

**SB**

**318**

**(File 3)**

State of Alaska  
Department of Natural Resources  
Division of Oil and Gas  
3601 C Street, Suite 1380, Anchorage, Alaska 99503

Fax Confirmation Phone (907)465-2400 Fax (907)465-3886

FACSIMILE TRANSMITTAL

DATE & TIME: April 3, 1996 4:20 PM

PLEASE DELIVER TO: Annette Kreitzer  
Alaska Senate Resources Committee

FAX NUMBER: 465-3810

NUMBER OF PAGES (including cover): 11

FROM: Ken Boyd

COMMENTS:

Senator Halford asked for a legal analysis regarding the conclusion that the development account on a lease is transferable by the original lessee to the lessee's assignee.

Attached is a copy of a decision by Judge Fabe, now Justice Fabe, reversing the DNR's decision that the development account could not be transferred. Justice Fabe's rationale was that the state's oil and gas leasing statute, AS 38.05.180, contemplates a lease-specific system, not a lessee-specific system and the development account is lease, not lessee, specific. Accordingly, she concluded that an assignment of the lease constitutes an assignment of the development account.

cc: Jeff Landry, DOL

Attachment

IN THE SUPERIOR COURT FOR THE STATE OF ALASKA  
THIRD JUDICIAL DISTRICT

BP EXPLORATION (ALASKA),  
INC.,

Appellant,

vs.

STATE OF ALASKA, DEPARTMENT  
OF NATURAL RESOURCES,

Appellee.

---

MARATHON OIL COMPANY, an  
Ohio Corporation,

Appellant,

vs.

STATE OF ALASKA, DEPARTMENT  
OF NATURAL RESOURCES,

Appellee.

---

Case No. JAN-90-225 Civil  
Case No. JAN-90-277 Civil  
(Consolidated)

DECISION

This court, having considered the parties' briefs on appeal, the record on appeal, and oral argument on January 24, 1991, hereby REVERSES the decision of the Department of Natural Resources for the following reasons:

I. FACTUAL BACKGROUND

In December, 1979, the State of Alaska conducted an oil and gas lease sale, issuing a net profit share lease

(hereafter "NPSL") to Marathon Oil Company (hereafter "Marathon") and Amerada Hess Corporation (hereafter "Amerada"), as co-lessees. The NPSL method is generally described in AB 38.05.180 as:

a fixed cash bonus with a fixed royalty share reserved to the state of not less than 12 1/2 percent in amount or value of the production removed or sold from the lease with the share of the net profit derived from the lease reserved to the state as the bid variable. AB 38.05.180(f)(5).

The relevant regulations, 11 AAC 83.201-295, detail the system, under which the lessee maintains a production revenue account, a development account, and a net profit payment account. When the lease begins to produce, the lessee applies revenue gained against the development costs expended. Only after recovering the development costs does the lessee begin to pay the state a percentage of its net profits.

In 1980, Marathon and Amerada entered into a contract with BP Exploration, Inc. (hereafter "BP") to drill a well. Surface entry was to be on land leased to BP, and the bottom hole was to be on land leased by Marathon and Amerada. Disagreements arose as to various details of the drilling, and a lawsuit resulted. In an effort to settle the case, Marathon and BP entered into a preliminary agreement by which Marathon would assign its interest in the lease to BP, retaining a future production override in return for BP's payment of an undisclosed amount. As an essential part of the agreement, Marathon and BP intend that Marathon's development account, worth \$23 million, transfer entirely to BP.

The parties wrote to the Department of Natural Resources (hereafter "DNR"), requesting DNR's interpretation of the relevant regulations as to whether the development account could transfer to BP. DNR, on April 14, 1989, responded that the development account was lessee, not lease, specific and that the account would not transfer in its entirety. Under DNR's interpretation, BP would have a development account balance that reflected its own direct costs, as well as that portion of the BP/Marathon contract that could be attributed to "acquisition of development expenses".

Marathon and BP asked DNR to reconsider its position and, on August 3, 1989, DNR confirmed its earlier interpretation, stating that the decision "comports with both the purposes of NPSL leasing and the insistency of industry that NPSL account balances be lessee-specific to account for the unique situation of each lessee". Again, on October 4, 1989, after reconsidering its earlier decisions and meeting with the parties, DNR's director affirmed DNR's position, noting that "[w]hile policy or fairness considerations arguably favor the treatment requested by Marathon and BP, 11 AAC 83.219(b)(7) precludes this treatment". The commissioner, on appeal, affirmed the director's decision on December 7, 1989.

11 AAC 83.219, entitled "Development Costs", provides as follows:

(b) The lessee's development costs for a NPSL equal direct charges, as defined in 11 AAC 83.243, that are not excluded under 11 AAC 83.217 and that are directly attributable to a NPSL for...

\* \* \*

(7) that portion of the full consideration given by the lessee in acquiring a production interest in the NPSL that is properly attributable to the wells, facilities and equipment on or in support of the NPSL which directly result in or are necessary for continued or enhanced production from the NPSL, as opposed to the consideration given for the lease itself; the lessee transferring the production interest must credit his development account for a like amount.... 11 AAC 83.219(b)(7).

BP and Marathon presently appeal DNR's decision.

BP argues that DNR erroneously interpreted 11 AAC 83.219, asserting that the development account is lease, not lessee, specific and that an assignment of the lease constitutes an assignment of the development account. In support of this position, BP refers to the statute's language, federal interpretation of similar federal statutes, and legislative intent. BP also alleges that this interpretation violates the lease's express terms.

Marathon joins in with these arguments and adds that DNR's decision represents an unconstitutional taking, violates equal protection, unjustly enriches the state, and constitutes a restraint of alienation.

## II. STANDARD OF REVIEW

The primary issue on appeal is whether DNR correctly interpreted the leasing statute and regulation, AS 38.05.180

and 11 AAC 83.219, respectively, in refusing to recognize the validity of the transfer from Marathon to BP of the development account.

The Alaska Supreme Court in Trustees for Alaska v. State DNR, 795 P.2d 805 (Alaska 1990), held:

To be valid a regulation must be consistent with the authorizing statute and reasonably necessary to carry out the statute's purpose....An administrative agency's interpretation of its own regulation is normally given effect unless plainly erroneous or inconsistent with the regulations. Id. at 812.

### III. INTERPRETATION OF 11 AAC 88.219

DNR interprets the statute and, particularly, the regulation to provide that only a small portion of the expenses which Marathon incurred on developing the lease will transfer to BP, reflecting only what BP paid Marathon for "wells, facilities, and equipment". This interpretation is both unjust and unlawful and must be set aside as plainly erroneous.

In reviewing the regulation, the court's first step is to address whether 11 AAC 88.219 is both consistent with AS 38.05.180 and reasonably necessary to carry out the statute's purpose. See Trustees for Alaska v. State DNR, SUPRA.

Because the plain language of AS 38.05.180 contemplates a lease-specific system, and 11 AAC 83.219, as interpreted by DNR, contemplates a lessee-specific system, 11 AAC 83.219 is inconsistent with the statute. Specifically, AS 38.05.180(f)(5)

discusses "production removed or sold from the lease" and the "share of the net profit derived from the lease" when describing the NPBL bidding method. (Emphasis added.) A plain reading of this language indicates that calculations are based on the money expended upon and earned from the lease. The statute does not suggest an intent to link these accounts to a particular lessee.

BP's analysis of the legislative history, the analogous federal statute, and other regulations support this reading, which is also apparent from the statute's face. For example, BP points to various reports contemplated by the Legislature when discussing the Alaska Land Act's 1978 amendments. Of particular interest is a 1977 report by Mason Gaffney, "Oil & Gas Leasing Policy: Alternatives for Alaska in 1977 (A Report to the State of Alaska, Jay S. Hammond, Governor, Department of Natural Resources, Guy Martin, Commissioner, and to the Alaska State Legislature, Interim Committee on Oil and Gas Taxation and Leasing Policy, Chancy Croft, Chairman)" (Feb. 1, 1977) (Microfiche No. 511-517, Anchorage Law Library). In this report, Gaffney discusses the net profit share in terms of a "net proceeds tax", and notes that this tax "is in rem: it is levied on the income and expenses attributable to a particular 'thing', in this case the leasehold". Id. at 52-53. He clearly distinguishes it from the example of an income tax, which is levied "in personam". Id.

The analogous federal statute and regulations, found in 43 U.S.C. § 1337(a)(1)(D), (E), (F) (West 1986) and 30 C.F.R. 220, also aid interpretation. In answer to a question about the assignability of the development account (called a "capital recovery account", in the federal scheme), the federal Minerals Management Service stated:

Because the NPSL capital account is maintained by lease and includes all costs incurred during the term of the NPSL, any costs incurred by the lessee would be carried forward to the assignee in the case of a farmout. That is, the assignee would begin NPSL operation with the same balance in the NPSL capital account as that remaining at the time of the farmout. December 3, 1985 letter from William S. Geldmiller, Chief, Royalty Valuation & Standards Division, United States Department of the Interior, Minerals Management Service, to Daniel Mills, Landman, Texaco U.S.A. (Doc. Supp. at 93.)

The federal statute, like the state statute, has language describing the NPSL system in terms of profits derived "from the lease". Thus, the federal government's interpretation of the NPSL as lease-specific, provides support for reading Alaska's NPSL system in the same manner.

The three-fold purpose of AS 38.05.180 has been discussed in Kelly v. Zamarello, 486 P.2d 906 (Alaska 1971), and includes an intent "to insure that leases on valuable oil and gas producing state lands will be made available to the public on a fair and equitable basis, that the state will be adequately compensated for its natural resources, and that the state's resources are developed in an orderly fashion".

Id. at 912. The purposes of the NPBL system specifically include avoiding premature lease abandonment, allowing less well financed operators to compete, and enabling payments to correspond with benefits. University of California, Walter J. Mead, Professor of Economics, "Comments From an Economic Perspective on House Bill No. 854 in the Legislature in the State of Alaska, Tenth Legislature -- Second Session", May 15, 1978. (Doc. Supp. at 415-416.)

11 AAC 83.219, as interpreted by DNR, furthers none of these aims and specifically detracts from some. For example, the fact that some of Marathon's expenses would be lost runs counter to the general purpose of fair and equitable availability of leases. Also, although the statute intends to insure adequate compensation of the state, DNR's interpretation would give the state, in this instance, more compensation than it would have had if Marathon had not transferred its interest. Thus, the regulation is not reasonably necessary to further the statute's purpose.

The correct interpretation of 11 AAC 83.219(b)(7) is that it pertains only to partial assignments of leasehold interests and would not apply to the complete assignment contemplated by BP and Marathon. This interpretation is consistent with the statute and furthers the statutory purposes by preventing double deductions of development costs.

Specifically, it prevents a development cost that is included in the assignor's development account from also being included in the assignee's development account. This interpretation gives effect to the regulation's requirement that "the lessee transferring the production interest must credit his development account for a like amount". 11 AAC 83.219(b)(7). This sentence would have no meaning under DNR's interpretation that the regulation applies to total assignments, as the assignor would have no development account to credit.

The effect of applying this regulation to a partial assignment is that there is no net change in the total amount of development costs that will be used to calculate net profits from the lease. It merely results in a reallocation of the total development costs.

The state alternatively argues that BP and Marathon are effectuating a partial assignment, because Marathon plans to retain an overriding royalty interest. The court finds that the agreement assigns all of Marathon's interests as lessee to BP, particularly given the fact that the regulation defines a lessee as someone who holds a "working interest" which, by definition, differs from a "royalty interest". See 11 AAC 83.295(27) and 11 AAC 83.295(30). Consequently, because this is a total assignment and the regulation, properly interpreted, applies to partial assignments, DNR's decision must be REVERSED.

DATED at Anchorage, Alaska this 25 day of July,  
1991.

*Dana Page*  
DANA PAGE  
SUPERIOR COURT JUDGE

I certify that on 7/25/91,  
a copy of the above was mailed to each  
of the following at their address of  
record: Mason/Mason/Johannson  
*J. Parson*  
Secretary/Deputy Clerk

State of Alaska  
Department of Natural Resources  
Division of Oil and Gas  
3601 C Street, Suite 1380, Anchorage, Alaska 99503

Fax Confirmation Phone (907)465-2400 Fax (907)465-3886

FACSIMILE TRANSMITTAL

DATE & TIME: April 3, 1996 2:35 PM

PLEASE DELIVER TO: Annette Kreitzer  
Alaska Senate Resources Committee

FAX NUMBER: 465-3810

NUMBER OF PAGES (including cover): 9

FROM: Ken Boyd

COMMENTS:

Attached is Kevin Banks' analyses of 1) the effect of a delay on the Northstar development and 2) an increase in the reserve estimates. Please call if you have any questions.

Attachment

MEMORANDUM  
DEPARTMENT OF NATURAL RESOURCES

State of Alaska  
DIVISION OF OIL AND GAS

TO: Ken Boyd  
Director

DATE: April 3, 1996

THRU:

FILE NO:

TELEPHONE: 269-8799

FROM: Kevin Banks   
Petroleum Economist

SUBJECT: Northstar Unit - Senate  
Resource Committee  
Requests

In response to Senator Halford's request about the effect on the economic benefits if a lawsuit delays development of the Northstar Unit, I analyzed the effect on economic benefits caused by a delay for any reason. In short, any delay increases the economic benefits to the state while decreasing the economic benefits to BPXA. The attached graph and table illustrate this point.

The graph shows that, as full production start-up is delayed beyond 1999, the net profit share falls and the supplemental royalty rises. The net profit share declines because the development account accrues interest at the prime rate. The supplemental royalty increases as the start-up date is delayed because of the effect of inflation, i.e., the supplemental royalty is triggered by a price that rises at just one-half the rate of inflation.

The first table shows in greater detail the effects of delaying full production start-up until 2002. This table is similar to one that was supplied in the DNR Northstar Briefing Paper, but includes a column to show the revenues from the supplemental royalty if the project is delayed.

I also considered Senator Halford's request to run the model at double BPXA's "most likely" reserve estimate of 130 million barrels. Following the hearing, I spoke to Senator Halford and he said I should be "realistic." Based on conversations with BPXA and DNR's resource evaluation staff, I do not believe that recovery of double the 130 million barrel estimate is realistic. Instead, I have run the model based on an assumption of 180 million barrels, which is the highest number put forward by either BPXA or DNR staff.

The four tables labeled "Reserves of 180+ Million Barrels" and "Reserves of 105+ Million Barrels" illustrate what happens to revenues if the reserves are much higher (though not doubled as Senator Halford suggested) and much lower than BPXA's "most likely" case. In the first two tables, I assume that reserves are 180 million barrels. This reserve estimate represents a 70 percent recovery rate--an unusually high number.<sup>1</sup> I also assumed that this recovery estimate is

---

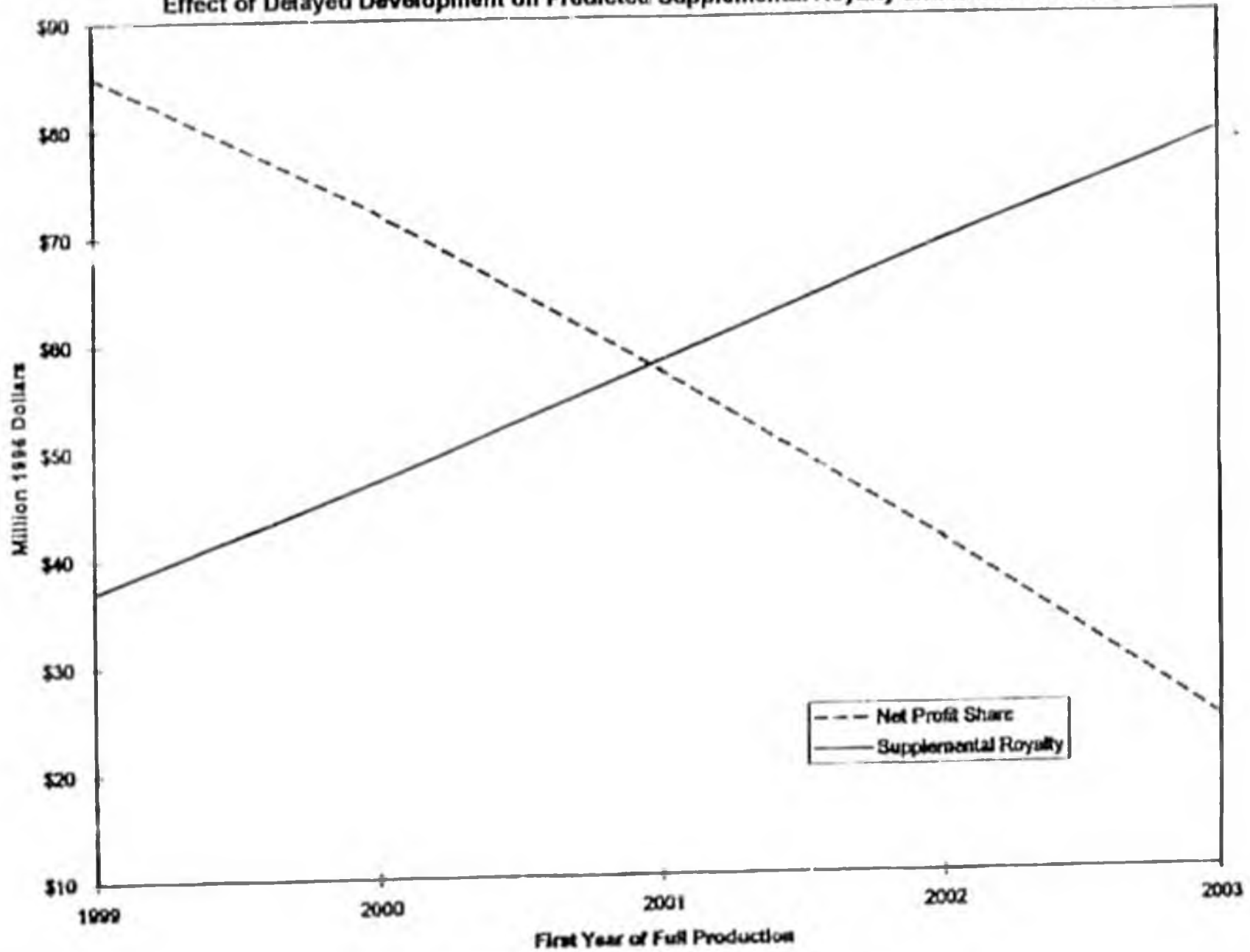
<sup>1</sup>Doubling the reserves as requested by Senator Halford would require a 100 percent recovery of BPXA's most likely original-oil-in-place estimate. The initial recovery rate for the Prudhoe Bay field was estimated at 40 percent. After substantial investment, the current recovery estimate has changed to 55 percent. A 70 percent recovery might be possible but only after extraordinary expense. Furthermore, the field would have to produce for many years before attaining this level.

achieved by adding capital expenditures of only \$28 million to the most likely case for more drilling. BPXA's "upside" case envisions an additional \$91 million in capital expenditures to achieve reserves estimated at 160 million barrels. Other assumptions are held constant.

The second two tables show the downside, i.e., if reserves are only 105 million. In this case, I assume that the capital expenditures estimated for the most likely case are spent and the field never attains the most likely case production rates. Other assumptions are held constant.

# Northstar Proposal

## Effect of Delayed Development on Predicted Supplemental Royalty and Net Profit Share



(This chart is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '98 Base Price Forecast.)

4/1/98, 11:58 AM

# Northstar Economic Evaluation



## Estimated Total Revenues

Effect of Delay	Supplemental Royalty and 1999 Development	Net Profit Share and 1999 Development	Supplemental Royalty and 2002 Development	Net Profit Share and 2002 Development
(Real 1998 Dollars)				
<b>State Revenues</b>				
State Royalty	256	258	257	257
State Supplemental Royalty	██████████	0	██████████	0
NPGL	-0	██████████	0	██████████
State Share of Federal Royalty	16	16	16	16
Severance Tax	58	58	56	59
Spill & Conserv. Tax	3	3	3	3
Ad Valorem Tax	42	42	46	48
Income Tax	24	22	22	23
<b>Total</b>	<b>436</b>	<b>481</b>	<b>469</b>	<b>444</b>
<b>Federal Revenues</b>				
Royalty (Net of State Share)	44	44	44	44
Income Tax	215	198	205	213
<b>Total</b>	<b>259</b>	<b>243</b>	<b>249</b>	<b>258</b>
<b>BPXA Cash Flow</b>				
After Tax Funds Flow	349	318	331	346
Real Rate of Return	20.0%	19.9%	19.2%	20.4%

Totals may not add due to rounding.

(This table is based on BPXA's most likely estimate of reserves, capital and operating costs, and BPXA's Post-98 State Price Commitment.)

## Northstar Economic Evaluation

### Estimated Total Revenues

At Reserves of 180+ Million Barrels.*	With Supplemental Royalty	With Net Profit Share
*(Real 1996 Dollars**)		
<b>State Revenues</b>		
State Royalty	383	363
State Supplemental Royalty	0	0
NPSL	0	0
State Share of Federal Royalty	23	23
Severance Tax	89	91
Spill & Conserv. Tax	4	4
Ad Valorem Tax	52	52
Income Tax	37	26
<b>Total</b>	<b>639</b>	<b>834</b>
<b>Federal Revenues</b>		
Royalty (Net of State Share)	63	63
Income Tax	341	237
<b>Total</b>	<b>404</b>	<b>300</b>
<b>BPXA Cash Flow</b>		
After Tax Funds Flow	581	389
Real Rate of Return	23.9%	21.7%

\*DNR assumes the MMSO total reserves, additional 8 production wells, a two year increase in field life, and an additional \$28 million in capital cost over BPXA's most likely case.

\*\*Totals may not add due to rounding.

## Northstar Economic Evaluation

### Estimated Total Revenues

At Reserves of 180+ Million Barrels.*	With Supplemental Royalty	With Net Profit Share
	(Discounted Net Present Value**)	
<b>State Revenues</b>		
State Royalty	223	223
State Supplemental Royalty	██████████	0
NPSL	0	██████████
State Share of Federal Royalty	14	14
Severance Tax	61	63
Spill & Conserv. Tax	2	3
Ad Valorem Tax	32	32
Income Tax	21	16
<b>Total</b>	<b>389</b>	<b>524</b>
<b>Federal Revenues</b>		
Royalty (Net of State Share)	39	39
Income Tax	195	149
<b>Total</b>	<b>234</b>	<b>188</b>
<b>BPXA Cash Flow</b>		
After Tax Funds Flow	281	194
Real Rate of Return	23.9%	21.7%

\*DNR assumes 106 MBOO total reserves, additional 6 production wells, a two year increase in field life, and an additional \$20 million in capital costs over BPXA's most likely case.

\*\*Assuming 10 percent nominal discount rate. Totals may not add due to rounding.

# Northstar Economic Evaluation



## Estimated Total Revenues

At Reserves of 105 Million Dollars\*

With Supplemental  
Royalty

With Net Profit  
Share

(Real 1998 Dollars\*\*)

### State Revenues

State Royalty	206	208
State Supplemental Royalty	0	0
NPSL	0	0
State Share of Federal Royalty	13	13
Severance Tax	30	30
Spill & Conserv. Tax	2	2
Ad Valorem Tax	42	42
Income Tax	17	18
Total	340	312

### Federal Revenues

Royalty (Net of State Share)	38	30
Income Tax	153	163
Total	189	198

### BPXA Cash Flow

After Tax Funds Flow	234	258
Real Rate of Return	14.6%	15.1%

\*DNR assumes 105 MBO total reserves, the minimum production indicated by BPXA in its "Proposal for Modified Lease Terms"

\*\*Assuming 3.2 percent inflation rate from DOR Fall 1996 Base Price Forecast. Totals may not add due to rounding.

(This table is based on BPXA's most likely estimate of reserves, implied and remaining costs, and DNR's Fall '96 Base Price Forecast.)

4/28/98, 1:41 PM

# Northstar Economic Evaluation



## Estimated Total Revenues

At Reserves of 105 Million Dollars\*

With Supplemental  
Royalty

With Net Profit  
Share

(Discounted Net Present Value\*\*)

### State Revenues

State Royalty	.136	136
State Supplemental Royalty	0	0
NPSL	0	0
State Share of Federal Royalty	-9	-9
Sovereignty Tax	23	23
Spill & Conserv. Tax	1	1
Ad Valorem Tax	27	27
Income Tax	10	11
Total	-223	-207

### Federal Revenues

Royalty (Net of State Share)	24	24
Income Tax	92	98
Total	116	121

### BPXA Cash Flow

After Tax Funds Flow	92	102
Real Rate of Return	14.5%	15.1%

\*DNR assumes 105 MMBO total reserves, the minimum production indicated by BPXA in its "Proposal for Modified Lease Terms"

\*\*Assuming 10 percent discount rate. Totals may not add due to rounding.

(This table is based on BPXA's most study estimate of reserves, capital and operating costs, and DNR's Full Well State Price Payments.)

4/29/96, 1:01 PM



# Alaska State Legislature

Official Business

Senate Resources Committee

State Capitol  
Juneau AK 99801

April 2, 1996

Mr. Ken Boyd, Director  
Division of Oil and Gas  
Department of Natural Resources  
via fax: 562-3852

Dear Director Boyd:

Last week you provided me with a copy of a notebook entitled "Northstar Unit Briefing Paper—March 1996" which contains several documents pertaining to the history of the leases within the Northstar Unit. Among those documents is a December 27, 1979, letter entitled "Results of the 30th Competitive Oil and Gas Lease Sale" (Tab 3) and an accompanying summary of the companies submitting bids in that sale and the amounts of those bids.

Some of the testimony and committee questions concerning Senate Bill 318 to date have centered on the litigation risk associated with renegotiating the competitively bid terms of Northstar leases as the commissioner has done in this case. For example, questions have arisen about who would have standing to litigate, whether the passage of time lessens the risk of successful litigation, whether other lessees with net profit leases are similarly situated to BPXA and whether the state would be sending the appropriate signals to other lessees by preferentially renegotiating amendments to the terms of these leases and not others.

In light of these questions, I would like to provide an opportunity for representatives of the other companies who competed for net profit leases in Sale 30 to address the committee to share their views on the policy implications and litigation risk involved with the passage of SB 318. In reviewing the list of bidders, I note that several of the companies no longer exist—Gulf Oil, for example—and that others may have new identities having been merged with other companies or simply having been renamed since 1979.

I would appreciate it if you provide committee staff with the current addresses and names for contact personnel within each of the companies that submitted net profit share bids in Sale 30. I recognize that you and your staff are quite busy, but in the interest of expediting hearings on SB 318, I ask that you provide this information by fax this afternoon if at all possible. We would like to notify these companies of their opportunity to participate in future hearings on SB 318.

Sincerely,

A handwritten signature in cursive script that reads "Loren A. Leman".

Senator Loren Leman, Chairman  
Senate Resources Committee



# Alaska State Legislature

## SENATE RESOURCES COMMITTEE

Official Business

State Capitol  
Juneau AK 99801

### MEMO

TO: Senator Pearce, ViceChairman  
Senator Halford  
Senator Frank  
Senator Taylor  
Senator Hoffman  
Senator Lincoln

FROM: Senate Resources Committee Staff (X49(17))

DATE: April 3, 1996

RE: Requested material on SB 318: Northstar Lease Agreement

Attached are materials requested or relevant to SB 318:

- 1) Letter to Ken Boyd (4/2/96) requesting names of representatives of other companies who competed for net profit leases in Sale 30. (and reply)
- 2) Memo to BP, DNR, Law requesting responses to questions asked by Committee members at March 29 hearing and reply from BP. Some responses still pending from Law and DNR.
- 3) Response from DNR to question of who owns the other existing 39 net profit share leases. In two formats:  
Format one is Ownership Within Leases  
Format two is a listing by lease number
- 4) Two articles relating to oil projects in Venezuela



DEPARTMENT OF NATURAL RESOURCES  
 OFFICE OF THE COMMISSIONER  
 400 WILLOUGHBY AVENUE  
 JUNEAU, ALASKA 99801-1796  
 PHONE: (907) 465-2400  
 FAX: (907) 465-3886

Please deliver to: Annela

Location: \_\_\_\_\_ FAX: 3810

Date: \_\_\_\_\_ Time: \_\_\_\_\_

From: Ken Boyd

Number of pages 6  
 Including cover sheet

Comments: THIS IS WHAT WE CALLED  
PUT TOGETHER TODAY

If you experience any problems receiving this FAX, please call Sharon or Eileen at the above phone number.

Names and Addresses of Sole Suppliers

Original Bidder Name	Current Name	Phone Number	Address	City	State
AMERADA HESS CORPORATION		713 609-6437	ATRN: J. Y. CAMPBELL	809 DALLAS ST	HOUSTON TX
AMOCO PRODUCTION COMPANY		713 888-5288	ATRN: LAND MANAGER/USA	PO BOX 3072	HOUSTON TX
ARLBERG FIELDFIELD COMPANY		907 265-4824	ATRN: LAND MANAGER	P.O. BOX 10288	ANCHORAGE AK
CHEVRON U.S.A. INC		713 754-7888	PO BOX 1435	ATRN: P.O. WALKER	HOUSTON TX
CITIZEN SERVICE COMPANY	OGY USA INC.	918 561-3886	PO BOX 300		TULSA OK
CONOCO INC		713 283-2764	680 NORTH DARTY AIRFORD	ATRN WILLIAM R DAUGHERTY	HOUSTON TX
COOK INLET REGION INC		907 288-8140	PO BOX 83300		ANCHORAGE AK
UDCON CORPORATION		713 684-7000	LANDREGULATORY AFFAIRS	PO BOX 2806	HOUSTON TX
CSTY OIL COMPANY	TEXACO INC	303 773-4144	PO BOX 7881	ATRN: LAND DEPARTMENT	DENVER CO
GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 754-7844	PO BOX 1636	ATRN: P.O. WALKER	HOUSTON TX
HONDA INC		907 661-8646	C/O JOHN MERRICK	4200 S ST 457	ANCHORAGE AK
MARATHON OIL COMPANY		713 629-6600	ATRN COMEFACT & DIVISION ORDER	P.O. BOX 2049	HOUSTON TX
MOBIL OIL CORP		214 951-8836	ATRN: PROPERTY MANAGEMENT	PO BOX 682172	DALLAS TX
MURPHY OIL CORPORATION	MURPHY OILCO. & PROD.CO	604 841-8811	ATRN: LAND DEPARTMENT	P.O. BOX 61780	NEW ORLEANS LA
NANA REGIONAL CORPORATION INC		907 264-4700	YORK E. BEMSON BLVD.	ATRN: MICHAEL PRESIDENT MINERALS	ANCHORAGE AK
PHILLIPS PETROLEUM COMPANY		713 489-3741	PO BOX 1967	ATRN: AL REGION/LAND MANAGER	HOUSTON TX
PLACID OIL CO		918 644-8886	C/O CITY USA INC.	P.O. BOX 300	TULSA OK
ROMAN PETROLEUM INC	ROMAN OIL INC	907 279-8448	1901 POST OAK TOWER	BOX 181 STRASHER II	HOUSTON TX
SEALASKA CORP		907 886-1612	ONE SEALASKA PLAZA, SUITE 408	MR WILLIAM M MORAY, PRESIDENT	JURIEAU AK
SHELL OIL COMPANY		713 678-4314	TWO SHELL PLAZA	PO BOX 2899	HOUSTON TX
SONO NATURAL RESOURCES	BP EXPLORATION (ALASKA) INC	907 641-8111	E. P. ZELICKOV, JR.	PO BOX 19612/POD E. BEMSON JR.	ANCHORAGE AK
TEXACO INC		303 773-4144	PO BOX 2780	ATRN: LAND DEPARTMENT	DENVER CO
TEXAS EASTERN EXPLORATION COMPANY	ENTERPRISE OIL EX CO INC	713 883-8471	C/O ALAN R. BULLINGTON	4001 FM 1960 WEST, STE. 310	HOUSTON TX
TEXAS GULF INC.		907 274-8100	8984 MCINTOSH BLVD		GOLDEN CO
UNION OIL COMPANY OF CALIFORNIA		907 278-7880	PO BOX 19827	ATRN: LAND MANAGER	ANCHORAGE AK

11 3202

FOR OFFICE OF THE COMMISSIONER  
P.O. BOX 100000 DENVER, CO 80201

307 455 7333  
ADNR/DIV OIL & GAS

APR 2 1998 17:26  
APR 2 1998 18:30

# NET PROFIT SHARE LEASE OWNERS

02-Apr-96

UNIT	HIGH BIDDER	BIDDING GROUP	BIDDER NAME	CURRENT NAME	PHONE #
<b>DUCK ISLAND UNIT</b>					
<b>SALE 30</b>					
	ADL	312828			
	.		COOK INLET REGION INC		637 2885188
	.		BOHRO NATURAL RESOURCES	BP EXPLORATION (ALASKA) INC	907 5815111
	.		SEALASKA CORP		907 8861812
	.		NANA REGIONAL CORPORATION INC		907 2854100
	.		MONIAD INC		907 5812868
			AMOCO PRODUCTION COMPANY		713 9886133
			CITIBI SERVICE COMPANY	OXY USA INC.	918 8613065
			ROMAN PETROLEUM INC	ROMAN DRILLING	907 2782448
			GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 7347855
			FLACID OIL CO		818 5813385
			GETTY OIL COMPANY	TEXACO INC	303 7854184
			TEXAS GULF INC.		907 2785100
			COMOCO INC		713 2802758
			MATATHON OIL COMPANY		713 8294880
			AMERADA HESS CORPORATION		713 6086537
			MURPHY OIL CORPORATION	MURPHY EXPLOR. & PROD.CO	304 5612811
			SHELL OIL COMPANY		713 8704817
			CHEVRON U.S.A. INC		713 7347855
			EXXON CORPORATION		713 6567008
			UNION OIL COMPANY OF CALIFORNIA		907 2787800
			ATLANTIC RICHFIELD COMPANY		907 2834824
	ADL	312834			
	.		EXXON CORPORATION		713 6567008
	.		UNION OIL COMPANY OF CALIFORNIA		907 2787800
	.		ATLANTIC RICHFIELD COMPANY		907 2834824
			CHEVRON U.S.A. INC		713 7347855

APR 2 1996 10:30 AM  
 207 453 1885  
 ADNR/DIV OIL & GAS  
 OFFICE OF THE COMMISSIONER  
 PHX NO. U10U1080410  
 11.03.02

APR 4 1986 17:25  
 ADMR/DIV OIL & GAS  
 OFFICE OF THE COMMISSIONER  
 PHA NO. U1501550415

UNIT	HIGH BIDDER	BIDDING GROUP	BIDDER NAME	CURRENT NAME	PHONE #
<b>NON UNITIZED PRODUCING</b>					
<b>SALE 30</b>					
	<b>ADL</b>	<b>312227</b>			
	.		14	MARATHON OIL COMPANY	713 6298800
	.		14	AMERADA HESS CORPORATION	713 6096637
			3	AMOCO PRODUCTION COMPANY	713 5922836
			7	GETTY OIL COMPANY	TEXACO INC 303 7934164
			7	TEXAS GULF INC.	907 2785180
			7	PLACID OIL CO	918 9813385
			7	ROWAN PETROLEUM INC	ROWAN DRILLING 907 2782446
			7	GULF OIL CORPORATION	CHEVRON U.S.A. INC 713 7547866
			7	CONOCO INC	713 2832736
			7	CITIZEN SERVICE COMPANY	OXY USA INC. 918 6813385
			17	EXCON CORPORATION	713 6467600
			18	COOK INLET REGION INC	307 2435180
			18	KOMIAG INC	907 6612868
			18	SEALASKA CORP	907 5381512
			18	MANA REGIONAL CORPORATION INC	907 2964160
			18	SONHO NATURAL RESOURCES	BP EXPLORATION (ALASKA) INC 907 8618111
<b>NORTHSTAR UNIT</b>					
<b>SALE 30</b>					
	<b>ADL</b>	<b>312798</b>			
	.		1	AMERADA HESS CORPORATION	713 6096637
			2	TEXACO INC	303 7934164
			2	TEXAS EASTERN EXPLORATION COMPANY	ENTERPRISE OIL EX CO INC 713 6826471
			3	AMOCO PRODUCTION COMPANY	713 5922836
			4	PLACID OIL CO	918 9813385
			4	CONOCO INC.	
			4	TEXAS GULF INC.	907 2785180
			4	CITIZEN SERVICE COMPANY	OXY USA INC. 918 6813385
			5	SHELL OIL COMPANY	713 6704314
			6	CHEVRON U.S.A. INC	713 7547866
			6	PHILLIPS PETROLEUM COMPANY	713 6822411

UNT	HIGH BIDDER	BIDDING GROUP	BIDDER NAME	CURRENT NAME	PHONE #
ADL	312799				
		1	AMERADA HESS CORPORATION		713 6006327
		2	TEXACO INC		303 7834184
		2	TEXAS EASTERN EXPLORATION COMPANY	ENTERPRISE OIL EX CO INC	713 8838471
		3	AMOCO PRODUCTION COMPANY		713 3663335
		7	ROWAN PETROLEUM INC	ROWAN DRILLING	807 2792448
		7	TEXAS GULF INC.		807 2786100
		7	GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 7547835
		7	CITIZEN SERVICE COMPANY	OXY USA INC.	818 9612885
		7	CONOCO INC		713 2832738
		7	GETTY OIL COMPANY	TEXACO INC	303 7834184
		7	PLACID OIL CO		818 5612885
		8	MURPHY OIL CORPORATION	MURPHY EXPLOR. & PROD.CO	304 5612811
		8	SHELL OIL COMPANY		713 8704314
		9	PHILLIPS PETROLEUM COMPANY		713 8833741
		9	MOBIL OIL CORP		214 9512838
		9	CHEVRON U.S.A. INC		713 7547835
		10	UNION OIL COMPANY OF CALIFORNIA		807 2787809
ADL	312808				
		11	TEXAS EASTERN EXPLORATION COMPANY	ENTERPRISE OIL EX CO INC	713 8838471
		6	CHEVRON U.S.A. INC		713 7547835
		6	PHILLIPS PETROLEUM COMPANY		713 8833741
		10	UNION OIL COMPANY OF CALIFORNIA		807 2787809
		12	GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 7547835
		12	CITIZEN SERVICE COMPANY	OXY USA INC.	818 9612885
		12	ROWAN PETROLEUM INC	ROWAN DRILLING	807 2792448
		12	TEXAS GULF INC.		807 2786100
		12	CONOCO INC		713 2832738
		12	PLACID OIL CO		818 5612885
		13	SHELL OIL COMPANY		713 8704314
		13	MURPHY OIL CORPORATION	MURPHY EXPLOR. & PROD.CO	304 5612811
		13	ATLANTIC RICHFIELD COMPANY		807 2534834

APR 2 1988 17:32  
 APR 2 1988 18:32  
 507 455 7835  
 ADNR/DIV OIL & GAS  
 THE OFFICE OF THE COMMISSIONER  
 OF OIL AND GAS

APR-02-1996 17:30  
 OFFICE OF THE COMPTROLLER  
 PH# NO. 016076630410  
 7:30  
 307-485-1896  
 ADMIN/OLC & OPS

UNIT	HIGH BIDDER	BIDDING GROUP	BIDDER NAME	CURRENT NAME	PHONE #
ADL	312809				
		11	TEXAS EASTERN EXPLORATION COMPANY	ENTERPRISE OIL EX CO INC	713 800471
		3	AMOCO PRODUCTION COMPANY		713 5883325
		9	CHEVRON U.S.A. INC		713 7547886
		8	MOBIL OIL CORP		214 8718938
		8	PHILLIPS PETROLEUM COMPANY		713 8003741
		10	UNION OIL COMPANY OF CALIFORNIA		807 2767800
		14	AMERMOA HESS CORPORATION		713 8080327
		14	MARATHON OIL COMPANY		713 6288900
		16	TEXAS GULF INC.		807 2788100
		18	GETTY OIL COMPANY	TEXACO INC	303 7834164
		19	CITIES SERVICE COMPANY	OXY USA INC.	818 9813085
		15	PLACID OIL CO		818 3413345
		19	GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 7547885
		15	ROWAN PETROLEUM INC	ROWAN DRILLING	907 2792448
		16	ATLANTIC RICHFIELD COMPANY		867 2634824
		18	SHELL OIL COMPANY		713 8704314
POINT THOMSON UNIT					
SALE 30					
ADL	312808				
		17	EXXON CORPORATION		713 8887000
		8	CHEVRON U.S.A. INC		713 7547886
		6	PHILLIPS PETROLEUM CO. PANY		713 8003741

**CAMBRIDGE ENERGY RESEARCH ASSOCIATES**

**FAX MESSAGE**

TO : ALASKA STATE LEGISLATURE  
ATTN: SEN. DRIE PEARCE  
FAX : 0019074653072

**Cambridge Energy Research Associates**

C E R A



LATIN AMERICA ENERGY



WORLD OIL

INSIDE

### Benefits to the Economy

A Boost in Confidence and in  
Capital Investment

### The Bottom Line

Maximum Returns to the State

### The Fiscal Terms

Dividing the Profits

# CERA ALERT

FEBRUARY 1, 1996

## VENEZUELA LEAPS FORWARD: THE SECOND COMING OF OIL?

January 22, 1996 marked the day that Venezuela re-opened the door to direct private investment in its oil and natural gas sectors.\* Sixty of the seventy-five companies that pre-qualified for the bidding round participated in the process that ended last week. Winners were chosen twice a day for the ten blocks containing an estimated 7 billion barrels of oil. An issue for many of the private investors was the amount of the take—the government participation in royalties and taxes—but the issue was not enough to derail investor interest.

Assuming that the PDVSA affiliate takes the maximum 35 percent share of the joint venture, the final division of profits in the profit sharing agreements will be between 88 and 92 percent for the government/PDVSA, leaving only 8 to 12 percent for the private investor consortium (see Figure 1, Venezuela: Bidding Round Results). This high level of take guarantees the government will receive large oil revenues in addition to what it already receives from PDVSA (between \$5 and \$6 billion per year).

More importantly, the low percentage of profits for the private investors may be an indication of a change in the emphasis of investor strategy—from the overall return on investment to securing long-term crude supplies. One reason this change is occurring for the Venezuelan bidding round is the sheer size of their natural resource base and the expectations of large prospects. Higher risk areas in Latin America are unlikely to be able to adopt similarly difficult terms, as seen in the lack of bids for the higher risk Catatumbo and El Sombrero blocks.

### Benefits to the Economy

The success of the bidding rounds will provide a much needed boost to Venezuela's economy over the long term through the expected capital investments by the private companies. More importantly, the high rate of government participation and cash bonuses pledged provides a tremendous boost to the country's confidence.

\*See the upcoming CERA Private Report, *Venezuela Opens the Upstream: The Impact on Exports*, February 1996.

## Cambridge Energy Research Associates

©1996, Cambridge Energy Research Associates. No portion of this report may be reproduced or in any form without prior written consent.  
25 Brattle Street, Cambridge, MA 02138, USA or Eurocor 14, rue Duguesclin, 75001 Paris, France.

The CERA Alert is part of CERA's Latin American Energy Market Advisory Service.  
For more information, please contact Steve Wood at (617) 452-0444.

Figure 1  
Venezuela: Bidding Round Results



Source: Cambridge Energy Research Associates, POVSA

\* CLM = Condensate/Light Naphtha  
\*\* Includes royalty, income tax, and PEG

After enduring a multi-year recession, a rapidly devaluing currency, weak foreign investment, and a near-collapse of its banking industry, Venezuela needed some good news. And now it is in a position to lock up a long-term tax revenue stream if estimated production levels are realized.

In addition to the state, PDVSA is also reaping a very large benefit, for it now has secured the investment capital needed to expand liquid productive capacity over the next ten years. If the ambitious estimates are realized, these private companies will help increase capacity from today's level of

approximately 3.2 million barrels per day (mmbd) to over 6.07 mbd by 2005. In terms of impact on the world oil market, PDVSA's export capacity would increase from nearly 2.0 mbd to over 4.7 mbd.

## The Bottom Line

Surprisingly, five bids in the first round—which determined the state's share of profits—were for an additional royalty of 50 percent (allowable bids were between 0 and 50 percent). Four of the five bids resulted in a tie among the bidders, requiring that the cash bonus envelope be opened in order to break the tie. These bonuses ranged from \$10 million to \$109 million per block, or \$244.8 million in total. Eight of the 10 blocks were successfully auctioned off, with two blocks—Catatumbo and El Sombrero—being pulled from the process due to a lack of bidders. Importantly, the winning bids for five of the blocks included the maximum level of discretionary royalty to the government (50 percent).

Initial exploratory drilling could begin as soon as late 1996 if everything goes according to plan, but production is not expected for several more years. The government hopes this program will attract over \$500 million in investments over the first two years and reach an aggregate \$11 billion in new investments over the life of the 20 year program.

## The Fiscal Terms: A Review

### PDVSA's Role

If a block is found to be commercially viable, the developing consortium is required to enter into a joint venture profit-sharing agreement with a PDVSA subsidiary. The subsidiary has the right to take up to a 35 percent position in the joint venture—a value of which will be determined by taking a pro-rata percentage of the exploration costs. For example, if the exploration cost were \$1 billion and the subsidiary opted for a 35 percent share, then they would be required to pay the consortium \$350 million. However,

this amount is to be paid from the profits of the joint venture. In effect, the consortium will be lending the subsidiary the capital until a profit stream is realized but will be allowed to charge a market-based interest rate for the "loan." Once the consortium has been paid back, the joint venture will split the profits according to their respective share. If the block is not commercially viable, the consortium bears the entire financial risk.

### The Government's Role

There are two components to the government's fiscal take in the profit sharing agreements—income taxes and royalties. The combined take for the government under the current structure is considered high in both absolute terms and also relative to other South American oil and gas investment opportunities.

- **Income taxes.** Income taxes are established by law, and changes would require Congressional approval. Currently, income taxes are set at 67.7 percent with a potential investment credit reduction of 2 percent.
- **Royalties.** The royalty component can be modified without a legislative change. In the case of the proposed profit sharing agreements, the royalty payment could be in two parts. The first part is established for the industry and is generally calculated at one sixth of the market value of the hydrocarbon produced. The government has the option to take all or part of the payment in kind.
- **The "PEG."** An additional royalty was invoked in the profit sharing agreements and was by design the determining factor in the winning bids. Called the Participacion del Estado en las Ganancias (PEG), it is an additional percentage of pre-tax profit offered by the private company or consortium during the bidding round. This percentage was bid up significantly in the most sought after fields, and determined which company was chosen. ■

Please mark your calendar for CERA's 15th Annual Executive Conference in Houston on February 13 and 14, 1996. For more information, call Brian Ward at (617) 441-2647.

CERA's new multibillion dollar study, *Latin America Energy Scenarios to 2010*, will be available soon. For more information please contact Brian Ward at (617) 441-2647.

TONY KNOWLES, GOVERNOR

## DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

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

February 22, 1996

The Honorable Bruce Pearce  
Capitol Building  
Juneau, Alaska 99801-1182

Dear Senator Pearce,


Following our conversation yesterday, we have located a couple of articles reporting the Venezuela state petroleum company's (Pdvs) recent signing of exploration and production profit sharing contracts. As noted in the January 15, 1996 Oil and Gas Journal article (page 24), this effort represented the first offering of exploration acreage in Venezuela since 1958, and encompasses a profit sharing plan designed to boost productive capacity by pursuing solo projects, joint ventures, and private oil company ventures in marginal field reactivation, exploration and production profit sharing deals, heavy oil projects and other ventures.

In the February 12, 1996 Oil and Gas Journal article (pages 31-34), details of the bidding are reported. Briefly, the contract/licenses garnered outlays of millions of dollars on each block, high profit sharing bonuses in the 40% to 50% range, high "tiebreaker" bonus bids in the millions of dollars, and provisions to purchase a working interest by paying a pro rata share of costs in the event of a commercial discovery.

Legal concerns apparently were raised by many oil companies regarding the structure of the tender offer and aspects of the proposed joint venture tax issues (OGJ, Feb. 12, 1996, pg. 34). Also, according to the January 29, 1996 Petroleum Intelligence Weekly (PIW), the major companies complained over the fiscal terms of the tender. Neither the tax issues nor the complaints over the fiscal terms appeared to dampen the impressive bidding.

I hope this information helps. Feel free to contact me if you have further questions.

Sincerely,

  
Kenneth A. Boyd  
Director

## EXPLORATION

# Oil, gas potential seen on 10 Venezuelan blocks

Gregory D. Croft Karl W. Stauffer *Pantera Petroleum Inc., San Leandro, Calif.*

Venezuela's congress approved on July 4, 1995, the offering of 10 exploration blocks after several months of discussion. This is the first new offering of exploration acreage in Venezuela since 1958 (OGJ, July 24, p. 21).

Terms for the offering include a sliding-scale royalty, various taxes, a fixed work commitment, and a government participation share. This last parameter is offered by the bidder, with the largest participation share being the winning bid.

The blocks are located in different parts of the country, but all 10 are located in basins that are prolific oil and gas producers. The following is a brief summary of the petroleum geology of each block.

## Block 1, Catatumbo

Located on the southwestern shore of Lake Maracaibo, this area is essentially unexplored but lies between the major Lake Maracaibo oil production and the oil producing areas along both sides of the border with Colombia.

It is certain that almost all of the oil produced from the Venezuela-Colombia border area was sourced by the prolific Cretaceous La Luna formation in the Maracaibo basin and migrated to the southwest, in part through this block. A second, lesser source rock is the shale and coal of the Paleocene Orucue formation, but this unit tends to be gas prone.

Reservoirs in this block would mostly be Tertiary sandstones, especially those of the Mirador and Carbon-

era formations. Cretaceous carbonates with sand interbeds are also likely reservoir rocks. Possible traps include stratigraphic wedgeouts as well as anticlines related to the thrust faults formed during the Miocene to recent uplift of the Merida Andes.

## Block 2, La Ceiba

This block is east of the southern part of Lake Maracaibo and immediately south of prolific Motatan field, which produces from Eocene Misoa sandstones. Well productivities from the Eocene sandstones at Motatan are quite variable but can exceed 5,000 b/d.

Oil seeps along the

foothills of the Merida Andes just south of this block indicate that oil migrated through the block from north to south. The source of the oil is the La Luna formation.

The most likely reservoir rocks are the Misoa formation and other Tertiary sandstones, as well as fractured carbonates and sands of the Cretaceous Cognin group. Traps are likely to be structures associated with the Andean uplift or with earlier, left lateral strike slip faulting.

## Block 3, Guanare

The block is located in the northeastern part of the Barinas basin, which is the northern extension of Colombia's prolific Llanos basin. Sedi-

ments in this block reach thicknesses of about 15,000 ft. The source of the hydrocarbons on this block is again the La Luna equivalent, principally the Cretaceous Escandolosa formation.

The most likely reservoirs are sandstones of Tertiary age, particularly the Eocene Gobernador formation that produces in the older fields to the southwest. Other possible reservoirs are the sands and limestones of the Upper Cretaceous.

This relatively unexplored block (only one well has been drilled in the area) has the glamor of traps associated with large horizontal thrusts. In the foothills along this same mountain front are the

## VENEZUELA 1995 EXPLORATION BIDDING ROUND



## EXPLORATION

giant fields of the Furrrial trend in eastern Venezuela and the Cusiana trend in the Llanos basin of Colombia.

### Block 4, San Carlos

This block is located along the southern margin of the Merida Andes near the El Baul arch, which separates the Eastern Venezuela basin from the Barinas basin.

This is a relatively unexplored block that has interesting potential. Source rock is not considered a problem as the Escandalosa formation is either on the block or nearby.

Structurally, this block is very complicated; it is at the intersection of two compressional trends, has sedimentary section that wedges out against the El Baul arch, and has south verging thrust faults.

Likely reservoirs in this block are the sandstones of the Tertiary, particularly the Eocene, and possibly sandstones and carbonates of the Cretaceous. Likely traps are anticlines associated with thrust faults, possibly older Tertiary fault blocks, and updip pinchouts. Late structural movement associated with the Merida Andes may have destroyed earlier traps.

### Block 5, El Sombrero

El Sombrero is located about 50 miles south of Caracas. The major natural gas accumulation at Yucal-Piacer is located immediately east of and on trend with this block. To the southeast is the Las Mercedes area, which has produced about 200 million bbl of oil from sands that range in age from Miocene to Cretaceous.

Sediments in this block are up to 10,000 ft thick and hydrocarbons may be either oil or gas. The bounding thrust fault of the Coastal Range is close to the northern boundary of the block.

Possible traps in this block include anticlines and thrust structures related to the uplift of the Coastal Range and sand pinchouts to the south in younger units. The major source rocks here are probably the shales of the La

## THE AUTHORS



Craft

Gregory D. Craft worked 11 years for Chevron Overseas Petroleum in Trinidad and Venezuela and completed his M.S. in Geology and Ph.D. in Geology and also in business planning. He left Chevron in 1984 to join Dr. Stauffer in founding Santos Petroleum, a San Leandro, Calif., consulting firm specializing in Venezuela. He has an M.S. in geology from Stanford University.



Stauffer

Karl W. Stauffer's early employment was with Royal Dutch/Shell and later Chevron. He was based from Caracas to Petroleros de Venezuela from 1977 through 1979. During which time he prepared a series of studies including a regional evaluation of the petroleum potential of the Maracaibo basin. He left Chevron in 1984 to form Santos Petroleum. He received a Ph.D. in geology from Stanford University.

Luna equivalent formations, although some sourcing from Tertiary shales, especially of gas, may have occurred.

### Block 6, Guayapiche

This area is east of the city of Mahurin along the famous Furrrial trend, where many giant oil and gas fields have been discovered in the last 10 years. The recent discoveries have all been to the west of this block, but the geologic structure in the area trends east-west and continues through the block.

Source rock is not a concern in this area given the prolific nearby discoveries. The major source is again the La Luna equivalent, here called Querecual and San Antonio, although there is probably a secondary contribution from the Miocene Carapita formation.

Potential reservoirs include Miocene, Oligocene, and Cretaceous sandstones, as in the Furrrial trend, as well as Mio-Miocene sands such as produce in Quinquie and Pedernales fields. Traps are probably related to thrust-faulted structures, although there may be stratigraphic traps in

the younger Tertiary and flank traps against shale diapirs.

Reservoir quality and continuity are the principal risks associated with this block.

### Blocks 7-9, Golf of Paria

These blocks cover the southern part of the Gulf of Paria from the Venezuelan coast to the marine boundary with Trinidad. These are the only wholly offshore blocks. The blocks are located near the axis of the gravity low that marks the center of Tertiary sediment accumulation in the Eastern Venezuela basin.

Sediments here may be more than 30,000 ft thick. That there are hydrocarbons in the area is clear. Pedernales field is just offshore to the south, the Furrrial trend is to the west, and the oil fields of southern Trinidad are on trend to the east.

Geological and structural trends do appear to continue all the way from the Furrrial area into Trinidad, although facies changes of individual units also occur. Source rocks are largely the Querecual of Upper Cretaceous age, called the La Luna further west and

the Naparaima Hill in Trinidad.

The most likely reservoirs are Neogene sands and perhaps Paleogene and Cretaceous sands. Traps in these blocks may include thrust related structures as well as unconformities, stratigraphic traps, and traps against the flanks of shale diapirs.

Reservoir continuity may be a problem in these blocks.

### Block 9, Punta Pescador

This block is located onshore and offshore the northernmost Amacuro delta. It is bounded to the north by the marine boundary with Trinidad and to the south shores in part a common border with Block 10.

Pedernales field to the west produces oil from stacked Pliocene and Miocene sandstone reservoirs on the flank of a shale diapir. The sedimentary section in this block is very thick, probably about 30,000 ft. The source rocks here are the Upper Cretaceous Querecual, called Naparaima Hill in Trinidad. Potential reservoirs include Neogene and perhaps Paleogene sands.

In addition to having deltaic-type structures that could serve as traps, this block may have structures related to earlier compression. Neogene submarine fan deposits could contain stratigraphic traps, and shale diapirism is also a likely trapping mechanism. A potential problem in this block is reservoir quality both due to the original facies and to compaction effects.

### Block 10, Delta Central

As its name suggests, this block is located in the middle of the Amacuro delta. In this block the sediment thickness is greater than in the productive Temblador-Tucupita trend to the southwest but less than in Block 9 to the north.

The source rock for the block would be the stratigraphic equivalent of the La Luna formation, either within the block or just beyond it. Possible reservoirs include

# EXPLORATION

sandstones ranging in age from Pliocene to Cretaceous. Traps may include deltaic-type extensional structures, pre-deltaic compressional structures and stratigraphic wedges combined with faults.

This block has fewer data than any of the other blocks; no wells have been drilled within the block, and little seismic has been acquired. The unknown quality and continuity of sandstone reservoirs may be the greatest risk in this block.

A recent oil discovery at Las Piedritas, just west of the block, flowed 2,700 b/d.

## CONCLUSIONS

The blocks to be offered in Venezuela's upcoming exploration round include some very exciting exploration potential.

The blocks are located mostly in the deeper parts of Venezuela's two most important oil producing basins, and several of them are in structurally complex areas.

Many of the blocks are highly prospective for natural gas as well as oil, but operators will face a challenge marketing large quantities of gas in Venezuela's well-supplied gas market.

The offering also represents a watershed in Venezuelan politics in that foreign companies have not been able to obtain exploration acreage in Venezuela for many years.

## NEVADA

Tide Petroleum of Nevada, Reno, staked the state's first wildcat to subthrust Paleozoic.

Permitted to 10,000 ft, it is the 2 Baseline Canyon Unit, Federal, in 21-1n-59c, Lincoln County. The spot is in Coal valley 2 1/2 miles south of Grand Canyon oil field.

## N. DAKOTA

Armstrong Operating Inc., Dickinson, completed a Mississippian Ludgopole

discovery in Stark County.

The 29-1 Haller, in 29-139n-96w, 3 miles southwest of Dickinson, flowed 157 b/d of oil, 78 Mcfd of gas, and 35 b/d of water from 9,622-34 ft.

The discovery opens Ver-sissippi field.

Baker Hughes Inc. reported 20 rotary rigs making hole in North Dakota in the week ended Sept. 1, compared with five in the same week in 1994.

## OKLAHOMA

OXY USA Inc. staked an Ardmore basin wildcat in Johnston County.

The 1A Airport, in 21-4s-6e, 2 miles south of Tishomingo, is projected to 9,500 ft. The spot is 5 miles northeast of an abandoned one well oil field, PI reported.

PetroCorp Inc., Houston, is connecting two gas wells in the Misener Trend of Alfalfa County.

PetroCorp expects sales to start this month at 1.5 MMcfd of gas from the 19C-4 Janet. Sales started Aug. 25 from the 10C-1 Sierra, averaging 200 Mcfd.

## TEXAS

### South

Tesoro Petroleum Corp., San Antonio, might shoot a 3D seismic survey next year over a potentially significant discovery in Webb County.

The 1 Longoria, 40 miles east of Laredo on Tesoro's 2,200-acre South Guerra prospect, flowed 3.5 MMcfd of gas through a 3/4-in. choke with 4,090 psi wellhead pressure. The well encountered

80 ft of gross pay sand in the tested interval and three other pay sands untested behind pipe.

The discovery well is 4 miles southwest of and analogous to Cuerra field, which has produced 125 bcf of gas.

Tests of the 1 Longoria continued to determine permeability and the need to fracture the pay sands. The company hopes to complete a directional delineation well by yearend to optimize contact with at least four identified prospective pay sands.

Mustang Oil & Gas Corp., a unit of Gulf Resources Corp., San Antonio, and Tesoro Petroleum Corp. opened new pays in Lopeno field in Zapata County.

The 1 Palmyra, enhanced by 3D seismic data, flowed as much as 107 MMcfd of gas on a 3/4-in. choke with 5,443 psig wellhead pressure from multiple zones in Eocene Upper Wilcox at about 11,000 ft. CAOF is 48,849 MMcfd.

The well cut 26 ft of gross pay sand in four producing intervals within the L-13, L-18, L-21, and L-22 sands.

Lopeno field, discovered in 1952, has produced about 120 bcf from L-5 through L-27 sands. Mustang used deviated drilling technology and multiple zone completion techniques that proved successful at Bob West gas field 6 miles southeast.

### Gulf Coast

Nuevo Energy Co. completed a Brookeland field well that is the third well on its 58,000-acre joint venture with Tetaco Exploration and Production Inc.

The 111 Springer, in Jasper

County, flowed 15.4 MMcfd of gas with 2,880 b/d of condensate through a 3/4-in. choke with 3,375 psi FTP.

The Cretaceous Austin chalk well produces through dual laterals a combined 9,062 ft long. True vertical depth is 31,850 ft.

Patterson Energy Inc., Snyder, Tex., has boosted its holdings in the Iola area of the Cretaceous Austin chalk trend in Grimes County to 3,700 net acres.

The new holdings are near Patterson's Norwood and Davis wells, which were dual lateral completions.

## UTAH

Amerac Energy Corp., Houston, formerly Wolverine Exploration Co., staked a wildcat in Summit County between Pineview and Bridger Lake fields.

Proposed TD is 17,000 ft at the 1 Table Top Unit, in 16-1n-10e, 18 miles east of Pineview oil field.

Barrett Resources Corp., Denver, is preparing to complete its 3 Cave Gulch well that has established the deepest production in Cave Gulch Unit in the Wind River basin.

The well was hooked to sales in mid-August at 5 MMcfd of gas and 40 b/d of oil from perforators at 8,537-8,830 ft in a previously untested section of the Upper Cretaceous Lower Lance. TD is 9,050 ft.

Dartlett plans to perforate additional zones in Lance.

The company recently staked the 10 Cave Gulch Unit, in 32-37n-86w, Natrona County, as a 9,200 ft Lance test in Walmman field.

## API MONTHLY U.S. WELL COMPLETIONS\*

	Oil wells	Footage	Gas wells	Footage	Dry holes	Footage	Total wells	Footage
June 1995	577	2,917,495	773	5,088,457	391	2,754,434	1,673	10,260,286
May 1995	606	2,819,998	779	4,814,814	383	2,114,441	1,778	9,809,259
June 1994	518	2,812,313	747	4,240,328	317	2,864,849	1,602	10,260,184

\*Total wells reported to API during June 1995 are stratigraphic and core tests, 1-includes oil, gas, and dry holes plus service wells.

# Pdvsas poised to sign first E&P profit sharing

Venezuela's state petroleum company Petroleos de Venezuela SA (Pdvsas) this month will sign its first exploration and production profit sharing contracts.

The effort represents Venezuela's most extensive offering of this type for private investment since nationalization 70 years ago. It also is the first offering of exploration acreage in Venezuela since 1938.

The program is expected to generate as much as \$12 billion in added investment in Venezuela's upstream sector the next 10-15 years.

## Pdvsas goals

The E&P profit sharing program falls in line with Pdvsas's goal of boosting oil productive capacity to more than 5 million b/d by 2005 from the current level of slightly more than 3 million b/d, in expectation of growing world oil demand.

Pdvsas's 10 year business plan calls for total outlay of \$60 billion to hike productive capacity to 5.691 million b/d. That breaks out as \$33 billion for Pdvsas solo projects, another \$11 billion for joint ventures, and \$16 billion from private oil companies for marginal fields reactivation projects, E&P profit sharing deals, Orinoco heavy oil projects, and other oil and gas ventures.

Meantime, Pdvsas has earmarked about \$6 billion in capital spending this year, with most of the focus on E&P to underpin production and reserves growth.

The company also is moving to consolidate its growing global role as a refiner and marketer of heavy crudes and related products.

## E&P program

The long awaited E&P profit sharing program is a departure from Venezuela's other recent efforts to attract private—especially foreign—investment to its upstream sector.

Pdvsas has signed some major "strategic alliance" agreements involving major oil companies for participation in heavy oil development/upgrading ventures (see table, OGI, Aug. 14, 1995, p. 37).

In addition, Pdvsas is making progress in a 3 year old program targeting private investment to reactivate marginal oil fields in Venezuela (OGI, June 12, 1995, p. 31).

Further, Pdvsas has all the elements in place except for a market for its liquefied natural gas export scheme, which includes offshore natural gas field development in cooperation with foreign oil companies (OGI, Sept. 4, 1995, Newsletter).

## VENEZUELA E&P PROFIT SHARING BIDDERS

Agip	Lesmo
Amoco	Maersk
Ampolco	Mitsubishi
Anadarko	Marubeni
ARCO	Mitsui
Asfa Landa	Mitsubishi
Berlon Oil & Gas	Mizu & Co
BHP	Mobil
Boc Energy	MOL
Bush	Morgan Gren
Bush Petroleum	Murphy Oil
Bush Gas	Nippon Oil
Brown & Hood	Norinco
Canadan	Norden
Occidental	Norsk Hydro
Ca. Gen. de Combustibles	Nuac
Chevron	OPIC
Clyde plc	Occidental
Coastal Corp	Pedco
Conoco	Pennrod
El Aguilone	Perez Companc
ENAP	Petrobras
Enron	Petrolina
Enserch	Petronas
Enxco	Phillips
Esso	Plaspetrol
Exxon	Ranger
Fluor	Repsol
Oil Canada	Royal Dutch
Home Oil	Shell
Mobil	Singapore
Hyundai	Talbot
Idemitsu	Tasmanian
Inpetrol	Tepecol
Japco	Tepeco
JIOC	Toto
Louisiana Land & Exploration	

The profit sharing scheme under Pdvsas's "apertura" (opening) oil program is the first time since nationalization in 1976 that private companies will be allowed to conduct E&P programs in Venezuela as equity owners.

The profit sharing deals call for exploration of 10 undeveloped blocks earmarked for joint ventures financed totally by private companies. Minimum investment is expected to be \$40-60 million/block.

The 10 blocks are spread over an area estimated at 4.5 million acres (see map, OGI, Sept. 18, 1995, p. 83). Potential reserves are estimated at 7 billion bbl of high quality medium and light gravity crudes.

If commercial volumes of oil and/or gas are discovered, the private companies will form joint ventures with one of Pdvsas's subsidiaries, sharing the venture's profits and being reimbursed for exploration costs.

## Companies, timetable

More than 300 companies have expressed an interest in the E&P profit sharing program, and about 70 have qualified to bid (see table).

Here is the schedule for opening sealed bids under the profit sharing program:

- Jan. 22, Catarumbu Block A, Zulia

and Merida states; La Ceiba Block B, Trujillo, Merida, and Zulia states.

- Jan. 23, Guanare Block C, Portuguesa state; San Carlos Block D, Cojedes and Portuguesa states.

- Jan. 24, El Sombrero Block E, Guanaco state; Guarapiche Block F, Monagas and Sucre states.

- Jan. 25, West Gulf of Paria Block C and East Gulf of Paria Block H, both Sucre state.

- Jan. 26, Punta Pescador Block I and Delta Centro Block J, both Delta Amacuro state.

## Pdvsas 1996 spending

Pdvsas's 1996 budget focuses heavily on its efforts to boost Venezuela's crude oil reserves to about 66 billion bbl, which it reckons would be an increase of about 1.6 billion bbl.

Oil & Gas Journal estimated Venezuela's proved crude reserves as of Jan. 1, 1996, at 64.5 billion bbl (OGI, Dec. 25, 1995, p. 41).

Pdvsas said its 1996 E&P program includes more funds for exploratory drilling in new areas such as the South Andean flank and North and Central Monagas state.

Increased spending also will go for development and appraisal drilling, secondary recovery, and steam injection projects.

In addition, Pdvsas expects to increase Venezuela's gas reserves by about 585 million bbl of oil equivalent (BOE) to about 25 billion BOE.

Pdvsas reported production of Orimulsion, its boiler fuel that is an emulsion of extra heavy crude, water, and a surfactant, will total about 4.8 million metric tons in 1996, up 104,000 tons from 1995. It also reported production and marketing of coal from its Carbones del Guasare joint venture will be about flat in 1996 with 1995's level of 4.5 million tons.

## Downstream plans

Pdvsas is pressing a program of upgrading and modernizing its refineries while eyeing possible further investments in refining abroad. All told, the goal is to add 600,000 b/d to worldwide refining capacity.

Plans call for increasing refining capacity in Venezuela by about 200,000 b/d by 2000 at a cost of about \$5.2 billion.

Current refining capacity in Venezuela is about 1.147 million b/d. Crude throughput is pegged at 983,000 b/d for 1996.

Much of the refining investment emphasis is on processing larger vol-

times of heavy and extra heavy crudes.

Plans call for Pdvs subsidiary Maraven SA to complete a \$2 billion upgrade of its 286,000 b/d Cardon refinery this year.

Pdvs also plans to expand the 195,000 b/d Puerto La Cruz and 115,000 b/d El Pilito refineries operated by its Corpoven SA unit.

### Amuay project

In addition, Pdvs subsidiary Lagoven SA will increase capacity of the hydrodesulfurization unit at its 571,000 b/d Amuay refinery. Plans call for expanding unit capacity to 250,000 b/d of high sulfur, heavy crudes from 190,000 b/d.

The project will allow the refinery to process feedstock from other refineries used distillates and gas oils, said Lagoven Refining Manager Heraldo Sifontes.

"That gas oil will be supplied to other refineries in the Pdvs circuit to be used at catalytic cracking units for the production of gasoline," Sifontes said.

Amuay's expanded deep conversion capacity of 98,000 b/d breaks out as 64,000 b/d of flexicoking and 34,000 b/d of delayed coking.

During first half 1995, Amuay processed about 102,000 b/d of heavy crudes, the highest in 45 years of operation. That volume of throughput is expected to rise to about 170,000 b/d as expansion work progresses, Sifontes said.

"Refining hard to market heavy

crudes means greater operational and commercial flexibility for Lagoven," Sifontes said.

Pdvs estimates about 73% of Venezuela's oil reserves are heavy and extra heavy crudes and 27% medium and light crudes and condensate.

### Foreign refining

Pdvs currently is negotiating the purchase of several refineries in the U.S. and possibly building another in Brazil, said Ronald Pantin, the company's strategic planning coordinator.

He did not disclose which plants are under consideration for purchase but said negotiations are based on an "association scheme" aimed at boosting Pdvs's refining capacity by 200,000 b/d in the U.S., with this about 70,000 b/d of refining capacity in wholly or partly owned refineries at Lake Charles, La., Corpus Christi, Tex., Paulsboro, N.J., Savannah, Ga., Lemont, Ill., and Houston.

In addition, Pdvs has 310,000 b/d of refining capacity at the Isla refinery in Curacao and a combined 260,000 b/d of capacity at refineries in Germany, Sweden, Belgium, and the U.K.

### Heavy oil upgrading

As an adjunct to the refining expansion, Pdvs continues in press projects with ARCO, Conoco, Mobil, and Total intended to produce a combined total of about 500,000 b/d of extra heavy crude and convert it into a more marketable synthetic crude.

Following an agreement last month setting up a \$2 billion heavy oil joint development/marketing venture be-

tween Chevron Corp. and Pdvs unit Maraven SA (OGJ, Dec. 25 1995, p. 29), Mobil is expected to complete negotiations on a similar project involving Orinoco extra heavy crudes with Lagoven.

"The prospects for that project look very positive," said Lagoven Pres. Julius Trinkunas.

He noted the prefeasibility study for the project is complete, and the contract should get a final green light for signing in the first quarter.

Under their strategic association, Mobil and Lagoven would set up a joint venture to produce about 100,000 b/d of extra heavy crude from the Orinoco belt's Cerro Negro region. The Cerro Negro crude will be upgraded at Lagoon's syn-crude.

The deal is expected not only to open markets to Lagoven in the U.S. but also lead to other joint ventures involving the two companies in the U.S.

Last November, Maraven signed a 35 year, \$1.5 billion strategic association contract with Conoco Inc. to produce, transport, and upgrade 120,000 b/d of Orinoco extra heavy crude (OGJ, Nov. 13, 1995 Newsletter).

Earlier, Maraven signed a contract with Total covering a \$2.85 billion project to produce and upgrade 160,000 b/d of Orinoco crude.

A \$3.5 billion strategic association between Corpoven and ARCO to produce 165,000 b/d of Orinoco crude, upgrade that to 210,000 b/d of syn-crude, and export the syn-crude still is pending approval (OGJ, Oct. 3, 1994, Newsletter).

## Protests linger over Shell Nigerian connection

Royal Dutch/Shell has come under more fire for its role in Nigerian operations.

In the latest development, London's Shell Centre buildings, U.K. headquarters for many of the company's international operations, was the starting point for a Jan. 4 protest against the company and Nigeria's military regime.

The Ogoni Community Association organized a march from Shell Centre to the Nigerian High Commission and on to St. James's Church, Piccadilly, for a memorial service for Ken Saro-Wiwa and eight other activists executed by the Nigerian government late last year (ULJ, Nov. 20, 1995, p. 37).

Also in London, members of Britain's Royal Geographical Society voted to expell Shell as one of their sponsors because of its Nigerian oper-

ations.

Meanwhile, Nigerian Minister of State for Petroleum Resources Kabir Chale said threats by Britain and the U.S. to boycott Nigeria's oil won't harm his country's economy if they develop.

Chale told Kaduna newsmen Nigeria would simply turn to other companies waiting to do business with his country if the U.K. and U.S. make good their threats.

### Target: Shell

Although Shell was once again the target of protests because of its supposed close links with government to facilitate its oil operations in Nigeria, the anti-Shell feeling was more muted than in recent months.

A Shell International spokesman said only about 30 protesters gathered outside Shell Centre, and there did not appear to be any reference to Shell in posters and banners they displayed.

The official said Shell had been asked to protest to Nigeria's government over 19 more Ogoni tribe protesters, currently held on the same charges, murder, as Saro-Wiwa and colleagues and due for trial at an undisclosed date.

In Kaduna, Chale pointed out that Iran and Libya are under U.S. oil embargos but are still exporting their oil to other buyers.

He said Nigeria is bolstering its economic relations with China, Russia, and eastern European countries to forestall any embarrassment sanctions from the West might cause.

## Pdvsa and Bitor lands biggest Asian supply contract for Orimulsion

Venezuela's Bitumenes Orinoco (Bitor) soon will sign a deal to sell 3.4 million tons/year of Orimulsion to Taiwan, matching its biggest sale to date.

Orimulsion is an emulsion of extra heavy crude oil, water, and a surfactant that is designed to back out coal as a low cost, environmentally preferred boiler fuel.

Bitor is a subsidiary of state owned Petroleos de Venezuela SA (PdVsa).

### Far East market push

Bitor Pres. Jorge Zemella said his company received "with great satisfaction" a report from Taiwan on the outcome of a tender by Taiwan's state owned power company to select new projects assigned to independent power producers (IPPs).

Zemella said Bitor affiliate MC Bitor Ltd. will "significantly penetrate" the Asian market with the Orimulsion sale to Taiwan.

Orimulsion will be the sole fuel of a power plant to be built by a group led by Interger at Lizhe in the Suao region on Taiwan's east

coast. Sales will begin in 2000.

The project is one of many proposed under a Taiwanese government initiative to solicit IPPs from the private sector to build power plants to meet Taiwan's soaring electric power demand.

Taiwan's Ministry of Economic Affairs recently chose from the first round of proposals seven groups to build a total of 7.11 million kw. Combined power capacity of 23 projects proposed in the first round totaled 30.3 million kw.

Oil products and natural gas will fuel some of the other winning projects.

### Lizhe project

Among the companies selected in the first round is a combine led by International Generating Co. (Interger), a joint venture of Bechtel Group and Pacific Gas & Electric affiliates. Other members of the group are Taiwan Synthetic Rubber Corp., APED, and China Steel.

The combine's Lizhe plant will have an installed generating capacity of 1.5 million kw involving two units of 750,000 kw each.

One of the units will begin operations about mid-2000 and the second by the end of that year.

MC Bitor and Mitsubishi Corp. will supply those units about 3.4 million tons/year of Orimulsion for 25 years exported from the Jose terminal in Anzoategui state, eastern Venezuela.

It will be the largest supply contract of Orimulsion in the Asia-Pacific region. MC Bitor and Interger are expected to sign the agreement soon.

Zemella said, "The approval constitutes the most significant step forward in the Asia-Pacific region by Bitumenes Orinoco, through MC Bitor, in penetrating the electricity segment of the energy market in the Far East."

The market has been dominated by energy sources such as gas, coal, and conventional liquid hydrocarbon fuels.

The next step in marketing Orimulsion in the region is to prepare an environmental impact study to obtain permits from Taiwanese local and regional authorities.

## Venezuela's E&D round mostly successful

Venezuela's last profit sharing exploration and development licensing round has yielded generally positive results.

Although two of the 10 blocks up for bid received no bids, some of the remaining blocks received hefty ones. State owned Petroleos de Venezuela (PdVsa) netted about \$215 million in rebroker bonuses in the round, in addition to about \$15 million from the sale of data packages to prospective bidders.

The 10 blocks, covering 4.5 million acres, are believed to contain potential oil reserves of at least 7 billion bbl of medium and light grade crude in addition to substantial potential volumes of natural gas (see map, OGJ, Sept. 18, 1995, p. 85). Preliminary estimates of potential oil reserves for the combined blocks ran as high as 23 billion bbl of light and medium gravity crude.

The tender marks the return of foreign companies to full equity participation in oil and gas E&D, a sector that Venezuela nationalized 20 years ago. It is expected to generate as much as \$12 billion in added investment in

Venezuela's upstream sector the next 10-15 years (OGJ, Jan. 15, p. 24).

The tender was marred by litigation stemming from concerns over clauses in proposed profit sharing contracts.

The push to expand foreign investment in Venezuela's upstream oil sector underlies the government's goal of doubling oil revenues in 7 years from the current \$6 billion/year.

To meet that goal, Carocis is counting on investment by PdVsa and private companies, especially foreign firms, to help jump productive capacity to 57 million b/d from today's 3.15 million b/d.

Venezuela currently claims to produce about 2.4 million b/d, close to its Organization of Petroleum Exporting Countries' quota of 2.359 million b/d. However, other sources have placed Venezuela's output considerably higher than that, exceeding quota by more than 300,000 b/d.

### How the bidding went

PdVsa voiced satisfaction with results of the E&D profit sharing license round. More than 75 companies pre-

qualified for the bidding.

"We are very pleased with the results," said PdVsa Pres. Luis Giusti. "The most important thing is that the massive attendance of large, medium, and small companies has rattled investor confidence in the country's petroleum industry."

Beyond concerns over tax and currency issues, international oil and gas executives praised PdVsa for a smoothly run tender.

"In some cases, we declined to submit bids simply because the risks in those areas were far too high or because we just did not have sufficient geological data to make a final decision," said one executive whose company failed to obtain a contract. "This by no means points to a lack of interest in Venezuela, which remains an attractive oil country."

PdVsa estimates \$1 billion will be spent in the first 3 year exploration period for the profit sharing blocks and another \$10 billion the following 7 years. The contracts call for outlays of

at least \$40-60 million/block.

In the event of a commercial discovery, license terms call for a Pdvsa affiliate to have an option to purchase a working interest by paying a pro rata share of costs incurred to date.

Pdvsa is expected to hand over the signal contracts early this month to the Energy & Mines Ministry, which in turn will send the documents to the cabinet of ministers, then to

Ronald Pantin, Pdvsa strategic planning coordinator, expressed surprise that Amoco and the Total/Statoil combine each offered a 50% PEG. He noted industry sees only one major oil play in the area but added that a major natural gas strike is highly prospective there.

In addition, the swampy region poses logistical challenges.

Oil Co./Luzmo plc, Petroleos Brasileiro SA/Benton Overseas Petroleum & Investment Co., Unocal Corp./Japan Petroleum Exploration Co. Ltd., and Repsol SA/Enterprise plc.

Work commitment for the La Ceiba block in the first 5 year phase of exploration is about \$50 million. The minimum work commitment calls for drilling of three wildcats. Plans call for seismic surveys to get under way this year.

Ronald Wilson, president of Mobil Latin America business development ventures, noting Mobil is familiar with the La Ceiba area, said, "We expect to find large accumulations."

Mobil first operated in Venezuela in 1934 and, with the country's new efforts to attract foreign investment, seeks to expand its presence.

Mobil is currently negotiating a \$1.8 billion strategic association with Pdvsa subsidiary Lagoven SA to produce and upgrade 100,000 b/d of extra heavy crude from the Orinoco oil belt. In addition, Mobil recently returned to lubricant manufacturing and marketing in Venezuela last year, when it purchased 50% of local company CA Nacional de Gases & Lubrificantes, the country's biggest lube plant.

Veba also has a long association with Pdvsa, dating to 1978 when it entered into a government backed accord between Germany and Venezuela for technical cooperation in the energy sector. In 1983, Veba and Pdvsa formed a joint venture, Ruhr Oel, to operate Germany's biggest refining system with throughput capacity of 440,000 b/d.

**Conoco blocks**

Conoco bid alone in winning the 1,793 sq km block on the northern shore of Lake Maracaibo on the first day of bidding, Jan. 22 (OGJ). Jan. 29, Newsletter) Interests in the block are Mobil 50%, Veba 30%, and Nippon 20%. Their winning tiebreaker bonus bid topped bids by nine other groups that matched the 50% PEG bonus.

**La Ceiba block**

A close second to the Guarapiche bid was the winning offer for the La Ceiba block along the southeast edge of Lake Maracaibo, thought to hold 790 million bbl of oil reserves.

Here, a Mobil Corp. led group that includes Germany's Veba Oil AG and Japan's Nippon Oil Exploration U.S.A. Ltd. made a winning bid of 50% PEG and tiebreaker bonus of almost \$104 million.

Mobil and partners snared the 1,793 sq km block on the northern shore of Lake Maracaibo on the first day of bidding, Jan. 22 (OGJ). Jan. 29, Newsletter) Interests in the block are Mobil 50%, Veba 30%, and Nippon 20%. Their winning tiebreaker bonus bid topped bids by nine other groups that matched the 50% PEG bonus.

Closest to the winning bid was Exxon/Shell, which offered a 50% PEG bonus plus a \$57.5 million tiebreaker bonus. Others bidding for La Ceiba were Amoco, Texaco Inc./Mitsubishi Corp./Maxus, Elf Aquitaine/Conoco Inc., Agip SpA/Norsk Hydro, Total/Statoil/Petronas Carigali, Marathon

**RESULTS OF VENEZUELA'S FEB. PROFIT SHARING ROUND**

Block	Area (sq km)	Estimated potential oil reserves (Million mmbbl)	Estimated potential production (1,000 bbl/d)	Winning bidder(s) (%)	Profit sharing bonus bid (Million \$)	Tiebreaker bonus bid (Million \$)	First year projected exploration investment (Million \$)	Five year projected investment (Million \$)
Quadrado	1,890	825	180	Elf 50, Conoco 50	50	—	55	541
San Carlos	1,171	405	95	Perez Compañac	40	—	23	690
Guarapiche	1,950	990	200	BP 37.5, Amoco 37.5, Maxam 25	50	109	162	1,583
West Gulf of Paria	1,134	600	135	Conoco 100	50	21.2	144	1,146
East Gulf of Paria	1,080	630	120	Enron 20, Inelectra 10	29	—	121	1,201
Delta Centro	2,138	820	180	LL & E 37.5, Norcen 37.5	41	—	107	1,393
Punta Pescador	2,046	700	134	Benton 25, Amoco 100	50	10.7	99	695
La Ceiba	1,742	791	160	Mobil 37.5, Veba 37.5, Nippon 25	50	104	120	1,452

\*Catatumbo and El Sombrero blocks did not receive bids

Venezuela's congress for final approval.

Exploration generally is expected to get under way in first quarter 1997.

**Amoco blocks**

Attracting the most interest in the bidding was the Guarapiche block in eastern Venezuela, which is believed to hold as much as 1 billion bbl of medium and light gravity crude.

A combine of Amoco Corp., British Petroleum Co. plc, and YPF SA unit Maxus Energy Corp. won the block based on a 50% pretax profit sharing bonus (PEG) plus a tiebreaker bonus of almost \$109 million.

Amoco bid solo to win the Punta Pescador block in eastern Venezuela, just east of the Guarapiche block in which the company is a partner. Amoco offered a 50% PEG and a tiebreaker bonus of \$10.7 million.

That topped a bid of 50% PEG and tiebreaker bonus of \$5.6 million by a combine of France's Total and Norway's Den norske stats oljeselskap AS.

Amoco plans to spend at least \$40 million to explore its Punta Pescador block. The block lies just south of gas fields Amoco is developing off Trinidad.

Gulf of Paria between Venezuela and Trinidad. Exploration is to get under way right after the contract is signed.

Conoco combined with Elf Aquitaine 50-50 to take the Guanare block in Portuguesa state in western Venezuela. The block is in the foothills of the Menda Andes.

The work commitment calls for a 5 year, \$30 million outlay to drill four wells and acquire seismic data. Work is to get under way immediately after the contract is signed.

Conoco also has a strong presence in Venezuela.

It formed a joint venture, Petrozuata, with Pdvsu unit Maraven SA to produce 15 billion bbl of Orinoco extra heavy crude and convert it to synthetic crude, most of which will be processed in Conoco's U.S. refineries. Construction on the \$1.4 billion project is to get under way early in 1997.

Conoco also is a partner with bitumenes Orinoco SA to convert Orinoco bitumen to Orimulsion. Pdvsu's proprietary heavy oil/water/surfactant emulsion is used as a boiler fuel.

### LL&E group block

A group made up of Louisiana Land & Exploration Co. (LL&E), New Orleans, Norcen Energy Resources Ltd., Calgary, and Benton Oil & Gas Co., Carpinteria, Calif., won the Delta Centro block in eastern Venezuela.

Operator LL&E will hold a 35% interest in the block. Norcen will take 35% and Benton 30%.

The Delta Centro block lies in a mostly marshy region of the Orinoco River delta in Northeast Venezuela's Delta Amacuro state.

The group's work commitment calls for acquiring and processing 1,300 line km of seismic data and drilling three wells in 5 years with an option to extend the exploration period 4 years.

Work is to get under way after the contract with Pdvsu is signed.

LL&E Chairman W. Leighton Stevens noted the Delta Centro block's marshy terrain is similar to marshlands in Louisiana where LL&E has long operated.

### Other bidding

Perez Compana SA took the San Carlos block in Cojedes and Portuguesa states of Southwest Venezuela.

The Argentina company topped a bid by Elf by offering a 40% PEG. Perez Compana currently is involved in reviving oil production in Venezuela under the country's marginal fields participation program.

A combine of Enron Corp. and

## WATCHING THE WORLD



With David Knott from London

# The unequal split of British Gas

Facing competition in U.K. gas markets, restrictions by government regulations, and massive gas contract debts, British Gas plc will split into two companies.

The former U.K. gas supply monopoly, privatized in stages beginning in 1986, will split into a large company, to be known as Transco International plc, and a smaller unit, British Gas Energy plc.

Chairman Richard Giordano said, "This demerger is about the creation of two separate companies that will manage our business more effectively to the advantage of our customers, shareholders, and employees."

But some pundits say the move is designed to protect the company's profitable businesses from losses in long term take or pay gas purchase contracts.

Ahead of gas market deregulation, U.K. operators developed gas fields to support their plans to supply gas directly to end users. Trading in gas began among companies. And with the glut of new gas the spot price fell.

### Assets share-out

Because of the low spot price, British Gas is said to face losses of £1.5 billion (\$2.25 billion) on long standing contracts worth a combined £40 billion (\$60 billion).

The new Transco unit will get the biggest asset, British Gas' transportation and storage business, along with most of the exploration and production assets and the potentially lucrative power generation business and international operations.

British Gas Energy will be a comparative runt, given only the parent's supply and trading business. This is where it faces intense competition from new suppliers and big losses on

gas purchase contracts.

British Gas Energy also will get U.K. Morecambe Bay producing gas fields, which a spokesman said would allow it to compete with independents in liberalized markets.

Two fields with original reserves amounting to 6.6 tcf of gas, one of which has been on stream since 1985 and one since 1994, does not seem a great deal with which to take on fierce competition—particularly when British Gas estimated its reserves in 1994 at almost 2 billion bbl of oil equivalent.

### Public outcry

British Gas said the smaller company will receive no exploration assets or expertise in the transfer. So it will face an immediate problem in replacing reserves to remain competitive.

Transco is to be like a utility with steady returns, while British Gas Energy will be more like a consumer company with ups and downs in income. And everybody knows how

muchly a consumer business can die. The demerger business can die. It was followed in the British press by the news that Cedric Brown, British Gas chief executive, is to retire Apr. 30.

Following a turn over Brown's 75% pay hike in December 1994, Britons are now incensed by reports that he will get a £4 million (\$6 million) retirement package and will be retained as a consultant for the demerger.

Government's original idea in privatizing British Gas was supposed to be to make a cumbersome giant efficient and profitable. This latest move is a warning against following political dogma to the detriment of practical considerations of gas supply

Inlectra won the East Gulf of Paria block.

Catatumbo block, southwest of Lake Maracaibo, and El Sombrero block, in Central Venezuela, failed to attract bids.

Noteworthy for their absence from the list of winning bidders was a combine of Exxon Corp. and Royal Dutch/Shell Group that was expected to dominate bidding. However, the combine bid conservatively for the La Ceiba and Punta Pescador blocks and came away empty handed.

Some prospective bidders were daunted by the stiff terms Venezuela

imposed on the profit sharing deals. They call for income taxes totaling 67.7% and royalties of 16.7% in addition to the PEG and tiebreaking bonuses.

### A second try

Pdvsa on Jan. 29 tried again and failed to attract bidders for the Catatumbo and El Sombrero blocks.

Representatives from several private companies said high risks, low prospects for crude oil discoveries, and lack of geological data discouraged interest in those areas.

Juan Szabo, president of Venezuelan

Petroleum Corp. (CVP), said, "The lack of interest in some areas is relatively normal because each company chooses those blocks that fit their figures and their particular strategies."

CVP, a once defunct Pdvsa subsidiary, was revived specifically for the bidding process and given the portfolio of blocks to be tendered.

Winning bidders will sign the profit sharing contracts and set up joint ventures (JVs) with CVP. The Pdvsa unit will own as much as 35% of the JV stock, with the remainder held by foreign partners.

Pdvsa is considering putting together another tender for new blocks as part of its apertura, or "oil opening" policy, which includes profit sharing contracts, operating agreements, strategic associations, and alliances. A new round of bidding could occur as early as the end of this year or early next year.

### Legal concerns

The tender was held against a backdrop of optimism in government and oil industry circles and concern among many oil executives regarding aspects of the proposed joint venture tax issues and Venezuela's onerous currency control regulations.

Venezuela currently is negotiating an economic restructuring accord with the International Monetary Fund, under which it had agreed to lift currency exchange controls in first quarter 1996.

In addition, a group of intellectuals including Central University of Venezuela Rector Simon Munoz and chamber of deputies (lower house) energy and mines committee Chairman Ali Rodriguez filed two lawsuits in Venezuela's supreme court over the proposed profit sharing contracts. They claimed the proposed clauses allowing international litigation to settle differences and barring municipal authorities from exercising autonomy on tax matters violate the constitution.

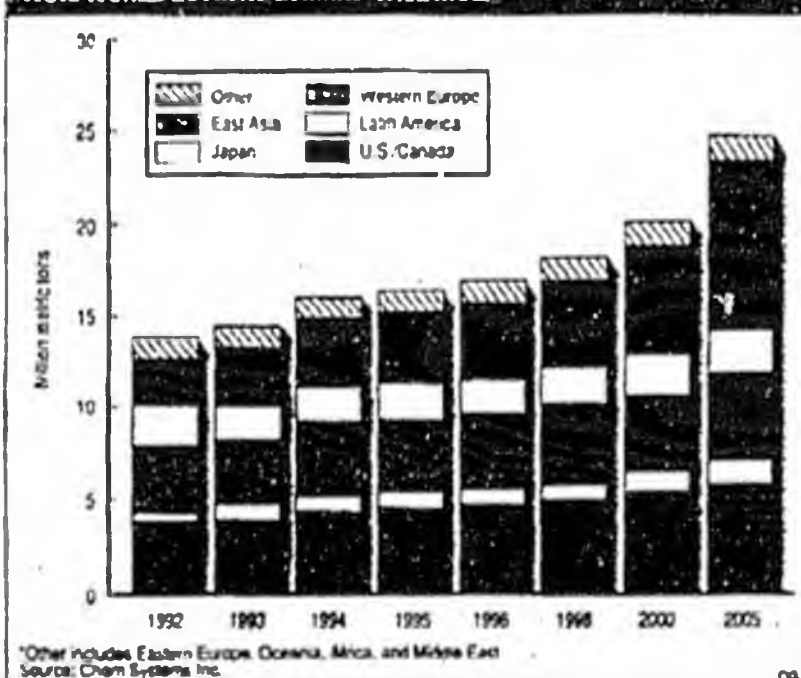
Giusti said there are no legal grounds for the lawsuits because under the constitution, municipal authorities have no autonomy to set taxes for the oil industry.

Regarding currency controls, Giusti said regulations currently allow companies to hold offshore dollar accounts and make profit remittances in foreign currency.

However, private oil companies contend issues such as municipal and other taxes and currency controls should be clarified in the contracts.

Government sources said a decree is being written to allow foreign companies operating in Venezuela to choose dollar accounting as the nation's stiff currency control system is put aside.

## HOW WORLD STYRENE DEMAND WILL RISE



## Strong styrene growth foreseen

Eastern Asia will lead hefty growth in world styrene demand through 2005.

Driving the region's 9.3%/year increase in styrene consumption are economic growth, improved standards of living, and increasing exports of finished products.

Those are the findings of a study by Chem Systems Inc., Tarrytown, N.Y.

The firm predicts world styrene consumption will increase at an average 4.1%/year through 2005, fueled by increased demand for polystyrene and acrylonitrile butadiene styrene (ABS).

Most styrene capacity expansion will take place in eastern Asia. Chem Systems expects additions in that region to total 2.5 million metric tons/year by 1998. This massive

capacity increase will reduce world operating rates, shift trade patterns, and squeeze profits in traditional exporting countries.

World styrene consumption increased 9.6% during 1994, making styrene one of the leaders in commodity petrochemicals' recent recovery.

Demand growth was strong for all styrene derivatives, especially polystyrene and ABS, which combined account for 73% of world styrene consumption.

In 1995, says Chem Systems, growth in styrene demand was less than anticipated because of inventory adjustments and an unexpected slide in shipments to China after the country closed its southern border.

European gasoline prices. Furthermore, if the WTO orders Washington to relax restrictions on gasoline from foreign plants, imports from Brazil could soar to 30,000 b/d, as in 1993, instead of the meager 12,000 b/d of components state Petrobras has been selling to the US of late (p8). The loss of 110,000 b/d of gasoline supply in the East Coast — enough to cover more than 3.5% of local demand — could add 1¢ a gallon to prices, according to Houston-based Stone Bond.

An expected drop in the availability of spot barrels — as Tosco diverts gasoline from its nearby Bayway refinery into its filling stations to replace the lost barrels from Marcus Hook — could also prove a stimulant to New York Harbor prices, by weakening the heavy-selling firm's bearish influence over that market. Recent changes to the New York gasoline futures contract should further boost liquidity and price transparency.

### Successful Tender Sets Stage For Next Act In Venezuela

Any remaining skepticism about the level of international company interest in Opec-member Venezuela's oil patch disappeared last week. At a licensing round for 10 exploration blocks, large foreign oil companies — led by British Petroleum, Conoco, and Mubil — bid aggressively in terms of both bonuses and proffered government take for the most prospective acreage, pushing the hemisphere's heavyweight closer to its goal of lifting burgeoning capacity from 3.1-million barrels a day to 5.5-million b/d in 2005. State Petroleos de Venezuela is now mulling over the next stage in the country's reopening, including the possibility of direct negotiations to reactivate smaller fields ahead of another competitive tender. Firms have conducted geological studies on some of Venezuela's oldest fields in PDV subsidiary Maraven's domain around Lake Maracaibo, with hopes of clinching direct service deals like the one Chevron signed for the Boscan field last month (PIW Dec.11,p8). Pennzoil has its eye on Mene Grande, and Canadian Occidental is targeting Cabimas, both of which now pump only a few thousand barrels a day. But political pressure still favors competitive bidding for most acreage awards, and PDV is already pondering which areas to offer in a third marginal-fields round at year's end.

Underscoring the majors' enthusiasm, despite complaints over local terms and lingering uncertainties in the profit-sharing contract, the bidding opened with an impressive nine-way tie out of 11 participants for the prized La Ceiba block east of Lake Maracaibo. It was finally awarded to Mubil and partners Germany's Yeba and Japan's Nippon Oil in a high-stakes runoff in which they posted a hefty \$104-million cash bonus. The runners-up were Exxon with Royal Dutch/Shell and Texaco with Mitsubishi and Argentine YPF. BP, Amoco, and YPF paid a \$109-million bonus in order to break a four-way tie for the coveted Guarapiche block in the swampy Delta region. Other blocks roused fewer heads, and the gas-prone El Sombrero generated no bids at all. El Sombrero, which lies southwest of Caracas, is to be re-offered this week. As at La Ceiba, which holds an estimated 800-million barrels or more of reserves, the companies offered the government the maximum 50% share in pre-tax profits at offshore Gulf of Paria West and at onshore Guanare, Guarapiche, and Punta Pescador. Conoco won the first after posting a \$21.2-million bonus, and then teamed up with Elf Aquitaine as operator to win Guanare. Amoco got Punta Pescador with a \$10.6-million cash bonus. Enron with local consulting giant Inlectra was sole bidder for offshore Gulf of Paria East, offering Caracas a 29% profit share, while Argentine Perez Companc outbid Elf for the San Carlos tract in the central region, offering the state 40% of profits (PIW Jan.15,p8).

Impending changes in PDV's upper ranks, possibly even uprooting savvy President Luis Giusti, probably won't shift the country's basic reopening campaign or its recession-driven grab for market share, given the gravity of the Caldera administration's domestic economic woes. Indeed, word that Giusti could take over the Finance Ministry raises the prospect of a further loosening in economic controls, a possibility that would spark even more interest in oil and gas projects. Talks with the International Monetary Fund, however, seem to be faltering, as President Rafael Caldera continues to resist another hike in subsidized domestic gasoline prices. The high level of bonuses obtained in the bid round may feed opposition to an IMF deal. A PDV insider would likely replace Giusti.



# Alaska State Legislature


Official Business

SENATE RESOURCES COMMITTEE

State Capitol  
Juneau AK 99801

## FAX MEMO

TO: Mr. John Morgan/BP Exploration <sup>5900</sup> (564-5514)  
Commissioner John Shively, DNR (269-8918)  
Attorney General Bruce Botelho (465-2075)

FROM: Annette Kreitzer, Aide to Senate Resources Committee 

DATE: April 1, 1996

RE: Requests for information from March 29 Resources meeting

---

Attached is the list of requests for information from the March 29 meeting of the Senate Resources Committee. Please provide the information to me as soon as possible. Information regarded by the state as confidential should be gathered to be disseminated during a confidential session of the committee. Please advise me, though, when the information is ready for the committee, so that the chairman can schedule a confidential session.

Thank you for your assistance.



# Alaska State Legislature

Senate Resources Committee  
Information Requests from Committee Members  
re: SB 318: Northstar Lease Agreement  
March 29, 1996 Hearing

State Capitol  
Juneau AK 99801

Official Business

## FIRST REQUEST:

- Halford: How much did BP pay Amerada Hess for the leases? (Available to Legislature under confidentiality measure).

## SECOND REQUEST:

In response to question from Senator Pearce, Senator Leman requested BP provide details on what BP agreed to in BP's successful January bid on leases in Venezuela that are similar or the same as net profit share leases.

## THIRD REQUEST:

Halford:

Want an analysis from Law re: conclusion as to whether development fund carries forward.

- ✓ Want list of other bidders on these parcels/leases in the sale (where BP acquired Amerada Hess leases).

If there is a lawsuit that stops development because of a change in the bid variable, what happens to the economic benefits (in the BP agreement)?

Want economic module to be run on 135 million barrels and on double that.

- ✓ Want to know what the projected severance tax rates will be.

## FOURTH REQUEST:

- ✓ Pearce: Federal definition of net profit share. (Patrick Coughlin verbalized at 3/30/96 hearing, but this was not passed out to members for context of where the definition appears. Mr. Coughlin needs to provide the definition and its context to the committee.)

## FIFTH REQUEST:

Leman: Wants list of how many and locations of employees from BP, CIRI, VECO and Arctic Slope and their subsidiaries. (after testimony from these companies regarding local hire)

## SIXTH REQUEST:

- ✓ Leman: Wants BP to provide the committee comparable numbers for BP's decisions to proceed with other North Slope developments. Estimated per barrel development costs which BP management considered before committing to develop: 1) Kuparuk, 2) shallow oil deposits at Milne Point (Schrader Bluff), 3) Niakuk, 4) Pt. McIntyre and any other North Slope fields BP has developed.



**BP EXPLORATION**

Alaska Exploration & Development

BP Exploration (Alaska) Inc.  
700 East Bannan Boulevard  
P.O. Box 190612  
Anchorage, Alaska 99519-0612  
(907) 561-5111

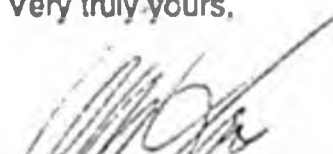
April 2, 1996

Hon. Loren Leman  
Chairman, Senate Resources Committee  
Alaska State Legislature  
State Capitol  
Juneau, AK 99801

Dear Senator Leman:

Per the request by Annette Kreitzer of your staff on April 1, I have enclosed responses to your six requests regarding SB 318 on the Northstar Lease Agreement. If you require additional information, please do not hesitate to call me (907-564-4892) or Daryl Kleppin (907-564-5418) on my staff.

Very truly yours,



---

E. M. Luttrell  
Vice President  
BP Exploration, Alaska Inc.

**BP Exploration, Alaska (Inc.)**  
**Response to Requests by Senate Resources Committee**  
**SB 318 - Northstar Lease Agreement**

- 1.) How much did BP pay Amerada Hess for the leases?  
The terms of the purchase agreement between Amerada Hess and BP for the Northstar leases are confidential. BP did secure permission from Amerada release that information under confidentiality agreements to specific staff within the Department of Natural Resources. We have requested permission from Amerada to provide that information to the Alaska Legislature under a similar confidentiality agreement.

- 2.) Please provide details on what BP agreed to in BP's successful bid on leases in Venezuela that are similar or the same as net profit share leases.  
Both Alaska and Venezuela derive their oil income from a combination of taxes and royalties. In addition, Venezuelan law allows the State Oil Company (PDVSA) to participate in the new E&P ventures up to 35% by paying full proportionate costs including any historical costs which are inflated at the prime interest rate. Reporting in the recent press assumes that PDVSA will do so.

Assuming that PDVSA takes its 35% share, the total government take in Venezuela (taxes, royalty, PDVSA) equals about 92% of profits. A comparable value for Northstar in Alaska is about 62% (State royalty, severance, and income tax; Federal royalty and income tax).

Venezuela can take a higher proportion of the benefits since the costs of developing, operating and transportation are substantially lower. In Venezuela, BP's cost per barrel (F&D, lifting, transportation) is about \$2.00 per barrel. Comparable costs in Alaska are about \$7.00 per barrel. In Venezuela, BP looks to make a profit of about \$1.20 per barrel from a capital investment (F&D) of about \$1.00 per barrel (a 1.2 ratio). In Alaska, we look to make about \$3.25 per barrel on a capital investment of about \$3.50 per barrel (a .94 ratio).

Economically (and from a view of simple capital efficiency), both of these ventures look attractive to BP, although BP's profit per barrel in Alaska is higher than in Venezuela. We also expect a much greater reserve potential in Venezuela (up to possibly 1 billion barrels).

- 3.) a) Please provide analysis from Law re: conclusion as to whether development fund carries forward.

To be provided by Alaska Department of Law

- b) Please provide a list of other bidders on these parcels/leases in the sale (where BP acquired Amerada leases).

See attachment #1.

c) If there is a law suit that stops development because of a change in the bid variable, what happens to the economic benefits (in the BP agreement)?  
To be provided by DNR staff.

d) Please provide economic model runs on 135 million barrels and on double that.  
The DNR will provide for an upside development case with reserves of 160 million barrels.

e) What is the projected severance tax rates?  
The ELF at field startup (1999) is .7 and goes to .03 in 2005 and zero there after. Therefore, the severance rate varies from 8.7% in 1999 to zero in 2006.

4.) Please provide Federal definition of net profit share.  
DNR and Department of Law to provide.

5.) Please provide list of how many and location of employees from BP, C'RI, Veco, and Arctic Slope and their subsidiaries.  
At year end 1985, BP employed 1,077 in Alaska of which 917 or 85.1% were Alaska residents. BPX would encourage it's Northstar Alliance contractors to provide similar data to the committee.

6.) Please provide to the committee a comparable number for BP's decisions to proceed with other North Slope developments. Estimate per barrel development costs which BP management considered before committing to develop: 1) Kuparuk; 2) shallow oil deposits at Milne Point (Schrader Bluff); 3) Niakuk; 4) Pt. McIntyre and other North fields BP has developed.

Field	Sanction Year	Development Cost (\$/bbl)	ANS WC (\$/bbl) (MOD)	ANS WC (1996\$) (real)
Kuparuk	1982	6.65	30	40
Endicott	1985	5.40	25	33
PBU: GHX-2	1992	4.45	18	19
Pt McIntyre	1992	2.30	18	19
Niakuk	1993	2.50	16	17
Not sanctioned				
MPU- Schrader Bluff	1996-97??	1.80	17	17
Northstar	1996-97?	2.90	17	17

## Attachment #1

## Sale 30 (12/79) Northstar Bidding

The following table outlines the sale 30 results (NPSL) showing the successful bidder and parties that bid unsuccessfully.

ADL 312788		
Bid Group/Co.	Co. Interest	NPS Bid
Amerada Hess	100%	93.20000%
Texas Eastern	50%	80.58789%
Texaco	50%	
Amoco	100%	71.12509%
Texas Gulf	10%	61.87000%
Conoco	48%	
Placid	22%	
Cities Service	20%	
Murphy	10%	40.79133%
Shell	90%	
Phillips	50%	34.48464%
Chevron	50%	

ADL 312808		
Bid Group/Co.	Co. Interest	NPS Bid
Texas Eastern	100%	85.25978%
Texas Gulf	6%	38.12530%
Gulf Oil	25%	
Conoco	25%	
Placid	16%	
Rowan	3%	
Cities Service	25%	
Unocal	100%	25.50000%
Phillips	50%	10.14550%
Chevron	50%	
Aramco Richfield	40%	2.11111%
Murphy	10%	
Shell	50%	

ADL 312789		
Bid Group/Co.	Co. Interest	NPS Bid
Amerada Hess	100%	91.20000%
Amoco	100%	82.59999%
Texas Eastern	50%	80.58789%
Texaco	50%	
Rowan	2%	71.62539%
Conoco	20%	
Texas Gulf	5%	
Getty	0.2	
Placid	13%	
Gulf	20%	
Cities Service	20%	
Murphy	10%	58.77133%
Shell	90%	
Phillips	33%	43.28273%
Mobil	33%	
Chevron	34%	
Unocal	100%	32.00000%

ADL 312809		
Bid Group/Co.	Co. Interest	NPS Bid
Texas Eastern	100%	85.25978%
Amoco	100%	71.25009%
Marathon	50%	63.83000%
Amerada	50%	
Gulf	25%	48.37549%
Placid	16%	
Getty	25%	
Texas Gulf	6%	
Rowan	3%	
Cities Service	25%	
Unocal	100%	38.00000%
Mobil	34%	34.23333%
Phillips	33%	
Chevron	33%	
Aramco Richfield	45%	31.89117%
Shell	55%	



## Net Profit Share Leases - Ownership Within Units

01-Apr-96

UNIT	LEASE NUMBER	NAME	WORKING INTEREST %
------	--------------	------	--------------------

### DUCK ISLAND

ADL	312828	BP EXPLORATION (ALASKA) INC	93.5
		COOK INLET REGION INC	2.5
		BOYON LIMITED	0.5
		NANA REGIONAL CORPORATION	1.5
Total for Segment			100

ADL	312834	ARCO ALASKA, INC	33.3333
		EDCON CORPORATION	33.3334
		UNION OIL COMPANY OF CALIFORNIA	33.3333
Total for Segment			100

### KUPARUK RIVER

ADL	313013	ARCO ALASKA, INC	100
Total for Segment			100

ADL	313024	ARCO ALASKA, INC	100
Total for Segment			100

ADL	313030	ARCO ALASKA, INC	100
Total for Segment			100

ADL	313033	ARCO ALASKA, INC	100
Total for Segment			100

### KUUKPIK

ADL	313038	ARCO ALASKA, INC	80
		EDCON CORPORATION	20
Total for Segment			100

		AMBRADA HESI CORPORATION	50
		EDCON CORPORATION	50
Total for Segment			100

ADL	313031	ARCO ALASKA, INC	100
Total for Segment			100

		MUNT PETROLEUM CORPORATION	16.80672
		PLACED OIL COMPANY	64.28573
		ROSEWOOD RESOURCES INC	18.90734
Total for Segment			100

ADL	313034	ARCO ALASKA, INC	100
-----	--------	------------------	-----

Post-it brand fax transmittal memo 7671 # of pages 6

From: Patricia Campbell  
To: DNR  
From: 269-8000  
To: 465-2095  
From: 465-3810

UNIT	LEASE NUMBER	NAME	WORKING INTEREST %
		Total for Segment	1 100
		HUNT PETROLEUM CORPORATION	16.80672
		PLACED OIL COMPANY	64.28172
		ROSEWOOD RESOURCES INC	18.90756
		Total for Segment	A 100
ADL	318826	ARCO ALASKA, INC	100
		Total for Segment	1 100
		ARCO ALASKA, INC	30
		TEDACO EXPLORATION & PRODUCTION	30
		Total for Segment	A 100
ADL	318836	ARCO ALASKA, INC	87.5
		UNION TEXAS PETROLEUM CORPORATION	12.5
		Total for Segment	1 100
		AMERADA HESS CORPORATION	30
		HUNT PETROLEUM CORPORATION	4.30168
		PLACED OIL COMPANY	28.37143
		ROSEWOOD RESOURCES INC	4.72489
		UNION TEXAS PETROLEUM CORPORATION	12.5
		Total for Segment	A 100
ADL	318837	ARCO ALASKA, INC	93.75
		UNION TEXAS PETROLEUM CORPORATION	6.25
		Total for Segment	1 100
		AMERADA HESS CORPORATION	25
		HUNT PETROLEUM CORPORATION	2.10084
		MIDGARD ENERGY COMPANY	25
		PLACED OIL COMPANY	14.385713
		ROSEWOOD RESOURCES INC	2.343443
		TEDACO INC	25
		UNION TEXAS PETROLEUM CORPORATION	6.25
		Total for Segment	A 100
ADL	318838	ARCO ALASKA, INC	93.75
		UNION TEXAS PETROLEUM CORPORATION	6.25
		Total for Segment	1 100
		AMERADA HESS CORPORATION	25
		HUNT PETROLEUM CORPORATION	2.10084
		MIDGARD ENERGY COMPANY	25
		PLACED OIL COMPANY	14.385713
		ROSEWOOD RESOURCES INC	2.343443
		TEDACO INC	25
		UNION TEXAS PETROLEUM CORPORATION	6.25
		Total for Segment	A 100
ADL	318839	ARCO ALASKA, INC	93.75
		UNION TEXAS PETROLEUM CORPORATION	6.25

UNIT	LEASE NUMBER	NAME	WORKING INTEREST %
		Total for Segment	1 100
		AMERADA HESS CORPORATION	25
		HUNT PETROLEUM CORPORATION	210084
		MEDGARD ENERGY COMPANY	25
		PLACID OIL COMPANY	14,28,5715
		ROSEWOOD RESOURCES INC	2,363,445
		TEXACO INC	25
		UNION TEXAS PETROLEUM CORPORATION	6,25
		Total for Segment	A 100
ADL	24866	ARCO ALASKA, INC	100
		Total for Segment	1 100
		ARCO ALASKA, INC	80
		TEXACO EXPLORATION & PRODUCTION	20
		Total for Segment	A 100
ADL	24476	AMERADA HESS CORPORATION	11.35
		ANADARKO PETROLEUM COMPANY	23
		ARCO ALASKA, INC	44.65
		UNION TEXAS PETROLEUM CORPORATION	23
		Total for Segment	1 100
ADL	24471	AMERADA HESS CORPORATION	11.35
		ANADARKO PETROLEUM COMPANY	23
		ARCO ALASKA, INC	44.65
		UNION TEXAS PETROLEUM CORPORATION	23
		Total for Segment	1 100
ADL	24473	ANADARKO PETROLEUM COMPANY	23
		ARCO ALASKA, INC	56
		UNION TEXAS PETROLEUM CORPORATION	23
		Total for Segment	1 100
		AMERADA HESS CORPORATION	30
		ANADARKO PETROLEUM COMPANY	6.16
		ARCO ALASKA, INC	21.84
		UNION TEXAS PETROLEUM CORPORATION	23
		Total for Segment	A 100
ADL	24477	ANADARKO PETROLEUM COMPANY	23
		ARCO ALASKA, INC	56
		UNION TEXAS PETROLEUM CORPORATION	23
		Total for Segment	1 100
		AMERADA HESS CORPORATION	30
		ANADARKO PETROLEUM COMPANY	6.16
		ARCO ALASKA, INC	21.84
		UNION TEXAS PETROLEUM CORPORATION	23
		Total for Segment	A 100
ADL	24474	AMERADA HESS CORPORATION	30
		ANADARKO PETROLEUM COMPANY	6.16
		ARCO ALASKA, INC	21.84
		UNION TEXAS PETROLEUM CORPORATION	23
		Total for Segment	A 100

UNIT	LEASE NUMBER	NAME	WORKING INTEREST %
		ARCO ALASKA, INC	74
		UNION TEXAS PETROLEUM CORPORATION	26
		Total for Segment	100
		AMERADA HESS CORPORATION	30
		ARCO ALASKA, INC	24
		UNION TEXAS PETROLEUM CORPORATION	26
		Total for Segment	100
ADL	34476	ARCO ALASKA, INC	74
		UNION TEXAS PETROLEUM CORPORATION	26
		Total for Segment	100
		AMERADA HESS CORPORATION	30
		ARCO ALASKA, INC	24
		UNION TEXAS PETROLEUM CORPORATION	26
		Total for Segment	100
ADL	34476	ARCO ALASKA, INC	74
		UNION TEXAS PETROLEUM CORPORATION	26
		Total for Segment	100
		AMERADA HESS CORPORATION	30
		ARCO ALASKA, INC	24
		UNION TEXAS PETROLEUM CORPORATION	26
		Total for Segment	100
ADL	34477	ARCO ALASKA, INC	23.001
		UNION TEXAS PETROLEUM CORPORATION	16.999
		Total for Segment	100
		AMERADA HESS CORPORATION	66.67
		ARCO ALASKA, INC	16.331
		UNION TEXAS PETROLEUM CORPORATION	16.999
		Total for Segment	100
ADL	34478	ARCO ALASKA, INC	68
		UNION TEXAS PETROLEUM CORPORATION	32
		Total for Segment	100
		AMERADA HESS CORPORATION	30
		ARCO ALASKA, INC	18
		UNION TEXAS PETROLEUM CORPORATION	23
		Total for Segment	100
<b>MILNE POINT</b>			
ADL	34816	BP EXPLORATION (ALASKA) INC	26.21
		BP EXPLORATION AND OIL COMPANY	64.38
		OCY USA INC	9.81
		Total for Segment	100
		AMERADA HESS CORPORATION	30

UNIT	LEASE NUMBER	NAME	WORKING INTEREST %
		MIDCOARD ENERGY COMPANY	30
		Total for Segment A	100
ADL	188017	BP EXPLORATION (ALASKA) INC	26.81
		BP EXPLORATION AND OIL COMPANY	64.38
		COXY USA INC	8.81
		Total for Segment 1	100
ADL	188018	BP EXPLORATION (ALASKA) INC	26.81
		BP EXPLORATION AND OIL COMPANY	64.38
		COXY USA INC	8.81
		Total for Segment 1	100
ADL	188021	BP EXPLORATION (ALASKA) INC	26.81
		BP EXPLORATION AND OIL COMPANY	64.38
		COXY USA INC	8.81
		Total for Segment 1	100
		AMERADA HILLS CORPORATION	30
		MIDCOARD ENERGY COMPANY	30
		Total for Segment A	100
<b>NON-UNIT PRODUCTION</b>			
ADL	312827	AMERADA HILLS CORPORATION	30
		BP EXPLORATION (ALASKA) INC	30
		Total for Segment 1	100
<b>NORTHSTAR</b>			
ADL	312798	BP EXPLORATION (ALASKA) INC	100
		Total for Segment 1	100
ADL	312799	BP EXPLORATION (ALASKA) INC	100
		Total for Segment 1	100
ADL	312808	BP EXPLORATION (ALASKA) INC	100
		Total for Segment 1	100
ADL	312809	BP EXPLORATION (ALASKA) INC	100
		Total for Segment 1	100
ADL	312841	BP EXPLORATION (ALASKA) INC	100
		Total for Segment 1	100
<b>POINT THOMSON</b>			
ADL	312844	EDCOON CORPORATION	100
		Total for Segment 1	100

UNIT	LEASE NUMBER	NAME	WORKING INTEREST %
ADL	34310	BP EXPLORATION (ALASKA) INC EDCOON CORPORATION	50 50
		Total for Segment 1	100
ADL	34310	MOREL OIL CORPORATION PHILLIPS PETROLEUM COMPANY	50 50
		Total for Segment 1	100
ADL	34311	BP EXPLORATION (ALASKA) INC	100
		Total for Segment 1	100
ADL	34311	BP EXPLORATION (ALASKA) INC CHEVRON U.S.A. INC	66.67 33.33
		Total for Segment 1	100
		CHEVRON U.S.A. INC	100
		Total for Segment A	100
		BP EXPLORATION (ALASKA) INC CHEVRON U.S.A. INC	66.67 33.33
		Total for Segment B	100

Post-it® Fax Note 7671

Date 4-1-96	# of pages 10
To Annette Kritzler	From Patrick Conaghan
Co. Dept. Senator Leona	Co. DAR
Phone # 465-2095	Phone # 269-8900
Fax # 465-3810	Fax #

**Net Profit Share Lease Ownership**

01-Apr-96

LEASE NUMBER	NAME	WORKING INTEREST %
ADL 312798	BP EXPLORATION (ALASKA) INC	100
	Total for Segment 1	100
ADL 312799	BP EXPLORATION (ALASKA) INC	100
	Total for Segment 1	100
ADL 312808	BP EXPLORATION (ALASKA) INC	100
	Total for Segment 1	100
ADL 312809	BP EXPLORATION (ALASKA) INC	100
	Total for Segment 1	100
ADL 312827	BP EXPLORATION (ALASKA) INC	50
	AMERADA HESS CORPORATION	50
	Total for Segment 1	100
ADL 312828	DOYON LIMITED	0.5
	NANA REGIONAL CORPORATION	1.5
	COOK INLET REGION INC	2.5
	BP EXPLORATION (ALASKA) INC	95.5
	Total for Segment 1	100
ADL 312834	ARCO ALASKA, INC	33.33333
	UNION OIL COMPANY OF CALIFORNIA	33.33333
	EXXON CORPORATION	33.33334
	Total for Segment 1	100
ADL 312866	EXXON CORPORATION	100
	Total for Segment 1	100
ADL 343108	EXXON CORPORATION	50
	BP EXPLORATION (ALASKA) INC	50
	Total for Segment 1	100
ADL 343110	PHILLIPS PETROLEUM COMPANY	50
	MOBIL OIL CORPORATION	50
	Total for Segment 1	100

LEASE NUMBER	NAME	WORKING INTEREST %
ADL 343111	BP EXPLORATION (ALASKA) INC	100
	Total for Segment	1
ADL 343112	CHEVRON U.S.A. INC	83.33
	BP EXPLORATION (ALASKA) INC	66.67
	Total for Segment	1
	CHEVRON U.S.A. INC	100
	Total for Segment	A
	CHEVRON U.S.A. INC	33.33
	BP EXPLORATION (ALASKA) INC	66.67
	Total for Segment	B
ADL 355001	BP EXPLORATION (ALASKA) INC	100
	Total for Segment	1
ADL 355016	OXY USA INC	8.81
	BP EXPLORATION (ALASKA) INC	26.81
	BP EXPLORATION AND OIL COMPANY	64.38
	Total for Segment	1
	AMERADA HESS CORPORATION	50
	MIDGARD ENERGY COMPANY	50
	Total for Segment	A
ADL 355017	OXY USA INC	8.81
	BP EXPLORATION (ALASKA) INC	26.81
	BP EXPLORATION AND OIL COMPANY	64.38
	Total for Segment	1
ADL 355018	OXY USA INC	8.81
	BP EXPLORATION (ALASKA) INC	26.81
	BP EXPLORATION AND OIL COMPANY	64.38
	Total for Segment	1
ADL 355021	OXY USA INC	8.81
	BP EXPLORATION (ALASKA) INC	26.81
	BP EXPLORATION AND OIL COMPANY	64.38
	Total for Segment	1
	MIDGARD ENERGY COMPANY	50
	AMERADA HESS CORPORATION	50
	Total for Segment	A
ADL 355023	ARCO ALASKA, INC	100

LEASE NUMBER	NAME	WORKING INTEREST %
	Total for Segment	100
ADL 355024	ARCO ALASKA, INC	100
	Total for Segment	100
ADL 355029	EXXON CORPORATION	20
	ARCO ALASKA, INC	80
	Total for Segment	100
	AMERADA HESS CORPORATION	50
	EXXON CORPORATION	50
	Total for Segment	100
ADL 355030	ARCO ALASKA, INC	100
	Total for Segment	100
ADL 355031	ARCO ALASKA, INC	100
	Total for Segment	100
	HUNT PETROLEUM CORPORATION	18.80672
	ROSEWOOD RESOURCES INC	18.90756
	PLACID OIL COMPANY	64.28672
	Total for Segment	100
ADL 355032	ARCO ALASKA, INC	100
	Total for Segment	100
ADL 355034	ARCO ALASKA, INC	100
	Total for Segment	100
	HUNT PETROLEUM CORPORATION	18.80672
	ROSEWOOD RESOURCES INC	18.00756
	PLACID OIL COMPANY	64.28672
	Total for Segment	100
ADL 355033	ARCO ALASKA, INC	100
	Total for Segment	100
	ARCO ALASKA, INC	50
	TEXACO EXPLORATION & PRODUCTION	50
	Total for Segment	100
ADL 355026	UNION TEXAS PETROLEUM CORPORATION	12.5
	ARCO ALASKA, INC	87.5
	Total for Segment	100
	HUNT PETROLEUM CORPORATION	4.30168

LEASE NUMBER	NAME	WORKING INTEREST %
	ROSEWOOD RESOURCES INC	4.72890
	UNION TEXAS PETROLEUM CORPORATION	12.5
	PLACID OIL COMPANY	28.57143
	AMERADA HESS CORPORATION	50
	Total for Segment	100
ADL 355037		
	UNION TEXAS PETROLEUM CORPORATION	6.25
	ARCO ALASKA, INC	93.75
	Total for Segment	100
	HUNT PETROLEUM CORPORATION	2.10084
	ROSEWOOD RESOURCES INC	2.363445
	UNION TEXAS PETROLEUM CORPORATION	6.25
	PLACID OIL COMPANY	14.285715
	AMERADA HESS CORPORATION	25
	MIDGARD ENERGY COMPANY	25
	TEXACO INC	25
	Total for Segment	100
ADL 355038		
	UNION TEXAS PETROLEUM CORPORATION	6.25
	ARCO ALASKA, INC	93.75
	Total for Segment	100
	HUNT PETROLEUM CORPORATION	2.10084
	ROSEWOOD RESOURCES INC	2.363445
	UNION TEXAS PETROLEUM CORPORATION	6.25
	PLACID OIL COMPANY	14.285715
	MIDGARD ENERGY COMPANY	25
	TEXACO INC	25
	AMERADA HESS CORPORATION	25
	Total for Segment	100
ADL 355039		
	UNION TEXAS PETROLEUM CORPORATION	6.25
	ARCO ALASKA, INC	93.75
	Total for Segment	100
	HUNT PETROLEUM CORPORATION	2.10084
	ROSEWOOD RESOURCES INC	2.363445
	UNION TEXAS PETROLEUM CORPORATION	6.25
	PLACID OIL COMPANY	14.285715
	MIDGARD ENERGY COMPANY	25
	AMERADA HESS CORPORATION	25
	TEXACO INC	25
	Total for Segment	100
ADL 355040		
	ARCO ALASKA, INC	100
	Total for Segment	100
	TEXACO EXPLORATION & PRODUCTION	20
	ARCO ALASKA, INC	80
	Total for Segment	100

LEASE NUMBER	NAME	WORKING INTEREST %
ADL 364470	AMERADA HESS CORPORATION	11.35
	UNION TEXAS PETROLEUM CORPORATION	22
	ANADARKO PETROLEUM COMPANY	22
	ARCO ALASKA, INC	44.85
	Total for Segment	100
ADL 364471	AMERADA HESS CORPORATION	11.35
	ANADARKO PETROLEUM COMPANY	22
	UNION TEXAS PETROLEUM CORPORATION	22
	ARCO ALASKA, INC	44.85
	Total for Segment	100
ADL 364472	UNION TEXAS PETROLEUM CORPORATION	22
	ANADARKO PETROLEUM COMPANY	22
	ARCO ALASKA, INC	56
	Total for Segment	100
	ANADARKO PETROLEUM COMPANY	6.16
	ARCO ALASKA, INC	21.84
	UNION TEXAS PETROLEUM CORPORATION	22
	AMERADA HESS CORPORATION	50
	Total for Segment	100
ADL 364473	ANADARKO PETROLEUM COMPANY	22
	UNION TEXAS PETROLEUM CORPORATION	22
	ARCO ALASKA, INC	56
	Total for Segment	100
	ANADARKO PETROLEUM COMPANY	6.16
	ARCO ALASKA, INC	21.84
	UNION TEXAS PETROLEUM CORPORATION	22
	AMERADA HESS CORPORATION	50
	Total for Segment	100
ADL 364474	UNION TEXAS PETROLEUM CORPORATION	28
	ARCO ALASKA, INC	74
	Total for Segment	100
	ARCO ALASKA, INC	24
	UNION TEXAS PETROLEUM CORPORATION	26
	AMERADA HESS CORPORATION	50
	Total for Segment	100
ADL 364475	UNION TEXAS PETROLEUM CORPORATION	26
	ARCO ALASKA, INC	74
	Total for Segment	100
	ARCO ALASKA, INC	24
	UNION TEXAS PETROLEUM CORPORATION	26

LEASE NUMBER	NAME		WORKING INTEREST %
	AMERADA HESS CORPORATION		50
	Total for Segment	A	100
ADL 364476			
	UNION TEXAS PETROLEUM CORPORATION		28
	ARCO ALASKA, INC		74
	Total for Segment	T	100
	ARCO ALASKA, INC		24
	UNION TEXAS PETROLEUM CORPORATION		28
	AMERADA HESS CORPORATION		50
	Total for Segment	A	100
ADL 364477			
	UNION TEXAS PETROLEUM CORPORATION		10.000
	ARCO ALASKA, INC		83.001
	Total for Segment	T	100
	ARCO ALASKA, INC		16.331
	UNION TEXAS PETROLEUM CORPORATION		18.000
	AMERADA HESS CORPORATION		66.67
	Total for Segment	A	100
ADL 364478			
	UNION TEXAS PETROLEUM CORPORATION		32
	ARCO ALASKA, INC		68
	Total for Segment	T	100
	ARCO ALASKA, INC		18
	UNION TEXAS PETROLEUM CORPORATION		32
	AMERADA HESS CORPORATION		50
	Total for Segment	A	100



DEPARTMENT OF NATURAL RESOURCES  
 OFFICE OF THE COMMISSIONER  
 400 WILLOUGHBY AVENUE  
 JUNEAU, ALASKA 99801-1796  
 PHONE: (907) 465-2400  
 FAX: (907) 465-3886

Please deliver to: Annette

Location: \_\_\_\_\_ FAX: 3810

Date: \_\_\_\_\_ Time: \_\_\_\_\_

From: Ken Boyd

Number of pages 6  
 Including cover sheet

Comments: THIS IS WHAT WE CALLED  
PUT TOGETHER TODAY

If you experience any problems receiving this FAX, please call Sharon or Eileen at the above phone number.

04-02-1986 17:28  
APR- 2-30 TUE 18:30

907 455 3586  
ADR/DIV OIL & GAS

DIR OFFICE OF THE COMMISSIONER  
P.O. BOX 111 UTAH 84303

1.02.02

Name and Address of Sole Bidder

Original Bidder Name	Current Name	Phone Number	Address	City	State
AMERADA HESS CORPORATION		713 699-8467	AT&T J. Y. CHRISTOPHER	809 DALLAS ST	HOUSTON TX
AMOCO PRODUCTION COMPANY		713 898-6888	AT&T LAND MANAGEMENT	PO BOX 3012	HOUSTON TX
ATLANTIC RICHFIELD COMPANY		907 288-8884	AT&T LAND MANAGEMENT	P.O. BOX 10000	ANCHORAGE AK
CHEVRON U.S.A. INC		713 784-7668	PO BOX 1406	AT&T P.O. WALKER	HOUSTON TX
CITIZEN SERVICE COMPANY	CITIZEN USA INC.	914 861-8888	PO BOX 305		TULSA OK
CONOCO INC		713 288-8794	480 NORTH DARY ABERFORD	AT&T WILHELM DAUGHERTY	HOUSTON TX
COOK BROTHERSON INC		907 288-8748	PO BOX 5030		ANCHORAGE AK
EDCO CORPORATION		713 688-7000	LAND/REGULATORY AFFAIRS	PO BOX 3506	HOUSTON TX
GULF OIL COMPANY	TEXACO INC	214 778-4444	PO BOX 2801	AT&T LAND DEPARTMENT	DENVER CO
GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 784-7666	PO BOX 1406	AT&T P.O. WALKER	HOUSTON TX
HONDA INC		907 861-8448	C/O JOHN MERRICK	400 S.W. 407	ANCHORAGE AK
MARATHON OIL COMPANY		713 629-4400	AT&T CONTRACT & DIVISION OFFICE	P.O. BOX 2249	HOUSTON TX
MORF OIL CORP		214 951-8888	AT&T PROPERTY MANAGEMENT	PO BOX 60022	DALLAS TX
MURPHY OIL CORPORATION	MURPHY OIL & PROD. CO	804 881-8711	AT&T LAND DEPARTMENT	P.O. BOX 67780	NEW ORLEANS LA
NANA REGIONAL CORPORATION INC		907 288-7708	1000 E. BIRCHWOOD	AT&T VICE PRESIDENT MERRICK	ANCHORAGE AK
PHELPS PETROLEUM COMPANY		713 488-8741	PO BOX 7967	AT&T AREA REGIONAL LAND MANAGER	HOUSTON TX
PLACO OIL CO		914 861-8888	C/O OXY USA INC.	P.O. BOX 388	TULSA OK
SONNEN PETROLEUM INC	SONNEN OIL INC	907 288-8448	7900 POST ONE TOWER	501 WASHINGTON	HOUSTON TX
TEALASKA CORP		907 886-1472	ONE TEALASKA PLAZA, SUITE 400	MR WILLIAM N FOWLE, PRESIDENT	JARVIS AK
SHELL OIL COMPANY		713 678-4314	TWO SHELL PLAZA	PO BOX 2899	HOUSTON TX
SONO MANUAL RESOURCES	BP EXPLORATION (ALASKA) INC	907 861-8111	E. P. ZELECHNY, JR.	PO BOX 79662, 700 E. BIRCHWOOD BL.	ANCHORAGE AK
TEXACO INC		214 778-4444	PO BOX 2801	AT&T LAND DEPARTMENT	DENVER CO
TEXAS EASTERN EXPLORATION COMPANY	ENTERPRISE OIL & GAS INC	713 888-8471	C/O ALAN R. BILLINGTON	401 FM 1947 WEST, STE. 310	HOUSTON TX
TEXAS OIL INC.		907 288-8740	804 MONROE STREET		ANCHORAGE AK
UNION OIL COMPANY OF CALIFORNIA		907 278-7877	PO BOX 19807	AT&T LAND MANAGER	ANCHORAGE AK

04-02-1996 17:28  
 APR - 2 - TUE 18:30

597 465 3886  
 ADMR/DIV OIL & GAS

DNR OFFICE OF THE COMMISSIONER  
 FAX NR UT00(0030418)

r. 0303

# NET PROFIT SHARE LEASE OWNERS

02-Apr-96

UNIT	HIGH BIDDER	BIDDING GROUP	BIDDER NAME	CURRENT NAME	PHONE #
<b>DUCK ISLAND UNIT</b>					
<b>SALE 30</b>					
<b>ADL 312828</b>					
.	15		COOK INLET REGION INC		907 288188
.	16		BOHIO NATURAL RESOURCES	BP EXPLORATION (ALASKA) INC	907 8819111
.	16		SEALASKA CORP		907 8861612
.	14		MAWA REGIONAL CORPORATION INC		907 2834100
.	16		KONBAG INC		907 5812888
.	3		AMOCO PRODUCTION COMPANY		713 680633
.	7		CITIB SERVICE COMPANY	CITY USA INC.	911 8813885
.	7		ROWAN PETROLEUM INC	ROWAN DRILLING	907 2780448
.	7		GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 7507853
.	7		PLACID OIL CO		913 8813885
.	7		GETTY OIL COMPANY	TEXACO INC	303 7884184
.	7		TEXAS GULF INC.		907 2788408
.	7		COMODO INC		713 8832786
.	14		MARATHON OIL COMPANY		713 6888880
.	14		AMERADA HESS CORPORATION		713 8088437
.	18		MURPHY OIL CORPORATION	MURPHY EXPLOR. & PROD.CO	304 8812811
.	18		SHELL OIL COMPANY		713 8704314
.	20		CHEVRON U.S.A. INC		713 7507856
.	22		ESION CORPORATION		713 6887008
.	22		UNION OIL COMPANY OF CALIFORNIA		907 2787800
.	22		ATLANTIC RICHFIELD COMPANY		907 2834824
<b>ADL 312834</b>					
.	21		ESION CORPORATION		713 6887008
.	21		UNION OIL COMPANY OF CALIFORNIA		907 2787800
.	21		ATLANTIC RICHFIELD COMPANY		907 2834824
.	20		CHEVRON U.S.A. INC		713 7507856

04-02-1986 17:29  
 APR 2 1986 TUE 18:31

907 455 3586  
 ADMR/DIV OIL & GAS

DNF OFFICE OF THE COMMISSIONER  
 FAX NO. 47607563075

F. 64

UNIT	HIGH BIDDER	BIDDING GROUP	BIDDER NAME	CURRENT NAME	PHONE #
<b>NON UNITIZED PRODUCING</b>					
<b>SALE 38</b>					
	ADL	312827			
	.		14 MARATHON OIL COMPANY		713 8228808
	.		14 AMERADA HESS CORPORATION		713 8080817
			3 AMOCO PRODUCTION COMPANY		713 8880106
			7 GETTY OIL COMPANY	TEXACO INC	308 7834184
			7 TEXAS GULF INC.		907 2763160
			7 PLACID OIL CO		918 8613081
			7 ROMAN PETROLEUM INC	ROMAN DRILLING	807 2780448
			7 GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 7847886
			7 CONOCO INC		713 2832738
			7 CITIB SERVICE COMPANY	OXY USA INC.	918 8613083
			17 EXXON CORPORATION		713 6467800
			8 DOCK INLET REGION INC		807 2835180
			15 HOKLAS INC		907 8613086
			18 SEALASKA CORP		907 8613082
			18 PANNA REGIONAL CORPORATION INC		907 2584180
			18 SOHIO NATURAL RESOURCES	BP EXPLORATION (ALABAMA) INC	907 8618111
<b>NORTHSTAR UNIT</b>					
<b>SALE 39</b>					
	ADL	312798			
	.		1 AMERADA HESS CORPORATION		713 8080817
			2 TEXACO INC		308 7834184
			2 TEXAS EASTERN EXPLORATION COMPANY	ENTERPRISE OIL EX CO INC	713 8880471
			3 AMOCO PRODUCTION COMPANY		713 8880106
			4 PLACID OIL CO		918 8613083
			4 CONOCO INC.		
			4 TEXAS GULF INC.		907 2763160
			4 CITIB SERVICE COMPANY	OXY USA INC.	918 8613083
			6 SHELL OIL COMPANY		713 8700184
			6 CHEVRON U.S.A. INC		713 7847886
			6 PHILLIPS PETROLEUM COMPANY		713 8880411

04-02-1996 17:29  
APR- 2-10 TUE 18:32

907 455 3986  
ADNR/DIV OIL & GAS

DNR OFFICE OF THE COMMISSIONER  
FAX No. 476/75630915

r. 03 05

UNIT	HIGH BIDDER	BIDDING GROUP	BIDDER NAME	CURRENT NAME	PHONE #
ADL	312799				
		1	AMEPADA HESS CORPORATION		713 8000327
		2	TEXACO INC		803 7834184
		2	TEXAS EASTERN EXPLORATION COMPANY	ENTERPRISE OIL EX CO INC	713 8888471
		3	AMOCO PRODUCTION COMPANY		713 8888338
		7	ROWAN PETROLEUM INC	ROWAN DRILLING	807 2782448
		7	TEXAS GULF INC.		807 2788100
		7	GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 7547805
		7	CITIES SERVICE COMPANY	OXY USA INC.	818 8813385
		7	CONOCO INC		713 2082759
		7	GETTY OIL COMPANY	TEXACO INC	803 7884184
		7	PLACID OIL CO		818 8813385
		8	MURPHY OIL CORPORATION	MURPHY EXPLOR. & PROD.CO	804 8812811
		8	SHELL OIL COMPANY		713 8704314
		8	PHILLIPS PETROLEUM COMPANY		713 8882741
		8	MOBIL OIL CORP		214 8613838
		9	CHEVRON U.S.A. INC		713 7547805
		10	UPSON OIL COMPANY OF CALIFORNIA		807 2787800
ADL	312805				
		11	TEXAS EASTERN EXPLORATION COMPANY	ENTERPRISE OIL EX CO INC	713 8888471
		6	CHEVRON U.S.A. INC		713 7547805
		6	PHILLIPS PETROLEUM COMPANY		713 8882741
		10	UPSON OIL COMPANY OF CALIFORNIA		807 2787800
		12	GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 7547805
		12	CITIES SERVICE COMPANY	OXY USA INC.	818 8813385
		12	ROWAN PETROLEUM INC	ROWAN DRILLING	807 2782448
		12	TEXAS GULF INC.		807 2788100
		12	CONOCO INC		713 2082759
		12	PLACID OIL CO		818 8813385
		12	SHELL OIL COMPANY		713 8704314
		13	MURPHY OIL CORPORATION	MURPHY EXPLOR. & PROD.CO	804 8812811
		13	ATLANTIC RICHFIELD COMPANY		807 2834824

64-02-1986 17:30  
APR-2-00 TUE 18:32

907-465-3865  
ADMIN/DIV OIL & GAS

DNF OFFICE OF THE COMMISSIONER  
FAX NO. 907-633-1110

P.06  
r.00

UNIT	HIGH BIDDER	BIDDING GROUP	BIDDER NAME	CURRENT NAME	PHONE #
ADL	312809				
		11	TEXAS EASTERN EXPLORATION COMPANY	ENTERPRISE OIL EX CO INC	713 6039471
		3	AMOCO PRODUCTION COMPANY		713 6863025
		9	CHEVRON U.S.A. INC		713 7547886
		9	MOBIL OIL CORP		214 8813838
		8	PHILLIPS PETROLEUM COMPANY		713 6863741
		10	UNION OIL COMPANY OF CALIFORNIA		807 2767800
		14	AMERADA HESS CORPORATION		713 6096637
		14	MARATHON OIL COMPANY		713 6296808
		15	TEXAS GULF INC.		807 2785100
		15	GETTY OIL COMPANY	TEXACO INC	308 7834144
		13	OXYES SERVICE COMPANY	OXY USA INC.	818 581 8085
		18	PLACID OIL CO		818 98 10385
		18	GULF OIL CORPORATION	CHEVRON U.S.A. INC	713 7547885
		15	ROWAN PETROLEUM INC	ROWAN DRILLING	907 2752448
		14	ATLANTIC RICHFIELD COMPANY		807 2634824
		15	SHELL OIL COMPANY		713 8704214
POINT THOMSON UNIT					
SALE 30					
ADL	312888				
		17	EXXON CORPORATION		713 6867008
		8	CHEVRON U.S.A. INC		713 7547886
		6	PHILLIPS PETROLEUM COMPANY		713 6863741



# Alaska State Legislature

## SENATE RESOURCES COMMITTEE

Official Business

State Capitol  
Juneau AK 99801

March 30, 1996

Mr. John Morgan, President  
BP Exploration (ALASKA) Inc.  
PO Box 196612  
Anchorage, AK 99519-6612

Dear Mr. Morgan:

As the Senate Resources Committee continues its deliberations on Senate Bill 318, Northstar Lease Agreement, we will need additional information from BP.

The next hearing on SB 318 is Wednesday, April 3, 1996. We may need to hold an evening session from 7 p.m. to 9 p.m..

The subject of the hearing will be a detailed presentation by BP of its anticipated development plan for the Northstar Unit. Please provide the Committee staff with copies of the materials supporting your presentation by 5:00 p.m. on Monday, April 1, 1996. In addition, please provide responses to the requests for additional information which the Committee members made during the hearing yesterday.

Technical representatives of the Department of Natural Resources will be available in Juneau for the hearing next Wednesday. You should have your support staff present or online to answer detailed questions regarding the Northstar Unit development plan.

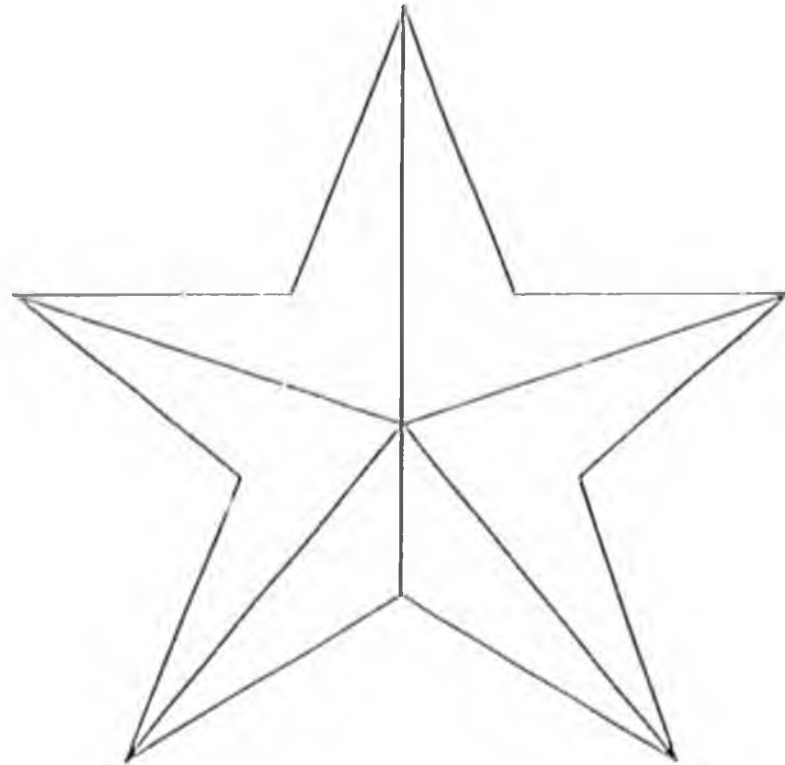
I am looking forward to continuing the hearings with the cooperation of BP and the departments of Law and Natural Resources.

Sincerely,

A handwritten signature in cursive script that reads "Loren A. Leman".

Senator Loren Leman  
Chairman, Senate Resources Committee

*Northstar*



*Northstar*

*Northstar*



## Project Description

---

- Fully appraised (4 wells in structure) 130 mmbbl field
- Well productivity over 7 mbd/well, oil quality 42° API
- 6 miles offshore from existing infrastructure
- BP with 98% WI and Murphy with 2%
- Lease Terms
  - 20% royalty on State leases
  - 16.67% royalty on Federal leases



## Plan of Development

---

- Three year POD (Plan of Development) approved by DNR in April, 1995
- Key items in POD
  - 3D seismic acquired in 3Q 1996
  - Updated reservoir description end 4Q 1996
  - Detailed development scenarios by 1Q 1998

*Northstar*



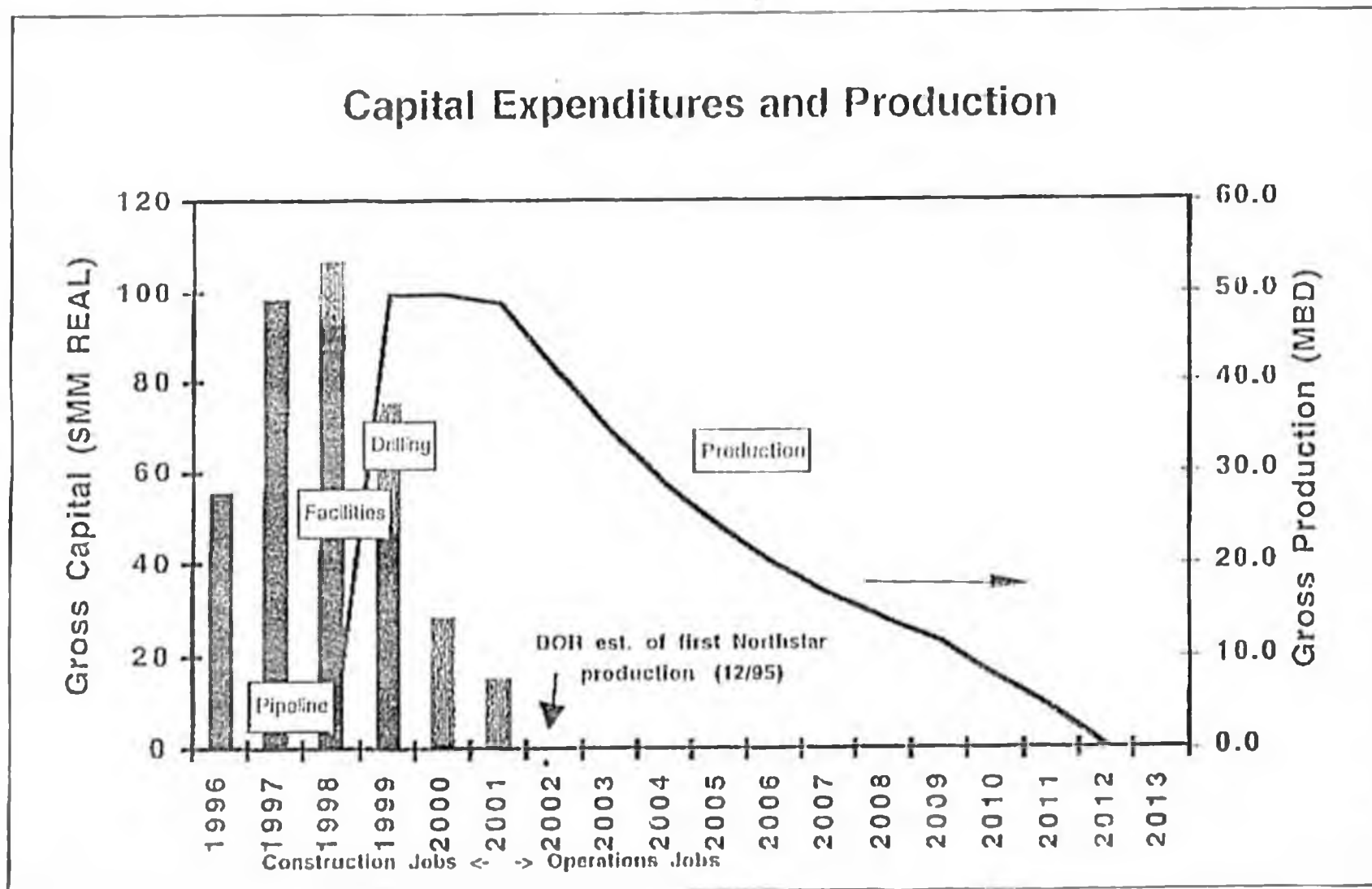
## Development Plans

---

- Stand alone facility
  - 15+ year project life
  - Use Seal Island and enlarge
  - 50, 000 bbl/day peak rate
  - ~25 wells



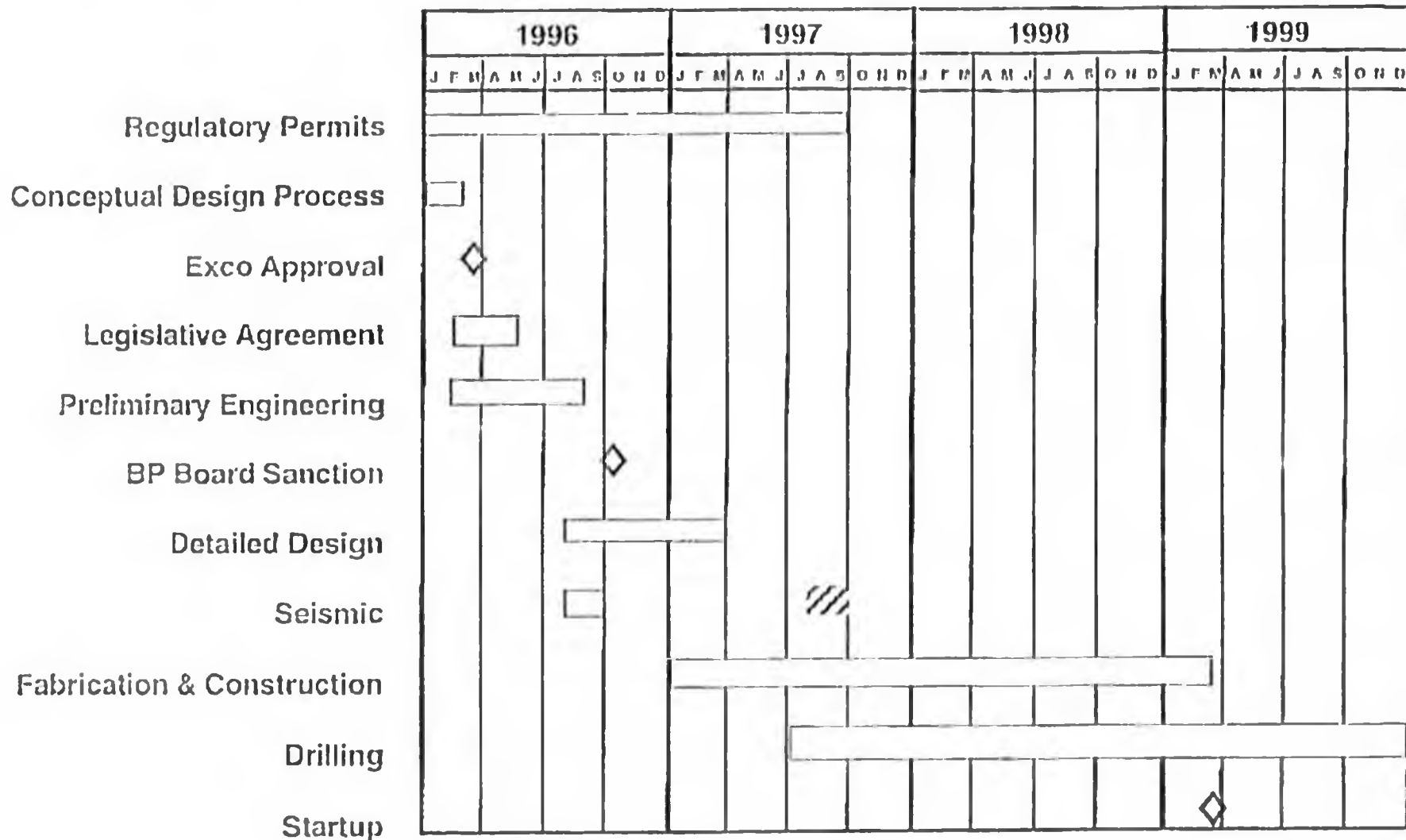
# Production and Capex







# Development Schedule



*Northstar*



## Preliminary Costs

	<u>Total Cost (\$mm)</u>	<u>Imported Materials (\$mm)</u>	<u>Contractor Costs (\$mm)</u>	<u>Contractor % Alaska</u>
Island	28	7	21	100%
Pipeline	28	8	20	100%
Facilities				
• Installation	12	2	10	100%
• Fabrication	110	48	62	75%
Engineering	16	0	16	10%
Drilling	85	30	55	100%
Environmental/ Other Services*	71	5	66	80%
Total	350	100	250	

\* Indirects (catering, transportation, etc.) and Infrastructure Costs

*Northstar*



## Preliminary Alaskan Content

---

Total Alaska Spend

\$210-\$230mm

Overall Northstar program

60-65%

Overall program

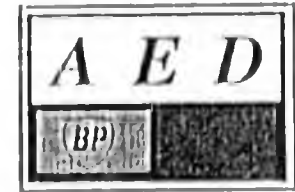
80-85%

(excluding purchased materials)

Facilities fabrication

70-75%

*Northstar*



## Alaska Fabrication

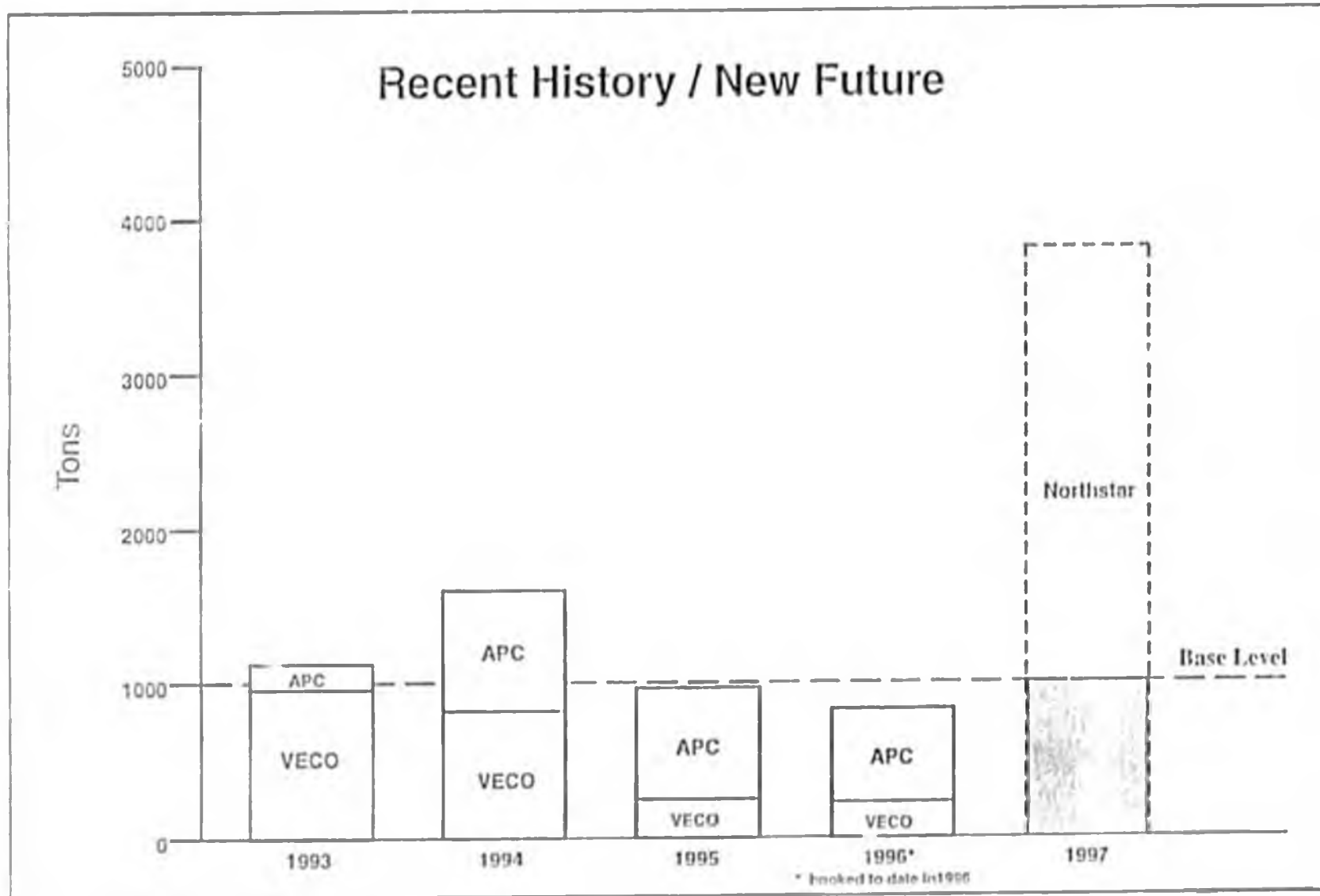
---

- New jobs and economic development of Alaska's support industry
- Potentially 75% of facilities could be fabricated in Alaska involving:
  - Increase number and complexity of modules fabricated at existing yards in Anchorage
  - Assembly of two meg-modules at Port of Anchorage for sea lift to Northstar
  - Requires commitment to Port assembly yard by mid-year 1996

Northstar



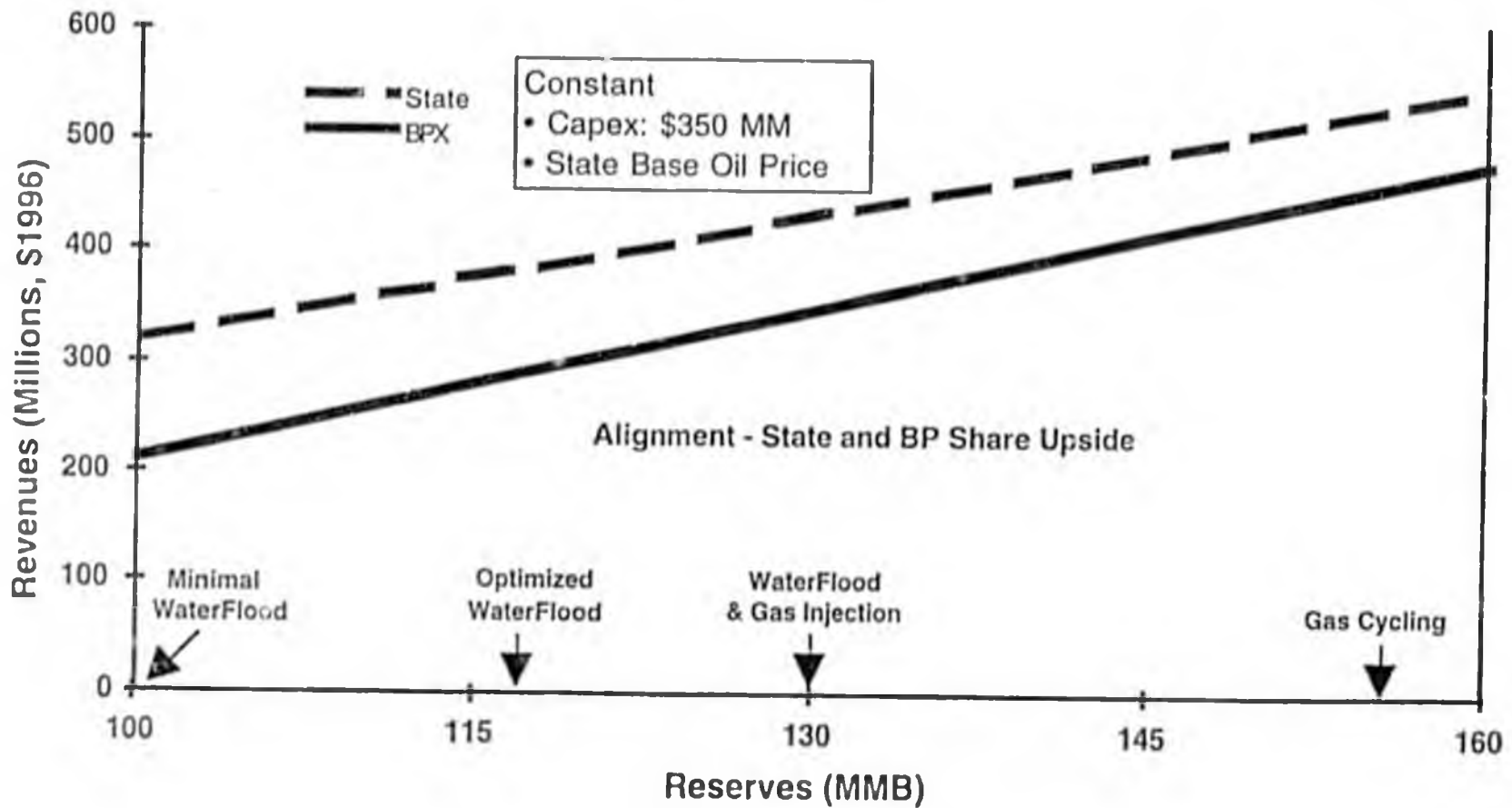
# Alaska Fabrication



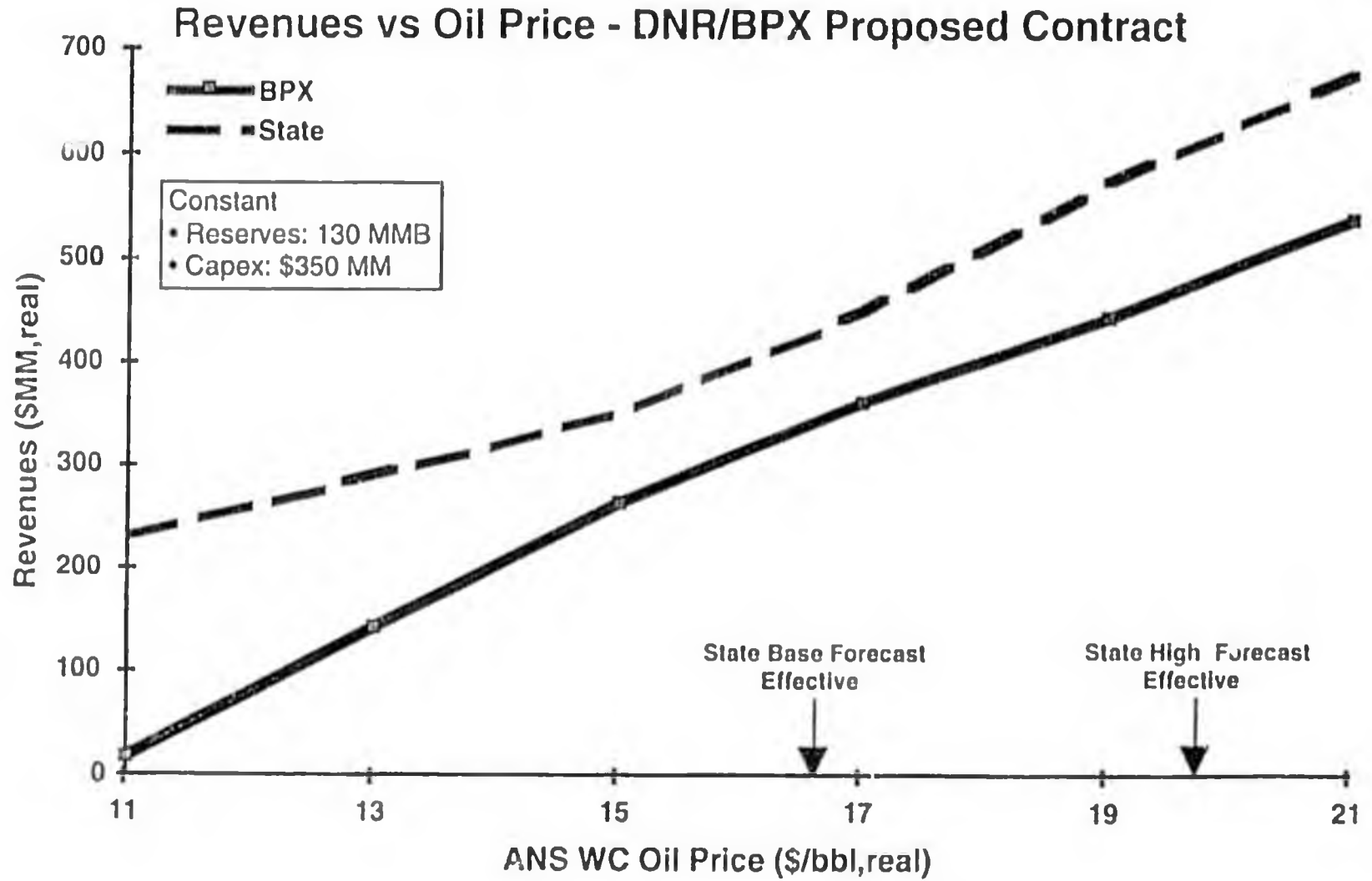
# Reserves Impact with Agreement



### Revenues vs. Reserves with Agreement

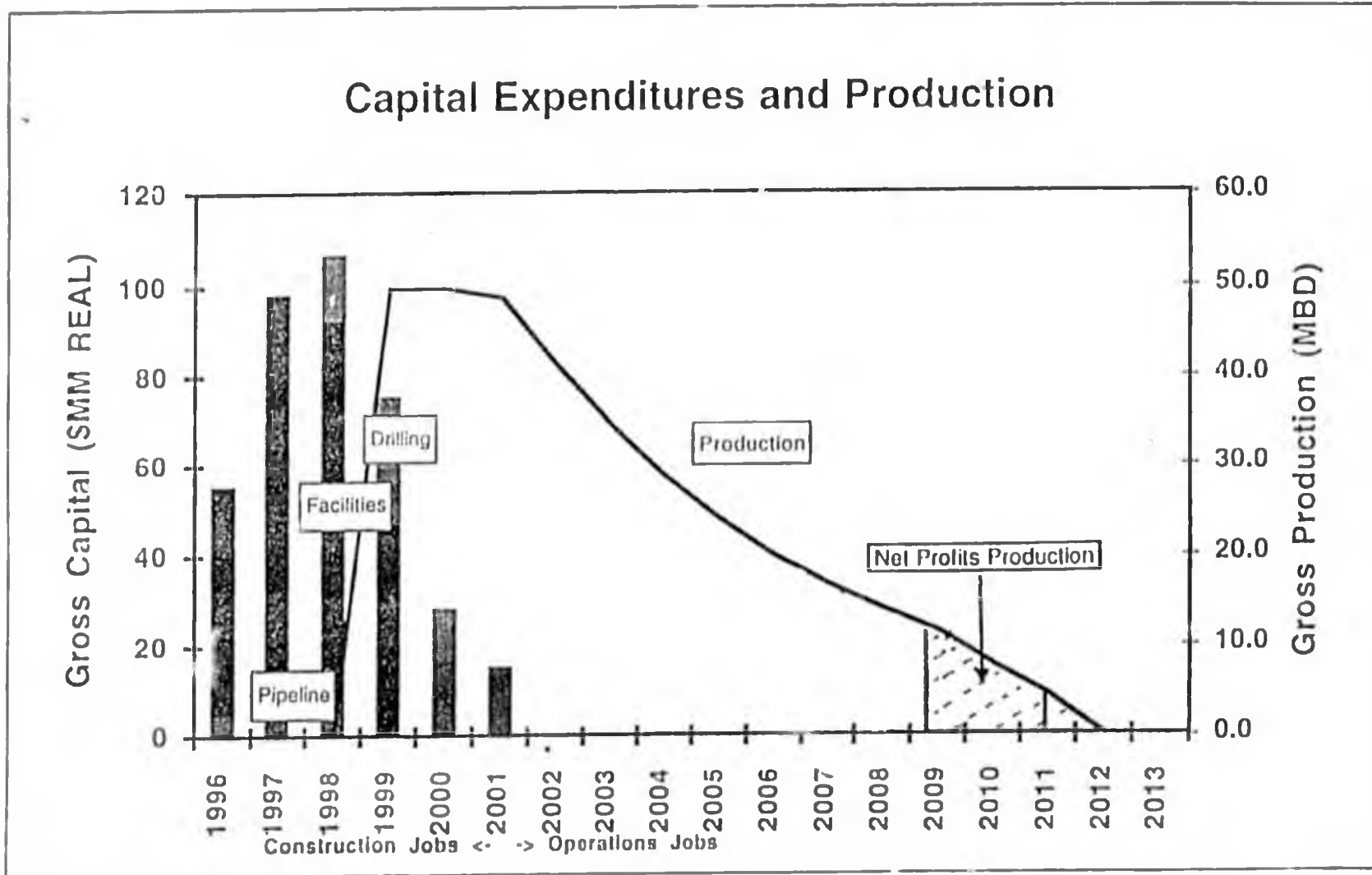


# Revenues vs Oil Price with Agreement





# Production and Capex





BP EXPLORATION

John C. Morgan  
President, Alaska

BP Exploration (Alaska) Inc  
900 East Benson Boulevard  
P.O. Box 126612  
Anchorage, Alaska 99512-6612  
(907) 564-5422

April 29, 1996

The Honorable Ramona Barnes, Chair  
House World Trade and State/Federal  
Relations Committee  
Alaska State Legislature  
State Capitol  
Juneau, Alaska 99801

Dear Representative Barnes:

The development of the Northstar field is an important project to the residents of Alaska and BP Exploration. Northstar development will provide jobs for Alaskans, new business opportunities for Alaskan businesses, and significant revenues to the state.

BP Exploration has voluntarily and publicly committed to recruit and hire qualified Alaska residents for the Northstar Development. We have also publicly committed to encourage Northstar contractors to recruit, hire, and train, when necessary, Alaska residents.

Furthermore, BP has voluntarily and publicly committed to use Alaska contractors to build in Alaska Northstar production and processing modules. BP has committed to spend \$30 - 40 million to build in Alaska the larger and more complex modules for assembly for sealift providing that suitable facilities to do this are available. We are working with our contractors to do everything possible to ensure the facilities will be available.

Our reputation depends on our honoring these commitments and reporting our results to the people of Alaska.

We appreciate the opportunity to provide comments to your committee.

Sincerely,

John C. Morgan

James E. Eason

Oil and Gas Operations, Management and Policy

3611 Lecher Circle • Anchorage, AK 99504-4209  
Phone (907) 337-3315 • Fax (907) 333-9087

May 2, 1996

The Honorable Loren Leman  
Chairman, Senate Resources Committee  
Alaska State Legislature  
State Capitol Building, Room 113  
Juneau, Alaska 99801-1182

Dear Senator Leman:

At your request last week Ms. Annette Kreitzer and I met with Division of Oil and Gas staff concerning the division's proposed amendments to the Senate Resources Committee's "Findings of Fact Regarding SB 318". Among the amendments requested by the division was the addition of the following language to Finding No. (4) of Article 3 of the Findings of Fact:

(4) The following day, on January 24, 1995, then Director Eason of the Department of Natural Resources approved BP Exploration (Alaska) Inc.'s request for a 90 day extension to submit a new plan of development because, according to Director Eason, it was "in everyone's best interest to allow BP additional time to conclude its acquisition and to formulate a new plan of development." Mr. Eason has not explained why he took this action, instead of simply disapproving the plan and letting the unit terminate. There is no evidence that Director Eason consulted the Department of Law regarding whether he could have used this authority to grant the extension and approve the Plan of Development to leverage earlier production. [AND] On January 24, 1995, the Minerals Management Service also approved BP Exploration (Alaska) Inc.'s request for an extension to file a more detailed Plan of Development until April 30, 1995.

With the exception of the text in bold lettering above, we agreed to amend the Findings of Fact to incorporate the division's language. In addition, as you requested, I am providing this letter for the record explaining why I agreed to a 90 day extension for BP Exploration (Alaska) Inc. to submit a new plan of development instead of disapproving the plan and letting the unit expire at that time.

To put the chronology of events in context, I was preparing to leave state employment at the time, having been informed by the governor's office that I was to be terminated. I was wrapping up several pending projects with the goal of leaving the division on February 10, 1995. There was much speculation at the time about my departure, both by members of my staff and the press. Some believed that my departure was related to my earlier handling of another BP matter—my unwillingness to approve the Badami Unit under terms proposed by BP, including a proposal to amend the royalty provisions of the Badami leases.

There had been several written exchanges between BP's Badami project manager, Mr. Terry Obeney, and me regarding the basis for my unwillingness to approve the unit's plan of exploration and my concern with BP's royalty amendment, which appeared to me to be a royalty reduction for which there was no statutory authority. Following several meetings with BP, I wrote Mr. Obeney on December 9, 1995 to outline those concerns. Pertinent excerpts from my letter are provided below:

"In addition to the two leases upon which the discovery wells were drilled, BP also proposes to unitize 10 adjoining leases encompassing almost 40,000 acres. More than half of those leases are scheduled to expire in either 1995 or 1996, and although each carried a primary term of ten years, they have yet to be explored. Unitization, under the terms you have proposed, would extend to BP a potentially very valuable property right in these leases for a minimum additional term of five years. Yet, BP is unwilling to make specific commitments to explore any of these leases during the Plan of Exploration period."

"We simply have a different view of prudent development. You characterize my reaction to BP's proposed Plan of Exploration as indicative that "...the DNR Director appears to be in the mode of discouraging prudent development..." I would suggest, alternatively, that it is my commitment to prudent development that really is the source of any disagreement. The plan you propose simply does not promote prudent development of the area proposed for unitization."

"Again, I appreciate your desire to minimize risk, enhance profitability and preserve options. However, there seems to be a fundamental imbalance in this instance where the state is being asked to adopt a royalty scheme that is both insensitive to BP's profits, and which will likely, under most conceivable circumstances, result in substantial royalty reductions."

As you will recall, the Badami Unit Agreement was later approved by the Department of Natural Resources, and the administration submitted legislation which would allow it to reduce the state's royalty share from the Badami field. Through its passage of HB 207 at the end of the session, the legislature granted the authority requested, but set specific guidelines for exercising that authority.

In one of Mr. Obeney's letters to me concerning my reluctance to approve the Plan of Development and the royalty modifications for Badami, he posed the question of whether someone else sitting in my seat would make the same decision. Shortly thereafter, I received a call from Mr. Stan Jones of the Anchorage Daily News asking whether there was a linkage between my subsequently having been asked to leave and Mr. Obeney's comment. I told Mr. Jones that in all honesty I did not know if there was any connection between the two events. However, my concern about the possibility of a linkage did play a role in my decision to grant the 90 day extension, as explained below.

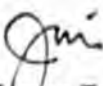
When BP approached the division with the news that it had purchased the Northstar leases with such a short time left under the department's default notice, I was concerned on two fronts. First, I was insistent that BP divulge the terms of its purchase so that I could make an informed judgment about whether or not the state should insist upon some sharing of the obvious, though undefined, value of the leases as a condition of further lease extension. BP refused repeated requests for that information.

Next, I was concerned about the specificity of BP's proposed Plan of Development. Given that the leases were fifteen years old and that the limits of the Northstar oil accumulation was fairly well defined, BP's willingness to purchase the leases with the risk of default and unit termination hanging over them, suggested to me that BP felt the development to be economical. With that in mind, I told BP that I viewed its proposed Plan of Development to be inadequate, and that I felt that it should make a firm commitment to development. BP was adamant that it would not make such a commitment.

I realized that under the circumstances, my decision to deny the application likely would lead to a request for reconsideration which would place my successor in a very unenviable position. He would have been confronted with having to make a difficult choice, only a matter of days after my departure, and under circumstances in which the new administration's policy was still being formulated. For better or worse, I thought that was both unfair to him, and an unnecessary further complication. I believed that by my providing the extension, it would allow all parties sufficient time to determine what the administration's policy was to be, and to settle on an appropriate Plan of Development. Obviously, I hoped that the result would be a commitment from BP to develop Northstar.

As to the last issue raised by the division in its response to the Findings of Fact, I do not recall consulting with the Department of Law before agreeing to the extension. However, I believed then, as I do now, that it was within my authority to grant the extension.

Sincerely;

  
James E. Eason

# STATE OF ALASKA

## DEPARTMENT OF LAW

OFFICE OF THE ATTORNEY GENERAL

APR 22 1996

April 22, 1996

Honorable Loren Leman  
Senator  
Alaska State Legislature  
Room 115 State Capitol  
Juneau, Alaska 99801

Re: SB318 (Northstar Unit net profit  
share reduction)

Dear Senator Leman:

You have requested our comments on the draft committee substitute to Senate Bill No. 318.

We recommend that the material set out beginning at page 1, line 5 through page 20, line 8 be deleted from the bill and placed in a separate committee report. The record speaks for itself, there is no need to select and insert excerpts of the record in the bill. It is sufficient that the committee investigate the facts and circumstances of the lease amendments and have a reasonable basis for the action it proposes. The technique of selecting excerpts from the record may be used by opponents of the transaction to argue that the committee placed too much, or not enough reliance on certain facts, when this was not the case. The committee will no doubt rely on the entire record in recommending a bill for passage by the Senate.

We believe that the insertion of an amended lease amendment in statute raises serious questions whether, in enacting this bill, the legislature would be violating the separation of powers doctrine implicit in Alaska Constitution. The governor proposed a bill that would give the Department of Natural Resources the power to reduce a net profit share lease. The governor's version would also have the legislature ratify the amendments negotiated for the Northstar Unit. The draft committee substitute would enact a counteroffer to the leaseholder which differs from the agreement between the department and British Petroleum. The negotiation of lease agreements is an executive function, not a lawmaking function. Clearly the legislature may delineate the power that the department has when it acts in these matters. It is when the legislature attempts to negotiate on behalf of the state that the separation of powers doctrine has been violated.

TONY KNOWLES, GOVERNOR

PLEASE REPLY TO:

1031 WEST 4TH AVENUE, SUITE 200  
ANCHORAGE, ALASKA 99501-1992  
PHONE (907) 269-5100  
FAX (907) 276-3697

KEY BANK BUILDING  
100 CUSHMAN ST., SUITE 400  
FAIRBANKS, ALASKA 99701-4679  
PHONE (907) 451-2811  
FAX (907) 451-2846

P.O. BOX 110300-DIMOND COURT HOUSE  
JUNEAU, ALASKA 99811-0300  
PHONE (907) 465-3600  
FAX (907) 465-6735

Hon. Loren Leman

April 22, 1996

Page 2

If the committee is determined to effect changes in the present lease amendment, it should consider redrafting the bill to set out limits on the power to reduce or change the net profits aspects of the North Star leases. If the legislature defines the power in a way that is inconsistent with the lease amendments presented, the parties must return to negotiations.

The lease provisions added in the committee substitute relating to local hire may present a legal defect that will lead to litigation. Protracted litigation may frustrate the purpose of the lease amendments. On page 28 lines 10 - 29, the provision appears to mandate resident hire on module fabrication projects. The provision also requires the lessee to ensure that all subcontractors practice local hire. These requirements appear to be similar to the local hire requirements that were struck down in Robison v. Francis, 713 P.2d 259 (Alaska 1986). For this reason, the committee is urged to recede from this proposed change to the lease agreement. It probably does not violate the United States or Alaska Constitutions to require a leaseholder to fabricate modules in Alaska.

Thank-you for the opportunity to comment on the draft committee substitute.

Very truly yours,

BRUCE M. BOTELHO  
ATTORNEY GENERAL

By:



James L. Baldwin  
Assistant Attorney General

JLB:clh

State of Alaska  
Department of Natural Resources  
Division of Oil and Gas  
3601 C Street, Suite 1380, Anchorage, Alaska 99503

Fax Confirmation Phone (907)762-2549 Fax (907)562-3852

FACSIMILE TRANSMITTAL

DATE & TIME: April 17, 1996 10:25 AM

PLEASE DELIVER TO: Senator Loren Leman

FAX NUMBER: 465-3810

NUMBER OF PAGES (including cover): 10

FROM: Ken Boyd  
269-8800

COMMENTS:

Attached is our response to your request for Northstar model forecasts assuming various production rates and reserve estimates. Please call if you have any questions

Attachment.

**MEMORANDUM**  
DEPARTMENT OF NATURAL RESOURCESState of Alaska  
DIVISION OF OIL AND GASTO: Ken Boyd  
Director

DATE: April 16, 1996

FILE NO:

THRU:

TELEPHONE: 269-8799

FROM: Kevin Banks

SUBJECT: Northstar--Response to  
Senate Resources Committee

You received a letter from Senator Loren Leman on April 12, 1996, which asked that the division provide to the Senate Resources Committee forecasts of state revenues using the "illustrative" Northstar model. The Senator's letter specifically requested model results assuming a peak rate of 80,000 barrels per day, assuming reserves of 190, 160, and 115 million barrels, and assuming capital expenditures and processing fees associated with facility sharing. The impact of these assumptions on State, federal, and BPXA revenues are attached. I did not analyze a facility sharing alternative, instead, I asked BPXA to provide their own analysis. I also asked BPXA what they felt would be the capital expenditure requirements for the various reserve assumptions and discussed their numbers with Bill Van Dyke.

These tables provide a forecast of revenues from a calculation of both supplemental royalties and net profit shares. Revenues including net profit shares are estimated assuming a full production start-up in 2002 and 1999. To be consistent, supplemental royalties should be compared to the net profit shares forecasted under the delayed development scenario.

The first table assumes that peak production of 80,000 barrels per day is achieved in 1999 for the estimate of supplemental royalties or 2002 for the estimate of net profit shares. Capital expenditures of \$139 million are added to the "most likely" case in order to achieve these rates. Production rates decline precipitously and the field shuts-in eight years after start-up.

The next three tables illustrate the effect of changing reserve assumptions. The 190 million barrel case assumes the same capital expenditures and peak production rates as above, but the production decline is less. The field life is the same as the "most likely" case. The 160 million barrel reserve case is achieved with capital expenditures of an additional \$48 million over the "most likely" case. The peak production rate is also 80,000 barrels per day. The last table illustrates the 115 million barrel case. No additional capital expenditures are assumed. The peak production rate and field life is the same as the "most likely" case.

Bill Van Dyke has also prepared a "per barrel" analysis of the cash flows in response to the questions asked by Senator Frank during the hearing on April 11, 1996. His analysis is also attached.

Senator Leman also wrote on April 15, 1996 requesting details about what I dubbed the "Marginal Lease Method," a system that calculates state take on the basis of cash flow.

This is the "formula" that Commissioner Shively referred to in his testimony. In a nutshell, the MLM approach allows for a reduction in state "take" so that the lessee can attain a rate of return necessary to develop an oil field. If, in any year, the cash flow (calculated from price, production, allowable operating and capital costs) actually received by the lessee exceeds the cash flow predicted to achieve the lessee's rate of return, the excess is paid to the state. The lessee pays this excess to the point that the state is made whole for the amount that the state's take was reduced. If the field earns additional revenues beyond this point, this excess is split between the lessee and the state. I have attached the spreadsheet that we shared with BPXA that shows how the MLM works. As you know, BPXA rejected the MLM approach stating that it was not interested in a "tax scheme," that it had "very little negotiating room," and that it wished to continue "discussion on the Supplemental Royalty approach."

Attachment.

# Northstar Economic Evaluation



APR-17-96 WED 09:39

DIV OF OIL AND GAS

FAX NO. 9075623852

P. 04/10

## Estimated Total Revenues

Sonata Resources Committee  
Letter--rec'd 4/12/96  
80,000 Barrels/Day Peak Rate

Supplemental Royalty  
and  
1999 Development

Net Profit Share  
and  
2002 Development

Net Profit Share  
and  
1999 Development

(Real 1996 Dollars)

### State Revenues

State Royalty	281	262	261
State Supplemental Royalty	16	0	0
NPSL	0	0	0
State Share of Federal Royalty	17	17	17
Severance Tax	94	109	94
Spill & Conserv. Tax	3	3	3
Ad Valorem Tax	34	37	34
Income Tax	11	11	11
Total	435	438	420

### Federal Revenues

Royalty (Net of State Share)	45	45	45
Income Tax	180	181	185
Total	225	226	230

### BPXA Cash Flow

After Tax Funds Flow	275	277	285
Real Rate of Return	20.1%	20.1%	20.6%

Totals may not add due to rounding.

# Northstar Economic Evaluation



APR-17-96 WED 09:39

DIV OF OIL AND GAS

FAX NO. 9075623852

P. 05/10

## Estimated Total Revenues

Senate Resources Committee  
Letter--rec'd 4/12/96  
190 MMBO Reserves

Supplemental Royalty  
and  
1999 Development

Net Profit Share  
and  
2002 Development

Net Profit Share  
and  
1999 Development

(Real 1996 Dollars)

### State Revenues

State Royalty	372	373	372
State Supplemental Royalty	49	0	0
NPSL	0	217	288
State Share of Federal Royalty	24	24	24
Severance Tax	115	133	116
Spill & Conserv. Tax	4	4	4
Ad Valorem Tax	57	62	57
Income Tax	19	15	14
<b>Total</b>	<b>639</b>	<b>827</b>	<b>873</b>

### Federal Revenues

Royalty (Net of State Share)	64	65	64
Income Tax	322	258	240
<b>Total</b>	<b>386</b>	<b>323</b>	<b>304</b>

### BPXA Cash Flow

After Tax Funds Flow	539	421	386
Real Rate of Return	25.8%	24.3%	23.7%

Totals may not add due to rounding.

# Northstar Economic Evaluation



## Estimated Total Revenues

Senate Resources Committee  
Letter-rec'd 4/12/96  
160 MMBO Reserves

Supplemental Royalty  
and  
1999 Development

Net Profit Share  
and  
2002 Development

Net Profit Share  
and  
1999 Development

(Real 1996 Dollars)

### State Revenues

State Royalty	316	317	316
State Supplemental Royalty	60	0	0
NPSL	0	131	201
State Share of Federal Royalty	20	20	20
Severance Tax	41	46	41
Spill & Conserv. Tax	3	3	3
Ad Valorem Tax	44	49	44
Income Tax	17	16	14
Total	501	581	641

### Federal Revenues

Royalty (Net of State Share)	55	55	55
Income Tax	292	266	243
Total	348	320	297

### BPXA Cash Flow

After Tax Funds Flow	490	441	399
Real Rate of Return	20.7%	20.5%	20.0%

Totals may not add due to rounding.

# Northstar Economic Evaluation



## Estimated Total Revenues

Senate Resources Committee  
Letter--rec'd 4/12/96  
115 MMBO Reserves

Supplemental Royalty  
and  
1999 Development

Net Profit Share  
and  
2002 Development

Net Profit Share  
and  
1999 Development

(Real 1996 Dollars)

### State Revenues

State Royalty	226	227	226
State Supplemental Royalty	32	0	0
NPSL	0	0	0
State Share of Federal Royalty	14	15	14
Severance Tax	44	50	44
Spill & Conserv. Tax	3	2	3
Ad Valorem Tax	42	46	42
Income Tax	11	11	11
<b>Total</b>	<b>371</b>	<b>350</b>	<b>340</b>

### Federal Revenues

Royalty (Net of State Share)	39	39	39
Income Tax	183	192	194
<b>Total</b>	<b>223</b>	<b>231</b>	<b>233</b>

### BPXA Cash Flow

After Tax Funds Flow	291	307	310
Real Rate of Return:	17.7%	18.0%	18.2%

Totals may not add due to rounding.

(This table is based on the Bureau of Minerals and Geology  
developed in Senate Resources Committee hearings--April 11, 1996)

# MEMORANDUM

## State of Alaska

DEPARTMENT OF NATURAL RESOURCES  
DIVISION OF OIL AND GAS

TO: Ken Boyd  
Director

DATE: April 16, 1996

FROM: Bill Van Dyke   
Petroleum Manager

TELEPHONE NO: 269-8786

FAX NO: 562-3852

SUBJECT: Net Profit Share Accounting

Enclosed for your review is the example west coast oil price net back calculation we discussed last Thursday night at the Senate Resources Committee hearing. If you have any questions please give me a call.

Enclosure

### Example Net Back Calculations for Determination of Net Profit Share and Royalty

Listed below are the calculation methodologies that one would use to determine the net back value (the LACT meter value for the oil at North Star) beginning with a west coast oil price. As was stated at the hearing last Thursday, not all deductions allowed for purposes of net profit share accounting are allowable deductions against royalty or taxes. For your information, both a net profit share net back and a royalty net back calculation are shown. For consistency, we used the assumptions shown in the North Star model for the year 2000 for these two examples.

#### Example Net Profit Share Calculation (for the year 2000)

\$18.64 west coast oil price in the year 2000 (\$/bbl)

-\$ 1.47 marine (tanker) transportation deduction

-\$ 2.69 TAPS tariff--Pump Station #1 to Valdez

-\$ 0.75 North Star pipeline tariff--North Star to PS#1

-\$ 2.74 royalty payment

-\$ 0.84 production tax payment

-\$ 2.26 direct operating cost (includes lifting costs)

---

\$7.89 per barrel production revenue that would be credited against any remaining monies in the development account

#### Example Royalty Calculation (for the year 2000)

\$18.64 west coast oil price in the year 2000 (\$/bbl)

-\$ 1.47 marine transportation deduction

-\$ 2.69 TAPS tariff

-\$ 0.75 North Star pipeline tariff

---

\$13.73 per barrel net back amount--20% of this amount (\$2.75/bbl) would be owed as the base royalty on each barrel of produced oil. The supplemental royalty as proposed would be \$0.04 per barrel at the given west coast oil price.

WVD 4/16/96





# Alaska State Legislature

## SENATE RESOURCES COMMITTEE

Official Business

State Capitol  
Juneau AK 99801

Mr. Ken Boyd, Director  
Division of Oil and Gas  
Department of Natural Resources  
via facsimile: X3886 3 pages including this one

Dear Mr. Boyd:

Will you please provide the Committee the results of the department's modeling of the anticipated revenue distribution between the State, BPXA and the federal government if the assumptions used in the "Illustrative Northstar Model" are changed to relate to peak production, reserves and capital costs in the following manner:

Peak production rate: 80,000 bbls/day

Reserves:

P(90) = 190 MMBO

Mean = 160 MMBO

P(10) = 115 MMBO

Capital Expenditures (real 1996 dollars):

Adjust facilities capital cost to reflect assumption that off-site processing facilities are used instead of constructing new production facilities.

A short narrative summary of your estimate of the state revenue losses resulting from amendment of the Northstar leases under these circumstances would be appreciated.

Also, in this transmittal is a copy of BPXA's response to specific Committee questions regarding rate of return on late field life that may be useful to you in responding to the question last night regarding the rate of return during recoupment of the capital account costs.

Sincerely,

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

Senator Loren Leman  
Chairman

APR 16 1996



BP EXPLORATION

BP Exploration (Alaska) Inc.  
900 East Benson Boulevard  
PO. Box 186612  
Anchorage, Alaska 99519-0612  
(907) 561-5111

April 16, 1996

The Honorable Loren Leman, Chair  
Senate Resources Committee  
Alaska State Legislature  
State Capitol  
Juneau, AK 99801

Dear Senator Leman:

In response to your letter of April 12, the Department of Natural Resources has requested BP to provide capital costs and economic analysis for off site facility sharing of Northstar production.

The analysis is based on the following assumptions:

- Total project costs are still \$378 million (same as stand alone costs);  
Conceptual engineering work has indicated that capital costs for facility sharing are substantially the same or higher than a stand alone production facility. The island expansion, drilling, subsea pipeline, environmental studies, and engineering costs are the same with facility sharing. The facility on the island would still require partial processing and water/gas re-injection capability. Therefore, the slightly reduced island facility cost is offset by higher pipeline and facility modifications costs.
- Reserves are 130 million barrels with a plateau rate of 50,000 barrels per day;
- A processing fee of \$2.50 per barrel of oil is required to access the facilities.  
The assumed processing fee is consistent with fees currently charged on the North Slope.

The impact on State, Federal, and BP revenues is attached for the following three scenarios (1) supplemental royalty and early development, (2) net profit share and delayed development, and (3) net profit share and early development.

If you require additional information, please do not hesitate to call me (907-564-4892) or Daryl Kleppin (907-564-5418) on my staff.

Very truly yours,

A handwritten signature in cursive script, appearing to read 'Daryl Kleppin', is written over the typed name.

for E.M. Luttrell  
Vice President, Exploration and Development  
BP Exploration (Alaska), Inc.

## Northstar Economic Evaluation

4/16/96

Estimated Total Revenues: Facility Sharing Case, Evaluated by BPXA

	<u>With Supplemental Royalty and Early Development</u>	<u>With Not Profit Share and Delayed Development (Real 1996 Dollars)</u>	<u>With Not Profit Share and Early Development</u>
<b><u>State Revenues</u></b>			
State Royalty	256	257	256
State Supplemental Royalty	37	-	-
NPSL	-	-	-
State Share of Federal Royalty	16	16	16
Severance Tax	58	58	58
Spill & Conservation Tax	3	3	3
Ad Valorem Tax	42	46	42
Income Tax	8	9	9
<b>Total</b>	<b>419</b>	<b>389</b>	<b>384</b>
<b><u>Federal Revenues</u></b>			
Royalty (Net of State Share)	44	44	44
Income Tax	133	150	145
<b>Total</b>	<b>177</b>	<b>194</b>	<b>189</b>
<b><u>BPXA Cash Flow</u></b>			
After Tax Funds Flow	197	229	220
Real Rate of Return	12%	14%	13%

State of Alaska  
Department of Natural Resources  
Division of Oil and Gas  
3601 C Street, Suite 1380, Anchorage, Alaska 99503

Fax Confirmation Phone (907)762-2549 Fax (907)562-3852

FACSIMILE TRANSMITTAL

DATE & TIME: April 15, 1996 3:41 PM

PLEASE DELIVER TO: Senator Loren Leman

FAX NUMBER: 465-3810

NUMBER OF PAGES (including cover): 2

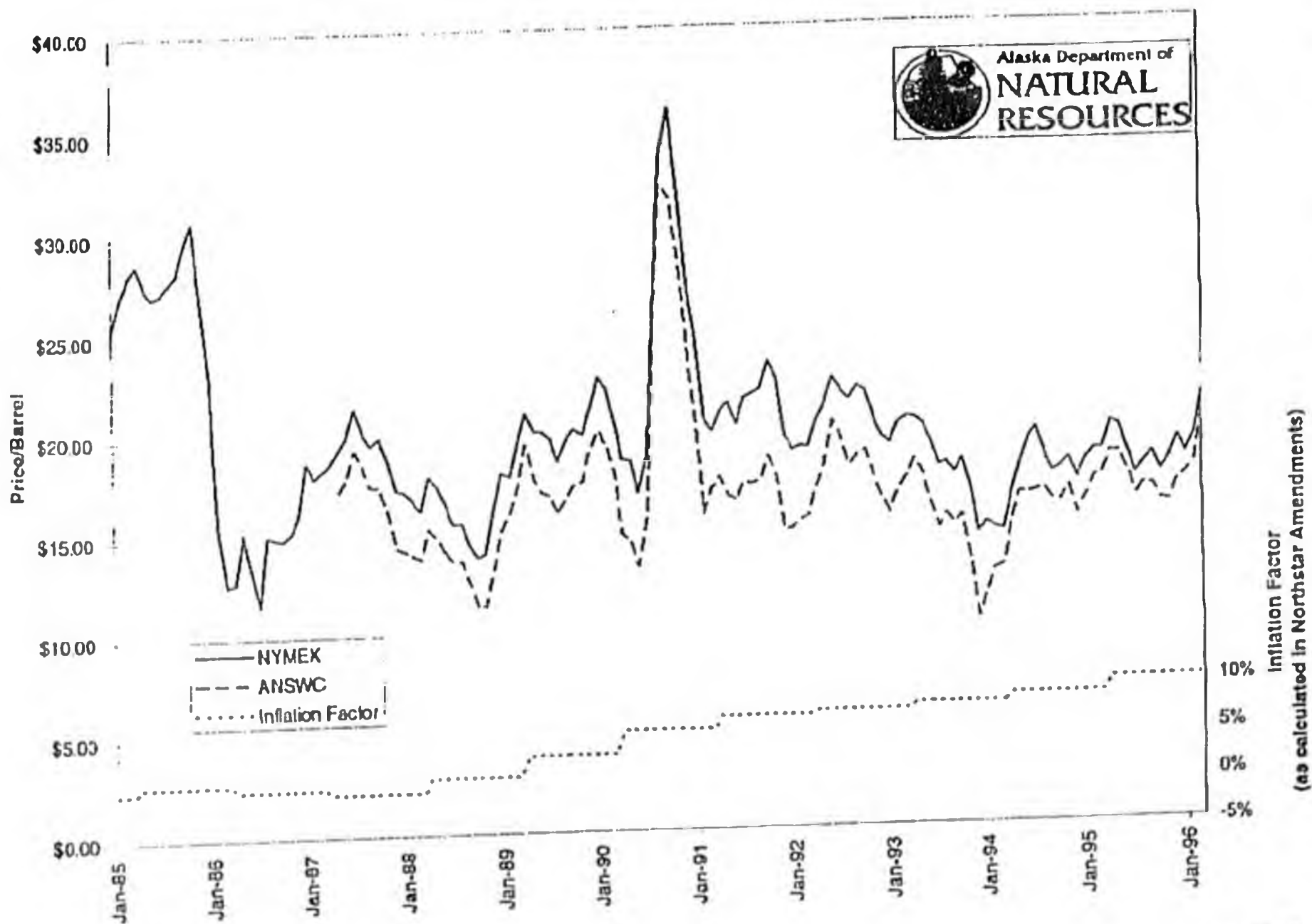
FROM: Kevin Banks  
269-8799

COMMENTS:

Attached is the chart that illustrates historical oil prices and inflation. Prices are nominal (money-of-the-day), i.e., no adjustment for inflation. The inflation factor is calculated from the PPI (for industrial commodities) as indicated in the Northstar Lease Amendments, replacing December 1995 with December 1984 to show how the factor would have been calculated over the 1985-1996 period.

Attachment.

# Historical Monthly NYMEX Oil Price and "Inflation Factor"





# Alaska State Legislature

## SENATE RESOURCES COMMITTEE

State Capitol  
Juneau AK 99801

Official Business

Mr. Ken Boyd, Director  
Division of Oil and Gas  
Department of Natural Resources  
via facsimile: X3886 3 pages including this one

Dear Mr. Boyd:

Will you please provide the Committee the results of the department's modeling of the anticipated revenue distribution between the State, BPXA and the federal government if the assumptions used in the "Illustrative Northstar Model" are changed to relate to peak production, reserves and capital costs in the following manner:

Peak production rate: 80,000 bbls/day

Reserves:

P(90) = 190 MMBO

Mean = 160 MMBO

P(10) = 115 MMBO

Capital Expenditures (real 1996 dollars):

Adjust facilities capital cost to reflect assumption that off-site processing facilities are used instead of constructing new production facilities.

A short narrative summary of your estimate of the state revenue losses resulting from amendment of the Northstar leases under these circumstances would be appreciated.

Also, in this transmittal is a copy of BPXA's response to specific Committee questions regarding rate of return on late field life that may be useful to you in responding to the question last night regarding the rate of return during recoupment of the capital account costs.

Sincerely,

Senator Loren Leman  
Chairman



# Alaska State Legislature

## SENATE RESOURCES COMMITTEE

State Capitol  
Juneau AK 99801

Official Business

Mr. Ken Boyd, Director  
Division of Oil and Gas  
Department of Natural Resources  
via facsimile: X3886 3 pages including this one

Dear Mr. Boyd:

Will you please provide the Committee the results of the department's modeling of the anticipated revenue distribution between the State, BPXA and the federal government if the assumptions used in the "Illustrative Northstar Model" are changed to relate to peak production, reserves and capital costs in the following manner:

Peak production rate: 80,000 bbls/day

Reserves:

P(90) = 190 MMBO

Mean = 160 MMBO

P(10) = 115 MMBO

Capital Expenditures (real 1996 dollars):

Adjust facilities capital cost to reflect assumption that off-site processing facilities are used instead of constructing new production facilities.

A short narrative summary of your estimate of the state revenue losses resulting from amendment of the Northstar leases under these circumstances would be appreciated.

Also, in this transmittal is a copy of BPXA's response to specific Committee questions regarding rate of return on late field life that may be useful to you in responding to the question last night regarding the rate of return during recoupment of the capital account costs.

Sincerely,

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

Senator Loren Leman  
Chairman

MEMORANDUM  
DEPARTMENT OF NATURAL RESOURCES

State of Alaska  
DIVISION OF OIL AND GAS

TO: Ken Boyd  
Director

DATE: April 12, 1996

THRU:

FILE NO:

FROM: Bill Van Dyke  
Kevin Banks

TELEPHONE: 269-8799

SUBJECT: Senate Resources Hearing--  
April 11, 1996

Several questions were raised at last night's Senate Resources Committee hearing on SB 318 (Northstar Lease Amendments). Senator Halford asked about the ultimate recovery expected for the Prudhoe Bay reservoir. As he observed, early recovery estimates were in the range of 9.6 billion barrels. We all know that this number has grown significantly over time. As of today the expected recovery at Prudhoe Bay is estimated to be 13 billion barrels.

Almost all this growth can be attributed to gas cycling and enhanced oil recovery benefits. The 9.6 billion barrel estimate did not include long-term high-volume gas cycling, nor did it include a miscible gas injection and NGL project. The benefits of gas cycling, miscible injection, and enhanced oil recovery, however, were not achieved without cost. The lessees have spent in excess of \$2 billion on these projects. The estimates of original-oil-in-place (OOIP) have changed very little since production start-up. The OOIP for the Prudhoe Bay reservoir is still about 23 billion barrels. As with the Northstar reservoir, the overall geology is pretty straight forward and the early seismic did a good job at defining the size and shape of the container. What has changed over time at Prudhoe Bay have been the estimates of how well the given container can be drained. Likewise, we do not believe that the size of the container at Northstar will change. Moreover, we believe that it is highly unlikely that the recovery rate at Northstar will exceed the recovery rate at Prudhoe Bay of 55 percent which was achieved after over \$2 billion of incremental investments.

We also discussed the 3-D seismic that will be shot at Northstar this summer season. That data will be used to target specific bottom-hole locations for each production and injection well. The 3-D data will allow BPXA to optimally place each wellbore, avoiding small faults and localized anomalies. I do not expect the 3-D data to significantly change the size or the shape of the overall container at Northstar.

Senator Frank asked during the hearing what the real rate of return would be to BPXA if it were to shut-in the field before the net profit share began to pay out to the state. Realistically, our assumption that development of the Northstar Unit under a net profit share system will be delayed should be used to examine this effect. Assuming that full production begins in 2002, the development account reaches zero in 2011, and net profit shares are paid to the state beginning in

2012. If the field produces for its full life, BPXA's RROR is 20.4%. If we cut off the calculation of the RROR at the year 2011, it drops slightly to 19.9%.<sup>1</sup> This demonstrates that there is still a positive cash flow, though discounted, to BPXA after 2011 which contributes to the RROR estimate.

After the hearing, Senator Halford asked about the effective severance tax rates applicable to the Northstar development as forecasted in the most likely case. The attached chart addresses his question and shows the annual effective severance tax rate after adjusting for the economic limit factor. This chart also shows the number of overall severance tax barrels based on these percentage rates. The timing of development has no affect on these figures; early development is shown.

Also attached is a second copy of the model that was presented last night to the committee. In this version of the model, the supplemental royalty is calculated. We have also included a revised copy of the "Assumptions Used in the Illustrative Northstar Model" handout that has the "Nominal Discount Rate 10%" in boldface type.

Kevin Banks will prepare a response to Senator Leman's letter received this morning, using the "Illustrative Northstar Model," as requested. These results should be available early next week.

Attachments.

---

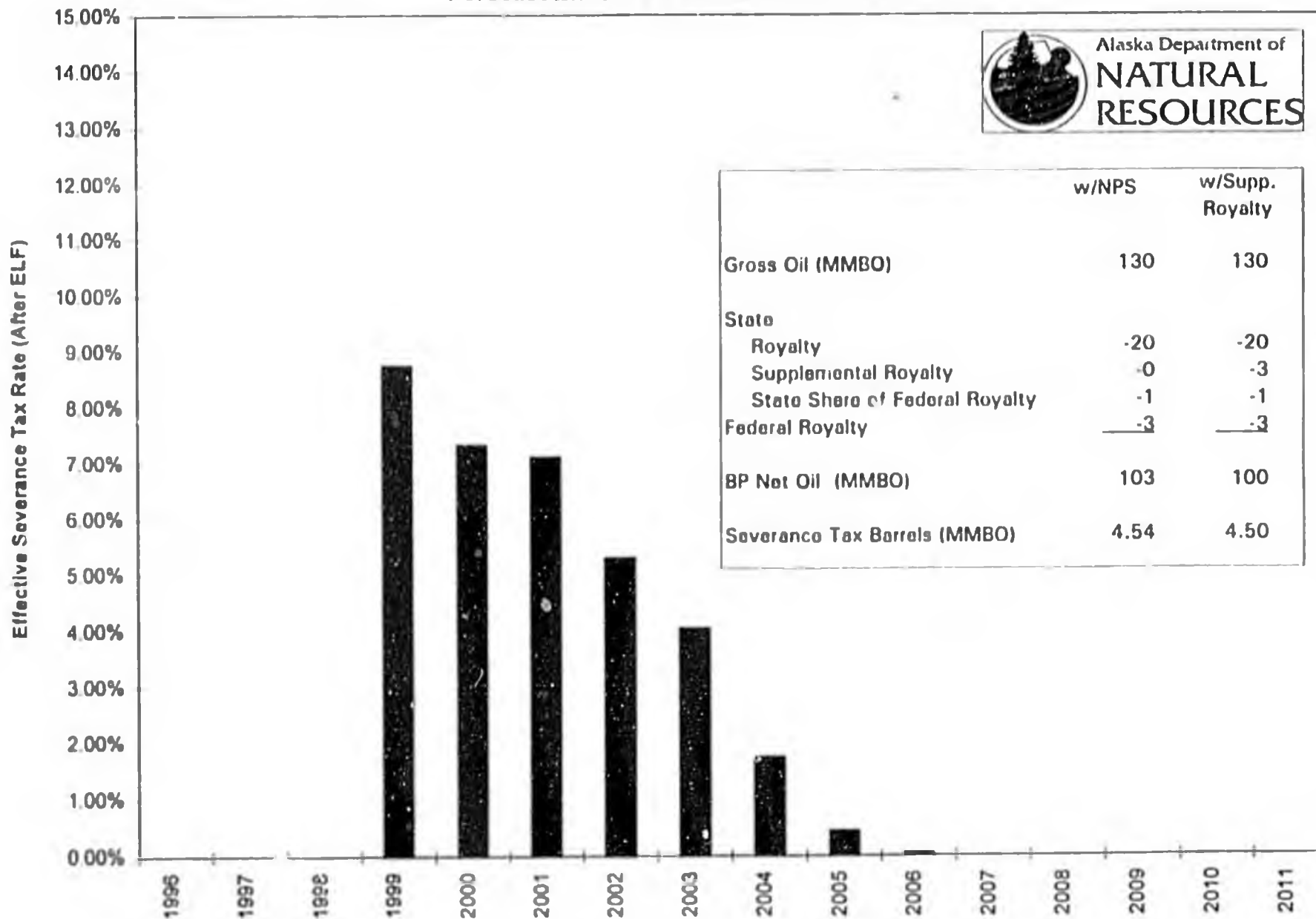
<sup>1</sup> This assumes delayed development. Senator Frank was looking at this question as if there would be no delay under the net profit share. The results are similar. Full field life RROR is 19.9. If the field were shut-in in 2007, the RROR is 19.4%.

# Northstar Proposal

## Forecast Effective Severance Tax Rates



Alaska Department of  
**NATURAL  
RESOURCES**



	w/NPS	w/Supp. Royalty
Gross Oil (MMBO)	130	130
<b>State</b>		
Royalty	-20	-20
Supplemental Royalty	0	-3
State Share of Federal Royalty	-1	-1
Federal Royalty	<u>-3</u>	<u>-3</u>
BP Net Oil (MMBO)	103	100
Severance Tax Barrels (MMBO)	4.54	4.50

## Assumptions Used in the Illustrative Northstar Model

- **Project Life:** Production ramp-up in 4th Quarter 1998; full production in 1999; end of field life in 2012.
- **Wells:** 15 producers.
- **Original Oil in Place (OOIP):**

P(90)	=	310 MMBO
Mean	=	260 MMBO
P(10)	=	210 MMBO
- **Reserves:**

P(90)	=	160 MMBO
Mean	=	130 MMBO
P(10)	=	105 MMBO
- **Peak Production rate:** 50,000 bbl/day
- **Capital Expenditures (real 1996 dollars):**

<b>Facilities:</b>	Low	=	\$205	MM
	Base	=	\$237	MM
	High	=	\$278	MM
<b>Drilling</b>	Low	=	\$75	MM
	Base	=	\$85	MM
	High	=	\$110	MM
<b>Pipeline</b>	Low	=	\$25	MM
	Base	=	\$28	MM
	High	=	\$53	MM
<b>Total</b>	Low	=	\$305	MM
	Base	=	\$350	MM
	High	=	\$441	MM
- **Appraisal Costs**

Low	=	\$25	MM
Base	=	\$28	MM
High	=	\$30	MM
- **Operating Costs**

Low	=	\$1.40/bbl
Base	=	\$1.50/bbl
High	=	\$2.00/bbl
- **Initial Abandonment Costs:**

5% Facility Capex	(estimate provided by DNR
10% Drilling Capex	Petroleum Engineer)
- **BPXA's Working Interest:** 98 % (Murphy Oil owns 10% of OCS Y-181)

- **Tract Allocation:** 76.8% State (No production allocated to ADL 355001)  
23.2% Federal
- **State royalty rate:** 20%
- **Supplemental royalty:** As proposed.
- **Federal royalty rate:** 16.67% (sliding scale not calculated; state receives 27% share of Federal royalty)
- **Net profit share:** 89.4% (average of the five state leases)
- **Development Account beginning balance (1996):** \$262 MM
- **Severance Tax:** 12.25% for first five years production, 15% thereafter; subject to ELF.
- **Conservation and oil spill tax:** \$0.034/bbl
- **Ad valorem tax rate:** 2%
- **State income tax rate:** 2% (estimate provided by DOR Petroleum Economist)
- **Federal income tax rate:** 35%
- **Oil Price Forecast:** DOR's Fall 1995 Base Price Forecast .  
PS-1 price = Northstar wellhead and derived from DOR's forecast of TAPS tariffs and marine costs. No adjustment made for quality, pumpability, infrastructure charges, or upstream tariffs.
- **Inflation Rate:** DOR's Fall 1995 Base Price Forecast  
3.0% in 1997; 3.2% thereafter.
- **Real Prime Rate:** 8.25% (Anchorage Daily News, 4/8/96)
- **Nominal Discount Rate:** 10% (A.D. Little Report)
- **General:** Stand-alone project, no facility sharing. Involves water flood and gas injection; process sales quality crude for delivery to TAPS. Expansion of the existing man-made Seal Island exploration island. Undersea, buried 12" pipeline to shore, 5 miles offshore/11 miles onshore; tie-in to Kuparuk Pipeline just west of TAPS Pump Station #1

Kevin Banks, ADNR  
April 12, 1996

Inputs

NPSLs: OFF

Supplemental Royalty:

ON

Working Interest	98%
Royalty Interest	10%
Split/Conservation Tax (Add)	0.034
AVT Tax Rate	2%
Fund Life (yr)	2012
Recoverability	130
	08-02 02-07 08-12
Lifting Costs (Per Barrel)	1.50 1.50 1.50
State Income Tax Rate	2.0% (EXEMPT - avg base rate)
Federal Tax Rate	34.5% (W/ state income tax)
Inflation Rate*	2.0% *Based on inflation input sheet
Real Discount Rate	7.0% (AD (10% Return))
Pass-through Rate NPSL	0.26% (AD (10%))
Supporting Services (mg)	202
Oil Production Multiplier	1
Oil Price Multiplier	1
Lifting Cost Multiplier	1
Facility Cost Multiplier	1
Abandonment Costs (% Prod)	
Starting Abandon Liability (\$MM)	23.9
Failure %	8% (20% Penalties)
Lifting Works	10% (Expire on 1)

Lease	Royalty	NPSL
State		
312700	20.0%	03.20%
312700	20.0%	01.20%
312000	20.0%	06.20%
312000	20.0%	05.20%
355001	20.0%	00.00%
Total		
Y01	0.1087	0
Y0170	0.1087	0

Market Simulation		OFF
Monthly Oil Price Std Dev		0.000000
Range	Low %	High %
Lifting Costs	0.899	1.233
Facilities Costs	0.854	1.172
Pipeline Costs	0.892	1.093
Reserves	0.806	1.221
Lifting Costs	0.825	1.205

NPSLs and Supplemental Royalty Control Panel	
NPSLs On/Off	ON
Supplemental Royalty (NPSL)	ON
Optimal Oil Base (MO) Price Differential	00.00

DCR Information	
Starting Wellbore Assets (\$MM)	0
Starting Field Assets (\$MM)	0
Starting Purchase Price Balance (\$MM)	0

	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total						
Gross Oil (MMbbl) Produced	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	0.0	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	0.0	130.0					
Gross Water (MMbbl) Produced	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	0.0	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	0.0	0.0	0.0				
Gross Gas (MMbbl) Produced	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	0.0	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	0.0	0.0	0.0				
Net Oil (MMbbl) Produced	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	0.0	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	0.0	0.0	0.0				
Return Gas Purchased	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	0.0	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	0.0	0.0	0.0				
MOI Net Oil Price (\$/bbl), month	111.05	112.20	07.72	112.09	010.40	010.92	015.04	015.97	010.00	010.00	017.52	010.10	010.70	010.40	020.00	020.55	021.32	021.92	022.62	023.22	023.92	024.64	025.30	026.10	026.92	027.74	028.57	029.42	030.31	031.22	032.14	033.07	034.01	034.97	035.94	036.92	037.91	038.91	039.92	040.94	041.97	043.01	044.06	045.11		
Pipeline Tariffs (\$/bbl), month	02.02	02.77	02.50	02.50	02.40	02.87	02.99	03.12	03.31	03.52	03.70	04.01	04.24	04.50	04.95	05.02	05.24	05.50	05.80	06.14	06.50	06.88	07.28	07.70	08.14	08.61	09.11	09.61	10.12	10.64	11.17	11.71	12.26	12.81	13.37	13.94	14.51	15.09	15.68	16.27	16.87	17.47	18.07	18.67	19.27	
Market Costs (\$/bbl), month	01.02	01.30	01.30	01.42	01.42	01.55	01.62	01.71	01.70	01.97	01.92	01.96	02.04	02.12	02.19	02.28	02.37	02.44	02.50	02.64	02.72	02.80	02.87	02.94	03.00	03.06	03.11	03.16	03.21	03.26	03.31	03.36	03.41	03.46	03.51	03.56	03.61	03.66	03.71	03.76	03.81	03.86	03.91	03.96	04.01	
MOI Value as % of Oil Price (mo)	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%	0%	0%	0%	0%	0%		
Other Income (\$/bbl), month	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00	00.00		
Production (MMbbl/d)	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	0	0	0	0			
Oil Serv. Rate	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	
Gas Serv. Rate	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%		
Abandonment (\$/bbl)																																														
Capital Ex. (Per)																																														
Lifting	10.0	2.0	10.0	20.0	20.0	15.0	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	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			
Facility	20.0	85.1	82.0	47.0	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	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	0.0			
Pipeline	5.0	15.0	10.0	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	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	0.0	0.0			
Com. Inflation Rate*	1.00	1.02	1.00	1.10	1.12	1.12	1.24	1.25	1.32	1.32	1.37	1.41	1.42	1.50	1.52	1.50	1.45	1.45	1.47	1.48	1.49	1.50	1.51	1.52	1.53	1.54	1.55	1.56	1.57	1.58	1.59	1.60	1.61	1.62	1.63	1.64	1.65	1.66	1.67	1.68	1.69	1.70	1.71	1.72	1.73	

Supplemental Royalty Rate		1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total			
Upper Price (10/ANS WC)		0	17.01	0	17.00	0	18.18	0	16.07	0	16.10	0	16.00	0	16.21	0	16.00	0	16.00	0	16.00	0	16.00	0	16.00	0	16.00	0	16.00	0	16.00	0	16.00	0	16.00	0	16.00	0	16.00	0	16.00	0	16.00	
Linear Slope (10/ANS WC)			1.5%																																									
Supplemental Royalty Cap			7.5%																																									

Caution - Only change inputs on the page

Summary Output

Development Summary		Months			
		MIN	MAX	MONTE	
Reserve	Gross CR (MM\$)	130	105	160	142
	Gross NGLR (MM\$)	0	0	0	0
Capex	DM (MM\$)	99	96	124	109
	Facility (MM\$)	251	211	244	250
	Hydro (MM\$)	28	25	33	34
	Total (MM\$)	378	331	471	393
Dev Costs	(MM\$)	23			28
Living Costs	(MM\$)	130	140	230	174

State Revenue (M. MOD)	
Royalty and supplement	108.0
State Share of Federal Royalty	20.3
Severance Tax	66.5
Gift & Conservation Tax	3.4
Ad Valorem Tax	0.0
NPPL	0.0
Income Tax	10.5
Total (M. MOD)	208.7
Total (M. real)	428.3

Federal Revenue (M. MOD)	
Royalty Port of State Share	64.8
Severance Tax	0.0
Gift & Conservation Tax	0.0
Ad Valorem Tax	0.0
NPPL	0.0
Income Tax	222.9
Total (M. MOD)	287.7
Total (M. real)	288.1

	1.00	1.02	1.04	1.10	1.12	1.17	1.21	1.24	1.28	1.33	1.37	1.41	1.46	1.50	1.55	1.60	1.65	1.70	1.75	1.80	1.85	1.90	1.95	2.00	2.05	2.10	2.15	2.20	2.25	2.30	2.35	2.40	2.44	2.48
Commodities Index	1.00	1.02	1.04	1.10	1.12	1.17	1.21	1.24	1.28	1.33	1.37	1.41	1.46	1.50	1.55	1.60	1.65	1.70	1.75	1.80	1.85	1.90	1.95	2.00	2.05	2.10	2.15	2.20	2.25	2.30	2.35	2.40	2.44	2.48
PS11 Oil Price (1000, real)	11.45	11.00	11.07	12.75	12.78	12.77	12.81	12.82	12.86	12.82	12.81	12.82	12.84	12.85	12.84	12.84	12.81	12.80	12.84	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78
All WC Oil Price (1000, MOD)	18.34	18.41	18.00	17.01	18.04	18.34	18.00	17.01	17.90	17.38	17.21	17.10	17.09	17.07	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04	17.04

All WC Oil Price (Random generated annual mean price forecast)		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Monthly Forecast Price	1992	18.24	18.28	18.58	17.20	18.32	18.00	18.73	20.47	21.23	22.00	22.80	23.70	24.50	25.50	26.41	27.20	28.25	29.27	30.23	31.27	32.27	33.24	34.23	35.28	36.20	37.28	38.20	39.28	40.41	41.50	42.62	43.78	44.88	45.91
Monthly MonteCarlo Price	1992	14.36	16.00	16.14	18.00	17.00	18.01	18.00	21.05	21.43	22.13	22.84	23.84	24.92	26.01	27.00	28.00	29.10	30.00	31.00	32.00	33.00	34.00	35.00	36.00	37.00	38.00	39.00	40.00	41.00	42.00	43.00	44.00	45.00	
ANS WC Mean Annual Value	1992	18.30	18.34	18.20	17.80	18.30	18.30	18.80	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	20.70	
PS11 Mean Annual Value	1992	11.05	11.20	11.05	12.01	11.40	11.27	11.44	11.07	11.09	11.17	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	

Country Supplemental State Royalty %		1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Country	Supplemental State Royalty %	0.00%	0.00%	0.00%	0.00%	0.00%	0.38%	1.00%	1.64%	2.25%	2.64%	3.00%	4.00%	5.42%	6.20%	7.15%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	
Jan	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	1.00%	1.74%	2.47%	3.14%	3.60%	4.00%	5.04%	6.41%	7.20%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%		
Feb	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	1.00%	1.74%	2.47%	3.14%	3.60%	4.00%	5.04%	6.41%	7.20%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%		
Mar	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	1.00%	1.74%	2.47%	3.14%	3.60%	4.00%	5.04%	6.41%	7.20%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%		
Apr	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	1.00%	1.74%	2.47%	3.14%	3.60%	4.00%	5.04%	6.41%	7.20%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%		
May	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	1.00%	1.74%	2.47%	3.14%	3.60%	4.00%	5.04%	6.41%	7.20%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%		
Jun	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	1.00%	1.74%	2.47%	3.14%	3.60%	4.00%	5.04%	6.41%	7.20%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%		
Jul	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	1.00%	1.74%	2.47%	3.14%	3.60%	4.00%	5.04%	6.41%	7.20%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%		
Aug	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	1.00%	1.74%	2.47%	3.14%	3.60%	4.00%	5.04%	6.41%	7.20%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%		
Sep	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	1.00%	1.74%	2.47%	3.14%	3.60%	4.00%	5.04%	6.41%	7.20%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%		
Oct	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	1.00%	1.74%	2.47%	3.14%	3.60%	4.00%	5.04%	6.41%	7.20%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%		
Nov	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	1.00%	1.74%	2.47%	3.14%	3.60%	4.00%	5.04%	6.41%	7.20%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%		
Dec	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	1.00%	1.74%	2.47%	3.14%	3.60%	4.00%	5.04%	6.41%	7.20%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%		
Total	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%	1.00%	1.74%	2.47%	3.14%	3.60%	4.00%	5.04%	6.41%	7.20%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%	7.50%		



Production (mcf)	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Term			
Gross Oil	0.0	0.0	5.4	48.8	49.8	48.7	41.2	34.7	29.7	23.9	20.0	16.7	13.9	11.5	7.8	4.3	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	120		
State Royalty Oil	0.00	0.00	0.83	7.85	7.85	7.46	6.32	5.33	4.41	3.88	3.07	2.57	2.14	1.77	1.17	0.88	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	3	
State Suppl Royalty Oil	0.00	0.00	0.00	0.01	0.15	0.42	0.82	0.75	0.80	0.88	0.86	0.87	0.84	0.80	0.57	0.32	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	1	
State Share of Federal Royalty Oil	0.00	0.00	0.05	0.48	0.48	0.48	0.40	0.34	0.28	0.23	0.20	0.18	0.14	0.11	0.07	0.04	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	3	
Royalty Oil Net of State Share	0.00	0.00	0.14	1.32	1.32	1.29	1.08	0.82	0.78	0.83	0.53	0.44	0.37	0.31	0.20	0.11	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	
Backout Loss	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	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	100		
Net BP Oil	0.00	0.00	4.29	29.52	29.29	26.25	22.10	24.81	21.89	18.05	15.02	12.41	10.21	8.25	5.48	3.10	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		
Oil Proceeds (see, med netback)	\$11.45	\$12.28	\$12.72	\$13.89	\$14.48	\$14.92	\$15.44	\$15.97	\$16.48	\$16.99	\$17.52	\$18.10	\$18.70	\$19.48	\$20.08	\$20.55	\$21.33	\$21.83	\$22.83	\$23.23	\$23.93	\$24.84	\$25.38	\$26.15	\$26.93	\$27.74	\$28.57	\$29.43	\$30.21	\$31.22				
Gross NGL	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	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		
State Royalty NGL	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	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	
State Suppl Royalty NGL	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	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	
State Share of Federal Royalty NGL	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	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	
Royalty NGL Net of State Share	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	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	
Backout Loss	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	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	
Net BP NGL	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	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	
NGL Proceeds (see, med netback)	\$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	\$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		
Other Income (if any, med)	\$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	\$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		
Revenue (\$m, med)	0.0	0.0	19.8	202.0	208.3	208.4	181.0	158.4	132.4	112.0	96.1	82.0	69.7	58.3	46.2	33.2	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	1591	
BP Net Revenue	0.0	0.0	19.8	202.0	208.3	208.4	181.0	158.4	132.4	112.0	96.1	82.0	69.7	58.3	46.2	33.2	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	1591
Net Revenue for Oil Severance	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	0.0	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	
Net Revenue for Gas Severance	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	0.0	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	
Royalty (\$m, med)	0.0	0.0	3.8	29.1	40.5	40.8	25.7	21.1	28.8	22.7	16.7	17.0	14.8	12.6	8.8	5.0	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	51
State	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	0.0	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	
State Supplement Royalty	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	0.0	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	
State Share of Federal Royalty	0.0	0.0	0.2	2.5	2.8	2.9	2.3	2.0	1.7	1.5	1.3	1.1	0.8	0.8	0.5	0.3	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	
Royalty Net of State Share	0.0	0.0	0.7	8.8	7.0	7.0	8.2	5.4	8.2	5.4	3.8	3.8	3.8	3.8	2.2	2.2	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	
Total	0.0	0.0	4.8	48.8	50.8	52.7	47.8	42.8	37.8	33.4	29.9	28.7	23.8	21.2	16.7	8.8	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	
Producing Wells	0	0	5	10	15	15	15	15	15	15	15	15	15	15	15	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Tax (\$m, med)																																		
Oil Sev. Rate	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	
Oil LLP	0.00	0.00	0.00	0.71	0.80	0.56	0.43	0.27	0.12	0.02	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	0.00	0.00	0.00	0.00	0.00	
Gas Sev. Rate	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	
Gas LLP	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
Total Severance	0.0	0.0	0.0	17.7	15.3	14.8	9.8	8.2	2.2	0.1	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	0.0	0.0	0.0	0.0	
Split & Conc	0.0	0.0	0.1	0.5	0.5	0.4	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	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	
AVT	0.0	0.0	2.3	4.3	5.4	5.4	5.2	4.8	4.5	4.1	3.7	3.3	2.8	2.3	1.8	1.2	0.8	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	
Capex (\$m, med, net)																																		
Drilling Tang	4.1	0.0	4.4																															

NPBL Calculation	1999	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030		
Traffic Alloc. Factor	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	78.00%	
Traffic Ownership	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
NPBL Share Ratio	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	89.30%	
Prime Interest Rate	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	
<b>Revenue Account</b>																																					
Prod. Revenue	0.0	0.0	18.8	156.3	183.3	183.3	141.9	172.8	103.7	87.8	79.3	84.3	54.7	48.5	51.5	16.2	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	0.0	
Operating Costs	0.0	0.0	(7.4)	(23.0)	(23.7)	(23.9)	(70.0)	(19.3)	(15.3)	(13.3)	(11.5)	(9.8)	(8.5)	(7.3)	(6.0)	(2.8)	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	0.0	
Production Taxes	0.0	0.0	0.0	(16.2)	(18.3)	(17.0)	(7.0)	(5.2)	(3.0)	(2.0)	(1.8)	(1.2)	(1.1)	(1.1)	(1.1)	(0.1)	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	0.0	0.0
Ad Valorem Tax	0.0	(0.8)	(2.0)	(3.4)	(4.2)	(4.2)	(4.1)	(2.0)	(2.0)	(2.1)	(2.1)	(2.1)	(2.1)	(1.8)	(1.4)	(1.0)	(0.5)	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	
UOP Alloc. Costs	0.0	0.0	(0.4)	(1.0)	(1.0)	(1.0)	(0.2)	(4.0)	(2.0)	(2.2)	(1.7)	(1.2)	(0.8)	(0.6)	(0.3)	(0.1)	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	0.0	
Closing Balance	0.0	(0.8)	(0.8)	(15.8)	(11.1)	(11.8)	(10.9)	(8.4)	(8.7)	(8.5)	(8.6)	(8.4)	(8.2)	(8.0)	(7.8)	(7.3)	(6.5)	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	
<b>Debt Account</b>																																					
Beginning Balance	(282.0)	(227.0)	(225.0)	(251.1)	(241.0)	(287.0)	(419.0)	(246.0)	(278.4)	(219.5)	(166.2)	(118.5)	(79.0)	(37.3)	(2.2)	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	0.0	0.0	
Capital Expend.	(42.7)	(77.0)	(87.3)	(83.2)	(74.3)	(112.5)	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Prod. Rev. Acc. Credit	0.0	0.0	10.0	115.0	119.1	117.0	103.9	81.4	79.7	88.5	58.0	50.4	42.8	36.7	24.0	14.3	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	0.0	
Prin. Closing Bal	(204.2)	(180.2)	(151.0)	(199.3)	(167.0)	(202.7)	(215.7)	(254.0)	(189.7)	(110.0)	(107.2)	(88.1)	(62.0)	(40.0)	(22.0)	(7.1)	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	0.0	
Average Annual DA Balance	(282.1)	(260.4)	(273.7)	(254.8)	(248.4)	(282.7)	(386.3)	(230.5)	(188.2)	(138.7)	(93.3)	(64.3)	(40.0)	(24.2)	(7.7)	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	0.0	0.0	
Accrued Interest	(23.4)	(20.2)	(20.1)	(43.2)	(40.0)	(29.0)	(20.3)	(24.8)	(18.8)	(15.2)	(11.3)	(7.7)	(4.5)	(3.1)	(1.8)	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	0.0	0.0	
DA Closing Balance	(227.0)	(187.4)	(151.1)	(241.0)	(187.0)	(181.8)	(246.0)	(278.4)	(219.5)	(166.2)	(118.5)	(79.0)	(37.3)	(2.2)	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	0.0	0.0	0.0	
<b>NPBL Payment Acc.</b>																																					
NPBL Payment*	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	0.0	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	

\* Payment on NPBL (DA OFF) switch in some states turned to "OFF"

Northstar Reserves, Royalty and MPSI Tract Allocations

Leases	MPSI	As-91	% of Total Reserves	% of MPSI Reserves	OP Ownership	MPSI Share Ratio	Working Interest	MPSI Tract Ratio	Royalty Fee by Lease	Weighted Royalty	BIT	
312700	83.20%	84,000	8.72%	9%	100%	8.18%			20%	1.344%		
312700	81.20%	555,000	44.40%	58%	100%	52.70%			20%	8.660%		
312800	85.20%	102,000	8.18%	11%	100%	9.00%			20%	1.822%		
312800	85.20%	219,000	17.52%	23%	100%	18.45%			20%	3.504%		
336001	80.00%		0.00%	0%	100%	0.00%			20.0%	0.000%		
		900,000	78.00%	100%	100%	89.21%	88%	78%		15.32%		
Effective State Royalty with 27% of Federal Take											18.042%	
V1B1		228,000	18.00%						18.87%	3.014%		
V0170		84,000	6.72%						18.87%	0.854%		
		1,700,000	100.00%							3.837%		
Effective Federal Royalty with 27% of Federal Take											2.855%	
										Total	19.00%	81.00%







	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
<b>DD&amp;A (MMOD)</b>																												
Reserve (IMBROE NRY)	0.0	0.0	0.0	98.8	84.4	70.0	56.1	44.3	34.5	26.5	19.9	14.4	8.9	0.7	0.1	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
Opening Balance	0.0	0.0	100.4	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	0.0	0.0	0.0	0.0	0.0	0.0
Additions (SPX Net After Royal)	0.0	0.0	1.8	14.4	14.4	11.7	9.0	8.0	6.6	5.5	4.5	3.7	2.9	2.0	1.1	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
SPX Net Production (MMB)	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Closing Balance	0.0	0.0	98.8	84.4	70.0	56.1	44.3	34.5	26.5	19.9	14.4	8.9	0.7	0.1	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
<b>Walkover Assets</b>																												
Beginning Balance (Net BMM)	0.0	13.7	13.7	27.8	51.5	71.2	72.4	57.3	44.8	34.3	25.7	18.7	12.8	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Additions (SPX Net BMM MOD)	13.7	0.0	14.8	20.1	21.1	17.2	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	0.0	0.0	0.0
DD&A Rate (1/BBL)	0.00	0.00	0.42	0.43	0.79	1.14	1.28	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	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
DD&A (SPX Net BMM MOD)	0.0	0.0	0.7	8.2	11.4	15.1	15.1	12.8	10.4	8.5	7.1	5.9	4.8	3.9	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Carry Forward (SPX Net BMM)	13.7	13.7	27.8	51.5	71.2	72.4	57.3	44.8	34.3	25.7	18.7	12.8	8.0	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
<b>Flue-Whistle Assets</b>																												
Beginning Balance (Net BMM)	0.0	25.3	121.3	202.5	218.8	182.3	148.0	115.4	89.8	68.0	51.9	37.8	25.0	10.1	0.7	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Additions (SPX Net BMM MOD)	25.3	85.8	88.5	50.5	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	0.0	0.0	0.0	0.0	0.0
DD&A Rate (1/BBL)	0.00	0.00	0.37	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	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
DD&A (SPX Net BMM MOD)	0.0	0.0	5.1	33.3	27.5	7.1	30.5	25.5	22.9	17.2	14.2	11.8	8.7	7.0	3.2	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Carry Forward (SPX Net BMM)	25.3	121.2	202.5	218.8	182.3	148.0	115.4	89.8	68.0	51.9	37.8	25.0	10.1	0.7	3.0	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
<b>SPX Purchase Price Allocation</b>																												
Beginning Balance (Net BMM)	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Additions (SPX Net BMM MOD)	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DD&A Rate (1/BBL)	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DD&A (SPX Net BMM MOD)	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Carry Forward (SPX Net BMM)	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
<b>Total DD&amp;A Rate (1/BBL)</b>	0.0	0.0	0.7	2.7	3.4	3.1	3.9	3.9	3.8	3.8	3.8	3.8	3.8	3.8	3.8	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
<b>Total DD&amp;A Rate (1/BBL)</b>	0.0	0.0	0.8	29.5	48.9	52.3	45.7	38.1	31.3	25.7	21.4	17.7	14.5	11.0	7.0	4.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
<b>LOP ARRANGMENT (MMOD)</b>																												
Beginning Balance (Net BMM)	29.4	29.4	29.4	26.8	28.4	31.5	34.4	17.8	12.7	8.9	6.0	3.8	2.3	1.2	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Additions (SPX Net BMM MOD)	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DD&A Rate (1/BBL)	0.00	0.00	0.79	0.29	0.42	0.45	0.42	0.40	0.37	0.34	0.30	0.27	0.22	0.19	0.14	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DD&A (SPX Net BMM MOD)	0.0	0.0	0.5	2.5	4.8	7.3	8.8	5.1	3.8	2.8	2.1	1.6	1.1	0.9	0.4	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Carry Forward (SPX Net BMM)	29.4	29.4	29.9	34.4	31.5	24.4	17.8	12.7	8.9	6.0	3.8	2.3	1.2	0.4	0.1	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

# **NPSL Accounting Handouts**

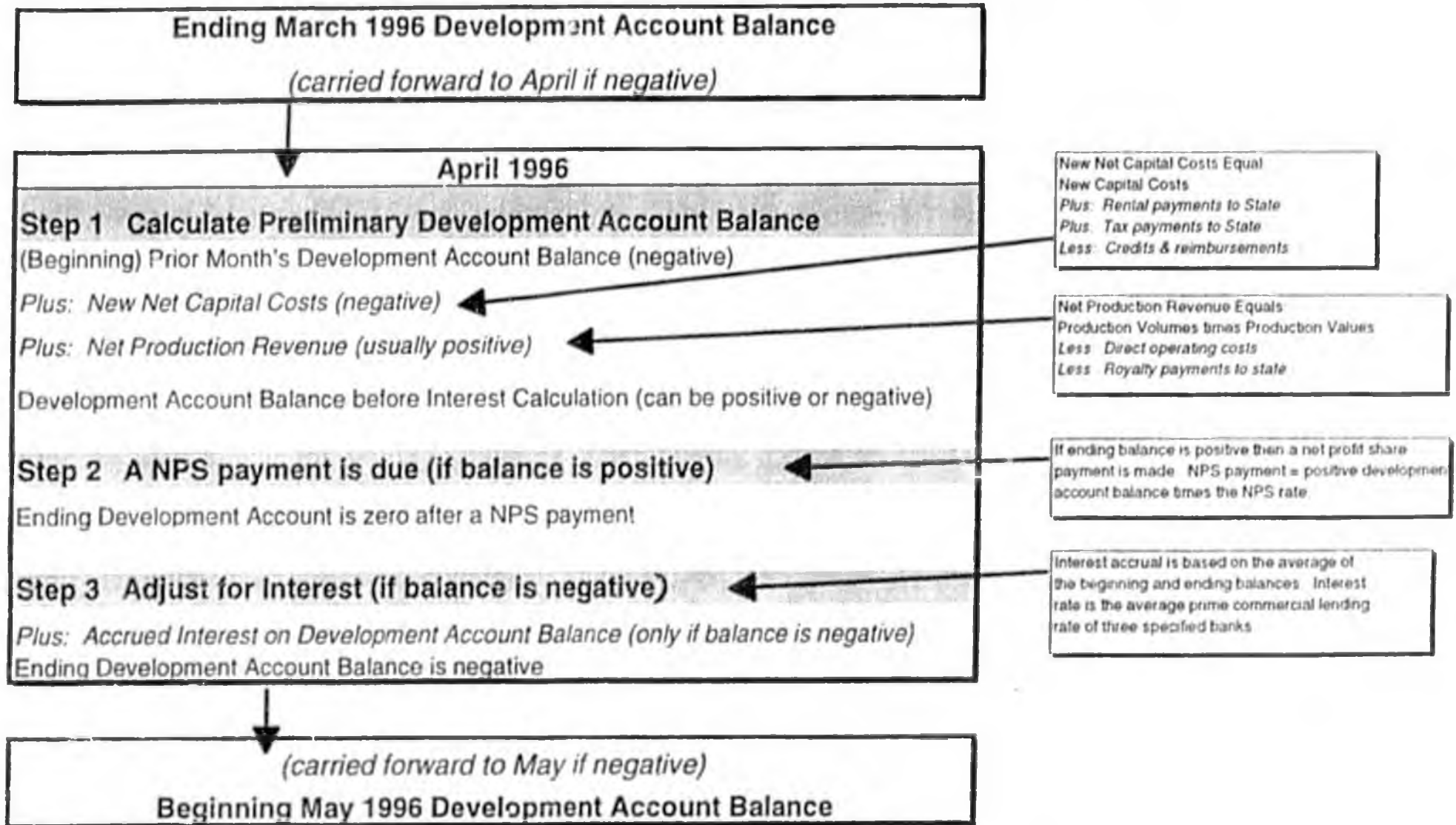
**April 11, 1996**

Prepared By

Alaska Department of Natural Resources

Division of Oil and Gas

# NPSL ACCOUNTING FLOW DIAGRAM



## NET PROFIT SHARE LEASE ACCOUNTING

### 1. OVERVIEW

The State's Net Profit Share Lease (NPSL) regulations define an accounting system and procedures to follow in the administration of NPSLs. The regulations' purpose is to allow a lessee to recover all appropriate development costs, with interest, and operating costs from production revenue before any net profit share becomes due the state from the lessee. These regulations provide for the monthly accumulation of certain costs in three accounts: the development account, the production revenue account, and the net profit payment account. 11 AAC 83.201-.295

In simple terms the system works as follows: Any positive balance remaining in the production revenue account (revenues minus operating costs and royalties) at the end of the month is used to reduce any accumulated costs in the development account. Any positive balance remaining in the development account is carried forward to the net profit payment account. The net profit payment account is shared with the State at the net profit share rate specified in the lease.

### 2. DEVELOPMENT ACCOUNT

The development account includes development costs which are generally capital expenditures. Rental payments to the State or taxes payable are an appropriate charge to the NPSL's development account for that month. Positive balances from the production revenue account are transferred monthly into the development account and reduce the accumulated costs in the development account to be carried forward.

The development account accumulates costs that are primarily capital in nature. These costs are defined in 11 AAC 83.219 subject to exclusions identified in 11 AAC 83.217. Development costs for NPSL generally consists of the following:

- 1) Cost of geological, geophysical, geotechnical and geochemical work performed on or adjacent to the NPSL relating to pre- or post-drilling operations. Such costs incurred prior to the inception of the lease (i.e. before the lease sale) are to be excluded.
- 2) Cost of design of construction projects as defined in the approved "Plan of Operations."

- 3) Cost of capital work in progress in support of the NPSL on or adjacent to the NPSL or on a contractor's premises.
- 4) Lease costs incurred to maintain an interest in the NPSL.
- 5) Cost of wells located on the NPSL.
- 6) Cost of facilities and equipment on or in support of the NPSL that are required for continued or enhanced production.
- 7) Cost of acquiring a production interest in the NPSL.
- 8) Capitalized ad valorem taxes.
- 9) General overhead and administrative expenses at the rate of three percent of the costs defined in 1), 2), 3), 5) and 6) above.

All costs are accounted for on an accrual basis and are limited by the definition of direct charges as established in 11 AAC 83.243. Further, only the reimbursable (from co-owners) portion of those costs of the lessee may be used in calculating the charge to the development account.

Development account balances are carried forward from month to month and interest is earned on these balances. The interest rate is specified in the lease sale terms, typically the average of the prime rates of three large banks. The interest that is earned on these balances further increases the total development costs to be carried forward until net production revenue is sufficient to recover the cumulative development costs plus interest to date. When the development account has a positive balance at month end, the positive balance is transferred to the net profit payment account, leaving a zero balance in the development account.

### **C. PRODUCTION REVENUE ACCOUNT**

The production revenue account captures production revenue, direct operating costs, and royalty payments (the net profit share payment to the state is excluded). The NPSL production revenue is a positive amount credited to the account for each month's production. NPSL direct operating costs and royalty payments are charges (negative amounts) to the account.

Production Revenue generally consists of:

- 1) The value at point of production of lessee's gross share of oil and gas

produced from the NPSL, excluding fuel consumed, and volumes flared for safety or unavoidably lost or reinjected for conservation purposes.

- 2) All extraordinary production revenue or loss.

Direct Operating Costs generally consists of:

- 1) Direct charges incurred for wells, facilities, and equipment on or in support of the NPSL after commencement of commercial production that are in support of development or production operations that are not excluded or charged as development costs.
- 2) General overhead and administrative expenses not to exceed nine percent (9%) of allowable direct operating costs defined in item 1 above.
- 3) Accrual of abandonment costs amortized on unit-of-production basis.
- 4) Liability for taxes imposed on the value of production or sales from an NPSL incurred by a lessee.
- 5) Ad valorem taxes paid which are based on the value of lessee's properties used directly in the production, gathering, or treatment of production from an NPSL.

When the month-end account balance in the production revenue account is negative, the amount is carried over to the following month. When the month-end balance is positive, the amount is transferred to the development account, leaving an ending balance of zero in the production revenue account.

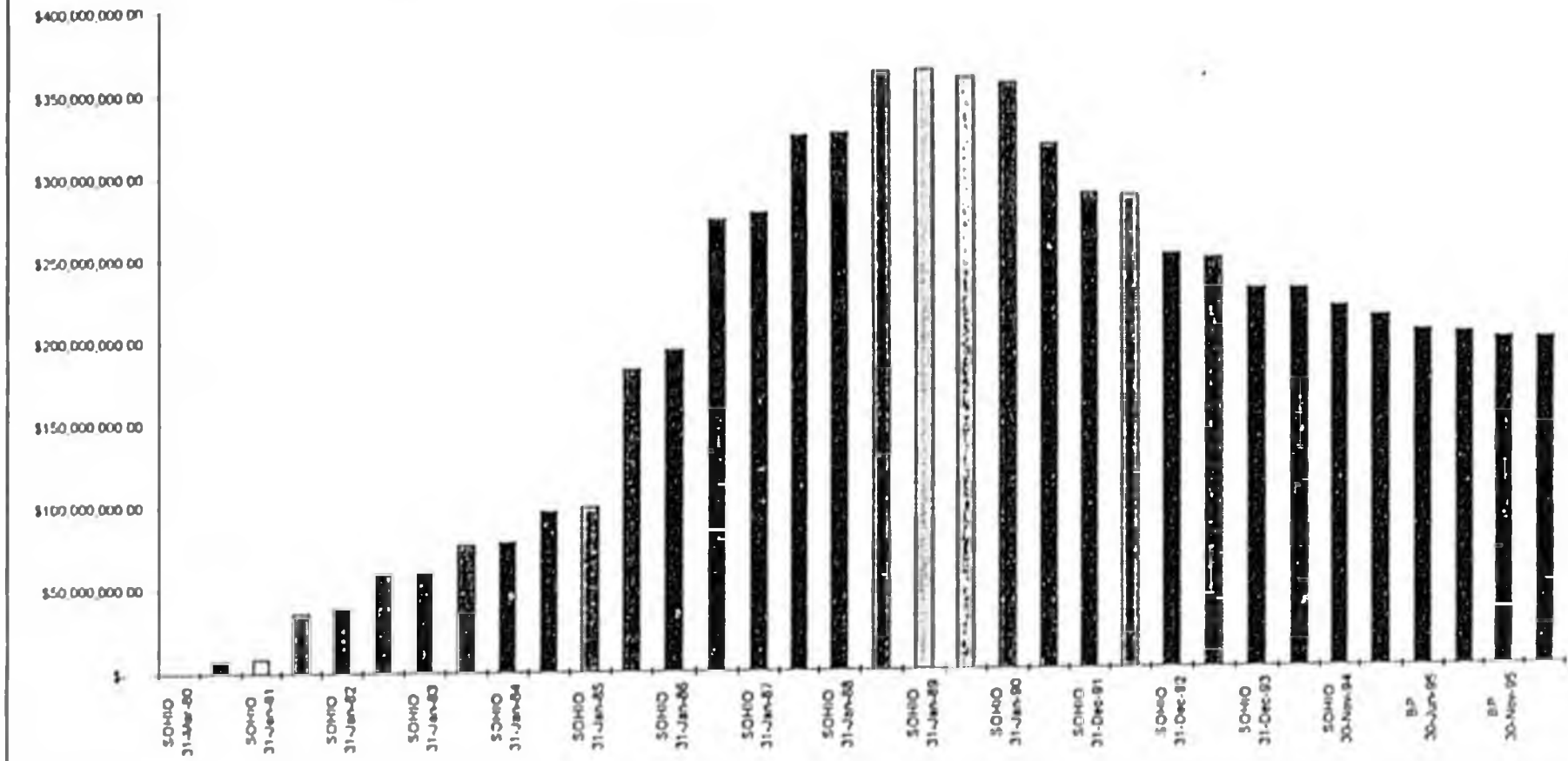
#### **D. NET PROFIT PAYMENT ACCOUNT**

The net profit payment account equals the positive amount, if any, transferred from the development account. The net profit share payment due the State equals the balance in the net profit payment account multiplied by the net profit share rate. This rate is a fixed percentage determined either through competitive bidding or by the Commissioner of Natural Resources prior to the lease sale. Further details about NPSL reporting and payment are contained in 11 AAC 83.201-295.

Two Examples of Actual NPS Development  
Account Balances--One Producing Lease and  
One Explored But Undeveloped Lease

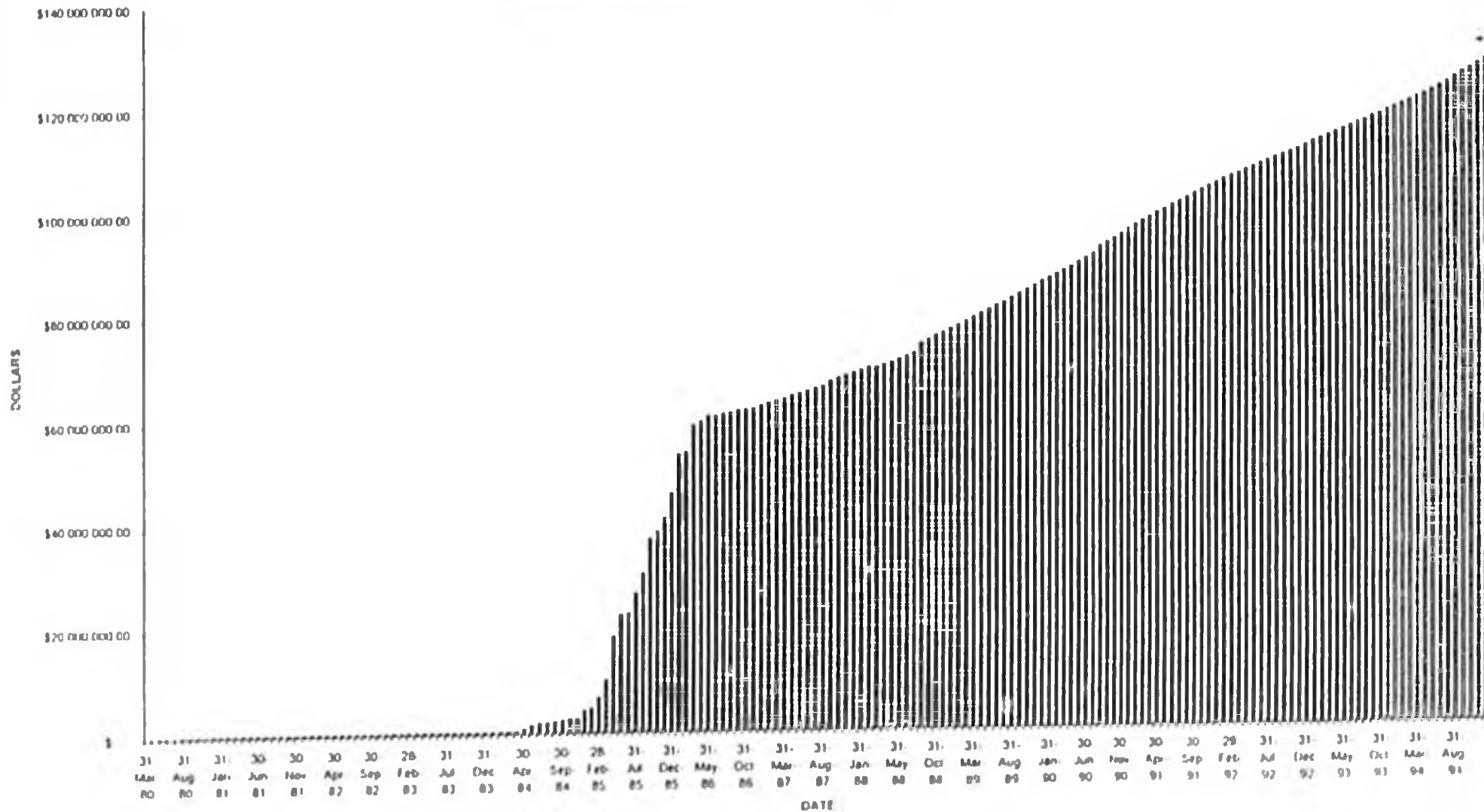
Listing of Current NPS Development Account  
Balances by Field

ADL 312828 SOHIO & BP DEVELOPMENT ACCOUNT ENDING BALANCES



NPS Lease  
 Duck Island Unit  
 Endicott Pool  
 Production Start Up Late 1987

ADL 312798 NPSL DEVELOPMENT ACCOUNT ENDING BALANCES



NPS Lease  
 North Star Unit  
 No Commercial Production to Date

NET PROFIT SHARE ACCOUNT  
BALANCES BY FIELD

DUCK ISLAND UNIT--TWO NPS LEASES  
\$203 MILLION

KUPARUK RIVER UNIT--FOUR NPS LEASES  
\$123 MILLION

MILNE POINT UNIT--FOUR NPS LEASES  
\$35 MILLION

NORTH STAR UNIT--FIVE NPS LEASES  
\$259 MILLION

KUUKPIK UNIT--18 NPS LEASES  
\$73 MILLION

POINT THOMSON UNIT--FIVE NPS LEASES  
\$93 MILLION

NORTH NIAKUK AREA--ONE NPS LEASE  
\$42 MILLION

GRAND TOTAL-- \$828 MILLION

### Assumptions used in Illustrative Northstar Model

- **Project Life:** Production ramp-up in 4th Quarter 1998; full production in 1999; end of field life in 2012.
- **Wells:** 15 producers.
- **Original Oil in Place (OOIP):**

P(90) =	310 MMBO
Mean =	260 MMBO
P(10) =	210 MMBO
- **Reserves:**

P(90) =	160 MMBO
Mean =	130 MMBO
P(10) =	105 MMBO
- **Peak Production rate:** 50,000 bbl/day
- **Capital Expenditures (real 1996 dollars):**

<b>Facilities:</b>	Low =	\$205	MM
	Base =	\$237	MM
	High =	\$278	MM
<b>Drilling</b>	Low =	\$75	MM
	Base =	\$85	MM
	High =	\$110	MM
<b>Pipeline</b>	Low =	\$25	MM
	Base =	\$28	MM
	High =	\$53	MM
<b>Total</b>	Low =	\$305	MM
	Base =	\$350	MM
	High =	\$441	MM
- **Appraisal Costs**

Low =	\$25	MM
Base =	\$28	MM
High =	\$30	MM
- **Operating Costs**

Low =	\$1.40/bbl
Base =	\$1.50/bbl
High =	\$2.00/bbl
- **Initial Abandonment Costs:**

5% Facility Capex	(estimate provided by DNR Petroleum Engineer)
10% Drilling Capex	
- **BPXA's Working Interest:** 98 % (Murphy Oil owns 10% of OCS Y-181)

- **Tract Allocation:** 76.8% State (No production allocated to ADL 355001)  
23.2% Federal
- **State royalty rate:** 20%
- **Supplemental royalty:** As proposed.
- **Federal royalty rate:** 16.67% (sliding scale not calculated; state receives 27% share of Federal royalty)
- **Net profit share:** 89.4% (average of the five state leases)
- **Development Account beginning balance (1996):** \$262 MM
- **Severance Tax:** 12.25% for first five years production, 15% thereafter; subject to ELF.
- **Conservation and oil spill tax:** \$0.034/bbl
- **Ad valorem tax rate:** 2%
- **State income tax rate:** 2% (estimate provided by DOR Petroleum Economist)
- **Federal income tax rate:** 35%
- **Oil Price Forecast:** DOR's Fall 1995 Base Price Forecast .  
PS-1 price = Northstar wellhead and derived from DOR's forecast of TAPS tariffs and marine costs. No adjustment made for quality, pumpability, infrastructure charges, or upstream tariffs.
- **Inflation Rate:** DOR's Fall 1995 Base Price Forecast  
3.0% in 1997; 3.2% thereafter.
- **Real Prime Rate:** 8.25% (Anchorage Daily News, 4/8/96)
- **Nominal Discount Rate:** 10%
- **General:** Stand-alone project, no facility sharing. Involves water flood and gas injection; process sales quality crude for delivery to TAPS. Expansion of the existing man-made Seal Island exploration island. Undersea, buried 12" pipeline to shore, 5 miles offshore/11 miles onshore; tie-in to Kuparuk Pipeline just west of TAPS Pump Station #1

Kevin Banks, ADNR  
April 11, 1996

"SIMPLE" Discounted Cash Flow Model					
Year	1	2	3	4	5
Gross Oil (MMBO/Y)	0	5	10	6	2
State Royalty Rate	12.5%	12.5%	12.5%	12.5%	12.5%
Royalty Oil	0	0.625	1.25	0.75	0.25
WIO Oil	0	4.375	8.75	5.25	1.75
Oil Price	12.00	12.10	12.15	12.20	12.25
WIO Revenue	0.00	52.94	106.31	64.05	21.44
Capex	100.00	75.00	0.00	0.00	0.00
Opex	0.00	7.50	15.00	9.00	3.00
Total Cost	100.00	82.50	15.00	9.00	3.00
Net Revenue	-100.00	-29.56	91.31	55.05	18.44
Income Tax Rate	0.35	0.35	0.35	0.35	0.35
Income Tax	-35.00	-10.35	31.96	19.27	6.45
After Tax Cash Flow	-65.00	-19.22	59.35	35.78	11.98
NPV @10% =	\$1.50				
ROR =	11%				

Report2

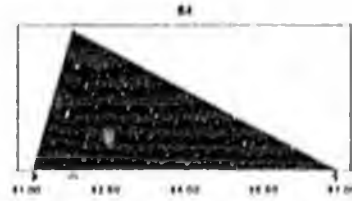
Assumptions

Assumption: S4

Coll: S4

Triangular distribution with parameters:

Minimum	\$1.00
Likeliest	\$1.80
Maximum	\$7.00



Selected range is from \$1.00 to \$7.00

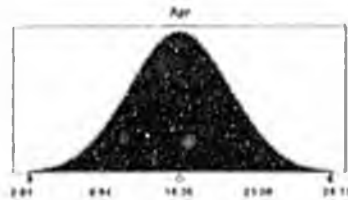
Assumption: Apr

Coll: B93

Normal distribution with parameters:

Mean	16.35	(= B80)
Standard Dev.	4.47	(= \$S\$4)

Selected range is from -21.51 to 402.42



End of Assumptions



Forecast: AKSUPP-REAL

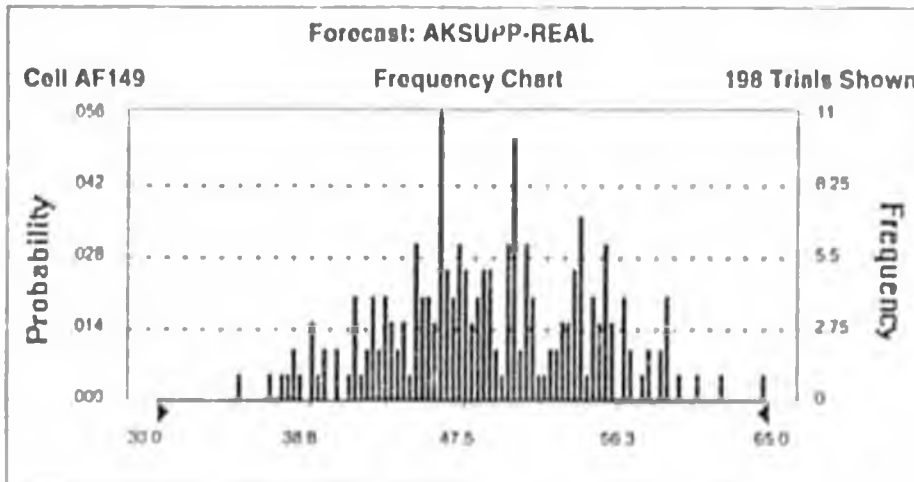
Cell: AF149

Summary:

Display Range is from 30.0 to 65.0  
 Entire Range is from 34.7 to 67.8  
 After 200 Trials, the Std. Error of the Mean is 0.4

Statistics:

Statistics:	Value
Trials	200
Mean	48.2
Med'ian (approx.)	48.8
Mode (approx.)	50.4
Standard Deviation	6.0
Variance	35.8
Skewness	0.23
Kurtosis	3.00
Coeff. of Variability	0.12
Range Minimum	34.7
Range Maximum	67.8
Range Width	33.2
Mean Std. Error	0.42





Forecast: AKSUPP-REAL (cont'd)

Cell: AF149

Percentiles.

<u>Percentile</u>	<u>Value (approx.)</u>
0%	34.7
10%	41.6
20%	44.2
30%	46.1
40%	47.2
50%	48.8
60%	50.5
70%	52.1
80%	54.4
90%	56.7
100%	67.8

End of Forecast



# Northstar Economic Evaluation



## Estimated Total Revenues

Accounting for the effects of "Price Volatility"	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
(Real 1996 Dollars)			
<b>State Revenues</b>			
State Royalty	255	256	257
State Supplemental Royalty	50	0	0
NPSL	0	107	41
State Share of Federal Royalty	16	16	16
Severance Tax	56	58	59
Spill & Conserv. Tax	3	3	3
Ad Valorem Tax	40	40	46
Income Tax	24	22	23
<b>Total</b>	<b>444</b>	<b>502</b>	<b>444</b>
<b>Federal Revenues</b>			
Royalty (Net of State Share)	44	44	44
Income Tax	218	198	213
<b>Total</b>	<b>262</b>	<b>242</b>	<b>258</b>
<b>BPXA Cash Flow</b>			
After Tax Funds Flow	355	319	346
Real Rate of Return	20.8%	21.1%	20.4%

\*Assuming 3.2 percent inflation rate from DOR Fall 1995 Base Price Forecast. Totals may not add due to rounding.

Inputs

NPSLs: ON Supplemental Royalty: OFF

Working Interest	80%
Royalty Interest	10%
Split/Conversion Fee (\$/bbl)	0.034
AVT Tax Rate	2%
Fed. Label Fee	2012
Recovery (months)	120
Leasing Costs (\$/bbl, fixed)	1.50
State Income Tax Rate	- 2.00% (DOE set - avg. corp. rate)
Federal Tax Rate	34.2% (effective after AB Fee)
Inflation Rate*	3.0% *Use if sum inflation and base
Real Discount Rate	7.0%
Prime Interest Rate (NPSL)	- 6.25% (MCM 6-6-00)
Beginning Balance (\$M)	292
Oil Production Multiplier	1
Oil Prod. Multiplier	1
Drilling Cost Multiplier	1
Facility Cost Multiplier	1
Abandonment Costs (\$/bbl)	
Starting Abandonment Liability (\$MM)	72.8
Failure %	5% (O&A Percentage)
Timing (days)	10% (Expense Est.)

Lease	Royalty	NPSL
212788	20.0%	83.20%
212789	20.0%	81.20%
212808	20.0%	85.28%
212809	20.0%	85.28%
255001	20.0%	80.00%
Federal		
V181	0.1887	0
V0179	0.1887	0

Monte Carlo Simulation:		Off
Monthly Oil Price End Date	12/31/2010	
Range:	Low %	High %
Oil Price	0.898	1.263
Gas Price	0.864	1.172
Water Price	0.997	1.092
Electricity	0.808	1.211
Leasing Costs	0.935	1.375

NPSLs and Supplemental Royalty Control Panel	
NPSLs ON/OFF	On
Supplemental Royalty ON/OFF	Off
AVT Fee - All Basin MOO Prod Estimation	80.00

DOA Information	
Starting Oilfield Assets (\$MM)	0
Starting Well Assets (\$MM)	0
Starting Purchase Price Balance (\$MM)	0

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total		
Gross Oil (MMbbl) Produced	0.0	0.0	5.4	48.8	48.8	48.7	41.2	34.7	29.7	25.8	20.0	16.7	13.8	11.5	9.6	8.3	7.0	6.0	5.0	4.0	3.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	130.0		
Gross Water (MMbbl) Produced	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Gross Gas (MMbbl) Produced	0.0	0.0	0.0	0.0	0.0	0.0	0.5	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	0.0	0.0	0.0		
Sales NGLs (MMbbl) Produced	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Return Gas (MMbbl) Purchased	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Return Gas Purchased	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
P&G Oil Prod (\$/bbl, mod)	111.45	112.28	112.72	113.89	114.48	114.87	115.88	115.87	116.48	116.89	117.52	118.10	118.78	119.48	120.08	120.85	121.33	121.81	122.82	123.29	123.83	124.84	125.39	126.18	126.81	127.74	128.57	129.43	130.21	131.22	
Pipeline Fees (\$/bbl, mod)	43.42	42.77	42.54	42.54	42.88	42.87	42.89	42.12	43.21	43.53	43.79	44.01	44.24	44.39	44.18	44.03	43.82	43.34	43.64	43.84	44.14	44.32	44.51	44.71	44.81	44.81	44.74	44.53	44.58	44.78	44.81
Monte Carlo (\$/bbl, mod)	11.48	11.28	11.28	11.42	11.47	11.55	11.53	11.71	11.79	11.87	11.93	11.99	12.04	12.12	12.18	12.79	12.23	12.41	12.48	12.54	12.64	12.72	12.80	12.86	12.87	13.00	13.18	13.25	13.34	13.44	
NGL Value as % of Oil Prod (mod)	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%	
Other Income (\$/bbl, mod)	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	
Producing Water Ft	0	0	5	10	15	15	15	15	15	15	15	15	15	15	15	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Oil Ser. Fee	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	12.25%	
Gas Ser. Fee	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	
Abandonment Fee		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	21.8	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	
Capital (\$/bbl, fixed)																															
Drilling	14.0	0.0	14.0	20.0	20.0	15.0	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	0.0	0.0	0.0	0.0	0.0	
Facility	30.0	0.1	13.0	47.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Pipeline	5.0	13.0	18.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Cost of Sales (\$/bbl)	1.00	1.03	1.08	1.10	1.12	1.17	1.21	1.24	1.28	1.33	1.37	1.41	1.46	1.50	1.55	1.60	1.65	1.70	1.75	1.80	1.85	1.90	1.95	2.00	2.05	2.11	2.17	2.23	2.29	2.37	

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Supplemental Royalty Rate																													
Trigger Price (\$/Bbl WCI)	17.25	17.01	17.00	18.18	18.67	18.76	18.80	18.37	18.88	19.21	19.60	20.07	21.21	21.85	21.88	22.34	22.79	23.07	23.43	23.81	24.18	24.54	24.87	25.37	25.79	26.18	26.81	27.83	28.67
Linear Slope (% \$/Bbl WCI)	1.0%																												
Supplemental Royalty Cap	1.0%																												

Caution - Only change inputs on this page

Summary Output

Development Summary			Monte Carlo			
		M.L.	MIN	MAX	MONTE	
Reserves	Crude Oil	MMBBL	130	105	180	142
	Gas	MMBBL	0	0	0	0
	Oil	MMBBL	0	0	0	0
Capex	Oil	(\$m real)	88	88	124	109
	Facility	(\$m real)	251	217	284	250
	Pipeline	(\$m real)	28	21	53	34
	Total	(\$m real)	378	331	471	393
Opex Costs	(\$MM)		2.8			2.8
Initial Costs	(\$MM)		1.50	1.40	2.00	1.74

State Revenue (\$m. MOD)	
Royalty (incl. supplemental)	217.4
State Share of Federal Royalty	20.3
Severance Tax	87.2
Spill & Conservation Tax	3.5
Ad Valorem Tax	52.8
NPSL	78.0
Income Tax	18.0
Total (\$m MOD)	555.1
Total (\$m real)	438.4

Federal Revenue (\$m. MOD)	
Royalty (Net of State Share)	54.9
Severance Tax	0.0
Spill & Conservation Tax	0.0
Ad Valorem Tax	0.0
NPSL	0.0
Income Tax	272.8
Total (\$m MOD)	328.5
Total (\$m real)	260.8

	1 00	1 03	1 04	1 10	1 12	1 17	1 21	1 24	1 29	1 33	1 37	1 41	1 48	1 50	1 55	1 60	1 65	1 70	1 75	1 82	1 87	1 93	1 98	2 04	2 11	2 17	2 23	2 30	2 37	2 44	
Cumulative Inflation																															
PE&I Oil Price (\$/bbl. real)	11.48	11.80	11.97	12.78	13.79	13.77	12.81	12.83	12.94	12.92	12.81	12.92	12.84	12.95	12.84	12.84	12.81	12.80	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78	12.78
Oil W.C. Oil Price (\$/bbl. MOD)	18.28	18.41	18.69	17.87	18.84	19.24	20.04	20.81	21.59	22.35	23.23	24.18	25.05	25.97	26.87	27.74	28.68	29.68	30.75	31.77	32.70	33.68	34.70	35.74	36.81	37.81	38.86	40.27	41.43	42.87	

ANS WC Oil Price (Random generated around mean price forecast)		1998	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
Monthly Forecast Price		18.34	18.39	18.54	17.38	18.33	18.73	20.47	21.23	22.02	22.84	23.70	24.51	25.30	26.41	27.32	28.25	29.22	30.23	30.23	31.27	32.27	33.24	34.23	35.24	36.23	37.41	38.63	39.88	40.88	42.10	
Monthly Monte Carlo Price		18.36	18	18.14	18.00	17.80	18.21	20.86	22.48	18.42	25.05	22.17	25.44	26.70	27.43	28.23	31.78	38.97	29.08	29.11	38.15	38.38	32.85	26.88	34.84	27.20	38.71	38.88	40.88	42.88	42.88	
ANS WC Mean Annual Value		18.38	18.44	18.82	17.80	18.34	19.86	20.77	20.81	21.58	22.38	23.23	24.18	25.05	26.87	27.82	28.82	31.74	29.70	29.69	38.71	31.74	32.71	31.88	34.78	35.74	38.81	37.82	39.88	40.27	41.43	42.87
PE&I Mean Annual Value		11.48	12.29	12.85	13.81	14.83	15.64	18.87	18.48	18.88	17.67	19.10	19.71	18.45	20.09	20.55	21.33	21.84	22.85	23.22	23.87	24.81	25.89	26.88	28.03	29.27	30.63	31.74	32.87	34.01	35.14	36.88

Quarterly Supplemental Oil Revenue %		1 00	1 03	1 04	1 10	1 12	1 17	1 21	1 24	1 29	1 33	1 37	1 41	1 48	1 50	1 55	1 60	1 65	1 70	1 75	1 82	1 87	1 93	1 98	2 04	2 11	2 17	2 23	2 30	2 37	2 44		
Jan		0.00%	0.00%	0.00%	0.00%	0.00%	0.36%	1.00%	1.84%	2.73%	3.64%	4.56%	5.42%	6.30%	7.15%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	
Feb		0.00%	0.00%	0.00%	0.00%	0.00%	0.47%	1.09%	1.74%	2.43%	3.14%	3.80%	4.70%	5.54%	6.41%	7.24%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Mar		0.00%	0.00%	0.00%	0.00%	0.00%	0.54%	1.18%	1.83%	2.52%	3.24%	3.81%	4.81%	5.88%	6.53%	7.37%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Apr		0.00%	0.00%	0.00%	0.00%	0.00%	0.64%	1.27%	1.87%	2.67%	3.34%	4.11%	4.92%	5.78%	6.06%	7.48%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
May		0.00%	0.00%	0.00%	0.00%	0.13%	0.73%	1.38%	2.02%	2.73%	3.44%	4.22%	5.03%	5.87%	6.76%	7.60%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Jun		0.00%	0.00%	0.00%	0.00%	0.21%	0.82%	1.45%	2.11%	2.87%	3.54%	4.22%	5.14%	6.09%	6.88%	7.60%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Jul		0.00%	0.00%	0.00%	0.00%	0.39%	0.91%	1.64%	2.31%	3.02%	3.76%	4.54%	5.39%	6.10%	6.96%	7.60%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Aug		0.00%	0.00%	0.00%	0.00%	0.39%	1.00%	1.83%	2.51%	3.23%	3.95%	4.54%	5.39%	6.10%	6.96%	7.60%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Sep		0.00%	0.00%	0.00%	0.00%	0.49%	1.08%	1.73%	2.40%	3.12%	3.84%	4.54%	5.39%	6.10%	6.96%	7.60%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Oct		0.00%	0.00%	0.00%	0.00%	0.54%	1.18%	1.83%	2.50%	3.23%	3.94%	4.78%	5.54%	6.48%	7.32%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Nov		0.00%	0.00%	0.00%	0.00%	0.64%	1.27%	1.81%	2.50%	3.23%	3.94%	4.78%	5.70%	6.54%	7.44%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
Dec		0.00%	0.00%	0.00%	0.15%	0.74%	1.36%	2.01%	2.70%	3.42%	4.17%	4.81%	5.81%	6.88%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
ANS WC Supplemental Oil Revenue %		0.00%	0.00%	0.00%	0.00%	0.36%	0.73%	1.00%	1.37%	1.74%	2.11%	2.48%	2.85%	3.22%	3.59%	3.96%	4.33%	4.70%	5.07%	5.44%	5.81%	6.18%	6.55%	6.92%	7.29%	7.66%	8.03%	8.40%	8.77%	9.14%	9.51%	9.88%	

**(\$M. MOO)**

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total	
State	0.0	0.0	3.0	39.1	40.6	40.9	39.7	21.1	20.6	22.7	19.7	17.0	14.8	12.8	8.8	6.0	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	0.0	317.4	
State Royalty	0.0	0.0	3.0	39.1	40.6	40.9	39.7	21.1	20.6	22.7	19.7	17.0	14.8	12.8	8.8	6.0	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	0.0	0.0	0.0
State Supplemental Royalty	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	0.0	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	
State Share of Federal Royalty	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	0.0	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	
Severance Tax	0.0	0.0	0.0	17.7	16.3	15.0	8.8	8.8	3.4	0.5	0.1	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	0.0	0.0	0.0	0.0	0.0	0.0	3.0	
Spill & Cleanup Tax	0.0	0.0	0.1	0.5	0.6	0.6	0.4	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.1	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	0.0	52.4	
Ad Valorem Tax	0.0	0.8	2.9	4.3	5.4	5.4	5.2	4.8	4.5	4.1	3.7	3.2	2.8	2.3	1.8	1.3	0.8	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	78.0		
APSL	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	0.0	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	16.0		
Income Tax	-0.28	-0.47	-0.70	1.05	1.06	2.22	2.18	1.06	1.20	1.08	1.08	1.41	1.19	0.33	0.22	0.19	-0.80	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	595.1		
Total (\$M. MOO)	0.7	0.3	5.0	60.7	60.1	64.4	64.0	60.7	57.2	56.7	56.6	57.8	51.7	52.7	56.1	51.0	-0.2	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		

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Federal	0.0	0.0	0.7	0.8	7.0	7.0	0.2	5.4	5.8	2.8	2.4	2.0	2.2	1.8	0.8	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	0.0	0.0	54.3
Royalty (Part of State Share)	0.0	0.0	0.7	0.8	7.0	7.0	0.2	5.4	5.8	2.8	2.4	2.0	2.2	1.8	0.8	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	0.0	0.0	273.0
Income Tax	-4.43	-7.10	-11.00	20.24	31.76	30.00	27.26	33.48	33.48	30.70	29.02	27.00	24.23	20.33	8.00	3.81	2.10	13.74	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	326.5	
Total (\$M. MOO)	4.4	6.9	11.3	20.8	20.7	48.1	43.8	38.9	36.3	33.8	30.5	27.2	22.9	7.9	6.2	2.9	13.7	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	

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
BP Exploration	49.2	61.4	64.5	79.7	92.8	101.0	103.0	90.4	77.8	64.8	54.3	45.0	36.0	10.8	7.1	4.8	25.5	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	479.7
Funds Flow (MOO)	MOA	MOA	53.90	2.75	0.44	7.21	0.01	0.10	4.35	0.41	0.20	0.40	0.42	2.10	2.21	2.21	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	
Funds Flow \$/bbl (MOO)	MOA	MOA	53.90	2.75	0.44	7.21	0.01	0.10	4.35	0.41	0.20	0.40	0.42	2.10	2.21	2.21	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	
Net Income (MOO)	4.7	7.7	20.8	79.0	71.7	60.0	51.4	47.3	42.4	35.0	30.0	25.0	21.5	10	1.7	-0.8	13.0	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	500.1	
Net Income \$/bbl (MOO)	MOA	MOA	13.23	0.51	0.60	4.31	4.30	4.70	5.10	5.20	5.10	5.24	5.22	-0.06	-0.77	-1.0	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	MOA	

**(\$M. REAL)**

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
State	0.0	0.0	3.0	38.0	39.7	39.8	29.0	20.7	17.1	14.4	12.0	10.0	8.4	6.5	3.1	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	0.0	255.8	
State Royalty	0.0	0.0	3.0	38.0	39.7	39.8	29.0	20.7	17.1	14.4	12.0	10.0	8.4	6.5	3.1	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	0.0	0.0	0.0
State Supplemental Royalty	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	0.0	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
State Share of Federal Royalty	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	0.0	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
Severance Tax	0.0	0.0	0.0	16.1	13.5	12.0	6.1	6.2	1.9	0.4	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.8
Spill & Cleanup Tax	0.0	0.0	0.1	0.4	0.4	0.4	0.3	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	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	0.0	42.0
Ad Valorem Tax	0.0	0.8	2.9	4.3	4.9	4.8	4.3	3.8	3.5	3.1	2.7	2.3	1.9	1.4	1.2	0.8	0.4	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	50.8	
APSL	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	0.0	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	12.0	
Income Tax	0.3	0.3	0.7	1.0	1.0	1.8	1.8	1.4	1.3	1.2	1.0	0.8	0.7	0.1	0.1	0.1	0.5	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	439.4	
Total (\$M. REAL)	0.7	0.7	5.0	59.9	59.4	59.3	48.0	37.1	32.0	27.2	23.0	19.2	16.9	12.1	7.2	1.2	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	108.8	
State Royalty - Real Dec.	0.0	0.0	3.2	39.4	39.8	39.3	29.1	18.0	12.4	9.6	7.4	6.0	4.8	3.8	2.3	1.2	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	0.0	
Sev. Royalty - Real Dec.	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	0.0	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	
State Share of Federal Royalty	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	0.0	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	
Severance Tax Real Dec.	0.0	0.0	0.0	13.3	10.5	9.2	5.3	5.2	1.1	0.2	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Spill & Cleanup Tax Real Dec.	0.0	0.0	0.0	0.4	0.3	0.3	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	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	0.0	
Ad Valorem Tax Real Dec.	0.0	0.1	2.1	3.2	3.7	3.3	2.8	2.5	2.1</																												



NPBL Calculation	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total	
Tract Alloc. Factor	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	78.80%	
Tract Ownership	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	
NPBL State Rate	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	89.28%	
Prime Interest Rate	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%	
<b>Reversal Amount</b>																																
Prod. Revenue	0.0	0.0	19.8	198.2	183.8	186.1	144.5	128.8	107.8	91.8	79.8	68.7	59.1	50.8	34.7	20.1	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
Operating Costs	0.0	0.0	12.41	123.01	123.71	123.81	120.81	118.21	116.51	113.31	111.51	108.81	105.51	102.11	15.01	12.81	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Production Taxes	0.0	0.0	10.01	118.21	112.41	112.11	108.01	105.41	102.11	100.81	100.21	100.11	100.11	100.11	100.11	100.11	100.11	100.11	100.11	100.11	100.11	100.11	100.11	100.11	100.11	100.11	100.11	100.11	100.11	100.11	100.11	
Ad Valorem Tax	0.0	10.81	12.01	13.41	14.21	14.21	14.11	13.81	13.51	13.21	12.81	12.41	12.01	11.61	11.41	11.01	10.51	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	
UOP Alloc. Costs	0.0	0.0	10.41	11.81	12.71	13.21	13.81	13.91	13.01	12.21	11.81	11.41	11.01	10.71	10.41	10.11	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	
Closing Balance	0.0	10.81	10.8	118.8	118.8	118.8	104.8	84.7	82.4	72.4	63.2	54.7	47.2	41.0	27.8	18.1	10.51	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	
<b>Debt Account</b>																																
Beginning Balance	1242.01	1327.81	1438.41	1581.01	1641.81	1488.81	1418.01	1340.01	1288.41	1204.81	1148.31	1082.81	1023.21	960.0	900.0	840.0	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Capital Expend	143.21	177.81	187.31	183.21	124.31	113.51	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	0.0	0.0	0.0	0.0	0.0	0.0	
Prod Rev Acc Credit	0.0	0.0	10.8	118.8	118.8	118.8	104.8	84.7	82.4	72.4	63.2	54.7	47.2	41.0	27.8	18.1	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	
Prism Closing Bal	1304.21	1405.21	1513.01	1688.31	1648.11	1380.81	1310.01	1248.31	1188.11	1122.41	1053.11	977.81	908.1	841.0	778.1	718.1	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	
Average Annual DA Balance	1282.11	1388.41	1473.71	1524.71	1483.81	1423.81	1383.31	1323.81	1277.81	1227.81	1188.81	1148.71	1093.31	1043.71	993.71	943.71	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	
Accrued Interest	123.41	130.21	138.11	143.31	140.71	138.81	130.01	124.11	118.81	113.81	108.51	103.41	98.41	93.41	88.41	83.41	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	
DA Closing Balance	1327.81	1438.41	1561.01	1688.81	1688.81	1418.81	1340.01	1288.41	1204.81	1148.31	1082.81	1023.21	960.0	900.0	840.0	780.0	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	
<b>NPBL Payment Acc</b>																																
Prism Sub. NPBL	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
NPBL Payments*	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

\* Payments null if NPBL ONA11 switch in control box is set to "OFF"

Northstar Reserves, Royalty and NPBL Tract Allocations												
Leases	NPBL	Ac/Ft	% of Total Reserves	% of NPBL Reserves	NPBL Ownership	NPBL Share Rate	Working Interest	NPBL Tract Ret	NPBL Royalty by Lease	Weighted Royalty	NPBL	
312798	83.20%	84,000	8.73%	8%	100%	8.18%			20%	1.244%		
312799	81.20%	555,000	44.40%	56%	100%	32.72%			20%	8.881%		
312800	89.28%	102,000	8.16%	11%	100%	8.08%			20%	1.432%		
312809	84.24%	218,000	17.52%	23%	100%	18.46%			20%	3.504%		
35800'	40.00%		0.00%	0%	100%	0.00%			20.0%	0.000%		
		880,000	78.80%	100%	100%	80.38%	88%	78%		18.28%		
Effective State Royalty with 27% of Federal Tax										10.87%	3.014%	
Y181		228,000	18.06%							18.87%	3.014%	
Y0178		84,000	3.12%							18.87%	0.954%	
		1,250,000	100.0%								2.827%	
Effective Federal Royalty with 27% of Federal Tax										2.865%		
										Total	18.00%	81.00%

0177		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
BP Revenue		0.0	0.0	19.8	203.0	209.1	210.7	184.4	180.3	137.2	117.2	101.8	87.8	75.4	64.8	44.2	29.8	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	1641
Severance Tax		0.0	0.0	0.0	17.7	16.3	16.0	8.8	8.6	2.4	0.8	0.1	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	87
Upst & Corros		0.0	0.0	0.1	0.6	0.6	0.6	0.4	0.3	0.3	0.2	0.2	0.1	0.1	0.1	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	4
AVI		0.0	0.8	2.8	4.3	5.4	5.4	5.2	4.8	4.6	4.1	3.7	3.3	2.8	3.3	1.8	1.2	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	53
NPSI		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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	78
Upes		0.0	0.0	3.1	26.3	20.2	20.8	28.7	27.2	18.8	18.8	14.7	12.7	10.8	8.3	8.2	3.7	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	237
Abandonment		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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39
Other income	Other Profit	0.0	-0.8	14.3	150.2	157.8	158.3	142.4	129.8	110.3	96.4	87.8	71.8	58.8	48.8	31.1	8.3	-40.0	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	1182
Other income		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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Capex		53.8	89.0	111.5	80.8	31.1	17.2	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	0.0	0.0	0.0	0.0	0.0	283
Inten Drill Dep	BTFF	-53.8	-89.0	-111.5	-80.8	-31.1	-17.2	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	0.0	0.0	0.0	0.0	0.0	769
Ten. Drill Dep		7.3	0.8	8.3	17.3	18.0	12.3	3.8	3.3	2.0	0.7	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	0.0	75
Ten. Drift Dep		6.8	21.9	40.8	50.7	48.1	38.0	28.8	24.8	18.7	10.7	3.8	0.8	0.2	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	290
Total		12.8	22.5	49.2	87.8	85.8	48.2	33.8	28.2	20.8	11.4	3.8	0.8	0.2	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	389
Fed Tax Income		-12.8	-27.3	-35.0	-82.2	-82.8	-111.0	-108.8	-87.8	-88.8	-84.0	-78.0	-70.7	-58.2	-48.8	-31.1	-8.3	-40.0	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	798

UOP Abandonment		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total	
Rate (\$/bbl)		0.00	0.00	0.78	0.38	0.42	0.44	0.43	0.40	0.37	0.35	0.32	0.28	0.26	0.22	0.17	0.09	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	29	
Total (\$M)		0.0	0.0	0.8	2.3	4.7	8.8	9.4	8.0	3.9	3.0	2.3	1.7	1.3	0.8	0.5	0.1	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	29	
DD&A																																	
Rate (\$/bbl)		0.00	0.00	3.88	2.88	3.30	3.83	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	3.78	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	385	
Total (\$M)		0.0	0.0	5.8	28.4	47.7	51.3	45.1	38.0	21.4	28.1	21.8	18.2	12.8	9.3	4.7	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	385	

Income Tax		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
State		-0.28	-0.47	-0.70	1.88	1.85	2.22	2.18	1.95	1.78	1.88	1.88	1.41	1.18	0.33	0.22	0.13	-0.80	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	16
Federal		-4.43	7.89	11.88	28.24	31.75	38.08	37.38	33.48	30.70	29.83	27.08	24.23	20.33	5.88	3.81	2.18	-13.74	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	274
Total		-4.69	6.45	12.88	28.88	33.80	40.30	38.83	35.44	32.48	30.81	28.87	25.85	21.81	6.01	4.04	2.28	-14.84	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	290

Funds Flow		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total	
ATFF - MOD		-48.2	-81.4	-64.5	38.7	82.8	101.8	102.8	80.4	77.8	84.8	84.3	45.8	38.0	10.8	7.1	4.1	-25.8	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	480	
ATFF - Real		-48.2	-81.4	-64.5	38.7	82.8	101.8	102.8	80.4	77.8	84.8	84.3	45.8	38.0	10.8	7.1	4.1	-25.8	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	353
ATFF - Real Disc		-48.2	-81.4	-64.5	38.7	82.8	101.8	102.8	80.4	77.8	84.8	84.3	45.8	38.0	10.8	7.1	4.1	-25.8	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	172
ATFF - Cum NPV		-48.2	-132.3	-202.1	-172.2	-108.8	-45.8	12.1	88.8	85.7	122.7	183.7	188.7	171.8	174.8	178.8	177.7	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	172.2	

Net Income		1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
		4.7	7.7	20.8	28.8	31.7	80.8	81.4	47.3	42.4	35.8	30.0	25.8	21.8	-3.0	-1.3	-0.8	13.8	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	1008

Ad Valorem Tax	1.00	1.03	1.06	1.08	1.12	1.15	1.18	1.22	1.26	1.30	1.34	1.38	1.42	1.46	1.50	1.55	1.60	1.65	1.70	1.75	1.80	1.85	1.91	1.97	2.03	2.09	2.15	2.21	2.28	2.35	Totals	
Inflation Rate	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
1996	1.0000																															
1997		0.9375	0.8750	0.8125	0.7500	0.6875	0.6250	0.5625	0.5000	0.4375	0.3750	0.3125	0.2500	0.1875	0.1250	0.0625	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
1998			1.0000	0.9286	0.8571	0.7857	0.7143	0.6429	0.5714	0.5000	0.4286	0.3571	0.2857	0.2143	0.1429	0.0714	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
1999				1.0000	0.9231	0.8462	0.7692	0.6923	0.6154	0.5385	0.4615	0.3846	0.3077	0.2308	0.1538	0.0769	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
2000					1.0000	0.9167	0.8333	0.7500	0.6667	0.5833	0.5000	0.4167	0.3333	0.2500	0.1667	0.0833	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
2001						1.0000	0.9091	0.8182	0.7273	0.6364	0.5455	0.4545	0.3636	0.2727	0.1818	0.0909	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
2002							1.0000	0.8000	0.7000	0.6000	0.5000	0.4000	0.3000	0.2000	0.1000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
2003								1.0000	0.8889	0.7778	0.6667	0.5556	0.4444	0.3333	0.2222	0.1111	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2004									1.0000	0.8750	0.7500	0.6250	0.5000	0.3750	0.2500	0.1250	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2005										1.0000	0.8571	0.7143	0.5714	0.4286	0.2857	0.1429	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2006											1.0000	0.8333	0.6667	0.5000	0.3333	0.1667	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2007												1.0000	0.8000	0.6000	0.4000	0.2000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2008													1.0000	0.7500	0.5000	0.2500	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2009														1.0000	0.5000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2010															1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2011																1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2012																	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2013																		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2014																			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2015																				0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2016																					0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2017																						0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2018																							0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2019																								0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2020																									0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2021																										0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2022																											0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2023																												0.0000	0.0000	0.0000	0.0000	0.0000
2024																													0.0000	0.0000	0.0000	0.0000
2025																														0.0000	0.0000	
AVT	0.00	0.80	2.54	4.38	5.51	5.47	5.28	4.93	4.58	4.21	3.85	3.48	3.11	2.77	2.43	2.12	1.83	1.55	1.29	1.05	0.82	0.60	0.40	0.20	0.00	0.00	0.00	0.00	0.00	0.00		
SP Imp AVT	0.00	0.78	2.43	4.23	5.40	5.36	5.18	4.83	4.48	4.13	3.77	3.41	3.07	2.73	2.39	2.07	1.79	1.51	1.25	1.01	0.78	0.56	0.36	0.16	0.00	0.00	0.00	0.00	0.00	0.00		



	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
<b>DO&amp;A (\$MDD)</b>																																
<b>Reserves (MMBOE NRY)</b>																																
Opening Balance	0.0	0.0	0.0	101.7	97.2	72.8	56.7	48.7	38.7	28.4	21.5	15.7	10.8	8.8	3.5	1.2	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	491.80	
Additions (BPX Net After Royalty MMB)	0.0	0.0	102.2	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	102.25	
BPX Net Production (MMB)	0.0	0.0	1.6	14.4	14.4	14.1	11.9	10.1	8.2	8.9	5.8	4.8	4.0	3.2	2.2	1.2	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	491.80	
Closing Balance	0.0	0.0	101.7	97.2	72.8	56.7	48.7	38.7	28.4	21.5	15.7	10.8	8.8	3.5	1.2	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	0.00	
<b>Wellbore Assets</b>																																
Beginning Balance (Net \$MM)	0.0	13.7	13.7	27.7	51.7	71.8	72.3	58.2	45.8	25.4	28.8	19.5	12.6	8.5	4.2	1.6	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	485.28	
Additions (BPX Net \$MM MOD)	13.7	0.0	14.8	30.1	31.1	17.2	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	0.0	0.0	0.0	0.0	0.0	108.64	
DO&A Rate (\$/BBL)	0.00	0.00	0.41	0.42	0.77	1.10	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	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	108.64
DO&A (BPX Net \$MM MOD)	0.0	0.0	0.8	8.1	11.1	15.8	14.9	12.8	10.4	8.8	7.2	6.0	5.0	4.2	2.8	1.8	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	485.28	
Carry Forward (BPX Net \$MM MOD)	13.7	13.7	27.7	51.7	71.8	72.3	58.2	45.8	25.4	28.8	19.5	12.5	8.5	4.2	1.6	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	0.00	
<b>Fieldwide Assets</b>																																
Beginning Balance (Net \$MM)	0.0	35.2	121.2	202.7	220.8	184.3	148.5	118.3	92.8	71.8	54.2	39.8	27.4	17.2	8.7	3.2	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	1346.00	
Additions (BPX Net \$MM MOD)	35.2	88.9	88.6	50.5	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	758.17	
DO&A Rate (\$/BBL)	0.00	0.00	3.18	2.24	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.53	2.13	2.53	2.53	2.53	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	258.17
DO&A (BPX Net \$MM MOD)	0.0	0.0	5.0	32.4	38.9	35.7	30.2	25.5	21.1	17.5	14.7	12.3	10.2	8.4	5.8	3.2	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	1346.00	
Carry Forward (BPX Net \$MM MOD)	35.2	121.2	202.7	220.8	184.3	148.5	118.3	92.8	71.8	54.2	39.8	27.4	17.2	8.7	3.2	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	0.00	
<b>BPX Purchase Price Allocation</b>																																
Beginning Balance (Net \$MM)	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	
Additions (BPX Net \$MM MOD)	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	
DO&A Rate (\$/BBL)	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	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	
DO&A (BPX Net \$MM MOD)	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	
Carry Forward (BPX Net \$MM MOD)	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.00	
<b>Total DO&amp;A Rate \$/BBL</b>	0.0	0.0	3.6	2.7	3.3	3.6	3.8	3.8	3.8	3.8	3.1	3.8	3.8	3.8	3.8	3.8	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	50.98
<b>Total DO&amp;A \$MM MOD</b>	0.0	0.0	5.8	38.4	47.7	51.2	45.1	38.0	31.4	28.1	21.8	18.3	15.2	12.8	8.2	4.7	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	394.81	
<b>UOP ABANDONMENT (\$MDD)</b>																																
Beginning Balance (Net \$MM)	39.4	39.4	39.4	38.8	38.8	31.8	25.1	18.7	12.7	8.8	8.8	4.5	2.8	1.5	0.8	0.1	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	
Additions (BPX Net \$MM MOD)	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
DO&A Rate (\$/BBL)	0.00	0.00	0.78	0.38	0.42	0.44	0.42	0.40	0.37	0.35	0.32	0.29	0.18	0.22	0.17	0.08	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	
DO&A (BPX Net \$MM MOD)	0.0	0.0	0.5	2.3	4.7	8.8	8.4	5.0	3.8	3.0	2.3	1.7	1.2	0.9	0.5	0.1	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	
Carry Forward (BPX Net \$MM MOD)	39.4	39.4	38.9	38.8	31.8	25.1	18.7	12.7	8.8	8.8	4.5	2.8	1.5	0.8	0.1	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	29.44	

Forecast: AKSUPP-REAL

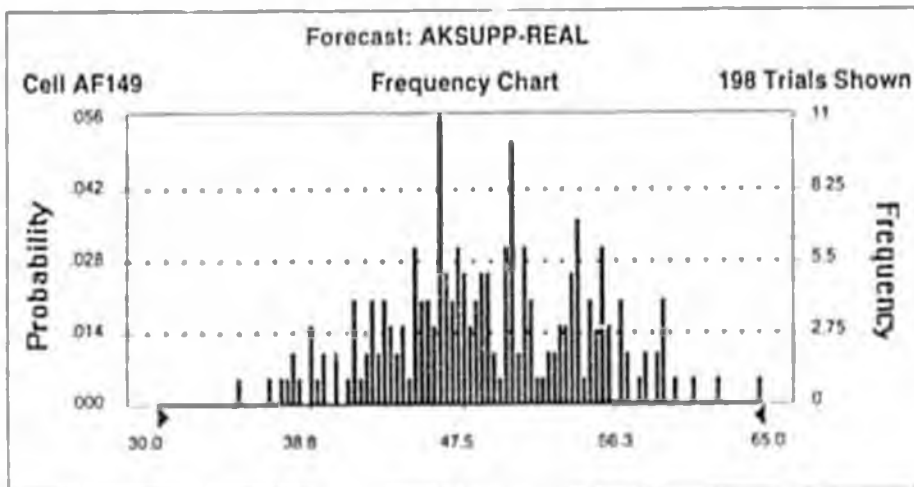
Cell: AF149

Summary:

Display Range is from 30.0 to 65.0  
 Entire Range is from 34.7 to 67.8  
 After 200 Trials, the Std. Error of the Mean is 0.4

Statistics:

	<u>Value</u>
Trials	200
Mean	49.2
Median (approx.)	48.8
Mode (approx.)	50.4
Standard Deviation	6.0
Variance	35.8
Skewness	0.23
Kurtosis	3.00
Coeff. of Variability	0.12
Range Minimum	34.7
Range Maximum	67.8
Range Width	33.2
Mean Std. Error	0.42





Forecast: AKSUPP-REAL (cont'd)

Cell: AF149

Percentiles:

<u>Percentile</u>	<u>Value (approx.)</u>
0%	34.7
10%	41.6
20%	44.2
30%	46.1
40%	47.2
50%	48.8
60%	50.5
70%	52.1
80%	54.4
90%	56.7
100%	67.8

End of Forecast

# Northstar Economic Evaluation



## Estimated Total Revenues

Accounting for the effects of "Price Volatility"	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
(Real 1996 Dollars)			
<b>State Revenues</b>			
State Royalty	255	256	257
State Supplemental Royalty	50	0	0
NPSL	0	107	41
State Share of Federal Royalty	16	16	16
Severance Tax	56	58	59
Spill & Conserv. Tax	3	3	3
Ad Valorem Tax	40	40	46
Income Tax	24	22	23
<b>Total</b>	<b>444</b>	<b>502</b>	<b>444</b>
<b>Federal Revenues</b>			
Royalty (Net of State Share)	44	44	44
Income Tax	218	198	213
<b>Total</b>	<b>262</b>	<b>242</b>	<b>258</b>
<b>BPXA Cash Flow</b>			
After Tax Funds Flow	355	319	346
Real Rate of Return	20.8%	21.1%	20.4%

\*Assuming 3.2 percent inflation rate from DOR Fall 1995 Base Price Forecast. Totals may not add due to rounding.

# STATE OF ALASKA

TONY KNOWLES, GOVERNOR

## DEPARTMENT OF NATURAL RESOURCES

OFFICE OF THE COMMISSIONER

400 WILLOUGHBY AVENUE  
JUNEAU, ALASKA 99801-1796  
PHONE: (907) 465-2400  
FAX: (907) 465-3886

April 11, 1996

Senator Loren Leman  
Chairman, Senate Resources Committee  
Alaska State Legislature  
State Capitol  
Juneau, AK 99801

Dear Senator Leman:

The Division of Oil and Gas responds to your list of questions dated April 5, 1996, as follows:

1. BPXA currently estimates that 76.8% of the recoverable reserves underlie the state's leases in the Northstar Unit (NSU). The Division's Resource Evaluation Group has reviewed this estimate and other confidential estimates, and believes that 75 to 80% is a reasonable range. This range could be slightly higher if BPXA develops the known reserves to the Northwest.

2. The Division does not possess the necessary information to estimate the bonus that the state would have received in 1979 if the NSU leases had been offered with a 12.5% royalty and no net profit share. In order to make such an estimate, the Division would need to know, among other things, the 1979 estimates (or ranges of estimates) of capital expenditures, operating costs, oil prices, dry hole risk, oil in place, recoverable reserves, TAPS wells, tanker costs, and federal tax rates. The Division employee responsible for such a pre-sale analysis is no longer employed by the state and the Division has been unsuccessful in locating a file containing a pre-sale analysis of the NSU leases.

If one is willing to make many assumptions, the most important of which are that the bidders would bid on all tracts in proportion to the reserves they believe underlie a tract and in 1979 and 1983 bidders believed that recoverable reserves were split between the state and federal leases as they have been estimated in 1996, then one can estimate the bid based upon the actual bids on the federal leases. The two federal leases received a combined winning bid of \$81,080,995. If that is assumed to be 23.2% of the total bid amount, then the state total bid for the state NSU unit would be \$268,406,052. One could also assume that the bid might be higher because the federal leases were leased at 16.67% sliding scale royalty and your hypothetical stipulates a 12.5% fixed royalty. Conversely, the state leases would pay severance tax while the federal leases would not and this might result in lower bids on the state leases.

3. If one assumes that 50% of the \$268,406,052 would have been deposited into the Permanent Fund, then based upon the annual realized rate of returns reported by the Permanent Fund in its 1995 annual report, then the balance for the year ending 1995 would be \$704,588,494.

4. The Division does not ordinarily calculate the bonuses that the state could expect to receive from a lease sale. Nor does it possess a model to estimate bonuses. In the usual pre-sale analysis, the Division does prepare an estimate of the net present value of the projected discounted cash flow (NPV or EMV) for a prospect to assist in setting the lease terms to offer in the sale. Terms which the Division considers include the royalty rate, net profit share rate, and whether to offer an exploration incentive credit. In attempting to maximize the revenue to the state, the NPV represents how much bidders may have available to bid. As part of that evaluation, the Division considers many factors including: prospectivity, company interest, development costs, operating costs, and oil prices. These factors are very important in deciding the balance to strike between the bonus bid and the size of the state's future royalty or net profit share ("state take").

In a world of certainty and competition, the amount of a bid should equal the "economic rent." Economic rent is the difference between the value of production and the total necessary cost of exploration, development, and production including a reasonable rate of return to the lessee. In this idealized world, the most efficient firm with the lowest hurdle rate would win the bid. Oil and gas competitive bidding, however, is often conducted under conditions of uncertainty and limited competition. It is widely believed that the winner tends to be the bidder who most overestimates reserve potential, although other factors such as underestimating costs can lead to the same result, particularly in frontier areas. It should be noted, however, that if the NSU leases were rebid, much of the uncertainty about reserves would have been resolved.

Bidders employ various strategies, ranging from intuition to formal models, for bidding in such high risk situations. Although profit maximization remains the object, bidders will examine the tradeoff between reducing the bid and reducing the probability of winning. In general, bidders will bid some fraction of the project's "expected mean value (EMV)."

To do an EMV calculation, an appropriate discount rate must be selected. Various hurdle rates for oil and gas companies have been reported in the literature, ranging from 5% to 15% (real). In addition, the Division has access to confidential information regarding hurdle rates for several companies. For purposes of this analysis, the Division has used discount rates of 10 and 15% (real).

Next, certain assumptions must be made regarding oil prices, production rates, capital expenditures, operating costs, taxes, and the like. For purposes of this analysis, the Division has used the same assumptions used in the Northstar model, as requested by you, except outcomes were varied over certain ranges: (1) the recoverable reserves from

105 MMBO to 160 MMBO; (2) capital expenditures from \$330 to \$471 MM; (3) operating costs from \$1.40/bbl to \$2.00/bbl; and (4) oil prices varied over an average of a normal distribution whose standard deviation is between \$1.00 to \$7.00 around the DOR mid-price forecast. The Division did 200 Monte Carlo trials to calculate an EMV at the 10 and 15% discount rates. The results under the various discount rates and royalty rates are presented in Table 1.

The results presented in attached Table represent the most a bidder, who believed that the Northstar project could be developed for about \$380 MM, including appraisal costs, would bid assuming the bidder's discount rate was 10% or 15% respectively. Because the results are the discounted value of real cash flows to the bidder, delaying the sale by one year, two years, or three years would only slightly increase the EMV if you assume DOR's projection of slight real growth in oil prices to be true. A bidder who believed that Northstar could be developed for \$380 MM, however, would attempt to develop a bidding strategy to obtain the NSU leases for less than the EMV.

An examination of the competition would suggest that the leases could be obtained for less than the EMV. If a prospective competing bidder determined that the project could not be developed for less than \$1.4 Billion (such as Amerada Hess did), then the project would have a negative EMV at either discount rate and the prospective competing bidder would not likely bid at the sale. Indeed, if Amerada Hess had turned the NSU leases back to the state for releasing, the Division would have expected the bonus bids to be very small at any royalty rate. Only because BPXA had the opportunity to work the project after acquiring information from Amerada Hess was BPXA able to reduce the development costs to the \$380 MM range. In sum, if a sale of the NSU leases were conducted in the future, the Division would expect bonus bids to range from a nominal amount to something less than \$225 MM depending on the royalty rate and discount rate. See attached Table.

I hope that this information is helpful to you. Please call me if you have any questions.

Sincerely,



Kenneth A. Boyd

Director

Division of Oil and Gas

# Northstar Economic Evaluation



## Expected Mean Value

	12.5% Royalty			20.0% Royalty		
	P(90)	Mean	P(10)	P(90)	Mean	P(10)
Discounted at 10%	\$173	\$225	\$281	\$137	\$182	\$231
Discounted at 15%	\$92	\$130	\$166	\$63	\$98	\$136



# Alaska State Legislature

## SENATE RESOURCES COMMITTEE

State Capitol  
Juneau AK 99801

Official Business

April 5, 1996

Mr. Ken Boyd, Director  
Division of Oil and Gas  
Department of Natural Resources

via facsimile: (907) 562-3852

Dear Mr. Boyd:

So we may better understand the relationships between the selection of lease sale bidding terms available to the Commissioner under the statutes and the size and timing of anticipated state revenues that may result, I would appreciate your written reply to the following questions before the presentation Mr. Banks is scheduled to make before the Resources Committee next Thursday.

1) What proportion of the Northstar oil reserves is estimated to underlie the State's leases in the unit?

2) According to Table 1 (Northstar Leases Information) of BP's document entitled "Northstar Project BP Exploration (Alaska) Proposal for Modified Lease Terms" (Proposal), the total bonuses received for the state's leases in the Northstar unit was \$15,469,000.

Based upon the division's ability to model bidding strategy as a function of the bidding variable selected for each sale, what would be its best estimate of the bonuses it would have received in 1979 had the leases been offered with the bonus as the bid variable, and with a 12.5 percent royalty and no net profit share instead of under the terms which the department selected?

3) Based upon the historical performance of the Permanent Fund, and your best estimate of total bonuses which would have been received under the circumstances outlined in question #2, please contrast for the committee the Permanent Fund revenues that would have resulted versus those which have occurred from the initial deposit of 50 percent of the bonuses actually received for the state leases.

4) Finally, as BP has noted on page 8 of its Proposal, in evaluating the alternative revenue stream which the state might expect were it to re-lease the Northstar leases, "[t]otal state revenues in this scenario would have to include the revenue from bonus bids on the leases." Using the model you have developed for evaluating the economics of the Northstar Agreement - or another model if you believe it would be more appropriate - please provide the committee your estimate of the bonuses you would anticipate under the following sets of circumstances:

- Bonus as the bid variable
- 12.5 percent royalty; not net profit share; 20 percent, no net profit share

- Recoverable oil reserves of 130 mmbbls; recoverable oil reserves of 160 mmbbls
- Capital and operating expenses as estimated for Northstar development and used in your existing model
- Timing of production delayed by one year, two years and three years, respectively, from the earliest date of production anticipated under the Northstar Agreement.

In addition to being prepared to discuss the state's modeling of revenues under the Northstar Agreement, I would appreciate it if Mr. Banks would be prepared to answer any follow-up questions the committee may have based on your responses to these questions.

Thank you once again for your cooperation, and that of your staff in providing this information.

Sincerely,

  
Senator Loren Lemman  
Chairman



**BP EXPLORATION**

BP Exploration (Alaska) Inc.  
900 East Benson Boulevard  
PO. Box 1966.2  
Anchorage, Alaska 99519-0612  
(907) 561-5111

April 10, 1996

The Honorable Loren Leman, Chair  
Senate Resources Committee  
Alaska State Legislature  
State Capitol  
Juneau, AK 99801

Dear Senator Leman:

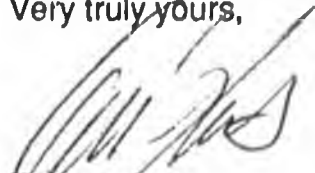
In response to the letter by Annette Kreitzer of your staff on April 5 regarding SB 318, BP provides the following information on the Northstar project and lease Agreement.:

1. Common Carrier Status of Northstar Pipeline and Estimated Tariff. The Northstar pipeline from Seal Island which will deliver sales oil to TAPS will be a regulated common carrier line. The tariff is estimated to be between \$.25- \$1.00 per barrel depending upon actual pipeline construction costs, throughput volumes, and operating expenses.
2. Acreage of Fabrication Yard. The estimated size of the required fabrication yard at the port area in Anchorage is approximately 5-10 acres.
- 3&4. Rate of Return on Late Life Field Investment with and without NPSL terms. A hypothetical incremental investment later in field life (2007) would have a rate of return of 21% without NPSL terms versus 10% with NPSLs in effect.
- 5&6. BP Comments on Net Profit Leasing Regulations (1979) and Net Profits Lease Sales (1979 and 1982) In response to your question, BP talked with parties involved in the initial NPSL legislation and regulations who recall that Sohio/BP and other companies almost uniformly opposed net profit share leasing. The industry did work with the state in drafting regulations to be workable from an accounting standpoint. They recall that while industry may not have been in supportive about the new NPSL statutory scheme, they worked with the state in order to have the regulations in place for the joint state-federal lease sale in 1979. We are continuing to review BP's files and will be happy to request the State of Alaska Department of Law for copies of comments and testimony which BP/Sohio may have provided.

April 10, 1996  
Page 2

We look forward to working with you and other members of the Senate on the Northstar legislation.

Very truly yours,

A handwritten signature in dark ink, appearing to read "E.M. Luttrell", written in a cursive style.

E.M. Luttrell  
Vice President, Exploration and Development  
BP Exploration (Alaska), Inc.



# Alaska State Legislature

## SENATE RESOURCES COMMITTEE

Official Business

State Capitol  
Juneau AK 99801

April 5, 1996

Mr. Eric Luttrell  
BP Exploration (Alaska) Inc.  
via facsimile: 564-5900

Mr. Luttrell:

During the April 3, 1996 Senate Resources Committee hearing several questions were asked and you responded that you would like to get back to the committee with the requested information.

I have listed the questions below:

- 1) Regarding the description of the island and facilities, the question was whether the pipeline would be a common carrier pipeline. Members sought additional confirmation that it is proposed to be a common carrier pipeline and the estimated dollars per barrel tariff. (You replied that Daryl Clipin could answer the question, and that you'd be able to supply the answer to the committee.)
- 2) Senator Taylor wanted to know the acreage necessary for your assembly. (This followed a discussion between Chairman Leman and you on fabrication.)
- 3) Senator Frank wanted to know if the rate of return on additional investment would always be prime. This was in reference to a discussion between you and Senator Frank on net profit leases. You clarified the question to "what would be the rate of return of late life investments in the field", and said you would "get back with a precise number".
- 4) Senator Frank wanted an example from BP of the rate of return on additional investment. (You said "we can go back and get a very simple calculation and bring it in and show it to you...")
- 5) Senator Leman wanted to know did BP participate in the rulemaking process or comment on the draft net profit leasing regulations when they were proposed by DNR.
- 6) Senator Leman wanted to know if BP ever provided testimony or formally communicated with DNR its view that the leasing provisions were not profit related before 1979 and 1982 when it successfully bid on the net profit sharing leases it owns in the Duck Island and Pt. Thomson units.

Sincerely,

  
Annette E. Kreitzer, Aide to  
Senate Resources Committee



BP EXPLORATION

BP Exploration (Alaska) Inc.  
900 East Benson Boulevard  
P.O. Box 196612  
Anchorage, Alaska 99519-6612  
(907) 561-5111

April 8, 1996

The Honorable Loren Leman, Chair  
Senate Resources Committee  
Alaska State Legislature  
State Capitol  
Juneau, AK 99801

Dear Senator Leman:

In response to your letter of April 3, 1996, BP has provided and will provide certain non-confidential and confidential information to the Alaska State Legislature in support of the negotiated agreement between BP and the Department of Natural Resources (DNR). Although a privilege of confidentiality could be asserted for much of the information, BP has willingly provided most of the information in order to facilitate a full and candid discussion of the agreement.

In addition to the substantial amount of information provided to DNR on a non-confidential basis, BP provided certain additional information (see attached list) for which it requested confidentiality pursuant to the statutory provisions you noted, namely AS 38.05.035(a)(9)(C) and (D). BP has consented to the disclosure of the following information to legislators on a confidential basis as outlined below :

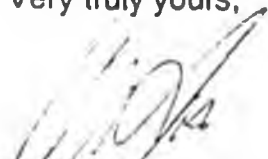
1. Purchase price paid by BP for its acquisition of Northstar from Amerada Hess. The purchase agreement between BP and Amerada Hess requires confidentiality. However, we have requested permission from Amerada Hess to disclose the purchase to the Alaska State Legislature on a confidential basis in executive session. BP will disclose this information when we have written authorization from Amerada Hess.
2. BPXA's Economic Model. DNR and/or BP will demonstrate BP's confidential economic model, which involves cost data and financial information, in an executive session. Either DNR or BP can run and Interrogate the model during the session with various scenarios requested by the legislators. However, we do not plan to leave a copy of the model with the legislature. BP is willing to work individually with any legislator to review the model and answer any questions.
3. BPXA's Approval and Sanction Process (GIAAPS) and BP's Economic Criteria (price forecasts). This is sensitive financial information which we are willing to disclose only to Alaska legislators on a confidential basis, without further disclosure to legislative advisors, consultants or staff members.

April 8, 1996  
Page 2

4. BP's NPSL Development (Investment) Account Review. BP has made an internal assessment of the NPSL Development Account which was provided to the DNR on a confidential basis. While we are willing to share that review with the Legislature, it may be more appropriate for you to ask the DNR for their review of the Development Account.

We look forward to working with you and other members of the Senate on the Northstar legislation.

Very truly yours,



E.M. Luttrell  
Vice President, Exploration and Development  
BP Exploration (Alaska), Inc.

attachment  
cc: Shively, Boyd

**NORTHSTAR PROJECT**  
**Negotiation of Modified Lease Terms**  
**BPXA Data Transmitted to DNR**

<u>Item</u>	<u>Date to DNR</u>	<u>Data for Public Release</u>
1) Northstar Project - Economic Evaluation Supplement to DNR	1/3/96	
A. Agreement for Purchase & Sale of Amerada Northstar Interest	1/11/96	NO
B. BP Preliminary Pre-acquisition Appraisal (GEM #59) See "F" below.	1/3/96	Not relevant
C. Development (Investment) Account Review	1/3/96	NO
D. BP Northstar AFEs	1/3/96	YES
E. BP Expenditures	1/3/96	YES
F. Draft Conceptual Eng. Report and Geology Final report issued in February, 1996	1/3/96	YES
G. Tract Allocation	1/3/96	YES
H. BP Approval and Sanction Process (GIAAPS)	1/9/96	NO
I. BP Economic Criteria (Price forecasts)	1/9/96	NO
J. BP/DNR Economic Model (Excel ss)	1/3/96	NO
K. Partner Economics	Not supplied	
L. Early Assessment of Risks and Reserves	1/3/96	Not relevant
M. Federal Royalty Relief Efforts	No data available	
N. Alaska Expenditures	No data available at the time	
2) Various BP and DNR Proposals on Modified Lease Terms and Draft Agreements	12/95-3/96	Not relevant



# Alaska State Legislature

## Senate Resources Committee

Official Business

State Capitol  
Juneau AK 99801

April 3, 1996

Commissioner John Shively  
Department of Natural Resources  
via fax: 465-3886

Dear Commissioner Shively:

I anticipate BPXA may ask that part of our review of the economics supporting the negotiated agreement between BPXA and the administration be conducted in executive session. Rule 22(b)(1)-(3) of the Uniform Rules of the Alaska State Legislature provides that:

A legislative body may call an executive session at which members of the general public may be excluded for the following reasons:

- (1) discussion of matters, the immediate knowledge of which would adversely affect the finances of a government unit;
- (2) discussion of subjects that tend to prejudice the reputation and character of a person;
- (3) discussion of a matter that may, by law, be required to be confidential.

Similarly, the Open Meetings Guidelines adopted by the Senate provide parallel provisions and requirements for executive sessions.

Testimony before this committee has established that the Department of Natural Resources is not opposed to public discussion of any of the material supporting its negotiations to amend the net profit share provisions of the Northstar leases.

BPXA, however, may decide to claim the privilege of confidentiality for certain of the information, and may ask that the committee review the information in executive session. Presumably BPXA would base its entitlement to confidentiality on the provisions of AS 38.05.035(a)(9)(C) and (D) which provide:

- (a) The director shall....
  - (9) maintain such records as the commissioner considers necessary, administer oaths and do all things incidental to the authority imposed; the following records and files shall be kept confidential upon request of the person supplying the information:
    - (C) all geological, geophysical and engineering data supplied, whether or not concerned with the extraction or development of natural resources;
    - (D) except as provided in AS 38.05.036, cost data and financial information submitted in support of applications, bonds, leases and similar items;

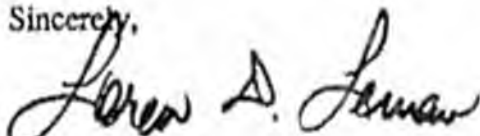
You, Governor Knowles, and BPXA President John Morgan have all said that you support full and candid discussion of the negotiations and the policy implications behind the legislature's decision of whether or not to ratify the agreement. To assure that the review is public, yet thorough, only that information which must be kept confidential by law will be treated as confidential.

Accordingly, before the committee votes to go into executive session, BPXA's representative should confirm that BPXA is indeed requesting confidentiality, and ~~to~~ state the statutory basis for the request.

DNR's representative should be prepared to certify that the information to be discussed is entitled to confidentiality under the department's statutes and regulations.

Thank you for your participation in these hearings.

Sincerely,



Senator Loren Leman  
Chairman