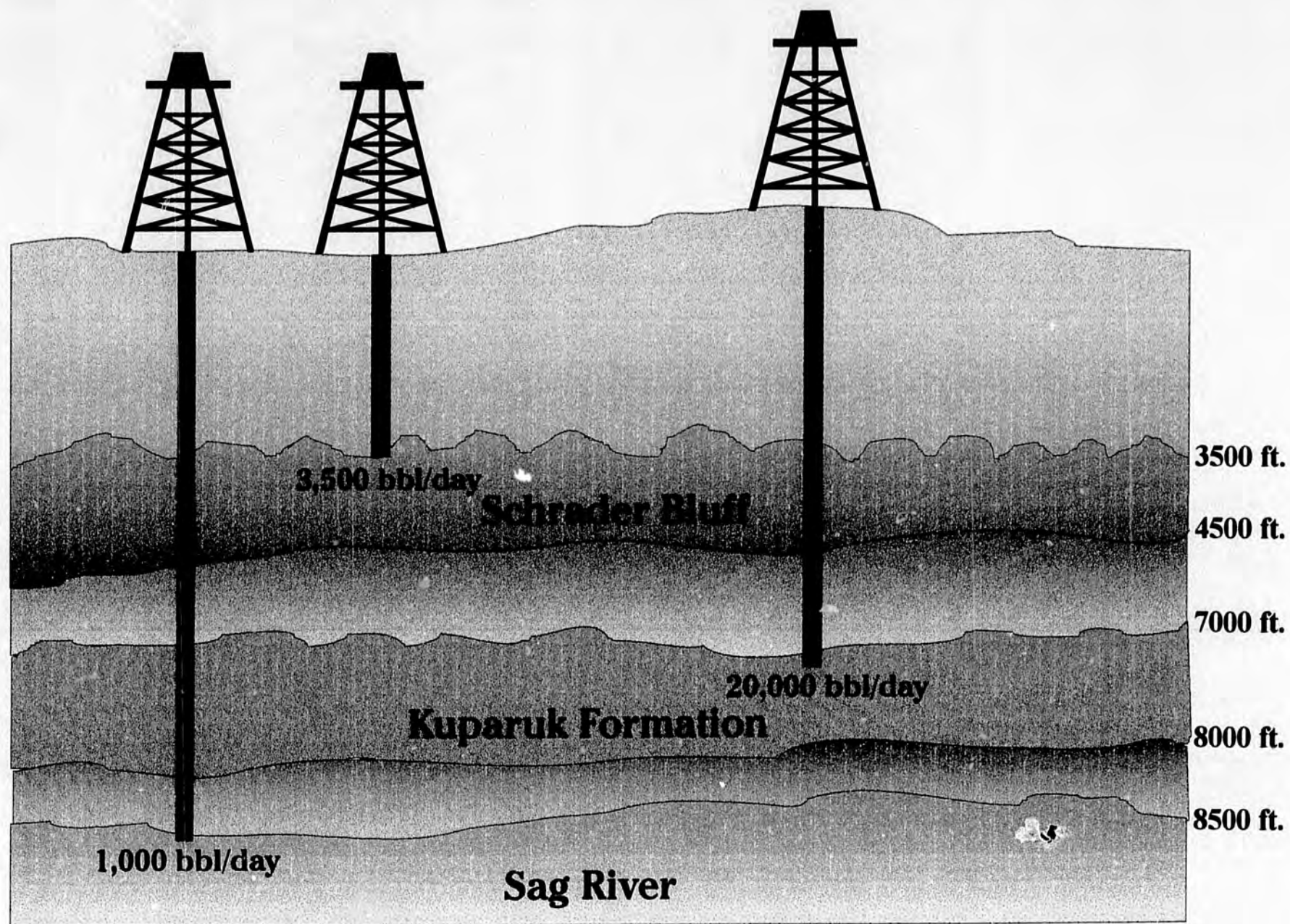
WHO IS OCCIDENTAL OIL AND GAS CORPORATION?

- *Oil & gas part of Occidental Petroleum Corporation*
- *Large independent in the US, no refining or marketing operations*
- *No financial interest in TAPS*
- *Operator of Heavy Oil properties in California*
- *The last original owner in Milne Point Unit with around 9% WI*



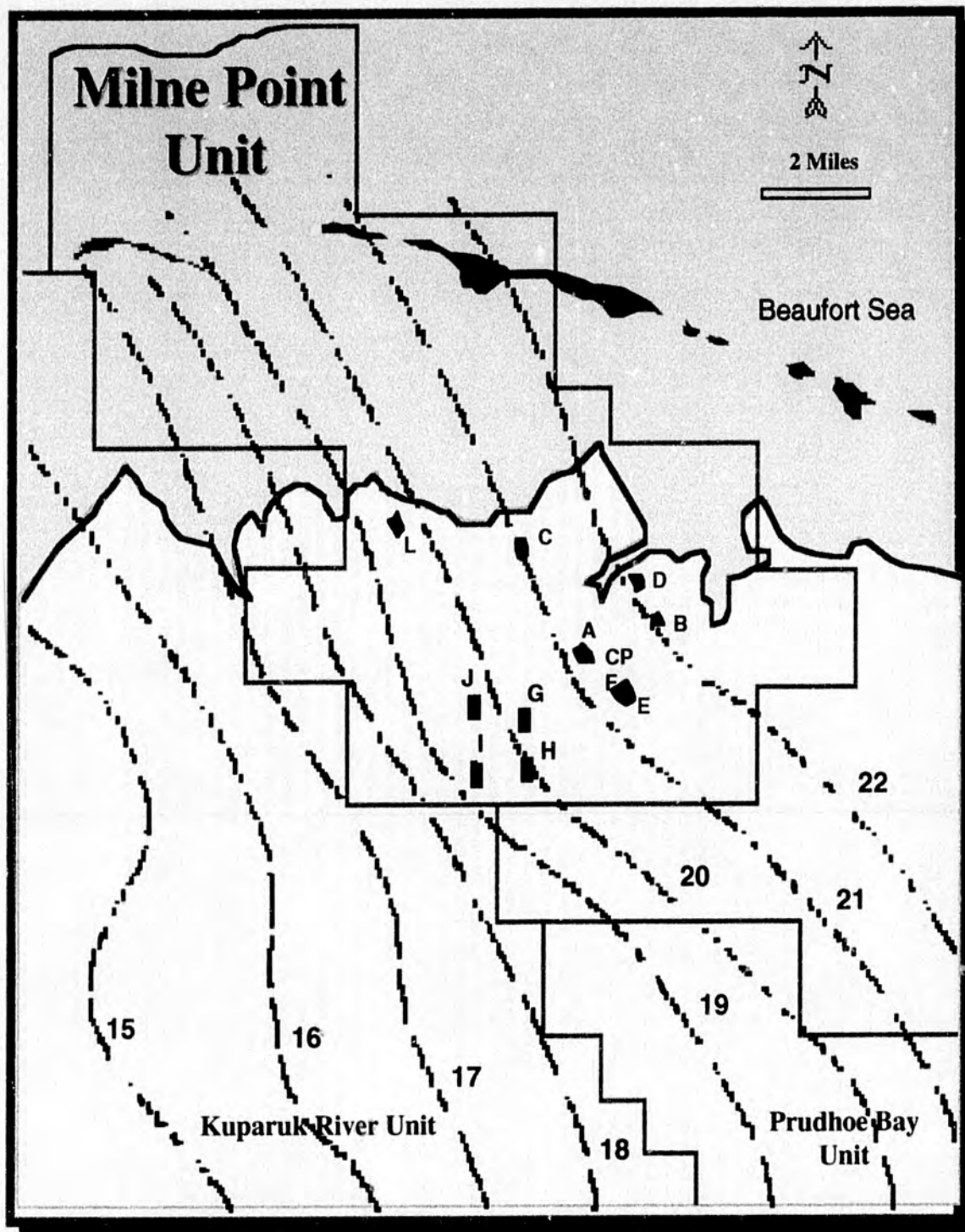
North Slope Fields and Milne Unit Outline

Occidental and BP produce oil from three formations at MPU

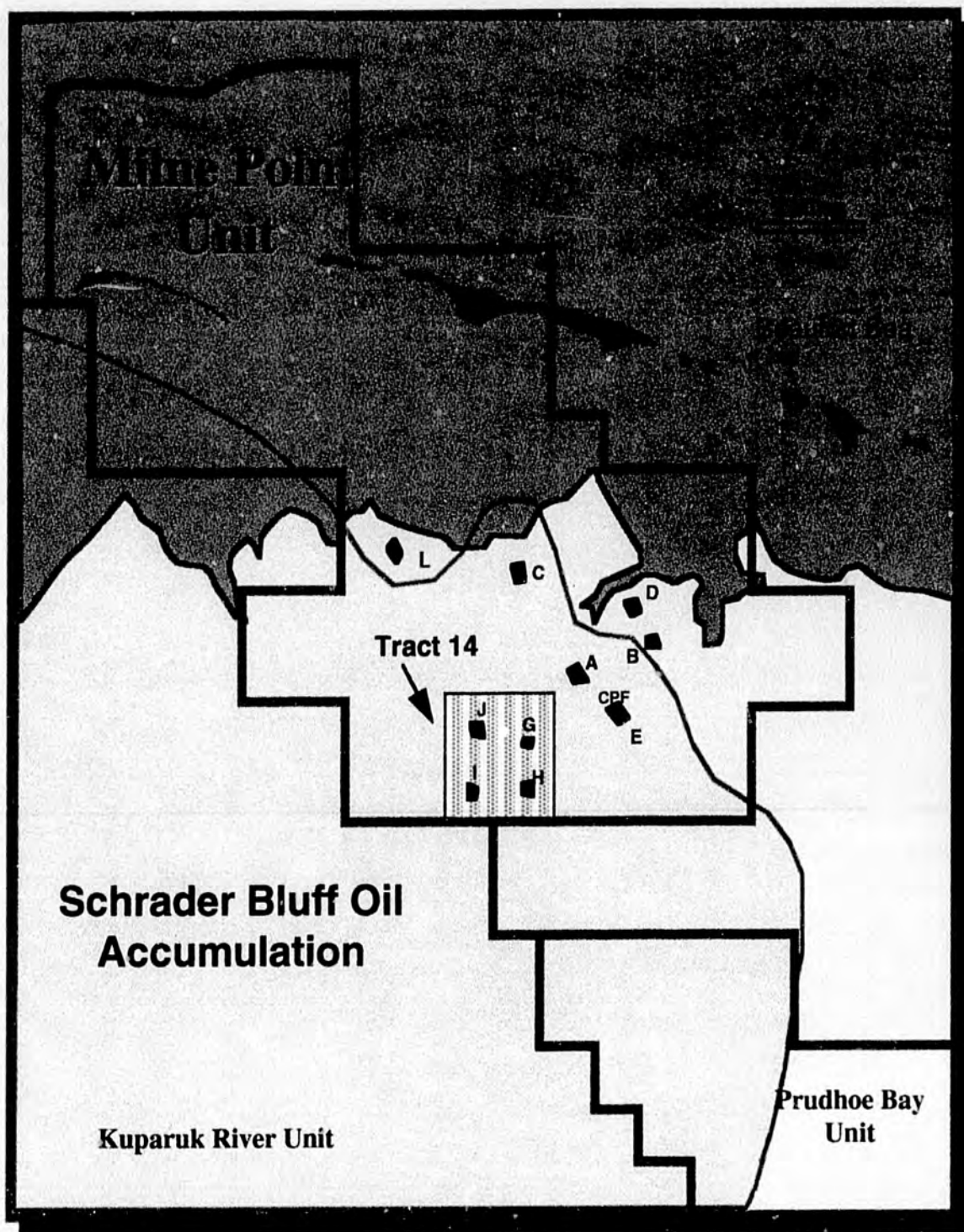


What is "heavy oil"?

- 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



Schrader Bluff Generalized API Gravity Map



Schrader Bluff Oil Accumulation

AGE	TYPE LOG		TERMINOLOGY				
			Informal		Formal		
	MILNE POINT UNIT		Milne Point Unit	Kuparuk River Unit	North Slope		
	Gamma Ray	Resistivity			GP.	FORMATION	
TERTIARY						COLVILLE	SAGAVAN-IRKTOK
				K Sands	UPPER UGNU SANDS		
				L Sands			
?				M Sands	LOWER	PRINCE CREEK	
A			N Sands		SCHRADER BLUFF		
B							
C							
D							
E							
F							
CRETACEOUS		A	O Sands				
		B					

Shallow Oil Sands Nomenclature

Previous Heavy Oil Development

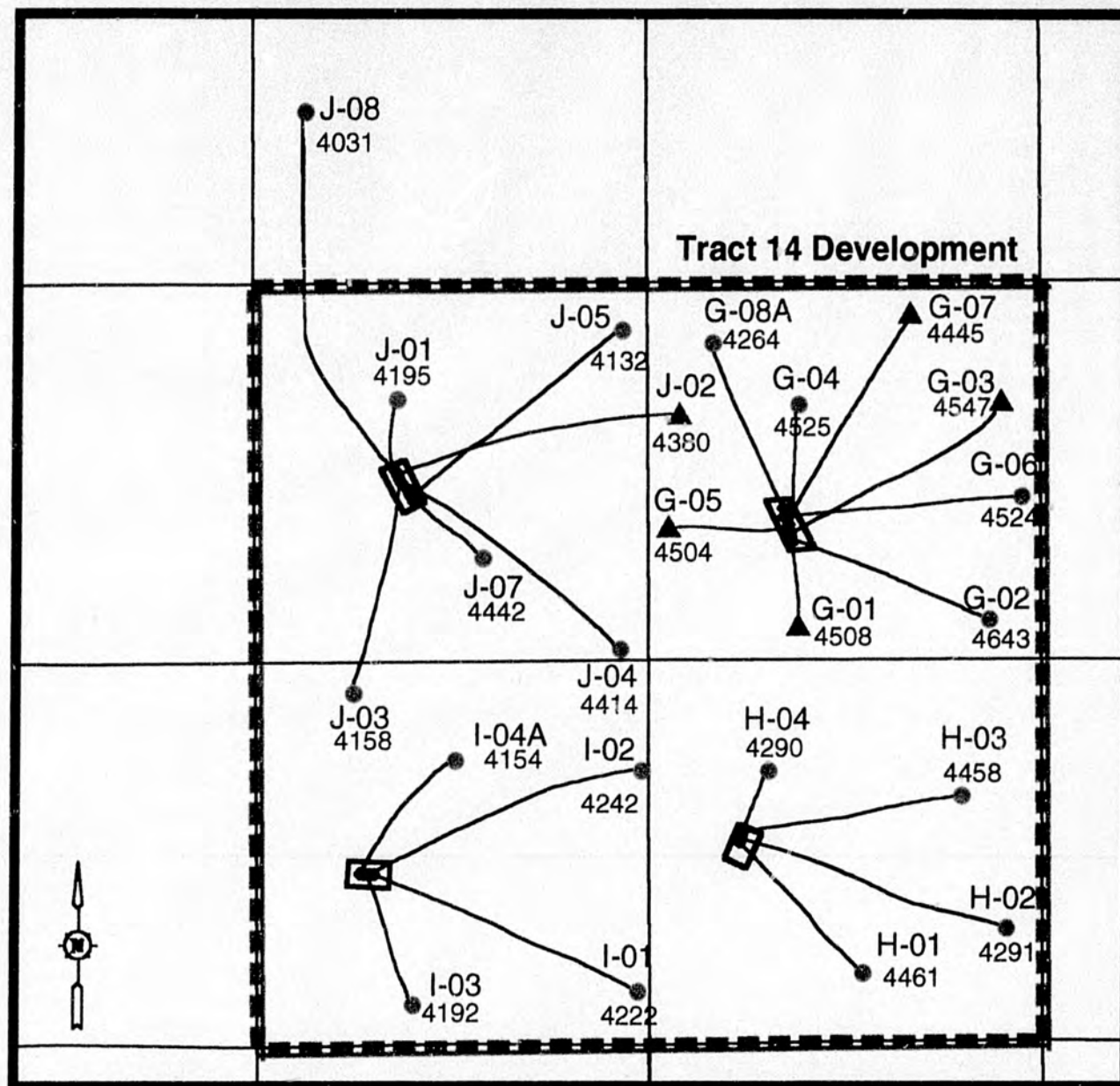
ARCO/West Sak Project

- *Spent \$135 Million on 13 wells and related facilities*
- *Average producing rate = 250 BOPD per well*
- *Recovery = 0.8 million barrels before abandonment in 1986*
- *Total Capital Investment = \$169/Barrel*
- *Uneconomical*

The Tract 14 Experience

Milne Point Unit Schrader Bluff Tract 14 Development

- Producer
- ▲ Injector

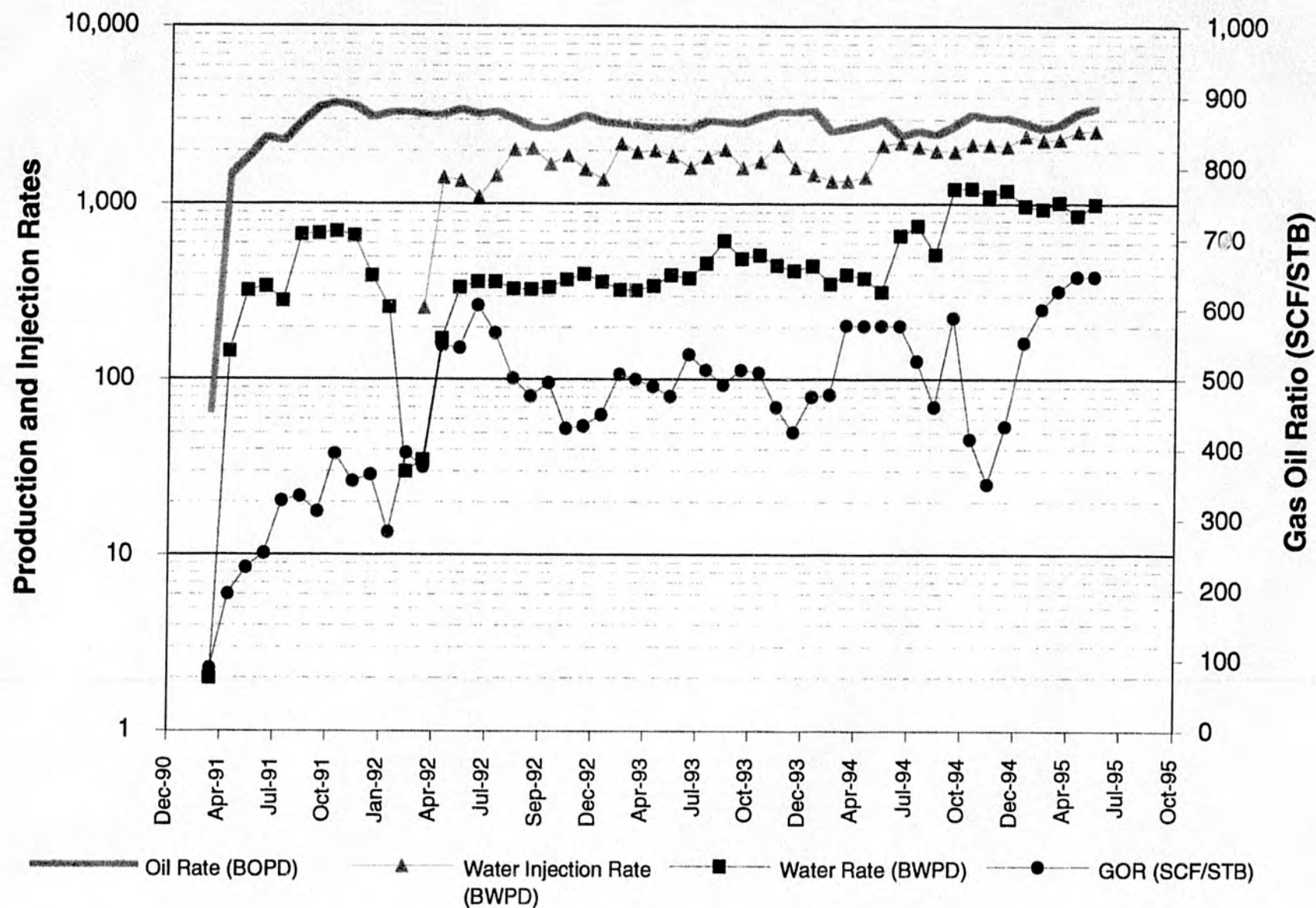


● TVDss (feet)

1 Mile

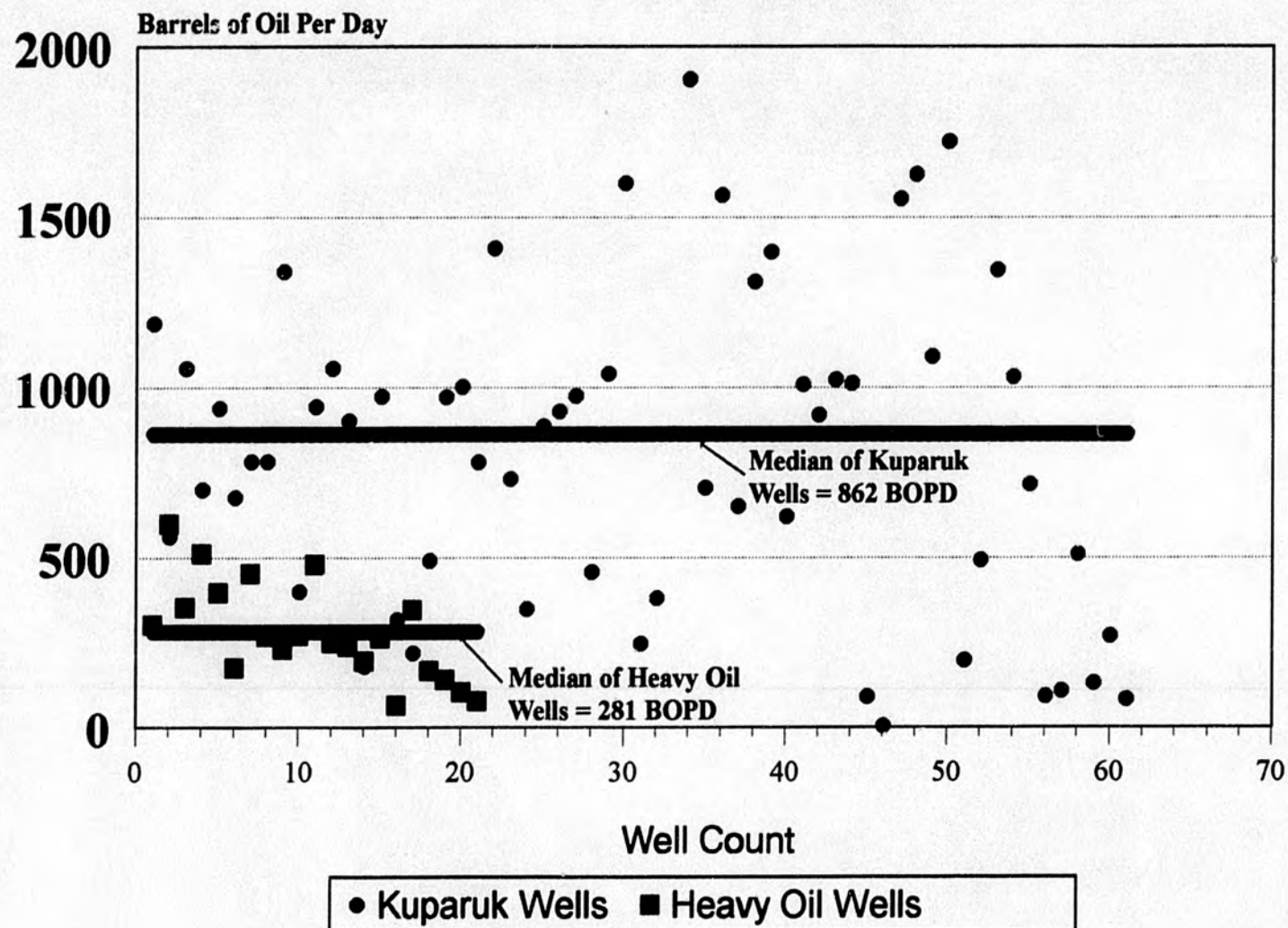
Schrader Bluff Tract 14

Monthly Average Production and Injection History



Heavy Oil Wells Have Much Lower Initial Flowrates

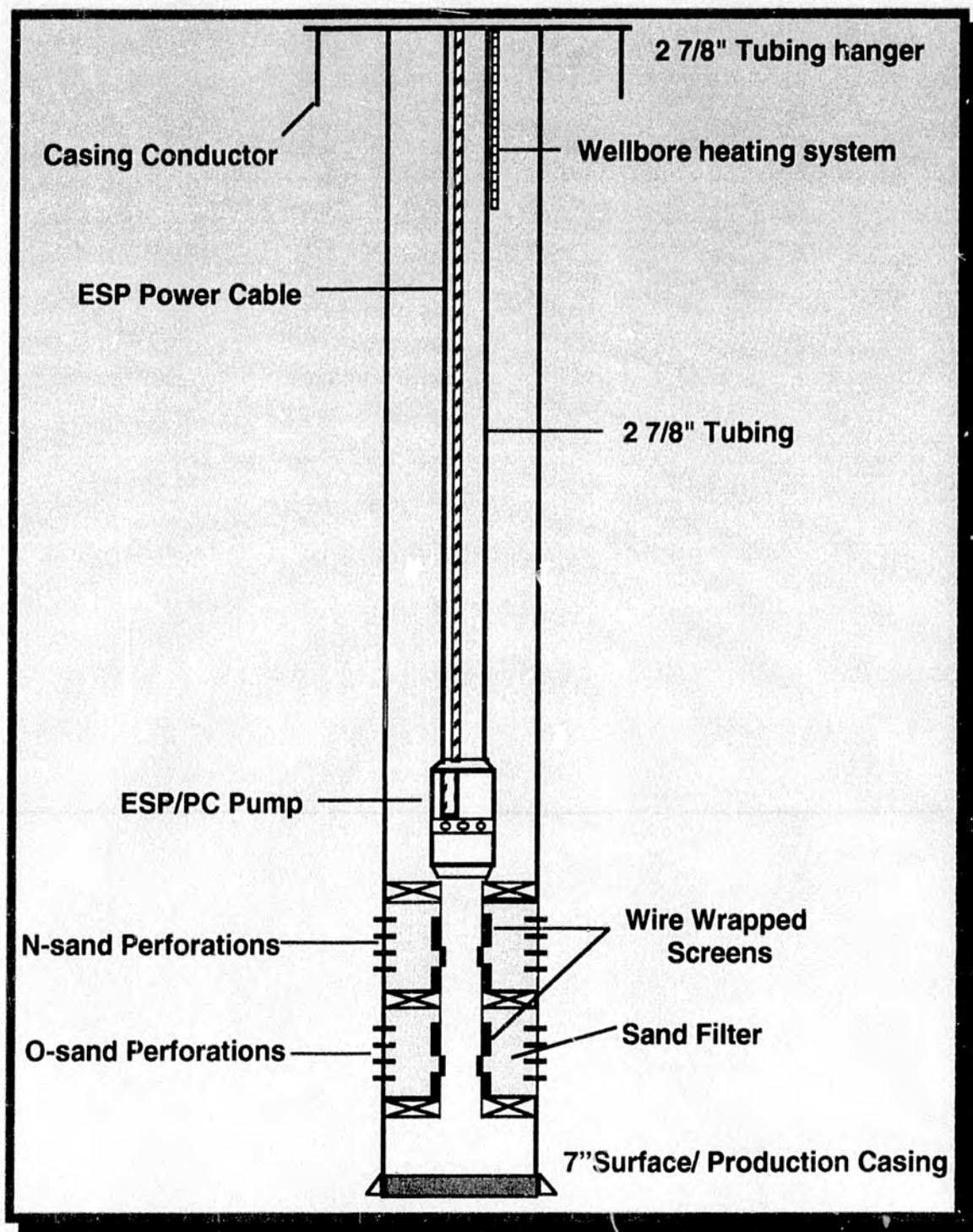
Milne Point Unit



Note: "H" on chart denotes horizontal well

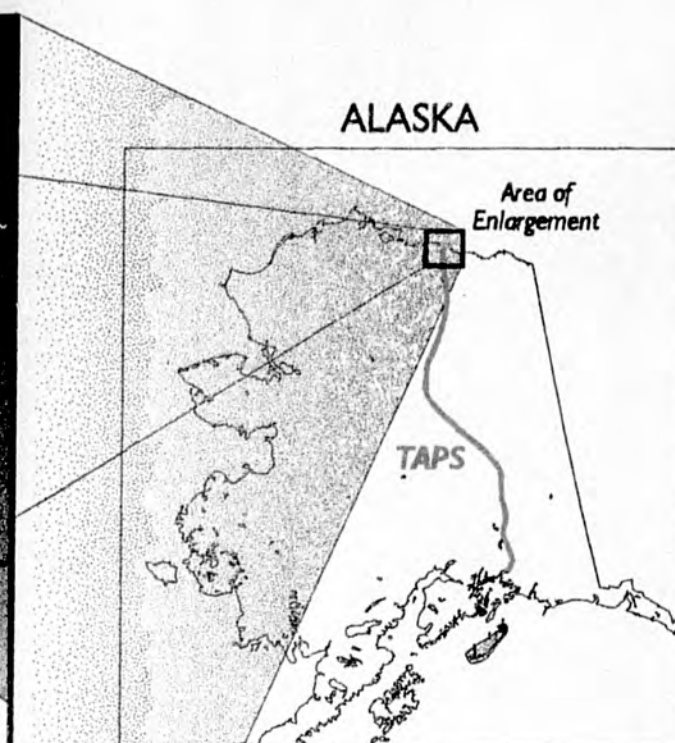
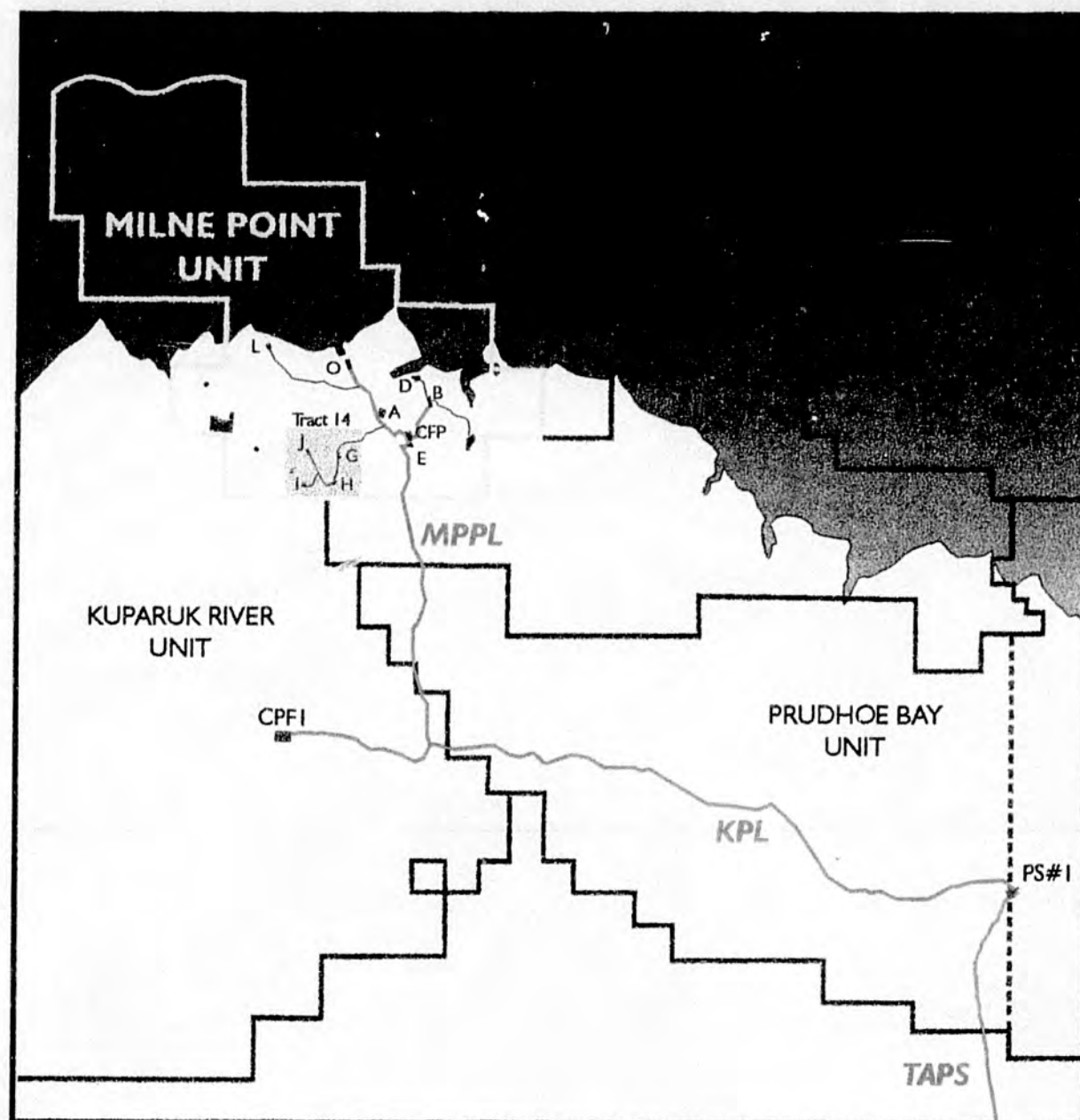
Problems With Producing Heavy Oil at Milne Point

- Produces sand that:
 - is tough on equipment
 - requires gravel packs and screens
- Produces water that is hard to separate
- Wells must be stimulated
- Wellbore heating system required
- Unusually high transportation cost



Future Schrader Bluff Completion

Getting Heavy Oil to Market is Expensive



Per Barrel Charges

MPPL	\$0.48
KPL	\$0.30
TAPS	\$4.06
TANKER	<u>\$1.30</u>

TOTAL \$6.14

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.

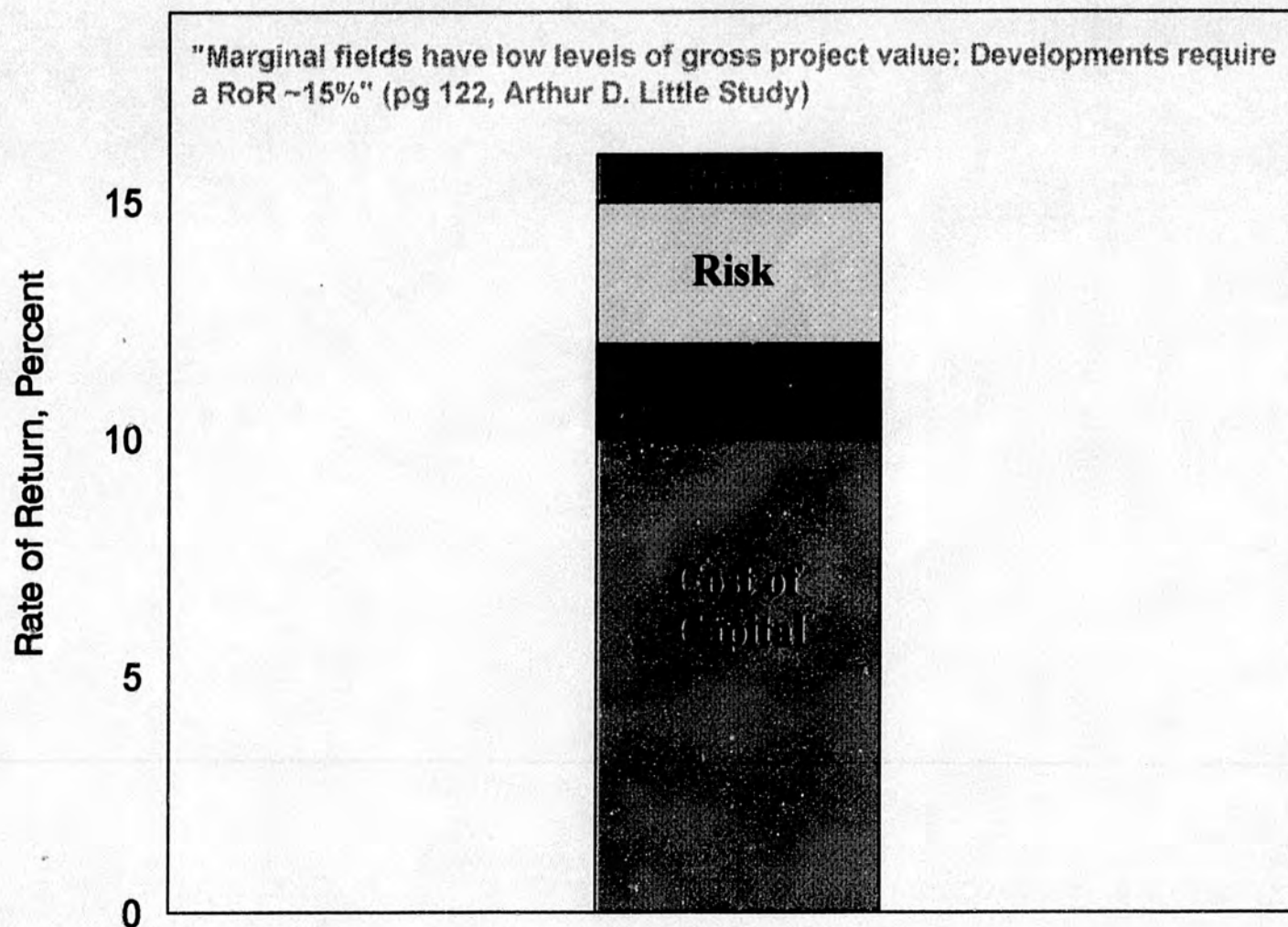
Can Technology Alone Save this Project?

Our experience so far....

- *Horizontal Drilling - 2 wells drilled, good initial flowrates but expensive to drill. At this time, the higher costs do not justify large scale application.*
- *Steamflooding - Typical for Lower 48 heavy oil production, not applicable on North Slope.*
- *Waterflooding - Heavy Oil in loose, unconsolidated formations is difficult to displace because of mobility differences. After three years of waterflooding Tract 14, we are not sure we see any benefit.*

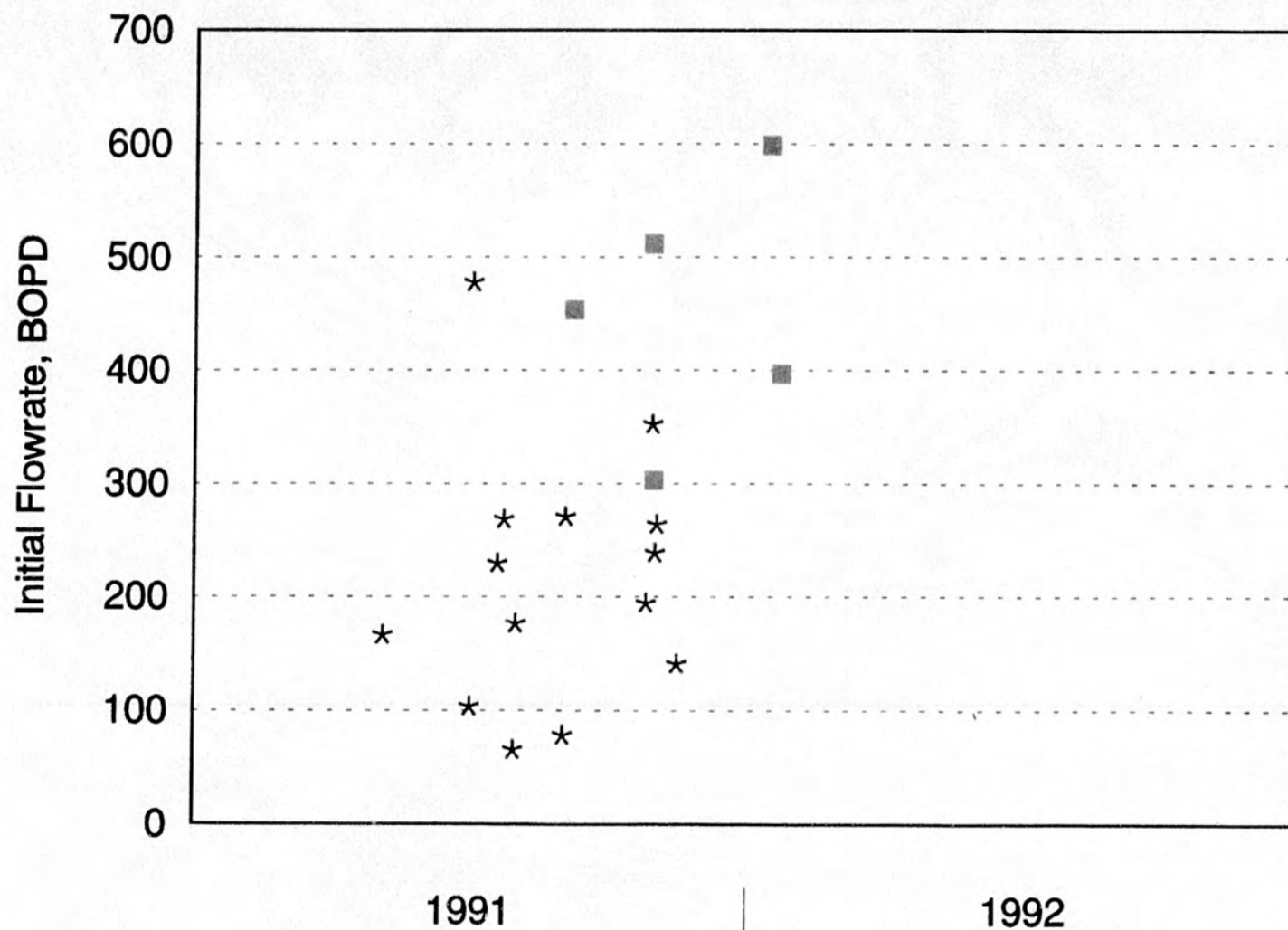
**The Current Economic
Outlook for Future
Capital Investment in
Heavy Oil
Development**

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



Initial Flowrates of Previous Tract 14 Wells

Best five shown in green



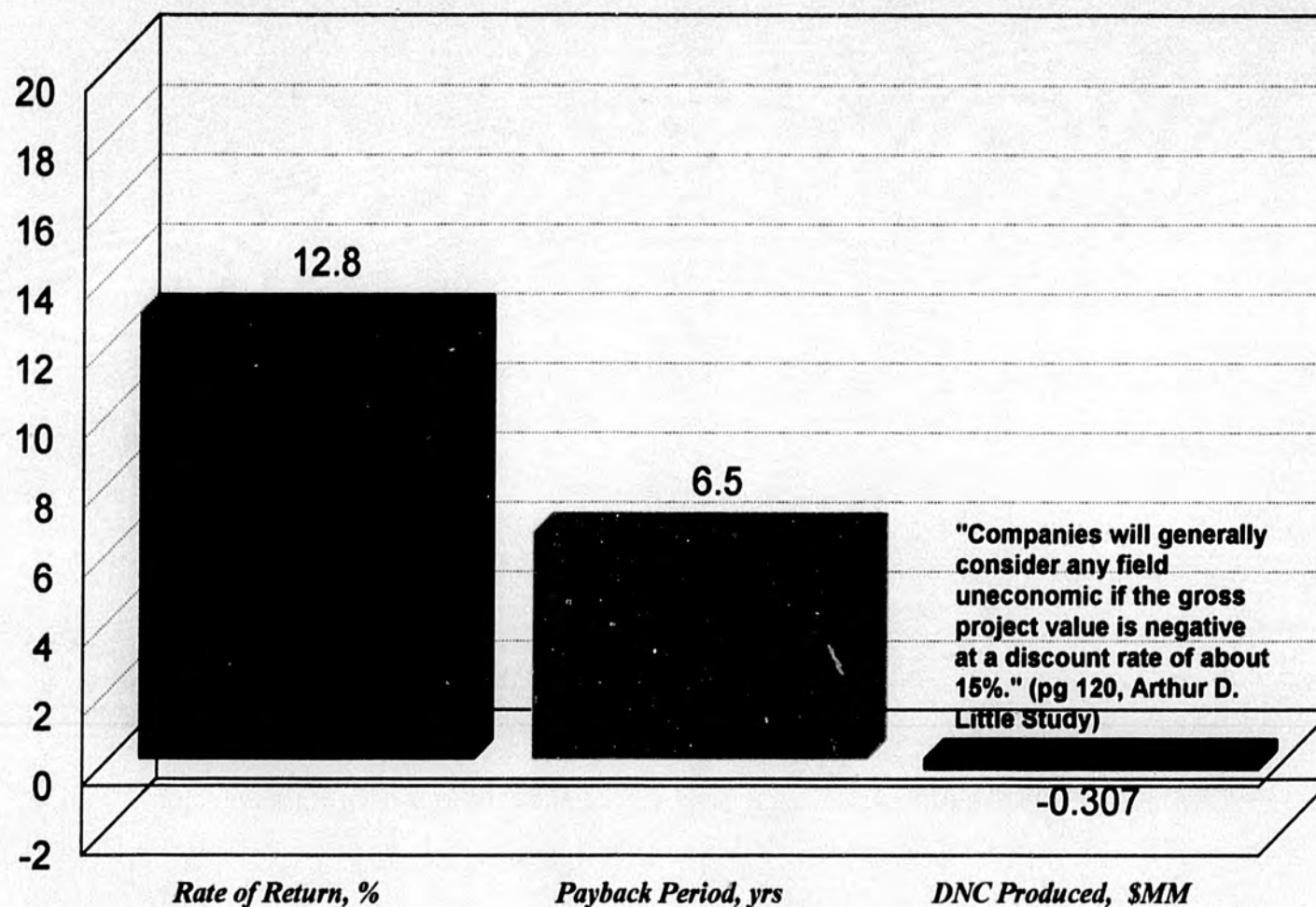
"Best five" based on expected ultimate recovery

Assumptions Used in the Economic Calculations

Assumption	Basis
Future Oil Prices	DOR's Spring 1995 Revenue Sources Book
Well Performance	Best 5 wells in Tract 14
Well Costs	Average of 21 wells in Tract 14
Facilities Costs	Operator's Estimates in 1995-1997 Business Plan
Operating Expenses	Current unit estimates for 1995
Property Taxes	Based on last three years history for the Unit

Typical Heavy Oil Well Economics

Based on the 5 best wells to date in Tract 14



Little, A.D. and Gault, L.: "Review of International Competitiveness of Alaska's Fiscal System," Report to the Oil & Gas Policy Council 8/11/95

**HB 325: A Proposed
Incentive for Heavy Oil
Development**

INFLUENCING ANS HEAVY OIL INVESTMENT DECISIONS

Criteria for an Effective Incentives Policy

- **SPECIFICITY:** *Aimed directly at the challenge of ANS heavy oil production.* "Alaska's current regime is not fiscally efficient. In a fiscally inefficient system...[s]maller and higher cost fields will not be developed... Thus, uniform fixed rate fiscal systems produce non-uniform results which are economically discriminatory" (pp. 10, 61).
- **RELEVANCY:** *Calculated to influence capital investment decisions.* "Because royalty is paid 'off the top' and is not related to field profitability, it often has the effect of reducing the gross project value of a field to levels below the investment target of the companies...Royalty holidays will encourage field development" (pp.188, 192).
- **CERTAINTY:** *Major investment decisions can be made in reliance on the incentive's availability.*
- **IMMEDIACY:** *The incentive must seize the current window of opportunity.* Of the problems with a "wait and see" policy, Arthur D. Little said that: "[While] oil price increases could result in activity increases, this may not occur for 5+ years which may be too late for the North Slope if TAPS line does not continue" (p. 186)
- **CREDIBILITY:** *The incentive has been successfully employed in other jurisdictions.*
- **SUFFICIENCY:** *The incentive is large enough to materially alter project economics.*
- **NECESSITY:** *Alaska should not leave money on the table.*

What are we proposing?

HB 325 by Representative Green

- Applicable to heavy oil production as defined by 26 U.S.C. 613A(c)(6)(F)
- Applicable only to the Alaska North Slope
- Suspension of royalty payments for each new well for the:
 - first five years
 - first 500 barrels of oil per day
- A simple, automatic process

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)

Texas "High - Cost Gas" Incentive

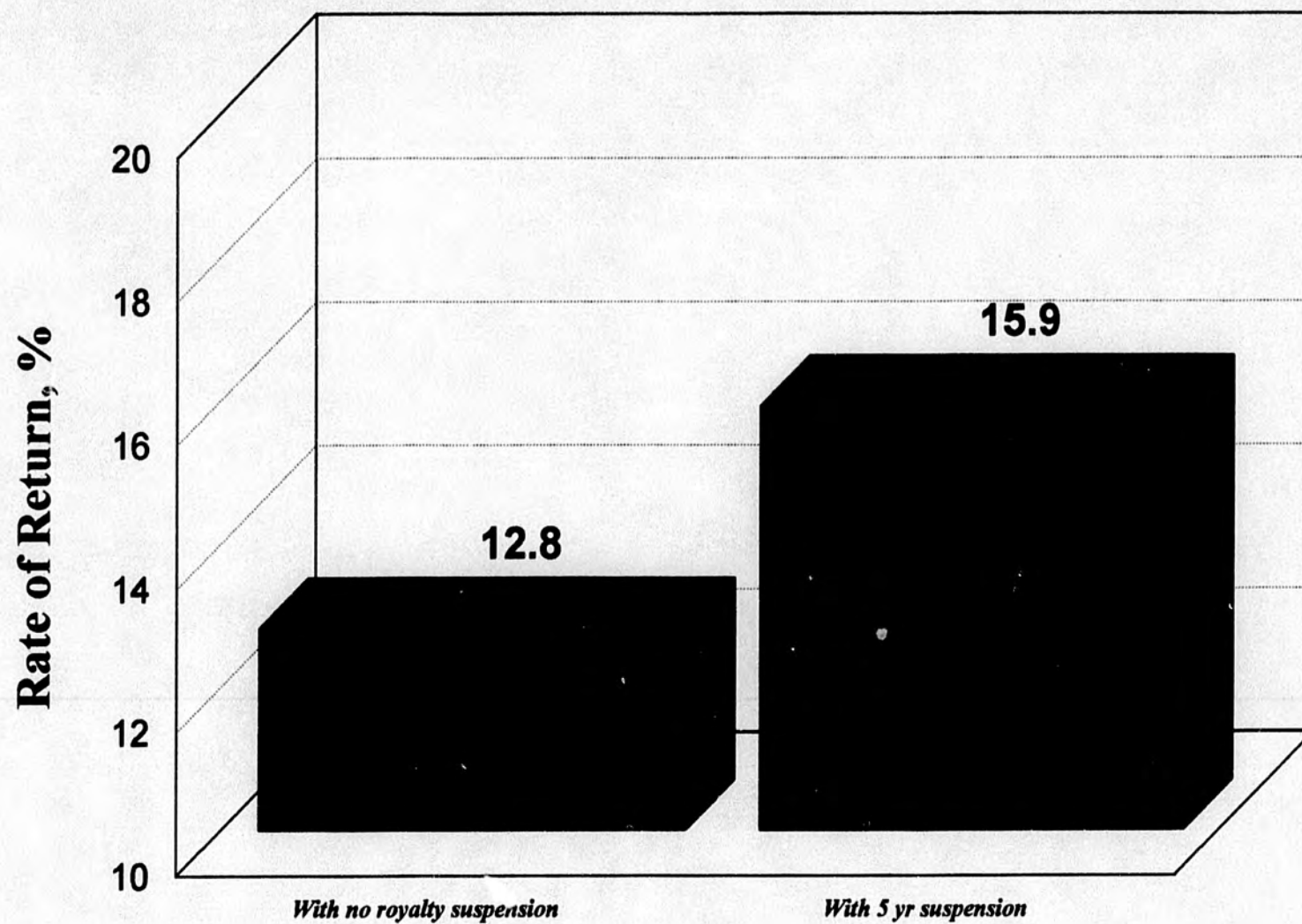
Benefits Identified

- 400% increase in the number of wells
- \$4.122 Billion more in gas produced
- \$240 Million in sales tax revenues generated
- 104,000 employment years created
- \$12 Billion in additional economic value generated for Texas

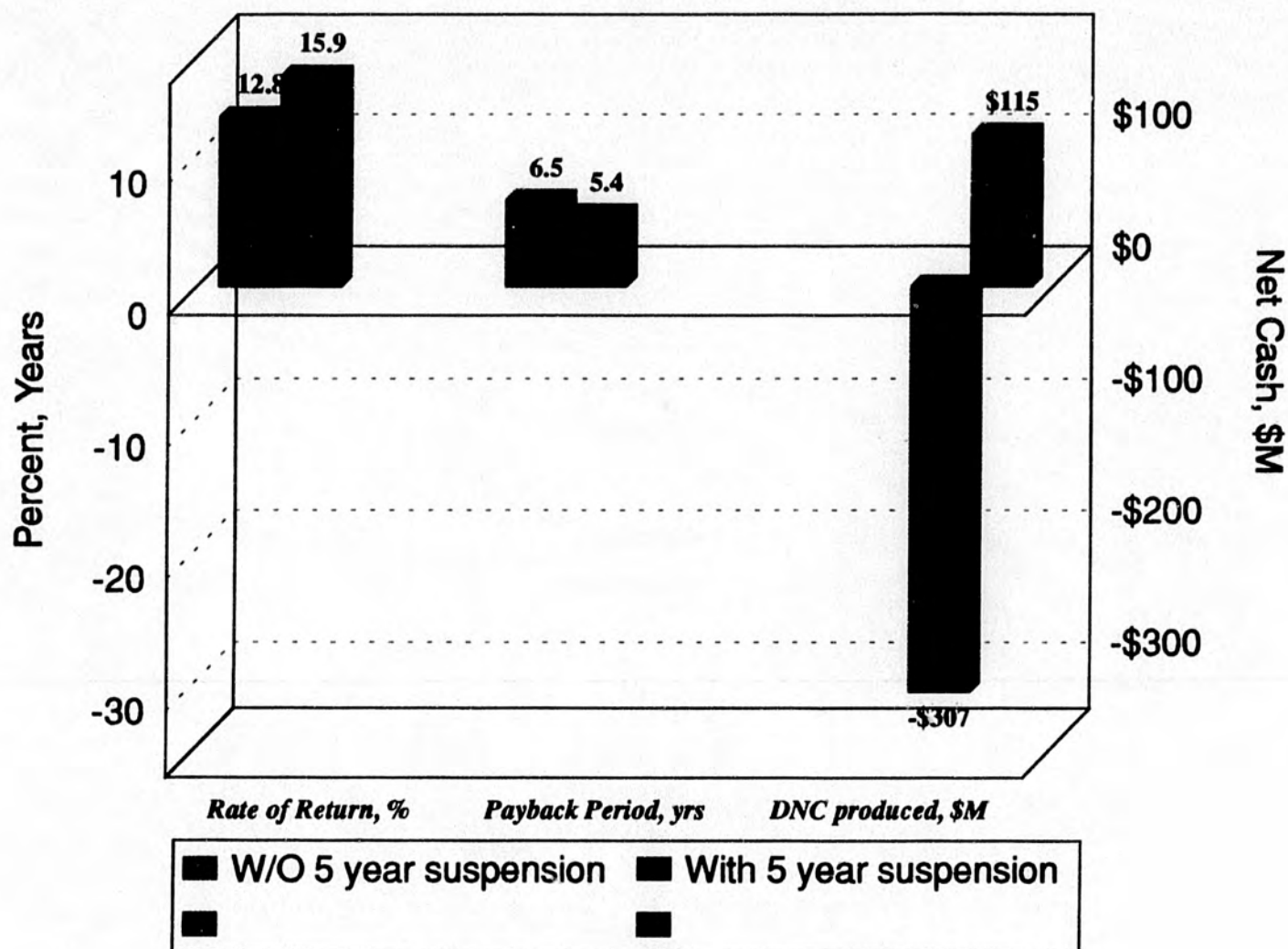
Source: Texas Railroad Commission

**Economic Impact of
HB 325**

The Effect of Royalty Suspension on Schrader Bluff Development Decisions

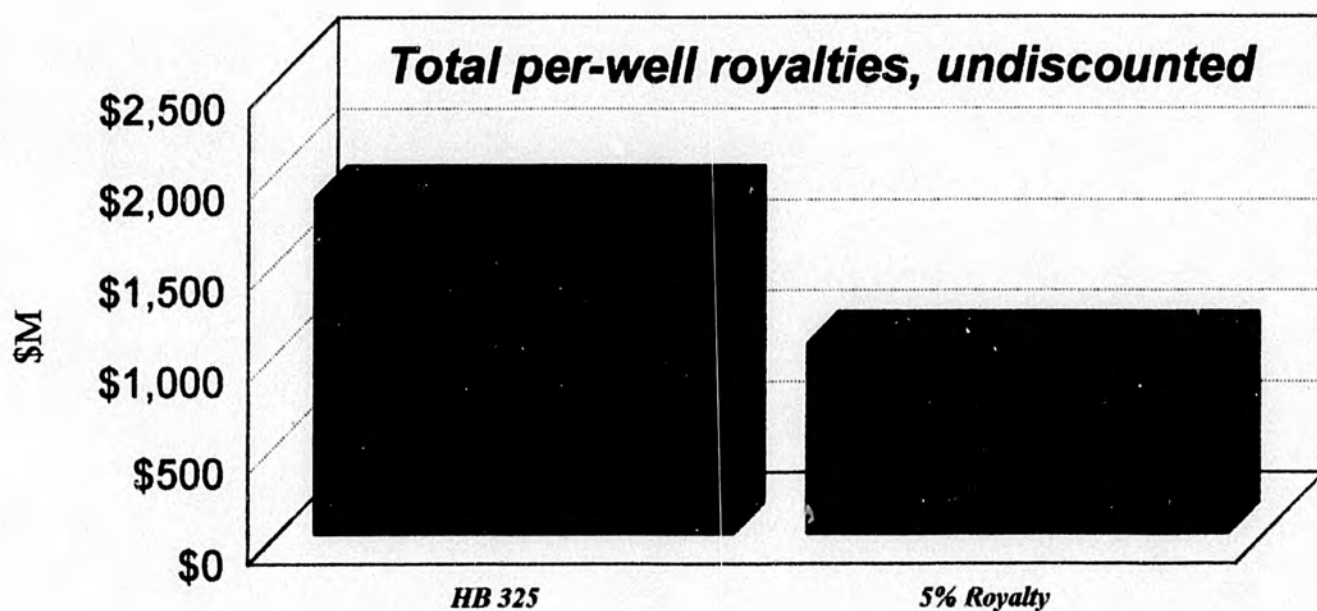
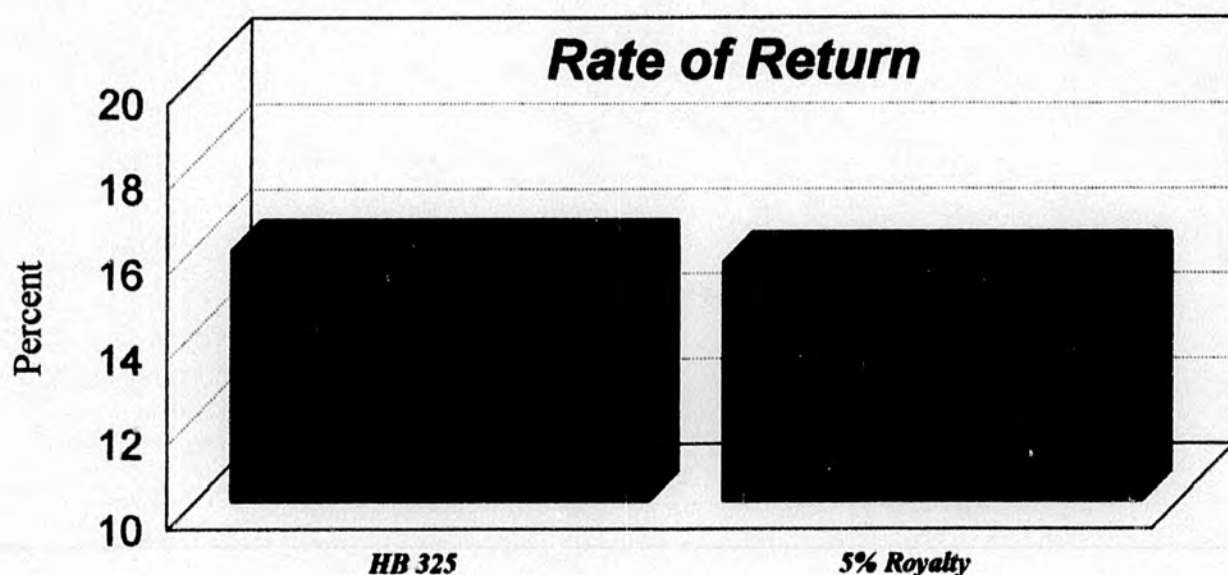


The Effect of Royalty Suspension on Schrader Bluff Economics



HB 325 Meets the Necessary and Sufficiency Criteria....

5 Year Royalty Suspension (HB 325) vs. 5% Royalty for the Well's Life



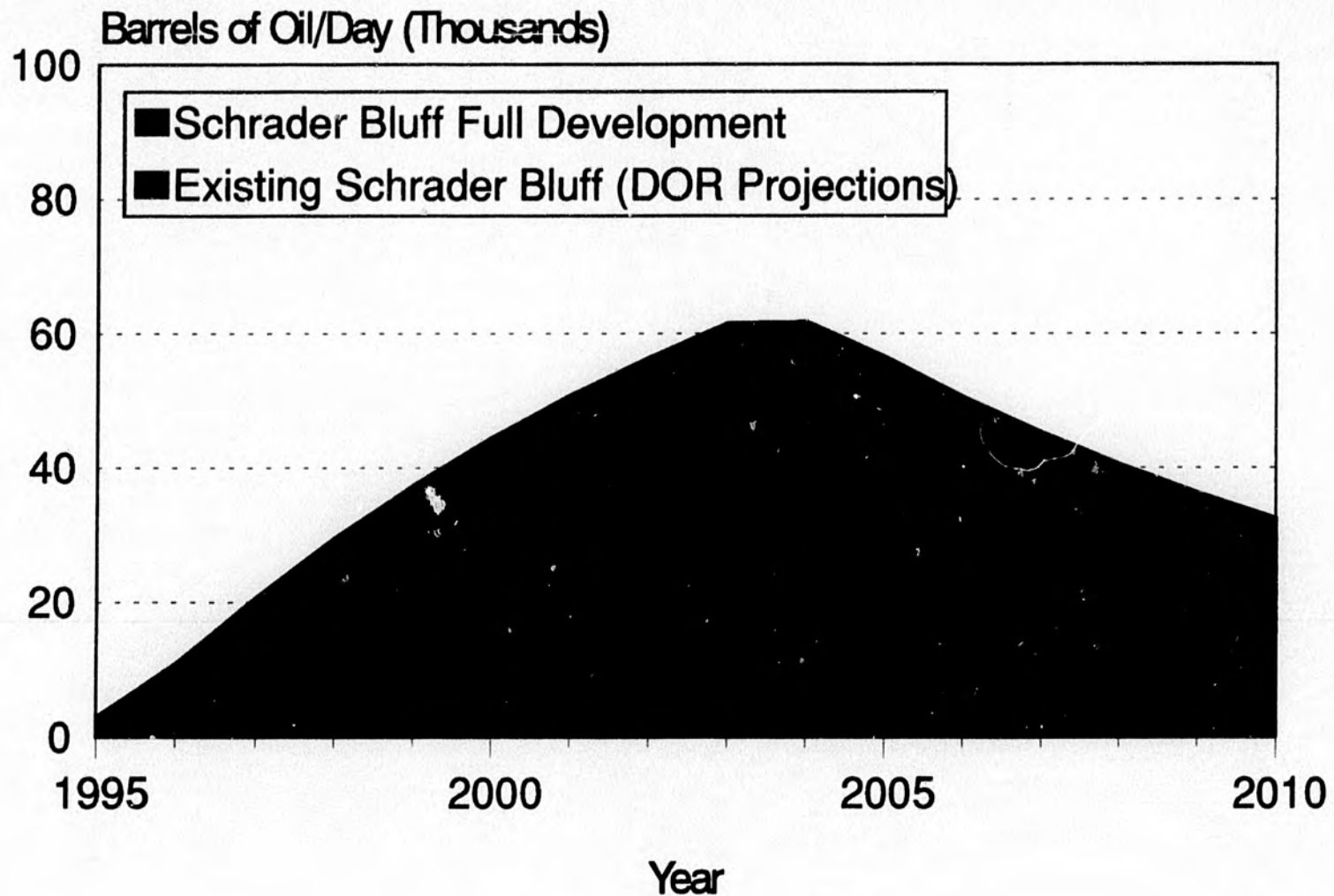
Full Development of Heavy Oil at Milne Point Unit

What does it mean?

Full Development Of HO at Milne Point Above & Beyond Existing Schrader Bluff

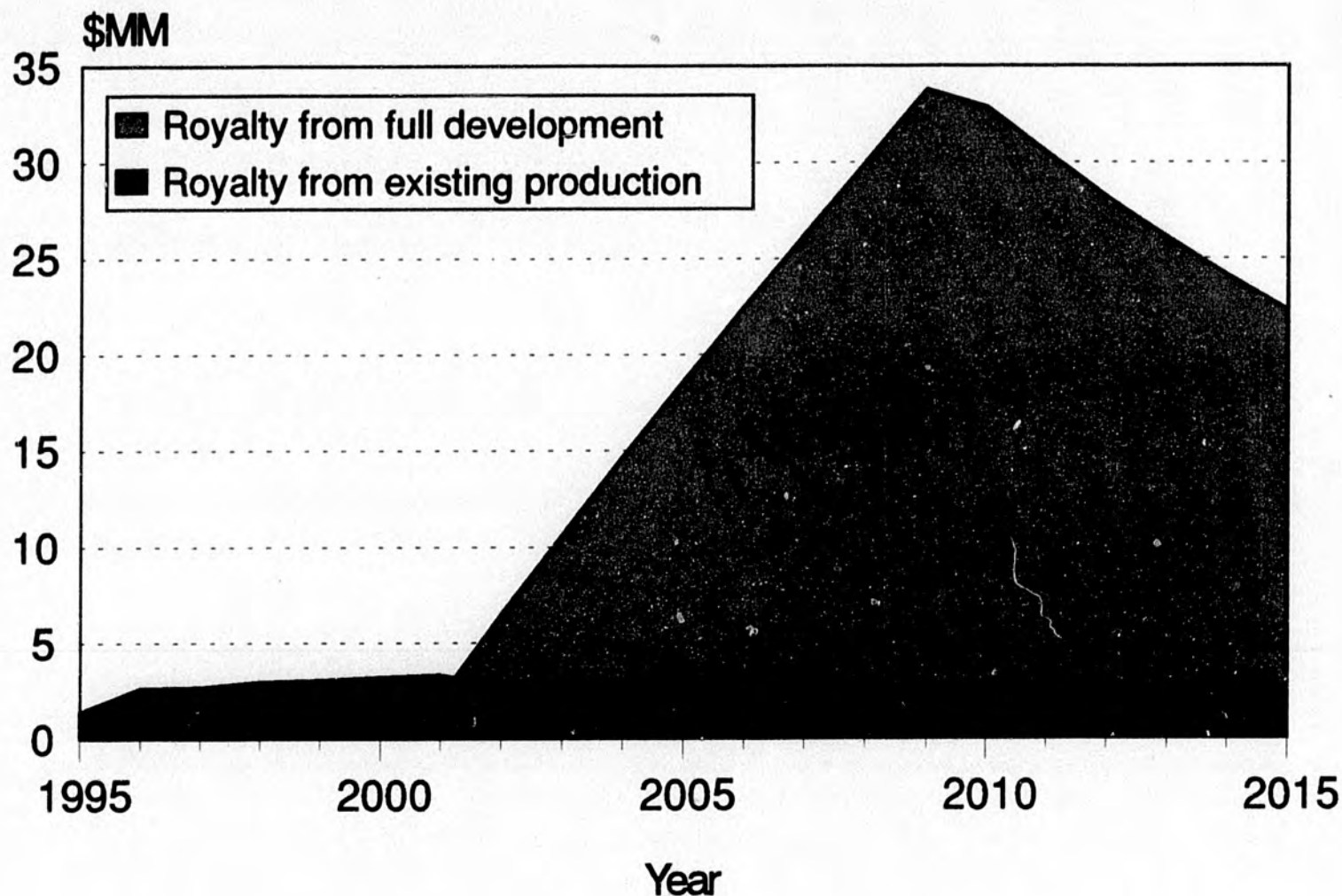
- *350 wells over a ten year period*
- *\$1.2 Billion in Capital Expenditures*
- *300 million barrels of additional oil produced*
- *60,000 BOPD production rate at peak*

Additional Production from Heavy Oil Development

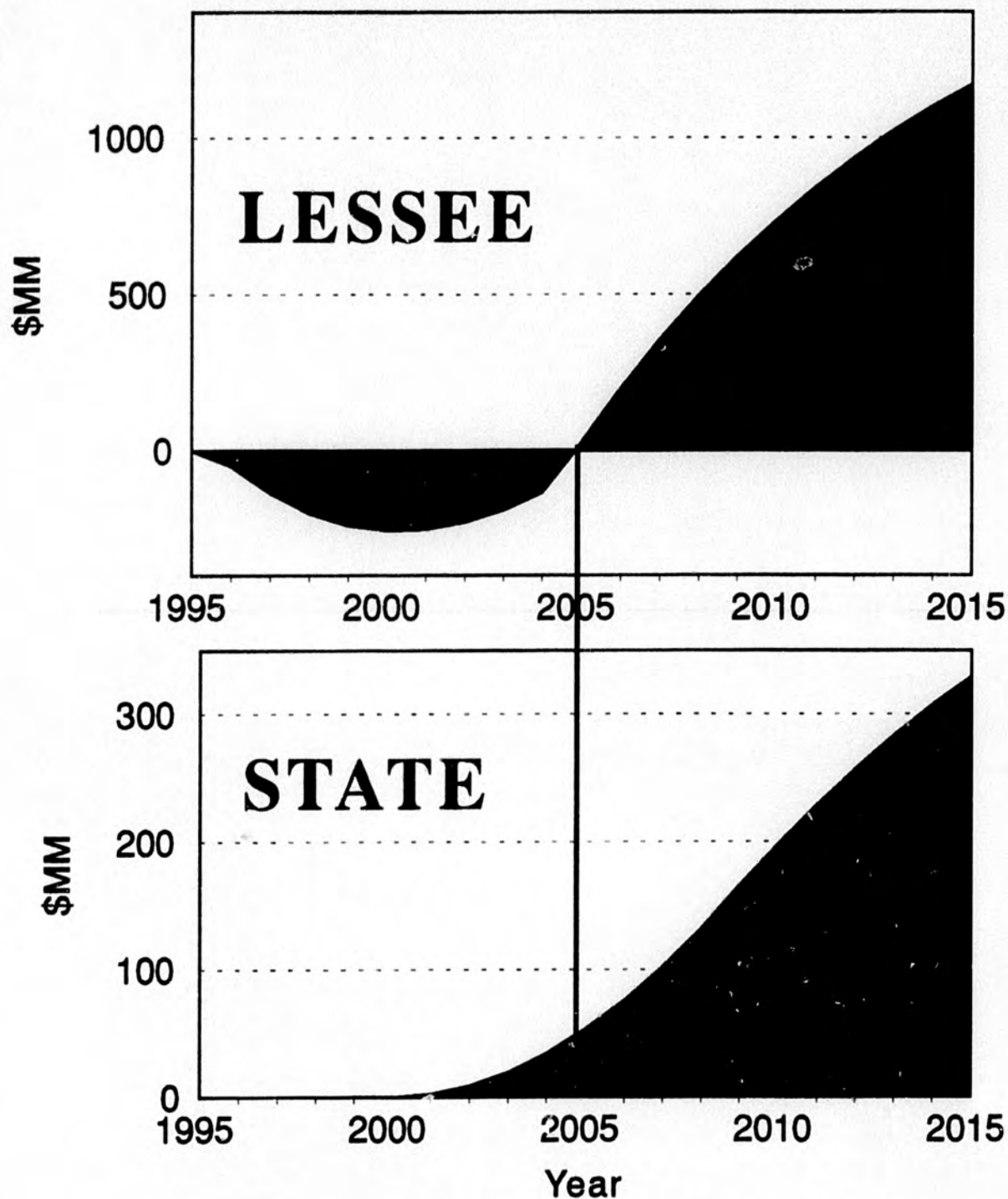


How Does Alaska Benefit?

Royalty payments from full development compared to existing production



Cumulative Cash Flows From Full Development



Oxy Presentation Page 2

MINUTES

OIL AND GAS POLICY COUNCIL

JUNE 28 and 29, 1995

The meeting was called to order at 2:15 p.m. the fifth floor conference room of the LIO Fourth Avenue, Anchorage.

Present: Esther Wunnicke, Mary Marshburn f Kevin Banks for John Shively, Margie Brown Condon, Dave Cline, Pete Leathard, John Mo Absent: George Ahmaogak, Sr., Gregory Carr Navarre, Drue Pearce, Ken Thompson.

1. AWARD OF RFP NO. 0176, Outside Consu:

The Chair introduced Roger Marks, petroleum economist with the Department of Revenue and the chair of the proposal evaluation team. Marks asked that the Council recess into closed session in order to discuss details of the two proposals. The Council recessed at 2:20 p.m. and reconvened to public session at 2:35 p.m.

Condon moved, seconded by Marshburn and it was passed without objection,

to adopt the recommendation of the evaluation team and select A.D. Little/John Gault to fulfill the obligations of the contract

The management team will consist of Roger Marks, Kevin Banks, Ray Jacobczak, Stefan Zuckut, Mike Hurley, Chuck Logsdon, Mike Greening and members of the Council. A draft document is due on August 15, 1995 and the Council is driving for a presentation by the principals at its meeting of September 7, 1995.

The meeting was recessed at 2:45 p.m. and reconvened at 9:00 a.m. on June 29, 1995.

Present: Esther Wunnicke, John Morgan, Dave Cline, Wilson Condon, John Shively, Margie Brown, Ken Thompson, Mary Marshburn for William Hensley.

Absent: George Ahmaogak, Sr., Gregory Carr, Mike Navarre Arriving during the meeting: Jim Branch, Mano Frey, William Hensley, Pete Leathard, Drue Pearce

1. APPROVAL OF COUNCIL MINUTES OF May 25, 1995
2. APPROVAL OF COUNCIL MINUTES OF June 12, 1995

Shively moved, seconded by Condon and it was passed without objection,

to approve the minutes of May 25 and June 12, 1995

3. HEAVY OIL DEVELOPMENT ON THE NORTH SLOPE - OXY USA, Inc.,

Shively

358-2916

See bottom of p. 1

Don Romine, Rick Foppiano and Ed Behm

* [John Tillinghast, attorney for OXY, introduced Romine, Behm and Foppiano.]

Behm, introducing OXY, noted that they have no interest in TAPS nor do they sell petroleum products. They have an interest in Milne Point. Heavy oil is thick, takes longer to produce, and is lower priced than light oil. ARCO attempted to produce heavy oil in its West Sak sands project but determined it to be uneconomical and stopped work in 1986. Conoco did better with the Milne Point Tract 14, improving production rates about 10% over West Sak and lowering the per barrel cost, but it was still too expensive to be economical. Behm covered the problems in producing heavy oil and potential alternatives/solutions which have been attempted. Primary production methods still appear to work best. Getting heavy oil to market is very expensive, costing \$6.14 per barrel to transport and the cash margin on Milne Point is only \$.93

OXY is spending approximately 10% of its domestic budget in Alaska and needs a 15% minimum rate of return on projects in order to justify capital investment.

The question remains as to whether the Milne Point sands will be fully developed. In exploring this, Foppiano covered the assumptions used in the company's economic calculations which result in a 12.8% ROR which is insufficient for full development. He continued that a final decision not to proceed has yet to be made but some significant decisions must be made soon. They believe that the answer to this difficulty is for the State to have an effective incentive policy. The criteria they have developed for an effective incentive policy which would positively influence ANS heavy oil investment decisions includes specificity at heavy oil production, relevance, reliability on the incentive's availability, immediacy to the current window of opportunity, credibility of the incentive as having been used successfully elsewhere, sufficiency to alter project economics and the necessity for Alaska not to leave money on the table.

HB 325, introduced by Representative Joe Green towards the end of the last legislative session, fits the bill. It is applicable to heavy oil production, only on the North Slope and provides for a suspension of royalty payments for each new well for the first 500 barrels of oil per day for the first five years of production.

Listing suspension incentives in other jurisdictions, Foppiano stated that HB 325 is analogous to the Texas high cost gas incentive. Texas has had 5 years of experience with this incentive and it was one of the only incentives renewed last year. He listed the benefits which included an increase in the number of wells, gas produced, sales tax revenue generated and employment. The effect of royalty suspension on Schrader Bluff

development would increase the ROR to 15.9% and decrease the payback period to 5.4 years.

Ken Thompson stated familiarity with the Texas incentive. Texas did a complete macroeconomic study of this with respect to jobs, corporate sales tax, property tax, etc. before instituting it. Pete Leathard asked about the status of HB 325 and was told that it had been introduced at the end of the session. Thompson said that heavy oil could be a key resource for Alaska and development would mean massive partnership. It deserves examination and he suggested that the Resource Assessment team look at how much heavy oil exists. The IC team should have the consultants look at worldwide incentives, particularly in Venezuela, and the macroeconomic picture must be fully assessed.

Asked about the effect of HB207 on Milne Point, Tillinghast said that it does not apply. Asked by Cline whether there was anything to be learned from Alberta's development of tar sands, Behm replied that was even more difficult.

4. MARATHON OIL, ALASKA EXPERIENCE - Ralph Dartez, Production Manager

Dartez said Marathon's Alaska operations are primarily focused in Cook Inlet and that they produce about 25% of the gas sold in Alaska. They operate an LNG plant and tankers, have been in Alaska since the 1950s and were participants in the Swanson River field discovery. He covered internal changes made within the past year to improve the company's economic viability and to extend field life in the Inlet's mature fields. Marathon would like to continue to grow in Alaska. They do not expect to find any new large, prolific fields but rather extensions of existing fields or small to moderate sized prospects. Hurdles to stimulating or encouraging investment in Alaska are land access, tax certainty and fairness and regulatory pressure.

There should be annual lease sales with an areawide best interest finding and acreage which is expired, relinquished or terminated should be reoffered to industry within a year of the lease termination. Regarding tax matters, tax rules and application need to be consistent and fair and tax incentives should be examined. State and federal regulations need to be reasonable and should meet but not exceed federal standards unless the costs are justified by environmental benefits.

Condon said the Legislature sets tax policy and the Administration is charged with administering that. If industry is seeing this done differently, then it needs to be addressed. Revenue recognizes that industry is its customer and must be treated fairly. Continuing, Condon said that Revenue must also collect the correct amount of tax and suggested that there are people in Marathon who can help clear confusion and bad feelings

that have existed. Dartez appreciated Condon's comments and noted a long history with the State. Perceptions are important, he said, and he has related many in his comments. For his company to do business in Alaska, the geological prospects are actually secondary to the perception of whether the company can do business with the State.

Asked by Hensley what the gas reserves are, whether they will bid on any future lease sales and if there were plans for expansion, Dartez replied that the Council should examine the DNR report with respect to reserves, although there looked to be a few errors in it. Marathon would like to expand their business in Alaska and will participate in future lease sales as they fit into the niche which they see for themselves in Cook Inlet, particularly those that are close to the infrastructure.

Thompson said that with respect to regulatory pressure, his company feels that burden more in duplication of effort and paperwork rather than extreme environmental regulations.

A meeting of the Council on the Peninsula was discussed and the Chair asked members to consider alternate methods of dispute resolution over lunch.

The Council recessed at noon for lunch and reconvened at 1:30 pm.

6. REPORT ON MMS WORKSHOP ON GENERAL LEASING POLICIES IN GULF OF MEXICO - Kevin Banks, DNR

Kevin Banks noted that the Gulf is a very different place for exploration and production than Alaska. MMS goals have been to slow the decline in production in the Gulf, promote deep water and other high cost area exploration and assure that the public gets its fair return. Production, however, is preeminent. MMS intends to improve the amount of unexplored acreage by decreasing bid rejections, reducing the minimum bid and increasing rent. Also in consideration are longer lease terms, larger tract size and new tracts with lower royalty rates. To increase production, MMS is looking at reducing the minimum royalty rate on new leases and reducing the royalty rate on existing leases in bilateral negotiation. Additionally, MMS intends to streamline the application and approval process for royalty relief, anticipating that there may be many situations meeting the royalty relief criteria. Jim Branch asked if any discussion of shallow water efforts to get more independents involved had been discussed and Kevin said not that he was aware of.

5. UPDATE: ARCTIC NATIONAL WILDLIFE REFUGE - Debbie Reinwand, Arctic Power

Debbie Reinwand briefed the Council on the various programs in progress by Arctic Power to encourage passage of legislation to

open the Refuge. These include informational meetings in Washington, D.C. with various legislators, tours for both media and policy makers of the Refuge, and monitoring of ad campaigns which are anti-opening. Mano Frey, Co-Chair of Arctic Power, said that one year ago he thought the opening of ANWR was simply a maintenance project but progress has been so significant that optimism is now very high.

7. RESOURCE ASSESSMENT SUBCOMMITTEE REPORT: Shively

John Shively distributed minutes from his subcommittee's meeting of June 16. The major presentations included Ryan Lance of ARCO on Alaska oil and gas reserves and resources, coal bed methane and gas hydrates. Should Alaska ever have a gas line, the gas hydrates offer a large source of supply. John Morgan asked what distinction had been made by the subcommittee between known resources and potential and John said that identification of potential resources has not been attempted. The subcommittee has examined what the odds are that something might be found but has not attempted to quantify that. Morgan said that he felt this was something which should be pursued.

8. INTERNATIONAL COMPETITION SUBCOMMITTEE REPORT: Condon

Condon distributed minutes of his subcommittee's meeting of June 6 and said that they have been focused on the A.D. Little proposal. A signed contract is now in hand. This was no small effort, Condon said. Roger Marks, chair of the proposal team, had told Condon that if he was successful in accomplishing the work, that Condon would owe him a holiday turkey. Noting the coming Fourth of July, Tamar diFranco presented Roger with a frozen turkey.

Condon and Shively reviewed their very recent trip to London and Norway with respect to oil and gas matters. The two countries are substantially different than Alaska in their level of government take but similar in that each has taken a look at a fixed royalty based on revenue and decided it was not a good idea and abolished the fixed royalty. Both governmental agencies operate with considerable authority and self confidence. The royal reduction question has been dealt with and they believe that it is a necessary for an area with mature fields. They recognize that as the development of oil and gas fields mature, policy adjustments ought to be made. They do not do bonus bidding, they license and it is not an economically driven decision but involves a number of other factors. The United Kingdom is driven to be energy independent and Norway, whose electricity is provided by hydro power, is interested in export. What struck Shively most was the small role oil and gas play in the countries tax revenues. He feels this is one of the major reasons they can be so flexible. It is about 2% of the United Kingdom's tax base and about 9% of Norway's. Condon said that

Norway was curious about Alaska's permanent fund as it wants to set up an oil fund.

9. EVALUATION OF SOCIAL/ECONOMIC/ENVIRONMENTAL IMPACTS
SUBCOMMITTEE REPORT: Wunnicke

Esther Wunnicke said their last meeting had been postponed because of the potential conflict with proposal interviews.

10. COUNCIL WORKPLAN

Discussion ensued with respect to the Council's workplan and timetable. It was agreed that not all of the Council's work could be completed by fall but that the remaining subject matter would be prioritized with those items considered most urgent undertaken for completion by the end of September. This would leave October for discussion and recommendation of policy changes or actions. In this manner the Administration would have time to develop legislation for introduction at the new session in January.

Other items to be considered in the Council's workplan are a meeting with the Long Range Fiscal Planning Commission to allow sharing of perspectives and a more formalized presentation/report by the Resource Assessment subcommittee as to the size of resource which the State will most likely be dealing with in the future. The assumption, from all that has been heard, is that it will be smaller, more marginal fields, but that is just a perception at this point.

The meeting schedule agreed to by the Council will be as follows:

July 21: Social/Economic/Environmental Impacts subcommittee
meeting, 9 a.m. - noon
Full Council worksession from one until 4 p.m. on
remaining areas of work

The management team is to prepare a timetable and a list of work for consideration at this worksession.

August 22: Council meeting.
September 7: Council meeting.
September 28: Tax and Royalty summit - DATE CHANGE FROM 9/27/95.
October 12: Council meeting, policy discussion.
November 2: Council meeting, policy.
November 30: Council meeting, policy.

Projected agenda material will be prioritized and shifted with those items placed aside which are of less immediate concern.

The Chair said that if the Council finished the first portion of its work by November 30, she would buy Ken Thompson a holiday

turkey.

Ray Jacubczak said that the A. D. Little video conference would be held at BP on July 6 and Council members were invited to attend. The Chair thanked John Morgan for use of their videoconferencing facilities.

There being no further business to come before the Council, the meeting was adjourned at 4:00 p.m.

Mmarshburn
6/30/95



TIM BRADNER

A little heavy lifting could do Alaska good

Some of the largest untapped oil and gas resources in North America are the West Sak and Ugnu heavy-oil deposits on the North Slope.

The estimated oil resource is 26 billion barrels locked in the underground reservoir rock. That exceeds even Prudhoe Bay's 23 billion barrels of oil-in-place.

Let's be clear: This is no Prudhoe Bay. West Sak, the best of the two reserves, might eventually produce 200,000 barrels a day. Still, that's a lot of oil, and it's important for the state's oil-services industry, because heavy oil is very capital-intensive development.

The problem is that this oil is thick and difficult to produce, and the reservoir conditions are very poor compared to the nearby Prudhoe Bay and Kuparuk River oil fields. With present technology and oil prices, this oil is not economic.

Still, even a small recovery of such a large resource is a lot of oil, and it's a big target for Arco Alaska Inc., BP Exploration (Alaska) Inc. and Oxy USA, three North Slope producers, who are now focusing attention on technical and economic problems of producing heavy oil.

By definition, heavy oil has an API gravity of 20 degrees or below, compared with 29 degrees in other North Slope fields. The oil is thick and more difficult to move than conventional crude oil.

It is more shallow than the other fields and is nearer the 2,000-foot layer of permafrost. That lowers its temperature, making it thicker and even harder to produce. Also, heavy-oil wells usually produce at lower rates than conventional wells.

Please see Page C-2, **BRADNER**

□ This weekly summary of news items on information technology is provided by Educom, a Washington, D.C.-based consortium of leading colleges and universities. It is edited by John Gehl and Suzanne Douglas.

Parts today for Kodiak.
Alamar's Gus W. Darnell arrives today from Ozol, Calif., and departs Tuesday

parts the same day for Thursday; cargo is fuel.
Tacoma.
Petro Star's Energizer arrives Thursday and departs Friday; cargo is fuel.
Sea Land's Tacoma arrives Tuesday with general

BRADNER: Heavy oil is difficult to move

Continued from Page C-1

North Slope operators would feel fortunate to get 500 barrels a day from a heavy oil well.

On the North Slope, the West Sak and Ugnu overlay large parts of the Kuparuk and Milne Point fields, as well as part of Prudhoe Bay. West Sak is considered a more likely candidate for near-term production.

Oil companies think that with luck, 800 million to 1 billion barrels of oil might be produced from the West Sak. Oil recovery rates are expected, under the best of circumstances, to range from 10 to 16 percent of the oil-in-place. This compares with 40 percent in Kuparuk and 50 percent in Prudhoe Bay. The Ugnu resource is shallower and colder than West Sak and will likely require some radical new technology.

The companies have already spent a lot of money on the West Sak. Arco spent over \$200 million in the 1980s on research and a pilot production project. Conoco, then the producer at Milne Point, spent an-

other \$126 million on West Sak test wells. The projects were uneconomic.

Now Arco and BP are taking a fresh look. Oxy, partner with BP in Milne Point, has a lot of experience with heavy oil in California and is intrigued with West Sak's potential.

What's changed since the late 1980s is that a lot of infrastructure is available on the North Slope, particularly enhanced oil recovery facilities, that may lower the cost of heavy-oil development. Spare capacity also will be available in existing oil processing facilities, as production declines in the other fields.

New, low-cost drilling techniques, particularly the new coiled-tubing systems, offer the promise of drilling wells at lower costs.

Development of the North Slope heavy oil could be important to the state's oil-services industry, because a large number of new wells and very specialized production enhancements, such as "fracturing" of underground rock with high-pressure fluid injection, would be

necessary.

Because the economics are marginal, West Sak might be a candidate for the incentives being discussed within Gov. Tony Knowles' Alaska Oil and Gas Policy Council, an industry-state advisory group. Oxy USA, for example, recently told the council that a five-year royalty suspension might speed capital recovery enough so that West Sak wells meet the company's minimum "hurdle rate" for profitability. Although it isn't another Prudhoe Bay, or an alternate to the Arctic National Wildlife Refuge in terms of new oil prospects, North Slope heavy oil could boost the North Slope's reserves and help keep the trans-Alaska pipeline operating until production from major new discoveries, such as are possible from ANWR, would be available.

□ Tim Bradner writes for an Alaska economic reporting service. His private clients include petroleum companies. His opinion column appears every fourth Sunday.

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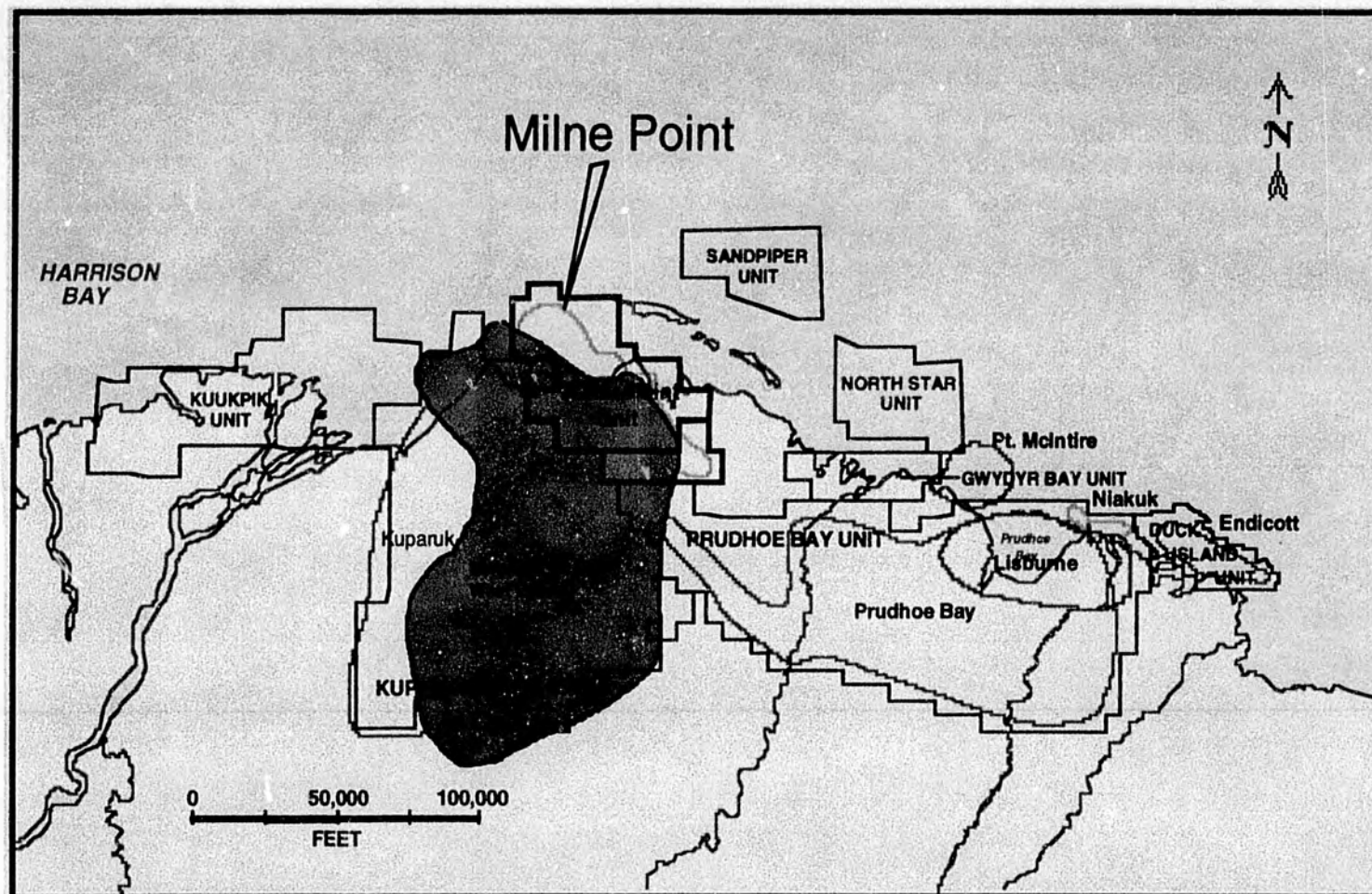
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BP Exploration (Alaska) Inc.
Presentation by BP Exploration (Alaska) Inc.
before the House Oil and Gas Committee

January 23, 1996

North Slope Fields



Schrader Bluff Heavy Oil Development

-
- The map illustrates the Schrader Bluff Heavy Oil Development. It features a large, irregularly shaped area outlined in black, representing the development boundary. This area is divided into several sub-regions. A large, dark grey area at the top is labeled 'Schrader Bluff Heavy Oil Development'. Below this, a light grey area is labeled 'KRU'. To the right of the 'KRU' area, a small, dark grey area is labeled 'CFP'. Below the 'KRU' area, a light grey area is labeled 'PBU'. The map also shows several small, dark grey areas representing 'Development at Acquisition' and 'Development in Progress'. A legend in the bottom left corner defines these symbols: a dark grey square for 'Development at Acquisition', a black square for 'Development in Progress', a light grey square for 'Future Development', a small black square for 'Existing Pad', and a small dark grey square for 'Future Pads'. The map is set against a background of a light grey area representing land and a dark grey area representing water.
- Development at Acquisition
 - Development in Progress
 - Future Development
 - Existing Pad
 - Future Pads

Schrader Bluff Development History

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

Significant technical and commercial hurdles remain to be overcome

MPU Schrader Bluff - Potential Program

1994

Drill Test Well

1995

Drill six "Test Wells"

?? - 1998 - ??

Potential Development

230 Wells

45,000 bpd Production

Key
Decisions

Determine viability and
scope for '95 wells.

Demonstrate increased
rate and reduce costs.

Establish viability of
larger scale initial
development.

1995 Schrader Bluff Development

- **Objectives**

- **Reduce capital requirements and operating costs**
- **Increased production rates from new wells**
- **Reduce development uncertainty**

- **Progress - 1995 spend \$15,000,000**

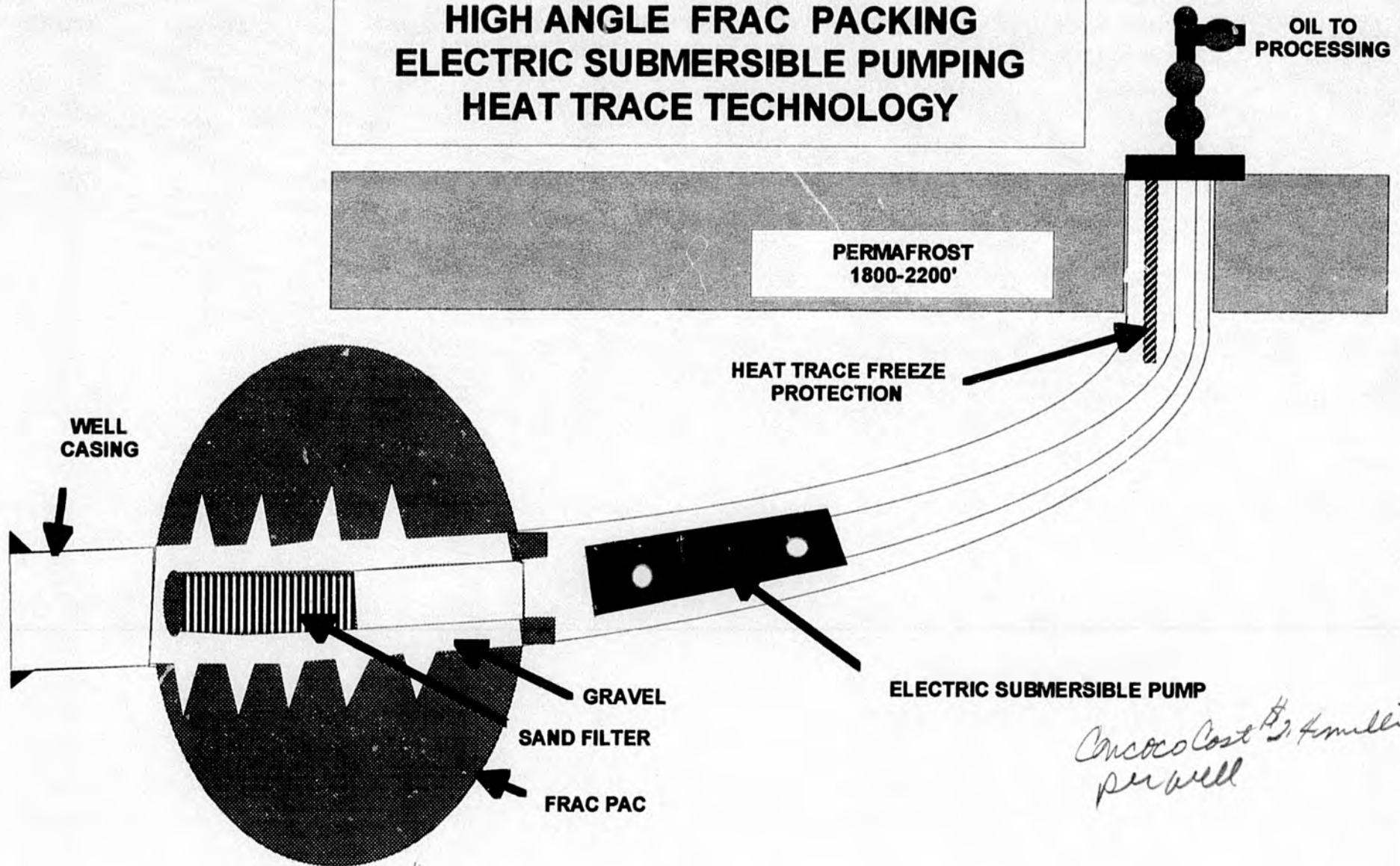
- **Six wells drilled; completions in progress; not on production**
- **Three wells recompleted and on production**
- **Reservoir and facility technical studies initiated**

- **Results**

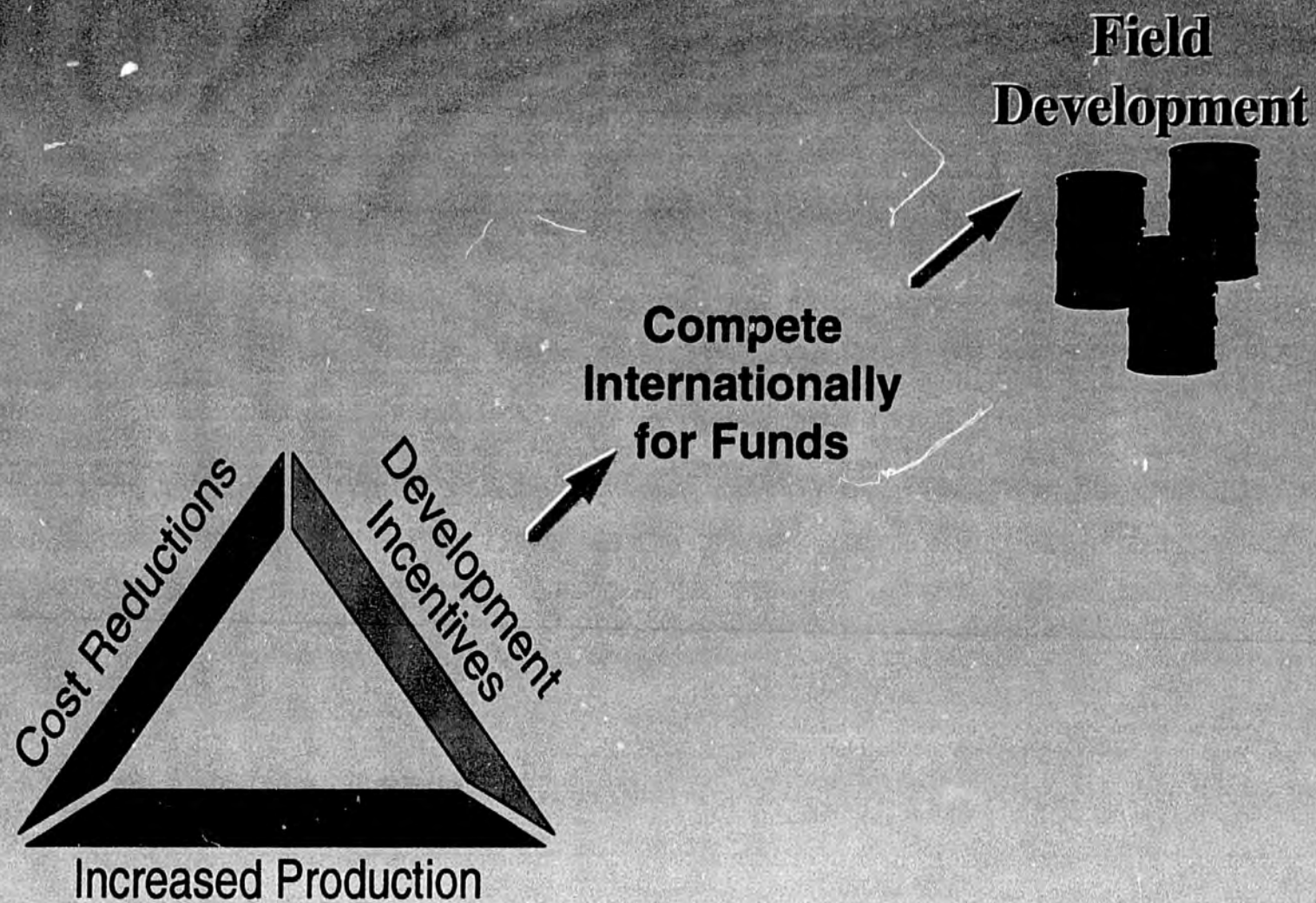
- **Drilling cost reduction demonstrated**
- **Completion cost remains problematic**
- **Improved submersible pump life realized**
- **Well performance and technical study results not yet available**

SCHRADER BLUFF TECHNOLOGY:

HEAVY OIL TEST BED
HIGH ANGLE FRAC PACKING
ELECTRIC SUBMERSIBLE PUMPING
HEAT TRACE TECHNOLOGY



Schrader Bluff Challenges



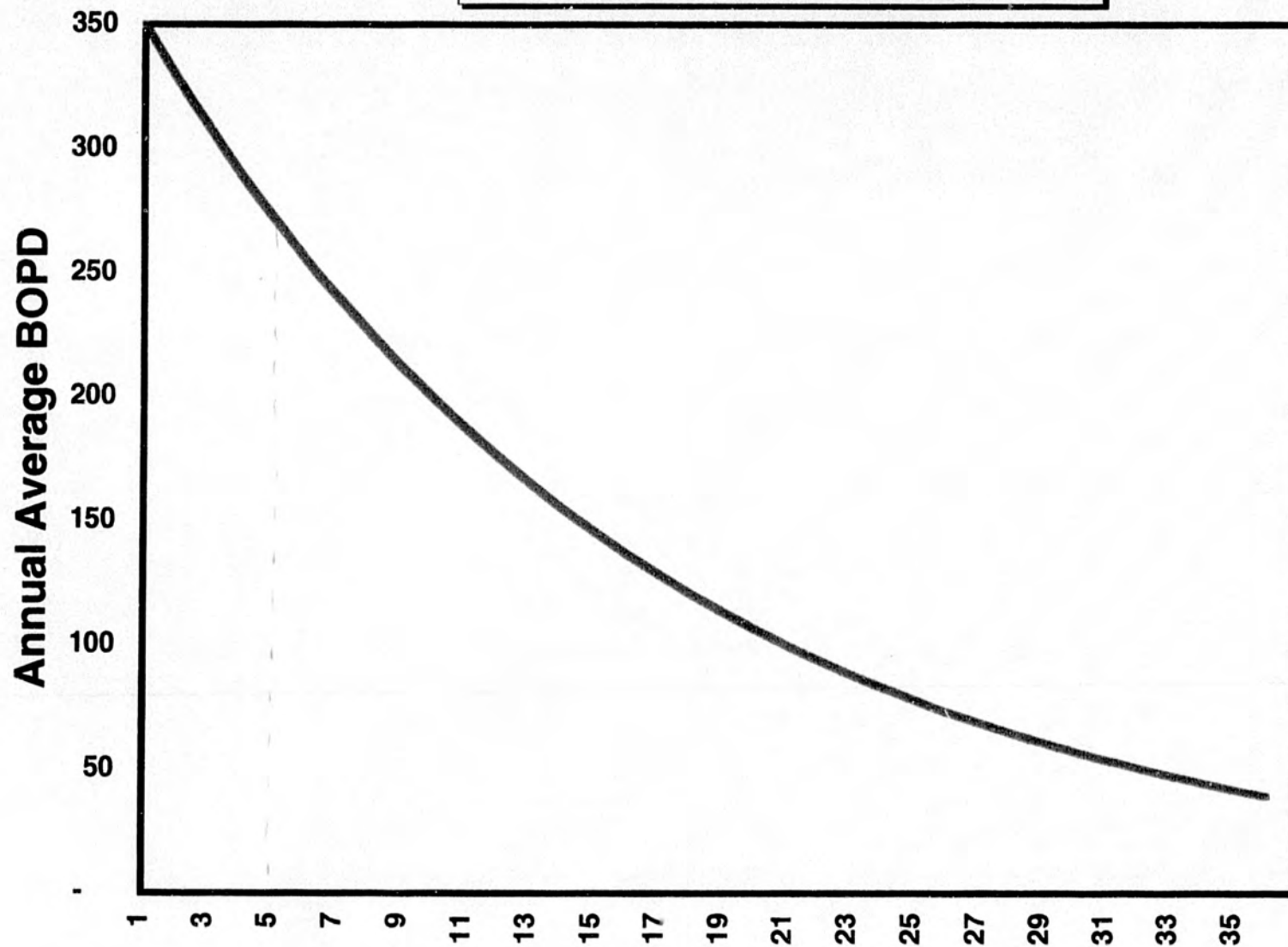
The “Prize” at Schrader Bluff

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

Heavy Oil Royalty Holiday (HB-325) Impact on Schrader Bluff Project

- **Royalty holiday will:**
 - **Reduce uncertainty**
 - **Encourage investment**
 - **Send positive signal**
 - **Accelerate pace and increase development scope**
- **Time lag from incentive to start of investment is short**
- **Ultimate project scope remains uncertain**

**Schrader Bluff Typical Well
Production Rate vs Time (years)**



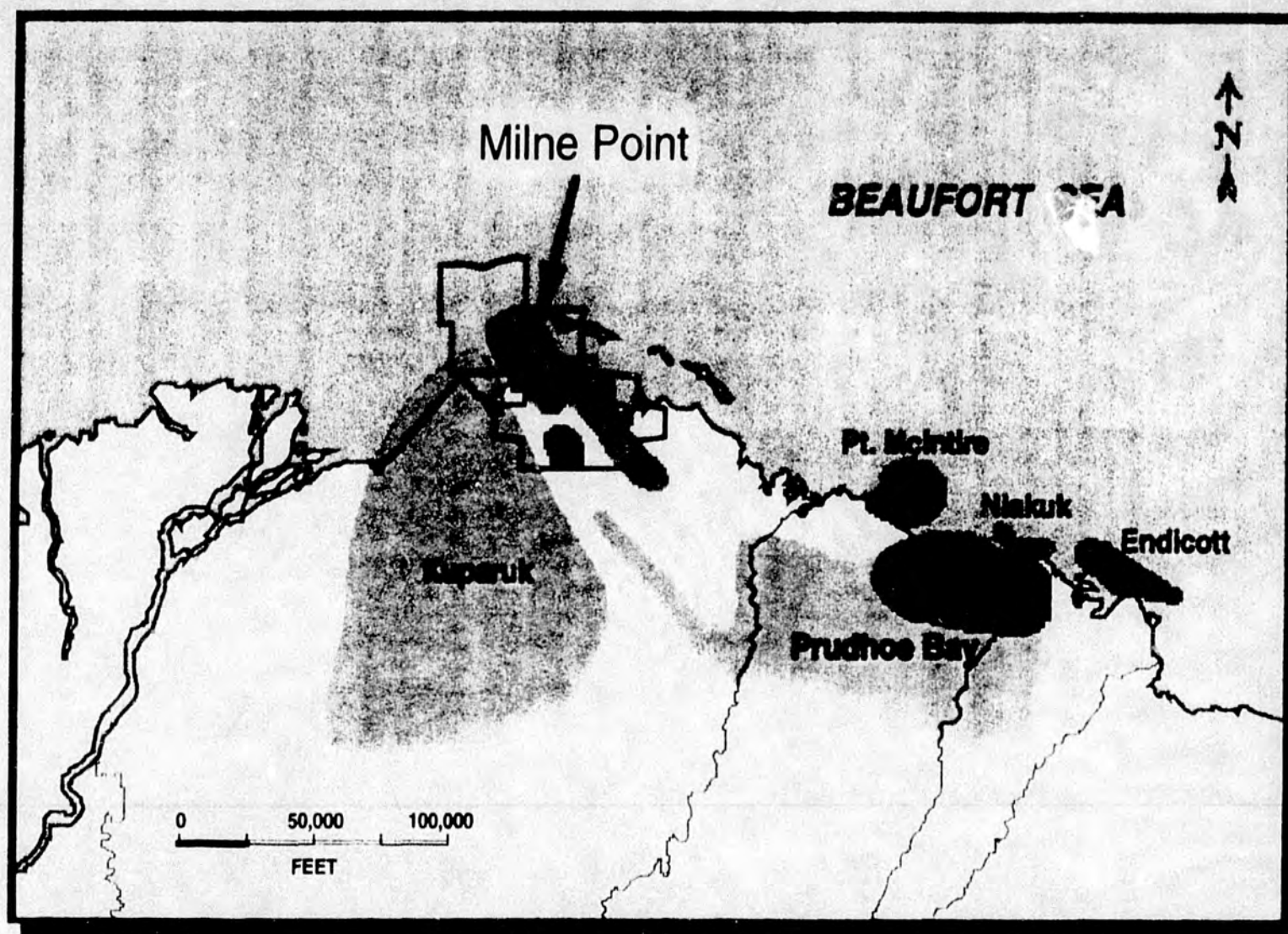
See 20% Kuparuk decline Rates
See 18% Erdenei decline rates
See 6%-8% decline at Schrader Bluff

The “Risk” of Project Development Delay

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

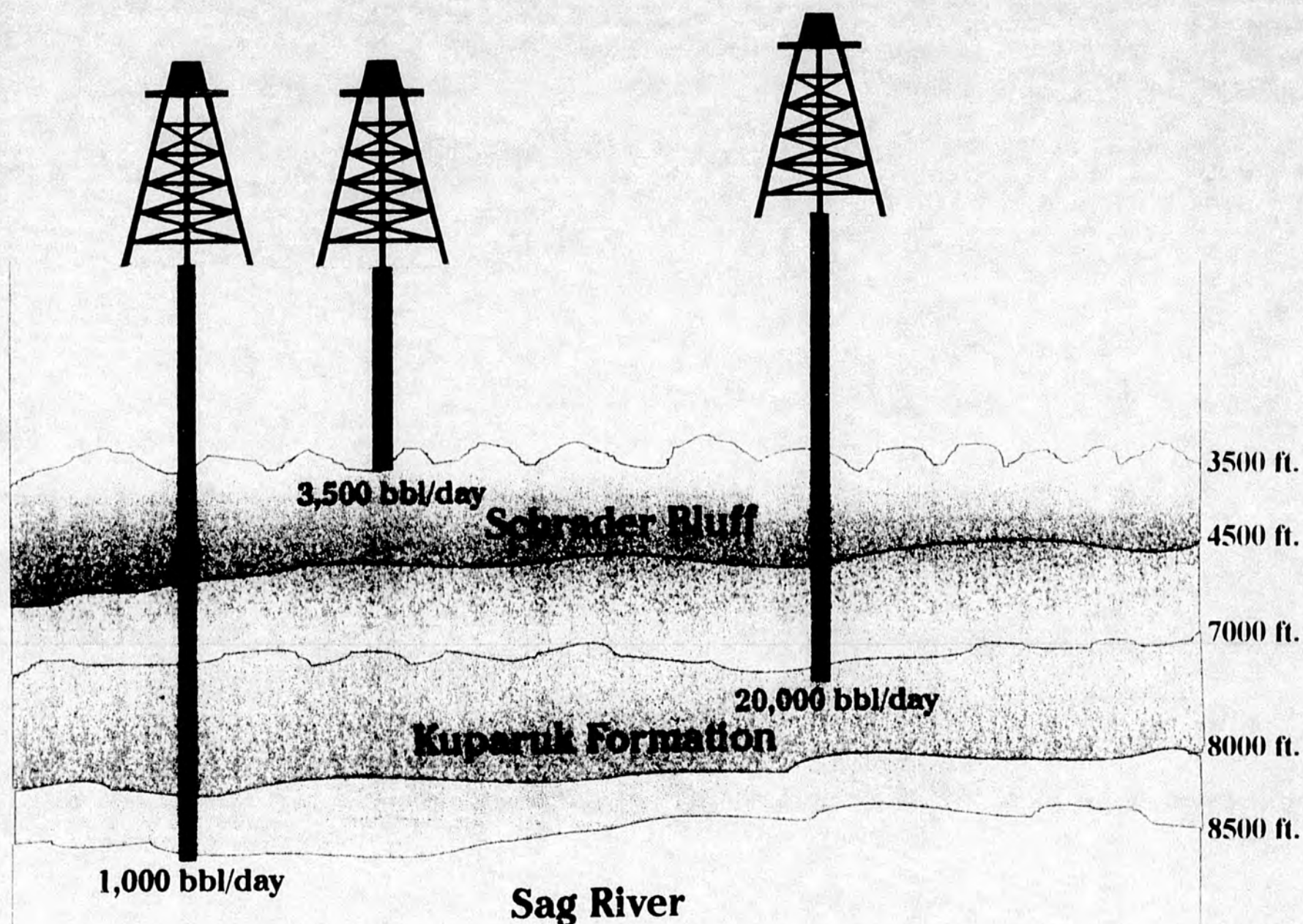
WHO IS OCCIDENTAL OIL AND GAS CORPORATION?

- *Oil & gas part of Occidental Petroleum Corporation*
- *Large independent in the US, no refining or marketing operations*
- *No financial interest in TAPS*
- *Operator of Heavy Oil properties in California*
- *The last original owner in Milne Point Unit with around 9% WI*



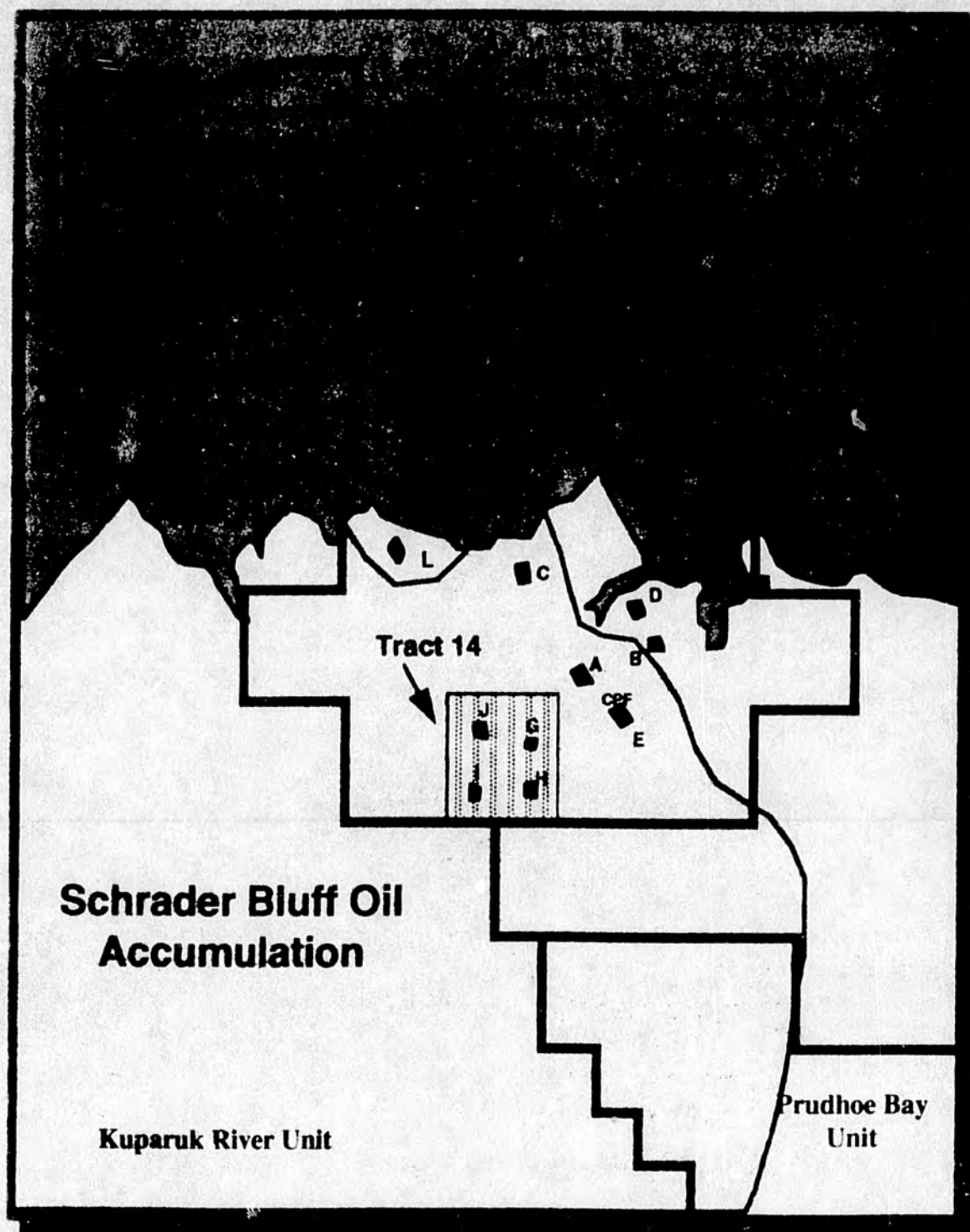
North Slope Fields and Milne Unit Outline

Occidental and BP produce oil from three formations at MPU



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



Schrader Bluff Oil Accumulation

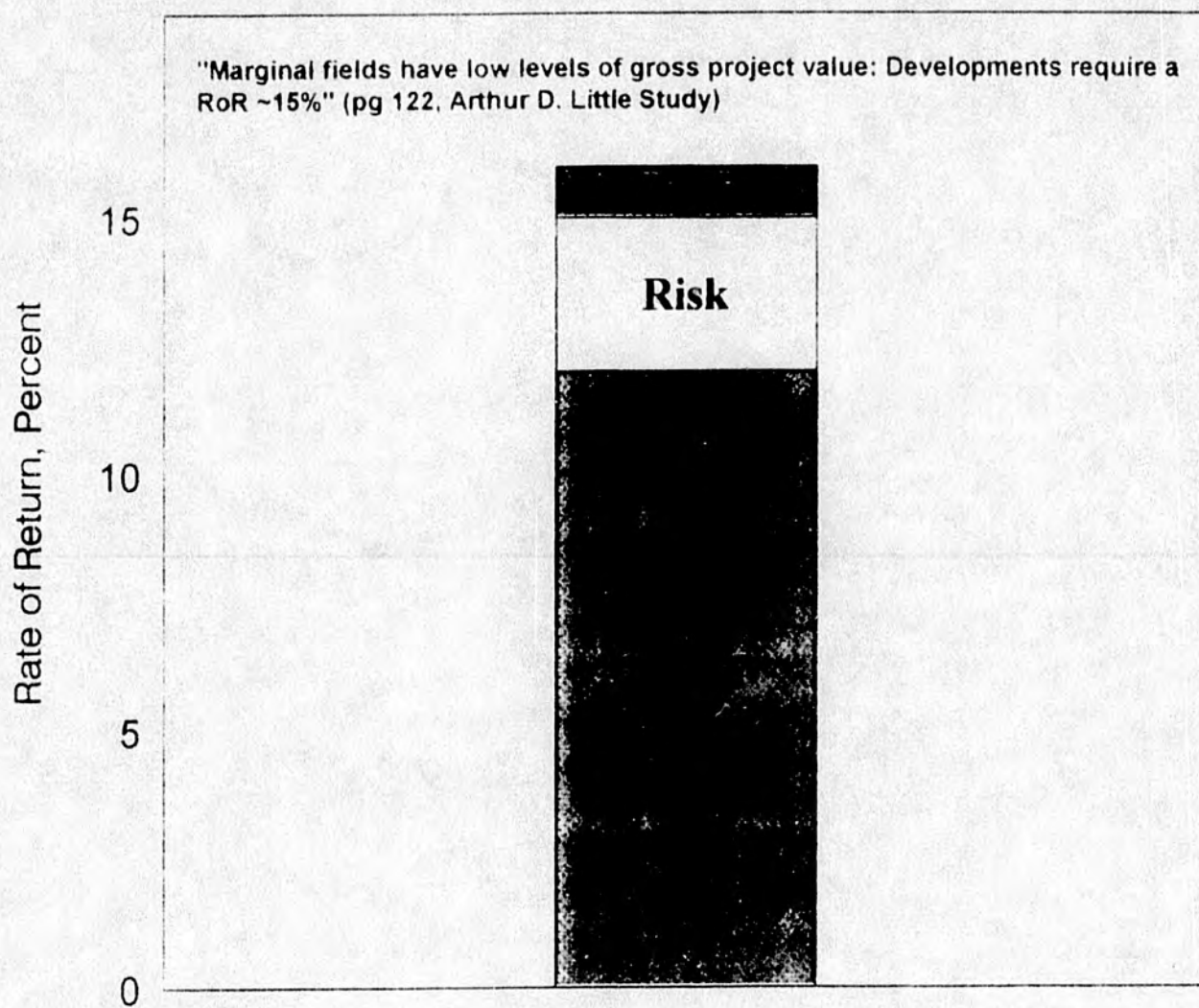
Previous Heavy Oil Experience

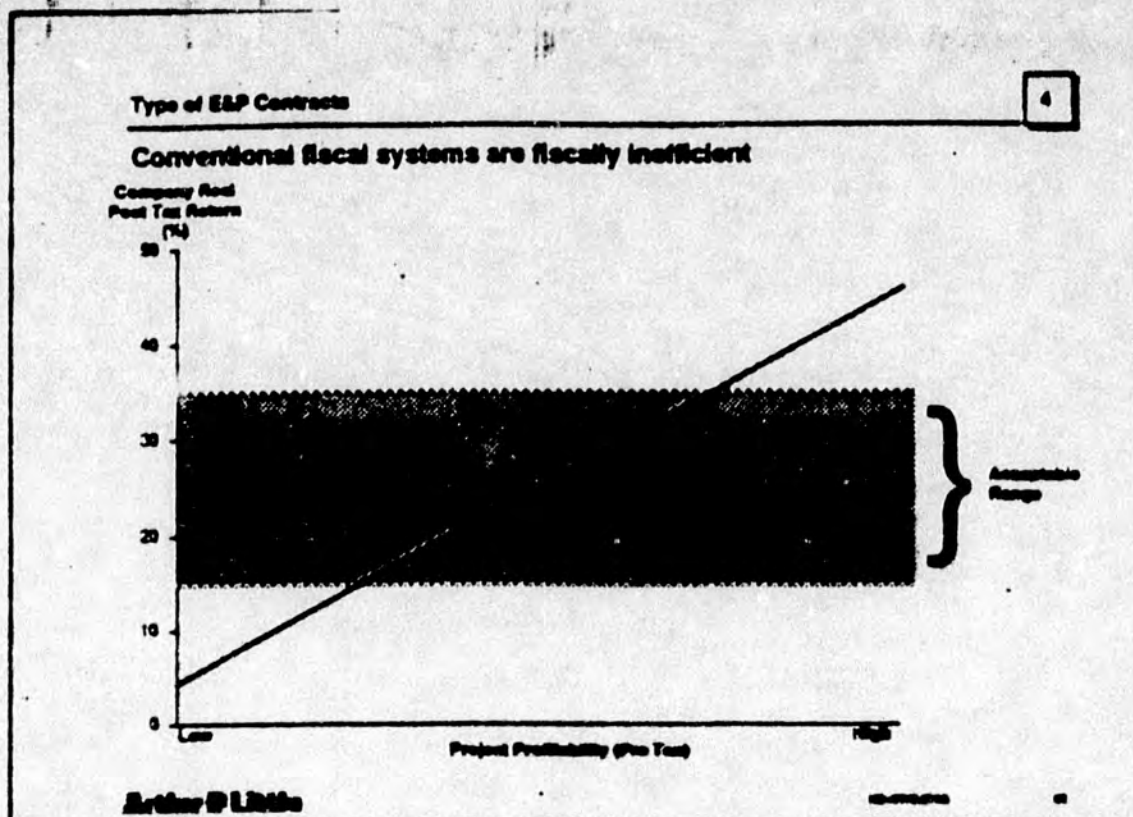
Conoco/Tract 14

- *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.

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



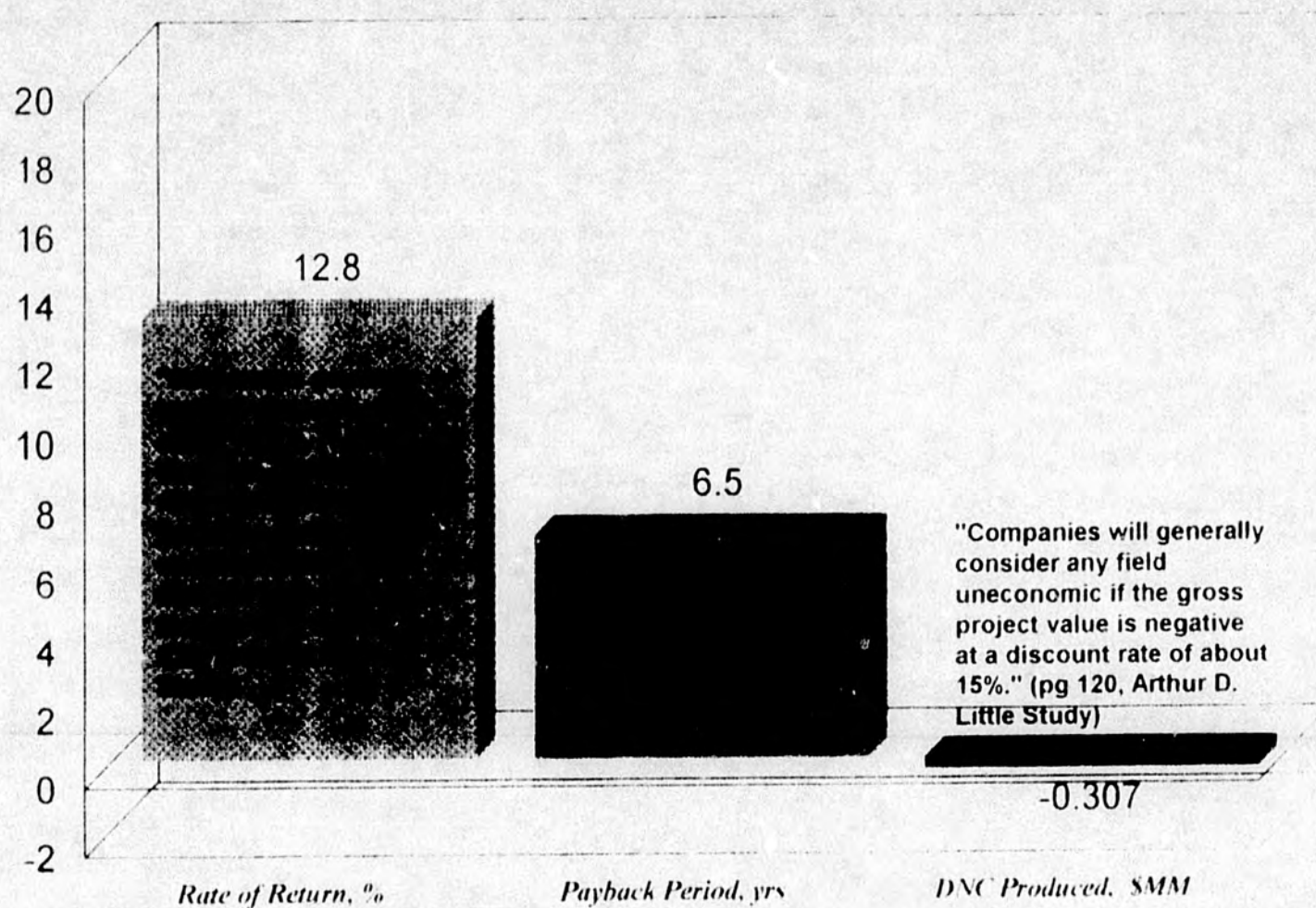


Conventional fiscal systems are fiscally inefficient:

- Under a traditional petroleum agreement (with fixed royalty and income tax rates under a licence agreement or fixed cost and profit sharing under a production sharing contract) the total government take and the oil company profitability change considerably with the characteristics of the discovery (size and development cost) and with oil prices.
- This type of system is "fiscally inefficient" and has fallen into disfavoured following the oil price fall in 1986 and a worldwide trend towards smaller field discovery sizes.
- In a fiscally inefficient system:
 - Smaller and higher cost fields will not be developed as the profitability is too low to attract oil companies.
 - Larger and least expensive fields will generate excessive profits for the companies; the government take will be lower than it has the potential to be.
 - Similar effects will be experienced if oil prices are unexpectedly high or low.
- Thus, uniform fixed rate fiscal systems produce non-uniform results which are economically discriminatory:
 - It is important to "tailor" the contractual terms so that the conditions offered are attractive both for significant and for small discoveries and so that the long term interests of host country and the investors are protected, for example, in the case of wide variations in crude oil prices.

Typical Heavy Oil Well Economics

Based on the 5 best wells to date in Tract 14



What are we proposing?

HB 325 by Representative Green

- Applicable to heavy oil production as defined by 26 U.S.C. 613A(c)(6)(F)
- Applicable only to the Alaska North Slope
- Suspension of royalty payments for each new well for the:
 - first five years
 - first 500 barrels of oil per day
- A simple, automatic process

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)

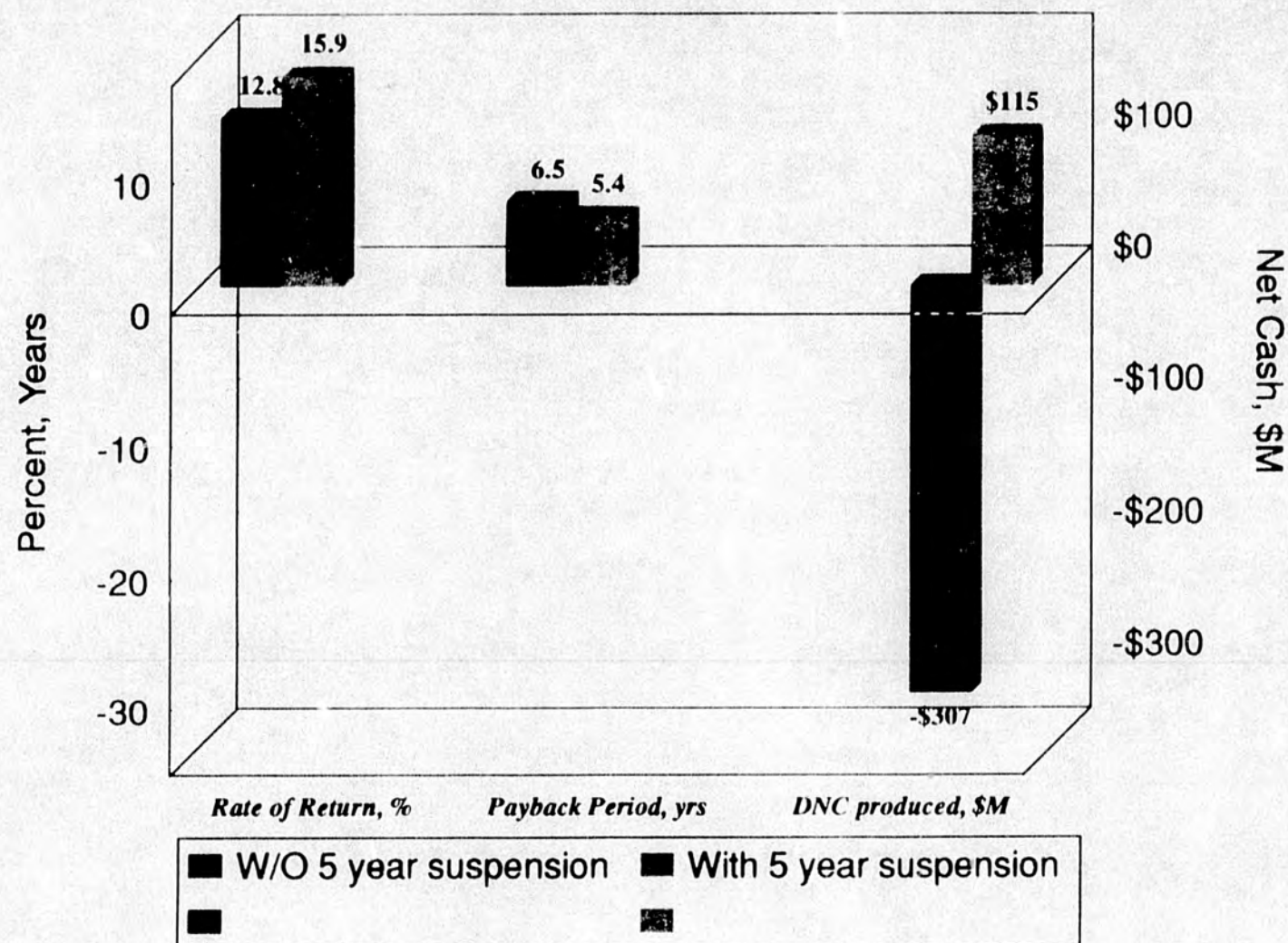
Kansas

- tertiary projects (for life of project)
- shallow wells (for life of project)
- discovery wells (first 12 years)

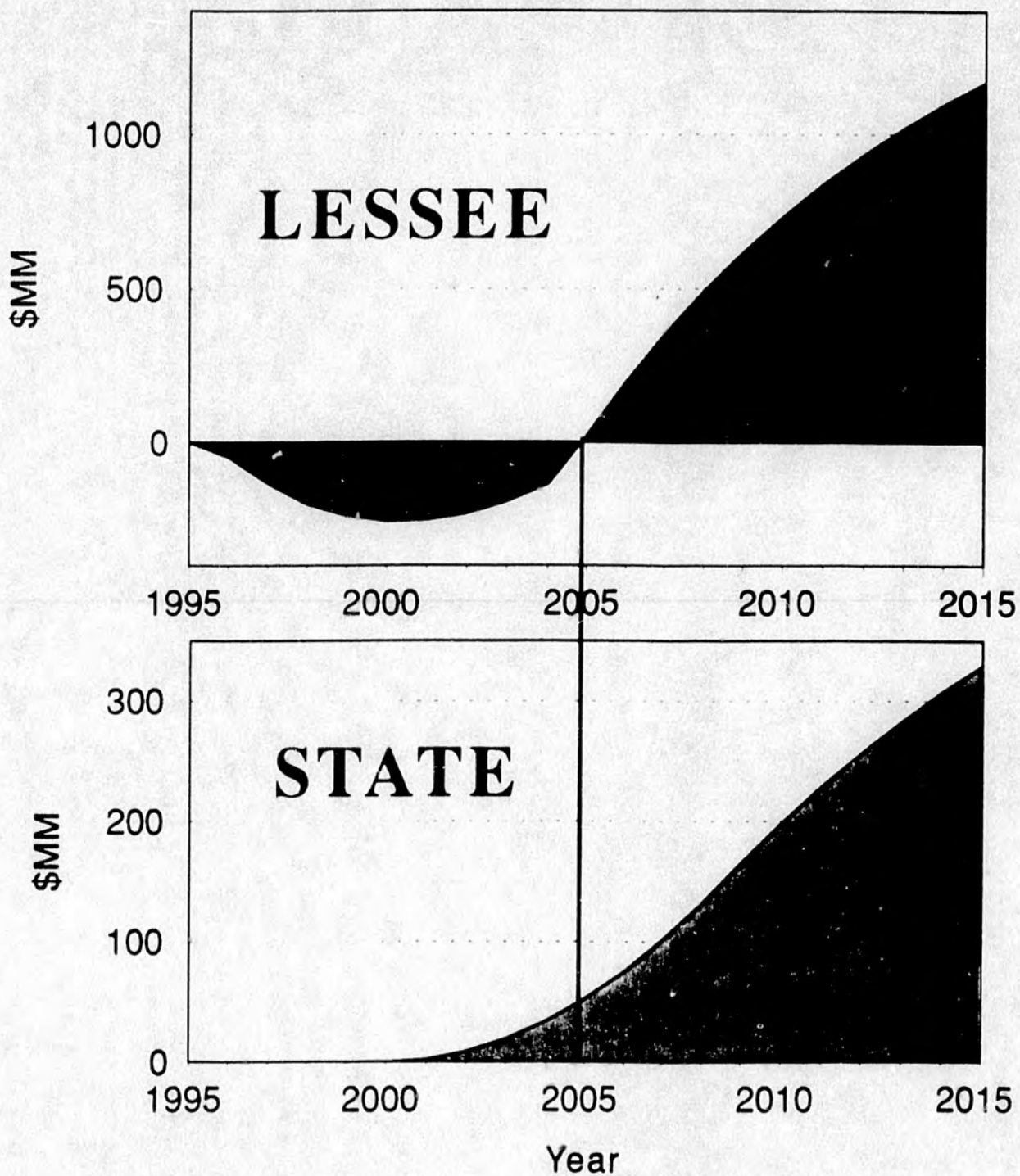
Arkansas

- discovery wells (first 5 years)

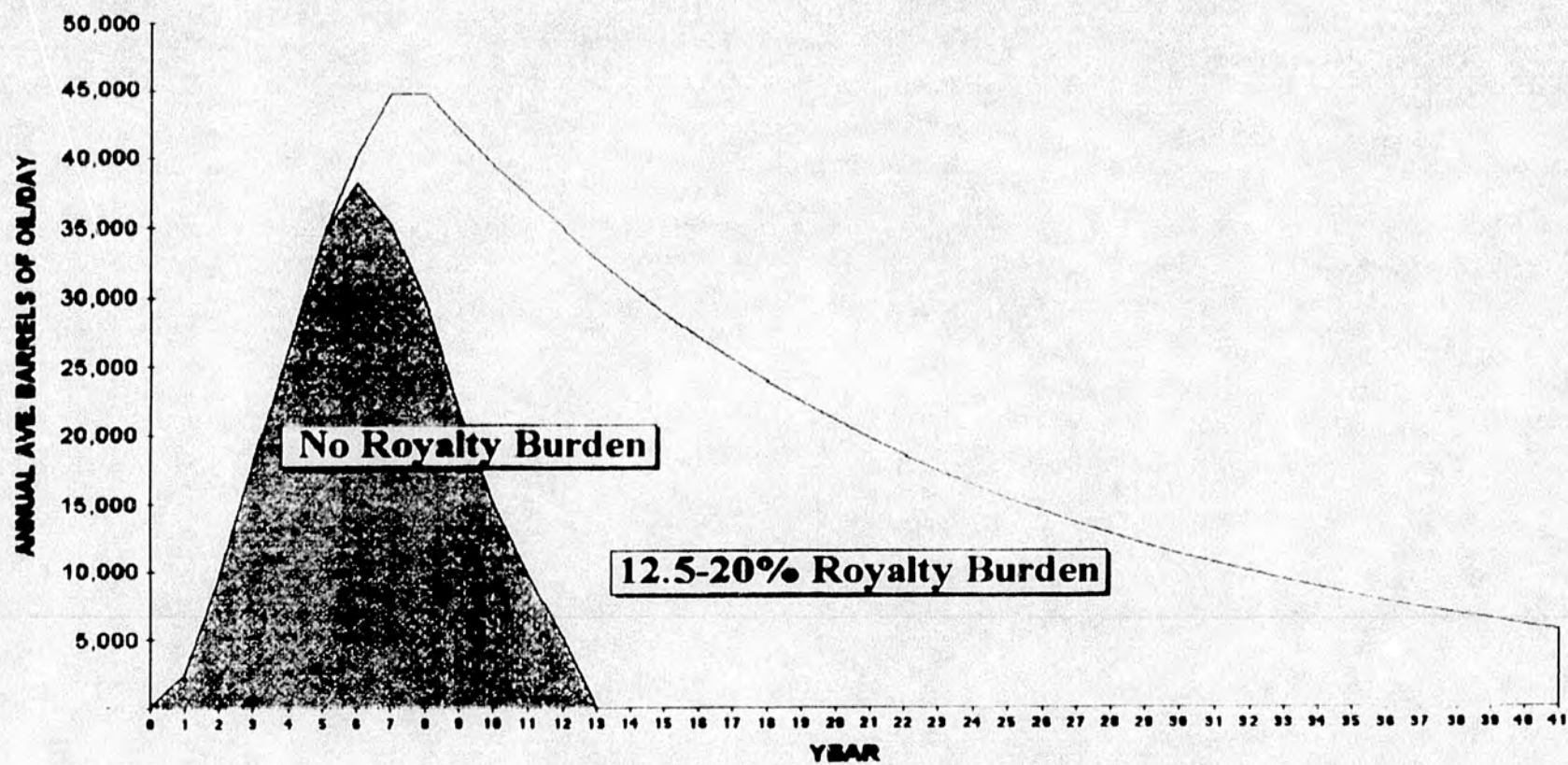
The Effect of Royalty Suspension on Schrader Bluff Economics



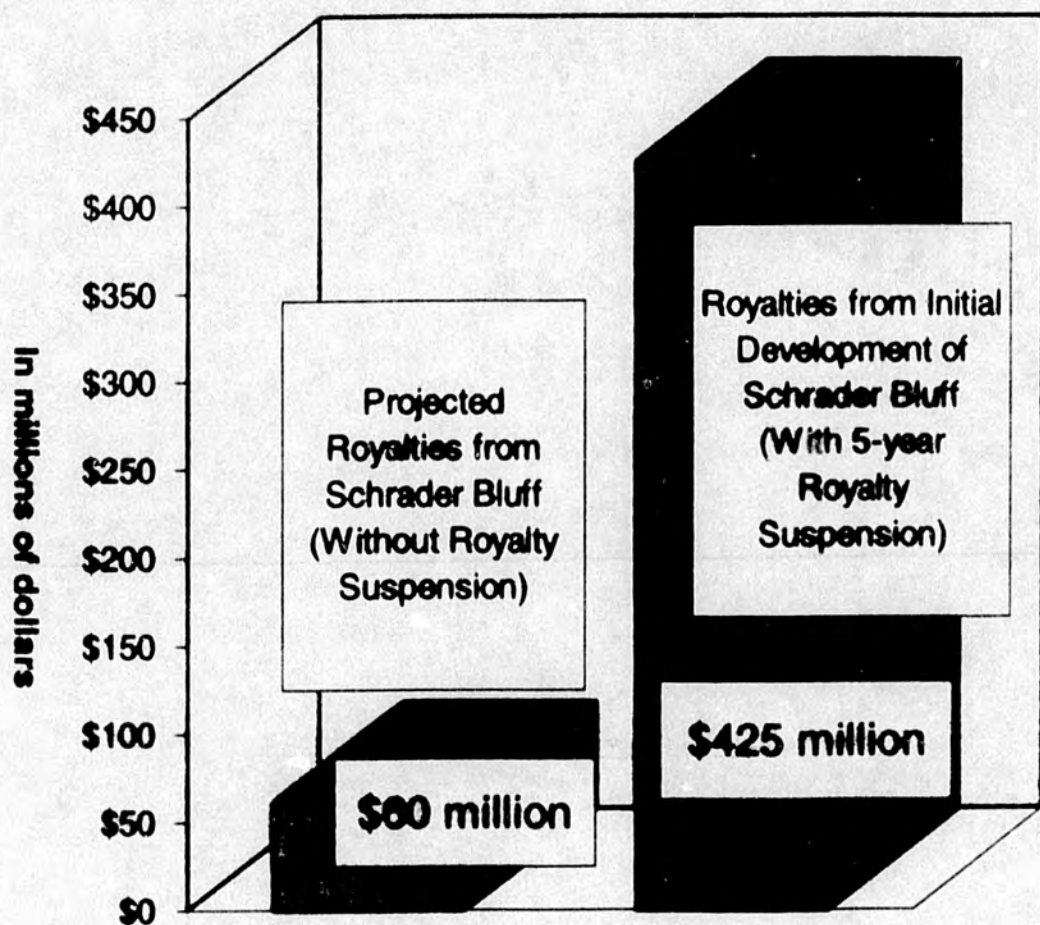
Cumulative Cash Flows From Full Development



ADDITIONAL PRODUCTION FROM HEAVY OIL
BY
DEVELOPMENT YEAR



Two Paths for Schrader Bluff





BP EXPLORATION

James A. Palmer

Director
External Affairs
Alaska

November 10, 1995

Representative Norman Rokeberg
Alaska State Legislature
716 W. Fourth Avenue, Suite 640
Anchorage, Alaska 99501-1123

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

Dear Representative Rokeberg:

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

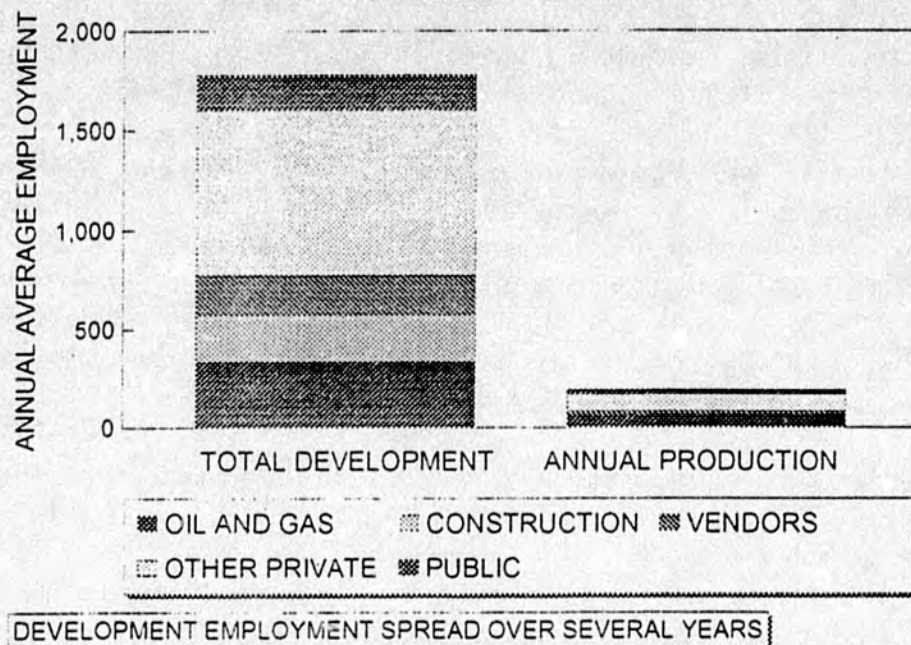


FIGURE 1B. MARGINAL FIELD ECONOMIC EFFECT:
RESIDENT PAYROLL

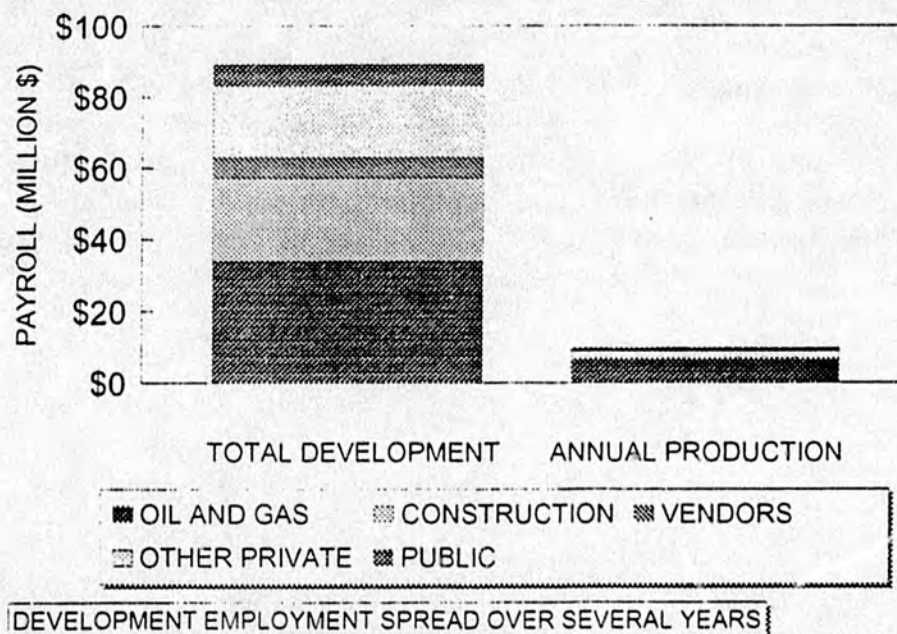
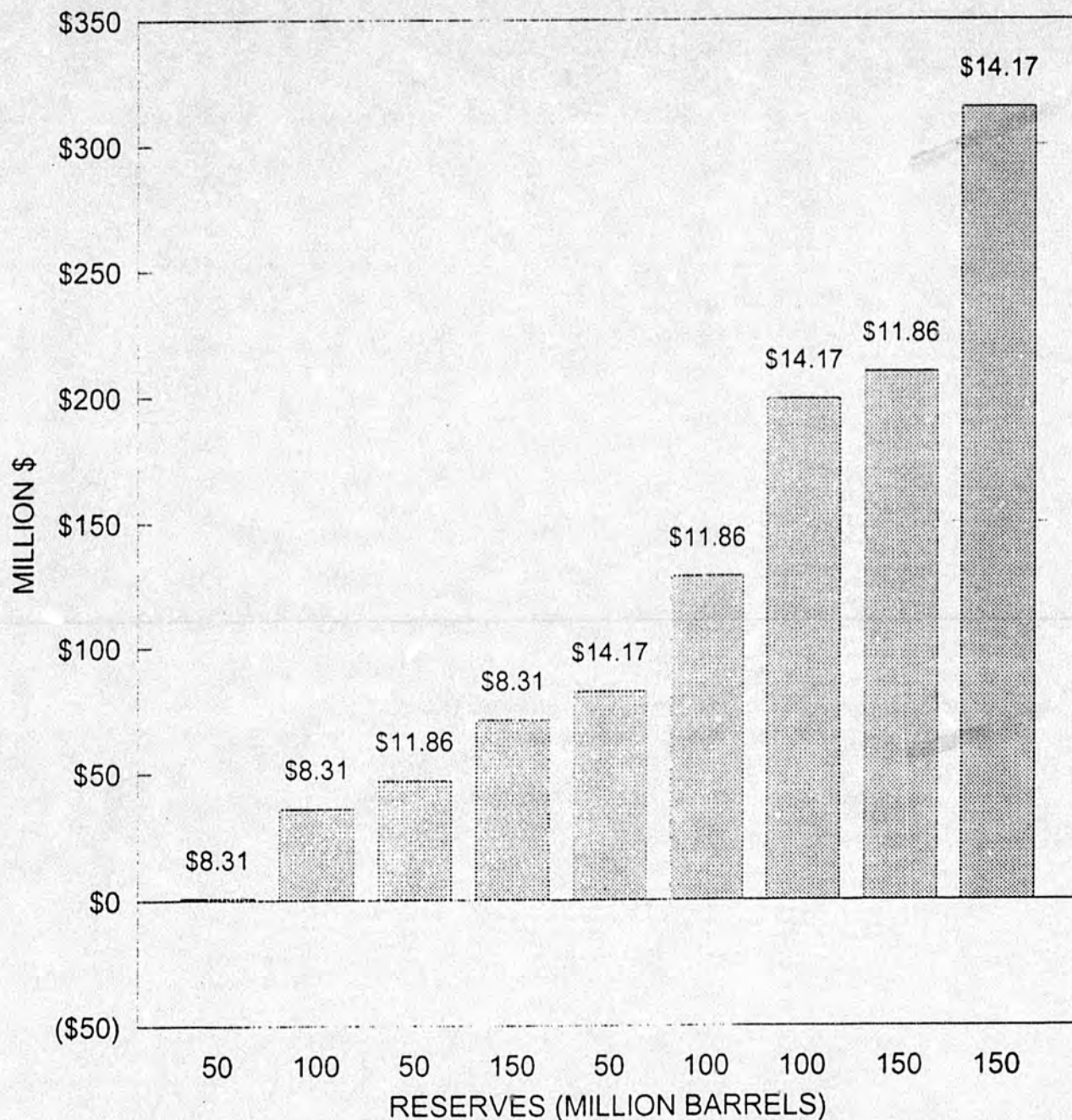


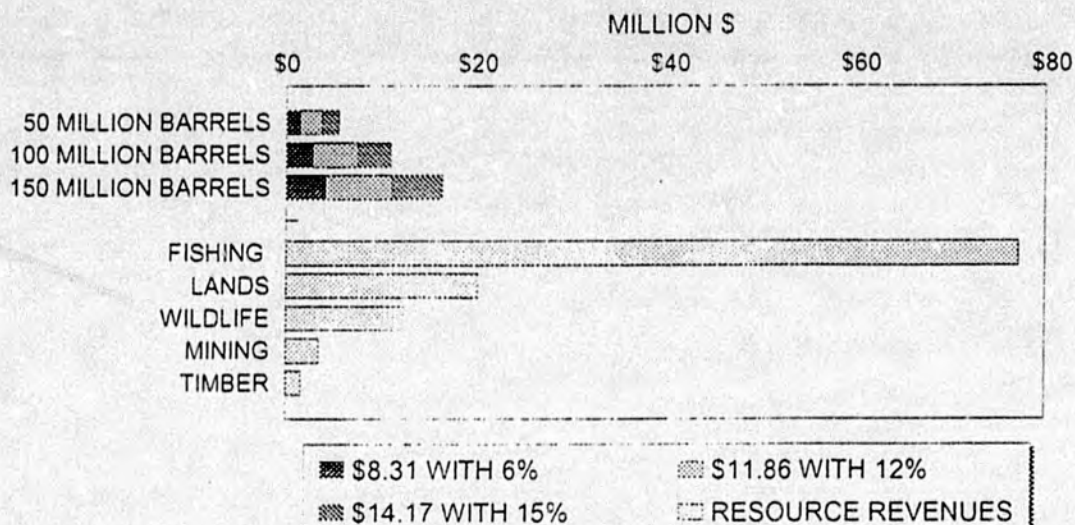
FIGURE 4. STATE REVENUE "DIVIDEND"

VARIATION IN RESERVES, PRICE, AND ROYALTY RATE



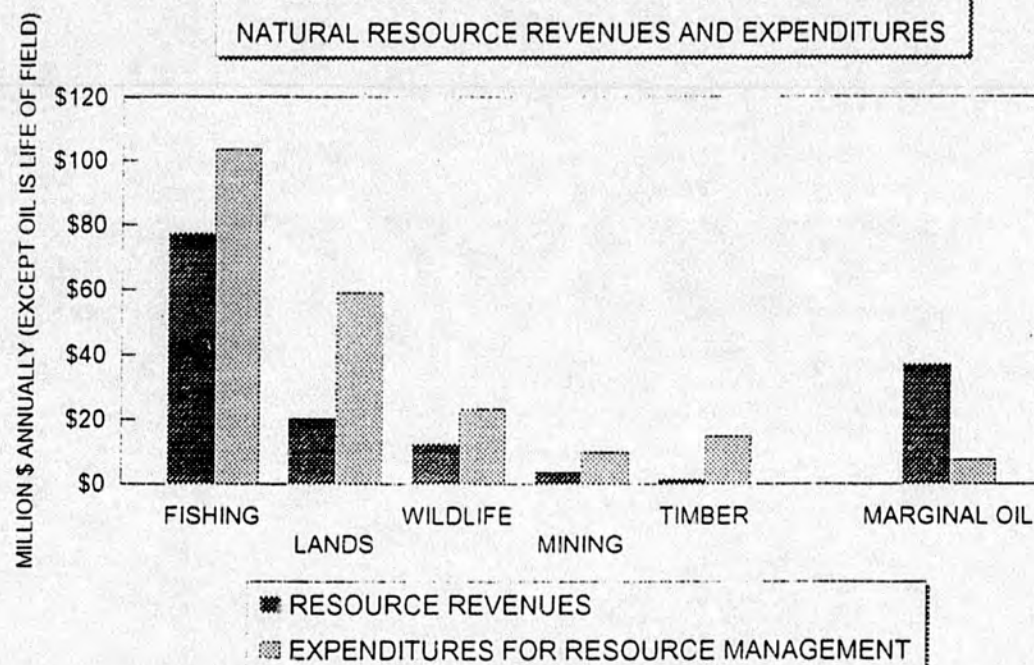
REVENUES IN EXCESS OF AMOUNT NEEDED
TO PROVIDE NEW PUBLIC SERVICES

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



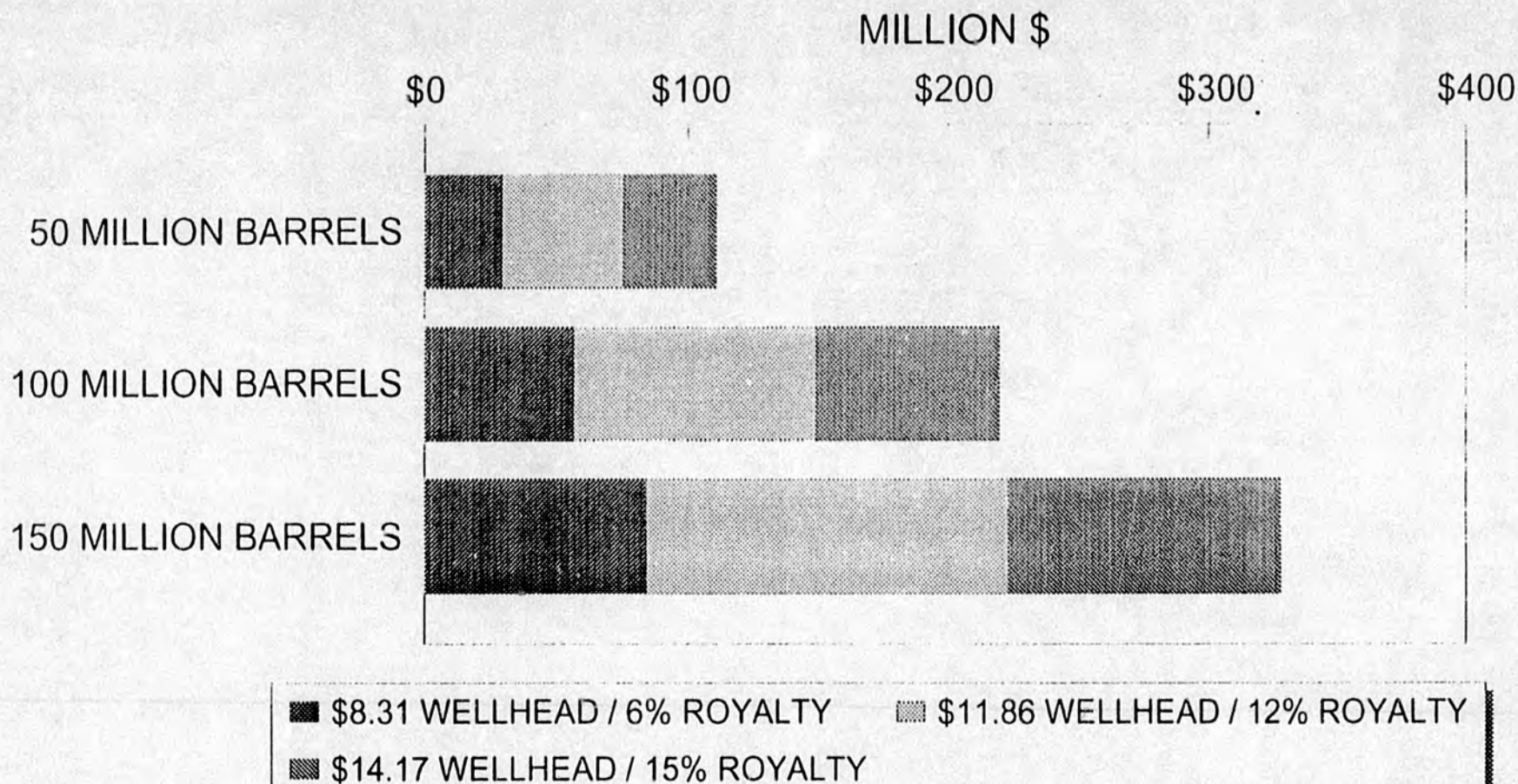
SOURCE FOR OTHER RESOURCES: LEGISLATIVE RESEARCH 1993.

**FIGURE 5B. STATE OF ALASKA
NATURAL RESOURCE REVENUES AND EXPENDITURES**



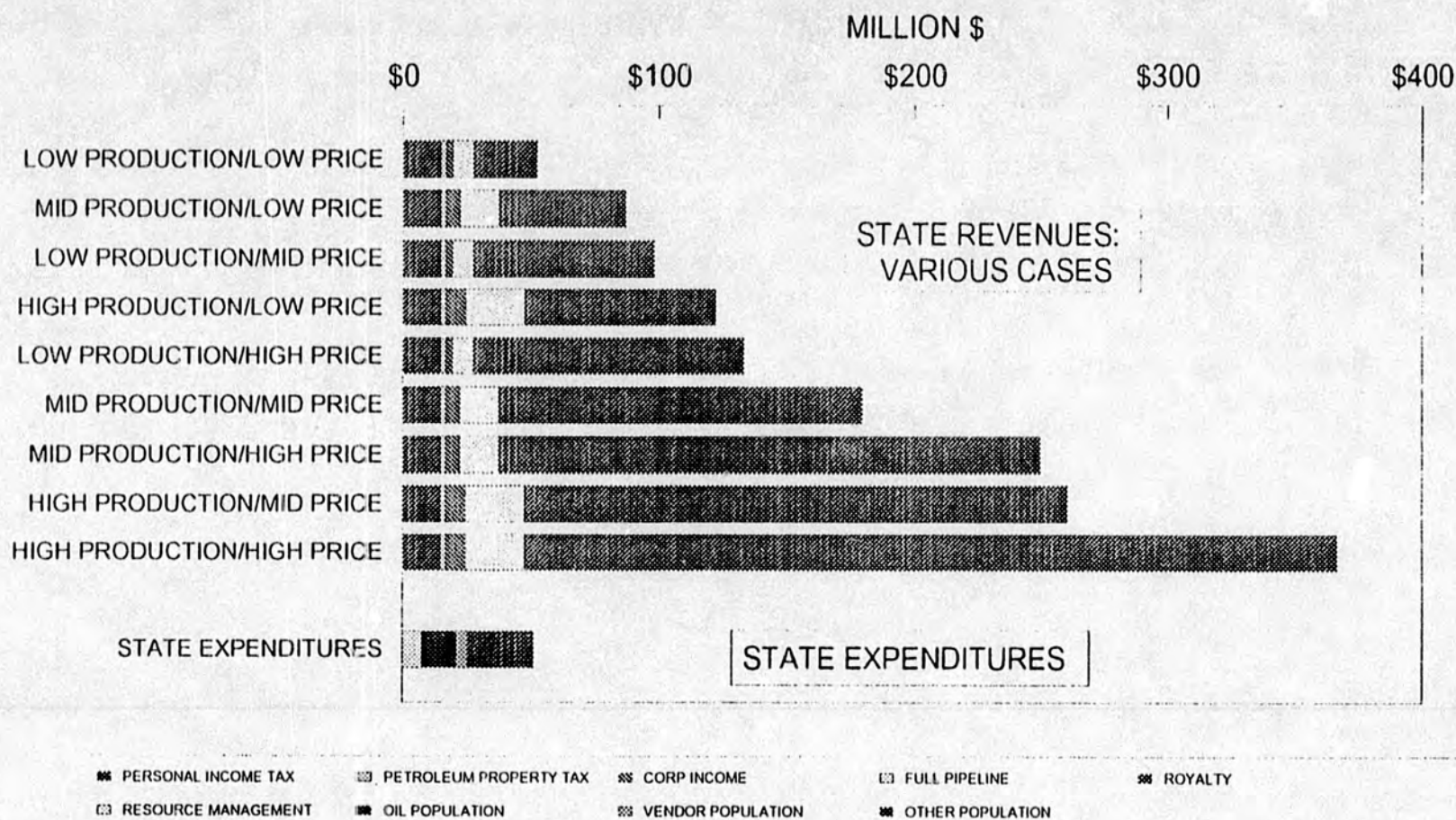
SOURCE: LEGISLATIVE RESEARCH, 1993.
EXCEPT MARGINAL OIL IS LOWEST REVENUE CASE FROM TEXT NET OF INCOME AND SALES TAX RE

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



Alaska State Legislature

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

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



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

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

Representative Joe Green

District 10

TO: Representative Norman Rokeberg, Chairman
House Special Committee on Oil & Gas

FR: Representative Joe Green

RE: HB 381

DATE: January 22, 1996

.....

I have introduced HB 381 - "An Act relating to oil & gas conservation and recovery" to provide some clarity and definition to the relationship between the Alaska Oil & Gas Conservation Commission and the Department of Natural Resources.

I would appreciate it if you could schedule this bill for a hearing in your committee at your earliest opportunity.

Thank you.

Alaska State Legislature

JAN 11 1996

WHILE IN SESSION:
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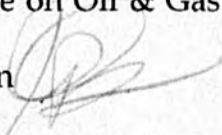
CO-CHAIR, RESOURCES COMMITTEE
VICE CHAIR, JUDICIARY COMMITTEE
MEMBER, STATE AFFAIRS COMMITTEE

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

Representative Joe Green

District 10

TO: Representative Norman Rokeberg, Chairman
House Special Committee on Oil & Gas

FR: Representative Joe Green 

RE: HB 325 - Heavy Oil Royalty Reduction

This is to request a hearing on CSHB 325 (O&G), currently in the Oil & Gas Committee.

As I'm sure you recall, the committee met last November and adopted a committee substitute to HB 325. At that time a question was raised about the legality of the committee taking such action during the legislative interim. My staff contacted the Legal Affairs Division and learned that, indeed, under rule 21 (C), the committee's action was appropriate.

Thank you for your help with HB 325.

Alaska State Legislature

WHILE IN SESSION
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FINANCE SUBCOMMITTEES:
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.

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

NOV 9 1995

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

ONE SEALASKA PLAZA, SUITE 300
JUNEAU, ALASKA 99801

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

November 7, 1995

Hon. Norman Rokeburg
Alaska House of Representatives
716 W. 4th Avenue
Anchorage, Alaska 99501

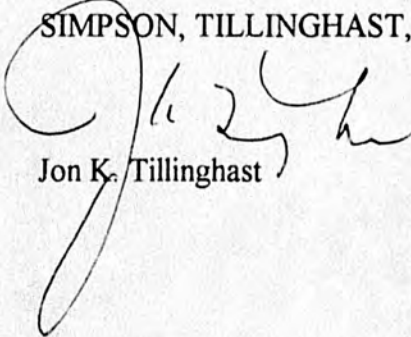
Re: HB 325
Our File No.: 840.1

Dear Representative Rokeburg:

Representative Green asked us yesterday for additional information on certain language in HB 325 and OXY's settlement agreement with DNR arising from OXY's prior royalty proceeding. Our response is enclosed. If you or Shirley have any questions regarding the matter, please feel free to give me a call.

Sincerely,

SIMPSON, TILLINGHAST, SORENSEN & LORENSEN


Jon K. Tillinghast

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

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

November 6, 1995

The Hon. Joe Green
Alaska House of Representatives
716 4th Avenue, Suite 350
Anchorage, Alaska 99501-2133

Re: HB 325
Our File No.: 840.1

Dear Representative Green:

The original version of HB 325, and OXY's proposed substitute, would provide that new heavy oil development would receive a five-year royalty suspension "notwithstanding" the terms of any lease, unit agreement or "any other agreement." The latter phrase would include: (1) with respect to OXY, its July, 1994 settlement agreement with DNR; and (2) with respect to other ANS producers, their various *Amerada Hess* settlement agreements, to the extent that those other agreements would otherwise require payment of royalty on heavy oil production.

OXY does not believe that either category of agreement would, absent the language quoted above, preclude a company from obtaining the royalty suspension provided by HB 325 (*see below*). The "notwithstanding" language was intended to forestall any argument to the contrary, irrespective of its merit. In this regard, remember that one purpose of HB 325 is to establish a process free of administrative complications and the threat of litigation. Leases, unit agreements and royalty settlement agreements all set out royalty terms. We don't think it's reasonable for anyone to maintain that these agreements limit the legislature's ability to establish royalty policy. But neither do we believe that implementation of HB 325 should be frustrated by contentions to the contrary. Hence the precautionary language.

As you know, the OXY settlement agreement with DNR ended two years of litigation arising from a unique royalty surcharge imposed by DNR at the time of

formation of the Milne Point Unit. The settlement agreement removed the surcharge, and returned OXY's Milne Point royalties to the 12.5% level that was originally agreed to at the time the leases were bid upon. Section 5.3 of that settlement agreement, which is enclosed, provides:

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] leases identified in Section 5.1 of this Agreement, 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.

OXY and DNR agreed to this clause because the parties had just completed a contentious, multi-year royalty reduction application process which neither party was interested in repeating.

We have spoken with the administration as early as May, 1995, and as recently as last week, about the relationship of this clause to HB 325. Our position has been that: (1) nothing in the settlement agreed purports to contract away the legislature's power to fashion royalty oil policy; and (2) OXY is free to participate in that debate. To this point, the administration has concurred in that assessment.

The settlement agreement and HB 325 address different issues, since the latter does not involve application for discretionary relief. What the settlement agreement does restrict is OXY's ability to employ the special royalty relief provision of the Milne Point Unit, and perhaps OXY's ability to apply for discretionary relief under HB 207.^{1/} The wording of Section 5.3 is quite narrow in that respect. It says only that OXY "cannot apply," and is thus self-executing. If OXY were to submit an application for discretionary relief, and were DNR to consider that application within the scope of the settlement agreement, DNR would simply deny it on that basis.

In our meetings with legislators, and in testimony, we have made our best effort to apprise legislators of the settlement agreement--hastening to add, however, that we do not believe that the legislature should make heavy oil policy based on OXY's situation. After all, OXY owns only 9% of the Milne Point Unit, and the 91% owner--BP--is unaffected

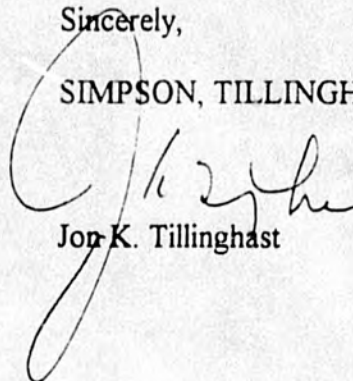
^{1/} That issue is less than certain, since the enactment of HB 207 post-dated the settlement agreement, and the sweeping changes made by that law could not have been anticipated by the parties at the time of the settlement agreement itself. OXY has not taken a position on the applicability of the settlement agreement to HB 207 (and, for argument's sake, has assumed that it is applicable), because the issue is immaterial to the point that OXY has tried to make in legislative debate on this matter: that is, that HB 207, even if it were available, is not the proper vehicle for stimulating full development of the North Slope's heavy oil reserves.

by the settlement agreement. For that reason, we have focused on the broader, policy reasons why HB 207 can't adequately serve as an incentive for new heavy oil development. And, we cannot stress too strongly that our belief in the superiority of a direct, simple legislative incentive, rather than the more uncertain and costly route of discretionary relief, has motivated OXY's participation in this debate.

If you have any further questions about this matter, please don't hesitate to ask.

Sincerely,

SIMPSON, TILLINGHAST, SORENSEN & LORENSEN

A handwritten signature in dark ink, appearing to read "Jon K. Tillinghast", is written over the typed name. The signature is fluid and cursive, with a large initial "J" and "K".

Jon K. Tillinghast

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SETTLEMENT AGREEMENT AND MUTUAL RELEASE

This SETTLEMENT AGREEMENT and MUTUAL RELEASE (collectively "Agreement") is effective as of December 30, 1993 , by and among Conoco, Inc., ("Conoco"), OXY USA Inc. ("OXY"), and the State of Alaska ("State").

RECITALS

This Agreement is made with reference to the following facts:

Royalty Reduction Facts

1. On February 28, 1990 and June 11, 1990, Conoco and OXY, respectively, applied to the State to reduce the royalty rate on certain State leases within the Milne Point Unit ("MPU"). The Commissioner ("Commissioner") of the Department of Natural Resources ("DNR") denied those royalty reduction applications on April 17, 1991.
2. On May 22, 1991, Conoco and OXY appealed the Commissioner's denial of the royalty reduction applications to the superior court in Conoco Inc. v. State of Alaska, 1-JU-797 Civ., and OXY USA Inc. v. State of Alaska, 1-JU-798 Civ. (collectively "Royalty Reduction Administrative Appeal"). Conoco and OXY claim in the Royalty Reduction Administrative Appeal that they are contractually entitled to pay a five percent royalty on all Kuparuk River formation oil production from certain MPU leases. The State claims that Conoco and OXY are contractually required to pay a twenty percent royalty on Kuparuk River formation production from the MPU leases bearing a twenty percent royalty rate and twelve and one-half percent royalty on production from the remaining leases within the MPU, and that Conoco and OXY are not entitled to a royalty reduction either under applicable statutes and regulations, or the MPU Agreement. The Royalty Reduction Administrative Appeal remains pending before the superior court.
3. On May 22, 1991, Conoco and OXY sued the State in Conoco Inc. and OXY USA, Inc. v. State of Alaska, 1-JU-796 Civ. ("the Contract Action"). In the Contract Action, Conoco and OXY claim damages of not less than \$16 million for alleged breach of the royalty reduction terms of the MPU

1 agree to amend the MPU Agreement to provide for 90 days' notice. Nothing in this Section obligates OXY
2 to obtain the agreement of other MPU lessees to amend the MPU Agreement.

3 5.0 FUTURE ROYALTY REDUCTION

4 5.1 Methodology

5 For production after March 31, 1994, the royalty rate specified in the MPU Agreement and
6 ADLs 47432, 47433, 47434, 47437, 47438, 47439, 315846, and 319717 (collectively 20% Leases) is
7 expressly amended for OXY only. The royalty rate for OXY's interest in the 20% Leases is reduced from
8 twenty percent to twelve and a half percent. The royalty rate for all other OXY leases and other lessees in
9 the MPU shall remain unchanged by this Agreement, but may be changed in the future as provided for in
10 applicable statutes, regulations, and agreements. The amended future royalty rate and limitations set forth
11 in Sections 5.1-5.3 of this Agreement shall not apply to Conoco or its assignees including BP and to OXY's
12 assignees.

13 5.2 Assignment

14 The right to pay royalty based upon the methodology set out in Section 5.1 of this
15 Agreement cannot be sold, assigned, cross-assigned, exchanged, or in any way transferred (collectively
16 "Transfers"). If OXY Transfers in any manner any portion of its respective interests in the 20% Leases,
17 the Transferee will have the obligation to pay royalty on the interest Transferred at the rate of twenty percent
18 of the Royalty Value of gross production, as value is defined in Section 4.1.

19 5.3 Limits on Future Royalty Reduction

20 Notwithstanding paragraph 18(h)(8) of the MPU Agreement and any otherwise applicable
21 law, OXY cannot apply for any reduced royalty: (1) for any of the leases identified in Section 5.1 of this
22 Agreement, during the remaining life of the MPU; or (2) for any other liquid hydrocarbon production from
23 the MPU, for five years from the effective date of this Agreement.

24 6.0 FUTURE DISCOVERY ROYALTY

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October 23, 1995

Representative Joe Green
716 W. Fourth Ave., Suite 350
Anchorage, Alaska 99501

Re: Proposed Amendments to HB 325
Our File No.: 840.1

Dear Representative Green:

As you know, we represent OXY USA Inc. and BP Exploration (Alaska) Inc. with respect to proposed heavy oil incentives legislation. In anticipation of the October 24 workshop on HB 325, enclosed are OXY and BP's proposed amendments to that bill.

Before briefly explaining the rationale for the amendments, let me point out two matters that are not included within our proposal:

(1) There may be some interest in conforming the language of HB 325 to CSSB 114, the Senate's current heavy oil bill. You should know that the heavy oil language in CSSB 114 was written to parallel language in the original SB 114 dealing primarily with declining Cook Inlet production. This was a necessary but uncomfortable adaptation, resulting in somewhat cumbersome heavy oil language that we believe has been successfully streamlined in HB 325. Moreover, CSSB 114:

(a) requires lessees to obtain a heavy oil certificate from the state. The intent of HB 325 is to make the legislation self-executing, without creating an application process. HB 325 accomplishes this; CSSB 114 does not; and

(b) CSSB 114 places royalty responsibilities with the Alaska Oil and Gas Conservation Commission. Whatever the merits may be of changing the relationship between AOGCC and DNR, this could raise an institutional controversy that would

considerably complicate the legislation. Since HB 325 is self-executing, that is a controversy that need not be raised in the context of this legislation; and

2. The proposed amendments continue to focus solely on encouraging ANS heavy oil development. From the legislature's perspective, HB 325 has the advantage of allowing the legislature itself to set state royalty policy, rather than delegating that task to the executive branch under discretionary standards. As other state legislatures have found, direct royalty policy legislation is feasible only if it focuses on a single, specific problem. If additional development incentives are added to the legislation, the debate complicates itself geometrically, and delegation of discretionary authority to make the final decisions becomes more attractive. This is not to say that HB 325 should not serve as a model for other legislative initiatives--indeed, we hope it does. But especially because HB 325 represents the Alaska legislature's first direct initiative in shaping state royalty policy, we'd respectfully suggest that the legislature take one matter at a time.

* * *

Our proposal includes these amendments:

(1) A July 1, 1996 effective date. HB 325 would extend the royalty suspension to wells drilled on or after July 1, 1995. The purpose of the bill is to create an incentive to develop ANS heavy oil reserves, and it is hard to justify retroactive application on that basis. We recommend that the retroactive aspect of the legislation be deleted;

(2) Compute the 1825 day suspension period by reference to "days in operation." Lessees are already required to report the number of actual production days to the AOGCC, and these are called "days in operation." Conforming the bill's language to pre-existing practice minimizes the possibility of dispute over whether a well produced oil on a given day;

(3) Specifying how a well qualifies as a heavy oil well. HB 325 extends the royalty suspension to an ANS "well producing heavy oil." While the bill requires lessee's to keep gravity records, it does not specify whether a well need only produce heavy oil initially, or continuously over the suspension period, or at least over regular sampling intervals.

Our amendments (see p. 3, ls. 5-10) attempt to clarify this in a way that protects that state while conforming, to the extent feasible, to current testing and measurement practice. The AOGCC does not require periodic oil gravity reporting. A lessee will certainly test for API gravity at the outset of production. However, since gravity from the same pool will change little over time, subsequent testing may only occur on an annual basis.

Our amendments provide that the lessee must test initially, and then quarterly thereafter, and provide those test results to DNR with its regular royalty reports. More frequent testing of potentially dozens of wells would pose an impractical burden without any corresponding benefit to the state.

As the bill would read, then, the period of suspension is absolute--1825 production days. If, within any given three-month period during the suspension, the required well tests yield a gravity higher than 20 degrees API, the lessee would lose the suspension for that quarter. From the state's perspective, then, the enclosed amendments are more protective than the original bill. The suspension cannot exceed five years' of production, but, for any given well, it may be materially less.

While the AOGCC does not require periodic gravity reporting, it does reference industry standard API measurement procedures in its regulations. Our amendments incorporate those standards for performing the periodic gravity measurements.

Finally, you are aware that HB 325 grants the suspension on a well basis, while royalties are usually paid on a lease basis (since different leases may have different royalty rates). However, royalty-free production from a heavy oil well can easily be attributed to the individual leases drained by that well, just as royalty-burdened production is apportioned now. Because the calculations are straightforward, we did not see any need to deal with that issue in the legislation.

(4) Style and technical changes. We are proposing that HB 325 add a new subsection to AS 38.05.180, rather than amend §180(j). With the amendments made to §180(j) by HB 207, the structure of that subsection is no longer compatible with the substance of HB 325. ^{1/} We have also cleaned up a cumbersome sentence at page 2, lines 17-24 in the original bill, and made certain other technical or style changes. ^{2/}

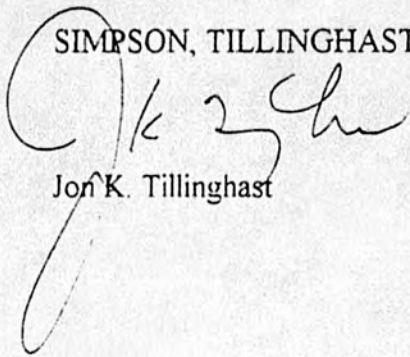
^{1/} For example, §180(j), in its entirety, is now premised with the phrase "the commissioner [may]." But HB 325 does not grant authority to the commissioner; rather, it sets royalty rates in a self-executing fashion. Thus, we can't simply add the body of HB 325 as something else that the commissioner "may," or even "shall," do.

^{2/} For example, at page 2, line 14 of our amendments, we refer to the suspension as "taken" rather than "claimed." We think the distinction important, since one purpose of the bill is to create an incentive that applies by operation of law, rather by agency decision. And in this respect, "claimed" sounds too much like "requested" or "applied for."

Thank you for the consideration that I know you will give our proposal, and we very much look forward to participating in the October 24th workshop.

Sincerely,

SIMPSON, TILLINGHAST, SORENSEN & LORENSEN



Jon K. Tillinghast

9-LS1122R
Chenoweth
1/22/96

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:

Referred:

Sponsor(s): REPRESENTATIVE GREEN

A BILL

FOR AN ACT ENTITLED

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

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

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

6 (dd) Notwithstanding any other provision of this section or any provision in
7 a lease, unit agreement, or other agreement between a lessee and the state that
8 establishes an obligation to pay royalty on production, royalty is not payable, under the
9 conditions and to the extent described in this subsection, for the production of heavy
10 oil that is removed or sold from a lease or leases located north of the Umiat baseline.
11 For purposes of this subsection, "heavy oil" means oil having a weighted average equal
12 to or less than 20 degrees API gravity as the term "API gravity" is defined in
13 AS 43.55.900. Under this subsection, the exemption from payment of royalty applies
14 (1) only to the portion of the value at the wellhead, net of eligible field

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

3 (A) the effective date of this section and until December 31,
4 1996, does not exceed \$15 per barrel; and

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

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

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

18 (4) for a well only if the lessee

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

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

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

9-LS1122\O✓
Chenoweth
1/22/96

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:
Referred:

Sponsor(s): REPRESENTATIVE GREEN

A BILL

FOR AN ACT ENTITLED

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

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

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

6 (dd) Notwithstanding any other provision of this section or any provision in
7 a lease, unit agreement, or other agreement between a lessee and the state that
8 establishes an obligation to pay royalty on production, royalty is not payable for the
9 portion of the production of heavy oil described in this subsection that is removed or
10 sold from a lease or leases located north of the Umiat baseline. For purposes of this
11 subsection, "heavy oil" means oil having a weighted average API gravity that meets
12 the definition of heavy oil in 26 U.S.C. 613A(c)(6)(F). Under this subsection, the
13 obligation to pay royalty on the production does not apply

14 (1) to the portion of the value at the wellhead, net of eligible field cost

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

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

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

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

(3) only to heavy oil produced during the 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

(4) for a well only if the lessee

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

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

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

9-LS1122\M
Chenoweth
1/15/96

*This version was adopted by
D+6 11/14/95.*

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:
Referred:

Sponsor(s): REPRESENTATIVE GREEN

A BILL

FOR AN ACT ENTITLED

1 "An Act authorizing suspension of payment of a portion of the royalty due the
2 state for initial production of heavy oil from wells on the Arctic Slope; and
3 providing for an effective date."

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

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

6 (dd) Notwithstanding any other provision of this section or any provision in
7 a lease, unit agreement, or other agreement between a lessee and the state that
8 establishes an obligation to pay royalty on production, the obligation to pay a royalty
9 on the amount or value of the production removed or sold from a lease or leases
10 located north of the Umiat baseline is suspended for the production of the first 500
11 barrels of daily production of heavy oil from a well. For purposes of this subsection,
12 "heavy oil" means oil having a weighted average API gravity that meets the definition
13 of heavy oil in 26 U.S.C. 613A(c)(6)(F). Suspension under this subsection of the
14 obligation to pay a royalty is available only

1 (1) if the actual drilling of the well on which the royalty payment may
2 be suspended began on or after July 1, 1996;

3 (2) for the first 1,825 days of well operation after the start of production
4 of oil from the well, as reported to the Alaska Oil and Gas Conservation Commission;
5 and

6 (3) for a well for which a lessee claims a suspension of the obligation
7 to pay the royalty and only if the lessee

8 (A) submits with its royalty report for the first month for which
9 the suspension is claimed and with subsequent royalty reports at quarterly
10 intervals for so long as the suspension continues, oil gravity test results
11 performed during the period for which the royalty report is filed demonstrating
12 that the oil tested is heavy oil; the report must be in accordance with the
13 standards for measurement and testing set out in the regulations of the Alaska Oil
14 and Gas Conservation Commission; and

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

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

AMENDMENT

TO: HB 325
9-LS1122\K

SPECIAL COMMITTEE ON OIL & GAS
NOVEMBER 14, 1995

Page 1, Line 11: Delete to the period (.), and Insert the following: "barrels of daily production of heavy oil from a well."

9-LS1122K
Chenoweth
11/13/95

CS FOR HOUSE BILL NO. 325()

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINETEENTH LEGISLATURE - SECOND SESSION

BY

Offered:
Referred:

Sponsor(s): REPRESENTATIVE GREEN

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9 on the amount or value of the production removed or sold from a lease or leases
10 located north of the Umiat baseline is suspended for the production of the first 500
11 barrels of daily production from a well producing heavy oil. For purposes of this
12 subsection, "heavy oil" means oil having a weighted average API gravity that meets
13 the definition of heavy oil in 26 U.S.C. 613A(c)(6)(F). Suspension under this
14 subsection of the obligation to pay a royalty is available only

1 (1) if the actual drilling of the well on which the royalty payment may
2 be suspended began on or after July 1, 1996;

3 (2) for the first 1,825 days of well operation after the start of production
4 of oil from the well, as reported to the Alaska Oil and Gas Conservation Commission;
5 and

6 (3) for a well for which a lessee claims a suspension of the obligation
7 to pay the royalty and only if the lessee

8 (A) submits with its royalty report for the first month for which
9 the suspension is claimed and with subsequent royalty reports at quarterly
10 intervals for so long as the suspension continues, oil gravity test results
11 performed during the period for which the royalty report is filed demonstrating
12 that the oil tested is heavy oil; the report must be in accordance with the
13 standards for measurement and testing set out in the regulations of the Alaska Oil
14 and Gas Conservation Commission; and

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

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