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North Star Unit

Briefing Paper

March 1996



North Star Unit

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March 1996



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
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March 29, 1996

The Honorable Drue Pearce
President of the Senate
State Capitol, Room 111
Juneau. Alaska 99801-1182
MS 3101

The Honorable Gail Phillips
Speaker of the House
State Capitol, Room 208
Juneau, Alaska 99801-1182
MS 3101

Dear President Pearce and Speaker Phillips:

The Governor recently transmitted a bill to you authorizing, approving, and ratifying the "First amendment to the Northstar Unit oil and gas leases between the State of Alaska and BP Exploration (Alaska) Inc. (BPXA)" The Department of Natural Resources (DNR) is providing you with this briefing paper in the hope that you will find it useful in your consideration of the bill.

This paper gives a brief history of the Northstar Unit and describes some of the changes in circumstances which have occurred since the state issued the Northstar leases and have led the administration to seek legislative approval of certain amendments to the leases, primarily the monetary terms. The Northstar Unit is composed of five state and two federal oil and gas leases located in the Beaufort Sea about six miles from Prudhoe Bay. It is the only joint state/federal unit in Alaska. According to BPXA and others, one of the primary deterrents to development of the unit is the high state net profit share

(NPS) which is in addition to the 20% royalty share. The state leases currently bear both the highest reserves-weighted royalty, 20%, and NPS, 89%, of any unit in the state. The amendments would remove the NPS terms of the leases and replace them with a supplemental royalty which would vary depending on oil prices. Also, BPXA has guaranteed that the base royalty of 20% would remain unchanged for the life of the field.

During the period from 1979 to 1983 when the state leased the Northstar Unit leases, optimism reigned in the oil industry in general and the North Slope oil industry in particular. Furthermore, the Northstar prospect was one of the state's best with some estimates exceeding a billion barrels of recoverable reserves. During this time frame, both industry and the state Department of Revenue (DOR) were predicting North Slope oil prices escalating to $70 to $100 per barrel by now. Adding to the mix was the legislature's authorization in 1978 of several new leasing methods, including using a NPS as a bid variable.

The first North Slope lease sale after the authorization to use a NPS method was the joint state/federal Beaufort Sea lease sale 30 held in December of 1979. The four state leases currently in the Northstar Unit were offered under the following terms: fixed cash bonus, 20% fixed royalty, and the NPS as the bid variable. In keeping with the prevailing optimism, industry bidding was very competitive with the winning NPS bids ranging from 85.26% to 93.2% on the four leases. The two federal leases in the unit were also leased at the joint sale carrying a 16.67 sliding scale royalty. The bonus bids for the two tracts exceeded $80 million. Sale 30 was the only time that state leases were offered with the NPS as the bid variable.

The fifth state lease in the unit was offered as part of sale 39 held on May 17, 1983. The DOR was still predicting ANS oil prices rising at roughly a 5.9% nominal rate to $72.32 in fiscal year 1999 (when BPXA is currently stating it will begin Northstar production). The lease was offered with a cash bonus as the bid variable, a 12.5% fixed royalty, and a fixed 40% NPS. The lease received three bids with a winning bid

of $72 thousand. BPXA's analysis of the field currently has no oil reserves within the unit allocated to this lease.[1]

Northstar Exploration efforts began in 1982. Amerada Hess Corporation (AHC) held the largest working interest in Northstar leases and was the operator. The working interest owners drilled the first exploratory well in 1983 which discovered hydrocarbons in the Ivishak Formation, the same formation that produces the majority of oil in the Prudhoe Bay field. Unfortunately, further exploratory drilling only served to reduce the size of potential reserves.

By 1993, publicly available data pegged the high side for potential reserves at 300 million barrels. In a 1993 study, the United States Department of Energy (DOE) concluded that Northstar "with the NP[S] in place is not economic for any of the oil price cases." The DOE's economic analysis was based upon capital costs of $1.4 billion, a "conservative" estimate of 200 million barrels of recoverable reserves, and higher oil prices than those forecasted by the DOR today. The DOE study stated that the "greatest deterrents to the development of [Northstar] are confirmation of reserves and the high net profit [share] applicable to the five state tracts." The study emphasized the deterrent to development caused by the NPS provisions stating they "add a very significant burden to the economic viability of [Northstar]." Even before the DOE study, AHC had approached the Cowper administration about economic relief for Northstar, but was rebuffed.

Despite the increasingly pessimistic picture, AHC and its partners drilled one more well in the Northstar Unit in 1994. The results were not as good as hoped for, and reserve estimates dropped to the current most likely estimate of 130 million barrels. AHC and

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[1]The next (and last) time the state offered leases with a NPS was the following year in 1984. There are currently 39 active leases on the North Slope with a NPS. Only nine have production allocated to them. None have ever paid a NPS to the state.

its partners elected not to pursue the development of the project. Their decision not to develop was based on the results of the 1994 drilling program, a reservoir analysis, and the project economics.

Following the decision not to develop, AHC and its partners attempted to sell their interests to several prospective purchasers. By the end of 1994, BPXA had acquired at 98.08 % interest in the unit with Murphy Oil retaining a 1.92% interest.

Using innovative technical approaches and contractor alliances with Alaskan companies, BPXA has reduced the former estimated capital costs from about $1.5 billion to only $350 million. However, the deterrent to development identified by the DOE, the NPS, remained. BPXA has informed the DNR that it "would not develop Northstar under these [NPSL] terms" and maintains that it "cannot risk its reputation for prudent, world class development practices " with late life NPSL problems which have a "high potential for premature field shut-in and revenue cessation ...." BPXA's exposition of its NPSL problems are set forth in its Proposal and will not be repeated.

As a result of BPXA's problems with the lease's NPS provisions, it approached me about modifying the lease terms in the spring of 1995. At that time they generally proposed an alternative which would remove the NPS provisions in exchange for early, certain development and some form of additional payment to the state. I instructed the DNR staff to enter negotiations with BPXA to see if an alternative could be reached which would remove the perceived NPS problem, yet provide more certain, earlier development, yield adequate compensation to the state, and set a goal of more Alaska contracting and hiring. Additionally, I did not want an alternative which resulted in any significant increase to BPXA's own estimate of a rate of return of 21% for the Northstar project.

Given the expected rate of return, I cannot say that the Northstar project is a marginal one. I, however, believe BPXA's assertion that they will not develop the project under the existing NPS terms. You will have to make your own judgment about that.

If you believe that they will not develop the project, I believe that you will determine, as I have, that the amendments negotiated by the DNR and BPXA to the Northstar Unit leases are in the best interests of the people of the State of Alaska. First, I would like to share the DNR's economic evaluation with you. If one assumes that BPXA would develop the field anyway with the NPS in place under the same expedited schedule as BPXA currently proposes with full production starting in early 1999 and compares that assumption with the same scenario but with a supplemental royalty in place, the evaluation shows that BPXA's rate of return remains virtually unchanged while the state receives $37 million in supplemental royalty compared to $85 million in NPS.[2] If one assumes that BPXA would not develop the field on an expedited basis, full production would not begin until 2002 at the earliest, as predicted by the DOR, and the NPS would be in place, and compares those assumptions with an assumption of full production in early 1999 with the supplemental royalty in place, the evaluation shows that BPXA's rate of return is slightly lower while the state receives $37 million in supplemental royalty compared to $41 million, only a $4 million difference. Obvicusly, if one assumes that development would occur, after 2002, the state would receive more under the supplemental royalty method than the NPS method.

Second, I would like to explain some of the other aspects of the amendments which I believe are beneficial to the state. The state is trading more speculative development and revenues for more certain development and revenues. The revenues and economic benefits to the state, which are substantial, will obviously be received sooner. Estimated state revenues are $435 million. In addition, the North Slope Borough will

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[2]I had earlier reported to you that the NPS figure was $95 million, leaving a roughly $60 million difference. Since that report an error in the model relating to the calculation of abandonment costs was fixed and the NPS figure is $85 million, leaving a roughly $50 million difference.

receive an estimated $42 million in ad valorem taxes. The state will be guaranteed the highest royalty rate of any producing field for the life of the field since BPXA has agreed to never seek royalty reduction. Moreover, because of the increased oil volume through TAPS, the per barrel TAPS charge will likely decrease benefiting all North Slope fields and extending the life of TAPS. In addition to state economic benefits, the project will provide substantial revenues to the federal government.

The amendments seek to insure this early development through a "use it or lose it" provision. If BP does not receive project sanction from their Board of Directors within one year after legislative approval, they must return all of the Northstar leases, including the leases containing certified wells. The leases could then be released. Absent this provision, BPXA would be able to hold all of the leases until at least May of 1998 and some for longer.

Importantly, this project will result in the employment of the people of our state. The Alaska Institute of Social and Economic Research and BPXA have estimated that the project will create 500 direct construction jobs, approximately the same number of indirect jobs, and up to 100 permanent operation jobs within the state. These jobs would have a statewide benefit. Further, BPXA has committed to the administration and the legislature to fabricate and assemble larger modules in Alaska if facilities are available to build them. The commitment is valued at $40 to $50 million. This commitment will help Alaska fabrication firms to expand their operations to accommodate this project as well as other future development. The terms of the agreement call for BPXA to employ Alaska residents or contractors. BPXA also voluntarily agrees to adopt a program to hire Alaska residents including advertising locally and using Alaska job service organizations. Furthermore BPXA has agreed to "use best efforts to contract with Alaska firms and fabricate modules in Alaska, whenever feasible." The project will also have unquantifiable benefits. Northstar will be the first truly offshore Arctic development including the first Arctic subsea oil pipeline. Northstar could be used as a model for other small offshore North Slope field

developments. If it demonstrates feasibility, it could increase the bonus bids at future state lease sales.

In sum, I believe that the amendments will provide the state substantial benefits while requiring that it give up little. I believe that the amendments are in the state's best interests. The administration seeks your help in making the Northstar project a certainty. My authority under current law to grant the relief requested is questionable. The Department of Law has concluded that the prudent course of action is to seek the legislature's approval of the amendments deleting the NPS provisions of the Northstar Unit leases. I welcome a candid and public debate regarding the amendments and urge your favorable consideration. The alternative is delay and uncertainty.

Sincerely,

John T. Shively
Commissioner

INDEX

1. Northstar Locator Map

2. Field History
   a. Attachments
   b. Correspondence

3. 1979 & 1983 Lease Sale Results

4. 1980 & 1983 Northstar Leases

5. A. Tussing, Reflections on the End of the OPEC Era (ISER 1982)

6. Excerpts from DOR Quarterly Petroleum Production Revenue Forecast for 6/79, 9/79, 12/79 & 3/83

7. Status of NPS Leases and NPS Location Map

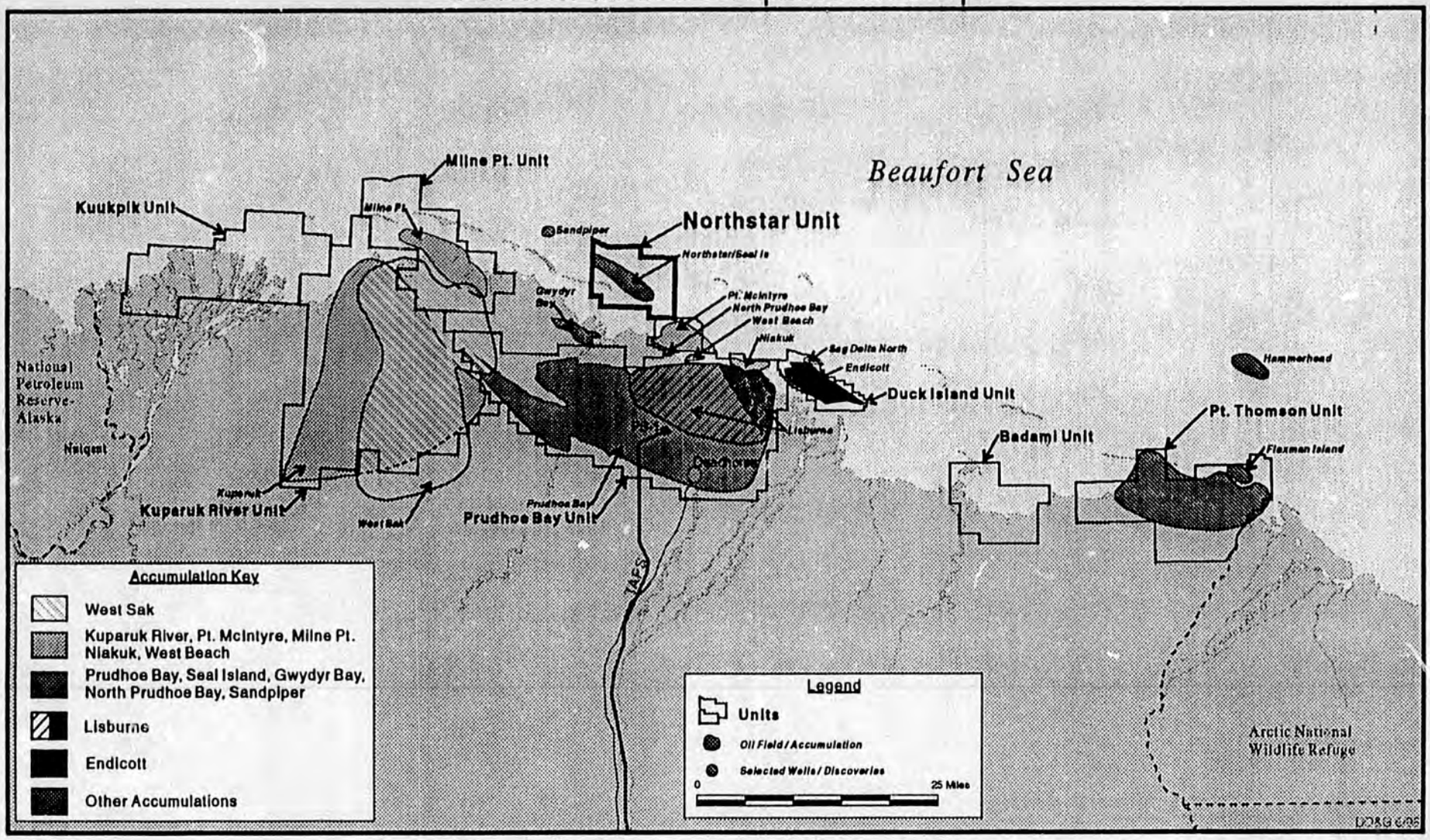
8. Excerpts from Alaska North Slope National Energy Strategy Initiative: Analysis of Five Underdeveloped Fields (U.S. DOE 1993)

9. DNR Northstar Economic Analysis
   a. Tables
   b. Graphs

10. Legal Opinion regarding Authority
    a. DOL Opinion (March 26, 1996)
    b. LAA Opinion (March 25, 1996)
    c. Kenai Lumber Co., Inc. v. LeResche, 646 P.2d 215 (Alaska 1982)

11. Northstar Lease Amendments

Central North Slope Unit Map



STATE OF ALASKA

TONY KNOWLES, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

3601 C STREET, SUITE 1380
ANCHORAGE, ALASKA 99503-5948
PHONE: (907) 762-2549

History of the Northstar Unit

The Northstar Unit (NSU) includes five State of Alaska oil and gas leases covering approximately 23,343 acres and two federal outer continental shelf oil and gas leases covering approximately 7494 acres. The leases are located approximately 8 miles from shore and 23 miles from Pump Station No. 1 in water 40 feet deep. The NSU is the first unit in Alaska's Beaufort Sea to be jointly managed by the State of Alaska, Department of Natural Resources (DNR) and the federal Minerals Management Service (MMS). All of the NSU leases were issued as a result of either the Joint State/Federal Beaufort Sea Lease Sale held on December 12, 1979, or the state Lease Sale No. 39, Beaufort Sea, held on May 17, 1983.

Four of the five state leases were issued on state lease form DMEM-1-79A (Net Profit Share). The four leases acquired in the joint state/federal sale, were BF-46 (ADL 312798), BF-47 (ADL 312799), BF-56 (ADL 312800), and BF-57 (ADL 312809). They were offered under the following lease sale terms: fixed $875/acre bonus, 20% royalty, and a variable NPS (the bid variable). The remaining State lease was issued on State of Alaska lease form DMEM-4-83 (Net Profit Share). The fifth state lease, 39-01 (ADL 355001), was offered under the following terms: bonus (bid variable), $10/acre minimum bid, 12.5% royalty, and a 40% NPS. All of the NSU state leases involved include a net profit share as well as a royalty share.

The NSU outline is shown in Attachment 1. The original working interest owners (WIOs) in the NSU were the Amerada Hess Corp. (AHC), Enterprise Oil, Murphy Oil USA, and Shell Oil (SWEPI). In 1990, AHC acquired Enterprise Oil's interest in the unit for $2 million. The participating interest is shown in Attachment 2.

A joint exploratory agreement among the original WIOs resulted in the construction of an offshore gravel island, Seal Island, on ADL 312799 in 1982. From Seal Island, in 1983, the WIOs drilled BF-47 #1 (Seal #1), which discovered hydrocarbons in the Ivishak Formation, the same formation as the primary producing horizon in the Prudhoe Bay field. A confirmation well, OCS-Y-181 #1 (Seal #2), was drilled in 1984 and was followed by another confirmation well, BF-57 #1 (Seal #3), which was completed in 1985. In that same year, however, OCS-Y-180 #1 (Seal #4) drilled on Amoco's federal lease, was a dry hole.

In 1985-1986, Amerada Hess constructed another gravel island in the unit area, Northstar Island on ADL 312798, and drilled a stepout well, BF-46 #1 (Northstar #1), to the northwest. BF-46 #2 (Northstar #2) was also drilled in 1986, but was abandoned due to downhole mechanical problems. To date, a total of six wells have been drilled into the Ivishak Formation within and adjacent to the NSU. Attachment 3 shows the unit area with the Ivishak wells within the NSU.

The NSU Agreement was approved with a five year plan of development that required specific work commitments throughout the initial five-year term of the unit (see Attachment #4 and #5). The initial term of the unit coincided with the five year plan of development (POD); that is, January 24, 1990 through January 23, 1995. As part of receiving State approval of the NSU, the State lessees were permitted to make progressively larger annual payments to the State in lieu of drilling a well during the initial POD. The extension fee payments were to be paid by the State lessees to the State, unless the fee obligation was extinguished by the drilling of a well within the unit area. The payment schedule was: (1) January 31, 1991 - $1 million ; (2) January 31, 1992 - $2 million; (3) January 31, 1993 - $2 million; (4) January 31, 1994 - $3 million; and (5) January 31, 1995 - $4 million. Since AHC did not drill the Northstar #3 well until early 1994, their total extension fee payment amounted to $5 million.

Including the state leases in the NSU agreement effectively extended the five state leases past their primary term. See ADL 312799, paragraph 5(b) and ADL 355001, paragraph 4(b). Absent inclusion in a unit, the two leases without certified wells on them would automatically terminate on February 1, 1990 for ADL 312799, and on August 1, 1993 for ADL 355001. See ADL 312799,

paragraphs 3, 4 and 5; and ADL 355001, paragraphs 3 and 4. The leases with certified wells would continue in effect unless the state ordered the WIOs to produce them and the WIOs did not do so within a reasonable time which could not be less than six months. See ADL 312799, paragraph 5(d) and ADL 355001, paragraph 4(d). Following a reasonable period of time, the state would have to institute a legal proceeding to terminate those leases. See ADL 312799, paragraph 28, and ADL 355001, paragraph 20. The state leases with wells certified capable of production in paying quantities are ADL 312798 (Northstar #1), ADL 312799 (Seal #1), and ADL 312809 (Seal #3). So long as the WIOs complied with the NSU Agreement, including its POD, none of the leases would terminate.

In early 1994, AHC drilled an Upper Kuparuk "C" Sand prospect within the NSU. This well, Northstar #3, was plugged and abandoned. This was the only well drilled within the NSU since the Northstar #1 and # 2 wells in 1986. During initial unit term, AHC always complied with the NSU POD. The work commitments were performed on time and the results of the petrological/petrophysical, production facilities design, and reservoir engineering studies were provided to the agencies.

After drilling the Northstar #3 well, AHC and its partners elected not to pursue the development of the NSU. Their decision not to develop was based on the results of the 1994 drilling program, an analysis of the reservoir, and the project economics. In June of 1994, AHC briefed the DNR and the MMS on its decision. See correspondence. As both islands, Northstar and Seal, experienced severe damage during the 1993-1994 winter, they decided to abandon the islands. The abandonment of the islands took place in July-August 1994.

Following the decision not to develop the NSU, AHC and Shell Frontier Oil & Gas Inc. (SFOGI) attempted to sell their interests to several prospective purchasers. Correspondence. Also in late 1994, DNR sent AHC a notice of default. Correspondence. Also in late 1994, BP Exploration (Alaska) (BPXA) entered into discussions with AHC and SFOGI for acquisition of a working interest and operatorship of the NSU. By the end of February 1995, agreements were reached with

AHC for their 80.85% interest and SFOGI's 17.23 % interest in the NSU. Correspondence. The current working interest ownership in the NSU is BPXA 98.08% and Murphy Oil 1.92%.

On January 13, 1995, BPXA requested the DNR and MMS approve a ninety-day extension to the notice of default, Attachment 14. Effective January 19, 1995, the DNR approved assignments of the state leases from AHC to BPXA. Correspondence. On January 20, 1995, both the DNR and MMS approved BPXA as successor to AHC as unit operator. Correspondence. On January 24, 1995, the DNR and MMS approved the request for an extension. Correspondence.

On January 23, 1995, the day the NSU was to expire, BPXA, as the new NSU operator, submitted a proposed two-year POD for the NSU. BPXA stated that with more time it could submit a more detailed and decisive plan. BPXA's request for an extension to file another POD was approved by both the DNR and the MMS until April 30, 1995, to allow BPXA additional time to conclude its acquisition of SFOGI's and Murphy's interest (Murphy did not sell its interest) in the NSU and to formulate a new POD. The DNR's approval was conditioned on BPXA making its technical staff available to DNR's representatives and working with the DNR and the MMS to find an acceptable NSU POD during the extension period. Correspondence.

On March 30, 1995, BPXA submitted the revised POD and a request to extend the NSU Agreement for a three-year term coincident with the POD term. Correspondence. The revised POD and extension until April 30, 1998 was approved by the MMS on May 1, 1995 and conditionally approved by the DNR on June 2, 1995. Correspondence. As part of the conditional approval, BPXA was required to submit annual program reports and a final report to the agencies that synthesizes the data and studies performed by BPXA during the extension period and BPXA's conclusions and recommendations regarding the development of the NSU. Correspondence. The POD does not require BPXA to start production during the three-year term. Assuming BPXA complies with all of the conditions of the second POD, the unit will not expire until April 30, 1998.

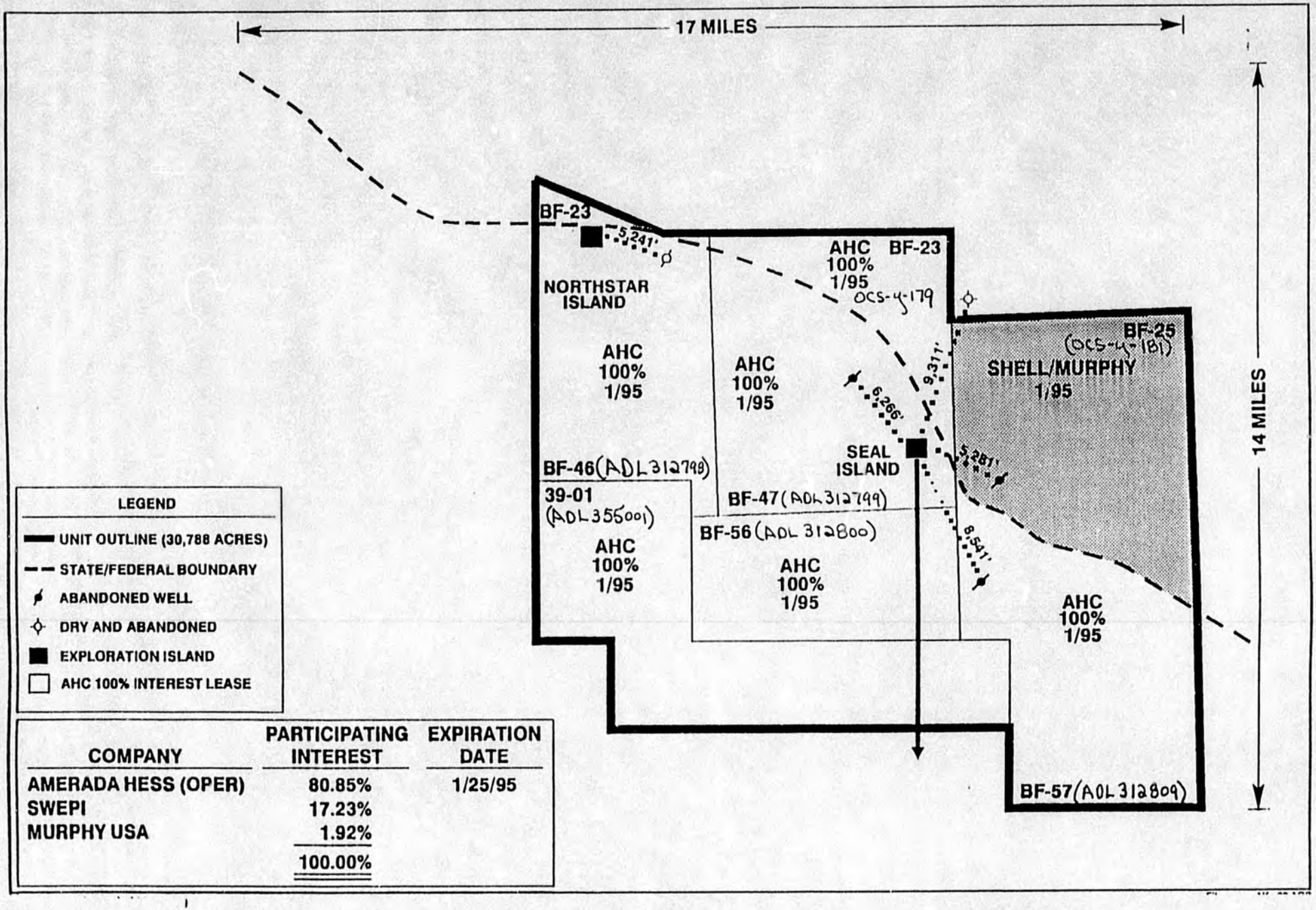
Attachments

032896.pc

Field History
Attachments

AMERADA HESS CORPORATION
UNITED STATES EXPLORATION AND PRODUCTION

NORTHSTAR UNIT



COMPANY	PARTICIPATING INTEREST	EXPIRATION DATE
AMERADA HESS (OPER)	80.85%	1/25/95
SWEPI	17.23%	
MURPHY USA	1.92%	
	100.00%	

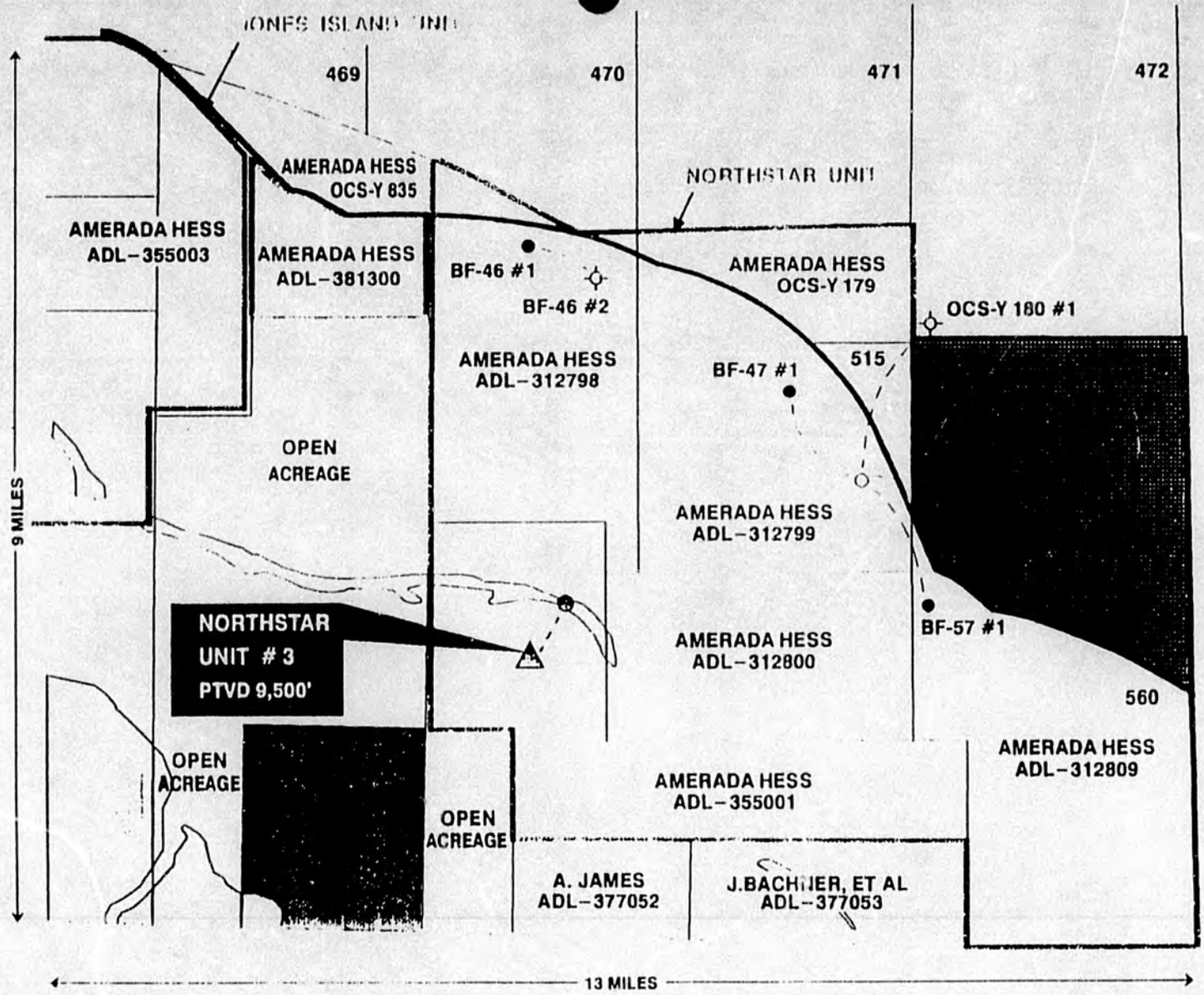
ATTACHMENT 1

AMERADA HESS CORPORATION
UNITED STATES EXPLORATION AND PRODUCTION
NORTHSTAR UNIT

UNIT LEASEHOLD

LINE NO.	LEASES	COMPANY	AHC WORKING INTEREST	ACREAGE	ROYALTY	NET PROFIT INTEREST	MEMO: ORIGINAL BONUS ($ 000'S) AHC	MEMO: ORIGINAL BONUS ($ 000'S) OTHERS
	A	B	C	D	E	F	G	H
	STATE							
1	BF-46	AHC (1980)	100%	4,343	20.0%	93.2%	$ 3,844	$ 0
2	BF-47	AHC (1980)	100%	4,472	20.0%	91.2%	3,913	0
3	BF-56	AHC (ENTERPRISE - 1990)	100%	3,433	20.0%	85.3%	1,000	3,000
4	BF-57	AHC (ENTERPRISE - 1990)	100%	5,301	20.0%	85.3%	1,000	4,640
5	39-01	AHC (1983)	100%	5,744	12.5%	40.0%	574	0
6	SUBTOTAL			23,293			10,331	7,640
	FEDERAL							
7	BF-23	AHC (AMOCO - 1989)	100%	2,252	16.7%	0	0	20,200
8	BF-25	SHELL/MURPHY	0	5,243	16.7%	0	0	60,890
9	SUBTOTAL			7,495			0	81,090
10	TOTAL			30,788			$10,331	$ 88,730

ATTACHMENT 2





LEGEND

WELL INFORMATION	LEASE INFORMATION
OIL WELL	AHC
DRY HOLE	ARCO, ETAL
SURFACE LOCATION	SHELL / MURPHY
BOTTOM HOLE	UNIT OUTLINE
	ACREAGE ELIGABLE FOR EXTENSION

AMERADA HESS CORPORATION

UNITED STATES EXPLORATION AND PRODUCTION

AMERADA HESS CORPORATION
UNITED STATES EXPLORATION AND PRODUCTION

NORTHSTAR UNIT PLAN OF DEVELOPMENT

COMMITMENTS	1990	1991	1992	1993	1994	1995	ESTIMATED PROJECT COSTS ($ MILLIONS) GROSS
EXPIRATION						▼	
MAINTAIN ISLANDS	$1.4	$1.1	$1.0	$.1	$5.0		$ 8.6
PETROLOGICAL/PETRO-PHYSICAL STUDIES	$.1	$.1					0.2
PRODUCTION FACILITIES DESIGN		$.4					0.4
SEISMIC PROGRAM		$1.8	$.7				2.5
SEISMIC MAPPING							—
RESERVOIR ENGINEERING STUDIES							—
SYNTHESIS AND FINAL PLANS					$.1		0.1
DRILLING DELAY PAYMENT		$1	$2	$2			5.0
DRILL – NORTHSTAR #3				$.2	$6.0		6.2
TOTAL – $ MILLIONS	$1.5	$4.4	$3.7	$2.3	$11.1	$0.0	$23.0

LEGEND

COMPLETED ACTUAL PLANNED ▼ EXPIRATION 1/25/95

ATTACHMENT 4

AMERADA HESS CORPORATION
UNITED STATES EXPLORATION AND PRODUCTION
NORTHSTAR UNIT

FIVE YEAR PLAN OF DEVELOPMENT

WORK COMMITMENTS	TIMING START	TIMING COMPLETE	ISSUES	PROJECT COSTS ($ MILLIONS)
1. MAINTAIN ISLANDS	AUG 1990	SEP 1994	SECURITY OF WELLS	$ 8.6
2. PETROLOGICAL/PETROPHYSICAL STUDIES	MAR 1990	DEC 1991*	LOG VALUES INCONSISTENT WITH PRODUCTION TESTS	0.2
3. PRODUCTION FACILITIES DESIGN	MAR 1990	DEC 1991*	UPDATE COSTS AND INCORPORATE LATEST TECHNOLOGY	0.4
4. SEISMIC PROGRAM	AUG 1991	MAR 1992	ASSESS RESERVES AND WELL LOCATIONS	2.5
5. SEISMIC ANALYSIS AND INTERPRETATION	OCT 1991	NOV 1992	ASSESS RESERVES AND WELL LOCATIONS	-
6. RESERVOIR ENGINEERING STUDIES	JUL 1992	JUN 1994	DETERMINE MAXIMUM RESERVE POTENTIAL	-
7. FINAL PLANS	MAR 1994	OCT 1994*	EXTEND OR DROP LEASES OR DEVELOP	0.1
			SUBTOTAL	$11.8
8. DRILLING DELAY PAYMENT				5.0
9. DRILL NORTHSTAR NO. 3				6.2
			TOTAL	$23.0

* REGULATORY AGENCY REVIEW

ATTACHMENT 5

Field History
Correspondence

Bin - FYI
Mike - Unit files

AMERADA HESS CORPORATION

J. V. SIMON
MANAGER CONSTRUCTION

1201 LOUISIANA, SUITE 700
HOUSTON, TEXAS 77002-5681
713-752-5820
713-752-5657

RECEIVED
OCT 24 1994
DIVISION OF OIL & GAS

October 18, 1994

Department of Natural Resources
Attention: Mr. James E. Eason
P. O. Box 107034
Anchorage, Alaska 99510-7034

Re: Northstar Unit
Plan of Development

Gentlemen:

It has been brought to our attention that your agency has inquired as to Amerada Hess Corporation 's (AHC) submittal of the final plan for the Northstar Unit during October 1994, as in accordance with the five year Plan of Development governing the Unit.

During our meeting held June 8, 1994 with representatives from your agency, Minerals Management Service, and the Alaska Oil and Gas Conservation Commission, AHC presented the results of its 1994 drilling program, analysis of the reservoir, and the project economics which resulted in AHC and its partners' determination not to develop the Unit. Since said meeting both the Seal and Northstar Islands have been abandoned and site clearance has been received from the respective agencies.

As a result of AHC and its partners decision not to develop the Northstar Unit, AHC has begun preliminary discussions with BP Exploration (Alaska) Inc. regarding a possible sale of our interest in the Unit. Pending the outcome of our discussions with BP, relief on the pending Unit expiration of January 25, 1995 may be requested from the agencies involved.

If you have any questions please advise.

Sincerely,

J. V. Simon

LBT:ja/455

cc: Minerals Management Service
Attention: Mr. Jeff Walker
949 E. 36th Avenue, Room 603
Anchorage, Alaska 99508-4302

Alaska Oil and Gas Conservation Commission
Attention: Mr. David W. Johnson
3001 Porcupine Drive
Anchorage, Alaska 99501-3192

WALTER J. HICKEL, GOVERNOR

DEPT. OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

P.O. BOX 107034
ANCHORAGE, ALASKA 99510-7034
PHONE: (907) 762-2553

(907) 762-2547

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

November 3, 1994

Amerada Hess Corporation
1201 Louisiana, Suite 700
Houston, Texas 77002-5681

Attn: Mr. J. V. Simon
Manager, Construction

Re: Northstar Unit
Notice of Default

Dear Mr. Simon:

The Division of Oil and Gas is in receipt of your letter dated October 18, 1994 regarding an updated Plan of Development (POD) for the Northstar Unit (NSU), and AHC and its partners' determination not to develop the NSU. Please be advised that failure to provide an updated POD on or before October 25, 1994 constitutes a default of the NSU Agreement per Articles 8.1 and 20.1 of the NSU Agreement and 11 AAC 83.343.

Pursuant to Article 20.2 of the NSU Agreement, this is notification of default of the Unit Agreement. Further, AHC and its partners may cure the default by (1) providing an updated POD within fifteen (15) days of receipt of this notice, or (2) voluntarily terminating the NSU Agreement per the provisions of Article 14.6 within fifteen (15) days of receipt of this notice.

If you have any questions or foresee any problems complying with the proposed default cure, please contact Mike Kotowski at (907) 762-2546.

Sincerely,

James E. Eason
Director

cc: Patrick Coughlin
Carol Lee
Jeff Walker - MMS

NSU.Default Notice.ltr

P 234 058 452

RECEIPT FOR CERTIFIED MAIL
NO INSURANCE COVERAGE PROVIDED
NOT FOR INTERNATIONAL MAIL
(See Reverse)

Sent to: Amerada Hess Corp
Attn: J. V. Simon
Street and No.: 1201 Louisiana, Ste 700
P.O. State and ZIP Code: Houston, TX 77002
Postage
Certified Fee X
Special Delivery Fee
Restricted Delivery Fee
Return Receipt Showing to Whom and Date Delivered
Return Receipt Showing to Whom, Date, and Address of Delivery
TOTAL Postage and Fees
Postmark or Date: 11/4/94

PS Form 3800, June 1985 * U.S.G.P.O. 1985-480-794

SENDER: Complete items 1 and 2 when additional services are desired, and complete items 3 and 4.
Put your address in the "RETURN TO" Space on the reverse side. Failure to do this will prevent this card from being returned to you. The return receipt fee will provide you the name of the person delivered to and the date of delivery. For additional fees the following services are available. Consult postmaster for fees and check box(es) for additional service(s) requested.
1. ☐ Show to whom delivered, date, and addressee's address. *(Extra charge)* 2. ☐ Restricted Delivery *(Extra charge)*

3. Article Addressed to:
Amerada Hess Corp.
Attn.: JV Simon
1201 Louisiana, Ste 700
Houston, TX 77002

4. Article Number
P 234-058-452

Type of Service:
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

Always obtain signature of addressee or agent and DATE DELIVERED.

5. Signature — Addressee

6. Signature — Agent
X Billy Riddle

7. Date of Delivery
11-7-94

8. Addressee's Address *(ONLY if requested and fee paid)*

RECEIVED
NOV 14 1994
DIVISION OF OIL & GAS

PS Form 3811, Apr., 1989 *U.S.G.P.O. 1989-238-815 DOMESTIC RETURN RECEIPT

AMERADA HESS CORPORATION

J. Y. CHRISTOPHER
OFFSHORE LAND MANAGER

500 DALLAS STREET
POST OFFICE BOX 2040
HOUSTON, TEXAS 77002-2040
713/609-5870
713/609-5608 (FAX)

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NOV 23 1994
DIVISION OF OIL & GAS

November 15, 1994

State of Alaska
Department of Natural Resources
Division of Oil and Gas
Attention: Mr. Mike Kotowski
P. O. Box 107034
Anchorage, Alaska 99510-7034

Re: Northstar Unit
Notice of Default

Gentlemen:

Amerada Hess Corporation (AHC) is in receipt of your letter of November 3, 1994 notifying AHC of its default of certain provisions of the Northstar Unit Agreement.

As advised in our meeting held on June 8, 1994 and AHC's letter of October 18, 1994, AHC and its partners elected not to pursue the development of the Northstar Unit, but only after diligent efforts to explore the unit were conducted in compliance and in fulfillment of the approved plan of development.

As previously advised, AHC is attempting to dispose of its interest in the Northstar Unit. AHC requests the State allow the Unit to be maintained until the expiration of the plan on January 23, 1995.

Thank you.

Sincerely,

J. Y. Christopher

LBT:526

Shell Frontier Oil & Gas Inc.
An affiliate of Shell Oil Company

P. O. Box 576
Houston, TX 77001

FAX & CERTIFIED MAIL

November 17, 1994

Mr. Mike Kotowski
State of Alaska
Department of Natural Resources
P. O. Box 107034
Anchorage, AK 99510-7034

Dear Mr. Kotowski:

SUBJECT: NOTICE OF DEFAULT - NORTHSTAR UNIT
C/AK/998/80/150
NORTHSTAR UNIT
BEAUFORT SEA, ALASKA

In response to the subject captioned notice to Amerada-Hess (Northstar Unit Operator) dated November 3, 1994, Shell Frontier Oil & Gas Inc. ("SFOGI"), as a working interest owner in the subject unit wishes to express our sincere concern over the possible outcome of noncompliance related to this default by the operator. Our understanding is that pursuant to State regulations, ninety (90) days prior to expiration of a current Plan of Development ("POD"), the unit operator is required to file a revised POD, however, we view this as an option and not as an obligation. If the State views this as an obligation, could this result in an early expiration of the current approved 5 year POD and in turn, the unit termination? We would appreciate your clarification of this issue. SFOGI feels that any action not allowing the unit to terminate consistent with the approved 5 year plan of development, which provides for a termination date of January 23, 1995, could significantly limit possible alternative development opportunities for the unit, which ultimately might benefit the State and MMS. SFOGI is involved in current negotiations with a third party for the possible transfer of our interest, which in turn could result in potential development at some future date. If the unit is allowed to terminate before January 23, 1995, then this option will most likely terminate with it.

We appreciate your advice and careful consideration on this issue. In the interim, should you have any questions or require additional information, please feel free to contact the undersigned at (713) 544-3195.

Sincerely,

D. B. Champlin
As Agent For Shell Frontier Oil & Gas Inc.

DBC:dbc

sfogi.doc

TONY KNOWLES, GOVERNOR

DEPT. OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

P.O. BOX 107034
ANCHORAGE, ALASKA 99510-7034
PHONE: (907) 762-2553

(907) 762-2547

December 12, 1994

Via Fax and Certified Mail

Amerada Hess Corporation
1201 Louisiana, Suite 700
Houston, Texas 77002-5681

Attn: Mr. J. Y. Christopher
Offshore Land Manager

Re: Northstar Unit
Amended Notice of Default

Dear Mr. Christopher:

The November 3, 1994 North Star Unit (NSU) Notice of Default to the Amerada Hess Corporation, the NSU Unit Operator, provided for fifteen (15) days in which to cure the default. However, the unitization default regulation, 11 AAC 83.374(b), states:

> The commissioner will give notice to a unit operator and defaulting party (if other than the unit operator) of the default. The notice will state the nature of the default and include a demand to cure the default by a specific date, which in the case of failure to pay rentals or royalties will be a date determined by the commissioner and in the case of any other default will be a date not less than 90 days after the date of the commissioner's notice of default.

Therefore, the second paragraph of the November 3, 1994 Notice of Default for the NSU is amended to the following:

> Pursuant to Article 20.2 of the NSU Agreement, this is notification of default of the Unit Agreement. Further, AHC and its partners may cure the default by (1) providing an updated POD within ninety (90) days, or (2) voluntarily terminating the NSU Agreement per the provisions of Article 14.6 within ninety (90) days.

Under this amendment, the time period for cure of the default is 90 days, commencing November 3, 1994. If you have any questions or foresee any problems complying with the amended default notice, please contact Mike Kotowski at (907) 762-2546.

Finally, if the NSU terminates, three State of Alaska leases will continue beyond their primary term pursuant to paragraph 5(d) of the lease. The three leases are ADLs 312798, 312799 and 312809. This is further notice that within 90 days of termination of the NSU, the lessee shall file a plan of development in compliance with the requirements set forth in paragraph 17 of the lease.

Sincerely,

James E. Eason
Director

cc: Carol Lee
Patrick Coughlin
D. B. Champlin - Shell Frontier O & G Inc.
Jeff Walker - MMS

NSU.Amended Default Notice.txt

BP EXPLORATION

Exploration Department

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

RECEIVED
JAN 18 1995
DIVISION OF OIL & GAS

January 13, 1995

Mr. James E. Eason, Director
State of Alaska
Department of Natural Resources
Division of Oil and Gas
3601 C Street, 13th Floor
Anchorage, Alaska 99503

Mr. Jeff Walker, Supervisor
Operations Review & Approval
U.S. Dept. of the Interior
Minerals Management Service
Alaska Outer Continental Shelf Region
949 E. 36th Avenue, Room 603
Anchorage, AK 99508-4302

Re: Request For Extension of Time
Northstar Unit
North Slope, Alaska

Gentlemen:

BP Exploration (Alaska) Inc. (BP) and Amerada Hess Corporation (AHC) are in the process of concluding an arrangement by which BP will acquire AHC's leasehold interest in the Northstar leases. Upon the conclusion of a satisfactory arrangement and with the acceptance of the other Northstar Unit working interest owners, BP will seek approval as the successor Unit Operator to the Northstar Unit Agreement and Unit Operating Agreement.

Subsequent to acquisition of AHC's interest and approval as successor Operator, BP will attempt to cure the default for the Northstar Unit. BP respectively requests an extension of time to cure said default. An extension of not less than ninety (90) days should provide BP the opportunity to conclude its acquisition, succeed as Unit operator, and formulate with the other working interest owners a new Plan of Development for the Northstar Unit .

It is our intention to discuss this with you in our meeting scheduled for 9:00 A.M., January 19, 1995. If you have any questions or concerns, please contact me at (907) 564-5083 or R.L. Skillern at (907) 564-5567.

Very truly yours,

E. P. Zseleczky, Jr.
Land Manager, Alaska

EPZ:lbs

cc: J.Y. Christopher - AHC
D.B. Champlin - Shell
G.M. Shirley - Murphy
J. Gottlieb - MMS

STATE OF ALASKA

TONY KNOWLES, GOVERNOR

DEPT. OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

3601 C STREET, SUITE 1380
ANCHORAGE, ALASKA 99503-5948
PHONE: (907)762-2553

DECISION

JAN 20 1995

Assignor: Amerada Hess Corporation Attn: J.Y. Christopher 1201 Louisiana, Suite 700 Houston, Texas 77002-5681	: : : : : : :	Oil and Gas Leases ADL's 312798, 312799, 312808, 312809, 355001
Assignee: BP Exploration (Alaska) Inc. Attn: Land Manager - Alaska P.O. Box 196612 Anchorage, AK 99519-6612	: : : : :	

Assignment Applications Approved

Applications for approval of assignment of 100.00 percent working interest from Amerada Hess Corporation to BP Exploration (Alaska) Inc. are hereby approved effective January 19, 1995.

These assignments are approved as to the working interest only and do not constitute approval or acceptance of any stipulations or attachments to the assignment instrument.

Approved assignments are enclosed with this decision.

James E. Eason
Director

Enclosures

JE/JS/js/312798~

1/24/95

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
Alaska Outer Continental Shelf Region
949 E. 36th Avenue, Room 603
Anchorage, Alaska 99508-4302

IN REPLY REFER TO:

JAN 20 1995

Mr. E. Pete Zseleczky, Jr.
Manager, Land Exploration Department
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

Dear Mr. Zseleczky:

Subject: Resignation of Unit Operator and Designation of Successor Unit Operator, Northstar Unit

We have reviewed the Northstar Unit Resignation of Unit Operator and Designation of Successor Unit Operator dated January 19, 1995. The resignation of Amerada Hess Corporation as Unit Operator of the Northstar Unit and designation of BP Exploration (Alaska) Inc. (BPXA) as Successor Unit Operator is approved by the Regional Supervisor in accordance with Article 6.1 of the Unit Agreement. Approval is also required by the Commissioner of the Department of Natural Resources before the designation becomes effective.

The BPXA, as Successor Unit Operator, has accepted all rights and obligations of the Northstar Unit Operator. Minerals Management Service is currently reviewing BPXA's request for a 90-day extension of the unit term. Unless a new unit plan of development or an extension is approved by the Regional Supervisor and the Commissioner in accordance with Article 14.2 of the Unit Agreement, the unit will terminate on January 25, 1995.

If you have any questions regarding this decision, please contact Barry A. Boudreau at (907) 271-6065.

Sincerely,

Orig. Sgd. by
Jeff Walker

Jeffrey Walker
Acting Regional Supervisor
Field Operations

STATE OF ALASKA

TONY KNOWLES, GOVERNOR

DEPT. OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

P.O. BOX 107034
ANCHORAGE, ALASKA 99510-7034
PHONE: (907) 762-2553

(907)762-2547

January 20, 1995

BP Exploration (Alaska) Inc.
PO Box 196612
Anchorage, Alaska 99519

Attn: Peter Zseleczky, Land Manager

Subject: Northstar Unit
Change of Unit Operator

Dear Mr. Zseleczky:

Pursuant to Article 5.1 of the Northstar Unit Agreement (NSUA), the Amerada Hess Corporation submitted its resignation as Unit Operator of the Northstar Unit (NSU). By vote of the Unit Working Interest Owners, BP Exploration (Alaska) Inc. (BPX) was approved as the successor Unit Operator. Furthermore, BPX has accepted the rights and obligations of the NSU Operator.

Pursuant to Article 6.1 of the NSUA, the division approves BPX as Successor NSU Operator, subject to the concomitant approval of the U.S. Department of the Interior, Minerals Management Service. The division's approval is effective January 20, 1995. Upon approval of assignments of interest in the Unit, the division requests that BPX submit updated Exhibits A and B to the NSUA.

Sincerely,

James E. Eason
Director

cc: Patrick Coughlin - ADOL
David Johnston -AOGCC
Judith E. Buono-BPX
J. Y. Christopher - AHC
Tom Murrell - MMS

NSU.ChangeofOperator.txt

BP EXPLORATION

Alaska Exploration & Developments

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

RECEIVED
JAN 23 1995
DIV. OF OIL & GAS
DIRECTOR'S OFFICE

January 23, 1995

CONFIDENTIAL

Mr. James E. Eason, Director
State of Alaska
Department of Natural Resources
Division of Oil and Gas
3601 C Street, 13th Floor
Anchorage, Alaska 99503

Mr. Jeff Walker
Acting Regional Supervisor
Field Operations
U.S. Dept. of the Interior
Minerals Management Service
Alaska Outer Continental Shelf Region
949 East 36th Avenue, Room 603
Anchorage, Alaska 99508-4302

Re: Plan of Development, Northstar Unit, North Slope, Alaska

Gentlemen:

Please find enclosed for your review two (2) copies each of an updated Plan of Development (POD) for the Northstar Unit. This POD is submitted by BP Exploration (Alaska) Inc. (BPX) as successor unit operator to Amerada Hess Corporation (AHC).

BPX requests your review and approval of the POD and an extension of the Unit Agreement for a two year term coincident with the POD term pursuant to Article 14.2 (b) of the Unit Agreement. We are also requesting strict confidentiality of the purchase and sale terms as outlined in paragraph two of this letter.

Thank you for your flexibility in discussing the Unit Agreement with BPX on short notice.

Very truly yours,

E. P. Zseleczky, Jr.
Land Manager, Alaska

EPZ:lbs

Enclosures

cc: Mr. John Shively, Commissioner,
Alaska Department of Natural Resources

Ms. Judith Gottlieb,
Regional Director, Minerals Mgmt. Service

RECEIVED
DIV. OF OIL &

3
DIV. OF OIL & GAS

NORTHSTAR UNIT
PLAN OF DEVELOPMENT

This two-year Plan of Development is submitted to the Commissioner of Natural Resources, State of Alaska, and to the Regional Supervisor, Field Operations, of the Minerals Management Service pursuant to Article 8 of the NorthStar Unit Agreement. The Plan describes proposed development activities based on data reasonably available at the time of submission in accordance with 11 AAC 83.343.

Introduction:

In 1980, Northstar/Seal leases were awarded to Amerada Hess Corporation, Amoco, Murphy Oil USA Inc., Shell Oil , and Texas Eastern as a result of successful bidding in the 1979 BF lease sale. Since that time, four wells were drilled on Seal Island; three were successful in finding hydrocarbon in the Ivishak formation, the fourth well was a dry hole. Northstar Island was constructed in 1984. Two wells were drilled; one was successful confirming the extension of the Ivishak; the second well was abandoned because of mechanical downhole difficulties before it reached the Ivishak.

Four of the six wells (BF-46 #1, BF-47 #1, OCS-Y-181, and BF-57 #1) have been certified by the State of Alaska or the Minerals Management Service as capable of producing in paying quantities. In 1994, the Northstar Unit Working Interest Owners (WIOs) abandoned the two exploration islands with the approval of the Department of Environmental Conservation.

In late 1994 BP Exploration (Alaska) Inc. entered into discussions on acquiring Amerada Hess Corporation's interest and operatorship in the Northstar Unit. By the middle of January, 1995, an agreement was reached and BPXA became the operator of the Northstar Unit. Discussions are currently ongoing with the other Working Interest Owners to determine their interest in development and to review the current geophysical and engineering work completed for the possible development of a producing Unit.

Previous Plan Of Development:

Amerada Hess, as operator of the Northstar Unit has completed the 1990 approved Five Year Plan of Development. The requirements of the approved plan were achieved, although the islands were not maintained as originally planned. The Northstar and Seal Islands were abandoned, with agency approval, in 1994.

Proposed Plan of Development:

BP Exploration (Alaska) Inc. hereby submits this two year Plan of Development on behalf of the Northstar Unit working Interest Owners to satisfy the requirements of Article 8 of the Northstar Unit Operating Agreement. This plan is composed of two parts, the first part will include determining Working Interest Owner commitment to the ultimate development of the Unit by reviewing all proposed development plans and options as well as reservoir modeling and conceptual engineering work to establish a base development plan. On the ground Environmental data gathering and studies (ice and water movement, water quality and benthic sampling, waterfowl presence, etc.) to support an Environmental Assessment will also commence in 1995 to support the various permit applications required for the development of the hydrocarbon reserves. Some of the Environmental data gathering could commence this winter with ice and water movements. BP intends to start the process of meetings with the North Slope Borough and State and Federal agencies to ensure the permit approvals for the 1996 3-D seismic acquisition.

Early agency participation and involvement, especially with the North Slope Borough, is included in this Plan of Development. This is to ensure the scope of work and timelines are well established in order to define a permittable project development plan. This project will also include participation by representatives of the Alaska Department of Natural Resources and the Minerals Management Service and other agencies as are necessary to ensure the success of the project. The intent of BPXA is to assimilate the collective knowledge of the Current Working Interest Owners of the Northstar Unit and to also partner with the State and Federal participants to leverage their knowledge and skills in determining a development plan that will satisfy the National and State's Best Interests.

The second part of the Plan of Development is a summer 1996 3-D Seismic Program to delineate the reservoir for optimum location of the development wells and positioning of the Offshore structure for drilling and development. We will be working very closely with the North Slope Borough, especially the Whalers Association to minimize disturbances to the annual whaling season. Additional follow-on environmental work will also be included in 1996.

The intent of the two part program is to define a base development plan in 1995 in cooperation with all major stakeholders, including WIOs, the State DNR and Federal MMS, and also to delineate the optimum location of the production wells and position of the production structure.

The proposed joint work plan is as follows: -

Commitment Part 1	Year
Finalize Amerada Hess acquisition and data transfer	Q1 / 95
Create a cooperative Stakeholder Relationship	Q1 / 95
Obtain WIO commitment to ultimate development	Q1 / 95
Partner with State DNR & Federal MMS & NSB	Q1 / 95
Review of all existing development options	Q1 / 95
Define scope of reservoir/conceptual engineering	Q2 / 95
Review Permitting requirements with regulators	Q2 / 95
Initiate On the Ground Environmental Studies	Q2 / 95
Initiate Permitting for the 1996 3-D seismic	Q2 / 95
Joint Industry/Agency review	Q3 / 95
Draft Environmental Assessment/Project Description	Q4 / 95

Commitment Part 2	Year
Permit approvals/Field Planning for 3-D Seismic	Q1 / 96
Initiate Preliminary Facility/Pipeline Engineering	Q1 / 96
Initiate Follow-on Environmental studies	Q2 / 96
Summer 3-D seismic acquisition	Q3 / 96
Seismic Processing	Q3 / 96
Pre-Application meetings with agencies	Q3 / 96
Final Environmental Assessment/Project Description	Q4 / 96
Submittal of Project construction Permit applications	Q1 / 97

The combined estimated cost for the proposed plan of development for the two year Plan of Development is $10, 000,000. The scope of the work will follow the requirements of the regulations and the outcomes of the Stakeholder meetings.

TONY KNOWLES, GOVERNOR

DEPT. OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

P.O. BOX 107034
ANCHORAGE, ALASKA 99510-7034
PHONE: (907) 762-2553

cc Ball
Mike
Ken
Hanson
Rich
Mark

January 24, 1995

Via Fax (564-5132)

Mr. Pete Zseleczky
Land Manager, Alaska
BP Exploration (Alaska) Inc.
P. O. Box 196612
Anchorage, Alaska 99519-6612

Dear Mr. Zselecsky:

This is in response to your letter dated January 13, 1995 requesting an extension of not less than 90 days to allow BP to submit a new plan of development for the Northstar Unit.

Since your letter, the division has had two meetings with representatives of BP and the MMS. In addition, BP has submitted a proposed plan of development, but has stated that with more time it could submit a more detailed and decisive plan. Based upon our discussions, BP's representations and submittals, and MMS's information, I believe that it is in everyone's best interest to allow BP additional time to conclude its acquisition and to formulate a new plan of development.

The extension is conditioned on BP's following through on its offer to make its technical staff available to the division and working with the division and the MMS to find an acceptable plan to further all parties' interest during the extension period. Accordingly, BP's request for an extension to file a proposed plan of development is extended to April 30, 1995.

Sincerely,

James E. Eason
Director

cc: Barry Boudreau, MMS *(via fax - 271-6805)*
Patrick Coughlin, Department of Law
Marty K. Rutherford, Acting Commissioner, DNR

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
Alaska Outer Continental Shelf Region
949 E. 36th Avenue, Room 603
Anchorage, Alaska 99508-4302

IN REPLY REFER TO:

Patrick

JAN 24 1995

Mr. E. P. Zseleczky, Jr.
Land Manager, Alaska
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, Alaska 99519-6612

Dear Mr. Zseleczky:

We have reviewed the revised Plan of Development and request for an extension of the Northstar Unit Agreement submitted by BP Exploration (Alaska) Inc. (BPX) on January 23, 1995. After further discussion with the State of Alaska and BPX we have agreed to an extension of the unit term to April 30, 1995, as provided by Article 14.2(b) of the Northstar Unit Agreement. The State of Alaska and MMS grant this extension to allow BPX time to prepare a more detailed Plan of Development and schedule of activities and to allow for a more comprehensive review of BPX's proposal.

A new or revised Unit Plan of Development must be approved prior to the end of this extension in order to maintain the Unit Agreement beyond April 30, 1995.

We look forward to working with you and the State of Alaska over the next several months. If you have any further questions, please contact either myself or Tom Murrell at (907) 271-6065.

Sincerely,

Barry A Boudreau

Barry A. Boudreau
Regional Supervisor
Field Operations

cc: Ms. Marty Rutherford
Acting Commissioner
Department of Natural Resources
3601 C Street, #1210
Anchorage, AK 99503

BP EXPLORATION

Alaska Exploration & Developments

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

March 30, 1995

Mr. Kenneth Boyd, Deputy Director
State of Alaska
Department of Natural Resources
Division of Oil and Gas
3601 C Street, 13th Floor
Anchorage, Alaska 99503

Mr. Barry Boudreau
Regional Supervisor
Field Operations
U.S. Dept. of the Interior
Minerals Management Service
Alaska Outer Continental Shelf Region
949 East 36th Avenue, Room 614
Anchorage, Alaska 99508-4302

Re: Plan of Development, Northstar Unit,
North Slope, Alaska

Gentlemen:

Please find enclosed for your review two (2) copies each of an updated Plan of Development (POD) for the Northstar Unit. This POD is submitted by BP Exploration (Alaska) Inc. (BPX), on behalf of itself, as Unit Operator of the Northstar Unit and Murphy Exploration & Production Company.

BPX requests your review and approval of the POD and an extension of the Unit Agreement for a three (3) year term coincident with the POD term pursuant to Article 14.2 (b) of the Unit Agreement.

We are available to meet with you to discuss this Plan at your earliest convenience. Please telephone me should you have any questions.

RECEIVED
MAR 30 1995
DIVISION OF OIL & GAS

Very truly yours,

E. P. Zseleczky, Jr.
Land Manager, Alaska
Phone: 564-5083

Enclosures

Received by: _____
Title: AC II
Date: 3/30/95

ATTACHMENT 7

cc: Mr. John Shively, Commissioner,
Alaska Department of Natural Resources

Ms. Judith Gottlieb,
Regional Director, Minerals Mgmt. Service

Mr. Jim Hunt,
Murphy Exploration & Production Company

RECEIVED
MAR 30 1995
DIVISION OF OIL & GAS

NORTHSTAR UNIT
1995-1997 PLAN OF DEVELOPMENT

The following three year Plan of Development is submitted to the Commissioner of Natural Resources, State of Alaska, and to the Regional Supervisor, Field Operations, of the Minerals Management Service pursuant to Article 8 of the Northstar Unit Agreement. The Plan describes proposed development activities based on data reasonably available at the time of submission in accordance with 11 AAC 83.343 and 30CFR 250.

Introduction:

Northstar Unit leases (ADLs 312798, 312799, 312808, 312809, Y0179 and Y0181) were acquired by Amerada Hess Corporation, Amoco, Murphy Oil USA Inc., Shell Oil , and Texas Eastern as a result of successful bidding in the 1979 joint state/federal Sale 30/BF Lease Sale. A seventh lease (ADL 355001) was acquired in 1983 at State Lease Sale 39.

Since the leases were issued, six exploration wells have been drilled in the Unit area. Four wells were drilled from Seal Island, three of which were successful in finding hydrocarbons in the Ivishak formation. The fourth well was a dry hole. Two wells were drilled from Northstar Island; one well confirmed the extension of the Ivishak formation; the second well was abandoned because of mechanical difficulties downhole before it reached the Ivishak formation.

Four of the six wells BF-46 #1 (North Star #1), BF-47 #1 (Seal Island #1), BF-57 #1 (Seal Island #3), and OCS-Y-181 #1 (Northstar #1) have been certified by the State of Alaska or the Minerals Management Service as capable of producing in paying quantities.

The Northstar Unit Working Interest Owners abandoned Seal and North Star islands with the approval of State and Federal Agencies in 1994.

In late 1994 BP Exploration (Alaska) Inc. (BPXA) entered into discussions for acquisition of a working interest and operatorship of the Northstar Unit. By the end of February, 1995 agreements were reached with Amerada Hess Corporation and Shell Frontier Oil & Gas Inc. for their interests. BPXA assumed operatorship of the Northstar Unit. Discussions are currently ongoing with the remaining Working Interest Owner (Murphy Exploration and Production Company) to review the current geophysical and engineering work completed to date and plan for development of, and production from the Unit.

1990-1995 Plan Of Development Status:

Amerada Hess, as operator of the Northstar Unit, has completed requirements of the 1990 - 1995 Five Year Plan of Development. The requirements of the plan were achieved, although the Northstar and Seal Islands were abandoned in 1994.

1995-1998 Proposed Plan of Development:

BP Exploration (Alaska) Inc., as Northstar Unit Operator, hereby submits this three year Plan of Development on behalf of the Northstar Unit Working Interest Owners to satisfy the requirements of Article 8 of the Northstar Unit Operating Agreement.

The intent of the three part program is to define 1.) a base development plan in 1995 in cooperation with all major stakeholders, including the Northstar WIOs, the State Department of Natural Resources and Federal Minerals Management Service, 2.) to delineate the optimum location of the production wells and position of the production structure using 3-D seismic and finally during early 1997 3.) to commit to a scope and timing for Northstar development. This plan is composed of three parts:

Part 1: Data Gathering/Project Development - 1995 thru 1998

Part 1 of the Plan of Development involves 1.) determining Working Interest Owner commitment to a plan of development for the Unit, 2.) commencement of environmental data gathering and studies, 3.) early agency participation and involvement, 4.) promulgation of marine mammal incidental take regulations and 5.) the signing of a cooperative agreement with the Alaska Eskimo Whalers Commission.

The Northstar Unit Working Interest Owner will determine their commitment to a plan of development for the Unit. This will be accomplished by reviewing development scenarios (including conceptual engineering and reservoir modeling) to establish an economically and environmentally sound base development plan.

On the ground environmental data gathering and studies (ice and water movement, benthic sampling, and wildlife presence) to support an Environmental Assessment and permitting requirements will commence in early 1995.

BPXA will seek the early participation and involvement of local, state and federal regulatory agencies. This is being done to ensure that a scope of work and timelines are well established so that 1.) permit approvals for 3-D seismic operations planned for the summer 1996 are issued in a timely manner, 2.) a project development plan is developed which addresses concerns of the regulatory agencies and 3.) promotes the concept of partnering and shared benefits between the Northstar Working Interest Owners and the public interest as represented by the various regulatory agencies.

In addition to the regular permitting issues, we anticipate that the promulgation of incidental take regulations for exploration, production and development activities will possibly require two years or more.

An Oil/Whalers Agreement that addresses concerns of local subsistence users will also need to be negotiated. The intent of BPXA is to assimilate the collective knowledge of the Northstar Unit Working Interest Owners, North Slope Borough, State and Federal regulatory agencies to leverage their knowledge and skills in determining a development plan that will serve the Nation's and State's Best Interests.

Part 2: 3-D Seismic Acquisition - Summer 1996

Part 2 of the Plan of Development is focused on the summer 1996 3-D Seismic Acquisition Program. This program will be used to delineate the reservoir and assess the optimum location for drilling and production facilities. BPXA will be working very closely with the North Slope Borough, and the Alaska Eskimo Whalers Commission (AEWC) to minimize impacts of the seismic program on the annual whaling season.

Environmental studies not completed in 1995 will continue during 1996.

Part 3: Overall Project Sanction Request - 1997

Part 3 of the Plan of Development addresses the processes and procedures leading to BPXA's request for sanction of the Northstar development project including identification of a target date for production start-up. This part of the plan includes the submittal of project construction permit applications, agency review of the applications (including appropriate opportunities for public comment), BPXA receipt of permit approvals and BPXA's internal request for sanction of the project.
It is recognized that funding commitments will depend on the economic competitiveness of the project compared to other BP projects worldwide, the business climate (oil price, etc.) and the status of the external permitting processes.

Plan of Development Part 1

Amerada Hess/Shell Oil acquisition and data transfer	Q1 / 95
Create a cooperative Stakeholder Relationship	Q1 / 95
Obtain WIO commitment to ultimate development	Q1 / 95
Partner with State DNR & Federal MMS & NSB	Q1 / 95
Review development options	Q2 / 95
Define scope of reservoir/conceptual engineering	Q2 / 95
Review Permitting requirements with regulators	Q2 / 95
Initiate On the Ground Environmental Studies	Q2 / 95
Initiate permit preparation for:	
- 1996 3-D seismic	Q2 / 95
- Incidental Take Regulations	Q2 / 95
- Federal and State Construction permits	Q2 / 95
Joint Industry/Agency review	Q3 / 95
Draft Environmental Assessment/Project Description	Q4 / 95
Submit permit applications for:	
- 1996 3-D seismic	Q4 / 95
- Incidental Take Regulations	Q4 / 95

- Risks to delivery:
  - Adequate open water season
  - Federal / State jurisdictional conflicts

Plan of Development Part 2

Permit Approvals/Field Planning for 3-D Seismic	Q1 / 96
Initiate Preliminary Facility/Pipeline Engineering	Q1 / 96
Initiate Follow-on Environmental studies	Q2 / 96
Summer 3-D seismic acquisition	Q3 / 96
Seismic Processing	Q3 / 94
Reservoir description	Q4 / 96
Pre-Application meetings with agencies	Q4 / 96
Final Environmental Assessment/Project Description	Q4 / 96

- Risks to delivery:
  - Adequate open water season
  - Extension of Incidental Take Regulations for Exploration
  - Successful negotiation of Oil/Whalers Agreement

Plan of Development Part 3

Submittal of Project Construction Permit applications	Q1 / 97
Agency review and public comment period	Q1 / 97
Integrate 3D Seismic and Reservoir Description	Q2 / 97
Permit approvals received or "in final review"	Q3 / 97
BPXA internal sanction request	Q4 / 97

- Risks to delivery:
  - EIS required thereby postponing approval dates
  - Development and production economics
  - Promulgation of Incidental Take Regulations for Production

The combined estimated cost for the proposed plan of development for the three year Plan of Development is approximately $12,000,000. BPXA intends to have yearly reviews to discuss results and plans and, despite the risks noted, we are committed to this program and will proceed to identify opportunities to accelerate parts of the plan.

United States Department of the Interior

MINERALS MANAGEMENT SERVICE
Alaska Outer Continental Shelf Region
949 E. 36th Avenue, Room 603
Anchorage, Alaska 99508-4302

IN REPLY REFER TO:

RECEIVED
MAY 04 1995
DIVISION OF OIL & GAS

MAY 1 1995

cc Bill
Mike

Mr. E. P. Zseleczky, Jr.
Land Manager, Alaska
BP Exploration (Alaska), Inc.
P.O. Box 196612
Anchorage, Alaska 99519-6612

Dear Mr. Zseleczky:

We have reviewed the revised Northstar Plan of Development, your request for an extension of the Northstar Unit Agreement, and your request for a suspension of operations for leases OCS Y-0179 and Y-0181 dated March 30, 1995.

The revised Plan of Development includes a new schedule of activities which are deemed necessary to bring the unit into production. Accordingly, a 3-year extension of the unit term is approved, subject to approval by the State of Alaska. The new termination date for the unit is April 30, 1998, unless the unit term is extended by production or other activities under an approved Unit Plan of Development. A new or revised Unit Plan of Development must be approved prior to the end of this extension in order to maintain the Unit Agreement beyond April 30, 1998.

During the term of this extension, BP will be required to submit an annual status report reflecting the past year's unit activities and those unit activities planned for the upcoming year. The annual report must be received by May 1st of each year.

Leases OCS-Y 0179 and OCS-Y 0181 are committed to the Northstar Unit and a suspension consistent with the term of the unit is warranted and in the National interest. Accordingly, a 3-year suspension of operations for leases OCS-Y 0179 and OCS-Y 0181 is approved pursuant to 30 CFR 250.10. Termination of the Northstar Unit Agreement would result in termination of this suspension. The period of suspension will commence on May 1, 1995, and will terminate on April 30, 1998.

We are notifying the Minerals Management Service Royalty Management Division of this action by copy of this letter. Please be advised that, in accordance with 30 CFR 218.154, the rental or minimum royalty payments on leases OCS-Y 0179 and OCS-Y 0181 must continue to be made during the period of suspension. Any questions concern-

ing the rentals or minimum royalty payments should be addressed to the Royalty Management Division at the following address:

Associate Director for Royalty Management
Minerals Management Service
P.O. Box 25165
Denver, Colorado 80225

We look forward to working with you, the State of Alaska, the North Slope Borough, and other Federal agencies on this project. If you have any further questions, please contact either myself or Tom Murrell at (907) 271-6065.

Sincerely,

Barry A Boudreau

Barry A. Boudreau
Regional Supervisor
Field Operations

cc: Ken Boyd
Acting Director, Division of Oil & Gas
Department of Natural Resources
3601 C Street, #1210
Anchorage, AK 99503

TONY KNOWLES, GOVERNOR

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

3601 C STREET, SUITE 1380
ANCHORAGE, ALASKA 99503-5948
PHONE: (907) 762-2549

(907)762-2547

June 2, 1995

BP Exploration (Alaska) Inc.
PO Box 196612
Anchorage, Alaska 99519-6612

Attn: Peter Zseleczky, Land Manager

Subject: Northstar Unit
Proposed Unit Plan of Development

Dear Mr. Zseleczky:

The Division of Oil and Gas has reviewed the proposed Second Northstar Unit Plan of Development (POD) and BPX's request for an extension of the Northstar Unit Agreement for a three year term coincident with the three year POD, dated March 30, 1995.

The proposed Second POD and the three year extension of the Northstar Unit (NSU) is approved subject to the following conditions:

1) During the three year term of the POD, BPX must submit an annual status report describing the unit activities conducted during the preceding year and the unit activities planned for the coming year. The annual report shall be filed with the Division by May 1 of each year.

2) The Division remains concerned with the appropriateness of continuing to include ADL 355001 within the NSU. In Part 2 of the proposed Second NSU POD, BPX plans to acquire and process 3-D seismic data during the 3rd Quarter 1996, and have a reservoir description available by the 4th Quarter 1996. BPX must present the results of the 3-D seismic acquisition program and the reservoir description to the Division by December 15, 1996. If the 3-D data is not acquired and the presentation not made to the Division, ADL 355001 will contract from the NSU as of December 31, 1996.

ATTACHMENT 8

printed on

The Division may waive the requirement for additional 3-D data on ADL 355001 specified in the preceding paragraph if, prior to December 15, 1996, BPX can provide other evidence demonstrating that ADL 355001 should remain within the NSU.

3) At least ninety (90) days before the termination of the three year extension period, the Division will require BPX to submit a report to the Division that synthesizes the data and studies performed by BPX during the extension period. The report shall include BPX's opinion of the extent and characteristics of the hydrocarbon accumulations within the NSU and address the development scenarios, timelines, and technical and environmental issues associated with developing the NSU. The report shall also include BPX's conclusions and recommendations regarding the development of the NSU.

Finally, the NSU will terminate on April 30, 1998, unless the unit term is extended by production or other activities under an approved NSU POD. A new or revised NSU POD must be submitted to the commissioner for approval at least 90 days before the expiration of the current plan.

Sincerely,

Kenneth A. Boyd
Director

cc: Barry Boudreau, MMS
Patrick Coughlin, ADOL
Marty K. Rutherford

NSU.2ndPOD.Approve.txt

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
MINERALS AND ENERGY MANAGEMENT

JAY S. HAMMOND, GOVERNOR

703 W. NORTHERN LIGHTS BLVD.
ANCHORAGE, ALASKA 99503

December 27, 1979

RESULTS OF THE 30TH COMPETITIVE
OIL AND GAS LEASE SALE

A total of 200 bids were submitted on 71 state-managed tracts (BF-46 through BF-116) offered in the State of Alaska's 30th Competitive Oil and Gas Lease Sale, held jointly with the federal government on December 11, 1979, in Fairbanks, for exploration and development rights in the Beaufort Sea, for an area encompassing approximately 341,140.18 acres.

Additional lands were offered, and bids were received by the federal government for tracts which are subject to a dispute as to ownership between the state and federal governments. In accordance with a Memorandum of Understanding, these tracts were offered and will be managed by the federal government until the legal dispute is resolved; information concerning the bidding on these tracts may be obtained from the Outer Continental Shelf Office, Bureau of Land Management, U. S. Department of Interior. Four of the 71 state-managed tracts, namely, BF-64, BF-70, BF-71, and BF-116, are subject to this same dispute and Memorandum of Understanding

Twenty-seven companies, 20 individuals, and one association participated in the bidding for 62 of the 71 state-managed tracts offered. The highest cash bonus bid was offered by Exxon Corporation for tract BF-110, a total of $85,689,000.00 representing a bid of $15,169.74 per acre. The lowest successful cash bonus bid was offered by Mary Gustafson, Cliff Burglin, and Alberta H. Grant for tract BF-81, a total of $14,312.05, representing a bid of $5.00 per acre. Of the tracts offered under the net profit share system of bidding, the highest bid (93.2%) was submitted by Amerada Hess Corporation for tracts BF-46 and BF-69; and the lowest successful bid (2.76002%), by Chevron USA, Inc. for tract BF-66. The nine state-managed tracts receiving no bid were all offered under the net profits system of bidding.

The following is a breakdown of the sale results as a whole:

	Net Profits Tracts	Sliding Scale Royalty Tracts	Total
# of Bids	57	143	200
Average Bid/ Tract	60.73892%	$10,573,464.13	$9,151,175.76
Tracts Offered/ Acres	26/119,169.00	45/221,970.27	71/341,140.18
Tracts Bid/ Acres	17/74,337.38	45/221,970.27	62/296,307.65
Leased/Unleased	62.3%/37.6%	100%/0%	86.8%/13.1%
Total Bonus	$91,585,611.25	$475,805,886.23	$567,391,497.48

Attached is a detailed recap of the bidding by tract and a list of the participants in the sale.

AGO 257826

State of Alaska

30th Competing Oil and Gas Lease Sale

** Beaufort Sea **

SALE RESULTS - Bid Recap by Tract

TRACT NO.	OCS NO.	BLOCK NO.	ACRES	SUBDIVISION	ADL NO.
BF046	20001	CC0470	4392.82	BLK 514	ADL 312798

312798

GRP NO.	NO.	PCT.	COMPANY NAME	BID PER ACRE	TOTAL BID	BID STANDING
	059	100%	AMERADA HESS CORPORATION	ROYALTY BID	91.20000	1 OF 6
4				ROYALTY BID	80.56789	2 OF 6
	235	50%	TEXAS EASTERN EXPLOR. CC			
	040	50%	TEXACO INC.			
	114	100%	AMOCO PRODUCTION COMPANY	ROYALTY BID	71.12509	3 OF 6
3				ROYALTY BID	61.67000	4 OF 6
	129	10%	TEXASGULF INC.			
	001	48%	CONOCO INC			
	066	22%	PLACID OIL COMPANY			
	369	20%	CITIES SERVICE COMPANY			
2				ROYALTY BID	40.79133	5 OF 6
	108	10%	MURPHY OIL CORPORATION			
	117	90%	SHELL OIL COMPANY			
1				ROYALTY BID	34.46464	6 OF 6
	056	50%	PHILLIPS PETROLEUM CORP			
	078	50%	CHEVRON USA INC			

TRACT NO.	OCS NO.	BLOCK NO.	ACRES	SUBDIVISION	ADL NO.
BF047	20002	CC0471	4472.37	BLK 515	ADL 312799

ADL 312799

GRP NO.	NO.	PCT.	COMPANY NAME	BID PER ACRE	TOTAL BID	BID STANDING
	059	100%	AMERADA HESS CORPORATION	ROYALTY BID	91.20000	1 OF 7
	114	100%	AMOCO PRODUCTION COMPANY	ROYALTY BID	82.59999	2 OF 7
4				ROYALTY BID	80.56789	3 OF 7
	040	50%	TEXACO INC.			
	235	50%	TEXAS EASTERN EXPLOR. CC			
6				ROYALTY BID	71.62539	4 OF 7
	355	2%	ROWAN PETROLEUM, INC.			
	001	20%	CONOCO INC			
	129	5%	TEXASGULF INC.			
	005	20%	GETTY OIL COMPANY			
	066	13%	PLACID OIL COMPANY			
	112	20%	GULF OIL CORPORATION			
	369	20%	CITIES SERVICE COMPANY			
2				ROYALTY BID	56.77133	5 OF 7
	108	10%	MURPHY OIL CORPORATION			
	117	90%	SHELL OIL COMPANY			
5				ROYALTY BID	43.26273	6 OF 7
	056	33%	PHILLIPS PETROLEUM CORP			
	039	33%	MOBIL OIL COMPANY			
	078	34%	CHEVRON USA INC			
	003	100%	UNION OIL COMPANY OF CAL	ROYALTY BID	32.00000	7 OF 7

AGO 257829

TRACTS BF-48 → -52 NO BID

08F053 20003 000520 5241.36 ADL 312805

081 100% TENNECO OIL COMPANY ROYALTY BID 21.58000 1 OF

08F054 20004 000521 5693.29 ADL 312806

081 100% TENNECO OIL COMPANY ROYALTY BID 59.00000 1 OF 1

08F055 20005 000522 5058.40 ADL 312807

081 100% TENNECO OIL COMPANY ROYALTY BID 31.67000 1 OF 1

08F056 20006 000514 3432.92 BLK 515 552 559 ADL 312808

235 100% TEXAS EASTERN EXPLOR. CCROYALTY BID 85.25978 1 OF 5

3 ROYALTY BID 38.12530 2 OF 5
129 6% TEXASGULF INC.
112 25% GULF OIL CORPORATION
001 25% CONOCO INC
066 16% PLACID OIL COMPANY
355 3% ROWAN PETROLEUM, INC.
369 25% CITIES SERVICE COMPANY

003 100% UNION OIL COMPANY OF CALROYALTY BID 25.50000 3 OF 5

1 ROYALTY BID 10.14550 4 OF 5
078 50% CHEVRON USA INC
056 50% PHILLIPS PETROLEUM COMP

7 ROYALTY BID 2.11111 5 OF 5
002 40% ATLANTIC RICHFIELD COMP
108 10% MURPHY OIL CORPORATION
117 50% SHELL OIL COMPANY

08F057 20007 000516 5301.38 BLK 560 ADL 312809

235 100% TEXAS EASTERN EXPLOR. CCROYALTY BID 85.25978 1 OF 7

114 100% AMOCO PRODUCTION COMPANYROYALTY BID 71.25009 2 OF 7

11 ROYALTY BID 63.83000 3 OF 7
115 50% MARATHON OIL COMPANY
059 50% AMERADA HESS CORPORATION

10 ROYALTY BID 46.37549 4 OF 7
112 25% GULF OIL CORPORATION
066 16% PLACID OIL COMPANY
005 25% GETTY OIL COMPANY
129 6% TEXASGULF INC.
355 3% ROWAN PETROLEUM, INC.
369 25% CITIES SERVICE COMPANY

003 100% UNION OIL COMPANY OF CALROYALTY BID 38.00000 5 OF 7

5 ROYALTY BID 34.23333 6 OF 7
056 33% PHILLIPS PETROLEUM COMP
[illegible]

9 ROYALTY BID 31.69117 7 OF 7
002 45% ATLANTIC RICHFIELD COMP

AGO 257830

39.11

BID TALLY LIST - O/G LEASE SALE 39

May 17, 1983

Tract #	No. of Bids	Bidder	% ownership	Bid amount	Bid/Acre	20% depos
1	3	Exxon Corp.	50%	60,300.00	10.49	12,060.0
ADL 355001		Sohio Alaska	50%			
		Kelley Everette	5%	64,620.00	11.25	13,000.0
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Robert Malone POA	15%			
		Bruce Burglin POA	45%			
		James F. Dieringer, Jr.	15%	72,144.64	12.56	14,428.9
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
002	3	Kelley Everette	5%	50,343.75	11.25	11,000.0
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Robert Malone POA	15%			
		Bruce Burglin POA	45%			
		James F. Dieringer, Jr.	15%	69,631.00	15.56	13.926.20
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Exxon Corp.	50%	281,100.00	62.81	56.220.00
		Sohio Alaska	50%			
003	5	Exxon Corp.	50%	35,200.00	10.08	7,040.00
		Sohio Alaska	50%			
		Kelley Everette	5%	39,251.25	11.25	8,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		David Burglin POA	60%			
		James F. Dieringer, Jr.	15%	43,817.07	12.56	8,763.41
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Shell Oil Co.	50%	47,485.00	13.61	9,497.00
		Amoco Production	50%			
		Amerada Hess Corp.	100%	1,212,295.45	347.50	242,459.09

Tract #	No. of Bids	Bidder	% ownership	Bid amount	Bid/Acre	20% deposi
004	2	Kelley Everette	5%	49,905.00	11.25	10,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Mary Gustafson POA	60%			
		James F. Dierinqer, Jr.	15%	69,013.42	15.56	13,801.68
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
005	3	Kelley Everette	5%	57,600.00	11.25	12,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Ladessa Nordale POA	15%			
		Barbara Burglin POA	45%			
		James F. Dierinqer, Jr.	15%	64,307.20	12.56	12,861.44
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Exxon Corp.	50%	4,116,800.00	804.06	832,360.00
		Sohio Alaska	50%			
006	3	Kelley Everette	5%	64,305.00	11.25	13,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Michael Petrocele POA	15%			
		Joe Burglin POA	45%			
		James F. Dierinqer, Jr.	15%	71,792.96	12.56	14,358.59
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Exxon Corp.	50%	1,104,500.00	193.22	220,900.00
		Sohio Alaska	50%			

Tract #	No. of Bids	Bidder	% ownership	Bid amount	Bid/Acre	20% depos
007	3	Kelley Everette	5%	43,020.00	11.25	9,000.0
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Constance Cole POA	15%			
		Joe Burglin POA	45%			
		James F. Dieringer, Jr.	15%	59,501.44	15.56	11,900.2
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Exxon Corp.	50%	70,300.00	18.38	14 060.0
		Sohio Alaska	50%			
008	4	Kelley Everette	5%	59,343.75	11.25	12,000.0
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Bernard Shier POA	15%			
		Bruce Burglin POA	45%			
		Shell Oil Co.	50%	73,457.00	13.92	14,691.40
		Amoco Production Co.	50%			
		James F. Dieringer, Jr.	15%	82,075.89	15.56	16,415.18
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Placid Oil Co.	100%	131,870.00	25.00	26,374.00
009	4	Kelley Everette	5%	53,167.50	11.25	11,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Constance Cole POA	15%			
		Brian Burglin POA	45%			
		James F. Dieringer, Jr.	15%	59,347.26	12.56	11,869.45
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Shell Oil Co.	50%	84,729.00	17.93	16,945.80
		Amoco Production Co.	50%			
		Placid Oil Co.	100%	118,127.50	25.00	23,625.50

Tract #	No. of Bids	Bidder	% ownership	Bid amount	Bid/Acre	20% depos
010	3	Shell Oil Co.	50%	58,431.00	10.14	11,686.2
		Amoco Production Co.	50%			
		Kelley Everette	5%	64,800.00	11.25	13,000.0
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Ed Carlson	15%			
		David Burglin	45%			
		James F. Dieringer, Jr.	15%	89,625.60	15.56	17,925.12
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
011	4	Kelley Everette	5%	64,125.00	11.25	13,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Mary Gustafson POA	60%			
		James F. Dieringer, Jr.	15%	88,692.00	15.56	17,738.40
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Shell Oil Co.	50%	210,794.00	36.98	42,158.80
		Amoco Production Co.	50%			
		Texaco Inc.	1/3%	410,400.00	72.00	82,080.00
		Amerada Hess Corp.	1/3%			
		Placid Oil Co.	1/3%			
012	2	Kelley Everette	5%	57,600.00	11.25	12,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Ed Carlson POA	15%			
		Barbara Burglin POA	45%			
		James F. Dieringer, Jr.	15%	79,667.20	15.56	15,933.44
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			

Tract #	No. of Bids	Bidder	% ownership	Bid amount	Bid/Acre	20% depos
013	2	Shell Oil Co.	50%	55,793.00	10.47	11,158.6
		Amoco Production Co.	50%			
		Kelley Everette	5%	59,906.25	11.25	12,000.0
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Jack Randolph POA	15%			
		Joseph Burglin POA	45%			
014	1	Kelley Everette	5%	56,463.75	11.25	12,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Frank McGilvary POA	15%			
		James Burglin POA	45%			
015	3	Shell Oil Co.	50%	46,112.00	10.29	9,222.40
		Amoco Production Co.	50%			
		Kelley Everette	5%	50,400.00	11.25	11,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Bruce Burglin POA	60%			
		James F. Dieringer, Jr.	15%	69,708.80	15.56	13,941.76
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
016	2	Kelley Everette	5%	57,048.75	11.25	12,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Bruce Burglin POA	15%			
		Brian Burglin POA	45%			
		James F. Dieringer, Jr.	15%	63,691.76	12.56	12,738.35
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			

Tract #	No. of Bids	Bidder	% ownership	Bid amount	Bid/Acre	20% depos
017	3	Kelley Everette	5%	50,400.00	11.25	11,000.0
		C. Burglin	15%			
		K. K. Everette POA	20%			
		David Burglin POA	60%			
		James F. Dieringer, Jr.	15%	69,708.80	15.56	13,941.76
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Chevron U.S.A. Inc.	33.33%	351,000.00	78.35	70,200.00
		Conoco Inc.	66.67%			
018	4	Kelley Everette	5%	57,183.75	11.25	12,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Mary Gustafson POA	60%			
		James F. Dieringer, Jr.	15%	79,091.48	15.56	15,818.30
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Amerada Hess Corp.	50%	195,695.50	38.50	39,139.10
		Diamond Shamrock Corp.	50%			
		Chevron U.S.A. Inc.	33.33%	808,000.00	158.96	161,600.00
		Conoco Inc.	66.67%			
019	2	Kelley Everette	5%	53,088.75	11.25	11,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Barbara Burglin POA	60%			
		Amerada Hess Corp.	50%	118,632.15	25.14	23,726.43
		Diamond Shamrock Corp.	50%			
020	2	Kelley Everette	5%	58,522.50	11.25	12,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Joseph Burglin POA	60%			
		James F. Dieringer, Jr.	15%	65,333.73	12.56	13,066.75
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			

Tract #	No. of Bids	Bidder	% ownersnip	Bid amount	Bid/Acre	20% depo:
021	3	Kelley Everette	5%	57,600.00	11.25	13,000.(
		C. Burglin	15%			
		K. K. Everette POA	20%			
		James Burglin POA	60%			
		Conoco Inc.	100%	73,165.00	14.29	14,633.(
		Amerada Hess Corp.	50%	257,177.60	50.23	51,435.5
		Diamond Shamrock Corp.	50%			
022	2	Kelley Everette	5%	64,507.50	11.25	13,000.0
		C. Burglin	15%			
		Gene Everette POA	20%			
		Bruce Burglin POA	60%			
		James F. Dieringer, Jr.	15%	89,221.04	15.56	17,844.2
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
023	4	Kelley Everette	5%	58,218.75	11.25	13,000.0(
		C. Burglin	15%			
		Gene Everette POA	20%			
		Brian Burglin POA	60%			
		James F. Dieringer, Jr.	15%	80,523.00	15.56	16,104.6(
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Chevron U.S.A. Inc.	50%	606,000.00	117.10	121,200.00
		Conoco Inc.	50%			
		Arco Alaska, Inc.	100%	2,365,233.75	457.05	473,046.75
024	3	Kelley Everette	5%	62,775.00	11.25	13,000.00
		C. Burglin	15%			
		Gene Everette POA	20%			
		David Burglin POA	60%			
		James F. Dieringer, Jr.	15%	86,824.80	15.56	17,364.96
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Arco Alaska, Inc.	100%	984,758.40	176.48	196,951.68

Tract #	No. of Bids	Bidder	% ownership	Bid amount	Bid/Acre	20% deposi
025	2	Kelley Everette	5%	41,411.25	11.25	11,000.00
		C. Burglin	15%			
		Gene Everette POA	20%			
		George Berry POA	20%			
		Mary Gustafson POA	40%			
		James F. Dieringer, Jr.	15%	57,267.96	15.56	11,453.59
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
026	2	Kelley Everette	5%	64,800.00	11.25	13,000.00
		C. Burglin	15%			
		Gene Everette POA	20%			
		Constance Cole POA	15%			
		Barbara Burglin POA	45%			
		James F. Dieringer, Jr.	15%	89,625.60	15.56	17,925.12
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
027	3	Kelley Everette	5%	48,993.75	11.25	11,000.00
		C. Burglin	30%			
		Gene Everette POA	20%			
		Joseph Burglin POA	45%			
		James F. Dieringer, Jr.	15%	67,758.04	15.56	13,551.61
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Chevron U.S.A. Inc.	100%	88,750.00	20.38	17,750.00
028	3	Kelley Everette	5%	53,887.50	11.25	11,000.00
		C. Burglin	30%			
		Gene Everette POA	20%			
		James Burglin POA	45%			
		Chevron U.S.A. Inc.	100%	58,185.00	12.15	11,637.00
		James F. Dieringer, Jr.	15%	60,157.63	12.56	12,031.53
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			

Tract #	No. of Bids	Bidder	% ownership	Bid amount	Bid/Acre	20% depc
029	3	Kelley Everette	5%	49,725.00	11.25	13,000.
		C. Burglin	15%			
		Gene Everette POA	20%			
		Bruce Burglin POA	60%			
		Chevron U.S.A. Inc.	100%	53,630.00	12.13	10,726.
		James F. Dieringer, Jr.	15%	55,515.20	12.56	11,103.
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
030	3	Kelley Everette	5%	50,400.00	11.25	11,000.0
		C. Burglin	15%			
		Jack Sexton POA	20%			
		Brian Burglin POA	60%			
		James F. Dieringer, Jr.	15%	69,708.80	15.56	13,941.7
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Arco Alaska, Inc.	100%	273,190.40	60.98	54,638.0
031	1	Kelley Everette	5%	64,395.00	11.25	13,000.0
		C. Burglin	15%			
		Jack Sexton POA	20%			
		David Burglin POA	60%			
032	3	Kelley Everette	5%	57,465.00	11.25	13,000.0
		C. Burglin	15%			
		Jack Sexton POA	20%			
		Mary Gustafson POA	60%			
		James F. Dieringer, Jr.	15%	64,156.48	12.56	12,831.3(
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Arco Alaska, Inc.	100%	262,295.80	51.35	52,459.16

Tract #	No. of Bids	Bidder	% ownership	Bid amount	Bid/Acre	20% deposi
033	2	Kelley Everette	5%	44,808.75	11.25	13,000.00
		C. Burglin	15%			
		Jack Sexton POA	20%			
		Barbara Burglin POA	60%			
		James F. Dierlinger, Jr.	15%	50,024.85	12.56	10,004.97
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
034	1	Kelley Everette	5%	64,800.00	11.25	13,000.00
		C. Burglin	15%			
		Jack Sexton POA	20%			
		Joseph Burglin POA	60%			
035	2	Kelley Everette	5%	64,125.00	11.25	13,000.00
		C. Burglin	15%			
		Jack Sexton POA	20%			
		Joseph Burglin POA	60%			
		Chevron U.S.A. Inc.	50%	102,000.00	17.90	20,400.00
		Getty Oil Co.	50%			
036	2	Kelley Everette	5%	64,800.00	11.25	13,000.00
		C. Burglin	15%			
		Paul Quist POA	20%			
		Charles Helmes POA	15%			
		Bruce Burglin POA	45%			
		Amerada Hess Corp.	50%	117,216.00	20.35	23,443.20
		Placid Oil Co.	50%			
037	4	Kelley Everette	5%	64,395.00	11.25	12,000.00
		C. Burglin	15%			
		Paul Quist POA	20%			
		Brian Burglin POA	60%			
		Union Oil Co. of CA	100%	70,691.40	12.35	14,138.28
		Chevron U.S.A. Inc.	40%	440,155.00	76.90	88,031.00
		Getty Oil Co.	25%			
		Gulf Oil Corp.	40%			
		Texaco Inc.	25%	4,081,212.00	713.00	816,242.40
		Amerada Hess Corp.	25%			
		Diamond Shamrock	25%			
		Placid Oil	25%			

Tract #	No. of Bids	Bidder	% ownership	Bid amount	Bid/Acre	20% dep
038	3	Kelley Everette	5%	64,800.00	11.25	13,000
		C. Burglin	15%			
		Paul Quist POA	20%			
		David Burglin POA	60%			
		Union Oil Co. of CA	100%	91,872.00	15.95	18,374.
		Texaco Inc.	25%	241,920.00	42.00	48,384.
		Amerada Hess Corp.	25%			
		Diamond Shamrock	25%			
		Placid Oil	25%			
039	3	Union Oil Co. of CA	100%	57,412.09	10.17	11,482.
		Kelley Everette	5%	63,417.50	11.25	13,000.
		C. Burglin	15%			
		Paul Quist POA	20%			
		Mary Gustafson POA	60%			
		Texaco Inc.	25%	2,054,867.36	364.00	410,973.
		Amerada Hess Corp.	25%			
		Diamond Shamrock	25%			
		Placid Oil	25%			
040	4	Kelley Everette	5%	57,802.50	11.25	13,000.0
		C. Burglin	15%			
		Paul Quist POA	20%			
		James Johnson POA	15%			
		Barbara Burglin	45%			
		James F. Dieringer Jr.	15%	79,942.77	15.56	15,988.5
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Arco Alaska, Inc.	100%	88,008.98	17.13	17,601.80
		Chevron U.S.A. Inc.	40%	102,580.00	19.97	20,516.00
		Getty Oil Co.	20%			
		Gulf Oil Corp.	40%			

Tract #	No. of Bids	Bidder	% ownership	Bid amount	Bid/Acre	20% deposi
041	3	Kelley Everette	5%	51,356.25	11.25	11,000.00
		C. Burglin	15%			
		Paul Quist POA	20%			
		Joseph Burglin POA	60%			
		James F. Dieringer Jr.	15%	71,029.84	15.56	14,205.97
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Chevron U.S.A., Inc.	100%	105,350.00	23.08	21,070.00
047	2	Kelley Everette	5%	59,265.00	11.25	13,000.00
		C. Burglin	15%			
		Paul Quist POA	20%			
		James Burglin POA	60%			
		James F. Dieringer Jr.	15%	81,962.14	15.56	16,392.43
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			

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46

FORM NO. DMEM-1-79A (NET PROFIT SHARE)
(Revised November 5, 1979)

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINERALS AND ENERGY MANAGEMENT

Competitive Oil and Gas Lease ADL No. 312798

THIS LEASE is made by and between the State of Alaska, acting by and through the Commissioner of Natural Resources or his authorized agent, hereafter referred to as "the State," and

Amerada Hess Corporation

hereafter referred to as "Lessee," whether one or more.

In consideration of the cash payment heretofore made by Lessee to the State, which payment includes the first year's rental and any required cash bonus, and the promises, terms, conditions and covenants contained herein, including the Stipulation(s) numbered

1, 2, 3, 6, 7, 8, 9, 12, 13, 14, 17 and 5

attached hereto and by this reference incorporated herein, the State and Lessee agree as follows:

1. GRANT (a) Subject to the promises, terms, conditions and covenants contained herein, the State hereby grants and leases to Lessee, without warranty, the exclusive right to drill for, extract, remove, clean, process and dispose of oil, gas and associated substances in or under the following described tract of land:

Tract C30--46 (BF-46) is a portion of Blocks 470 and 514 as shown on the "Leasing and Nomination Map" for the Federal/State Beaufort Sea Oil and Gas Lease Sale, dated 1/30/79, more particularly described as follows:

Those lands located Easterly of the West boundary of T13N, and T14N, R13E U.M. Ak. being the North-South line intersecting the North and South boundary of Block 470, within the offshore three-mile arc lines listed as state area of Block 470 "Supplemental Official O.C.S. Block Diagram" approved 10/4/79, containing 690.35 Hectares, and those lands in Block 514 Easterly of the West boundary of T13N, R13E, U.M. Ak. (being identical with line 1 -2 of Block 514) and lying Northerly of the South boundary of Sections 7 and 8 T13N, R13E U.M. Ak. (being identical with line 2-3 of Block 514) and that portion of Section 16 T13N, R13E U.M. Ak. within the N½S½ (being Easterly of line 3-4 of Block 514), being a portion of the listed state area of Block 514 on the "Supplemental Official O.C.S. Block Diagram" approved 12/9/79 containing 1087.37 Hectares.

(General Location: T14N,R13E; T13N,R13E; U.M., Ak.)

containing approximately 4392.82 acres, more or less (hereafter referred to as the "leased area"), the nonexclusive right to conduct within the leased area geological and geophysical exploration for oil, gas and associated substances, and the nonexclusive right to install pipelines and structures thereon to find, produce, save, store, treat, process, transport, take care of and market all such substances and to house and board employees in its operations thereon.

(b) For the purposes of this lease, the leased area contains the legal subdivisions as shown on the attached plat marked Exhibit A.

(c) If the leased area is described above by protracted legal subdivisions and the State hereafter causes the leased area to be surveyed under the public land rectangular system, the boundaries of the leased area are those established by such survey, when approved, subject, however, to the provisions of applicable regulations relating to such surveys. If for any reason the leased area includes more acreage than the maximum permitted under applicable law (including the "rule of approximation" authorized in AS 38.05.145 and defined in AS 38.05.965(13)), this lease is not void and the acreage included in the leased area shall be reduced to the permitted maximum. If the State determines that this lease exceeds the permitted acreage and notifies Lessee in writing of the amount of acreage that must be eliminated, Lessee shall have sixty (60) days after such notice to surrender one or more legal subdivisions included in the leased area comprising at least the amount of acreage that must be eliminated. Any such subdivision(s) surrendered must be located on the perimeter of the leased area as originally described. If such a surrender is not filed within sixty (60) days, the State may terminate this lease as to the acreage that must be eliminated by mailing notice of such termination to Lessee describing the subdivision(s) eliminated.

(d) If the State's ownership interest in the oil, gas and associated substances in the leased area is less than an entire and undivided interest, the grant under this lease is effective only as to the State's interest in that oil, gas and associated substances, and the royalties and rentals herein provided shall be paid to the State in the proportion which the State's interest bears to the entire undivided fee.

2. RESERVED RIGHTS. (a) The State, for itself and others, reserves all rights not expressly granted to Lessee by this lease. Without limiting the generality of the foregoing sentence, such reserved rights include:

(1) the right to explore for oil, gas and associated substances by geological and/or geophysical means;

(2) the right to explore for, develop and remove natural resources other than oil, gas and associated substances on or from the leased area;

(3) the right to establish or grant easements and rights-of-way for any lawful purpose, including without limitation for shafts and tunnels necessary or appropriate for the working of the leased area or other lands for natural resources other than oil, gas and associated substances;

(4) the right to dispose of land within the leased area for well sites and well bores of wells drilled from or through the leased area to explore for or produce oil, gas and associated substances in and from lands not within the leased area; and

(5) the right otherwise to manage and dispose of the surface of the leased area or interests therein by grant, lease, permit or otherwise to third parties.

(b) Rights reserved by the State may be exercised in any manner which does not unreasonably interefere with or endanger Lessee's operations under this lease.

3. TERM. This lease is issued for an initial primary term of ten (10) years from the effective date hereof, which term may be extended as provided in Paragraph 4 below. This lease may be extended beyond its primary term as provided in Paragraph 5 below.

4. EXTENSION OF PRIMARY TERM. (a) By Suspension of Operations. If, prior to the expiration of the primary term, the State directs or approves in writing suspension of all operations on or production from the leased area, the primary term shall be extended by adding the period of suspension to the primary term originally specified. For purposes of this subparagraph, any suspension of operations or production required by any stipulation made a part of this lease shall not be considered a suspension under any order by, or with the written consent of, the State.

(b) By Force Majeure. If the State determines that, prior to the expiration of the primary term, Lessee has been prevented by any of the conditions specified in Paragraph 32 from performing any act which would extend the lease beyond the primary term, the primary term shall be extended by adding the period of disability to the primary term originally specified.

e/m 1/11/80 or

5. EXTENSION BEYOND PRIMARY TERM. (a) By Production. This lease shall be extended automatically if and for so long as oil and gas is produced in paying quantities from the leased area.

(b) By Commitment to Approved Unit. This lease shall be extended automatically if it is committed to a unit agreement approved by the State, and shall remain in full force and effect as long as it remains committed to such a unit agreement.

(c) By Drilling. (1) If drilling has commenced as of the date on which this lease otherwise would expire and is continued with reasonable diligence, this lease shall continue in full force and effect until ninety (90) days after cessation of such drilling and for so long thereafter as oil or gas is produced in paying quantities from the leased area. (2) If oil or gas in paying quantities is produced from the leased area, and if such production ceases at any time, this lease shall not terminate if drilling or reworking operations are commenced on the leased area within (6) months after cessation of production and thereafter are prosecuted with reasonable diligence; if such drilling or reworking operations result in the production of oil or gas, this lease shall remain in full force and effect as long as oil or gas is produced in paying quantities from the leased area.

(d) By Shut-in Production. If there is a well capable of producing oil or gas in paying quantities on the leased area, this lease shall not expire because Lessee fails to produce the same unless the State gives notice to Lessee allowing a reasonable time, which shall not be less than six (6) months, after such notice to place the well on a producing status, and Lessee fails to do so. If producing status is established within the time allowed, this lease is extended only for so long thereafter as oil or gas is produced in paying quantities from the leased area.

(e) By Suspension of Operations or Production. This lease shall not expire because of any suspension of operations on or production from the leased area if the suspension is made under any order by, or with the written consent of, the State. Upon removal of such suspension, Lessee shall have a reasonable time, which shall not be less than six (6) months after notice that the suspension has been removed, to resume operations or production. For purposes of this subparagraph, any suspension of operations or production required by any stipulation made a part of this lease shall not be considered a suspension under any order by, or with the written consent of, the State.

(f) By Force Majeure. If the State determines that Lessee has been prevented by any of the conditions specified in Paragraph 32 from performing an act which would extend the lease beyond the primary term, this lease shall not expire during the term of disability plus a reasonable time thereafter, which shall not be less than sixty (60) days, for Lessee to resume operations or production.

6. RENTALS. (a) Lessee shall pay annual rental to the State in accordance with the following rental schedule:

(1) For the first year, $1.00 per acre or fraction thereof;

(2) For the second year, $1.50 per acre or fraction thereof;

(3) For the third year, $2.00 per acre or fraction thereof;

(4) For the fourth year, $2.50 per acre or fraction thereof;

(5) For the fifth year and following years, $3.00 per acre; provided that the State may increase the annual rental rate as provided by law upon extension of this lease beyond the primary term.

(b) Annual rental paid in advance is a credit on the royalty or net profit share due under this lease for that year.

(c) Lessee shall pay the annual rental to the State (or any depository designated by the State with at least sixty (60) days' notice to Lessee) in advance, on or before the annual anniversary date of this lease. The State is not required to give notice that rentals are due by billing Lessee, and no bill need be sent by the State to Lessee. If the State's (or depository's) office is not open for business on the annual anniversary date of this lease, the time for payment is extended to include the next day on which said office is open for business. If the annual rental is not paid timely, this lease automatically terminates as to both parties at 11:59 p.m., Alaska Standard Time, on the date by which the rental payment was to have been paid.

e/m AZ 1/11/80

7. SHARE OF NET PROFIT. Lessee will pay to the State 93.20000% of the net profit derived by Lessee from this lease. For purposes of this Paragraph, calculation of the net profit shall be determined in accordance with 11 AAC 83.201 through 11 AAC 83.295 as those regulations exist on the effective date of this lease, copies of ~~which are attached as Exhibit B~~ and by this reference made a part of this lease. The amount of interest to be earned on the net profit share development account pursuant to 11 AAC 83.212 will be the average of the prime rates of the Citibank, NA New York; Chase Manhattan Bank, NA New York; and the Bank of America, NT and SA San Francisco, prevailing during the month.

8. ROYALTY ON PRODUCTION. (a) Except for oil, gas and associated substances used on the leased area for development and production or unavoidably lost, Lessee shall pay to the State as royalty the following:

(1) On oil, twenty (20) percent in amount or value of the oil saved, removed, or sold from the leased area.

(2) On gas, twenty (20) percent in amount or value of the gas saved, removed or sold from the leased area or used on the leased area for the extraction of natural gasoline or other products therefrom.

(3) On associated substances, twenty (20) percent in amount or value of the associated substances saved, removed, or sold from the leased area.

9. REDUCTION OF ROYALTY. After two (2) years' initial production from the field in which the leased area is located has occurred, the State, in its discretion, may reduce Lessee's obligations to pay royalty on all of the leased area or on any tract or portion thereof segregated for royalty purposes upon (1) request by Lessee, (2) a clear showing by Lessee that the revenue from all oil, gas and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to Lessee's total investment in the field, and (3) a clear showing by Lessee that a reduction in royalty will increase total production from the field.

10. ROYALTY IN VALUE. Unless the State elects to receive all or a portion of its royalty in kind as provided in Paragraph 12 below, Lessee shall pay to the State the value of all royalty oil, gas and associated substances as determined under Paragraph 11 below. Royalty paid in value shall be free and clear of all lease expenses (and any portion of such expenses which is incurred away from the leased area), including, but not limited to, expenses for separation, cleaning, dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substances for transportation off the leased area. All royalty that may become payable in money to the State shall be paid on or before the last day of the calendar month following the month in which the oil, gas or associated substances are produced. Royalty payments shall be accompanied by copies of run tickets or such other information relating to valuation of royalty as the State may require, which may include, but is not limited to, evidence of sales, shipments, and amounts of gross oil, gas and associated substances produced.

11. VALUE. (a) For purposes of computing royalties due under this lease, the value of royalty oil, gas or associated substances shall not be less than the highest of:

(1) the field price actually received by Lessee for such oil, gas or associated substances;

(2) Lessee's posted price in the field for such oil, gas or associated substances;

(3) the volume weighted average field price actually received by other producers in the same field or area for oil of like grade and gravity, gas of like kind and quality or associated substances of like kind and quality at the time such oil, gas or associated substances are removed from the leased or unit area or such gas is delivered to an extraction plant if such a plant is located on the leased or unit area; or

(4) the volume weighted average posted price in the field of other producers in the same field or area for oil of like grade and gravity, gas of like kind and quality or associated substances of like kind and quality at the time such oil, gas or associated substances are removed from the leased or unit area or such gas is delivered to an extraction plant if such a plant is located on the leased or unit area.

(b) If oil, gas or associated substances are sold away from the leased or unit area, the term "field price" in subparagraph (a) above shall be the actual price for such oil, gas or associated substances received from the purchaser thereof less the actual cost of transportation away from the leased or unit area to the point of delivery.

(c) Minimum Value Determinations. The State may establish minimum values for purposes of computing royalties on oil, gas or associated substances obtained from this lease, with consideration being given to the price actually received by Lessee, to the price or prices paid in the same field or area for production of like quality, to posted prices, to prices received by Lessee and/or other producers from sales occurring away from the leased area, and to other relevant matters. Each such determination will be made only after Lessee has been given notice and a reasonable opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty oil, gas or associated substances under this lease may not necessarily equal the price of such oil, gas or associated substances.

12. ROYALTY IN KIND. (a) At the State's option, which may be exercised from time to time upon not less than six (6) months' notice to Lessee, Lessee shall deliver all or a portion of the State's royalty oil, gas or associated substances produced from the leased area in kind. Delivery shall be on the leased area or at a place mutually agreed to by the State and Lessee, and shall be to the State or to any individual, firm or corporation designated by the State.

(b) Royalty oil, gas or associated substances delivered in kind shall be delivered in good and merchantable condition and be of pipeline quality, and shall be free and clear of all lease expenses (and any portion of such expenses which are incurred away from the leased area), including, but not limited to, expenses for separation, cleaning, dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substances for transportation off the leased area.

(c) After having given notice of its intention to take, or after having taken, its royalty oil, gas or associated substances in kind, the State, at its option and upon six (6) months' notice to Lessee, may elect to receive a different portion or none of its royalty in kind. If, under federal regulations, the Lessor's taking of royalty oil, gas or associated substances in value creates a supplier-purchaser relationship, Lessee hereby waives its right to continue to receive royalty oil, gas or associated substances under such a relationship, and further agrees that it will require any purchasers of the royalty oil, gas or associated substances to likewise waive any such rights.

(d) Lessee shall furnish storage for royalty oil and natural gas liquids produced from the leased or unit area to the same extent that Lessee provides storage for Lessee's share of oil and natural gas liquids. Lessee shall not be liable for the loss or destruction of stored royalty oil and natural gas liquids from causes beyond Lessee's reasonable control.

13. RECORDS. Lessee shall keep and have in its possession books and records showing the development and production (including records of development and production expenses) and disposition of all oil, gas and associated substances produced from the leased area. Lessee shall permit the State or its agents to examine such books and records at all reasonable times. Such books and records of development and production must employ methods and techniques that will ensure the most accurate figures reasonably available without requiring Lessee to provide separate tankage and/or meters for each well. Lessee shall use standard and consistent accounting procedures which are common to the industry.

14. APPORTIONMENT OF ROYALTY FROM APPROVED UNIT. The landowner's royalty share of the unit production allocated to each separately owned tract shall be regarded as royalty to be distributed to and among, or the proceeds of it paid to, the landowners, free and clear of all unit expense and free of any lien for it. Under this provision, the State's royalty share of any unit production allocated to the leased area shall be regarded as royalty to be distributed to, or the proceeds of it paid to, the State, free and clear of all unit expenses (and any portion of such expenses which is incurred away from the unit area), including, but not limited to, expenses for separation, cleaning, dehydration, gathering, saltwater disposal, and preparing oil, gas or associated substances for transportation off the unit area, and free of any lien for it.

15. PAYMENTS. All payments to the State under this lease shall be made payable to the State in the manner directed by the State, and shall be tendered to the State at

DEPARTMENT OF NATURAL RESOURCES
323 EAST FOURTH AVENUE
ANCHORAGE, ALASKA 99501

or to any depository designated by the State with at least sixty (60) days' notice to Lessee.

16. PLAN OF OPERATIONS. (a) No lease operations other than surface reconnaissance may be undertaken by Lessee, its agents or assigns, on the leased area, except in conformity with a plan of operations approved by the State. Lessee shall file with the State four (4) copies of its application for approval of its proposed plan of operations.

(b) The application shall set forth a detailed proposed plan of operations, including, but not limited to, statements and maps or drawings setting forth each of the following: (1) the sequence and schedule of the operations proposed to be conducted on the leased area; (2) projected use requirements associated with the proposed operations, including, but not limited to, the location and design of well sites, material sites, water supplies, buildings, roads, utilities, airstrips and all other facilities necessary for exploration, development and production of the leased area; (3) plans for restoration of the leased area upon the completion of operations or phases thereof; and (4) a description of operating procedures designed to prevent or minimize adverse impacts upon other natural resources and other uses of the leased area and adjacent areas.

(c) Within sixty (60) days of Lessee's filing of complete application for approval of its proposed plan of operations, the State shall approve or deny the application. If the application is denied, the State shall state in writing its reasons for such denial and may propose modifications which, if accepted by Lessee, would qualify the plan for approval.

(d) Subsequent modification of an approved plan of operations may be proposed by Lessee. A modification of an approved plan of operations proposed by Lessee shall be considered under the same procedures used for review and approval of Lessee's original plan of operations.

(e) Approval by the State of a plan of operations or any modifications thereto signifies only that the State has no objection to the operations outlined in the plan from the standpoint of the lease administrator and does not relieve Lessee of its obligations to obtain approvals and permits required by other governmental agencies having regulatory authority over such operations.

(f) All of Lessee's operations on the lease area shall be in conformance with the approved plan of operations.

17. PLAN OF DEVELOPMENT. (a) Within six (6) months after certification of a well capable of producing oil, gas or associated substances in paying quantities, Lessee shall file two (2) copies of an application for approval by the State of an initial plan of development. The initial plan of development shall describe Lessee's plans for developing the leased area. No development of the leased area may occur until a plan of development has been approved by the State.

(b) Within sixty (60) days of Lessee's filing of a complete application for approval of its proposed initial plan of development, the State shall approve or deny the application. If the application is denied, the State shall state in writing its reason for such a denial and may propose modifications which, if accepted by Lessee, would qualify the plan for approval.

(c) The plan of development shall be revised, updated and submitted for the State's approval annually on the anniversary date of this lease or on such other date as may be mutually agreed to by Lessee and the State. If no changes from an approved plan are contemplated for the following year, a statement to that effect shall be filed in lieu of the required revision and updating.

18. EXCEPTION FOR LEASE INCLUDED IN AN APPROVED UNIT. If this lease is included in an approved unit, the Lessee shall not be required to submit a separate plan of operations or plan of development under Paragraphs 16 and 17 above.

19. LOGS AND OTHER RECORDS OF OPERATIONS. (a) Lessee shall file all logs and surveys taken, a description of all tests run for each well drilled on the leased area, together with a plat showing the exact location of each such well, with the State within thirty (30) days after each such well has been completed, suspended or abandoned.

(b) Any and all information filed by Lessee with the State in connection with this lease shall be available at all times for the confidential use of the State for the purpose of enforcing compliance with the promises, terms, conditions and covenants of this lease and the provisions of State law. Inspection of such information by any persons other than officers or employees of the State (and persons performing any function or work assigned to them by the State) shall be governed by applicable law.

20. DIRECTIONAL DRILLING. This lease may be maintained in force by directional wells drilled under the leased area from locations on other lands not covered by this lease. In such circumstances, drilling shall be considered to have commenced on the leased area when actual drilling is commenced on such other lands for the purpose of directionally drilling under the leased area. Production of oil or gas from the leased area through any directional well surfaced on such other lands or drilling or reworking of such directional well shall be considered production or drilling or reworking operations on the leased area for all purposes of this lease. Nothing contained in this Paragraph is intended or shall be construed as granting to Lessee any interest, license, easement or other right in or with respect to such lands in addition to any such interest, license, easement or other right which the Lessee may have lawfully acquired from the State or from others.

21. DILIGENCE AND PREVENTION OF WASTE. (a) Lessee shall exercise reasonable diligence in drilling, producing and operating wells on the leased area unless consent to suspend operations temporarily is granted by the State.

(b) Upon discovery of oil or gas on the leased area in quantities which would appear to a reasonable and prudent operator to be sufficient to recover ordinary costs of drilling, completing and producing an additional well in the same geologic structure at another location with a reasonable profit to the operator, Lessee shall drill such wells as a reasonably prudent operator would drill, having due regard for the interest of the State as well as the interest of the Lessee.

(c) Lessee shall carry on all operations under this lease in a good and workmanlike manner in accordance with the methods and practices set out in the approved plan of operations and plan of development with due regard for the prevention of waste of oil, gas and associated substances and the entrance of water to the oil and gas-bearing sands or strata to the destruction or injury of the same, and to the preservation and conservation of the property for future productive operations. Lessee shall carry out at Lessee's expense all orders and requirements of the State relative to the prevention of waste and the preservation of the leased area. If Lessee fails to carry out such orders, the State shall have the right, together with any other available legal recourse, to enter on the leased area to repair damage or prevent waste at Lessee's expense.

(d) Lessee shall securely plug in an approved manner any well before abandoning it.

22. OFFSET WELLS. Lessee shall drill such wells as a reasonably prudent operator would drill to protect the State adequately from loss by reason of drainage resulting from production on other land. Without limiting the generality of the foregoing sentence, if oil or gas should be produced in a well on other land not owned by the State or on which the State receives a lower rate of royalty than under this lease, and such well is within 500 feet in the case of an oil well or 1,500 feet in the case of a gas well of lands then subject to this lease, and such well produces oil or gas for a period of thirty (30) consecutive days in quantities which would appear to a reasonable and prudent operator to be sufficient to recover ordinary costs of drilling, completing and producing an additional well in the same geologic structure at an offset location with a reasonable profit to the operator, and if, after notice to Lessee and an opportunity to be heard, the State finds that production from such well is draining lands then subject to this lease, Lessee shall within thirty (30) days after written demand by the State begin in good faith and diligently prosecute drilling operations for an offset well on the leased area. In lieu of drilling any well required by this Paragraph, Lessee may, with the State's consent, compensate the State in full each month for the estimated loss of royalty through drainage in the amount determined by the State.

23. UNITIZATION. (a) Lessee may unite with others, jointly or separately, in collectively adopting and operating under a cooperative or unit agreement for the exploration, development or operation of the pool or field or like area or part thereof which includes or underlies the leased area or any part thereof whenever a regulatory agency having appropriate jurisdiction determines and certifies that such an agreement is in the public interest for the purpose of properly conserving the natural resoures of any oil or gas pool, field or like area or any part thereof.

(b) Lessee agrees, within six (6) months after demand by the State, to subscribe to a reasonable cooperative or unit agreement which shall adequately protect all parties in interest, including the State. The State reserves the right to prescribe such an agreement.

(c) With the consent of Lessee, the State may establish, alter, change, or revoke drilling, producing, rental and royalty requirements of this lease if the leased area is committed to any such cooperative or unit agreement, and may adopt such regulations with reference to this lease in connection with the institution and operation of any such cooperative or unit agreement as the State determines are necessary and proper to secure the proper protection of the public interest.

(d) If a portion of the leased area or any separate and distinct zone or geological horizon is committed to an approved or prescribed unit agreement, the committed acreage or zone or horizon shall be segregated into a separate and distinct lease having the same effective date as this lease. Any portion of the leased area or any separate and distinct zones or geological horizons not committed to such a cooperative or unit agreement shall remain subject to the terms and conditions of this lease unaffected by the pooling or unitization of any other portion of the leased area or zone or horizon or by operations in any such unit.

24. INSPECTION. Lessee shall keep open at all reasonable times, for inspection by any duly authorized representative of the State, the leased area, all wells, improvements, machinery and fixtures thereon, and all reports and records relative to operations and surveys or investigations on or with regard to the leased area or under this lease.

25. SUSPENSION. The State may from time to time direct or approve in writing suspension of production or other operations under this lease.

26. ASSIGNMENT, PARTITION AND CONVERSION. This lease, or any undivided interest herein, may, with the approval of the State, be assigned, subleased or otherwise transferred as to the entire leased area or any one or more legal subdivisions included therein, or any separate and distinct zone or geological horizon underlying the leased area or such one or more legal subdivisions therein, to any person or persons qualified to hold a lease. No assignment, sublease or other transfer of an interest in this lease, including assignments of working or royalty interests and operating agreements and subleases, shall be binding upon the State unless approved by the State. Lessee shall remain liable for all obligations under this lease accruing prior to the approval by the State of any assignment, sublease or other transfer of an interest in this lease. All covenants, conditions and agreements contained in this lease shall extend to and be binding upon the heirs, administrators, successors, and assigns of the State and/or Lessee. Applications for approval of an assignment, sublease or other transfer shall comply with all applicable regulations and must be filed within ninety (90) days after the date of final execution of the instrument of transfer. Transfer of this lease or an interest therein shall be approved by the State unless (1) Lessee fails to comply with applicable statutes and regulations or (2) the State determines in writing that the best interests of the State justify a denial. Where an assignment, sublease or other transfer is made of all or a part of Lessee's interest in and to a portion of the leased area, that portion may, at the option of the State or upon request of the transferee and with the approval of the State, be segregated into a separate and distinct lease having the same effective date as this lease.

27. SURRENDER. Lessee at any time may make and file with the State a written surrender of all rights under this lease or any portion thereof comprising one or more legal subdivision or, with the consent of the State, any separate and distinct zone or geological horizon underlying the leased area or one or more legal subdivisions thereof. Such a surrender shall be effective as of the date of filing, subject to the continued obligations of Lessee and his surety to make payment of all accrued royalties and to place all wells and surface facilities on the surrendered land or in the surrendered zones or horizons in condition satisfactory to the State for suspension or abandonment. Thereafter, Lessee shall be released from all obligations under this lease with respect to the surrendered lands, zones or horizons.

28. DEFAULT AND TERMINATION; CANCELLATION. (a) The failure of Lessee to perform timely its obligations under this lease, or the failure of Lessee otherwise to abide by all express and implied promises, terms, conditions and covenants of this lease, shall be deemed to be a default in Lessee's obligations hereunder. Whenever Lessee fails to comply with any of the provisions of this lease (other than a provision which, by its terms, provides for automatic termination) and fails within sixty (60) days after written notice of such default to commence to remedy and thereafter diligently prosecute operations to remedy such default, the State may terminate this lease if at that time there is no well on the leased area capable of producing oil or gas in paying quantities. If at that time there is a well on the leased area capable of producing oil or gas in paying quantities, this lease may be terminated by an appropriate judicial proceeding. In the event of any termination under this subparagraph, Lessee shall have the right to retain under this lease any and all drilling or producing wells as to which no default exists together with a parcel of land surrounding each well or wells and such rights-of-way through the leased area as are reasonably necessary to enable Lessee to drill, operate, and transport oil and/or gas from such retained well or wells.

(b) The State may cancel this lease at any time if the State determines, after Lessee has been given notice and a reasonable opportunity to be heard, that (1) continued operations pursuant to this lease probably will cause serious harm or damage to biologic resources, to property, to mineral resources or to the environment (including the human environment), (2) the threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time, and (3) the advantages of cancellation outweight the advantages of continuing this lease in force. Any cancellation under this subparagraph shall not occur unless and until operations under this lease have been under suspension or temporary prohibition by the State, with due extension of the term of this lease, continuously for a period of five (5) years or for a lesser period upon request of the Lessee. Any cancellation under this subparagraph will entitle Lessee to receive such compensation as Lessee demonstrates to the State is equal to the lesser of (1) the value of the cancelled rights as of the date of cancellation, with due consideration being given to both anticipated revenues from this lease and anticipated costs, including costs of compliance with all applicable regulations and stipulations, liability for clean-up costs or damages, or both, in the case of an oil spill, and all other costs reasonably anticipated under this lease, or (2) the excess, if any, over Lessee's revenues from this lease (plus interest thereon from the date of receipt to date of reimbursement) of all consideration paid for this lease and all direct expenditures made by Lessee after the effective date of this lease and in connection with exploration or development, or both, pursuant to this lease, plus interest on such consideration and such expenditures from the date of payment to the date of reimbursement.

29. RIGHTS UPON TERMINATION. Upon the expiration or earlier termination of this lease as to all or any portion of the leased area, Lessee will be directed in writing by the State and shall have the right at any time within a period of one (1) year thereafter, or such extension thereof as may be granted by the State, to remove from the leased area or portion thereof all machinery, equipment, tools, and materials. Upon the expiration of such period and at the option of the State, any machinery, equipment, tools, and materials which Lessee has not removed from the leased area or portion thereof become the property of the State or may be removed by the State at Lessee's expense. At the option of the State, all improvements such as roads, pads and wells shall either be abandoned and the sites restored by Lessee to the satisfaction of the State or be left intact and Lessee absolved of all further responsibility as to their maintenance, repairs and eventual abandonment and restoration. Subject to the foregoing, Lessee shall deliver up the leased area or such portion or portions thereof in good condition.

30. DAMAGES AND INDEMNIFICATION. (a) No rights under reservations contained in leases or grants of Alaska land may be exercised by the State or by its Lessee until provision has been made to pay the owner of the land upon which the reserved rights are sought to be exercised full payment for all damages sustained by the owner by reason of entering on the land. If the owner for any reason refuses or neglects to settle the damages, the State or its Lessee may enter upon the land after posting a surety bond determined by the State, after notice and an opportunity to be heard, to be sufficient as to form, amount, and security to secure to the owner payment for damages, and may institute legal proceedings in a court of competent jurisdiction where the land is located to determine the damages which the owner of the land may suffer. Lessee hereby agrees to pay any damages that may become payable under AS 38.05.130 and to indemnify the State and hold it harmless from and against any claims, demands, liabilities and expenses arising from or in connection with such damages. The furnishing of a bond in compliance with this Paragraph shall be regarded by the State as sufficient provision for the payment of all damages that may become payable under AS 38.05.130 by virtue of this lease.

(b) Lessee shall indemnify the State for, and hold it harmless from, any claim, including claims for loss or damage to property or injury to a person or persons caused by or resulting from any act or omission committed pursuant to this lease by or on behalf of Lessee. Lessee shall not be held responsible to the State under this subparagraph for any loss, damage or injury caused by or resulting from the sole negligence of the State.

(c) Lessee expressly waives any defense to an action for breach of a covenant of this lease or for damages resulting from an oil spill or other harm to the environment which is based on the fact that the act or omission complained of was committed by an independent contractor. Lessee expressly agrees to assume responsibility for all actions of its independent contractors.

31. BONDS. (a) If required by the State, Lessee shall furnish a bond prior to the issuance of this lease in an amount equal to at least $5.00 per acre or fraction thereof contained in the leased area, but no less than $10,000.00, and shall maintain said bond as long as required by the State.

(b) Before beginning drilling operations on the leased area, Lessee shall furnish a bond in the amount of at least $100,000.00 and shall maintain said bond as long as required by the State.

(c) Lessee may, in lieu of the bond required under (a) above, furnish and maintain a Statewide bond in accordance with applicable regulations.

(d) The State may, after notice to Lessee and a reasonable opportunity to be heard, require a bond in a reasonable amount greater than the amount specified in (a) and (b) above where such greater amount is justified by the nature of the surface and its uses and the degree of risk involved in the types of operations being or to be carried out under this lease. A Statewide bond shall not satisfy any requirement of a bond imposed under this subparagraph, but shall be considered by the State in determining the need for and the amount of any additional bond under this subparagraph.

(e) If the leased area is committed in whole or in part to a cooperative or unit agreement approved or prescribed by the State and a unit bond is furnished, Lessee need not thereafter maintain any bond with respect to the portion of the leased area committed to such agreement.

32. FORCE MAJEURE. If the State determines that Lessee has been prevented, after efforts made in good faith, from complying with any express or implied promise, term, condition or covenant of this lease, from conducting drilling operations, or from producing or marketing oil or gas from the leased area, by reason of war, riots, acts of God, unusually severe weather, or any other cause beyond Lessee's reasonable ability to foresee or control (including delays caused by judicial decisions or lack thereof), whether similar to those enumerated or not, Lessee's obligation to comply with such provision shall be suspended, but not voided, and Lessee shall not be liable for damages for failure to comply therewith. If Lessee's obligations to conduct drilling or reworking operations are suspended under this Paragraph and the continuation of such operations without suspension would have had the effect of preventing the expiration or termination of this lease, this lease shall not terminate during the period which the obligation to perform such operations is suspended. Nothing in this Paragraph shall be construed to suspend the obligation to pay rentals, or to suspend the obligation to pay royalties or other production or profit-based payments from operations on the leased area which are not suspended or from operations which are not affected by any such suspension, to the State.

33. AUTHORIZED REPRESENTATIVES. The State Director of the Division of Minerals and Energy Management, Department of Natural Resources, and the person executing this lease on behalf of Lessee shall be the authorized representatives for their respective principals for purposes of administering this lease. The State or Lessee may change the designation of its authorized representative or the address to which notices to that representative are to be sent by a notice given in accord with Paragraph 34 below. Where activities pursuant to a plan of operations are underway, Lessee will also designate, pursuant to a notice under Paragraph 34 below, by name, job title and address, an agent who will be present in the State during all such activities.

34. NOTICES. Any notices required or permitted under this lease shall be by electronic media producing a permanent record or in writing and shall be given personally or by registered or certified mail, return receipt requested, addressed as follows:

TO THE STATE:

DIRECTOR, DIVISION OF MINERALS AND ENERGY MANAGEMENT
DEPARTMENT OF NATURAL RESOURCES
703 W. NORTHERN LIGHTS BOULEVARD
ANCHORAGE, ALASKA 99503

TO THE LESSEE:
Amerada Hess Corporation
C/o N. D. Bernard
P. O. Box 2040
Tulsa, Oklahoma 74102

Any such notice shall be effective when delivered to the foregoing authorized representative.

35. STATUTES AND REGULATIONS. This lease is subject to all State and Federal statutes and regulations in effect on the effective date hereof, and, insofar as is constitutionally permissible, to all statutes and regulations hereinafter placed in effect. This lease shall not be interpreted as a limitation upon the exercise by the State of Alaska or by the United States of America of the power to enact and enforce legislation or to promulgate and enforce regulations affecting, directly or indirectly, the activities of Lessee or its agents in connection with this lease or the value of the interests held under this lease.

36. INTERPRETATION. This lease is to be interpreted in accordance with the rules applicable to the interpretation of contracts made in the State of Alaska. The Paragraph headings are not part of this lease and are inserted only for convenience. The State and Lessee expressly covenant that the law of the State of Alaska shall apply in any judicial proceeding under this lease.

37. INTEREST IN REAL PROPERTY. It is the intention of the parties that the rights granted to Lessee by this lease constitute an interest in real property in the lease area.

38. SEVERABILITY. If it is finally determined in any judicial proceeding that any provision of this lease is invalid, the State and Lessee may jointly determine and agree by a written amendment to this lease that, in consideration of the promises, terms, conditions and covenants contained in that written amendment, the invalid portion of the lease will be treated as severed from the lease and that the remainder of the lease, as amended, will remain in effect.

39. DEFINITIONS. All words and phrases used in this lease are to be interpreted where possible in the manner required in respect to the interpretation of statutes by AS 01.10.040. However, the following words have the following meanings unless the context unavoidably requires otherwise:

(1) "oil" means crude petroleum oil and other hydrocarbons regardless of gravity which are produced in liquid form by ordinary production methods, including liquid hydrocarbons known as distillate or condensate recovered by separation from gas other than at a gas processing plant;

(2) "gas" means all natural gas (except helium gas) and all other hydrocarbons produced which are not defined herein as oil;

(3) "associated substances" means all substances except helium produced as an incident of production of oil or gas by ordinary production methods and not defined herein as oil or gas;

(4) "drilling" means the act of boring a hole to reach a proposed bottom hole location through which oil or gas may be produced if encountered in paying quantities, and includes redrilling, sidetracking, deepening or other means necessary to reach the proposed bottom hole location, testing, logging, plugging and other operations necessary and incidental to the actual boring of the hole;

(5) "reworking operations" means all operations designed to secure, restore or improve production through some use of a hole previously drilled, including, but not limited to, mechanical or chemical treatment of any horizon, plugging back to test higher strata, etc; and

(6) "paying quantities" means quantities sufficient to yield a return in excess of operating costs, even though drilling and equipment costs may never be repaid and the undertaking considered as a whole may ultimately result in a loss.

40. CONDITIONAL LEASE. If all or a part of the leased area is land that has been selected by the State under laws of the United States granting lands to the State, but such land has not been patented to the State by the United States, then this lease is a conditional lease as provided by law until such a patent becomes effective. If for any reason such a selection is not finally approved, or such a patent does not become effective, any rental, royalty or profit-based payments made to the State under this lease will not be refunded.

41. EMPLOYMENT OF ALASKAN RESIDENTS. Lessee shall comply with all valid and applicable laws and regulations with regard to the hiring of Alaska residents. Lessee will not discriminate against Alaska residents, as prohibited by applicable laws and regulations of the State of Alaska. Lessee will furnish the Alaska Department of Labor a quarterly report regarding the employment of Alaska residents on the leased area in compliance with regulations adopted by the Commissioner of Labor.

IN WITNESS WHEREOF the parties have executed this lease effective as of the 1st day of February, 19 80.

LESSEE
AMERADA HESS CORPORATION

By _____
V. M. Hebertson, Vice President, U.S. Exploration & Offshore Joint Venture Operations

STATE OF ALASKA

By: Ethel H. Nelson
ETHEL H. NELSON
Title: Leasing Manager

THE UNITED STATES OF AMERICA)
) ss.
STATE OF ALASKA)

Acknowledgement of Lessor

This certifies that on the 11th day of January 19 80, before me, a notary public in and for the State of Alaska, duly commissioned and sworn, personally appeared ETHEL H. NELSON to me known to be the person who executed the foregoing lease on behalf of the State of Alaska, who, after being duly sworn according to law, stated to me under oath that he has authority pursuant to law to execute the foregoing lease on behalf of the State of Alaska, acting through the Division of Minerals and Energy Management, Department of Natural Resources and that he executed the same freely and voluntarily as the act and deed of the State of Alaska and for the Division of Minerals and Energy Management, Department of Natural Resources.

WITNESS my hand and official seal.

Mary K. Weisenberger
Notary Public in and for Alaska
My Commission expires 3/29/83

MARY K. WEISENBERGER
NOTARY PUBLIC
STATE OF ALASKA

RECEIVED
JAN

STATE OF ALASKA
30th COMPETITIVE OIL AND GAS LEASE SALE
– BEAUFORT SEA –

LEASE STIPULATIONS

ADL 312798

State Stipulation No. 1 - Historic and Archaeologic Discoveries

In the event any site, structure, or object of historic or archaeologic significance should be discovered during the conduct of any operations on the leased area, the lessee shall report immediately such findings to the Director, Division of Minerals and Energy Management, and make every reasonable effort to preserve and protect such site, structure, or object from damage until the Director has given directions as to its preservation.

Upon abandonment of the drilling platform or related facilities, such facilities will be removed to the extent that they no longer intrude on the historic or cultural scene or could otherwise adversely affect an archaeologic, or historic site or area included in or eligible for inclusion in the National Register of Historic Places.

State Stipulation No. 2 - Environmental Training

The lessee shall include in any exploration and/or development plans a proposed environmental training program for all personnel involved in exploration or development activities (including personnel of the lessee's contractors and subcontractors) for review and approval by the Director, Division of Minerals and Energy Management. The program shall be designed to inform each person working on the project of specific types of environmental, social, and cultural concerns which relate to the individual's job. The program shall be formulated and implemented by qualified instructors experienced in each pertinent field of study and shall employ effective methods to ensure that personnel understand and use techniques necessary to preserve archaeological, geological, and biological resources. The program shall also be designed to increase the sensitivity and understanding of personnel to community values, customs, and lifestyles in areas in which such personnel will be operating.

The lessee shall also submit for review and approval a continuing technical environmental briefing program for supervisory and managerial personnel of the lessee and its agents, contractors, and subcontractors.

State Stipulation No. 3 - Site Restoration

After completion of the exploratory drilling phase, all structures will be removed from the lease and the lessee will restore the site to its original condition unless the structure or site will be used in the production phase or for additional exploratory drilling or unless it is not in the best interest of the public or the environment to require removal or restoration. Authorization to leave the structure in place must be obtained from the Director, Division of Minerals and Energy Management, after consultation with the Department of Fish and Game and the Department of Environmental Conservation.

~~State Stipulation No. 4 - Surface Entry~~

~~Surface entry by the lessee or subcontractors will be prohibited on Cross Island (State leasing unit BF-54) and Pole Island (State leasing units BF-91 and BF-92) during the period May 15 to August 15. Surface entry during other periods may be permitted by the Director, Division of Minerals and Energy Management, provided any structures, equipment, personnel, or supplies are removed before May 15.~~

State Stipulation No. 5 - Special Biological Resources

If biological populations or habitats which may require additional protection are identified by the Director, Division of Minerals and Energy Management, on any tracts in the leasing area, the Director will require the lessee to conduct environmental surveys, as approved by the Director, to determine the extent and composition of biological populations or habitats, and the effects of proposed or existing operations on the populations or habitats which might require additional protective measures. The Director shall provide written notice to the lessee of his decision to require such surveys. Such surveys will be required for the area known as the Boulder Patch, which applies to the following leasing units: BF-62, BF-70, BF-71, BF-76, BF-77, BF-78, BF-79, BF-82, BF-83, BF-98, and BF-116. For all other tracts within the lease area, the nature and extent of any surveys will be determined by the Director on a case-by-case basis.

Based on any surveys which the Director may require of the lessee, or other information available to the Director on special biological resources, the Director may require the lessee to: (1) locate the site of such operation so as not to adversely affect the resource identified; (2) establish to the satisfaction of the Director, on the basis of a site-specific survey, either that such operation will not have a significant adverse effect upon the resource identified or that a special biological resource does not exist; (3) operate during those periods of time that do not adversely affect the biological resources as established by the Director; and (4) modify operations in such a way as not to affect adversely the significant biological populations or habitats deserving protection.

The lessee agrees that, if any area of biological significance should be discovered during the conduct of any operations on the leased area, he shall immediately report such findings to the Director, and make every reasonable effort to preserve and protect the biological resource from damage until the Director has given the lessee directions with respect to its protection.

The lessee shall submit all data obtained in the course of such surveys to the Director, with the locational information for drilling or other activity. The lessee may take no action that might result in any effect on the biologic populations or habitats surveyed, until the Director provides written directions to the lessee, with regard to permissible actions.

Known special biological resources and their habitats include hard and rocky bottoms with kelp, bryozoans, sponges, coral, or other epibenthic communities.

State Stipulation No. 6 - Drilling Discharges

1. Discharge of produced waters into marine waters is prohibited, except that the Commissioner of the Department of Environmental Conservation may approve discharges in tracts greater than 10 meters of water on a case-by-case basis.

2. Discharge of drilling muds and cuttings into marine waters is prohibited, except that the Commissioner of the Department of Environmental Conservation may approve discharges (a) in tracts greater than 10 meters of water on a case-by-case basis and (b) in tracts of less than 10 meters of water on a case-by-case basis if effluents are shown to be non-toxic and can be adequately dispersed.

State Stipulation No. 7 - Pipelines

1. Pipelines will be required (a) if pipeline rights-of-way can be determined and obtained; (b) if laying such pipelines is technically feasible and environmentally preferable; and (c) if, in the opinion of the lessor, pipelines can be laid without net social loss, taking into account any incremental costs of pipelines over alternative methods of transportation and any incremental benefits in the form of increased environmental protection or reduced multiple-use conflicts. The lessor specifically reserves the right to require that any pipeline used for transporting production to shore be placed in certain designated managment areas. In selecting the means of transportation, consideration will be given to any recommendation of the Beaufort Sea Coordination Committee. Where feasible, and environmentally preferable, all pipelines, including both flow lines and gathering lines for oil and gas, shall be designed and constructed to provide for adequate protection from water currents, storm and ice scouring, subfreezing conditions, and other hazards as determined on a case-by-case basis.

2. Following the completion of pipeline installation of sufficient capacity, no crude oil production will be transported by surface vessel from offshore production sites, except in the case of emergency. Determinations as to emergency conditions and appropriate responses to these conditions will be made by the Director, Division of Minerals and Energy Management.

3. Where the three criteria set forth in the first sentence of this stipulation are not met and surface transportation must be employed, all vessels used for carrying hydrocarbons to shore from the leased area will conform with all standards established for such vessels, pursuant to the Ports and Waterways Safety Act of 1972 (46 U.S.C. 391(a)).

State Stipulation No. 8 - Solid Waste

Solid waste disposal on natural or artificial islands or in marine waters within the lease area is prohibited.

State Stipulation No. 9 - Seasonal Operations

Exploratory drilling and testing, and other downhole exploratory activities from surface locations outside the barrier islands will be limited to the period November 1 through March 31, unless the Director, Division of Minerals and Energy Management, after consulting with the Oil and Gas Conservation Commission, determines that continued operations are necessary to prevent a loss of well control or to ensure human safety. This stipulation will remain in effect for two years following issuance of the lease.

Exploratory drilling and testing, and other downhole exploratory activities from surface locations inside the barrier islands will be limited to the period November 1 through March 31, except the Director, Division of Minerals and Energy Management after consultation with the Biological Task Force may allow drilling and downhole activities to continue no later than May 15 if the lessee demonstrates the ability to operate safely and ice conditions justify; provided, however, that the Director, Division of Minerals and Energy Management, after consultation with the Oil and Gas Conservation Commission may allow continued operations leading to shut down which are necessary to prevent loss of well control or to ensure human safety. This stipulation will remain in effect two years following issuance of the lease.

~~State Stipulation No. 10 - Operational Restrictions (Block 700)~~

Exploratory drilling operations, emplacement of structures (platforms) or seafloor wellheads for production or storage of oil or gas, and the emplacement of pipelines will not be allowed on the state-owned portion of lease block 700. All exploration for and development of oil and gas must be performed from locations outside of the state-owned portion of lease block 700.

State Stipulation No. 11 - Interim Agreement

This lease is subject to the "Agreement Between the United States and State of Alaska pursuant to Section 7 of the Outer Continental Shelf Lands Act, and Alaska Statutes 38.05.137" (signed on October 26, 1979, and commonly referred to as the "Interim Agreement"), and the lessee hereby consents to every term of that agreement.

Any loss incurred or sustained by the lessee as a result of obtaining validation and recognition of this lease pursuant to the "Interim Agreement," and in particular any loss incurred or sustained by the lessee as a result of conforming this lease with any and all provisions of all applicable laws of the party prevailing in United States of America v. State of Alaska, United States Supreme Court No. 84, Original, shall be borne exclusively by the lessee.

No taxes payable to the State of Alaska will be required to be paid with respect to this lease until such time as ownership of or jurisdiction over the lands subject to this lease is resolved. In the event that the lands subject to this lease, or any portion of them, are judicially determined to be state lands, the lessee shall pay to the State a sum equivalent to the state taxes which would have been imposed under Alaska law if the lands, or portion thereof determined to be state lands, had been undisputed state lands from the date the lease was executed, plus interest at the rate of 10 percent per year accruing from the date the taxes would have become due under Alaska law. Such payment shall be in lieu of and in satisfaction of the actual state taxes.

State Stipulation No. 12 - Unitization Agreement

This lease is subject to the "Agreement Regarding Unitization for the Proposed Joint Federal/State Beaufort Sea Lease Sale" executed by the United States and State of Alaska on October 26, 1979, and the lessee is bound by the terms of that agreement.

State Stipulation No. 13 - Seismic Activity

Seismic activity will be prohibited during the period March 20 until the breakup of sea ice, except that the Director, Division of Minerals and Energy Management, after consulting with the Biological Task Force, may allow seismic activity to occur after March 20 on a case-by-case basis.

State Stipulation No. 14 - Coastal Zone

During the conduct of all activities related to this lease, the lessee will be subject to the provisions of all valid coastal zone plans and ordinances.

~~State Stipulation No. 15 - Coastal Zone~~

If the State is ultimately determined to be the owner of lands on which this lease is located, conduct of all activities on this lease will thereafter be subject to the provisions of all valid coastal zone plans and ordinances.

State Stipulation No. 16 - Drilling Commitment (Five-Year)

The lessee must commence to drill a well, or commit the lease to an exploratory unit approved by the Commissioner of Natural Resources, by the end of the fifth year of the lease. If a well has not been commenced or the lease has not been committed to an approved unit by that time, ~~the lease terminates automatically as to both parties.~~

State Stipulation No. 17 - Drilling Commitment (Seven-Year)

The lessee must commence to drill a well, or commit the lease to an exploratory unit approved by the Commissioner of Natural Resources, by the end of the seventh year of the lease. If a well has not been commenced or the lease has not been committed to an approved unit by that time, the lease terminates automatically as to both parties.

~~State Stipulation No. 18 - Royalty in Kind~~

Although the royalty rate specified in this lease, or as subsequently modified in accordance with applicable regulations and stipulations, is applicable to all production under this lease, not more than 16.66667 percent of the production saved, removed, or sold from the leased area may be taken as royalty in amount (in kind); the royalty on any portion of the production saved, removed, or sold from the lease in excess of 16.66667 percent may only be taken in value of the production saved, removed, or sold from the leased area.

State Stipulation No. 19 - Royalty in Kind

Although the royalty rate specified in this lease or as subsequently modified in accordance with applicable regulations and stipulations, is applicable to all production under this lease, not more than twenty (20) percent of the production saved, removed, or sold from the leased area may be taken as royalty in amount (in kind); the royalty on any portion of the production saved, removed, or sold from the lease in ~~excess of twenty (20) percent may only be taken in value of the production saved, removed, or sold from the leased area.~~

FORM NO. DMEM-4-83
(NET PROFIT SHARE)
(Revised May 5, 1983)
DNR 10-1113

BOOK 40 PAGE 844
Barrow Recording District

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES

Competitive Oil and Gas Lease

ADL No. 355001

THIS LEASE is entered into August 1 , 1983 , between the State of Alaska, "the state," and

J. ANDREW BACHNER (30%), JAMES F. DIERINGER, JR. (15%), W.G. STROECKER (22.5%), RICHARD E. WAGNER (32.5%)

"the lessee," whether one or more, whose sole address for purposes of notification under Paragraph 25 is

J. Andrew Bachner et al
c/o Main Hurdman
1001 Noble Street, Fairbanks, AK 99701

In consideration of the cash payment made by the lessee to the state, which payment includes the first year's rental and any required cash bonus, and subject to the provisions of this lease, including applicable stipulation(s) and mitigating measures attached to this lease and by this reference incorporated in this lease, the state and the lessee agree as follows:

1. GRANT. (a) Subject to the provisions in this lease, the state grants and leases to the lessee, without warranty, the exclusive right to drill for, extract, remove, clean, process, and dispose of oil, gas, and associated substances in or under the following described tract of land:

TRACT 39-01

T. 13 N., R. 13 E., Umiat Meridian, Alaska

Section 17, Protracted, All, 640.00 acres;
Section 18, Protracted, All, 631.00 acres;
Section 19, Protracted, All, 633.00 acres;
Section 20, Protracted, All, 640.00 acres;
Section 25, Protracted, All, 640.00 acres;
Section 26, Protracted, All, 640.00 acres;
Section 27, Protracted, All, 640.00 acres;
Section 28, Protracted, All, 640.00 acres;
Section 29, Protracted, All, 640.00 acres.

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DIVISION OF OIL & GAS
ANCHORAGE, ALASKA

containing approximately 5744.00 acres, more or less (referred to in this lease as the "leased area"); the nonexclusive right to conduct within the leased area geological and geophysical exploration for oil, gas, and associated substances; and the nonexclusive right to install pipelines and build structures on the leased area to find, produce, save, store, treat, process, transport, take care of, and market all oil, gas, and associated substances and to house and board employees in its operations on the leased area. The rights granted by this lease are to be excercised in a manner which will not unreasonably interfere with the rights of any permittee, lessee or grantee of the state consistent with the principle of reasonable concurrent uses as set out in article VIII, section 8 of the Alaska Constitution.

(b) For the purposes of this lease, the leased area contains the legal subdivisions as shown on the attached plat marked Exhibit A.

(c) If the leased area is described by protracted legal subdivisions and, after the effective date of this lease, the leased area is surveyed under the public land rectangular system, the boundaries of the leased area are those established by that survey, when approved, subject, however, to the provisions of applicable regulations relating to those surveys. If for any reason the leased area includes more acreage than the maximum permitted under applicable law (including the "rule of approximation" authorized in AS 38.05.145 and defined in AS 38.05.365(13)), this lease is not void and the acreage included in the leased area must be reduced to the permitted maximum. If the state determines that the leased area exceeds the permitted acreage and notifies the lessee in writing of the amount of acreage that must be eliminated, the lessee must have 60 days after that notice to surrender one or more legal subdivisions included in the leased area comprising at least the amount of acreage that must be eliminated. Any subdivision surrendered must be located on the perimeter of the leased area as originally described. If a surrender is not filed within 60 days, the state may terminate this lease as to the acreage that must be eliminated by mailing notice of the termination to the lessee describing the subdivision eliminated.

(d) If the State of Alaska's ownership interest in the oil, gas, and associated substances in the leased area is less than an entire and undivided interest, the grant under this lease is effective only as to the state's interest in that oil, gas, and associated substances, and the royalties and rentals provided in this lease must be paid to the state in the proportion that the state's interest bears to the entire undivided fee.

(e) The state makes no representations or warranties, express or implied, as to title, or access to, or quiet enjoyment of, the leased area. The state is not liable to the lessee for any deficiency in title to the leased area, nor is the lessee or any successor in interest to the lessee entitled to any refund due to deficiency in title for any rentals, bonuses, or royalties paid under this lease.

2. RESERVED RIGHTS. (a) The state, for itself and others, reserves all rights not expressly granted to the lessee by this lease. These reserved rights include, but are not limited to:

(1) the right to explore for oil, gas, and associated substances by geological and geophysical means;

(2) the right to explore for, develop, and remove natural resources other than oil, gas, and associated substances on or from the leased area;

(3) the right to establish or grant easements and rights-of-way for any lawful purpose, including without limitation for shafts and tunnels necessary or appropriate for the working of the leased area or other lands for natural resources other than oil, gas, and associated substances;

(4) the right to dispose of land within the leased area for well sites and well bores of wells drilled from or through the leased area to explore for or produce oil, gas, and associated substances in and from lands not within the leased area; and

(5) the right otherwise to manage and dispose of the surface of the leased area or interests in that land by grant, lease, permit, or otherwise to third parties.

(b) The rights reserved may be exercised by the state, or by any other person or entity acting under authority of the state, in any manner that does not unreasonably interfere with or endanger the lessee's operations under this lease.

3. TERM. This lease is issued for an initial primary term of 10 years from the effective date of this lease. The term may be extended as provided in Paragraph 4 below.

4. EXTENSION. (a) This lease will be extended automatically if and for so long as oil or gas is produced in paying quantities from the leased area.

(b) This lease will be extended automatically if it is committed to a unit agreement approved or prescribed by the state, and will remain in effect for so long as it remains committed to that unit agreement.

(c) (1) If the drilling of a well whose bottom hole location is in the leased area has commenced as of the date on which the lease otherwise would expire and is continued with reasonable diligence, this lease will continue in effect until 90 days after cessation of that drilling and for so long as oil or gas is produced in paying quantities from the leased area.

(2) If oil or gas in paying quantities is produced from the leased area, and if that production ceases at any time, this lease will not terminate if drilling or reworking operations are commenced on the leased area within six months after cessation of production and are prosecuted with reasonable diligence; if those drilling or reworking operations result in the production of oil or gas, this lease will remain in effect for so long as oil or gas is produced in paying quantities from the leased area.

(d) If there is a well capable of producing oil or gas in paying quantities on the leased area, this lease will not expire because the lessee fails to produce that oil or gas unless the state gives notice to the lessee, allowing a reasonable time, which will not be less than six months after notice, to place the well into production, and the lessee fails to do so. If production is established within the time allowed, this lease is extended only for so long as oil or gas is produced in paying quantities from the leased area.

(e) If the state directs or approves in writing a suspension of all operations on or production from the leased area (except for a suspension necessitated by the lessee's negligence), or if a suspension of all operations on or production from the leased area has been ordered under federal, state, or local law, the lessee's obligation to comply with any express or implied provision of this lease requiring operations or production will be suspended, but not voided, and the lessee shall not be liable for damages for failure to comply with that provision. If the suspension occurs before the expiration of the primary term, the primary term will be extended at the end of the period of the suspension by adding the period of time lost under the primary term because of the suspension. If the suspension occurs during an extension of the primary term under this paragraph, upon removal of that suspension, the lessee will have a reasonable time, which will not be less than six months after notice that the suspension has been removed, to resume operations or production. For the purposes of this subparagraph, any suspension of operations or production specifically required or imposed as a term of sale or by any stipulation made a part of this lease will not be considered a suspension ordered by law.

(f) If the state determines that the lessee has been prevented by force majeure, after efforts made in good faith, from performing any act that would extend the lease beyond the primary term, this lease will not expire during the period of force majeure. If the force majeure occurs before the expiration of the primary term, the primary term will be extended at the end of the period of force majeure by adding the period of time lost under the primary term because of the force majeure. If the force majeure occurs during an extension of the primary term under this paragraph, this lease will not expire during the period of force majeure plus a reasonable time after that period, which will not be less than 60 days, for the lessee to resume operations or production.

(g) Nothing in subparagraph (e) or (f) suspends the obligation to pay royalties or other production or profit-based payments to the state from operations on the leased area that are not affected by any suspension or force majeure, or suspends the obligation to pay rentals.

5. RENTALS. (a) The lessee shall pay annual rental to the state in accordance with the following rental schedule:

(1) For the first year, $1.00 per acre or fraction of an acre;

(2) For the second year, $1.50 per acre or fraction of an acre;

(3) For the third year, $2.00 per acre or fraction of an acre;

(4) For the fourth year, $2.50 per acre or fraction of an acre;

(5) For the fifth year and following years, $3.00 per acre or fraction of an acre; provided that the state may increase the annual rental rate as provided by law upon extension of this lease beyond the primary term.

(b) Annual rental paid in advance is a credit on the royalty or net profit share due under this lease for that year.

(c) The lessee shall pay the annual rental to the State of Alaska (or any depository designated by the state with at least 60 days notice to the lessee) in advance, on or before the annual anniversary date of this lease. The state is not required to give notice that rentals are due by billing the lessee. If the state's (or depository's) office is not open for business on the annual anniversary date of this lease, the time for payment is extended to include the next day on which that office is open for business. If the annual rental is not paid timely, this lease automatically terminates as to both parties at 11:59 p.m., Alaska Standard Time, on the date by which the rental payment was to have been made.

6. RECORDS. The lessee shall keep and have in its possession books and records showing the development and production (including records of development and production expenses) and disposition (including records of sales prices, volumes, and purchasers) of all oil, gas, and associated substances produced from the leased area. The lessee shall permit the State of Alaska or its agents to examine these books and records at all reasonable times. These books and records of development, production, and disposition must employ methods and techniques that will ensure the most accurate figures reasonably available without requiring the lessee to provide separate tankage or meters for each well. The lessee shall use standard and consistent accounting procedures.

7. APPORTIONMENT OF ROYALTY FROM APPROVED UNIT. The state's royalty share of the unit production allocated to each separately owned tract must be regarded as royalty to be distributed to and among, or the proceeds of it paid to, the state, free and clear of all unit expenses and free of any lien for them. Under this provision, the state's royalty share of any unit production allocated to the leased area will be regarded as royalty to be distributed to, or the proceeds of it paid to, the state, free and clear of all unit expenses (and any portion of those expenses incurred away from the unit area), including, but not limited to, expenses for separating, cleaning, dehydration, gathering, saltwater disposal, and preparing oil, gas, or associated substances for transportation off the unit area, and free of any lien for them.

8. PAYMENTS. All payments to the State of Alaska under this lease must be made payable to the state in the manner directed by the state, and, unless otherwise specified, must be tendered to the state at

DEPARTMENT OF NATURAL RESOURCES
POUCH 7-005
ANCHORAGE, ALASKA 99510
ATTENTION: ACCOUNTING

or to any depository designated by the state with at least 60 days notice to the lessee.

9. PLAN OF OPERATIONS. (a) Except as provided in subparagraph (b) below, no lease operations may be undertaken on the leased area until a plan of operations has been approved by the state if:

(1) the State of Alaska owns all or part of the surface estate of the leased area;

(2) the lease reserves a net profit share to the State of Alaska; or

(3) the State of Alaska owns all or part of the mineral estate, but the entire surface estate of the leased area is owned by a party other than the State of Alaska and a surface owner requests that a plan of operations be required by the state for the portion of the leased area owned by that surface owner.

(b) A lease plan of operations will not be required by the state for:

(1) lease operations that would not require a land use permit under 11 AAC; or

(2) lease operations undertaken under an approved unit plan of operations in accordance with 11 AAC.

(c) Before undertaking operations on the leased area, the lessee shall provide for full payment of all damages sustained by the owner of the surface estate as well as by the surface owner's lessees and permittees by reason of entering the land. If the surface estate is owned by a party other than the State of Alaska, the lessee shall also notify the surface owner of his opportunity to request that the state require a plan of operations before allowing lease operations to be undertaken on the portion of the leased area owned by the requesting surface owner.

(d) The lessee shall file with the state 10 copies of its proposed plan of operations if the proposed operations are within the coastal zone, and five copies if the proposed operations are not within the coastal zone.

(e) An application for approval of a plan of operations must contain sufficient information, based on data reasonably available at the time the plan is submitted for approval, for the state to determine the surface use requirements and impacts directly associated with the proposed operations. An application must include statements and maps or drawings setting out the following:

(1) the sequence and schedule of the operations to be conducted on the leased area, including the date operations are proposed to begin and their proposed duration;

(2) projected use requirements directly associated with the proposed operations, including but not limited to the location and design of well sites, material sites, water supplies, solid waste sites, sumps, buildings, roads, utilities, airstrips, and all other facilities and equipment necessary to conduct the proposed operations;

(3) plans for rehabilitation of the affected leased area after completion of operations or phases of those operations; and

(4) a description of operating procedure designed to prevent or minimize adverse effects on other natural resources and other uses of the leased area and adjacent areas, including fish and wildlife habitats, historic and archeological sites, and public use areas.

(f) In approving a lease or unit plan of operations, or an amendment of a plan, the state will require amendments it determines necessary to protect the state's interest, including the environment. The state will not require any amendment that would be inconsistent with the terms of sale under which the lease was obtained or with the terms of the lease itself, or would deprive the lessee of reasonable use of the leasehold interest.

(g) The lessee may, with the approval of the state, amend an approved plan of operations.

(h) Approval by the state of a plan of operations or any modifications of a plan of operations signifies only that the state has no objection to the operations outlined in the plan from the standpoint of the lease administrator and does not relieve the lessee of its obligation to obtain approvals and permits required by other governmental agencies having regulatory authority over those operations.

(i) All of the lessee's operations on the leased area must be in conformance with the approved plan of operations.

(j) Upon completion of operations, the lessee shall inspect the area of operations and submit a report indicating the completion date of operations and stating any noncompliance of which the lessee knows, or should reasonably know, with requirements imposed as a condition of approval of the plan.

10. PLAN OF DEVELOPMENT. (a) Except as provided in subparagraph (d) below, within 12 months after certification of a well capable of producing oil, gas, or associated substances in paying quantities, the lessee shall file two copies of an application for approval by the state of an initial plan of development that must describe the lessee's plans for developing the leased area. No development of the leased area may occur until a plan of development has been approved by the state.

(b) The plan of development must be revised, updated, and submitted to the state for approval annually before or on the anniversary date of the previously approved plan. If no changes from an approved plan are contemplated for the following year, a statement to that effect must be filed for approval in lieu of the required revision and update.

(c) The lessee may, with the approval of the state, subsequently modify an approved plan of development.

(d) If the leased area is included in an approved unit, the lessee will not be required to submit a separate lease plan of development for unit activities.

11. LOGS AND OTHER RECORDS OF OPERATIONS. (a) The lessee shall file with the state all logs, geological and geophysical surveys taken, a description of all tests run for each well drilled on the leased area, and a plat showing the exact location of each well, within 30 days after each well or survey has been completed, suspended, or abandoned.

(b) Any information filed by the lessee with the state in connection with this lease will be available at all times for the use of the state and its agents, subject to the duty to keep the information confidential as provided in AS 38.05.035(a)(9), AS 31.05.035, and applicable regulations.

12. DIRECTIONAL DRILLING. This lease may be maintained in effect by directional wells whose bottom hole location is on the leased area but that are drilled from locations on other lands not covered by this lease. In those circumstances, drilling will be considered to have commenced on the leased area when actual drilling is commenced on those other lands for the purpose of directionally drilling into the leased area. Production of oil or gas from the leased area through any directional well surfaced on those other lands, or drilling or reworking of that directional well, will be considered production or drilling or reworking operations on the leased area for all purposes of this lease. Nothing contained in this paragraph is intended or will be construed as granting to the lessee any interest, license, easement, or other right in or with respect to those lands in addition to any interest, license, easement, or other right that the lessee may have lawfully acquired from the state or from others.

13. DILIGENCE AND PREVENTION OF WASTE. (a) The lessee shall exercise reasonable diligence in drilling, producing, and operating wells on the leased area unless consent to suspend operations temporarily is granted by the state.

(b) Upon discovery of oil or gas on the leased area in quantities that would appear to a reasonable and prudent operator to be sufficient to recover ordinary costs of drilling, completing, and producing an additional well in the same geologic structure at another location with a reasonable profit to the operator, the lessee must drill those wells as a reasonable and prudent operator would drill, having due regard for the interest of the state as well as the interest of the lessee.

(c) The lessee shall perform all operations under this lease in a good and workmanlike manner in accordance with the methods and practices set out in the approved plan of operations and plan of development, with due regard for the prevention of waste of oil, gas, and associated substances and the entrance of water to the oil and gas-bearing sands or strata to the destruction or injury of those sands or strata, and to the preservation and conservation of the property for future productive operations. The lessee shall carry out at the lessee's expense all orders and requirements of the State of Alaska relative to the prevention of waste and to the preservation of the leased area. If the lessee fails to carry out these orders, the state will have the right, together with any other available legal recourse, to enter the leased area to repair damage or prevent waste at the lessee's expense.

(d) The lessee shall securely plug in an approved manner any well before abandoning it.

14. OFFSET WELLS. The lessee shall drill such wells as a reasonable and prudent operator would drill to protect the state from loss by reason of drainage resulting from production on other land. Without limiting the generality of the foregoing sentence, if oil or gas is produced in a well on other land not owned by the State of Alaska or on which the State of Alaska receives a lower rate of royalty than under this lease, and that well is within 500 feet in the case of an oil well or 1,500 feet in the case of a gas well of lands then subject to this lease, and that well produces oil or gas for a period of 30 consecutive days in quantities that would appear to a reasonable and prudent operator to be sufficient to recover ordinary costs of drilling, completing, and producing an additional well in the same geological structure at an offset location with a reasonable profit to the operator, and if, after notice to the lessee and an opportunity to be heard, the state finds that production from that well is draining lands then subject to this lease, the lessee shall within 30 days after written demand by the state begin in good faith and diligently prosecute drilling operations for an offset well on the leased area. In lieu of drilling any well required by this paragraph, the lessee may, with the state's consent, compensate the state in full each month for the estimated loss of royalty through drainage in the amount determined by the state.

15. UNITIZATION. (a) The lessee may unite with others, jointly or separately, in collectively adopting and operating under a cooperative or unit agreement for the exploration, development or operation of the pool, field, or like area or part of the pool, field, or like area that includes or underlies the leased area or any part of the leased area whenever the state determines and certifies that the cooperative or unit agreement is in the public interest.

(b) The lessee agrees, within six months after demand by the state, to subscribe to a reasonable cooperative or unit agreement that will adequately protect all parties in interest, including the state. The state reserves the right to prescribe such an agreement.

(c) With the consent of the lessee, and if the leased area is committed to a unit agreement approved by the state, the state may establish, alter, change, or revoke drilling, producing, and royalty requirements of this lease as the state determines necessary or proper to secure the proper protection of the public interest.

(d) Except as otherwise provided in this subparagraph, where only a portion of the leased area is committed to a unit agreement approved or prescribed by the state, that commitment constitutes a severance of this lease as to the unitized and nonunitized portions of the leased area. The portion of the leased area not committed to the unit will be treated as a separate and distinct lease having the same effective date and term as this lease and may be maintained only in accordance with the terms and conditions of this lease, statutes, and regulations. Any portion of the leased area not committed to the unit agreement will not be affected by the unitization or pooling of any other portion of the leased area, by operations in the unit, or by suspension approved or ordered for the unit. If the leased area has a well certified as capable of production in paying quantities on it before commitment to a unit agreement, this lease will not be severed. If any portion of this lease is included in a participating area formed under a unit agreement, the entire leased area will remain committed to the unit and this lease will not be severed.

16. INSPECTION. The lessee shall keep open at all reasonable times, for inspection by any duly authorized representative of the State of Alaska, the leased area, all wells, improvements, machinery, and fixtures on the leased area, and all reports and records relative to operations and surveys or investigations on or with regard to the leased area or under this lease. Upon request, the lessee shall furnish the State of Alaska with copies of and extracts from any such reports and records.

17. SUSPENSION. The state may from time to time direct or approve in writing suspension of production or other operations under this lease.

18. ASSIGNMENT, PARTITION, AND CONVERSION. This lease, or any undivided interest in this lease, may, with the approval of the state, be assigned, subleased, or otherwise transferred as to the entire leased area, or any one or more legal subdivisions included in the leased area, or any separate and distinct zone or geological horizon underlying the leased area or one or more legal subdivisions of the leased area, to any person or persons qualified to hold a lease. No assignment, sublease, or other transfer of an interest in this lease, including assignments of working or royalty interests and operating agreements and subleases, will be binding upon the state unless approved by the state. The lessee shall remain liable for all obligations under this lease accruing prior to the approval by the state of any assignment, sublease, or other transfer of an interest in this lease. All provisions of this lease will extend to and be binding upon the heirs, administrators, successors, and assigns of the state and the lessee. Applications for approval of an assignment, sublease, or other transfer must comply with all applicable regulations and must be filed within 90 days after the date of final execution of the instrument of transfer. Transfer of this lease or an interest in this lease will be approved by the state unless (1) the lessee fails to comply with applicable statutes and regulations, (2) the state determines in writing that the transfer would adversely affect the interests of the State of Alaska, or (3) at the discretion of the state, if the transfer covers a portion of the leased area or a separate and distinct zone or geological horizon. Where an assignment, sublease, or other transfer is made of all or a part of the lessee's interest in a portion of the leased area, this lease may, at the option of the state or upon request of the transferee and with the approval of the state, be severed, and a separate and distinct lease will be issued to the transferee having the same effective date and terms as this lease.

19. SURRENDER. The lessee at any time may file with the state a written surrender of all rights under this lease or any portion of the leased area comprising one or more legal subdivisions or, with the consent of the state, any separate and distinct zone or geological horizon underlying the leased area or one or more legal subdivisions of the leased area. That surrender will be effective as of the date of filing, subject to the continued obligations of the lessee and its surety to make payment of all accrued royalties and to place all wells and surface facilities on the surrendered land or in the surrendered zones or horizons in condition satisfactory to the state for suspension or abandonment. After that, the lessee will be released from all obligations under this lease with respect to the surrendered lands, zones, or horizons.

20. DEFAULT AND TERMINATION; CANCELLATION. (a) The failure of the lessee to perform timely its obligations under this lease, or the failure of the lessee otherwise to abide by all express and implied provisions of this lease, is a default of the lessee's obligations under this lease. Whenever the lessee fails to comply with any of the provisions of this lease (other than a provision which, by its terms, provides for automatic termination), and fails within 60 days after written notice of that default to begin and diligently prosecute operations to remedy that default, the state may terminate this lease if at the time of termination there is no well on the leased area capable of producing oil or gas in paying quantities. If there is a well on the leased area capable of producing oil or gas in paying quantities, this lease may be terminated by an appropriate judicial proceeding. In the event of any termination under this subparagraph, the lessee shall have the right to retain under this lease any and all drilling or producing wells for which no default exists, together with a parcel of land surrounding each well or wells and rights-of-way through the leased area that are reasonably necessary to enable the lessee to drill, operate, and transport oil or gas from the retained well or wells.

(b) The state may cancel this lease at any time if the state determines, after the lessee has been given notice and a reasonable opportunity to be heard, that (1) continued operations pursuant to this lease probably will cause serious harm or damage to biological resources, to property, to mineral resources, or to the environment (including the human environment), (2) the threat of harm or damage will not disappear or decrease to an acceptable extent within a reasonable period of time, and (3) the advantages of cancellation outweigh the advantages of continuing this lease in effect. Any cancellation under this subparagraph will not occur unless and until operations under this lease have been under suspension or temporary prohibition by the state, with due extension of the term of this lease, continuously for a period of five years or for a lesser period upon request of the lessee. Any cancellation under this subparagraph will entitle the lessee to receive compensation as the lessee demonstrates to the state is equal to the lesser of (1) the value of the cancelled rights as of the date of cancellation, with due consideration being given to both anticipated revenues from this lease and anticipated costs, including costs of compliance with all applicable regulations and stipulations, liability for clean-up costs or damages, or both, in the case of an oil spill, and all other costs reasonably anticipated under this lease, or (2) the excess, if any, over the lessee's revenues from this lease (plus interest on the excess from the date of receipt to date of reimbursement) of all consideration paid for this lease and all direct expenditures made by the lessee after the effective date of this lease and in connection with exploration or development, or both, under this lease, plus interest on that consideration and those expenditures from the date of payment to the date of reimbursement.

21. RIGHTS UPON TERMINATION. Upon the expiration or earlier termination of this lease as to all or any portion of the leased area, the lessee will be directed in writing by the state and will have the right at any time within a period of one year after the termination, or any extension of that period as may be granted by the state, to remove from the leased area or portion of the leased area all machinery, equipment, tools, and materials. Upon the expiration of that period or extension of that period and at the option of the state, any machinery, equipment, tools, and materials that the lessee has not removed from the leased area or portion of the leased area become the property of the state or may be removed by the state at the lessee's expense. At the option of the state, all improvements such as roads, pads, and wells must either be abandoned and the sites rehabilitated by the lessee to the satisfaction of the state, or be left intact and the lessee absolved of all further responsibility as to their maintenance, repair, and eventual abandonment and rehabilitation. Subject to the above conditions, the lessee shall deliver up the leased area or those portions of the leased area in good condition.

22. DAMAGES AND INDEMNIFICATION. (a) No rights under the AS 38.05.125 reservation may be exercised by the lessee until the lessee has provided to pay the owner of the land, his lessees and permittees, upon which the AS 38.05.125 reserved rights are sought to be exercised, full payment for all damage sustained by the owner by reason of entering the land. If the owner for any reason does not settle the damages, the lessee may enter the land after posting a surety bond determined by the state, after notice and an opportunity to be heard, to be sufficient as to form, amount, and security to secure to the owner, his lessees and permittees, payment for damages, and may institute legal proceedings in a court of competent jurisdiction where the land is located to determine the damages which the owner of the land may suffer. The lessee agrees to pay for any damages that may become payable under AS 38.05.130 and to indemnify the state and hold it harmless from and against any claims, demands, liabilities, and expenses arising from or in connection with such damages. The furnishing of a bond in compliance with this paragraph will be regarded by the state as sufficient provision for the payment of all damages that may become payable under AS 38.05.130 by virtue of this lease.

(b) The lessee shall indemnify the state for, and hold it harmless from, any claim, including claims for loss or damage to property or injury to any person caused by or resulting from any act or omission committed under this lease by or on behalf of the lessee. The lessee is not responsible to the state under this subparagraph for any loss, damage, or injury caused by or resulting from the sole negligence of the state.

(c) The lessee expressly waives any defense to an action for breach of a provision of this lease or for damages resulting from an oil spill or other harm to the environment that is based on an act or omission committed by an independent contractor in the lessee's employ. The lessee expressly agrees to assume responsibility for all actions of its independent contractors.

23. BONDS. (a) If required by the state, the lessee shall furnish a bond prior to the issuance of this lease in an amount equal to at least $5 per acre or fraction of an acre contained in the leased area, but no less than $10,000, and must maintain that bond as long as required by the state.

(b) The lessee may, in lieu of the bond required under (a) above, furnish and maintain a statewide bond in accordance with applicable regulations.

(c) The state may, after notice to the lessee and a reasonable opportunity to be heard, require a bond in a reasonable amount greater than the amount specified in (a) above where a greater amount is justified by the nature of the surface and its uses and the degree of risk involved in the types of operations being or to be carried out under this lease. A statewide bond will not satisfy any requirement of a bond imposed under this subparagraph, but will be considered by the state in determining the need for and the amount of any additional bond under this subparagraph.

(d) If the leased area is committed in whole or in part to a cooperative or unit agreement approved or prescribed by the state, and the unit operator furnishes a statewide bond, the lessee need not maintain any bond with respect to the portion of the leased area committed to the cooperative or unit agreement.

24. AUTHORIZED REPRESENTATIVES. The Director of the Division of Minerals and Energy Management, Department of Natural Resources, State of Alaska, and the person executing this lease on behalf of the lessee shall be authorized representatives for their respective principals for the purposes of administering this lease. The state or the lessee may change the designation of its authorized representative or the address to which notices to that representative are to be sent by a notice given in accordance with Paragraph 25 below. Where activities pursuant to a plan of operations are underway, the lessee shall also designate, pursuant to a notice under Paragraph 25 below, by name, job title, and address, an agent who will be present in the state during all lease activities.

25. NOTICES; PROTEST. (a) Any notices required or permitted under this lease must be by electronic media producing a permanent record or in writing and must be given personally or by registered or certified mail, return receipt requested, addressed as follows:

TO THE STATE:

DIRECTOR, DIVISION OF MINERALS AND ENERGY MANAGEMENT
DEPARTMENT OF NATURAL RESOURCES
POUCH 7-034
ANCHORAGE, ALASKA 99510

TO THE LESSEE:

J. Andrew Bachner et al
c/o Main Hurdman
1001 Noble Street
Fairbanks, Alaska 99701

(b) Any notice given under this paragraph will be effective when delivered to the above authorized representative.

(c) A lessee who wishes to protest the amount of money due the state under the lease or any action of the state regarding a provision of this lease must file a written protest with the Division of Minerals and Energy Management within 30 days after the mailing date of the state's notice or bill. A lessee who fails to file a protest within the required time waives any further right to protest. The state will establish the administrative appeal procedure to be followed and will inform the lessee of the procedure no later than 30 days after the filing of the written protest.

26. STATUTES AND REGULATIONS. This lease is subject to all applicable state and federal statutes and regulations in effect on the effective date of this lease, and insofar as is constitutionally permissible, to all statutes and regulations placed in effect after the effective date of this lease. A reference to a statute or regulation in this lease includes any change in that statute or regulation whether by amendment, repeal and replacement, or other means. This lease does not limit the power of the State of Alaska or the United States of America to enact and enforce legislation or to promulgate and enforce regulations affecting, directly or indirectly, the activities of the lessee or its agents in connection with this lease or the value of the interest held under this lease. In case of conflicting provisions, statutes and regulations take precedence over this lease.

27. INTERPRETATION. This lease is to be interpreted in accordance with the rules applicable to the interpretation of contracts made in the State of Alaska. The paragraph headings are not part of this lease and are inserted only for convenience. The state and the lessee expressly agree that the law of the State of Alaska will apply in any judicial proceeding affecting this lease.

28. INTEREST IN REAL PROPERTY. It is the intention of the parties that the rights granted to the lessee by this lease constitute an interest in real property in the leased area.

29. WAIVER OF CONDITIONS. The state reserves the right to waive any breach of a provision of this lease, but any such waiver extends only to the particular breach so waived and does not limit the rights of the state with respect to any future breach; nor will the waiver of a particular breach prevent cancellation of this lease for any other cause or for the same cause occurring at another time. Notwithstanding the foregoing, the state will not be deemed to have waived a provision of this lease unless it does so in writing.

30. SEVERABILITY. If it is finally determined in any judicial proceeding that any provision of this lease is invalid, the state and the lessee may jointly agree by a written amendment to this lease that, in consideration of the provisions in that written amendment, the invalid portion will be treated as severed from this lease and that the remainder of this lease, as amended, will remain in effect.

31. LOCAL HIRE. The lessee is encouraged to hire Alaska residents to the extent they are available and qualified, to perform work done in Alaska in connection with this lease. The lessee shall submit annually to the Director, Division of Minerals and Energy Management, for transmission to the Alaska Department of Labor, a report that details the specific measures the lessee and its contractors and subcontractors have taken or are planning to take to recruit qualified Alaska residents for available jobs, and describes on-the-job training opportunities. The report must also include statistical data concerning the number of resident personnel hired within the past year for Alaska operations.

32. CONDITIONAL LEASE. If all or a part of the leased area is land that has been selected by the state under laws of the United States granting lands to the state, but the land has not been patented to the state by the United States, then this lease is a conditional lease as provided by law until the patent becomes effective. If for any reason the selection is not finally approved, or the patent does not become effective, any rental, royalty, or other production or profit-based payments made to the state under this lease will not be refunded.

33. NONDISCRIMINATION. The lessee and the lessee's contractors and subcontractors may not discriminate against any employee or applicant because of race, religion, marital status, change in marital status, pregnancy, parenthood, physical handicap, color, sex, age, or national origin as set out in AS 18.80.220. The lessee and its contractors and subcontractors must, on beginning any operations under this lease, post in a conspicuous place notices setting out this nondiscrimination provision.

34. DEFINITIONS. All words and phrases used in this lease are to be interpreted where possible in the manner required in respect to the interpretation of statutes by AS 01.10.040. However, the following words have the following meanings unless the context unavoidably requires otherwise:

(1) "oil" means crude petroleum oil and other hydrocarbons, regardless of gravity, that are produced in liquid form by ordinary production methods, including liquid hydrocarbons known as distillate or condensate recovered by separation from gas other than at a gas processing plant;

(2) "gas" means all natural gas (except helium gas) and all other hydrocarbons produced that are not defined in this lease as oil;

(3) "associated substances" means all substances except helium produced as an incident of production of oil or gas by ordinary production methods and not defined in this lease as oil or gas;

(4) "drilling" means the act of boring a hole to reach a proposed bottom hole location through which oil or gas may be produced if encountered in paying quantities, and includes redrilling, sidetracking, deepening, or other means necessary to reach the proposed bottom hole location, testing, logging, plugging, and other operations necessary and incidental to the actual boring of the hole;

(5) "reworking operations" means all operations designed to secure, restore, or improve production through some use of a hole previously drilled, including, but not limited to, mechanical or chemical treatment of any horizon, plugging back to test higher strata, etc.;

(6) "paying quantities" means quantities sufficient to yield a return in excess of operating costs, even if drilling and equipment costs may never be repaid and the undertaking considered as a whole may ultimately result in a loss; quantities are insufficient to yield a return in excess of operating costs unless those quantities, not considering the costs of transportation and marketing, will produce sufficient revenue to induce a prudent operator to produce those quantities; and

(7) "force majeure" means war, riots, acts of God, unusually severe weather, or any other cause beyond the lessee's reasonable ability to foresee or control and includes operational failure of existing transportation facilities and delays caused by judicial decisions or lack of them.

35. ROYALTY ON PRODUCTION. (a) Except for oil, gas, and associated substances used on the leased area for development and production or unavoidably lost, the lessee shall pay to the state as a royalty 12½ percent in amount or value of the oil, gas, and associated substances saved, removed, or sold from the leased area and of the gas used on the leased area for extraction of natural gasoline or other products from the leased area.

36. VALUE. (a) For the purposes of computing royalties due under this lease, the value of royalty oil, gas, or associated substances must not be less than the highest of:

(1) the field price received by the lessee for the oil, gas, or associated substances;

(2) the volume-weighted average of the three highest field prices received by other producers in the same field or area for oil of like grade and gravity, gas of like kind and quality, or associated substances of like kind and quality at the time the oil, gas, or associated substances are sold or removed from the leased or unit area or the gas is delivered to an extraction plant if that plant is located on the leased or unit area; if there are less than three prices reported by other producers, the volume-weighted average will be calculated using the lesser number of prices received by other producers in the field or area;

(3) the lessee's posted price in the field or area for the oil, gas, or associated substances; or

(4) the volume-weighted average of the three highest posted prices in the same field or area of the other producers in the same field or area for oil of like grade and gravity, gas of like kind and quality, or associated substances of like kind and quality at the time the oil, gas, or associated substances are sold or removed from the leased or unit area or the gas is delivered to an extraction plant if that plant is located on the leased or unit area; if there are less than three prices posted by other producers, the volume-weighted average will be calculated using the lesser number of prices posted by other producers in the field or area.

(b) If oil, gas, or associated substances are sold away from the leased or unit area, the term "field price" in subparagraph (a) above will be the cash value of all consideration received by the lessee or other producer from the purchaser of the oil, gas, or associated substances, less the reasonable costs of transportation away from the leased or unit area to the point of sale. The "reasonable costs of transportation" are as defined in 11 AAC 83.228—11 AAC 83.229 as those regulations exist on the effective date of this lease.

(c) In the event the lessee does not sell in an arm's-length transaction the oil, gas, or associated substances after removal from the leased or unit area, the term "field price" in subparagraphs (a) and (b) above will mean the price, on the leased or unit area, the lessee would expect to receive for the oil, gas, or associated substances if the lessee did sell the oil, gas, or associated substances in an arm's-length transaction. The lessee shall determine this price in a consistent and logical manner using information available to the lessee and report that price to the state.

(d) The state may establish minimum values for the purposes of computing royalties on oil, gas, or associated substances obtained from this lease, with consideration being given to the price actually received by the lessee, to the price or prices paid in the same field or area for production of like quality, to posted prices, to prices received by the lessee and other producers from sales occurring away from the leased area, and to other relevant matters. In establishing minimum values, the state may use, but is not limited to, the methodology for determining "prevailing value" as defined in 11 AAC 83.227 in circumstances where terms of a contract set a single price for oil, gas, or associated substances for periods of longer than six years without adjustments tied to market conditions, or where the terms of a contract set prices which do not reasonably reflect market conditions for production from that field or area prevailing at the time the contract is executed or renegotiated, or where fraud or an intent to evade payment is demonstrated. Each minimum value determination will be made only after the lessee has been given notice and a reasonable opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty oil, gas, or associated substances under this lease may not necessarily equal the price of the oil, gas or associated substances.

37. ROYALTY IN VALUE. Unless the state elects to receive all or a portion of its royalty in kind as provided in Paragraph 38 below, the lessee shall pay to the state that value of all royalty oil, gas, and associated substances as determined under Paragraph 36 above. Royalty paid in value will be free and clear of all lease expenses (and any portion of those expenses that is incurred away from the leased area), including, but not limited to, expenses for separating, cleaning, dehydration, gathering, saltwater disposal, and preparing the oil, gas, or associated substances for transportation off the leased area. All royalty that may become payable in money to the State of Alaska must be paid on or before the last day of the calendar month following the month in which the oil, gas, or associated substances are produced. The amount of all royalty in value payments which are not paid when due under this lease or which are subsequently determined to be due as the result of a redetermination will bear interest from the date the obligation accrued, until it is paid in full, at a variable annual rate equal to 1.25 percent plus the prime rate as announced from time to time by the Bank of America, San Francisco, California. Royalty payments must be accompanied by copies of run tickets or other information relating to valuation of royalty as the state may require which may include, but is not limited to, evidence of sales, shipments, and amounts of gross oil, gas, and associated substances produced.

38. ROYALTY IN KIND. (a) At the state's option, which may be exercised from time to time upon not less than six months' notice to the lessee, the lessee shall deliver all or a portion of the state's royalty oil, gas, or associated substances produced from the leased area in kind. Delivery will be on the leased area or at a place mutually agreed to by the state and the lessee, and must be delivered to the State of Alaska or to any individual, firm, or corporation designated by the state.

(b) Royalty oil, gas, or associated substances delivered in kind must be delivered in good and merchantable condition and be of pipeline quality, and must be free and clear of all lease expenses (and any portion of those expenses incurred away from the leased area), including, but not limited to, expenses for separating, cleaning, dehydration, gathering, saltwater disposal, and preparing the oil, gas, or associated substances for transportation off the leased area.

(c) After having given notice of its intention to take, or after having taken its royalty oil, gas, or associated substances in kind, the state, at its option and upon six months' notice to the lessee, may elect to receive a different portion or none of its royalty in kind. If, under federal regulations, the taking of royalty oil, gas, or associated substances in value by the state creates a supplier-purchaser relationship, the lessee hereby waives its right to continue to receive royalty oil, gas, or associated substances under that relationship, and further agrees that it will require any purchasers of the royalty oil, gas, or associated substances likewise to waive any supplier-purchaser rights.

(d) The lessee shall furnish storage for royalty oil and natural gas liquids produced from the leased or unit area to the same extent that the lessee provides storage for the lessee's share of oil and natural gas liquids. The lessee shall not be liable for the loss or destruction of stored royalty oil and natural gas liquids from causes beyond the lessee's reasonable control.

(e) If a state royalty purchaser refuses or for any reason fails to take delivery of oil, gas, or associated substances, or in an emergency, and with as much notice to the lessee as is practical or reasonable under the circumstances, the state may elect without penalty to underlift for up to six months all or a portion of the state's royalty on oil, gas, or associated substances produced from the leased or unit area and taken in kind. The state's right to underlift is limited to the portion of royalty oil, gas, or associated substances that the royalty purchaser refused or failed to take delivery of, or the portion necessary to meet the emergency condition. Underlifted oil, gas, or associated substances may be recovered by the state at a daily rate not to exceed 10 percent of its royalty interest share of daily production at the time of the underlift recovery.

BOOK 40 PAGE 851
Barrow Recording District

39. REDUCTION OF ROYALTY. After initial production for two years from the field in which the leased or unit area is located has occurred, the state, in its discretion, may reduce the lessee's obligations to pay royalty on all of the leased area or on any tract or portion of the leased area segregated for royalty purposes upon (1) request by the lessee, (2) a clear showing by the lessee that the revenue from all oil, gas, and associated substances produced from the field is insufficient to produce a reasonable rate of return with respect to the lessee's total investment in the field, and (3) a clear showing by the lessee that a reduction in royalty will increase total production from the field.

40. SHARE OF NET PROFIT. The lessee shall pay to the State of Alaska 40% of the net profit derived from this lease. For the purposes of this paragraph, calculation of the net profit will be determined in accordance with 11 AAC 83.201 through 11 AAC 83.295 as those regulations exist on the effective date of this lease, which by reference are made a part of this lease. The amount of interest to be earned on the net profit share development account pursuant to 11 AAC 83.212 will be the average of the prime rates of the Citibank, NA New York; Chase Manhattan Bank, NA New York; and the Bank of America, NT and SA San Francisco, prevailing during the month.

41. EFFECTIVE DATE. This lease takes effect on August 1, 1983.

BY SIGNING THIS LEASE, the state as lessor and the lessee agree to be bound by its provisions.

LESSEE

By: J. Andrew Bachner

Title: J. Andrew Bachner

By: James F. Dieringer, Jr.

Title: James F. Dieringer, Jr.

By: W.G. Stroecker

Title: W.G. Stroecker

By: Richard E. Wagner

Title: Richard E. Wagner

STATE OF ALASKA

By: Kay Brown

Title: Kay Brown, Director, DMEM

STATE OF ALASKA)
)ss.
Third Judicial District)

This is to certify that on July 19, 1983 before me appeared KAY BROWN of the Division of Minerals and Energy Management of the State of Alaska, Department of Natural Resources, and who executed this lease and acknowledged voluntarily signing it on behalf of the State of Alaska as lessor.

Carol D Wilkinson
Notary public in and for Alaska
My commission expires:

STATE OF ALASKA
NOTARY PUBLIC
CAROL D. WILKINSON
My Commission Expires Oct. 19, 1986

INSERT NOTARY ACKNOWLEDGEMENT OF LESSEE'S SIGNATURE HERE.

This is to certify that on June 23, 1983, before me appeared J. Andrew Bachner, James F. Dieringer, Jr., W.G. Stroecker, and Richard E. Wagner of J. Andrew Bachner et al, and who executed this lease and acknowledged voluntarily signing it.

Ellen G Ring
Notary public in and for Alaska
My commission expires: 9-11-84

ELLEN G. RING
NOTARY PUBLIC
STATE OF ALASKA

EXHIBIT "A"

TRACT 39-01

BOOK 40 PAGE 852
Barrow Recording District

T. 13 N., R. 13 E., Umiat Meridian, Alaska

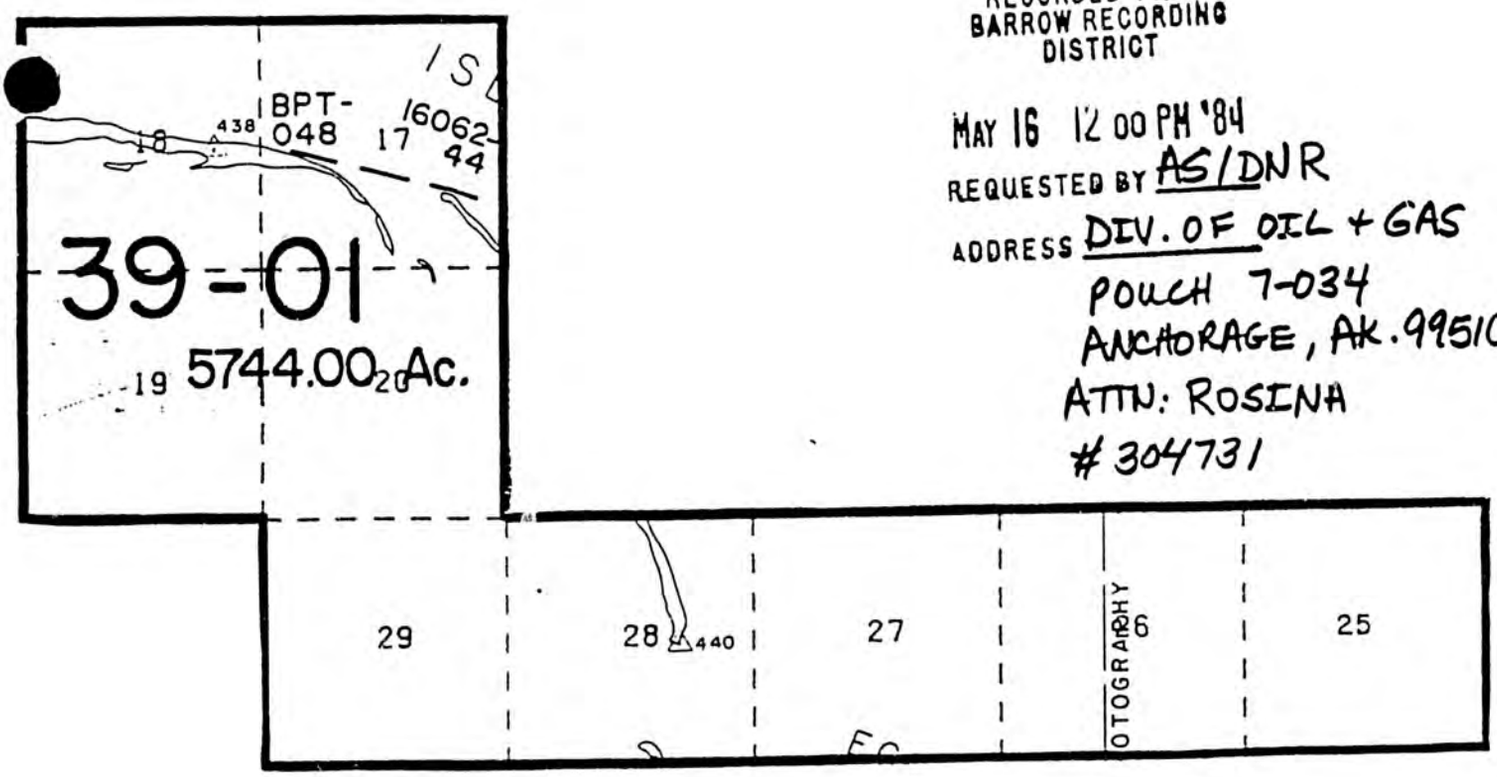
Section 17,	Protracted, All,	640.00 acres;
Section 18,	Protracted, All,	631.00 acres;
Section 19,	Protracted, All,	633.00 acres;
Section 20,	Protracted, All,	640.00 acres;
Section 25,	Protracted, All,	640.00 acres;
Section 26,	Protracted, All,	640.00 acres;
Section 27,	Protracted, All,	640.00 acres;
Section 28,	Protracted, All,	640.00 acres;
Section 29,	Protracted, All,	640.00 acres.

This tract contains 5744.00 acres more or less.

840579
32.00

RECORDED-~~FILED~~
BARROW RECORDING
DISTRICT

MAY 16 12 00 PM '84
REQUESTED BY AS/DNR
ADDRESS DIV. OF OIL + GAS
POUCH 7-034
ANCHORAGE, AK. 99510
ATTN: ROSINA
304731



MITIGATING MEASURES

AS 38.05.035(a)(14) and the departmental delegation of authority give the Director, Division of Minerals and Energy Management (DMEM), the authority to impose conditions or limitations, in addition to those imposed by statute, to ensure that a resource disposal is in the state's best interest. Lease stipulations will be enforced throughout the term of the lease. Measures listed under "Plans of Operations and Other Terms of Sale" will be imposed through Plans of Operations and other permits to mitigate the social and environmental effects of lease activities. These measures have been developed considering the Social, Economic, and Environmental Analysis for Lease Sale 39, public comment, and measures imposed in prior north slope lease sales.

Lease Stipulations

1. Spill Prevention Control and Countermeasure (SPCC) Plan:

   A Spill Prevention, Control and Countermeasure Plan must be submitted to the Department of Environmental Conservation for approval prior to onshore drilling operations and construction of onshore oil and gas storage facilities (with a capacity of greater than 660 gallons), transfer, and transportation facilities. In addition to addressing the prevention, detection and cleanup of oil, the SPCC plan for drilling operations should include, but not be limited to, methods for controlling blowouts, location of spill clean-up equipment, identification and location of a suitable alternative drilling rig, and the time required to obtain equipment, mobilize, rig-up, and commence drilling of a relief well, if needed.

2. Discovery of historic or archeologic objects:

   In the event any site, structure, or object of historic or archeologic significance is discovered during operations on the leased area, the lessee must report immediately such findings to the Director, DMEM, and make every reasonable effort to preserve and protect such site, structure, or object from damage until the Director, after consultation with the State Historic Preservation Officer, has given directions as to its preservation.

3. Seasonal drilling restriction:

   This stipulation will be reevaluated periodically on the basis of experience and new information.

   A principle purpose of this stipulation is to ensure that the migration route of the bowhead whale will be oil free in the fall.

   This stipulation assumes compliance with otherwise applicable laws and regulations, including a Plan of Operations approved by the Department of Natural Resources (DNR) and an Oil Discharge Contingency Plan approved by the Department of Environmental Conservation (DEC).

The restrictions set out below apply only to exploratory drilling offshore. As a matter of policy, the state does not intend to impose seasonal drilling restrictions during development or production stages; however, seasonal restrictions will be imposed as necessary in the development and production stages to satisfy requirements of the federal Endangered Species Act and other applicable state and federal laws and regulations.

The seasonal drilling restriction does not apply to exploratory operations on Pingok Island, which has been identified by the Commissioner of Natural Resources, in consultation with the Commissioners of Environmental Conservation and Fish and Game, as analogous to upland areas because of its size and configuration.

Logistical, construction, and other activities related to exploratory drilling may be restricted outside the barrier islands during the fall whale migration.

The threshold depth as used in this stipulation is a point above which major accumulations of hydrocarbons are not likely. This depth will be determined on a case-by-case basis by the Division of Minerals and Energy Management after consultation with the Alaska Oil and Gas Conservation Commission and, when appropriate, the Minerals Management Service.

Tier 1 is effective immediately. Tier 2 will be available on a case-by-case basis for each proposed well.

TIER 1

A. On and inside the barrier islands--(Figure 1 indicates the tracts and portions of tracts that are located "on and inside" and "outside" the barrier islands.)

1. Exploratory drilling and other downhole activities above a predetermined threshold depth will be allowed year-round.

2. Testing will be allowed year-round provided that casing has been set through the zones to be tested and DNR and DEC find compliance with applicable laws and regulations.

3. Exploratory drilling and other downhole activities below the predetermined threshold depth will be allowed from November 1 to May 15, except on tracts at the mouths of major rivers that are inundated by river overflow in the spring. On these tracts, which are shown in Figure 8, exploratory drilling and other downhole activities below the predetermined threshold depth must cease by April 30 unless the Commissioner of Natural Resources, in consultation with the Commissioners of Fish and Game and Environmental Conservation, determines that ice conditions justify an extension to May 15. Exploratory drilling and other downhole activities below the predetermined threshold depth will be allowed during the "open water" period except during the fall bowhead whale migration.

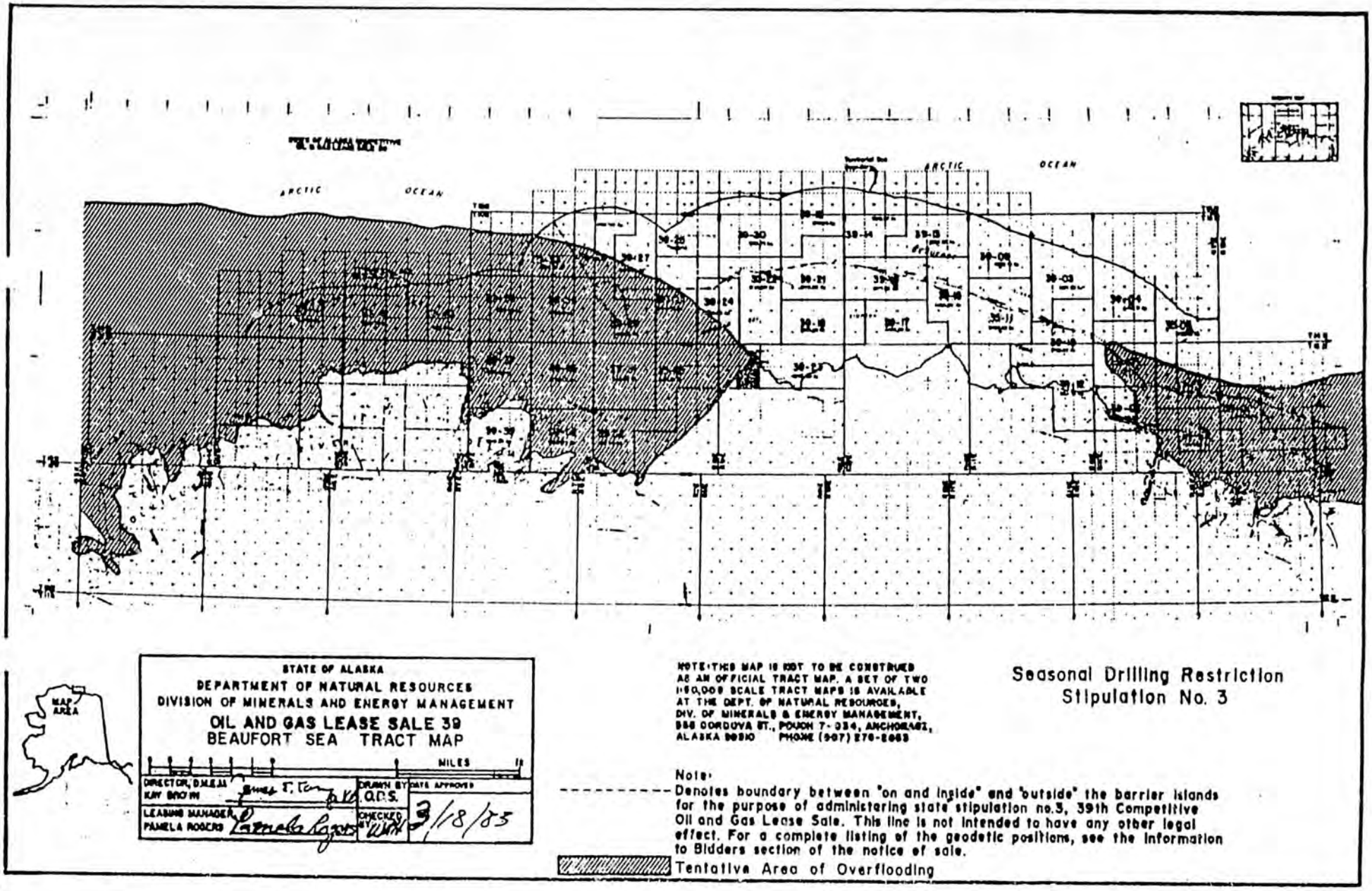

ARCTIC OCEAN
ARCTIC OCEAN
MAP AREA
STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF MINERALS AND ENERGY MANAGEMENT
OIL AND GAS LEASE SALE 39
BEAUFORT SEA TRACT MAP
MILES
DIRECTOR, D.M.E.M.
KAY BROWN
LEASING MANAGER
PAMELA ROGERS
DRAWN BY
Q.D.S.
DATE APPROVED
CHECKED BY
3/18/85
NOTE: THIS MAP IS NOT TO BE CONSTRUED AS AN OFFICIAL TRACT MAP. A SET OF TWO 1:60,000 SCALE TRACT MAPS IS AVAILABLE AT THE DEPT. OF NATURAL RESOURCES, DIV. OF MINERALS & ENERGY MANAGEMENT, 550 CORDOVA ST., POUCH 7-034, ANCHORAGE, ALASKA 99510 PHONE (907) 276-2653
Seasonal Drilling Restriction
Stipulation No. 3
Note:
Denotes boundary between "on and inside" and "outside" the barrier islands for the purpose of administering state stipulation no.3, 39th Competitive Oil and Gas Lease Sale. This line is not intended to have any other legal effect. For a complete listing of the geodetic positions, see the information to Bidders section of the notice of sale.
Tentative Area of Overflooding

FIGURE 1

For the purpose of administering this stipulation, "open water" shall begin when the ice concentration between the drill site and a major onshore staging and support area (such as the West Dock) does not restrict the transport of heavy equipment and supplies (including drilling muds, cleanup equipment, casing and drill rigs) and when the ice concentration within a mile radius of the drill pad is 25 percent or less. Once a determination is made that open water conditions exist, drilling and other downhole activity below the threshold depth will not be suspended until the commencement of the bowhead whale migration or freezeup, whichever is first, even if ice incursions result in ice concentrations greater than 25 percent.

The Director, Division of Minerals and Energy Management (DMEM), in consultation with the Department of Environmental Conservation (DEC), shall determine when the criteria stated above have been met based on: 1) information obtained from on-site inspections by Department of Natural Resources (DNR) or DEC representatives, at the request of the lessee, or 2) corroborating information and photographs obtained from a qualified independent consultant hired by the lessee who certifies that these conditions exist.

4. A monitoring program will be required if lessees propose to drill above the threshold depth or test through casing during the fall bowhead whale migration. The program will be initiated and funded by the lessee(s) proposing to conduct the activity. The proposed monitoring program should be submitted with the lessee's Plan of Operations for the well for review by DNR, the National Marine Fisheries Service and other members of the Beaufort Sea Biological Task Force. If the proposed monitoring program is approved by DNR, the lessee may conduct the stipulated operations during the migration period (provided other necessary state and federal permits have been obtained).

B. Outside the barrier islands

1. Exploratory drilling and other downhole activities above the predetermined threshold depth will be allowed year-round except during the fall bowhead whale migration.

2. Testing will be allowed year-round, except during the fall bowhead whale migration, provided that casing has been set through the zones to be tested and DNR and DEC find compliance with applicable laws and regulations.

3. Exploratory drilling and other downhole activities below the predetermined threshold depth will be allowed from November 1 to May 15, except on tracts at the mouths of major rivers that are likely subject to river overflow in the spring. Exploratory drilling and other downhole activities below the predetermined threshold depth on these tracts must cease by April 30 unless the Commissioner of Natural Resources, in consultation with the Commissioners of Fish and Game and Environmental Conservation, determines that ice conditions justify an extension to May 15.

TIER 2

All exploratory drilling and other downhole activities will be allowed areawide year-round except outside the barrier islands during the fall bowhead whale migration. Whale monitoring will be required to determine when the whales are actually migrating through or near the area.

This modification of the drilling restriction will be approved on a case-by-case basis for the benefit of lessees who demonstrate compliance with applicable laws and regulations, including the theoretical and physical capability to detect, contain, clean up and dispose of spilled oil in broken ice conditions.

Plans of Operations and Other Terms of Sale

Lessees must submit a detailed plan of operations to the Division of Minerals and Energy Management for approval prior to conducting any exploratory or development operations. The lessee shall concurrently submit an informational copy of its plan of operations to the North Slope Borough. The following restrictions will be imposed as a condition of the approval of plans of operations:

1. Road and pipeline crossings must be aligned perpendicular or near perpendicular to watercourses. Permanent facilities will be prohibited within 500 feet (152 m) of the Colville and Ugnuvarik rivers. Facilities will be prohibited within 100 feet (30 m) of all other streams and fish-bearing lakes unless the Director, Division of Minerals and Energy Management, after consultation with the Department of Fish and Game, determines that such facilities placement will not disturb critical wildlife habitats or that such a requirement is not feasible or prudent. The Department of Fish and Game will identify potential fish-bearing lakes within 30 days of the date a request for approval of a plan of operations is received. The Department of Fish and Game will confirm the presence or absence of fish at the earliest opportunity when ice conditions permit. If fish are not present in lakes, the 100 foot setback provision may be waived.

2. Measures will be required to minimize the impact of industrial development on key wetlands, waterfowl and shorebirds. Key wetlands include deep pendent grass ponds and lakes (Class IV) and basin - complex wetlands (Class VI), and coastal wetlands (Class VIII). Measures will include restricting certain facility siting to the least environmentally sensitive portions of these wetlands. Specific measures include the requirements that:

   a. Lessees identify on a map or aerial photograph the largest surface area within which it is anticipated that a facility is to be sited, or an activity is to occur. The map or photograph must accompany the plan of operations submitted to DMEM. DMEM and the Department of Fish and Game will identify the least environmentally sensitive area(s) within the industry-identified area of interest. The industry-identified surface area must be large enough to contain the proposed facility and to accommodate planned expansion.

b. Drill pads, roads, pipelines and other facilities must be sited outside of productive Class IV, VI and VIII wetlands, unless the Director, DMEM, after consultation with the Department of Fish and Game, determines that there are no feasible alternatives.

c. Where facilities must be sited within Class IV, VI and VIII wetlands, such facilities will be sited, designed and constructed in a manner that will maintain natural hydrological patterns and prevent oil contamination.

d. Draining or dewatering Class IV, VI and VIII wetlands is prohibited.

3. Impermeable lining and diking will be required for sewage ponds and onshore oil storage facilities (with a storage capacity greater than 660 gallons). Buffer zones of not less than 100 feet and up to 1,500 feet will be required to separate oil storage facilities (with a capacity greater than 660 gallons) and sewage ponds from freshwater supplies, streams, lakes, and Class IV and VI wetlands unless the Director, DMEM, after consultation with the Department of Environmental Conservation, determines that such a requirement is not feasible or prudent. Sumps and reserve pits must be impermeable and otherwise fully contained through diking or other means.

4. All lease activities and structures must be designed to maintain normal water flow or drainage patterns and to allow free movement and safe passage of fish and mammals, unless the Director, DMEM, after consultation with the Department of Fish and Game, determines that such a design is not feasible or prudent.

5. Exploration activities must be supported only by ice and winter roads and trails, existing road systems, and air service. On-tundra travel may be permitted if the Director, Division of Land and Water Management and the Director, DMEM, determine that travel can be accomplished without disturbing the vegetative mat or an emergency condition exists.

6. Facilities and surface transportation routes must be consolidated to the extent feasible and prudent.

7. No restriction of public access to, or use of, the leased area will be permitted as a consequence of oil and gas activities except in the immediate vicinity of drill sites, buildings and other related structures. Such areas where access is to be restricted must be identified in the plan of operations. No lease facilities or operations may be located where they would block public access to or along navigable and public waters as defined in AS 38.05.365(22) and (23). If lease facilities are proposed to be located in the vicinity of these public waters, an easement will be reserved under AS 38.05.127 and 11 AAC 53.330 to ensure the right of public access.

8. The lessee must include in any exploration and/or development plans a proposed environmental training program for all personnel involved in exploration or development activities (including personnel of the lessee's contractors and subcontractors) for review and approval by

the Director, DMEM. The program must be designed to inform each person working on the project of specific types of environmental, social, and cultural concerns which relate to the individual's job. The program must be formulated and implemented by qualified instructors experienced in each pertinent field of study and must employ effective methods to ensure that personnel understand and use techniques necessary to preserve archeological, geological, and biological resources. The program must also be designed to increase the sensitivity and understanding of personnel to community values, customs, and life styles in areas in which such personnel will be operating.

The lessee must also submit for review and approval a continuing technical environmental briefing program for supervisory and managerial personnel of the lessee and its agents, contractors, and subcontractors.

9. The lessee is encouraged to hire Alaska residents to the extent that they are available and qualified, to perform work done in Alaska in connection with this lease. As indicated in paragraph 31 of the lease form, the lessee must submit annually to the Director, Division of Minerals and Energy Management, for transmission to the Department of Labor, a report that details the specific measures the lessee and its contractors and subcontractors have taken or are planning to take to recruit qualified Alaska residents for available jobs, and describes on-the-job training opportunities. The report must also include statistical data concerning the number of resident personnel hired within the past year for Alaska operations.

10. Solid waste disposal on natural or artificial islands and into marine waters, rivers, streams, natural lakes and Class IV and VI wetlands is prohibited. Before the lessees dispose of solid waste in other areas, the disposal must be approved through permits by the Commissioner, Department of Environmental Conservation.

11. Discharge of produced water, drilling muds, and cuttings:

    a. Disposal of produced water to freshwater bodies, including Class IV and VI wetlands, is prohibited. Disposal of produced waters in upland areas, including Class IV and VI wetlands, will be by subsurface disposal techniques, except that the Commissioner of the Department of Environmental Conservation may permit alternate disposal methods if he determines that subsurface disposal techniques are not feasible or prudent.

    b. Discharge of drilling muds and cuttings to lakes, streams, rivers, and Class IV and VI wetlands is prohibited. Uplands disposal of contaminated muds and cuttings may be made into approved sumps and reserve pits which are impermeable and otherwise fully contained through diking or other means.

c. Discharge of produced waters into open or ice-covered marine waters of less than 10 meters in depth is prohibited. All submerged Sale 39 tracts, except seaward portions of Tracts 3, 4, 8, 9, 13, 14, 19, 20, 25, 27, 28, and 33 are within the 10-meter isobath. The Commissioner of the Department of Environmental Conservation may approve discharges into waters greater than 10 meters in depth based on a case-by-case review of environmental factors and consistency with the conditions of a development production phase general NPDES permit for the sale area.

d. Disposal of oil-based or oil-contaminated drilling muds and cuttings to offshore waters and on sea ice is prohibited.

e. During winter exploratory drilling, drilling muds and cuttings free of hydrocarbon contamination may be disposed of on the sea ice surface in areas free of cracking or major stress fractures. During periods of reduced ice thickness or instability, uncontaminated drilling muds and cuttings may be discharged under sea ice if ice surface disposal methods, such as direct disposal by pumping, artificial thickening of sea ice or use of light or routine drilling effluent handling equipment, are impractical. Each part of drilling fluid discharged under sea ice must be prediluted with nine parts seawater.

f. During summer exploratory drilling, drilling muds and cuttings free of hydrocarbon contamination may be discharged to open water. The discharge shall be diluted at a ratio of at least nine parts seawater to one part drilling fluid. Drilling muds and cuttings generated from winter drilling may not be stockpiled at the drill site for open water disposal except when above ice disposal is determined impractical due to broken ice conditions. The disposal of drilling muds within the two-meter isobath and the entirety of Simpson Lagoon is prohibited unless the lessee can demonstrate to the satisfaction of the Commissioner of the Department of Environmental Conservation that effluents can be adequately dispersed.

g. Disposal of drilling muds and cuttings during development and production will be subject to the conditions of NPDES permits issued by the Environmental Protection Agency and those State of Alaska Coastal Management Program consistency requirements incorporated in or accompanying the NPDES permit.

12. Exploration facilities, with the exception of drill pads, will be temporary and must not be constructed of gravel. However, use of existing abandoned gravel structures may be permitted on an individual basis by the Director, DMEM, after consultation with the Director of the Division of Land and Water Management and the Department of Fish and Game. Approval for use of abandoned structures will depend on the extent and method of restoration needed to return these structures to a usable condition.

13. In meeting gravel needs for exploration, development, and production, gravel from nearby abandoned drill pads and existing material sites must be used first unless the Director, Division of Land and Water Management, after consultation with the Director, DMEM, and the Department of Fish and Game, determines that the reuse of such sources is not feasible and prudent.

14. Gravel mining sites required for exploration activities must not be located within an active floodplain of watercourses, unless the Director, Division of Land and Water Management, after consultation with the Department of Fish and Game, determines that a floodplain source will cause the least adverse environmental impact. Mining site development and rehabilitation within floodplains must follow the procedures outlined in Gravel Removal Guidelines For Arctic and Subarctic Floodplains, 1980, U.S. Fish and Wildlife Service-Woodward Clyde Consultants. Under AS 16, Department of Fish and Game approval is required if the mining site is located within an anadromous stream or could block fish passage.

15. Borrow extraction from barrier islands is prohibited. Borrow extraction from lagoons and nearshore areas is prohibited unless the Director, Division of Land and Water Management finds, in consultation with the Department of Fish and Game and the Department of Environmental Conservation, that, on the basis of scientific evidence, borrow extraction in these areas will not adversely affect the environment or that no alternative feasible and prudent source exist.

16. Gravel mining sites required for development activities will be restricted to the minimum number of upland or approved offshore sites needed to develop the field efficiently and with minimal environmental damage. Where feasible, upland gravel sites will be designed and constructed to function as reservoirs for winter water supplies. Gravel mining will not be allowed from active floodplains during development and production activities, unless the Director, Division of Land and Water Management, after consultation with the Department of Fish and Game, determines that there is no other feasible and prudent alternative.

17. Pipelines will be located so as to facilitate the containment and clean up of spilled hydrocarbons. Where feasible, pipelines will be located on the upslope side of roadways and construction pads unless the Director, Division of Land and Water Management, determines that an alternative site is an acceptable environmental alternative.

18. All garbage and refuse will be incinerated. Residue and nonburnables will be disposed of at an approved upland site. No new solid fill disposal sites, except possibly for the disposal of drilling muds and cuttings, will be approved during the exploratory phase.

19. Except for those on approved exploratory drill sites, stationary fuel storage facilities shall not be placed, nor vehicle refueling occur, within the active floodplains. Exceptions may be allowed during the permitting process under AS 16.06.870 for the refueling of slow-moving construction equipment, such as graders, tractor pulled scrapers and front end loaders, within floodplains.

20. Prior to the construction or placement of any onshore structure, road, or facility resulting from exploration, development, or production activities, the lessee must conduct an inventory of archeological and historical sites within the area affected by a proposed activity. Such inventory must consider literature provided by the North Slope Borough and local residents, documentation of oral history regarding historic and prehistoric uses of such sites, evidence of consultation with the Alaska Heritage Resources Survey and the National Register of Historic Places, and site surveys. The inventory must also include a detailed analysis of the potential effects estimated to result from the proposed activity. The inventory must be submitted to the Director, DMEM, for distribution to the Director of the Division of Parks and the Mayor of North Slope Borough for purposes of review and comment. In the event that an archeological or historical site or area may be adversely affected by an activity, the Director, DMEM, after consultation with the Director of the Division of Parks and the North Slope Borough, will direct the lessee as to what course of action will be necessary to mitigate the adverse effect.

21. Upon abandonment of drilling sites, roads, buildings, airstrips or other facilities, such facilities will be removed and the site rehabilitated, unless the Director, DMEM, after consultation with the departments of Fish and Game and Environmental Conservation, determines that such removal and rehabilitation is not in the state's interest.

22. The following measures will be imposed by the Department of Fish and Game under Title 16 of the Alaska Statutes to protect anadromous streams:

a. Alteration of river banks is prohibited unless approved by the Department of Fish and Game.

b. Except for approved stream crossings, equipment must not be operated within willow stands (Salix spp.).

c. The operation of equipment, excluding boats, in open water areas of rivers and streams will be prohibited unless approved by the Department of Fish and Game.

d. Bridges must be used as watercourse crossings whenever feasible. Culverts may be used only when bridges are shown not to be feasible or prudent. The siting, design, and construction of both bridges and culverts must be approved by the Department of Fish and Game prior to the placement of either of these structures.

e. Removal of freshwater or snow cover from fish bearing rivers, streams, and natural lakes will be prohibited from freeze up until spring breakup. Compaction of snow cover overlying fish-bearing waterbodies will be prohibited except for perpendicular crossings approved by the Department of Fish and Game. If ice thickness is not sufficient to facilitate a crossing, ice and/or snow bridges will be required.

f. Water intake pipes utilized for summer water removal from the river must be surrounded by a screened enclosure to prevent fish entrainment and impingement. Pipes and screening must be designed and constructed so that the maximum water velocity at the surface of the screen enclosure is no greater than 0.1 foot per second. Screen mesh size shall not exceed 0.04 inch unless another size has been approved by the Department of Fish and Game.

g. To protect fish and other aquatic fauna, explosives must not be detonated within, beneath, or in close proximity to fish-bearing waters unless prior drilling indicates that the waterbody, including its substrate, is solidly frozen. The minimum acceptable offset from fish-bearing waters for various size charges is:

1-2 pound charge	--	80 feet
5 pound charge	--	120 feet
10 pound charge	--	170 feet
25 pound charge	--	270 feet
100 pound charge	--	530 feet

Lessees are advised that documented anadromous rivers in and adjacent to the lease sale area include: the Colville, Ungnuvarik, and Kuparuk rivers.

23. The lessee will be responsible for ensuring that an adequate supply of water is available for winter use through development of such means as storage reservoirs and snow melting. Water appropriations shall be authorized pursuant to AS 46.15.

24. The following measures will be required to minimize impacts on the Central Arctic Caribou Herd.

a. The movement of equipment and personnel to and from Sale 39 tracts through the Kuparuk calving ground of the Central Arctic Herd depicted in Figure 3 may be restricted between May 15 and June 25. All authorized movement of equipment and personnel must be on established roads and must be consolidated and scheduled to reduce disturbance to caribou. The necessity and conditions for limiting equipment and personnel movement will be identified on a case-by-case basis during review of plans of operations by the Director, Division of Minerals and Energy Management, in consultation with Alaska Department of Fish and Game.

b. Pipelines should be consolidated to the extent feasible and must be constructed to allow safe passage of caribou. Adequate elevation, ramping, or burial of pipelines will be required in areas identified by the Department of Fish and Game as important caribou movement zones.

25. Routes of travel must avoid preferred polar bear denning habitat unless human safety dictates otherwise. Polar bears den on Pingok and Cottle islands and within 25 miles of the coastline in deeply drifted areas (6 ft. or greater) adjacent to the cutbanks of drainages. The use of explosives will be prohibited within 1/4 mile of cutbanks identified by the Department of Fish and Game. The Department of Fish and Game will make maps identifying documented high density polar bear denning habitat available to the Director and lessees within 45 days of the date a request for approval of a plan of operations is received.

26. The following provisions will govern aircraft operations in and near the sale area.

    a. From May 15 through September 30, aircraft must fly at altitudes of greater than 1,500 feet (457 m) or at a lateral distance of one mile around barrier islands, lagoons, river deltas, and wetlands within one mile of the Beaufort Sea coast (excluding take-offs and landings).

    b. From May 15 through June 20, aircraft overflights within 30 miles (24 km) of the coast between the Colville and Kuparuk rivers must avoid caribou by an altitude of at least 1,500 feet (457 m) or a lateral distance of one mile (1.6 km) (excluding take-offs and landings).

    c. Human safety will take precedence over aircraft restrictions.

27. Surface use will be restricted, as necessary, to prevent unreasonable conflicts with local subsistence harvests.

28. Bidders are advised that the North Slope Borough (NSB) Assembly has adopted a Comprehensive Plan and Land Management Regulations under Title 29 of the Alaska Statutes. The regulations require NSB approval for certain activities necessary for exploration and development of the lease. The state may not in all instances accept this assertion of jurisdiction.

29. During the conduct of all activities related to this lease, the lessee will be subject to the provisions of all valid coastal zone plans and ordinances. DMEM will require, as a condition for consistency approval of lease operations, such modification or stipulations as may be necessary to ensure consistency with the Coastal Management Act, and with sound planning and management of coastal zone resources.

30. Plans of operations for lease activities and specific permit applications which are subject to approval by the U.S. Corps of Engineers or which require a Certificate of Reasonable Assurance from the Department of Environmental Conservation must be submitted simultaneously for state agency review and approval, at least 60 days prior to the proposed conduct of such activities.

31. If only the subsurface estate is owned by the state, or if the surface is owned by the state but subject to third party interests, including any native allotments, the lessee must not enter upon such land until the lessee makes a good faith effort to agree with the surface interest holder on settlement of damages that may be caused by lease activities. If an agreement cannot be reached, Director, DMEM, has the authority to approve the activity, provided adequate provisions have been made with the state to pay for any damages the surface interest holder may suffer.

32. The proposed activities under a plan of operations must not unreasonably diminish the use and enjoyment of lands encompassed within a native allotment. Before entering a pending or approved native allotment, lessees must contact the Bureau of Indian Affairs and the Bureau of Land Management and obtain approval to enter, if required. Lessees must also comply with applicable federal law on native allotments.

33. In conducting offshore geophysical surveys, neither lessees nor their agents will use explosives in open water areas. Offshore geophysical surveys will be restricted as necessary during the spring to comply with the provisions of the Marine Mammal Protection Act. Offshore geophysical surveys will be restricted as necessary during the fall to comply with the provisions of the Endangered Species Act as they relate to the bowhead whale. In determining these restrictions, the Director, DMEM, will at a minimum consult the North Slope Borough, the Alaska Eskimo Whaling Commission, the Beaufort Sea Biological Task Force, and affected permittees.

34. Continuous fill causeways are prohibited. Noncontinuous fill causeways may be permitted when the Director, DMEM, after consultation with the Department of Fish and Game and the Department of Environmental Conservation, determines that a causeway is necessary for field development and that no other feasible and prudent alternative exists.

35. An Oil Discharge Contingency Plan will be required for offshore operations under AS 46.04.030 and 18 AAC 75.

36. Oil and gas transportation pipelines will be encouraged if the Director, DMEM, determines that the laying of such pipelines is technically feasible and environmentally preferable to transport via oil tanker. Pipelines, including flow and gathering lines, must be designed and constructed to provide adequate protection from water currents, storm and ice scouring, subfreezing conditions, and other hazards as determined on a case-by-case basis. Following the installation of a pipeline of sufficient capacity, no crude oil will be transported by surface vessel from offshore production sites, except in an emergency. The Director, DMEM, will evaluate the emergency and determine an appropriate response to the condition. If the use of a pipeline is not feasible and preferable and surface transportation must be employed, all vessels used for carrying hydrocarbons to shore will conform with all standards established for such vessels, pursuant to the Ports and Waterways Safety Act of 1972 (46 U.S.C. 391(a)) and the Port and Tanker Safety Act of 1978 (33 U.S.C. 1221).

37. Many of the environmental concerns associated with the offshore tracts within the area of the Joint Federal-State Beaufort Sea Sale (Sale 30) apply to the offshore tracts in the Sale 39 area. Consequently, in the enforcement of Stipulation No. 3 and Terms of Sale Nos. 8, 15, 33, and 36 of Sale 39, the Director, DMEM, will continue to receive recommendations from a biological task force composed of designated representatives of the following state agencies: Department of Fish and Game, Department of Environmental Conservation, and Department of Natural Resources. In addition, the office of the Governor and representatives of interested federal agencies, including the Bureau of Land Management, U.S. Fish and Wildlife Service, Minerals Management Service, the National Marine Fisheries Service, and the Environmental Protection Agency will be afforded the opportunity to continue their participation in these consultations.

38. The movement of equipment and personnel to and from Sale 39 tracts through the whistling swan staging area in T13N, R8E, Umiat Meridian 3 will be restricted as necessary between July 15 and September 1. The necessity and conditions for limiting equipment and personnel movement will be identified on a case-by-case basis during review of plans of operations by the Director, DMEM, in consultation with the Department of Fish and Game.

39. For the purpose of administering the seasonal drilling restriction, Stipulation 3, the boundary between the areas classified as "on or inside" and "outside" the barrier islands will be a line connecting the following salient points:

Salient Pt. No.	Latitude	Longitude
16045-5	70°14'19.00" N=7792349.21	146°38'12.00" E=513710.74
16062-44	70°28'35.30" N=7819850.41	148°49'06.4[illegible]" E=432180.64
BPT-001	70°33'13.40" N=7830108.992	149°56'53.50" E=390487.531
BPT-002	70°33'14.20" N=7830127.595	149°56'41.20" E=390615.559
BPT-003	70°33'31.60" N=7830628.325	149°55'25.40" E=391423.076
BPT-007	70°33'50.00" N=7831057.169	149°50'38.20" E=394410.503
BPT-008	70°34'13.50" N=7831597.007	149°44'02.10" E=398525.888

Salient Pt. No.	Latitude	Longitude
BPT-014	70°34'02.30" N=7831066.516	149°37'17.70" E=402678.052
BPT-015	70°33'54.10" N=7830766.831	149°35'34.10" E=403734.968
BPT-024	70°33'00.90" N=7828848.509	149°24'55.90" E=410248.229
BPT-025	70°32'41.80" N=7828200.199	149°22'35.90" E=411669.399
BPT-031	70°31'43.80" N=7826214.688	149°14'32.40" E=416592.684
BPT-032	70°31'30.50" N=7825744.507	149°11'57.80" E=418174.547
40-X	70°29'24" N=7821637.360	149°03'12" E=423474.097
41-X	70°29'27" N=7821728.505	149°03'07" E=423528.980
BPT-048	70°28'49.60" N=7820332.598	148°51'12.20" E=430891.228
HBE-027	70°33'21.90" N=7830116.402	150°11'50.00" E=604102.175
HBE-031	70°33'08.10" N=7829784.852	150°08'31.20" E=606172.061
Western Termination	70°35'50.80" N=7834584.60	144°16'50.23" E=600800.00

ALASKA
REVIEW OF SOCIAL AND ECONOMIC CONDITIONS

UNIVERSITY OF ALASKA, INSTITUTE OF SOCIAL AND ECONOMIC RESEARCH, DEC. 1982, Vol. XIX, No. 4

Reflections on the End of the OPEC Era

This paper is intended to put the OPEC oil-price rises of the 1970s and the more recent oil-price decline into historical perspective. Alaskans can then weigh the chance that energy prices will resume their upward climb, giving new momentum to economic growth in the state, against the prospect that the OPEC era is indeed over—meaning that Alaska, along with other energy-exporting regions, must accept a radical and mostly downward adjustment in its development expectations.

Oil Prices and Alaska's Economy

Alaska's labor force, population, and personal income have been increasing faster than those of any other state for almost a decade. Very little of this growth would have happened without the two great surges in world oil prices that most people identify with the rise of OPEC—the Organization of Petroleum Exporting Countries.

The fivefold price increase for Middle Eastern crude oil in 1973-74 and the resulting threefold increase in the market value of U.S. domestic crude oil made it economically feasible to develop the Prudhoe Bay field and complete the Trans-Alaska oil pipeline (TAPS). Even if real oil prices had remained at their 1975-78 levels, Prudhoe Bay oil royalties and taxes would have made Alaska the richest state government *per capita* throughout the 1980s, and the spending and respending of these revenues in Alaska would have combined with continuing private investment in energy resources to put Alaska among the faster-growing states in income and employment.

World oil prices took off once more in 1979-80, however. Real prices at the Persian Gulf "only" tripled this time, but the stability of transportation charges between the North Slope and Lower-48 refineries caused the price of Prudhoe Bay oil—and consequently Alaska's royalty and severance-tax collections—to grow almost five-fold. At their peak in 1981, oil revenues were flowing into the state treasury at an annual rate of more than $10,000 per capita. The effect of this bonanza on state spending for government operations, transfer payments, loan programs, and public works was as awesome as it was predictable. In 1980 the Legislature abolished personal income taxes, and in 1982 it voted to distribute a "Permanent Fund dividend" check of $1,000 to each resident.

By the second quarter of 1981, when crude-oil prices began their present downward trend, most private and governmental planning in the state had come to reflect the assumption that oil prices, and with them the prices of other fossil fuels, would keep rising without limit. Disagreement about the long-term oil price outlook was largely confined to the question of whether price increases would average 2, 3, or 5 percent in excess of general inflation.

The prospect of ever-rising oil prices implied that Prudhoe Bay would generate more and more revenue for the state, and that the spending and respending of that revenue would provide more and more public- and private-sector jobs. It also promised to sustain a high level of exploration activity on state lands and the federal outer continental shelf (OCS) and, most likely, a series of major new discoveries. Rising oil prices convinced sponsors of the proposed Alaska gas pipeline that they could just about ignore the difficulty of marketing North Slope gas as a constraint on the project's economic feasibility.

An ever-increasing real price of oil on world markets also seemed to assure Alaska a petrochem-

This report was adapted from the appendix of a larger study entitled "Alaska Energy Planning Studies," performed by Arlon R. Tussing and Gregg K. Erickson for the Division of Policy Development and Planning, Office of the Governor, October 1982.

ALASKA REVIEW OF SOCIAL AND ECONOMIC CONDITIONS

VOL. XIX, No. 4, December 1982

Published by

Institute of Social and Economic Research
University of Alaska
Anchorage • Fairbanks • Juneau

Jay Barton—President, University of Alaska
E. Lee Gorsuch—Director, Institute of Social and Economic Research

Institute Editor: Ronald Crowe
Editorial Assistant: K. Lee Crowe
907-278-4621

Main Institute Office:
707 "A" St., Suite 206
Anchorage, Alaska 99501

FEATURE

Arlon R. Tussing — Reflections on the End of the OPEC Era

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icals boom based on the growing cost advantage North Slope natural-gas liquids (NGLs) would have over oil-based petrochemical feedstocks used elsewhere; it also seemed to guarantee development of Alaska's coal for export. Higher and higher prices for oil meant, moreover, that natural gas and coal would be too valuable to use for generating electric power in Alaska; this outlook has been the main rationale for planning a multi-billion dollar hydroelectric generating plant on the Susitna River and has led many legislators to believe that the state would be able to finance the Susitna project with a direct appropriation from the General Fund.

The price of oil is thus the biggest single outside influence on Alaska's economy, and in 1982, uncertainty about the oil-price outlook has become the biggest single source of uncertainty about the state's economic future. The possibility that the oil-price boom may be over has profound consequences which thus far have been easier to ignore in Alaska than in other energy-exporting areas.

Since the upward movement of oil prices ended in 1981, economic distress has already overtaken many of the top oil-exporting countries. By the end of 1982, all but two OPEC nations are likely to be in a deficit fiscal and foreign-exchange position. In less than a year, a record boom has given way to a grave depression in the deep-gas areas of Oklahoma, among oilfield-service contractors, and for the financial institutions that specialized in backing them. All but a handful of synthetic-fuels projects have now been abandoned, and the future of those remaining is doubtful.[1]

Several forces have joined to perpetuate a petroleum-driven boom in Alaska that has lasted longer than in other petroleum-exporting regions. Most crucial has been the fact that actual spending of state money appropriated in 1980 and 1981 has continued to increase month by month well into 1982. Another factor has been the momentum of North Slope oil exploration and development programs, some of which would be economical at any world oil-price level higher than (say) $10 per barrel. A third element in the present boom is a host of Anchorage commercial building projects for which the key decisions and commitments were made before 1981. Finally, the continuing increase in the amount of state money actually flowing into the economy has combined with the flow of oil-industry investments to perpetuate a mood of high optimism among private investors in Alaska's non-energy industries, particularly residential and commercial real-estate development.

Nevertheless, in 1982, the beginnings of a

downward slide in world oil prices has already drastically altered the state government's official view of the future. From June 1980 through January 1982, the Alaska Department of Revenue's quarterly *Petroleum Production Revenue Forecast* had been predicting that nominal-dollar ("inflated") oil revenues would increase over the 4 years beginning on each forecast date at a compound annual rate between 12.2 and 25.8 percent. In its March 1982 *Forecast*, the department's 3-year estimate of the expected annual change in state revenues fell abruptly to a *negative* 0.8 percent.[2]

Specifically, the "most likely" projection in the March *Forecast* was that the weighted average wellhead value for Alaska North Slope (ANS) crude oil in fiscal year (FY) 1983 would be 29 percent lower than in FY-1982, and that world prices would then resume their nominal-dollar increase at a compound annual rate of about 7 percent. The department did not expect prices to regain FY-1982 levels until the beginning of FY-1987. With respect to constant-dollar ("real") oil prices, the March *Forecast* boldly reported "a consensus that oil prices will continue to fall,"[3] and projected declining real oil prices through 1998.[4] Table 1 above compares the state's June 1981 and 1982 forecasts.

Table 1

Petroleum-Revenue Projections by the Alaska Department of Revenue June 1982 vs. June 1981
(1982 constant dollars)

Fiscal Year	Oil and Gas Revenue ($ millions)* June 1981 Forecast "Expected Value"	June 1982 Forecast "Expected Value"	June 1982 Forecast "30-percent" Series
1983	4,030	2,654	2,399
1984	4,137	2,657	2,250
1985	4,271	2,623	2,177
1986	4,448	2,953	2,411
1987	4,713	3,305	2,644
1988	4,851	3,196	2,507
1989	4,983	3,365	2,595
1990	4,742	3,095	2,246
1991	4,544	2,714	1,862
1992	4,382	2,477	1,668
1993	3,979	2,285	1,427
1994	3,637	2,149	1,265
1995	3,144	1,826	1,059
1996	2,701	1,622	936
1997	2,289	1,608	908

*Includes royalties, production taxes, and corporate income taxes on petroleum products.

Source: Alaska Department of Revenue, *Petroleum Production Revenue Forecast, Quarterly Report*, June 1981, p. 13; Personal Communication, Charles Logsdon to Gregg K. Erickson, June 1982, p. 18.

The 1981 Turning Point

At the end of 1981, oil prices were suffering their greatest decline in half a century, but industry executives and forecasters—even outside Alaska—cautioned that the attendant "glut" was a temporary phenomenon.[5] Despite many signals to the contrary, that opinion has persisted well into 1982, with Occidental's Chairman Armand Hammer and others predicting $100-per-barrel oil in 10 years.[6] The scarcity mentality that fed the price leaps of 1974 and 1979, plus a belief that unpredictable Middle Easterners control the world oil market through OPEC, gave such assumptions nearly axiomatic status during the past decade. But the exporting nations' boast that "oil in the ground is a better investment than money in the bank" is turning out to be so much wishful thinking.

The truth is that neither an end to the recession, nor OPEC's attempts at production quotas, nor continued wars in the Middle East will long be able to shore up a sagging crude-oil market. It is, indeed, because oil prices climbed so rapidly and so high in the 1970s that they are now almost certain to fall and keep falling—perhaps as steeply and as far as they rose. Today's prices are still higher than markets can tolerate, and the forces that led to the enormous price hikes of the past decade work just as effectively in reverse.

While real (constant-dollar) crude-oil prices are unlikely to rise again to their 1980-81 levels any time in this century, forecasting prices for any specific future year is a nearly hopeless task. The fall in crude-oil prices that began last year will someday give way to another increase, and so on. As Table 2 and Figure 1 show us, crude oil markets are inherently *cyclical* and, except during a unique period of almost four decades when the State of Texas dominated both U.S. and world crude oil markets, oil price fluctuations have been large and frequent. *History shows us no long-term oil-price trends*, but only a series of cycles of uneven duration and amplitude. The era of OPEC's opportunistic price-gouging is over, but no other entity is in sight with the power to move oil prices in any consistent direction or to stabilize them at any given level.

Table 2

U.S. Crude-Oil Prices, 1870-1981
Current and Constant Dollars

	Crude-Oil Prices 1870-1972, Average U.S. Wellhead Prices; 1973-1981, U.S. Refiner-Acquisition Cost of Imported Crude Oil (Current Dollars per Barrel)	Price Deflator 1870-1925, Wholesale Price Index: 1925-1981, GNP Deflator (1972 = 100)	Price Deflator 1870-1925, Wholesale Price Index: 1925-1981, GNP Deflator (March 1982 = 100)	Crude-Oil Prices (1972 = 100)	Crude-Oil Prices (March 1982 = 100)
1870	3.36	26.53	129	12.67	25.97
1871	4.34	25.54	.125	16.99	34.83
1872	3.64	26.72	.130	13.62	27.92
1873	1.83	26.13	.127	7.00	14.36
1874	1.17	24.76	.121	4.73	9.69
1875	1.35	23.19	.113	5.82	11.94
1876	2.56	21.61	.105	11.84	24.28
1877	2.42	20.83	.102	22.62	23.82
1878	1.19	17.88	.087	6.66	13.64
1879	.86	17.68	.086	4.86	9.97
1880	.94	19.65	.096	4.78	9.81
1881	.91	20.24	.099	4.50	9.22
1882	.77	21.22	.104	3.63	7.44
1883	1.09	19.85	.097	5.49	11.26
1884	.83	18.27	.089	4.54	9.31
1885	.86	16.70	.081	5.15	10.56
1886	.70	16.11	.079	4.34	8.91
1887	.71	16.70	.081	4.25	8.71
1888	.88	16.90	.082	5.21	10.68
1889	.94	15.92	.078	5.91	12.11
1890	.87	16.18	.079	5.38	11.03
1891	.67	15.98	.078	4.19	8.59
1892	.56	15.33	.075	3.65	7.49
1893	.67	15.66	.076	4.28	8.77
1894	.80	14.68	.072	5.45	11.17
1895	1.23	14.49	.071	8.49	17.41
1896	1.10	14.10	.069	7.80	16.00
1897	.76	14.16	.069	5.37	11.00
1898	.91	14.55	.071	6.25	12.82
1899	1.29	15.07	.074	8.56	17.55
1900	1.37	15.79	.077	8.68	17.79
1901	1.14	15.66	.076	7.28	14.93
1902	1.09	16.18	.079	6.74	13.81
1903	1.24	15.37	.080	7.57	15.53
1904	1.18	16.56	.081	7.12	14.60
1905	.90	16.95	.083	5.31	10.88
1906	.85	17.34	.085	4.90	10.05
1907	.84	18.06	.088	4.65	9.54
1908	.81	17.93	.087	4.52	9.26
1909	.76	18.58	.091	4.09	8.39
1910	.67	19.10	.093	3.51	7.19
1911	.68	18.90	.092	3.60	7.37
1912	.65	19.68	.096	3.30	6.77
1913	1.15	19.55	.095	5.88	12.06
1914	.98	19.94	.097	4.91	10.07
1915	.79	20.85	.102	3.79	7.77
1916	1.42	23.39	.114	6.07	12.45
1917	2.07	29.04	.142	7.13	14.61
1918	2.64	32.68	.159	8.08	16.56
1919	2.79	37.29	.182	7.48	15.34
1920	4.30	42.48	.207	10.12	20.75
1921	2.21	35.40	.173	6.24	12.80
1922	2.10	32.55	.159	6.45	13.23
1923	1.68	33.32	.163	5.04	10.33
1924	1.81	33.26	.162	5.44	11.16
1925	2.19	33.71	.164	6.50	13.32
1926	2.41	33.19	.162	7.26	14.88
1927	1.72	32.48	.158	5.30	10.86
1928	1.68	33.00	.161	5.09	10.44
1929	1.78	32.87	.160	5.42	11.10
1930	1.62	31.80	.155	5.09	10.44
1931	.93	28.89	.141	3.22	6.60
1932	1.17	25.67	.125	4.56	9.34
1933	.92	25.14	.123	3.66	7.50
1934	1.36	27.32	.133	4.98	10.20
1935	1.31	27.83	.136	4.71	9.65
1936	1.45	28.01	.137	5.18	10.61
1937	1.58	29.34	.143	5.39	11.04
1938	1.46	28.66	.140	5.09	10.44
1939	1.32	28.48	.139	4.63	9.50
1940	1.32	29.13	.142	4.53	9.29
1941	1.48	31.34	.153	4.72	9.68
1942	1.53	34.39	.168	4.45	9.12
1943	1.54	36.18	.176	4.26	8.73
1944	1.56	37.03	.181	4.21	8.64
1945	1.58	37.92	.185	4.17	8.54
1946	1.82	43.95	.214	4.14	8.49
1947	2.50	49.70	.242	5.03	10.31
1948	3.39	53.13	.259	6.38	13.08
1949	3.30	52.59	.257	6.27	12.86
1950	3.31	53.64	.262	6.17	12.65
1951	3.34	57.27	.279	5.83	11.96
1952	3.34	58.00	.283	5.76	11.81
1953	3.55	58.88	.287	6.03	12.36
1954	3.68	59.69	.291	6.17	12.64
1955	3.67	60.98	.297	6.02	12.34
1956	3.71	62.90	.307	5.90	12.09
1957	3.89	65.02	.317	5.98	12.26
1958	4.09	66.06	.322	6.19	12.69
1959	4.00	67.52	.329	5.92	12.14
1960	3.87	68.67	.335	5.64	11.55
1961	3.87	69.29	.338	5.59	11.45
1962	3.89	70.55	.344	5.51	11.30
1963	3.88	71.59	.349	5.42	11.11
1964	3.87	72.71	.355	5.32	10.91
1965	3.89	74.32	.363	5.23	10.73
1966	3.88	76.76	.374	5.05	10.36
1967	3.90	79.02	.385	4.94	10.12
1968	3.93	82.57	.403	4.76	9.76
1969	4.15	86.72	.423	4.79	9.81
1970	4.29	91.36	.446	4.70	9.63
1971	4.56	96.02	.468	4.75	9.74
1972	4.57	100.00	.488	4.57	9.37
1973	5.38	105.80	.516	5.09	10.42
1974	12.52	116.02	.566	10.79	22.12
1975	13.93	127.15	.620	10.96	22.46
1976	13.48	122.71	.599	10.99	22.52
1977	14.53	141.70	.691	10.25	21.02
1978	14.57	152.05	.742	9.58	19.62
1979	21.67	165.46	.807	13.10	26.85
1980	33.89	177.36	.865	19.11	39.17
1981	36.80	193.58	.944	19.01	38.97

Market Control by the Texas Railroad Commission (1935-1972)[7]

To understand OPEC's helplessness in today's crude oil market, it is useful to review how the market operated before OPEC came to power, and how the Texas Railroad Commission (TRC) managed to exercise control for nearly 40 years.

The TRC's rule emerged in the mid-1930s from circumstances quite different from those that nurtured OPEC in the 1960s and 1970s. In the era between 1859, the year Colonel Drake first discovered oil in Pennsylvania, and the Great Depression, crude oil markets everywhere were dominated by events in the United States, where one black-gold rush after another unleashed an oversupply and sent prices plummeting.[8] Growing oil demand rapidly restored prices after most of these crises, as petroleum captured markets that were previously held by whale oil, gas, or coal, and as the automobile population swelled.

The Yates field in Texas, for example, was first tapped in 1926. It was the biggest field yet found, and over its first year of production, average crude oil prices in the United States fell 24 percent. Prices recovered quickly, but in 1930, the beginning of the Depression coincided with discovery of the even larger East Texas field. Oil literally ran in the creeks, and prices fell locally to 10 cents per barrel.

Much of this market chaos resulted from the common-law "rule of capture." The principle that nobody owned oil until it was brought to the surface generated frenzied competition among drillers to lift as much as oil as they could from each newly-discovered pool before their neighbors got it. The east Texas drilling rush ended in 1931 only when the governor sent the National Guard into the field to shut down production. The next year, a bitterly divided Texas legislature granted the TRC authority to limit output from individual wells in the interest of conservation and market order. Under "market-demand prorationing," refiners told the TRC how much oil they wanted to buy each month, and the Commission parceled out the "allowable" share of this demand to each well. This system assured every Texas producer a buyer for at least some of his oil, no matter how much excess producing capacity other producers held. The TRC's ability to stabilize the market was bolstered by market-demand prorationing in several other states including Louisiana, the number-two U.S. producer. Under state regulation, physical shortages and surpluses both became a thing of the past; "conservation" replaced physical waste, and the violent short-term fluctuations of crude oil prices ended.

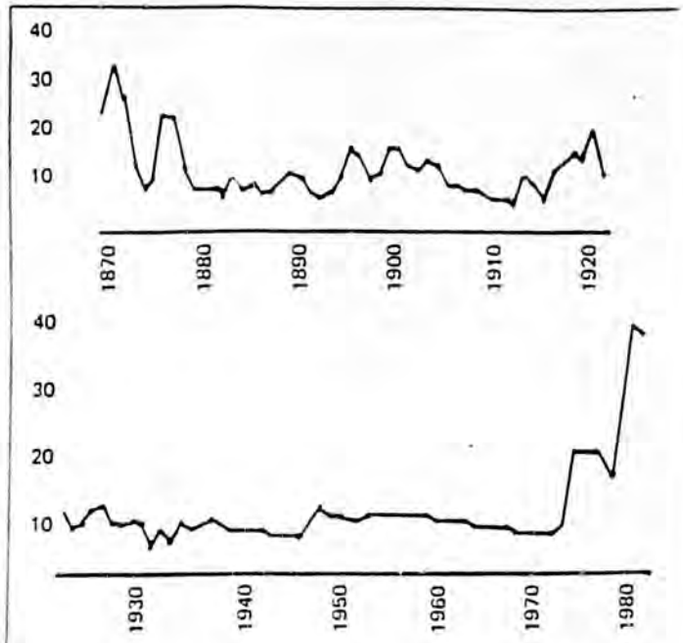


Figure 1. U.S. Crude Oil Price Trends, 1870-1981
(March 1982 constant dollars)

Even more important were a series of federal actions backstopping TRC authority. In the 1935 Connally "hot-oil" law, Congress made it a federal crime to ship oil produced in violation of state conservation orders. After World War II, the executive branch acted to prevent uncontrolled imports of low-cost foreign crude oil from undermining the states' control of U.S. oil supplies. For a while, the handful of largely U.S.-based oil companies that controlled the oil reserves of the Middle East and the Caribbean cooperated successfully in limiting petroleum production from their foreign concessions to just about the amount demanded by their own foreign refineries.

Nevertheless, by 1948, the huge low-cost oil reserves overseas had become enough of a threat to Texas regulation that the Truman administration started assigning "voluntary" import quotas to the companies. In 1958, after independents like Hunt and Occidental developed enormous new reserves in Libya, President Eisenhower established a mandatory oil-import program (MOIP). The MOIP gave each U.S. refiner the right to import some lower-priced foreign oil, but it enabled the TRC and other state conservation authorities to continue setting the total volume of crude oil supplied to the domestic market.[9]

Critics of market-demand prorationing and import quotas, including the 1970 Cabinet Task Force on Oil Import Control, headed by George Shultz, saw the combination mainly as an arrange-

ment that kept U.S. prices artificially high and perpetuated wasteful excess capacity. It did, indeed, shut in much of the nation's lowest-cost oil, while creating an incentive to develop domestic fields that would not have been viable in a free market.[10] But precisely because it sheltered surplus producing capacity, Texas prorationing functioned as the balance wheel of the world oil market for four decades. Texas was the "price-maker"; the TRC determined the price all domestic producers received for their oil, and it was at the same time the most powerful single force in the world crude oil market. Other producers were relegated to the passive role of "price-takers" who could always sell as much or as little oil as they wished, once they accepted the price structure established by Texas.

The TRC could play the price-maker's role because it had control over sufficient spare producing capacity to supply refiners with all the Texas oil they wanted at the established price, offsetting any rise in demand prompted by boom conditions or long-term economic growth, or any drop in output by other producers at home or abroad. The Commission also had the power to enforce production cuts if necessary to prevent a surplus from appearing when oil demand waned or production outside Texas increased.

The Texas system worked nearly 40 years, through World War II, the U.S. recessions of the 1950s, and several supply disruptions caused by Middle Eastern political upheavals in the 1950s and 1960s. Oil supplies were seriously curtailed in 1952-54, for example, following Mossadeq's nationalization of the Iranian oil concessions; during the Suez crisis of 1956; and again during the 1967 Yom Kippur War. U.S. and world crude-oil prices remained relatively stable, however, as the majors produced more oil in the unaffected Persian Gulf countries, while the TRC and other state commissions increased production at home. From 1935 to 1972, roughly the period of the TRC's domination of the world market, the average annual change in real crude-oil prices in the United States was only 4 percent, plus or minus, a stark contrast to the average annual change of 21 percent between 1871 and 1935.[11]

One reason for the TRC's success was that it did not exploit its market power opportunistically. The 1952, 1956, and 1967 Middle Eastern conflicts offered Texas producers (and the state of Texas, a major royalty owner) a chance for huge short-run profits, as they did the big international oil companies. But each time, the TRC and the majors opted for long-term stability, forestalling the kind of consumer panic that generated the price run-ups of 1974 and 1979 after the TRC had lost control.

Once domestic production reached full capacity in 1972, the U.S. Government had no choice (politically, at least) other than to do away with import controls, leaving consumers exposed to whatever upheavals might occur in the oil-exporting countries. Meanwhile, nationalization of the major oil companies' overseas concessions, plus the growing influence of independents (including national oil companies like those of France, Italy, and Brazil), had stripped the majors of their ability to balance supply and demand outside of North America. A supply curtailment by the Arab oil producers, which would have hardly caused a ripple in oil prices 10 years or even 2 years earlier, transformed world energy markets and, for a few years at least, handed control of those markets to OPEC.

Panic Pricing in 1973-74 and 1979

OPEC's spectacular successes in the 1970s were due more to market psychology rather than to anyone's direct manipulation of crude oil supplies. OPEC *per se* did not engineer either of the decade's great price leaps; they came instead from *consumer panics* that spread through the spot market after the 1973-74 Arab embargo and the 1978 Iranian revolution. In both cases, OPEC merely voted, *after the panic had run its course*, to establish the prevailing spot prices as the base prices for all crude oil sales.

Crisis psychology was thus the key to the short-term oil market behavior that ratcheted prices upwards. The physical shortfall that provoked the panic of 1973-1974 was proportionally no greater than the shortfalls (or excess supplies) that the industry faced periodically because of unusual weather or the business cycle, and there was no reduction in output at all immediately before the 1979 price spiral. In neither case was the actual shortage greater than the sum of (1) the oil then being consumed by electrical-generating and manufacturing plants that had the capacity to use other fuels, (2) the standby or underutilized oil-producing capacity of U.S. and uninvolved foreign producers, and (3) the inventory cushions that industry ordinarily would have drawn down in order to prevent market turmoil.

The price leaps, rather, began both times with a handful of large-scale buyers who believed that the "shortage" was real, and who were thus willing to pay almost anything. The crisis mentality had a powerfully perverse effect on the market; instead of restraining demand, soaring spot prices gave the shortage credibility and helped propagate the panic to every class of consumer, so that demand actually increased. Much of the apparent supply deficiency

was caused by hoarding, the most memorable example of which was the fashion of topping-off gasoline tanks daily in private automobiles. This practice alone probably created demand for an additional 600 million gallons of gasoline in the United States.[12]

However socially irrational that hoarding may have been, it seemed quite reasonable at the time from an individual company or consumer standpoint. In 1973-74, both the Arab producers and the Western media were insisting that the embargo and production cutbacks were in fact harming the consuming countries. Congress had passed an Emergency Petroleum Allocation Act; President Nixon had declared an "energy emergency" and had begun allocating crude oil and petroleum products.

No one knew how long the apparent shortage would last or how high prices might go before it was over; hence, it made sense for anyone with a preferred position in the allocation scheme to take every drop of price-controlled gasoline or fuel oil allowed under the rules, regardless of current need, and for every other consumer to buy as much at the prevailing price as he could store. Motorists, households, and businesses all sought to build up and maintain high inventories in case things "really got bad" later, while producers, refiners, and others expected to profit from holding products for resale at higher prices in the future. All of these anticipations, of course, validated themselves: supplies did get tighter and prices continued to rise.

The Role of Spot Prices[13]

Oil producers and refiners usually try to plan their physical operations and to budget their purchase outlays and revenues well in advance. For this reason, the great bulk of the world's crude oil moves in "captive" channels from producing companies to their own refinery affiliates or on relatively long-term contracts between producers and refiners. "Spot" transactions—sales of a single tanker-load or less—usually account for only a few percent of world supply, but they are an indispensable part of the total market because they allow any company or government to dispose of a temporary oversupply or fill a temporary shortfall. A general surplus or shortage equal to only (say) 3 percent of total world demand may thus show up as a surplus or shortage amounting to 50 or 100 percent of normal spot-market demand. As a result, spot prices tend to fluctuate daily and seasonally, and to range widely above and below "posted" or contract price levels, which typically change slowly and infrequently.

Changes in crude oil spot prices occasionally herald deep-seated market changes, but more often they are only exaggerated reflections of unexpected weather or business conditions, the buildup or drawdown of inventories, or political events. After some such contingency has caused a spot prices to diverge sharply from contract prices, the spot market normally returns to a relatively narrow band of prices in the vicinity of previous contract-price levels. What was special about the OPEC-dominated markets of the 1970s is that they twice failed to respond in this normal way. After the panics of 1973-74 and 1979, spot prices did *not* fall back to pre-crisis levels; instead, contract prices rose—by OPEC decree—to the peak values to which the panic had carried spot prices. This feat was OPEC's great triumph which, ironically, is now begetting its downfall.

The Power of Saudi Arabia and OPEC

The TRC determined prices by actively manipulating the aggregate supply of crude oil; as a state agency, it had the power to enforce its orders on the many thousands of Texas producers regardless of their conflicting individual interests and viewpoints. OPEC, on the other hand, has never had any authority over the diverse and sometimes warring sovereignties that make up its membership.

Nevertheless, in the early 1970s, once the surplus capacity of Texas and Louisiana had disappeared, Saudi Arabia by itself conceivably could have taken over the TRC's balance-wheel role. Its potential authority came from a combination of the world's largest reserves of conventional crude oil and a population on the order of only 5 million. The Saudis have thus had the same mix of assets, at least theoretically, that earlier gave the TRC its power—the ability to *increase or decrease* output over a wide range.

Proved and indicated reserves in Saudi Arabia number in the hundreds of billions of barrels—how many hundreds, no one knows or much cares, because it has never been worthwhile to carry out the intensive exploration and development work needed to get an accurate estimate.[14] The known reserves are, in any event, so large and so easy to develop that it would take Saudi Arabia only a few months to double its exports from the current level of less than 6 million barrels per day. (After all, production was almost 11 million barrels per day only one year ago.) With 2 or 3 years for drilling of development wells and construction of gathering lines and terminals, exports probably could rise to something like 18 million barrels per day. Indeed, before the 1973 embargo, the big oil companies (the Aramco shareholders) that controlled the Saudi concession were

planning for production on the order of 20 million barrels per day by 1976.

Saudi market power rests on the ability to curtail as well as to increase production. The country's small population has permitted Saudi Arabia to reduce its output by almost half over the last year, from 10.6 million barrels per day in August 1981 to less than 5 million in November 1982, without suffering a fiscal or foreign-exchange crisis. Throughout the 1970s, therefore, Saudi Arabia, with or without the cooperation of other OPEC nations, had much of the wherewithal to stabilize the market in the same way as the Texas Railroad Commission once did.

The OPEC Mystique

It was a worldwide obsession with scarcity, rather than deliberate management of total world supplies, that underpinned the OPEC mystique and locked in the high prices OPEC decreed in 1974 and 1979 after the direct causes of panic had vanished. The doctrine of imminent resource exhaustion was embraced in the 1970s by a broad spectrum of parties who had entirely different world views and different ends.

Environmentalists hoped to slow the wasteful plundering of the earth's riches; oil companies were seeking to ward off price controls and attacks on their tax preferences; alternative-energy entrepreneurs sought business; politicians found in the energy crisis a moral equivalent of war; civil servants made it the rationale for massive expansion of their agencies and intervention into almost everything; and an army of academics, consultants, and journalists waxed rich and famous by studying, interpreting, or advocating national energy policies. Each group wanted to believe, or at least to persuade others, that "the wolf is really here"—that OPEC's prices might have risen too abruptly for comfort but that, in the last analysis, those prices only expressed the dictates of geological necessity.

"Oil in the Ground is Better than Money in the Bank"

In this intellectual climate, each price increase, regardless of its proximate cause, helped convince the oil-exporting nations that "oil in the ground is a better investment than money in the bank." This doctrine could remain valid for just as long as most producers believed in it, because it encouraged them to hold oil off the market in the faith that its value would be much higher in the future. It was therefore the most effective and durable weapon in OPEC's ideological arsenal.[15] Although the organization had no enforcement machinery, and did not even attempt a prorationing scheme until 1982, its members did reduce production when preservation of the price gains of 1974 and 1979 required it.

When the OPEC nations cut back their total exports in 1974 and again in 1979, it is important to note that they made the required cuts individually. They did so *without coordination or urging by OPEC*, because they had more money than they needed at the moment, and because they believed that their oil would be worth more later. Even the 1973-74 price rise had been so immense that most OPEC countries had substantial financial surpluses; only Algeria, Ecuador, and Indonesia were in deficit. In 1975, OPEC as a whole had a $59-billion (or 14-percent) surplus of export revenues over import expenditures. Several countries understandably concluded that their economies couldn't absorb further increases in oil income without generating intolerable inflation and social unrest.

It also seemed obvious to the producers that oil prices would continue to advance at a higher rate than their surplus cash would yield in risk-free financial instruments. Thus, Kuwait, Libya, and Venezuela together reduced their exports by 4 million barrels per day after the 1974 price rises. Saudi Arabia abandoned Aramco's 20 million barrel-per-day target in 1974, and cut production sharply in January 1979 and then again in April—ostensibly to offset an imminent oil glut, which was in fact an aftermath of the price panic that followed the overthrow of the Shah. In neither price rise did OPEC as such have any role in initiating or orchestrating the curtailments.

Thus, a short-lived belief in acute scarcity twice created a real scarcity that caused spot prices to soar. A belief that chronic energy shortages would engender a permanent seller's market then led producers and consumers alike to interpret an unusual and otherwise transitory market phenomenon as obedience to holy writ. The self-fulfilling doctrine that oil in the ground was the world's best investment not only encouraged OPEC officially to adopt spot market prices generated by consumer panic; it also enabled those prices to stick. In 1973-74, the world price of crude oil (measured at the Persian Gulf) increased fivefold in real terms, and then in 1979-80 it again tripled (a vivid contrast to the decades of tranquility under the TRC).

The End of the OPEC Era

OPEC's hold over world energy markets in the 1970s was no less real because it was mainly psychological. However, the cartel's mystique is far more fragile than the earlier market power of Texas,

which stemmed from the TRC's direct control over production volumes. Today, few of the material requisites for further OPEC success remain. Its share of the world oil market has fallen from 55 percent in 1974 to 27 percent in October 1982, and Saudi Arabia's share is already less than the share Texas held as late as the mid-1960s.

Some recognition of these shifting realities began to strike the Saudi leadership only after two deliberate production cuts in 1979 had locked in a series of huge price increases voted by OPEC. Saudi Arabia's actions have now become more-or-less consistent with the professions of the kingdom's oil minister, Sheikh Yamani, who had long given lip-service to the cause of moderation and market order. Explicitly invoking the memory of the TRC, Yamani claims to have engineered the 1980-81 "oil glut"—increasing production from less than 8 million barrels per day to almost 11 million, specifically in order to bring prices down to $34 per barrel and to persuade his OPEC partners that they should join a prorationing scheme under Saudi leadership. In 1982, after succeeding too well, perhaps, the Saudis have abruptly reversed course, now *cutting* their exports by over half in an attempt to support the $34 price.

But Saudi Arabia appears to have been too late in discovering the market power it alone possessed. While the TRC held crude oil prices in the United States above short-term free-market levels, it still kept them low enough to encourage ever-increasing oil consumption and stave off the development of alternative energy sources. The Saudis, however, wittingly or unwittingly had a key role in both OPEC price hikes of the 1970s, unleashing inexorable and profound reactions from both producers and consumers, which today threatens to make OPEC oil a dispensable commodity.

Contrary to a near-consensus of industry, government, and the academic/consulting community during the 1970s, crude oil demand does respond—slowly but massively—to price changes. In the long run, higher prices have a profound effect on oil supply too, but the relationship is too complex to pursue in detail here. In any event, non-OPEC output has grown rapidly and will continue to grow: production from the North Sea, Alaska, and Mexico, for example, increased by 4 million barrels per day between 1977 and early 1982, and Mexico's exports—driven now by economic necessity—could increase another 3, 5, or more millions of barrels per day before 1990. Most clearly and most importantly, however, high oil prices are shrinking oil demand both by reducing total energy consumption and by making coal, natural gas, nuclear power, and other energy sources more attractive.

The Flight from Oil

After a modest dip in 1974, total world oil consumption resumed its growth, and finally turned down only 1979. This experience reinforced the impression that oil demand was insensitive to price changes, misleading economists as well as industry executives and government officials in both oil-producing and oil-consuming countries. An absolute decline in U.S. oil consumption was first visible in 1979; the rest of the industrialized world followed a year later. In retrospect, it is remarkable how many were unable to see what was happening.

Exxon in 1977 forecast that U.S. consumption of petroleum liquids would be *20.3 million barrels per day in 1980*. In 1979, Shell predicted *18.6* million barrels per day consumption in 1980, and both the *Oil and Gas Journal* and the Independent Petroleum Association of America (IPAA) forecast 18.4 million. As late as mid-1980, Shell had only revised its published estimate downwards to *17.2* million barrels per day, while the IPAA had come down to *17.4. At year-end in 1980, however, average consumption for the year stood at only 16.3 million barrels per day*.[16]

The drop in total oil use over the last 3 years and the experts' tardiness in recognizing the trend of consumption stems from profound changes in the structure of world energy demand that have actually been under way since 1974. From 1960 to 1973, oil prices were low and declining in real terms. As a result, absolute oil consumption in the industrialized countries grew at an annual rate of 7.6 percent. Japan led this growth with an 18-percent average over the 13-year period. After 1974, however, the quadrupled crude oil price led to a gradual leveling off of demand for oil everywhere. Total oil consumption in the industrialized countries dropped slightly in 1974-75; growth resumed between 1975 and 1979 at an annual rate of about 1 percent, but this partial recovery only concealed the fundamental shift that had taken place in the world's energy-use patterns.

More telling than gross consumption figures is the change in oil use per unit of economic activity, or "gross domestic product"—the oil/GDP ratio. After rising at an annual rate of 1.3 percent from 1960 to 1973, the oil/GDP ratio for the major industrialized countries showed a 1.5-percent annual *decline* between 1973 and 1979. The 1979 upheaval initiated an even more decisive and long-lasting shift away from oil, reflecting both an immediate reaction to the second OPEC price surge and the delayed but cumulating response to the price increases of the early

1970s. From 1979 to 1981, oil consumption in the industrialized countries fell 7 percent per year, and the oil/GDP ratio fell at an annual rate of 8 percent.

Since the latter measure represents the amount of oil used *per unit of economic activity* rather than an absolute figure, its fall implies that an end to the present recession will not be the panacea that much of the energy industry and many analysts still seem to anticipate. The die has been cast. It is unlikely that individual homeowners will tear the insulation out of their houses if the price or home heating oil drops, or scrap their new fuel-efficient automobiles in response to lower real prices for gasoline. Nor will the housing construction and automobile industries abandon their new energy-efficient designs. Those who attribute the oil glut and the current "softness" of oil markets primarily to the world recession forget that economic recovery will mean a *more rapid replacement* of existing vehicles, industrial machinery, and buildings with models designed since 1974 in response to high energy prices.

Except in a couple of OPEC countries, no new base-load electrical generating plants fired by oil, or any large-scale oil-fired boilers of any sort, have been built since the mid-1970s; over the past decade, industry has been relentlessly converting existing oil-burning equipment to coal, natural gas, and other energy sources. Because changes in the world's fuel-use patterns are generally embodied in long-lived capital-intensive investments such as buildings, transportation equipment, and industrial machinery, the extended period it has taken for the 1974 price rises to produce an absolute decline in oil consumption only reflect the time required to replace these assets. This long lag in adjusting the world's capital [illegible] to changed energy-supply conditions also [illegible] that the all-time high oil prices of 1974-1982 [illegible]uence consumption patterns for many more years, *even if world oil prices now fall as rapidly and as far as they rose in the 1970s.*

The truism that the world's petroleum resource is finite thus does not mean that oil prices will continue to rise. The world has no demand for crude oil as such, but only for the heat, motive power, and chemical building blocks it provides, and only for so long as it is the cheapest source of these goods. No matter how scarce natural petroleum liquids become, their prices cannot rise and remain above the cost at which each of these wants can be dispensed with or served in some other way.

It should be fairly obvious now that predictions of $100 per barrel oil are ludicrous. At $15 per barrel, oil was already more expensive than coal everywhere in the world, and had consequently priced itself out of electrical-generation and other large-scale stationary-heat and boiler-fuel markets. At well under $50 per barrel, given a few years for market and infrastructure development, liquid petroleum products would have become marginal even as transportation fuels, increasingly replaced by some combination of compressed and liquefied hydrocarbon gases and alcohols. A world that is already fleeing from oil at $32 per barrel would hardly have any use for it at two or three times that price.

This dynamic does not bode well for OPEC, or for the ability of Saudi Arabia or anyone else to manipulate or stabilize the market. Only when demand falls is the power of a price-maker tested. Can the OPEC nations, many of whom are deeply in debt, now afford to cut back production as they must?

On this point too, the OPEC of 1982 is as different from its predecessor, the Texas Railroad Commission, as it is from the OPEC of the mid-1970s. In comparing OPEC with the TRC, it is essential to remember that the Commission's power developed during the Depression, and that its institutions were designed expressly to manage a chronic excess of producing capacity. Once that excess was gone, the TRC became impotent and economically irrelevant. OPEC, in contrast, showed its muscle under totally opposite conditions. It twice seized upon a brief moment of consumer panic, convinced itself and consumers alike that a permanent world oil scarcity existed, and for a while reaped the benefits of a seller's market even after the foundations of that market had vanished.

There is little prospect that OPEC can function effectively in a chronic buyer's market, especially in the face of the organization's current internal dissensions and the precarious financial situation of its members. At its March 1982 meeting, the group made its first serious attempts at TRC-style prorationing. The experiment was an instant failure, with at least three members brazenly exceeding their quotas from the beginning.[17] By July 1982, Iran was selling 1.0 million barrels per day above its quota, Nigeria .3 million, and Libya .25 million. Venezuela—the sole advocate of OPEC prorationing before 1980—had threatened to start selling more than its assigned 1.5 million barrels per day if the other countries didn't get in line. In August, the Saudis, who had already reduced their own output by 45 percent in the hope of supporting the $34 marker price, were also hinting that they would raise their own output if the cheating did not stop.[18]

Even holding the line at today's production level

is not enough to bolster OPEC's flagging power, as world oil consumption continues to shrink and the production of nonmembers—especially Mexico—continues to grow. The organization as a whole must somehow manage to reduce production even further if present prices are to hold. Yet its member-nations individually face internal problems and pressures that urge them in just the opposite direction.

The greatest source of downward pressure on prices is the shaky financial condition of the exporting countries, a drastic turn-around from the situation of 1975. Since 1973, OPEC spending for imports has risen at an average annual rate of 30 percent, because of ambitious industrialization plans in every one of them and extravagant purchases of military hardware in many. Already, the combination of declining oil demand and rapidly rising expenditures has resulted in trade deficits for all but three OPEC members. Unless oil production or prices increase sharply, every member, including Saudi Arabia, could slip into deficit by the end of 1982.

These deficits, exacerbated by the continuing Iran-Iraqi war, are already beginning to take their toll as the most hard-pressed countries, in search of revenues to pay for today's imports, produce as much oil as they can sell. Moreover, with declining or even stable prices and real (inflation-adjusted) interest rates at their highest level in history, the slogan that oil in the ground is a better investment than money in the bank is obsolete even for countries that do not have an immediate cash-flow or foreign-exchange deficit. In the 1980s, it is hard for even a cash-surplus oil-exporter to avoid recognizing that *oil in the ground is a non-earning asset*, which ought to be cashed out so the proceeds can be invested in high-yielding financial instruments. This doctrine is just as true and may be just as self-fulfilling today as was the opposite notion in 1975 or 1979.

To put OPEC's weakness into further perspective, consider the following:

- In August 1982, world crude oil production was about 54 million barrels per day. Out of this total, the Saudi share was about 5.5 million, or 10 percent; all of OPEC was producing about 17 million barrels per day, or 31 percent of world supply. If new production in non-OPEC countries plus further declines in consumption were to equal only 10 percent of present world demand, OPEC's members would have to reduce their own production by 32 percent in order to defend any chosen price level.

Saudi Arabia, which has already reduced its exports by 45 percent over the last year, cannot and will not accommodate much of this burden, as a 10-percent shift in world supply or demand would be just about equal to the country's current export volume. Further growth in non-OPEC production and a further fall in world consumption are not only plausible but nearly inevitable. Thus, Saudi Arabia's reign as world price-maker is ending virtually as soon as it began.

- Conservation, fuel-switching, and recession caused the noncommunist world's oil consumption to fall by 7.5 million barrels per day between 1979 and mid-1982. If consumption declined by only half as much over the next 2 years, OPEC's output would have to fall by an amount equal to the combined production of Kuwait, Libya, Algeria, and Indonesia in August 1982, or by 68 percent of current Saudi output.
- Crude oil production from Alaska, Mexico, and the North Sea increased by more than 4 million barrels per day between 1977 and 1981. If all non-OPEC producers were to increase their output by another 4 million, OPEC could maintain control of prices only if its members could cut production by at least the equivalent of 73 percent of the August 1982 Saudi Arabian production.
- Production from Iran, the world's former number-two oil exporter, has fallen 4 million barrels per day from its 1974 peak. The former number-three exporter, Iraq, is producing 2.6 million barrels per day less than its 1978 peak it reached in 1978. If the war between these countries should end and they returned to the market with their 1978 sales volumes, other OPEC countries would have to curtail production by an amount equal to 90 percent of the August 1982 Saudi output.
- Finally, if by chance the last three developments all took place, and if OPEC hoped to sustain world prices at current levels, it would have to find places to cut production by at least 12.7 million barrels per day—75 percent of the organization's current output, or 231 percent of August 1982 Saudi production.

The range of conditions within which OPEC, Saudi Arabia, or anyone can continue to dictate or even defend the level of world oil prices is thus extremely narrow. The reckless opportunism that held sway in the 1970s is now taking its toll. Long-term changes in supply and demand adverse to OPEC's interests have been under way ever since the cartel's first big coup in 1974. As these changes become visible to everybody, the mystique that has

been OPEC's chief source of power will vanish along with forecasts of hundred-dollar oil. The world market will soon be, if it is not already, out of anyone's control.

What Have We Learned?

A big new disturbance in world oil markets could push prices either up or down. It is still conceivable, if only barely so, that a sharp economic upturn and an exceptionally cold winter could combine with the right kind of Middle Eastern political crisis and send prices soaring for a third time to levels significantly above those reached in 1980-81.

The probabilities, however, weigh heavily on the other side. There is a huge overhang of excess producing capacity in the oil-exporting countries. Several of them are in extreme fiscal distress; Mexico in particular has both the ability and a desperate need to increase oil exports. Meanwhile, the price-induced flight from oil is still gathering a momentum that will not be spent for years, *no matter what happens to oil prices today.*

All of these forces together, not to mention a worldwide economic slump that is far from over, add up to irresistible downward pressure on oil prices. Prices must *eventually* go down, and they must go down substantially. The serious questions are whether they will descend smoothly or chaotically, and how deep they will go. There is still a sliver of a chance that prices could firm for weeks or months, or even—given the unlikely coincidence of events described above—increase once more. But an oil market collapse this year or next has a far bigger likelihood—a collapse every bit as spectacular as the two price eruptions of the 1970s.

Looking back across the years of OPEC and energy crises to the relative tranquility of the TRC era and beyond, there are several lessons for the future.

1. **Worldwide scarcity and rising real resource costs had little or no direct responsibility for the energy price upheavals of the 1970s.**

The earth's *known* resources still include plenty of crude oil that could be developed and produced at resource costs (capital, material, and labor costs) well below 1973 real prices. Considering these resources alone, there is enough low-cost oil left to satisfy the world's current rate of consumption for several decades.

2. **In the absence of an effective price-maker like the Texas Railroad Commission, crude-oil markets are inherently cyclical.**

Oil demand is highly responsive ("elastic") to price changes, but this response is very slow, because fuel-use patterns are embodied in capital goods whose turnover is measured in decades: buildings, transportation equipment, industrial machinery, and production processes. For the same reason, demand is exceedingly inelastic to price changes in the short run. This contrast between short- and long-term price-responsiveness inevitably fosters cyclical price behavior. In the 1970s, *short-term price-inelasticity* spawned a steep cyclical upswing after years of artificially-maintained stability, and in 1981, a high *long-term price-elasticity* finally began to show itself in the beginning of a downswing.

If there is no "surge-tank" or "damping" mechanism comparable to market-demand prorationing, moreover—

3. **Market structure and psychology can exaggerate an episodic oil-price fluctuation, up or down, far out of proportion to the original supply-demand imbalance that triggered it.**

Inventory accumulation or liquidation, the financial position of major producers, and consumer panic can all cause markets to behave perversely over a "short-run" that can last for several years. In a mockery of the "normal" supply-demand map, an oil-price rise can for a while create an incentive to build inventories, and sustained price rises can encourage the withholding of production. A price reduction, likewise, can provoke liquidation of inventories and the expansion of output. As a result—

4. **A small excess of demand or supply, real or imagined, can send the market soaring or plummeting far beyond the price level that ultimately could have brought it back into balance.**

Thus, there is no *stable* equilibrium toward which an unregulated petroleum market unfailingly "hunts" once it is disturbed. The upheavals of the 1970s, which carried prices well *above* any level that could be long sustained, have now set the stage for a descent far *below* the range of sustainable prices.

5. **No cartel or regulatory system could have held world oil prices at the low levels of the early 1970s, and none can do so in the future.**

Before 1973, state regulators in the United States and the cartel of international companies maintained prices that were above the shortest-term "market-clearing" levels, but which were still so low

that oil totally dominated transportation-fuel markets (even capturing railroads that had earlier been powered by electricity generated from coal). Except in a small corner of the United States, these low oil prices virtually swept coal from the world's markets for industrial boiler fuels and organic-chemical feedstocks. At the same time, however, the prices were too low to perpetuate the surplus oil-producing capacity in the United States, to which the state regulators owed their market power. Though the world's stock of very low-cost oil was still immense, the loss of spare capacity in the United States concentrated the power to rapidly increase or curtail production in a handful of economically underdeveloped and politically turbulent countries.

The problem, therefore, was not a permanent worldwide scarcity of "cheap" oil. Instead, it was the absence of short-term oil-demand flexibility, together with the disappearance of the short-run supply flexibility that had previously been exercised by governmental and private institutions consciously striving for market order. In these circumstances, a relatively small curtailment of sales by a few producers openly aiming at market disruption could and did trigger an upward explosion of prices. If world oil prices now fell to pre-1973 levels (in constant-dollar terms) once more, a world-wide "energy crisis" would be with us again sooner or later. Likewise, however—

6. **No group of producers could long hold world oil prices at the high levels of the early 1980s, and it is unlikely anyone will ever be able to do so.**

Today's prices area not viable, because they are well on the way to pricing oil out of both the industrial fuels market and the market for petrochemical feedstocks. If prolonged, today's prices would even begin to erode oil's monopoly in transportation-fuels markets. Oil at $30 and up has, therefore, guaranteed the emergence of excess producing capacity not in just one or a handful of political entities (Texas and Lousiana, for example, or Saudi Arabia, Kuwait, and Abu Dhabi), but all over the globe.

7. **Market stability at any price requires the supply-demand balance to respond promptly and in the normal direction to any price change, and requires and requires prices to respond promptly and in the normal direction to any change in the supply-demand balance.**

If the world is to avoid repeated violent swings in oil prices, market arrangements must be such that a small rise in oil prices can cause either a sizable *increase in effective oil supply or a sizable decrease in oil consumption*, or both. A small drop in prices must, likewise, be able to induce a prompt reduction in supply or increase in consumption.

8. **Short-term supply-side adjustments that foster price stability rather than instability require a TRC-style price-maker, but none is now in sight.**

Any supplier or group of suppliers that hopes to regulate the market must have the ability and the will to swing world oil production upward to satisfy any surge of demand or supply interruption, or (more importantly now) to swing it downward in order to make room for a surge of supply or slump in demand. The system run by the TRC, through *underpricing*, destroyed its power to increase output whenever it was needed. OPEC as such never had *either* the will or the capacity to take responsibility, and Saudi Arabia—out of greed or timidity, we may never know—blew its chance. It has now, through *overpricing*, destroyed its ability to reduce production sufficiently to support world prices at present levels or, most likely, at any level.

The only plausible new candidates for price-maker may be PEMEX (Mexico's state oil company) and the U.S. Strategic Petroleum Reserve. However, even if one of them maneuvers itself into the right strategic spot in the world market, there is only the barest chance that domestic politics in the United States or Mexico would permit either institution to move quickly, independently, and responsibly enough to serve as the world's oil-supply balance wheel.

9. **The only price level that even a supply-side price-maker can maintain for long is one that fosters demand-side stability as well.**

10. **Specifically, the range of sustainable oil prices is limited to those prices at which oil, coal, and gas are effective and close competitors in the world's markets for electrical-generation fuels, industrial boiler and stationary heating fuels, and petrochemical feedstocks.**

If the price of oil remains within a range where oil, natural gas, and coal effectively compete for industrial sales in North America, Europe, and East Asia, many of the world's large energy consumers will find it worthwhile to install dual or multi-fuel capacity, expressly in order to take advantage of small shifts in relative prices. The ability of a large consuming sector to switch fuels rapidly in response

to changes in relative fuel prices or availability would preempt the perverse market behavior that has permitted small market shocks to explode into global crises. Multi-fuel consumers would simply let go of enough oil in a tight market, and absorb enough additional oil in a slack market, to avoid even the *illusion* of a physical shortage or surplus. The greater this demand-side flexibility becomes, the more modest will be the world's need for a supply side price-maker like the TRC, the less onerous will be the price-maker's task if one is still needed, and the less damage an incompetent or irresponsible price-maker will be able to cause.

11. The most stable and easily sustainable price range is probably on the order of $10 to $18 per barrel (in 1982 constant dollars), delivered to the world's major consuming regions.

Unlike pre-1973 prices, the $10-to-$18 price range is high enough to cover the cost of mining and transporting coal, *and burning it in an environmentally acceptable fashion*, almost but not quite everywhere in the world. These prices are also high enough to justify shipping liquefied natural gas (LNG) from any low-cost gas-producing area near tidewater to almost any port in the world, and to justify building transcontinental natural-gas pipelines (though maybe not the Alaska or Yamal pipelines). Prices in this range would still leave oil holding a significant fraction of the markets for electric-utility and industrial boiler fuels and for petrochemical feedstocks. Any price excursion outside of this range, however, would still carry the threat of prices sharply fluctuating farther away from, or substantially overshooting, any attainable equilibrium.

History offers some empirical support for the viability of a long-term world oil price in the $10-to-$18 range. Over 110 years of crude-oil price records in the United States, the average price in 1982 dollars has been almost exactly $13 per barrel and, despite an average constant-dollar price fluctuation of more than 20 percent per year, no long-term trend can be detected. (The average 1982-dollar price between 1871 and 1925 was $12.96 per barrel, and the average price between 1926 and 1980 was $13.04 per barrel.) Thus, the *safest* guess as to the *average* crude-oil price over (say) the next 25 years may be about $13 per barrel in 1982 dollars. However—

12. These generalizations do not warrant a forecast of a $13 price, or any other specific price at any specific future time.

In the absence of a secure mechanism for getting world oil prices into this range and keeping them there for several years, and in the absence of a competent and responsible successor to the Texas Railroad Commission, the prospect is for wide and unforeseeable fluctuations in world oil prices like those that occurred before the TRC took control in the mid-1930s. The managing director of Royal Dutch Shell, D. deBruyne, summarized the new outlook well when he wrote that "we are in for a period of severe and unpredictable discontinuities."[19] The most ambitious forecast we dare make with any confidence is that—without some new market-ordering mechanism, which is not now in sight—

13. World oil prices will fluctuate both randomly and cyclically. In any given future year, however, the most likely price will be far below 1979-1982 levels.

In summary, there is no basis in geology, resource-economics, or history for predicting a never-ending increase in the real price of oil. Private investments and governmental institutions founded on that proposition are sure losers.

NOTES

[1]None of the several recent price forecasts I have seen, prepared for *internal* use by major petroleum producers (corporations or governments), expects sustained growth in the real price of oil during the rest of this century. All of them now assume continued constant-dollar price declines through at least 1985. At least two major integrated oil companies that now assume for their own planning purposes that the long-term oil price trend will fall somewhere *between a level nominal-dollar and a level constant-dollar trajectory*, released *public* forecasts in 1982 that still show long-term real-price increases for oil.

More significant than what the companies are saying, however, is what they are doing.

The dramatic change in industry's long-term oil price expectations over the last 2 years is impossible to ignore: the companies have scuttled every major unsubsidized synthetic-fuels project in North America, and most of the subsidized ones to boot. Oil companies are cutting back massively on drilling programs, but the most telling indicator of the drastic change in their expectations is the fact that *they are now paying only about half as much per barrel for proved petroleum reserves* as they were paying in late 1980. (On the last point, see B.F. Picchi, "The Valuation of U.S. Petroleum Reserves: Exploding the Myths" in Salomon Brothers, Inc. Stock Research/Industry Analysis, October 15, 1982.)

The change in the energy market did not take everyone by surprise. For early warnings in Alaska or from Alaskans about the impending turndown in oil prices and state revenues, see my remarks in the minutes of the U.S. Department of Commerce Economic Advisory Board during 1979 and 1980; also A.R. Tussing, "The 1981 Oil Price Outlook" in *The Economic Outlook for 1981*, University of Michigan, November 1980; A.R. Tussing, "Will Oil Prices Keep Rising? Maybe Not," *Anchorage Daily News*, February 14, 1981; Jon Matthews, "State Revenues Likely Will Drop: Oil Prices are Heading Down," *Anchorage Daily News*, May 29, 1981; A.R. Tussing, "Alpetco's Collapse Has Lessons for Budget Planners," *Anchorage Daily News*, May 23, 1981; Bob Shallit,

"State Faces Revenue Loss, Economists Say," *Anchorage Daily News*, January 15, 1982; "Alaska Cuts Forecasts," January 18, 1982; Erickson & Associates for the Alaska State Legislature, *The World Oil Market and Alaska State Revenues: A Fifteen-Month Forecast* (Juneau: March 1982).

[2]Alaska Department of Revenue, Division of Petroleum Revenue, *Petroleum Production Revenue Forecast*: (Quarterly, Anchorage: June 1980 through September 1982). In June 1982 the Department of Revenue's oil price forecasts were revised slightly upward. In September, however, the Department issued a forecast which in the long term is even more pessimistic regarding state oil revenues than the March report.

[3]Alaska Department of Revenue, Division of Petroleum Revenue, *Petroleum Production Revenue Forecast*, March 1982, p. 5.

[4]Charles Logsdon, Chief Petroleum Economist, Alaska Department of Revenue, personal communication to G.K. Erickson, July 18, 1982. When the Department of Revenue reduced the figures in each of the series of forecasts that corresponded to a specific confidence level, greater attention to the uncertainty of petroleum price forecasts led the department to emphasize its "30-percent" rather than its "50-percent" series. The different percentage figures indicate the Department's judgment about the probability that actual revenues will be *less* than the figure shown.

[5]" 'OPEC Will Survive,' Oilman Hammer says." Associated Press story in *Seattle Post-Intelligencer*, July 12, 1982, p. B8.

[6]Acres American, Inc. (the principal contractor on the feasibility study for the Susitna River hydroelectric project) offered the following list of "major forecasts of oil price trends" in order to refute forecasts of declining oil prices in another ISER report (A.R. Tussing and G.K. Erickson, *Alaska Energy Planning Studies: A review of three consultant studies submitted to Alaska state agencies in fiscal-year 1982*. Anchorage: ISER. Final report November 1, 1982):

Source	Date of Forecast	Forecast Trend (%)
Data Resources, Inc.	Summer 1982	+2.8
Int'nl Energy Agency	Spring 1982	−0.5 to + 2.0
U.S. DOE Energy Info Adm.	Spring 1982	above + 3.0
Canada: Energy Mines & Res.	Summer 1982	+ 1.7
Ontario Hydro	Spring 1982	+ 1.8
Energy Modeling Forum Avg. of ten models	February 1982	+ 1.9 to + 5.3
Dr. F. Fesharaki	Spring 1982	+ 1.7

From Alaska Power Authority, *Susitna Hydroelectric Project*, "Commentary on 'Alaska Energy Planning Studies' (A.R. Tussing and G.K. Erickson)," prepared by Acres American, Inc., September 7, 1982.

While the Acres compilation does not reveal the time span of the projections cited, it is representative of the kind of forecasting institutions that Acres polled, even in late 1982. Significantly, however, this list does not contain a single petroleum-producing company, financial institution, or agency of an oil-*exporting* political entity (see note 1), while four (half) of the forecasts cited come from governmental entities that have a powerful institutional stake (as does the Alaska Power Authority) in perpetuating the belief that real oil prices will continue to rise.

The published forecasts of government agencies and the big consulting firms indeed seem to be among the last to recognize the changed outlook, just as they were among the last to recognize that the high prices established in 1973-74 would be with us for a while.

[7]For the history of oil conservation and the rise of the Texas Railroad Commission, see Wallace F. Lovejoy and Paul T. Homan, *Economic Aspects of Oil Conservation regulation*, (Baltimore: The Johns Hopkins University Press, 1967), pp. 33-57, and Stephen L. McDonald, *Petroleum Conservation in the United States: An Economic Analysis* (Baltimore: The Johns Hopkins University Press, 1971), pp. 29-55.

[8]From the July 1882 *Scientific American*:

> The history of the discoveries in the Pennsylvania oil fields has been one of a series of disappointments to the producers. From 1866 to 1872 the price per barrel averaged from $4 to $5, and the producers were making money rapidly. Then the field in Butler County was struck, and from that day to this the production has been greater than the consumption. Then came the Bullion pool with its 2,000- and 3,000-barrel wells, which forced the price down to $1.50. This field was soon exhausted, and better times for the producers were at hand when the Bradford field, the largest in extent ever known, was opened. Then Bradford began to decline and again a silver lining was seen, but again disappointment came.
>
> In May of last year the first well was struck in Allegany County, New York, and a new field was opened that soon more than made up for the decline. Then was the great "646" well struck, and with it followed disaster to the owners of wells generally, and lower-priced oil than since the summer of 1874, when for a time it sold for 45 cents a barrel. Where the next field will be is only a matter of conjecture.

[9]For the history of import controls, including the influence of the Texas Railroad Commission on import policy, see M.A. Adelman, *The World Petroleum Market* (Baltimore: The Johns Hopkins University Press, 1972), pp. 150-154.

[10]Lovejoy and Homan, *Economic Aspects . . .*, pp. 265-285, and the Cabinet Task Force on Oil Import Control, *The Oil Import Question* (Washington: U.S. Government Printing Office, 1970), pp. 24, 121, 216, 242-246.

[11]Adelman, . . . *World Petroleum* . . . For a history of oil prices during the entire era, see pp. 131-191.

[12]M.A. Adelman, "Coping with Supply Insecurity," *The Energy Journal*, October 1982, pp. 1-16.

[13]On the role and operation of spot markets, see Paul H. Frankel, *Topical Problems* (London: Petroleum Economics, Ltd.), July/August 1973, p. xx; January/ February 1976, p. iv; and June 1979, pp. xvii-xviii.

[14]Estimated proved reserves as of January 1, 1982, can be found in Robert J. Enright, "Worldwide Report," *Oil and Gas Journal*, December 28, 1981, p. 86. The *Journal* lists Saudi Arabia's proved reserves as 164.6 billion. John Blair in *The Control of Oil* (New York: Vantage, 1978), pp. 18-19, quotes Yamani as saying that "Saudi Arabia's 'true reserves' are more than two and a half times the 'ultra conservative numbers' at which 'proved reserves' were being carried."

In 1972, James Akins, then U.S. Ambassador to Saudi Arabia, told Senator Mike Gravel and me that Saudi Arabia's reserves were "realistically" at least 700 billion barrels and "probably closer to a trillion." At a Central Intelligence Agency briefing I attended in 1975, an Agency spokesman gave almost the same estimates (likely from a common source) of the ultimate reserves in the known fields in Saudi Arabia. He added that Iraq's reserves were probably "almost as big."

For our present purposes it doesn't matter which of these reserve estimates is the most realistic; even the most conservative of them implies that Saudi Arabia is physically capable of producing considerably more than 20 million barrels per day without any new discoveries.

[15]See, for example, the remarks of Jahangir Amuzegar, Iranian Ambassador-at-Large and sometime petroleum minister, at a 1975 Salomon Brothers conference in London (World Petroleum: The Economics of Current Pricing and Supply Policies. London: Salbro Press, 1976, p. 30):

> Notwithstanding Western calculations and projections to the contrary, OPEC members believe that their oil reserves underground will be worth more in the future compared to the present—even with accumulated returns on the invested revenues.

Adelman makes a plausible case that this notion is

economically fallacious and, by implication, cynical and deliberately misleading (M.A. Adelman, "OPEC as a Cartel" in Griffin and Teece, *OPEC Behavior and World Oil Prices*, pp. 38-53).

However, Adelman's argument that oil reserves *never* earned as much as financial investments rests on discount rates that reflect the short life expectancies of Third World governments. This approach ignores the *ideological* content of national policy. Economic policy in most OPEC nations is either made by nationalist bureaucrats who view their nations as something *different from* the present government, or by heads of state who believe that their persons are *identical with* the nation, which is itself immortal. Either case results in lower discount rates and longer amortization periods than Adelman assumes for a non-ideological world.

Adelman's analysis also virtually dismisses the *specific* ideological role played by the concept of oil reserves as a long-term investment. OPEC spokesmen were doubtless sincere when they insisted that the asset-value of their resources was appreciating at a higher rate than the real rate of return on risk-free financial investments. My ground for accepting such professions at face value stems both from personal contact with high-placed and lowly believers, and the fact that it was in the oil exporters' interest that they and their customers both believe their motives were something more honorable than greed and their production scheduling built on something more substantial than simple opportunism.

My remarks at the same 1975 conference (A.R. Tussing, discussant, comments on speeches by Chief M.O. Feyide, Secretary-General of OPEC; Amuzegar; T.O. Enders, U.S. Assistant Secretary of State for Economic Affairs; Adelman; and P.T. Frankel, Director of Petroelum Economics, Ltd., *Topical Problems*, pp. 41-44) directly addressed Amuzegar's 1975 argument and anticipated Adelman's 1981 argument:

> To Karl Marx, who gave us the concept, "ideology" was a body of doctrine that provided a religious, moral, or scientific cloak to self-interest. Ideology is in the first place a political weapon: if they believe in it, its sponsors can draw from it moral fervor and confidence of success. And an effective ideology can also captivate or neutralize its adversaries. Believing one's own propaganda uncritically (or that of one's opponents) has, however, led to some remarkable foolishness, as various crusades from the Middle Ages to Vietnam have shown.
>
> I suppose that my message today is not to take OPEC's rhetoric too seriously, nor the opposing rhetoric. . . . The conservationist element in OPEC doctrine deserves more serious attention (than its profession of solidarity with the poor and exploited everywhere), particularly as it is a notion shared by a rich, industrialized non-OPEC oil producer like Canada and by a variety of environmentalists and Malthusian doomsayers in all of the rich countries. The common theme of all these parties is that mankind ought to keep its cheapest energy source, petroleum, in the ground because it will be more valuable in the future than it is today.
>
> This proposition cannot be dismissed out of hand. There may well be *some* producing country or countries with reserves of only ten to fifteen times current production, without the hope of major new discoveries and with only limited opportunities for productive investment at home. Such a country could reasonably estimate the so-called user cost of its petroleum —the present value of future production given up by producing today—to be as great or greater than the current world price. Such a country might reasonably believe, in other words, that its oil could appreciate in value over the average life of its reserves at a higher rate than the rate of earnings on risk-free foreign investment. Or it may believe that the risks—market and political—of all foreign investments are so great that they make speculation in oil inventories at home a more prudent investment.
>
> I am not certain there is such a country—*but that country surely is not Iran or Venezuela*, whose ability to absorb foreign exchange in profitable domestic investment ventures is insatiable, *nor is it Saudi Arabia*, whose potential reserves are so huge that the present value of a barrel of oil not produced today is truly negligible.
>
> No, to each of these countries, limiting production is rational *not* because its oil will be more valuable in the future but because *less production means higher prices today. Conservation, however, sounds more noble in the producers' own ears than maximization of monopoly profit*, and it appeals to a fashionable intellectual current in the rich consuming nations. The conservationist rhetoric is, therefore, a particularly effective ideological weapon of the cartel (emphasis added).

We need not be overly skeptical about the OPEC nations' belief in a doctrine that helped enrich them, when the same doctrine was believed by so many statesmen and scholars (including the majority of "energy economists") in Europe and America, who used it to rationalize policies that helped impoverish their own nations.

[16]As late as September 1980, it was possible for Cambridge economist Nicholas Kaldor to write seriously that, ". . . OPEC changed everything. By cornering oil it managed to increase the price fourfold, then double it again, and presumably it could be doubled again, *without any really serious impact on consumption.*" (Emphasis added. From "The Energy Issues" in T. Barker and V. Brailovsky, *Oil or Industry*: edited proceedings of Conference on Policy Issues in Energy Self-Sufficient Economies at Different Stages of Industrialization, held at Oaxaca, Mexico in September 1980. London: Academic Press, 1981, p. 3).

[17]Youssef M. Ibrahim, "Saudi Role in OPEC Under Siege" in *The Wall Street Journal*, July 21, 1982, p. 33.

[18]"Oil Nation Warns its Partners," Associated Press story in the Seattle *Post-Intelligencer*, July 8, 1982, p. B9. On Saudi Arabia's threats, see *Platt's Oilgram*, July 13, 1982, p. 1A.

[19]D. deBruyne, quoted in *Petroleum Intelligence Weekly*, June 14, 1982, p. 8.

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June '79

ASSUMPTIONS

North Slope Oil Prices

On December 17, 1978, OPEC announced from Abu Dhabi that the price of Arabian light crude oil would escalate from $12.70 to $14.54 per barrel by October 1, 1979, an increase of 14.5 percent. The price of oil was increased to $13.33 on January 1, 1979 (an increase of 5 percent over $12.70). However, shortly after the December announcement that OPEC members were increasing their official prices an average of 10 percent during calendar year 1979, a political revolution in Iran eliminated crude exports from that country. The international crude market lost about 5 million barrels a day and spot prices for crude oil soared to as much as $31 a barrel - over twice the official base price. As a consequence of this event, an extraordinary price fixing meeting of the OPEC countries was held in Geneva on March 26 to set prices more in line with spot market levels. At that meeting the base price of Arabian light crude oil was raised to $14.54 per barrel. An increase that was not to have taken effect until October 1, 1979. Since this historic meeting, spot market prices have continued to increase and OPEC is once again expected to significantly raise the base price of its benchmark crude oil when it convenes in Geneva later this month. In this forecast, we are assuming an 11 percent weighted average OPEC price increase for FY 1980 when compared to our March 1979 forecast. In addition, we have assumed an end to the discounting of Alaskan North Slope crude on the West and Gulf coasts.

Weighted average OPEC prices increase over the 17-year forecast period from $12.94 in FY 1979 to $44.78 by FY 1995; roughly a 7.5 percent average per annum increase. Weighted average wellhead values for oil royalty calculations for Prudhoe Bay range from a low of $5.17/B in FY 1979 to a high of $32.95/B in FY 1995. The weighted average annual wellhead values for royalty calculations for FY 1979-FY 1985, given the assumptions made in this forecast, are roughly: $5.17, $8.91, $10.87, $12.99, $14.87, $16.84, and $18.30. Weighted average wellhead values for oil royalty calculations are net of field cost deductions. Field costs are not deducted from wellhead values for purposes of severance tax calculations.

TAPS tariffs in this 17-year forecast were based on a number of scenarios for the estimated gross revenue requirements of the pipeline companies. In the majority of cases it was assumed that the TAPS owner companies would receive the rate base and rate of return which they requested in testimony before FERC.

Tanker tariffs and refinery market delivery forecasts were based on data supplied by the Petroleum Audit Supervisor's office, journal articles, company studies and various studies done by government and private agencies. Tanker tariff scenarios were inflated on the average at

roughly 4 percent per annum due to the capital intensive structure of tanker operations. Market first sales in the March 1979 forecast were assumed to reflect the average of the first sales including July 1978 through December 1978. West Coast first sales (including Alaska) averaged approximately 786,000 B/D and Gulf/East Coast (Trans-Panama) first sales averaged around 403,000 B/D over this period. More recently in FY 1979 (October 1978 through March 1979), West Coast first sales have averaged around 814,000 B/D and Gulf/East Coast first sales 389,000 B/D. West Coast first sales in this forecast were assumed to average only 770,000 B/D. The remaining throughput was assumed to be delivered through the Panama Canal until the Northern Tier line becomes operational. It was assumed that the Northern Tier line would be operational at 700,000 B/D by the third quarter of FY 1982. The Northern Tier line was given a 50 percent chance of being built and it was further assumed that no deliveries to Japan would be made. The Long Beach to Texas pipeline (PACTEX) was not included in this forecast due to Sohio's recent announcement that it was abandoning the project.

North Slope Gas Prices

Under the interim rules of the Natural Gas Policy Act of 1978, the ceiling price of Prudhoe Bay gas as of December 1, 1978 is $1.63 per MMBTU. Given 1.092 MMBTU per Mcf, Prudhoe Bay gas will realize a field value of $1.78 per Mcf. Assuming 6 percent inflation per annum, Prudhoe gas should command $2.52 per Mcf by FY 1985--the earliest date that we are forecasting throughput along the Alcan. FERC recently ruled that conditioning costs to remove the carbon dioxide and natural gas liquids and to compress and chill the gas should be deducted from the ceiling price that producers receive for the gas. Assuming conditioning costs of $1.21 per Mcf in 1985 dollars, the weighted average wellhead value of Prudhoe Bay gas (after deducting conditioning costs) by FY 1985 was assumed to be about $1.31 per Mcf. However, allowances were made in the pricing scenarios for the possibility that the costs of conditioning could be shared by the producers and pipeline companies or that either could end up bearing the full cost burden.

North Slope Oil Production

Multiple well and production scenarios for oil and gas were developed from forecasts furnished by the producing companies and the Division of Oil and Gas Conservation. Simulation run number 3A of the Division of Oil and Gas Conservation served as the baseline case for the throughput and well scenarios. Weighted average North Slope oil production was predicted to increase from a low of 1.184 MMB/D in FY 1979 to a high of 1.540 MMB/D for FY 1986-1989 and then to decrease to .705 MMB/D by FY 1995. North Slope production other than Sadlerochit was assumed to begin in FY 1982-1995. TAPS throughput was not expected to exceed the current 1.23 MMB/D capacity until the third quarter of FY 1980. Weighted average volumes for the next five years, beginning with FY 1979, were assumed to be 1.18 MMB/D, 1.26 MMB/D, 1.35 MMB/D, 1.43 MMB/D and 1.5 MMB/D respectively.

ASSUMPTIONS Sep '79

North Slope Oil Prices

World petroleum market developments during the first three quarters of 1979 have proven to be extremely difficult to forecast. Fears of world crude oil shortages estimated to be from 2 to 5 million barrels per day resulted in near panic buying. The resulting market disorder forced OPEC ministers to meet in extraordinary session twice, once in March 1979 when the official OPEC marker crude price was raised to $14.54/B and again late in June 1979 when the OPEC marker crude price was upped to $18.00/B. Even after these cumulative price increases, which equalled approximately 42 percent for Saudi Arabian Light crude oil (and over 60 percent for other OPEC producers), world demand remained high. Fears were that only minimal amounts of crude oil at "official prices" would be available to refining companies and countries without guaranteed sources of crude oil. For example, U.S. Gulf Coast refiners saw the "official" FOB price of Mexican crude oil rise 72.5 percent from $13.10/B to $22.60/B in six-months time. When petroleum buyers were forced to buy crude on the open market they also found that spot market crude oil prices were even higher (some shipments were quoted in the $35.00/B range on the Gulf Coast). In this kind of market, given the wide range of prices (official versus spot) and differences in specific company transfer pricing practices (sales to affiliated parties versus sales to third parties), it is not surprising that declared, pre-audit destination sales prices for Prudhoe Bay type crude oil are difficult to forecast. In this forecast we assume that no further increases will be announced by OPEC until December 1979. However, due to the decline of the dollar and due to Saudi Arabia's relatively low market prices for crude oil in the face of growing economic pressure to increase that price, it has been assumed that the OPEC marker price will be raised 8 percent effective January 1, 1980. After this point more moderate quarterly increases are projected as OPEC moves to maintain the real dollar price of its crude oil.

Given these conditions, it is assumed that weighted average OPEC prices over the 17-year forecast period will rise from $12.91 in FY 1979 to $18.37/B in FY 1980 to $51.32 by FY 1995--roughly a 9.0 percent average per annum increase. Weighted average wellhead values for oil royalty calculations for Prudhoe Bay range from a low of $5.22/B in FY 1979 to a high of $32.95/B in FY 1995. The weighted average annual wellhead values for royalty calculations for FY 1979-FY 1985, given the assumptions made in this forecast, are roughly: $5.22, $12.05, $15.02, $17.62, $19.70, $22.00, and $23.82. These weighted-average wellhead values for oil royalty calculations are, however, net of field cost deductions. On the other hand, field costs are not deducted from wellhead values for purposes of severance tax calculations.

Projections of TAPS tariffs, as a component of transportation costs, in this 17-year forecast were based on a number of scenarios for the estimated gross revenue requirements of the pipeline companies. In the majority of those scenarios it was assumed that the TAPS owner companies would receive the rate base and rate of return which they requested in testimony before FERC.

Tanker tariffs and refinery market delivery forecasts were based on data supplied by the Petroleum Audit Supervisor's office, journal articles, company studies and various studies done by government and private agencies. Tanker tariff scenarios were inflated on the average at roughly 4 percent per annum due to the capital intensive structure of tanker operations. Market sales by destination in the September 1979 forecast were adjusted to reflect the average first sales reported during the first six months of 1979. During this time roughly 850,000 B/D were delivered to the West Coast (including Alaska and Hawaii) while Gulf/East Coast (Trans-Panama) and four Corners Pipeline deliveries were approximately 340,000 B/D. These actual West Coast shipments were 10 percent above earlier estimates of the ability of West Coast refiners to absorb Prudhoe Bay type crude oil. Undoubtedly, the world crude oil supply crisis during the Iranian crisis period led to increased buyer interest in Alaskan oil. For this reason, peak West Coast sales may decline somewhat from the levels reached during the last several months should world crude oil shortages begin to slacken. This has been allowed for in the current forecast. Until the third quarter of 1982 it is assumed that Prudhoe Bay crude surpluses will be shipped through the Panama Canal and four Corners Pipeline to Texas, Gulf/East Coast markets. Beginning in the second quarter of 1982, it is assumed that there is a 50 percent possibility that the Northern Tier pipeline project will be built.

North Slope Gas Prices

Under the interim rules of the Natural Gas Policy Act of 1978, the ceiling price of Prudhoe Bay gas as of December 1, 1978 is $1.63 per MMBTU. Given 1.092 MMBTU per Mcf, Prudhoe Bay gas will realize a field value of $1.78 per Mcf. Assuming 6 percent inflation per annum, Prudhoe gas should command $2.52 per Mcf by FY 1985--the earliest date that we are forecasting production or throughput along an Alcan route for a gas pipeline. FERC recently ruled that conditioning costs to remove the carbon dioxide and natural gas liquids and to compress and chill the gas should be deducted from the ceiling price that producers receive for the gas. Assuming conditioning costs of $1.21 per Mcf in 1985 dollars, the weighted average wellhead value of Prudhoe Bay gas (after deducting conditioning costs) by FY 1985 was assumed to be about $1.31 per Mcf. However, allowances were made in the pricing scenarios for the possibility that the costs of conditioning could be shared by the producers and pipeline companies or that either could end up bearing the full cost burden.

Dec '79

ASSUMPTIONS

North Slope Oil Prices

Of the many input assumptions which are used in preparing this forecast, none are as important or difficult to forecast as world oil prices for crude oils comparable to those produced in Prudhoe Bay. During 1979, world oil markets have been extremely disorderly. At the last three OPEC meetings, the cartel delegates have been unable to establish a single, coherent pricing structure. During the year at least three distinct pricing tiers existed: (1) the moderate OPEC group led by Saudi Arabia at about $18.00/B, (2) the radical OPEC group led by Iran at about $23.50/B, and (3) the spot market segment (5 percent to 15 percent) used by all OPEC governments at about $30.00/B-$40.00/B. These prices merely represent a snapshot of a highly volatile market which is evolving in a very complex and uncertain world setting. Among the many unsettling factors which complicate the analysis of supply, demand, and price of world crude oil are: (1) confusion as to the onset, severity and duration of the long expected U.S. economic recession, (2) worldwide capital flight from financial paper assets to real assets (gold, silver, art, income producing resources, etc.), (3) threats of continued revolution in Iran with the potential loss of 5 percent of the world's oil production, and (4) continued ambiguity and uncertainty in U.S. energy policy regarding intended plans to completely deregulate U.S. crude oil prices at the wellhead and imposition of the "windfall profits tax." As a consequence, the future for world crude oil prices appears to be highly uncertain and for this reason a wide range of assumptions has been used in the simulation model.

The starting point in assessing potential future price movements in the world oil market begins with the reexamination of recent trends. Between September 1979 and December 1979, most of the major oil exporting nations raised their oil prices to or above the price ceilings established at the June 1979 OPEC meeting. Spot market prices trended upward from $30.00/B to $45.00/B. On December 13, a week prior to the December OPEC meetings, Saudi Arabia, and subsequently three other OPEC countries, announced a $6.00/B increase in the price of its crude oil retroactive to November 1, 1979. This brought the price of the bell-wether, Saudi Light crude, to $24.00/B. With this preemptive move, the Saudi government hoped to moderate further price increases that were to be agreed upon in Caracas, Venezuela on December 17, 1979. At that OPEC meeting, once again no agreement on a unified price structure was reached even though the Saudi's were said to have offered to increase their crude oil prices by an additional $2.00/B or approximately 8 percent. At the close of the meeting, OPEC members were allowed to price their oil as market conditions would allow. In this situation the only fact that is known with certainty is that the oil price assumptions used in the September quarterly forecast were too conservative.

Given these conditions, it is assumed that weighted average OPEC prices over the 17-year forecast will rise from $21.84/B in FY 1980 to $28.62/B in FY 1981 to $81.29/B by FY 1996--roughly a 8.6 percent average per annum increase. Weighted average wellhead values for oil royalty calculations for Prudhoe Bay range from a low of $12.66/B in FY 1980 to a high of $70.66/B in FY 1996. The weighted average annual wellhead values for royalty calculations for FY 1980-FY 1985, given the assumptions made in this forecast, are roughly: $12.66/B, $18.37/B, $26.64/B, $30.95/B, $33.51/B, and $37.10/B. These weighted average wellhead values for oil royalty calculations are, however, net of field cost deductions. On the other hand, field costs are not deducted from wellhead values for purposes of severance tax collections.

Projections of TAPS tariffs, as a component of transportation costs, in this 17-year forecast were based on a number of scenarios for the estimated gross revenue requirements of the pipeline companies. In the majority of those scenarios it was assumed that the TAPS owner companies would receive the rate base and rate of return which they requested in testimony before FERC.

Tanker tariffs and refinery market delivery forecasts were based on data supplied by the Petroleum Audit Supervisor's office, journal articles, company studies and various studies done by government and private agencies. Tanker tariff scenarios were inflated on the average at roughly 4 percent per annum due to the capital intensive structure of tanker operations. Market sales by destination in the December 1979 forecast were adjusted to reflect the average first sales reported during the first nine months of 1979. During this time roughly 870,000 B/D were delivered to the West Coast (including Alaska and Hawaii) while Gulf/East Coast (Trans-Panama) and Four Corners Pipeline deliveries were approximately 362,000 B/D. Undoubtedly, the continuing world crude oil supply shortage led to increased buyer interest in Alaskan oil. For this reason, peak West Coast sales may decline somewhat from the levels reached during the last several months should world crude oil shortages begin to slacken. This has been allowed for in the current forecast. Until the third quarter of 1982 it is assumed that Prudhoe Bay crude surpluses will be shipped through the Panama Canal and Four Corners Pipeline to Texas, Gulf/East Coast markets. Beginning in the second quarter of 1982, it is assumed that there is a 50 percent possibility that the Northern Tier pipeline project will be built.

North Slope Gas Prices

Under the interim rules of the Natural Gas Policy Act of 1978, the ceiling price of Prudhoe Bay gas as of December 1, 1978 is $1.63 per MMBTU. Given 1.092 MMBTU per Mcf, Prudhoe Bay gas will realize a field value of $1.78 per Mcf. Assuming 6 percent inflation per annum, Prudhoe gas should command $2.52 per Mcf by FY 1985--the earliest date that we are forecasting production or throughput along an Alcan route for a gas pipeline. FERC recently ruled that conditioning costs to remove the

Mar '83 Forecast

ASSUMPTIONS

Inflation

The outlook for inflation continues to be mixed as uncertainty over the direction of monetary policy at the Central Bank has kept real interest rates relatively high. Whether the Federal Reserve will continue to watch the monetary aggregates soar to provide liquidity for the current economic recovery or cut money supply growth to keep inflation in check is a key question. The overriding consideration is perhaps the economic philosophy and goals of the Reagan administration, which appears willing to swap higher unemployment for lower rates of inflation. In any event, as always, a wide range of inflationary scenarios were considered. The weighted average rate is assumed to be 6.7 percent through FY 1984 rising to 6.86 percent in 1985, 7.5 percent in FY 1986 and roughly 6.5 percent for FY 1987-FY 1999. The weighted average inflation assumption for FY 1987-FY 1999 represents an annual rate of inflation a full percentage point below that assumed in December.

North Slope Oil Prices

International Trends

At its recent meeting in London, OPEC, for the first time in its history, lowered its price structure. The latest accord cut the marker price of Saudi Arabian light crude oil from $34.00/bbl to $29.00/bbl and established a production ceiling of 17.5 million bbls/day. Production quotas were set for individual member countries, with Saudi Arabia playing the role of swing producer by adjusting its production to preserve the crude output ceiling.

This radical adjustment in the cartel's pricing and production policy was reached in the face of rapidly deteriorating crude oil prices world-wide and a shrinking market for OPEC crude oil. The financially weaker members, such as Nigeria, were increasingly under pressure to lower price or lose customers. It is still not clear whether the recent OPEC agreement is sufficient to stem the downward movement in crude oil prices although spot prices have been relatively stable for the last month or so. Many analysts have been watching the British National Oil Company's (BNOC) pricing policy since they are sellers of crude oil who compete for the same market as Nigeria. So far announced price cuts of $.50/bbl by BNOC do not appear to threaten the current price structure.

The current price structure of internationally traded crude oil is as follows:

1. Saudi Arabia and other Arabian Gulf "discretionary producers" and Iraq around $29/bbl.

2. Mexican light crude oil, comparable to Saudi, at $29/bbl; with heavy Mayan crude at $23/bbl, comparable to Venezuelan heavy which is also at $23/bbl.

3. African producers of light sweet crude at $30.00 to $30.50/bbl.

4. North Sea crude oil, comparable to African light oil, at $30.00 to $30.50/bbl.

5. Iran at roughly $26.00/bbl for comparable light crude oil.

As always, with a demand induced supply overhang, resolution of OPEC's current dilemma relies upon demand recovery. Low oil prices should increase oil consumption if the price elasticity of demand is at all significant. At the same time, low oil prices should provide additional stimulus to the economic recovery. Analysts disagree about the magnitude of the effect of an econmic recovery on crude oil demand (income elasticity of demand) since it is unclear as to how much the recent decline in oil consumption is accounted for by structural change (more efficient automobile fleet, increased use of insulation) and how much by the idling of machinery due to the recession. Most analysts do agree that the economic recovery will be slow and for that reason will provide only minor stimulus to crude oil consumption.

Although OPEC's current output is hovering around 14 million bbls/day, current inventory statistics suggest that considerable restocking activity is expected to occur in the short term, which should allow some increase in OPEC production. For the elimination of the current supply overhang, OPEC members must resist the temptation to produce beyond their quotas in response to a demand surge. These two factors result in a March production of somewhat lower near term crude oil prices and lower growth rates over the next three years than was assumed in the December projections.

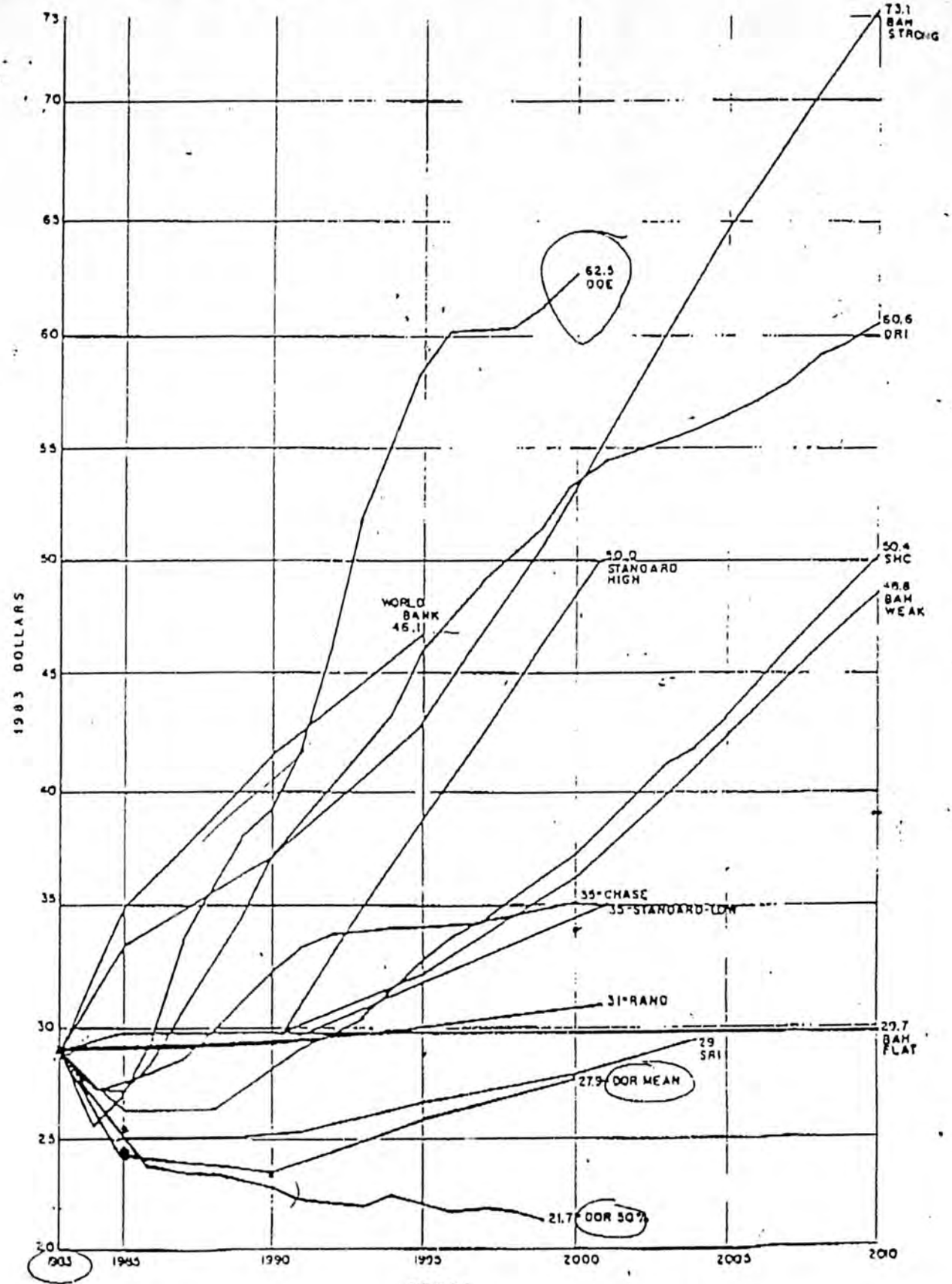
As always, we have assumed for forecasting purposes a wide range of both optimistic and pessimistic price growth scenarios for the marker crude oil. The average assessment is for generally flat prices through FY 1987 with real or inflation adjusted price growth resuming in the late 1980's. The Saudi pricing asumptions in the short term reflect the assumed market clearing price rather than the official contract price in order to minimize subjective adjustment of price premiums or discounts between Saudi and Alaska North Slope crude oil. In this forecast, it was assumed that the weighted average market clearing price for Saudi Arabian crude oil was $28.10/bbl in February 1983. Price was assumed, on average, to fall to $26.04 in April 1983 and to roughly $25.50 for FY 1984 increasing slowly thereafter (Graph A). Over the 17 year period, weighted average prices for Prudhoe Bay type crudes are forecast to rise from $28.95/bbl in FY 1983 to $72.32/bbl in FY 1999 - roughly 5.9 percent average annual increase in nominal dollar terms.

Domestic Price Trends

Crude oil prices for domestically produced oil began to slide in late December 1982 and generally stopped by the first of February at $3.00/bbl to 4.00/bbl below December levels. The average contract price for Alaska crude oil delivered on West and Gulf Coasts was relatively

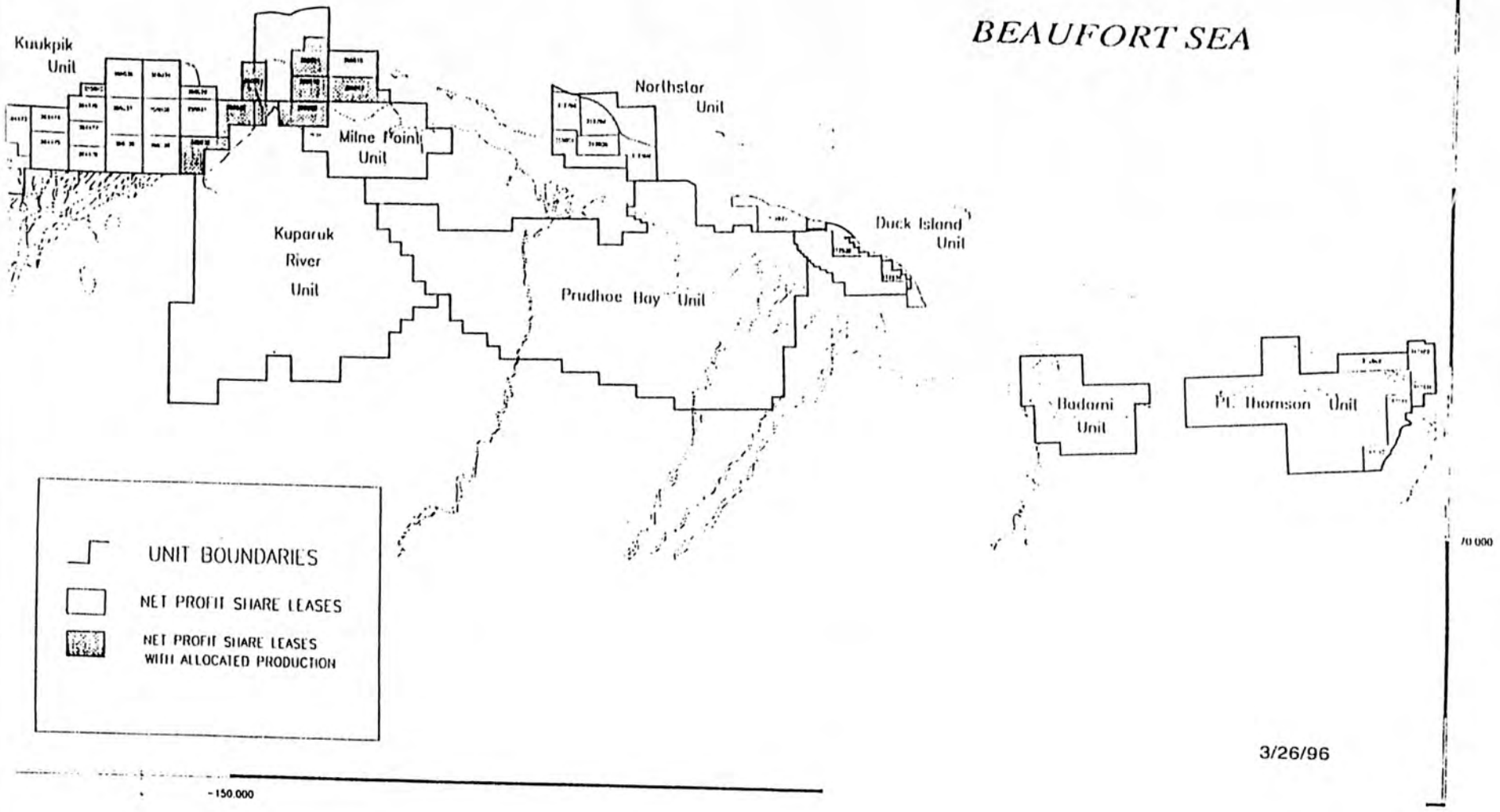
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OIL PRICE FORECAST
1983 - 2010

ACTIVE NET PROFIT SHARE LEASES



Status of Net Profit Share Leases (NPSLs)

Lease	Sale	Lease Date	Unit	Bonus Bid	NPS Percent	Royalty Percent	Bid Type	Unit Acres	Allocated Production?
Duck Island Unit									
ADL 312828	30	01-Feb-80	Duck Island	$7,524,545.00	79.59350%	20.0%	Fixed Royalty an NPS	3,068.49	Yes
ADL 312834	30	01-Feb-80	Duck Island	$6,266,120.00	48.87031%	20.0%	Fixed Royalty and Variable NPS	1,610.13	Yes
Kuupik Unit									
ADL 355029	39	01-Aug-83	Kuupik	$55,515.20	30.00000%	12.5%	Fixed Royalty and fixed NPS	1,903.00	
ADL 355031	39	01-Aug-83	Kuupik	$64,395.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	5,724.00	
ADL 355034	39	01-Aug-83	Kuupik	$64,800.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	5,760.00	
ADL 355035	39	01-Aug-83	Kuupik	$102,000.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	5,699.87	
ADL 355036	39	01-Aug-83	Kuupik	$117,216.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	5,760.00	
ADL 355037	39	01-Aug-83	Kuupik	$4,081,212.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	5,724.00	
ADL 355038	39	01-Aug-83	Kuupik	$241,920.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	5,760.00	
ADL 355039	39	01-Aug-83	Kuupik	$2,054,867.36	30.00000%	12.5%	Fixed Royalty and fixed NPS	5,645.24	
ADL 355040	39	01-Aug-83	Kuupik	$102,580.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	1,280.00	
ADL 364470	43A	01-Aug-84	Kuupik	$112,700.70	30.00000%	12.5%	Fixed Royalty and fixed NPS	3,180.00	
ADL 364471	43A	01-Aug-84	Kuupik	$119,153.71	30.00000%	12.5%	Fixed Royalty and fixed NPS	5,759.00	
ADL 364472	43A	01-Aug-84	Kuupik	$294,682.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	4,480.00	
ADL 364473	43A	01-Aug-84	Kuupik	$294,682.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	4,480.00	
ADL 364474	43A	01-Aug-84	Kuupik	$2,586.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	3,819.00	
ADL 364475	43A	01-Aug-84	Kuupik	$587,158.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	5,748.00	
ADL 364476	43A	01-Aug-84	Kuupik	$1,233,216.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	3,840.00	
ADL 364477	43A	01-Aug-84	Kuupik	$3,102,720.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	3,840.00	
ADL 364478	43A	01-Aug-84	Kuupik	$1,255,680.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	3,840.00	
Kuparuk River Unit									
ADL 355023	39	01-Jun-83	Kuparuk River	$2,365,233.75	30.00000%	12.5%	Fixed Royalty and fixed NPS	5,175.00	Yes
ADL 355024	39	01-Jun-83	Kuparuk River	$984,758.40	30.00000%	12.5%	Fixed Royalty and fixed NPS	5,580.00	Yes
ADL 355030	39	01-Jul-83	Kuparuk River	$273,190.40	30.00000%	12.5%	Fixed Royalty and fixed NPS	4,480.00	Yes
ADL 355032	39	01-Jul-83	Kuparuk River	$262,295.80	30.00000%	12.5%	Fixed Royalty and fixed NPS	5,108.00	Yes
Milne Point Unit									
ADL 355016	39	01-Aug-83	Milne Point	$63,691.76	40.00000%	12.5%	Fixed Royalty and fixed NPS	5,071.00	
ADL 355017	39	01-Aug-83	Milne Point	$351,000.00	40.00000%	12.5%	Fixed Royalty and fixed NPS	4,480.00	Yes
ADL 355018	39	01-Aug-83	Milne Point	$808,000.00	30.00000%	12.5%	Fixed Royalty and fixed NPS	5,083.00	Yes
ADL 355021	39	01-Aug-83	Milne Point	$257,177.60	30.00000%	12.5%	Fixed Royalty and fixed NPS	5,120.00	Yes
Northstar Unit									
ADL 312798	30	01-Feb-80	Northstar	$3,843,717.50	93.20000%	20.0%	Fixed Royalty and Variable NPS	4,392.82	
ADL 312799	30	01-Feb-80	Northstar	$3,913,323.75	91.20000%	20.0%	Fixed Royalty and Variable NPS	4,472.37	
ADL 312808	30	01-Feb-80	Northstar	$3,003,805.00	85.25978%	20.0%	Fixed Royalty and Variable NPS	3,432.92	
ADL 312809	30	01-Feb-80	Northstar	$4,638,707.50	85.25978%	20.0%	Fixed Royalty and Variable NPS	5,301.38	
ADL 355001	39	01-Aug-83	Northstar	$72,144.64	40.00000%	12.5%	Fixed Royalty and fixed NPS	5,744.00	

Status of Net Profit Share Leases (NPSLs)

Lease	Sale	Lease Date	Unit	Bonus Bid	NPS Percent	Royalty Percent	Bid Type	Unit Acres	Allocated Production?
Pt. Thomson Unit									
ADL 312866	30	01-Feb-80	Pt. Thomson	$4,318,536.25	52.35200%	20.0%	Fixed Royalty and Variable NPS	4,935.47	
ADL 343109	36	01-Aug-82	Pt. Thomson	$4,224,852.00	40.00000%	12.5%	Fixed Royalty and fixed NPS	4,263.88	
ADL 343110	36	01-Aug-82	Pt. Thomson	$4,109,750.00	40.00000%	12.5%	Fixed Royalty and fixed NPS	1,920.00	
ADL 343111	36	01-Aug-82	Pt. Thomson	$15,355,000.00	40.00000%	12.5%	Fixed Royalty and fixed NPS	2,400.00	
ADL 343112	36	01-Aug-82	Pt. Thomson	$2,570,026.80	40.00000%	12.5%	Fixed Royalty and fixed NPS	3,446.00	
Not Unitized									
ADL 312827	30	01-Feb-80		$9,880,867.50	74.83000%	20.0%	Fixed Royalty and Variable NPS	0.00	

DOE/ID/01570-T164
Distribution Category UC-122

ALASKA NORTH SLOPE
NATIONAL ENERGY STRATEGY INITIATIVE

Analysis of Five Undeveloped Fields

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May 1993

Work Performed Under Contract No. DE-AC07-76ID01570

Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Prepared by
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ALASKA NORTH SLOPE NATIONAL ENERGY STRATEGY INITIATIVE (ANALYSIS OF FIVE UNDEVELOPED FIELDS)

ABSTRACT

The U.S. Department of Energy was directed in the National Energy Strategy to establish a federal interagency task force to identify specific technical and regulatory barriers to the development of five undeveloped North Slope Alaska fields and make recommendations for their resolution. The five fields are West Sak, Point Thomson, Gwydyr Bay, Seal Island/Northstar, and Sandpiper Island. Analysis of environmental, regulatory, technical, and economic information, and data relating to the development potential of the five fields leads to the following conclusions:

- Development of the five fields would result in an estimated total of 1,055 million barrels of oil and 4.4 trillion cubic feet of natural gas and total investment of $9.4 billion in 1992 dollars.

- It appears that all five of the fields will remain economically marginal developments unless there is significant improvement in world oil prices. However, the analysis indicates that improved technology and reduced costs through the combined cooperative efforts of industry and government could make it economically feasible to develop some of these fields.

- Costs of regulatory compliance and mitigation, and costs to reduce or maintain environmental impacts at acceptable levels influence project investments and operating costs and must be considered in the development decision making process. These costs can result in reduced reserves and delays in development. Efforts to reduce these costs and impacts would be beneficial to the development of the five fields and other potential discoveries.

- The development of three of the fields (West Sak, Point Thomson, and Gwydyr Bay) that are marginally feasible would have an impact on North Slope production over the period from about 2000 to 2014 but cannot replace the decline in Prudhoe Bay Unit production or maintain the operation of the Trans-Alaska Pipeline System (TAPS) beyond about 2014 with the assumption that the TAPS will shut down when production declines to the range of 400 to 200 thousand barrels of oil/day.

- Recoverable reserves left in the ground in the currently producing fields and soon to be developed fields, Niakuk and Point McIntyre, would range from 1 billion to 500 million barrels of oil corresponding to the time period of 2008 to 2014 based on the TAPS shutdown assumption.

EXECUTIVE SUMMARY

1. Introduction

The National Energy Strategy (NES) issued in February 1991 sets out two fundamental objectives to enhance energy security. One objective is to expand U.S. and worldwide oil production capacity and strategic stocks; the second is to reduce U.S. oil consumption through a combination of measures aimed at increased efficiency, introduction of alternative transportation fuels, and aggressive research and development of new energy and oil saving technology. As part of the objective to expand oil production capacity, the NES calls for accelerated development of five undeveloped Alaskan North Slope fields. These five fields are West Sak, Point Thomson, Gwydyr Bay, Seal Island/Northstar, and Sandpiper Island. These five fields are referred to throughout the report as the five NES fields. The U.S. Department of Energy (DOE) was directed in the NES to establish a task force to identify specific technical and regulatory barriers to the development of these fields and make recommendations for their resolution. DOE has established an interagency task force consisting of representatives from DOE, U.S. Department of Interior, Environmental Protection Agency, Department of Defense (Army Corps of Engineers), Council on Environmental Quality, and Department of Commerce (National Marine Fisheries Service) to identify specific technical and regulatory hurdles to development of these fields and make recommendations for their resolution.

The five NES fields are known resource accumulations that have not been developed because of technical or economic conditions or both. These five fields are diverse in terms of geographic location, size of resources (potential reserves), areal extent, depth of productive horizon, type and quality of hydrocarbons, age and lithologic character of the rocks of the productive horizons, physiographic position, and other factors that ultimately must be addressed in the decision-making process. All of the fields are currently in a non-producing status and most will require further exploration/delineation before development decisions can be made. One result of this non-producing status is that public information is limited on all five fields.

This report provides the environmental, regulatory, technical, and economic information and data relating to the development potential of the five discovered but undeveloped fields. Information and data were obtained from open literature, industry, federal agencies, and state and local agencies in Alaska. The production forecasts, investment forecasts, and operating costs used in the analyses were developed

by the authors based on the available information and were not provided by any agency or company. The environmental, regulatory, and technical issues and the interaction of these issues with the economic factors that control the development of each of the five NES fields are analyzed. Sensitivity analyses illustrate the relative influence of these factors for a variety of potential technical, regulatory, and economic options providing the basis for the interagency task force to develop recommendations to assist in the development of these fields.

Summary of Approach

In 1990, the DOE Office of Fossil Energy, in cooperation with the state of Alaska, conducted a study of the Alaska North Slope oil and gas resources. A report titled, "Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity?" was released in March 1991. The report presented an analysis of several potential scenarios concerning future production from the North Slope. The five North Slope producing oil fields (Prudhoe Bay, Kuparuk, Lisburne, Milne Point, and Endicott), two fields that were nearing development (Niakuk and Point McIntyre), four of the five NES fields (West Sak, Gwydyr Bay, Seal Island/Northstar, and Sandpiper), and the potential development of three exploration areas were analyzed for their effect on the lifetime of the Trans-Alaska Pipeline System (TAPS). The same basic methods used in the 1991 DOE report are used for this analysis.

The status of the five currently producing North Slope oil fields (Prudhoe Bay, Kuparuk, Lisburne, Milne Point, and Endicott) and the two fields nearing productive status (Niakuk and Point McIntyre) are updated to provide a background for operations on the North Slope and expectations for continued operation of North Slope infrastructure. Production forecasts and economics are updated to 1/1/92 using actual 1990 and 1991 production. An important factor affecting the future of these fields and all future development on the North Slope is the continued operation of TAPS. Although the actual minimum throughput rate for TAPS has not been established, a range of 400 to 200 MBPD is assumed to illustrate the effects of a shutdown of TAPS. The minimum rate for operation of TAPS will be determined by both mechanical and economic factors.

The development decision-making process for development of new fields on the North Slope of Alaska is driven by economic considerations and acceptability of the environmental impacts. Although the development decision-making process may differ by company, the fundamental steps are (a) defining the scope, (b) designing environmentally acceptable development plans, (c) estimating uncertainty,

(d) optimizing project design, and (e) finalizing the development decision. The analysis of the five NES fields is designed to take into account the evolving business environment, which includes (a) increasing labor and materials costs, (b) increasing technological costs and risks associated with developing more marginal prospects in a harsh environment, (c) an increasing level of industry responsibility and costs in dealing with environmental laws and regulations, (d) highly unstable oil prices, and (e) the continuing need for additional revenue by both federal and state sectors.

The method used to quantify the value of the projects is the present worth (PW) of the project, where PW is the cumulative after tax cash flow generated from the project's time sequenced revenues and expenses discounted to 1992 dollars. Nominal discount rates of 10 to 15% are used in the analysis. An inflation rate of 3.5% is used. Four oil price cases are used to show the effects of oil price on the project economics. The four cases include the NES Low oil price case from the *Technical Annex 2, Integrated Analysis Supporting the National Energy Strategy: Methodology, Assumptions and Results*, U.S. Department of Energy, 1991 (DOE/S-0086P) and three cases for the Energy Information Administration's (EIA) *Assumptions for the Annual Energy Outlook 1992*, January 1992 [DOE/EIA-0527(92)]. The NES Low oil price case lies between the EIA Mid-level and Low price cases as shown in **Table 1.** These are world oil prices defined as the average cost to U.S. refiners of acquiring imported oil. All four cases contain some level of real price increase and include the effects of economic growth, conservation, fuel substitution, and supply.

Table 1. World oil price cases ($/BBL, constant 1/1/92$).

	1992	1995	2000	2005	2010	2015	2020
EIA High	22.07	26.97	33.90	39.34	42.86	45.04	47.35
EIA Mid-Level	20.15	22.17	28.15	32.52	35.61	38.36	41.32
NES Low[a]	20.41	15.86	22.01	27.03	29.47	30.61	32.50
EIA Low	15.88	17.06	19.08	21.43	24.09	26.87	29.95

a. NES Current Policy Base Case includes three oil price projections, High, Base, and Low.

Economic uncertainty is addressed through sensitivity analyses performed to test the economic effect of changes in the variables including oil price, recovery and rate, operating costs, capital investment, federal and state taxes, and discount rate. Methods such as Monte Carlo techniques, sometimes applied by industry and government agencies, are not used. Effects of changes in individual

variables and combinations of variables are evaluated to test the impacts of the economic driving forces on the economic viability of the five fields.

Data are not available to accurately quantify the costs of environmental and regulatory issues. Regulatory and environmental requirements are factors that influence investments, operating costs, reserves, and development schedules. The effects of these factors and costs on the technical and economic viability of developing the five NES fields are evaluated in the sensitivity analysis.

Technical and environmental issues related to each of the five fields are analyzed on a field by field basis. Input data, forecasts, and economic results are developed for each field. The economic analysis is on a project basis and does not involve integrated economics, which would involve additional complex evaluation including TAPS ownership, shipping, refining, and marketing activities for major integrated oil companies. Although the majority lease ownership on the North Slope is generally limited to major oil companies, large and small independents, native corporations, and individual groups of investors have ownership in some leases. Hence, the use of integrated economics is outside the scope of this study.

Environmental and Regulatory Issues

The complex, and often controversial, nature of the regulatory permit processes on the North Slope of Alaska is a direct result of the sensitive environmental issues surrounding exploration and development of oil and gas reserves. Environmental impacts as a result of the loss of wetlands through gravel mining and placement, disturbance of subsistence hunting and fishing, and disruption of coastal flow patterns or fish migrations by solid-fill causeways are major issues on the North Slope. The regulatory processes (lease sales and permits), including the National Environmental Policy Act process, are sensitive to these environmental issues. In fact, major regulatory Acts (e.g., Section 404 of the Clean Water Act, the Coastal Zone Management Act, Endangered Species Act) are focused at regulating impacts to wetlands, the coastal zone, and subsistence resources. In addition, the question of waste management on the North Slope will become increasingly important as fields mature and field shutdown becomes a reality. Waste management regulation will likely be costly to industry, requiring remediation of existing and abandoned sites.

The cost of regulatory compliance affects the amount of crude oil reserves that are economically viable. However, the distinction must be made between the *cost of compliance* (e.g., mitigation, foregone oil revenues) and the *cost of administering* the regulatory process (e.g., labor and material associated with permit applications, Environmental Assessments, and Environmental Impact Statements). Regulatory processes (e.g., lease sales, permits) are necessary in order to provide for protection of the environment. The steps and timing associated with these processes are well defined. Consequently, the costs associated with the administration of these processes are part of operating costs and are known to industry. While the costs of the administrative process are not small, the majority of the regulatory costs are associated with compliance. The cost of breaching a causeway or moving a well pad affects the viability of a project to a greater degree than the administration of the lease sale and permit process. The exception is when delays are caused by agencies invoking the *elevation process*. These kinds of delays could take several months to several years to resolve and the resulting administrative costs can be substantial.

Several steps can be taken to reduce the cost of administrative and regulatory costs, or at least some of the risk associated with the uncertainty of these costs on project economics. First, streamlining the lease sale and permit processes could save some time. These processes, however, are well defined, and little can be done to reduce the time between steps. For example, the documentation for National Environmental Policy Act (e.g., Environmental Assessments and Environmental Impact Statements) will likely require substantial time to complete. This is especially true on the North Slope where most large projects will be controversial and require environmental impact statements. A second step that could be taken to reduce cost of regulatory compliance is avoidance of areas where mitigative costs will be high. The identification of high valued resources (e.g., wetlands with important functions and values, endangered species habitat) using the Clean Water Act Section 404 Advanced Identification process or similar method would help industry avoid areas with demonstrated value where mitigative costs are likely to be high. In a field such as West Sak where the reservoir is shallow and pads and facilities must be much closer together than is currently the case for the Kuparuk field, this may result in lost reserves. This would also help reduce delays associated with controversial issues such as subsistence resources, wetlands, endangered species, and causeways. A third step that could help reduce the uncertainty in mitigative costs would be more effective use of *pre-consultation* and coordination with regulatory agencies.

Major Fields--Prudhoe Bay and Kuparuk fields are the No. 1 and No. 2 producing rate fields in the U.S. and produce about 18% of the nation's daily output of oil or about 1.6 million barrels (MMB) of the total 8.9 MMB. Prudhoe Bay production is declining; Kuparuk production is expected to remain fairly steady for several more years before a significant decline begins.

Remaining reserves are estimated at 5,300 MMB for Prudhoe Bay and 1,300 MMB for Kuparuk. It is these two fields with their reserves and rate of production that dominate predictions for the duration of economic oil production on the North Slope of Alaska. Using a TAPS shutdown ranging from year-end 2008 (400 MBPD) to year-end 2014 (200 MBPD), the possible "lost" recoverable liquids from these two fields would be about 1,000 MMB to 500 MMB, respectively.

The impact of the Prudhoe Bay field discovery, development, and creation of infrastructure, including TAPS, can be appreciated in total only by realizing that all of the other producing fields and all of the potentially productive fields are dependent upon the existing infrastructure. If TAPS does, in fact, shut down by year-end 2008, then the timeline for bringing discovered fields on production is rapidly approaching criticality because of the lengthy period between decision to develop and first production. The time factor is even more critical for potential undiscovered fields, such as in ANWR or offshore, because the time from lease sale to first production is greater than 10 years.

Recently Developed Fields--The recently developed fields, Endicott, Milne Point (including Schrader Bluff), and Lisburne, provide examples of fields that have been developed with the benefit of the infrastructure and TAPS that are in place as a result of the discovery and development of the super-giant Prudhoe Bay field. These fields illustrate the advancement of arctic technology that has reduced the size of the footprint required in the arctic since the start of Prudhoe Bay development. Factors influencing these technological advances are low oil prices, environmental and regulatory concerns, and relatively small reserves.

Although sizable by Lower 48 standards, Endicott, Milne Point, and Lisburne fields are not major factors on the North Slope in terms of reserves or production rate. Nevertheless, these three fields are more typical of the five NES fields. Their history provides a comparison for evaluation of factors affecting future development.

Long delays ensued between discovery and production of the recently developed fields; i.e., Endicott - 9 years; Milne Point - 16 years; Lisburne - 18 years. A similar pattern can be assumed for other relatively small North Slope fields, discovered or undiscovered.

These three fields combine to total 592 MMBO of remaining reserves and begin to decline in 1993 for Endicott, 1994 for Lisburne, and 2008 for Milne Point/Kuparuk and Schrader Bluff. Production limits are reached in 2010, 2007, and 2016, respectively, for the three fields. Except for a minor amount by Schrader Bluff, they have no effect on extending TAPS beyond 2010.

The major lessons to be learned from these fields are the economic and environmental benefits derived from careful engineering design for facilities down-sized for lower reserves and rates than those of the Prudhoe Bay field. Another major factor in viability of these fields is the use of, and integration into, the Prudhoe Bay infrastructure.

From an industry perspective, the additional 650 ft breach in the Endicott causeway adds a $56 MM burden to capital investment totalling $106 MM over the remaining productive life of the 240 MMBO reserve. At an ultimate reserve total of 404 MMBO, Endicott ranks third among North Slope fields. Smaller fields, or large ones with lesser remaining reserves, may be unable to achieve or continue economic recovery under similar circumstances.

Fields with Development Potential (Point McIntyre and Niakuk)--Contrary to the normal long delays between discovery and production, Point McIntyre field should set a record of only 6 years from the 1988 discovery to the 1994 beginning of production. Located adjacent to Prudhoe Bay and Lisburne fields, Point McIntyre benefits from proximity to existing infrastructure to a remarkable degree. In addition, it benefits (as does Niakuk) from the pending agreement to share in the Lisburne Participating Area (LPA) production facilities. Investment savings to Point McIntyre total about $262 MM, indicating the substantial positive impact facilities sharing can have on prospects on the North Slope. Facilities sharing also reduces environmental impact through reduction of footprint size.

Reserves are estimated at 300 MMBO for Point McIntyre and 70.4 MMBO (53.4 MMBO proven) for Niakuk. Production will begin in 1994 from both fields. Point McIntyre will begin to decline in 2002 and could produce through 2015. Niakuk begins to decline in 1998 and maintains production through 2008. Thus, the later production from these fields helps to offset the earlier declines of

production from the bigger fields. Nevertheless, the impact is insufficient to alter the overall North Slope production decline to an extent that would prolong the life of TAPS. Many more Point McIntyre size fields or one or more super-giant field discoveries are necessary to significantly prolong the life of TAPS.

The Niakuk Kuparuk field was discovered in 1985, followed by two confirmation wells. The initial plan provided for development from an enlarged offshore island connected to shore by a causeway. Plans to develop from the offshore island were abandoned in 1991 and a study of development from shore was undertaken. Onshore development includes facilities sharing with the LPA and reduces the investment required by about $70 MM (1/1/92$). A loss of 29 MMBO of recoverable oil (proven plus potential) is expected from onshore development because the reservoir that can be reached from shore is limited by current directional drilling technology. The estimated recoverable oil volume (proven plus potential) from the onshore development is about 70.4 MMBO.

Summary of Currently Producing Fields and Fields with Development Potential--The total estimated remaining recoverable oil in the seven fields described above is about 7,600 MMBO. It is evident that the declines of Prudhoe Bay and Kuparuk fields impose the dominant time constraint on future North Slope production and exploration.

West Sak--West Sak sands are encompassed by three producing units, the Prudhoe Bay Unit (PBU) established in 1977, the Milne Point Unit (MPU) established in 1979, and the Kuparuk River Unit (KRU) established in 1981. West Sak and Ugnu sands containing low gravity, heavy oil sands of Upper Cretaceous and Tertiary age have been demonstrated to extend over an area of about 200,000 acres and contain an estimated total of between 25 and 44 billion barrels in place (BBOIP). West Sak sands contain oil at depths from 2,000 to 4,500 ft in the MPU and KRU, with the deepest portion in the northeast in the MPU. Average depth of permafrost in the area is less than 1,500 ft. Oil production from the Schrader Bluff oil pool in the MPU operated by Conoco started in March 1991. The "O" sands of the Schrader Bluff sands are equivalent to the West Sak sands in the KRU but the "N" sands are more equivalent to the lower Ugnu sands. Reservoir temperatures range from 45 to 100°F in West Sak sands with Schrader Bluff averaging 90°F at 4,000 ft subsea. Hence, direct comparisons of Schrader Bluff with the balance of the West Sak area should be approached with caution.

West Sak contains the largest resource volume of the five NES fields, with estimates of up to 20 BBOIP. West Sak crude properties and reservoir conditions present formidable challenges to economic

development. Low gravity, high viscosity oil in a shallow, thin bedded, low temperature reservoir that is highly faulted presents a number of problems to be resolved before any development can take place. With production coming from unconsolidated beds, completion techniques must be developed or existing techniques adopted to the West Sak conditions. Laboratory testing and a hot-water injection pilot indicate that a miscible water-alternating-gas (WAG) process, using close well spacing is the most likely recovery process. Further work may be required before final selection of a process is made. Because of the shallow depth of the reservoir, drilling pads would be required on every section developed, which would result in more numerous and concentrated surface impacts on the environment. Environmental concerns could lead to pattern changes to reduce surface environmental concerns resulting in loss of reserves because of the concentrated pads and facilities necessary to develop the shallow reservoir.

Although considerable study has apparently been conducted by the operator, little of this proprietary information is public. Based on available data, is it estimated that between 500 and 600 MMBO can be recovered from better quality reservoir on about 30,000 acres. The timing of the development of these potential reserves is dependent on having an adequate oil price and an economical source of miscible injectant (MI). The volume of MI on the North Slope is limited at present and will be used in the most economical projects first. This places West Sak at least third behind PBU and KRU. The timing of obtaining MI for West Sak is critical when considering the time frame of TAPS shutdown. About 239 MMBO would be unrecovered under these development scenarios, if TAPS shuts down at year-end 2008.

Results of the economic evaluation of West Sak, using the four oil price scenarios indicate that the EIA Mid-level oil price case is required to obtain a rate of return between 10 and 15%. These economic results clearly indicate that West Sak is an economically marginal project for development.

Point Thomson--The Point Thomson Unit (PTU) covers a gas condensate field about 50 mi east of TAPS pump station (PS) No. 1. The unit contains about 83,800 acres, much of which is offshore. The current reserve estimates for the PTU carried by the Alaska Department of Natural Resources are 5 TCF gas and 300 MMB of oil and condensate. Recent seismic results indicate that the reservoir may be about one-third smaller than originally thought. Thus, a reduction in reservoir size is considered for comparison purposes.

The Point Thomson field is different from the other five NES fields because the main resource is gas condensate from a deep overpressured reservoir that is located mostly offshore. In addition, it is the only one of the five NES fields that is not located within or close to the PBU/KRU infrastructure. It does not appear that development of Point Thomson for sales of liquids alone is economically feasible. However, with no major gas purchase line on the North Slope, and none anticipated in the foreseeable future, the date that Point Thomson might be developed is unknown.

By itself, the resulting Point Thomson reserve volume will not justify sale of gas from the North Slope. Sales from the much larger PBU gas cap, or a similar size gas reserve, will be required to justify any sales scenario. The earliest this might occur from PBU is about 2005. However, before any gas sales can occur from the North Slope, a gas market must be available that will provide a purchase price for the gas that can justify development of the gas resources and the required infrastructure and facilities. In addition, the Point Thomson project faces the construction of field delivery lines to the Prudhoe Bay area that will encounter five major river crossings and be in the coastal plain. The impact of these conditions will not be determined until environmental assessments are conducted.

Provided a gas sales line is available as assumed for the analysis, the economics of developing PTU for the base case and reduced reserves case assumptions indicate that either of these scenarios could provide at least a 10% rate of return for all price cases except the EIA Low price case. Gas prices are related to the oil price cases in the analysis.

Gwydyr Bay—The Gwydyr Bay Unit (GBU) is located north of the PBU and contains hydrocarbon accumulations in its eastern and western tracts. The eastern accumulation will be included in the Point McIntyre development. The western accumulations are not well defined; therefore, experience factors are used to estimate potential reserves of from 40 to 56 MMBO with 48 MMBO used for analysis. The joint use of existing facilities does not appear feasible for GBU due to its isolated location. Independent development is assumed except that a portion of the Kuparuk pipeline is used to deliver crude to PS No. 1. Because additional delineation is necessary, initial production is assumed for early 1999. Recovery is expected to last 16 years or through 2014. If development of this small project is economical, about 11.5 MMBO recoverable oil would be lost if TAPS is shutdown at year-end 2008.

The economics of developing GBU, assuming the reserves are confirmed and that development in the Kuparuk River Delta can be accomplished in an environmentally acceptable manner at the assumed

costs, this project would provide a rate of return of 10% or greater for all price cases except the EIA Low case.

Seal Island/Northstar--The Seal Island/Northstar prospect, or Northstar Unit (NU), is located about 6 mi offshore in the Beaufort Sea, about 15 mi northwest of Prudhoe Bay. NU has been partially delineated by the drilling of six exploratory wells. Other than test rates and bottomhole well locations, little information is available on the size of the accumulation. Recoverable oil estimates range from 150 to 300 MMBO, and a reserve volume of 200 MMBO is used for evaluation. The development scenario, including production/drilling structures and subsea pipelines, is based on arctic studies because there are no offshore arctic Alaska developments that can be used as a guideline. The analysis assumes current technology can be adopted or will be developed as required. The greatest deterrents to the development of this field are confirmation of the reserves and the high net profits interest (NPI) applicable to five state tracts. Economics results indicate that with the NPI in place this prospect is not economic for any of the oil price cases. Economic sensitivities indicate that with removal of the NPI, this prospect is similar to the previous three fields. Using an assumed start-up of 1/1/98, recovery of oil would extend into 2011. Shutdown of TAPS in 2008 would result in an estimated loss of about 23 MMBO should development occur as assumed.

Sandpiper--The Sandpiper discovery, located 9 mi offshore and about 10 mi west of NU, has been explored by only two wells. Approval of the Sandpiper Unit by the MMS in November 1992 may indicate that future exploration or delineation drilling may take place. Previous to the formation of the Unit, there were no indicatic . .nat further exploration efforts were planned. Based on the very limited information available, potential reserves of 93 MMBO were estimated. An operator's estimate of potential reserves of about 87 MMBO is used. The development scenario is based on arctic studies. As with the NU evaluation, it is assumed existing technology can be adapted or will be developed as required. Using an assumed start-up date of 2000, the life of the project would extend through 2012. Shutdown of TAPS in 2008 would result in an estimated loss of about 19 MMBO should development occur as assumed. Economics of development of this discovery under the scenario described for four oil price forecasts indicate that this prospect will remain uneconomic unless greater reserves are confirmed.

Summary of the Five NES Fields--The five NES fields are diverse in terms of geographic location, size of resources, areal extent, depth of producing horizon, type and quality of hydrocarbons, and type of

reservoir rock. All are currently in a non-producing status and most will require further exploration/delineation before development decisions can be made.

Consequently, where data are missing, comparisons to producing North Slope fields, empirical relationships developed by industry, and personal knowledge are used in forecasting rates, reserves, operating costs, and development investments. It is assumed that existing technology could be adapted to the arctic North Slope developments or that technology can be developed to meet the particular conditions that would be encountered. For example, technology will have to be proven for the development of Northstar and Sandpiper that are about 9 mi offshore in 50 ft of water, and Point Thomson where highly deviated wells will encounter an overpressured reservoir. In addition, it appears that added study would be helpful in determining the best recovery and completion methods for West Sak.

Even the smallest of the five NES fields would be a major economic discovery in the Lower 48. However, the high investment and operating costs on the North Slope and technical constraints such as lack of availability of MI and a gas sales pipeline make development of any of the fields questionable at this time. Even though a large gas reserve exists at Point Thomson, it is not large enough by itself to justify a gas sales line for North Slope gas. A gas cycling project for liquid recovery at Point Thomson was not analyzed, but development on this basis could become feasible if additional large discoveries are made and developed that would support the development of a pipeline and related infrastructure, such as the strike announced on October 15, 1992 by ARCO at the ARCO Kuvlum No. 1 in the eastern Beaufort Sea 60 mi east of Prudhoe Bay and 16 mi offshore.

Investments are forecast taking into consideration each field's particular circumstances, such as location, size of accumulation, possibility of facilities sharing, estimated maximum recovery rate, and timing of development. Total estimated recoverable hydrocarbons are 1,055 MMB and 4.4 TCF (Point Thomson 5 TCF case) of natural gas and total investment requirements are $9.4 billion in 1992 dollars as shown in **Table 2**.

Sensitivity Analysis—The components of the economic evaluation are (a) revenue, (b) operating costs, (c) investment, and (c) taxes and royalties. These components are driven by (a) oil and gas prices, (b) technical aspects of the accumulation, (c) environmental and regulatory issues, (d) federal and state revenue needs, (e) cost reduction measures used by the industry, and (f) technical advances. For example, the costs of environmental/regulatory requirements are included in both operating costs and

Table 2. Forecasts of recoverable hydrocarbons and investments for the five NES fields.

Field	Liquids (MMB)	Gas (TCF)	Investments - $MM (1/1/92$)	1st Year Production	Forecast Life
West Sak A	502	(a)	4,078	2001	2013
West Sak B	106	(a)	1,085	2008	2013
Point Thomson - 5 TCF[b]	112	4.4	1,579	2008	2035
Point Thomson - 3.4 TCF[b]	99	3.0	1,367	2008	2026
Gwydyr Bay	48	(a)	340	1999	2014
Northstar	200	(a)	1,405	1998	2012
Sandpiper	87	(a)	860	2000	2012

a. No estimate made - gas used in field operations only.
b. Condensate and NGL reserves limited by TAPS shutdown at 200 MBPD (2014) and gas sales less CO_2 and NGL.

investments. Initial planning and coordination with regulating agencies can potentially reduce some of the uncertainty associated with environmental and requlatory costs but cannot be expected to eliminate them. Operating costs are affected through such things as the labor costs to perform environmental assessments, permitting activities, increased fluid handling costs, waste management, and mitigation requirements. Investments, and sometimes reserves, have been affected by requirements for causeway breaches and alternate or less optimum pad locations; e.g., events at Endicott, Point McIntyre, and Niakuk provide examples of effects of the causeway issues and Kuparuk Drillsite 3-L illustrates effects that can result from pad location issues. The comparison of the Niakuk onshore project with the offshore Niakuk project illustrates the effects environmental requirements can have on reserves and economics. The proven and potential reserves for the onshore project are estimated to be 70.4 MMBO compared 99.0 MMBO for the original offshore project resulting in a potential loss of reserves of 29 MMBO. The cash flow to industry and revenue to the state of Alaska and federal government are reduced by a total of $135 MM (1/1/92$) using the NES Low oil price scenario. Project delays causing increases in time between investments and production also affect the economics of projects and illustrate the importance of early planning and cooperation by industry and regulating agencies.

Decreases in operating costs and investments and increases in reserves can be achieved through improved technology for drilling, facility design, production technology, streamlining of environmental permitting, reduced costs of environmental compliance, and improved recovery processes.

The magnitude of the impact on project economics by changes (on the order of 10 to 15%) in selected factors and combinations of factors for the five NES fields show that various combinations of reductions in investments and operating costs, reserves increases, and reductions in taxes, royalties, and net profits interests could potentially provide rates of return between 10 and 15% for portions of West Sak, Point Thomson, Gwydyr Bay, and Seal Island/Northstar. Basic technical requirements for development to be feasible include availability of MI for West Sak, a gas pipeline from the North Slope for Point Thomson, confirmation of adequate reserves in Gwydyr Bay, and adaptation of existing offshore pipeline technology to arctic North Slope environments for development of Seal Island/Northstar.

Summary Observations

(1) Under the assumptions used, the economic results for three of the five NES fields (West Sak, Point Thomson, and Gwydyr Bay) indicate that only price forecasts with significant real growth can provide industry with a positive PW at a discount rate of 10%. The two offshore fields (Seal Island/Northstar and Sandpiper) do not provide a positive PW at a 10% discount rate for any of the price scenarios.

(2) The economic sensitivity analyses show that combinations of reduced operating costs, investments, tax and royalty rates, net profits interests, and increased reserves could make development of these five fields potentially economic provided the following requirements are met:

- MI is available for use in West Sak, which will be at least third after PBU and KRU.
- A gas sales line is developed for PBU gas before Point Thomson can be developed.
- The potential reserves at Gwydyr Bay must be proven and the uncertainty of costs related to development in the Kuparuk River delta resolved.
- The Northstar Unit does not appear feasible without removal of the NPI burden.
- Larger reserves at Sandpiper must be confirmed.

(3) The Alaska North Slope production profile (**Figure 1**) is based on the EIA Mid-level oil price. At these prices, using a cut-off of a 10% discount rate, West Sak, Point Thomson, and Gwydyr Bay provide a positive PW and are included in the production profile. Point Thomson and Gwydyr Bay also provide a 10% rate of return at the NES Low oil price. Seal Island/Northstar and Sandpiper do not meet this economic hurdle rate and are not included. At the EIA Low oil price case none of the five NES fields provide a positive PW at a 10% discount rate and result in an Alaska North Slope production profile as shown in **Figure 2**.

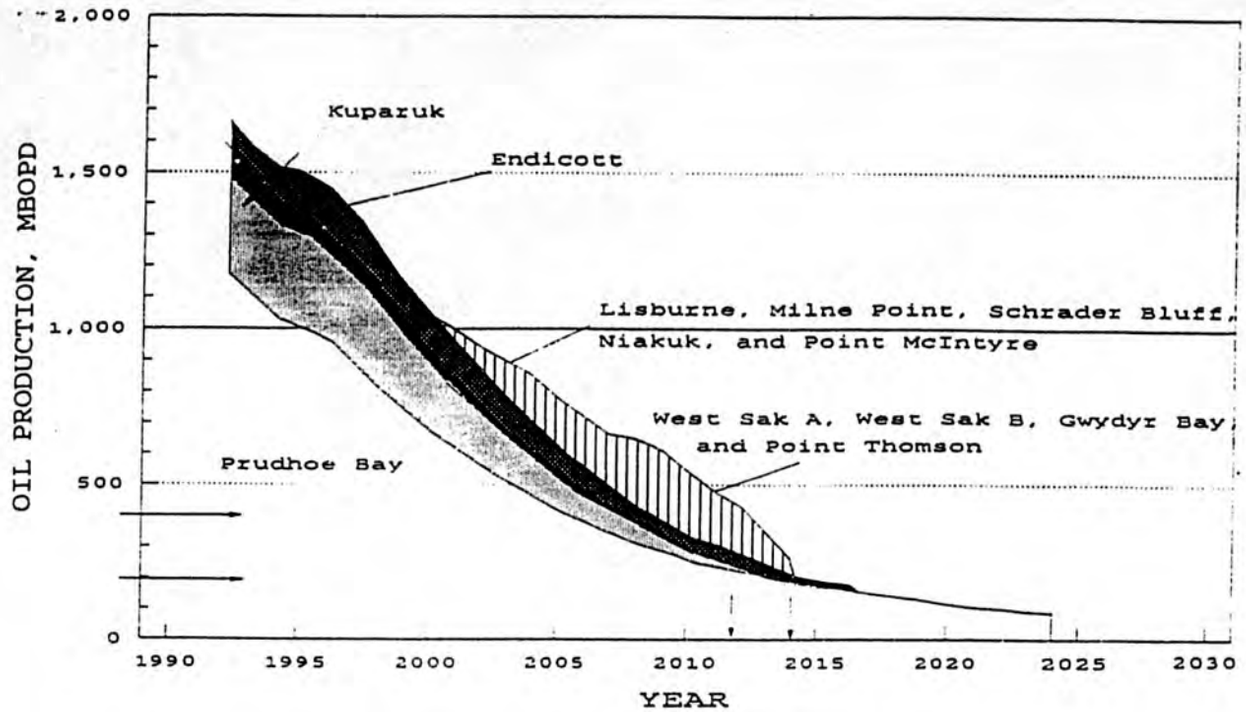


Figure 1. Alaska North Slope production rate forecast including forecasted production from West Sak, Point Thomson, and Gwydyr Bay (arrows indicate the potential range of TAPS shutdown).

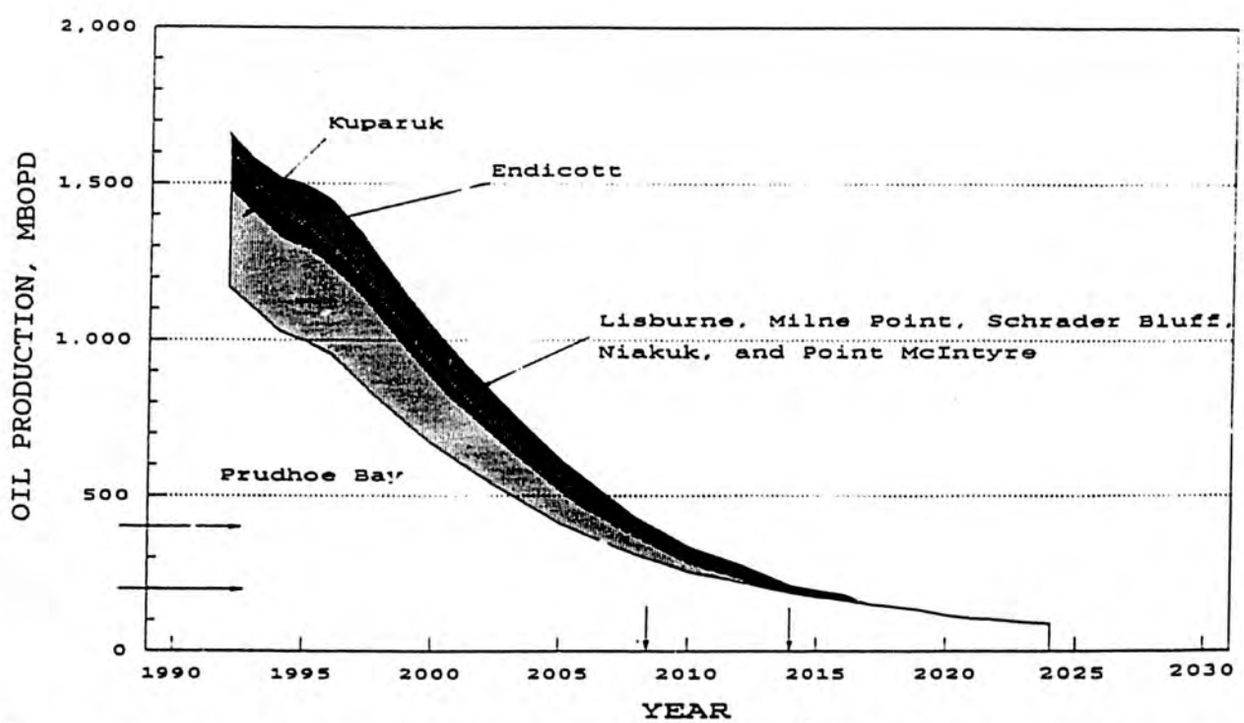


Figure 2. Composite production for seven North Slope fields (arrows indicate the potential range of TAPS shutdown).

(4) Alternate investment opportunities would be expected to seriously compete with the investment capital for the five NES fields at any oil price that provides industry with only a 10% rate of return.

(5) State benefits from the development of each of the five NES fields are significant. Federal benefits, although limited at the two lowest oil price cases, are significant at the higher oil price cases. State and federal benefits and those for industry demonstrate the different levels of benefit that accrue to industry and to state and federal governments with the current royalty and tax rates and illustrate the possibility for share redistribution to encourage development.

(6) State and federal benefits from the currently producing fields are significant. Prudhoe Bay has been beneficial to all parties (industry and state and federal governments). The other four producing fields have provided value to the state and to industry. The federal government has benefitted to a lesser degree. However, these four fields, on a stand-alone basis, have not provided a positive cumulative discounted (10%) after-tax cash flow to the industry (1992 base year) and may not unless oil prices increase to levels at or above the EIA Mid-Level oil price scenario. It is significant that the decision to develop all four of these fields was made during the period of time between 1975 and 1986 when world oil prices were about $30/BBL or above.

(7) Stable world oil prices, high enough to provide adequate rates of return to offset the financial risks involved in development in the harsh environmental conditions of the North Slope, would be the most sure guarantee of development of the five NES fields and other similar fields on the North Slope. However, the sensitivity analyses indicate that reductions in operating costs and investments and increases in recovery volume through combinations of improved technology and streamlined processes for environmental and regulatory requirements or both can feasibly move some of these fields to development. Reductions in tax and royalty rates would provide additional incentive.

Conclusions

- Development of the five fields would result in an estimated total of 1,055 million barrels of oil and 4.4 trillion cubic feet of natural gas and total investment of $9.4 billion in 1992 dollars.

- It appears that all five of the fields will remain economically marginal developments unless there is significant improvement in world oil prices. However, the analysis indicates that improved

technology and reduced costs through the combined cooperative efforts of industry and government could make it economically feasible to develop some of these fields.

- Costs of regulatory compliance, mitigation, and costs to reduce or maintain environmental impacts at acceptable levels influence project investments and operating costs and must be considered in the development decision making process. These costs can result in reduced reserves and delays in development. Efforts to reduce these costs and impacts would be beneficial to the development of the five fields and other potential discoveries.

- The development of three of the fields (West Sak, Point Thomson, and Gwydyr Bay) that are marginally feasible would have an impact on North Slope production over the period from about 2000 to 2014 but cannot replace the decline in Prudhoe Bay Unit production or maintain the operation of TAPS beyond about 2014 with the assumption that the Trans-Alaska pipeline (TAPS) will shut down when production declines to the range of 400 to 200 thousand barrels of oil/day.

- Recoverable reserves left in the ground in the currently producing fields and soon to be developed fields, Niakuk and Point McIntyre, would range from 500 million to 1 billion barrels of oil corresponding to the time period of 2008 to 2014 based on the TAPS shutdown assumption.

and costly because of locations in the Kuparuk River delta. Proximity to the producing infrastructure of Milne Point, Kuparuk, and Prudhoe Bay fields will improve economics. However without a dramatic, and unexpected, increase in the oil exploration potential in Gwydyr Bay area, it appears that the likelihood of significant production is low.

B.7 Seal Island/Northstar History

In 1979, a joint lease sale was conducted by the state of Alaska and the U.S. Mineral Management Service (MMS) in the offshore waters of the Beaufort Sea. One group of successful bidders, with Shell as initial operator, formed a joint effort to explore their state/federal leases centered about 15 miles northwest of Prudhoe Bay. Shell completed the construction of Seal Island in 1982. The first well, BF-47 No. 1, resulted in a discovery testing 4,750 BOPD from the Ivishak formation of the Sadlerochit group, the main producing interval in the Prudhoe Bay field.

Ultimately, four wells were drilled from Seal Island resulting in two certified producers, another that encountered hydrocarbons, and one dry hole (MMS 1989a). In 1985, Amerada Hess constructed Northstar Island about 4½ mi northwest of Seal Island and drilled a successful confirmation well, the BF 46 No. 1 in 1986. This well tested at rates of up to 3,500 BOPD from the Ivishak with oil gravity "similar to that in the Seal Island wells, in the 40°s." A subsequent well, deviated to the southeast, encountered mechanical problems and was abandoned without reaching the Ivishak. Shell estimated the structure held more than 300 MMBO total (OGJ 1986).

B.7.1 Data Summary

In 1989, the working interest owners (Amerada Hess Corporation, Murphy Oil USA, Inc., Shell Western E&P, Inc., and Enterprise Oil Ex Co. Inc.), formed the Northstar Unit (NU) (**Figure B.18**) with Amerada Hess as operator and submitted a POD to the MMS and ADNR. This plan called for a total expenditure of $21 MM during the 1990 to 1994 period. The plan included island maintenance, a petrophysical/petrographic study, production facility design, about 250 mi of 2-D seismic, seismic analysis and interpretation, reservoir engineering studies, extension fee payments (in lieu of drilling) that will escalate from $1 MM to $4 MM over the 5-year period, and a unit area reevaluation to be conducted in 1993 (MMS 1989a). In 1991, a $1 MM payment to the state was made in lieu of drilling. The petrophysical/petrographic study and conceptual production facilities design were initiated. Island

maintenance was done in July to August 1991 and the 1991 summer seismic program acquired 210 line miles of data (ADNR 1991d; ADNR 1991e).

During 1991, the petrophysical/petrographic program was completed by Neil Barry and Associates and Core Lab, Inc. The conceptual facilities design was also completed by R.M. Parsons Company. A modification of the seismic plan proposes additional coverage during the 1992 winter season, which will exceed that of the original plan. Because a delineation well was not drilled during 1991, Amerada Hess paid $2 MM to the state in January 1992 (ADNR 1992a).

At the time NU was formed, an estimated total of $280 MM had been expended on lease acquisition, island construction, and exploratory drilling. If all estimated expenditures for the POD are spent, the total cost prior to initial development or an eventual decision to cancel the project will exceed $300 MM.

Limited public technical data, consisting only of well logs and histories, preclude a reliable independent assessment of potential reserve volume. Published data specific to Seal Island/Northstar indicate a range of potential reserves from 150 to 300 MMBO (OGJ 1986; ADNR 1991a). However, data representing undeveloped reserves for the Beaufort Sea published by the state of Alaska in June 1991, indicate a range of 180 to 225 MMBO (mid to high). It is assumed that those reserve estimates apply specifically to Seal Island/Northstar (ADNR 1991). Using the available data, a conservative estimate of 200 MMBO as a potentially recoverable resource is made and used for evaluation purposes (see **Figure B.18**).

B.7.2 Lease Summary

Leases were acquired at Seal Island/Northstar from both the state of Alaska and the federal government in sale BF-79. Federal leases carried a 10-year primary term with expiration on July 31, 1990 with a 1/6 royalty. State tracts were also for a 10-year primary term expiring January 31, 1990, with four leases carrying a 20% royalty and one carrying a 12.5% royalty. All the state leases also include a net profit share percentage, ranging from 40% to 93.2% (see **Figure B.19**) (MMS 1989; ADNR 1991f).

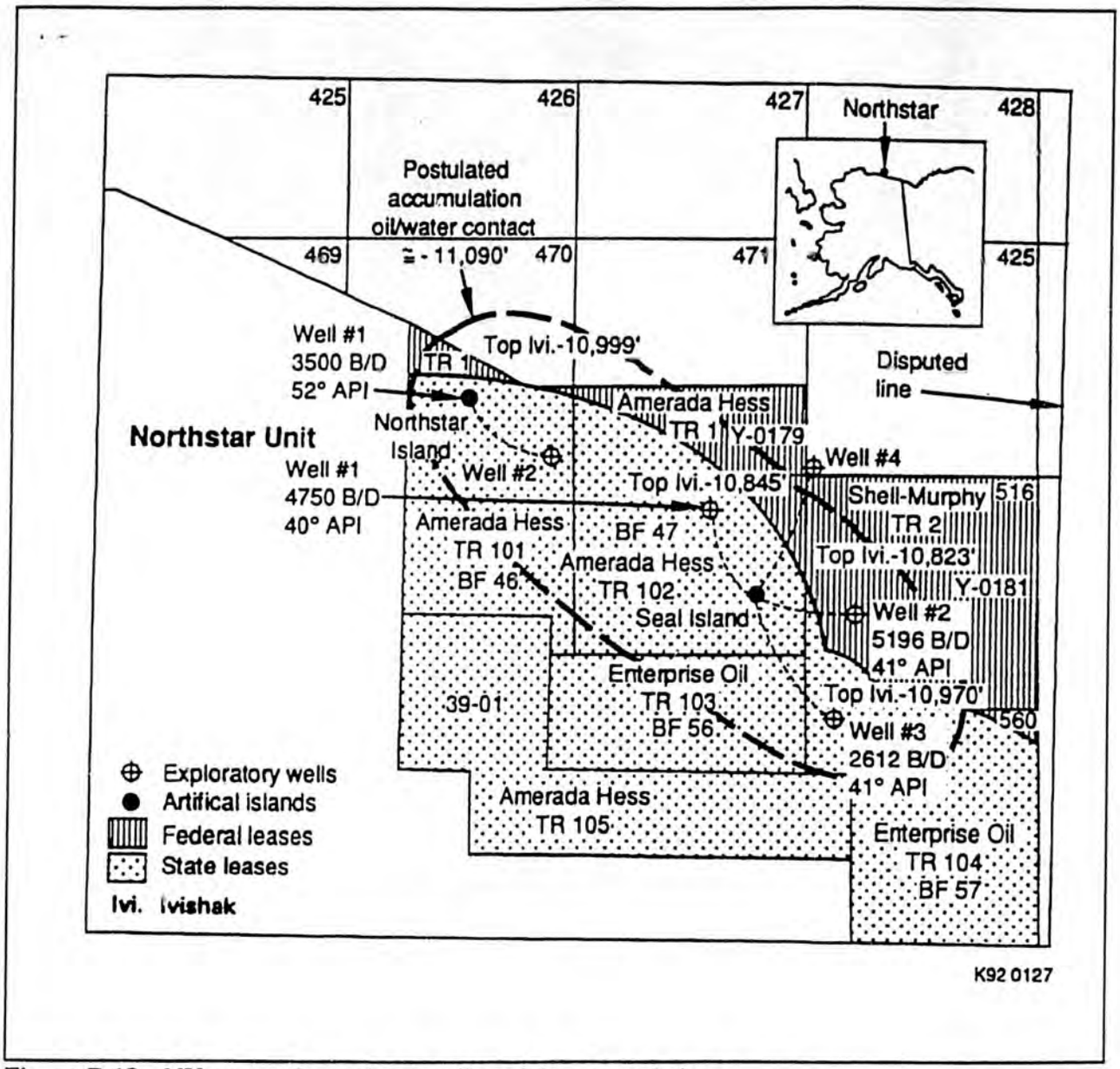


Figure B.18. NU map and postulated outline of the accumulation.

Current status of ownership provides that costs will be shared (unless otherwise stated in the Unit Operating Agreement) as follows (ADNR 1991f):

- Amerada Hess (operator) 80.85%
- Murphy Oil USA, Inc. 1.92%
- Shell Western E&P, Inc. 17.23%

Total NU area is 30,837.99 acres comprised of 7,494.50 acres of federal land and 23,343.49 acres of state land (see **Figure B.19**).

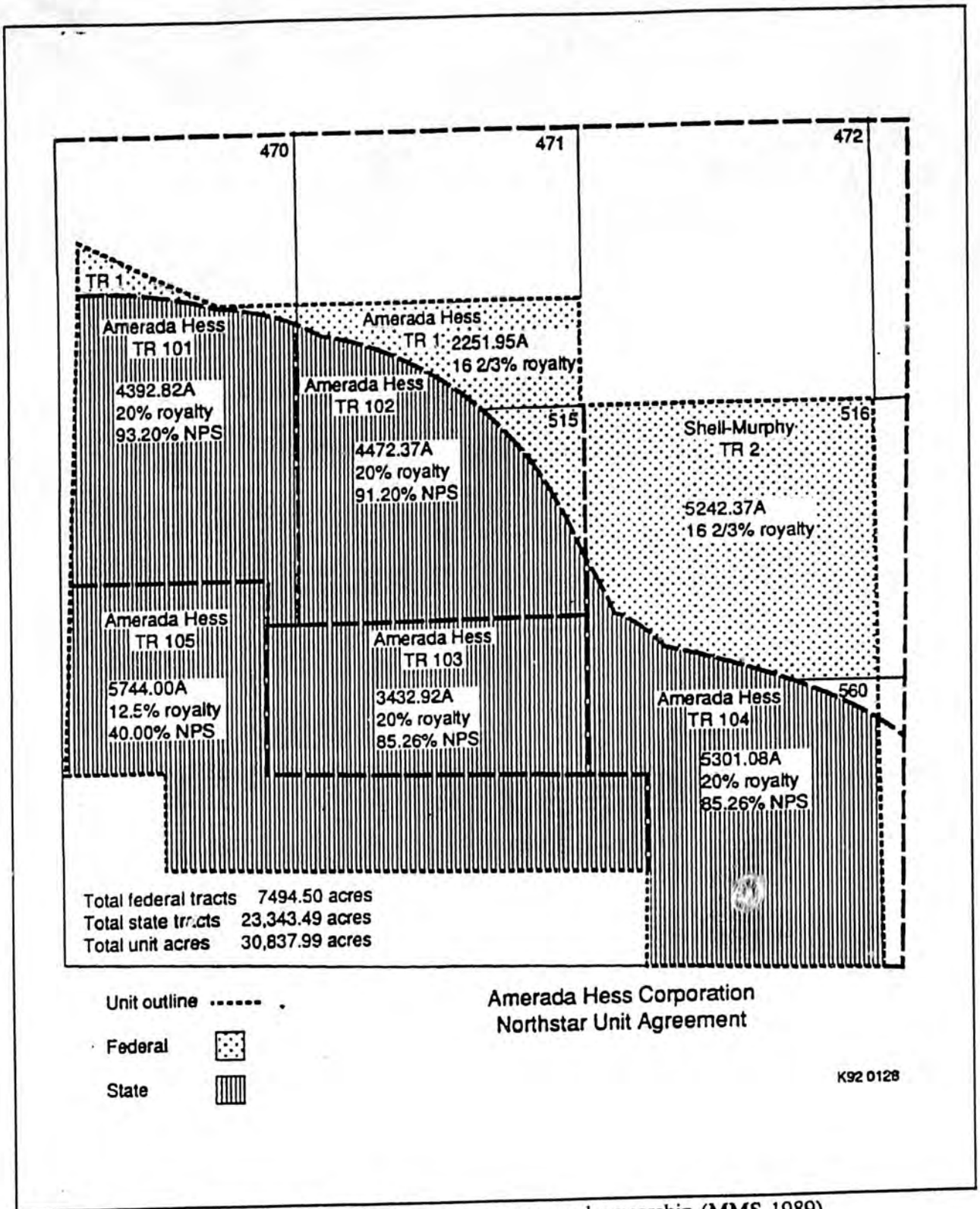


Figure B.19. NU royalties, net-profit share percentages, and ownership (MMS 1989).

B.8 Seal Island/Northstar Issues

As the NU evaluation process continues during the current POD covering the period from 1990 to 1994, the primary technical issues are the size of the accumulation, development costs, and the field production rate.

It appears the NU owners currently think the accumulation is too small to be economically developed. The high test rates in the exploration wells indicate good reservoir rocks in the Sadlerochit and the high gravity reported indicates good quality crude. The economics of construction of development and production facilities, including ice-resistant platforms and subsea pipelines in 50 ft water depths 15 mi offshore, present formidable challenges. For comparison, Endicott field, lies 2 mi offshore in about 4 ft water depths, produces from a gravel island, and is connected to shore by a gravel causeway. Total, ultimate reserves for Endicott are 403.8 MMBO.

Ultimately, the working interest owners will have to decide whether the accumulation is economic to produce. The net profit share provisions of the state leases add a very significant burden to the economic viability of NU.

B.9 Sandpiper Island History

Leases were first acquired in what would eventually be called the Sandpiper Island area in OCS Lease Sale 71 in 1982. It is located approximately 25 mi northwest of Prudhoe Bay. Six leases in the immediate area totaled $73,731,567 in successful high bids at the federal sale. Shell Western E&P Inc. became the operator for a group consisting of Shell, Amoco Production Co., Murphy Oil USA, Petrofina Delaware Inc., and Koch Industries Inc.

By 1986, Shell had constructed Sandpiper Island to drill the first well on the group's Harvard prospect. The gravel island was built for an estimated cost of $29 MM (OGJ 1986a). That year Shell drilled the OCSY-370 No. 1 (Sandpiper No. 1) to a total depth of 12,575 ft. During tests of the Sadlerochit, the well flowed at a rate of 2,419 BOPD, 275 BWPD, 3613 GOR, 41.2°API gravity from a lower zone and 409 to 2,325 BPD condensate, 2.9 to 18.6 MCFPD, 49 to 51°API gravity from an upper zone (AOGCC 1986). The well bottomed approximately 3,300 ft north of the island.

SEAL ISLAND / NORTHSTAR, WITH NET PROFITS INTEREST - PAGE 1
NES LOW OIL PRICE
MILLIONS OF THEN CURRENT $
****

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
OIL PRODUCTION RATE, Mbbl/day	0.00	0.00	0.00	0.00	21.92	41.10	54.80	54.80	54.80	54.80	54.80	46.58
OIL PRICE	$18.94	$17.89	$19.95	$22.14	$24.45	$26.90	$29.49	$31.91	$34.46	$37.17	$40.01	$43.01
WELLHEAD OIL PRICE	13.22	12.42	14.66	17.05	19.38	21.61	23.91	26.16	28.37	30.70	33.32	35.99
GROSS REVENUE	$0	$0	$0	$0	$155	$324	$478	$523	$567	$614	$666	$612
TOTAL OPERATING COST	0	0	0	0	51	93	151	157	162	168	174	180
COST SHARING FEE	0	0	0	0	0	0	0	0	0	0	0	0
OPERATING COST IN CONSTANT $	0	0	0	0	41	72	113	113	113	113	113	113
CUM OP COST IN CONST $	0	0	0	0	41	113	226	339	452	565	678	791
ROYALTY	0	0	0	0	30	62	92	100	109	118	128	117
SEVERANCE TAX	0	0	0	0	5	10	19	18	19	25	27	15
AD VALOREM	0	0	0	0	28	28	28	28	28	28	27	27
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	0	0	0	0	0	1	1	1	1	1	1	1
STATE NET PROFIT INTEREST	0	0	0	0	28	89	127	149	170	187	211	186
STATE INCOME TAX	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL STATE	0	0	0	0	91	190	267	297	326	359	394	345
FEDERAL INCOME TAX	0	0	0	0	0	0	0	0	0	0	0	0
OPERATING CASH FLOW	0	0	0	0	13	42	59	70	79	87	98	87
TOTAL INVESTMENT	0	434	450	538	75	78	40	42	14	0	0	0
CUM INVESTMENT IN CONST $	0	385	770	1,215	1,275	1,335	1,365	1,395	1,405	1,405	1,405	1,405
TOTAL CASH FLOW	$0	$-434	$-450	$-538	$-62	$-36	$19	$28	$65	$87	$98	$87

NOMINAL DISCOUNT RATE IS 10%
****

CUM PW TOTAL CASH FLOW	$0	$-311	$-603	$-921	$-955	$-972	$-964	$-952	$-929	$-899	$-870	$-846
CUM PW STATE REVENUE	0	0	0	0	49	141	260	380	500	620	739	835
CUM PW FEDERAL REVENUE	0	0	0	0	0	0	0	0	0	0	0	0

SEAL ISLAND / NORTHSTAR, WITH NET PROFITS INTEREST PAGE 2

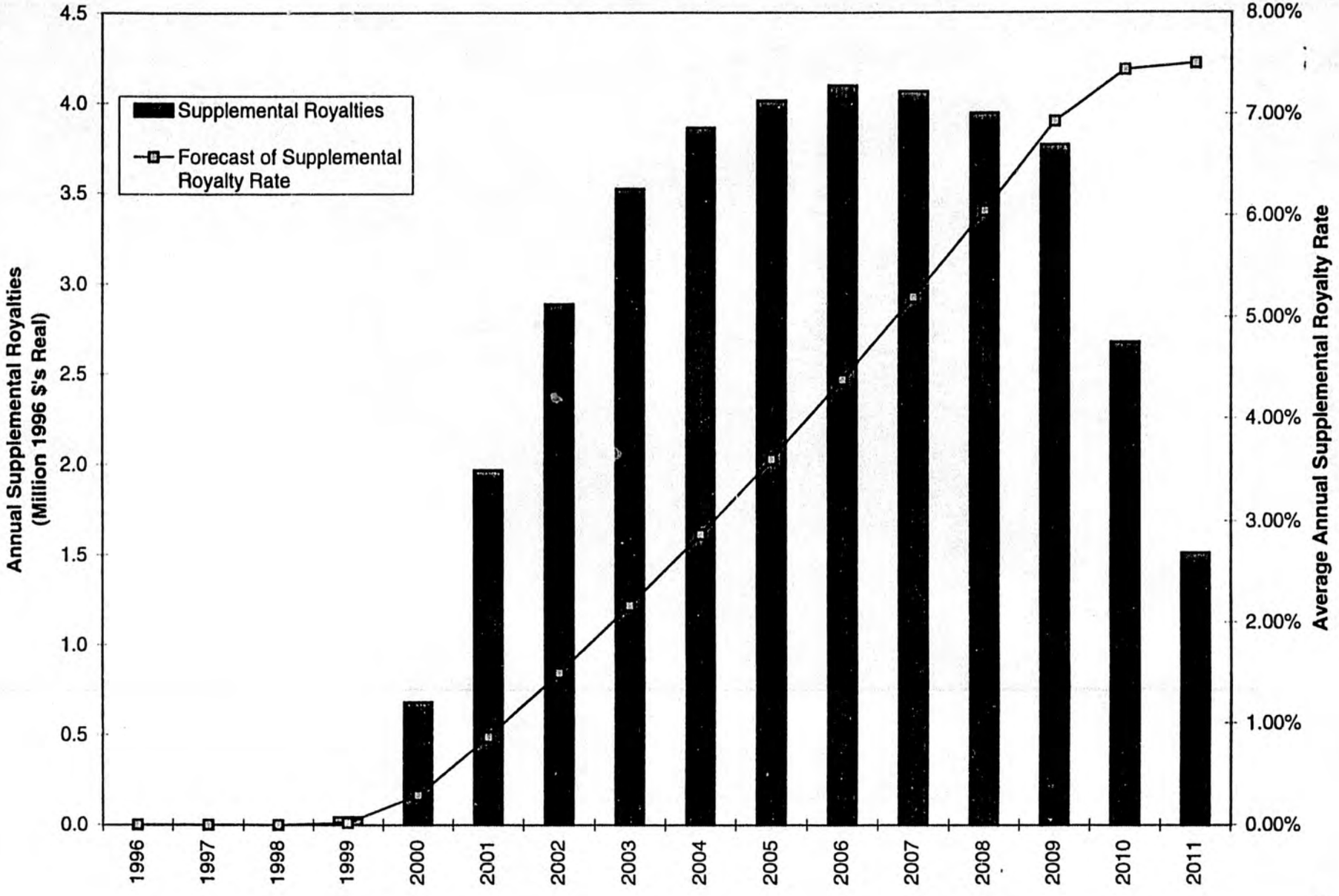
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
OIL PRODUCTION RATE, Mbbl/day	39.59	33.65	28.60	24.31	20.67	17.57	14.93	0.00	0.00	0.00
OIL PRICE	$45.31	$47.73	$50.27	$52.92	$55.70	$58.08	$60.58	$63.18	$65.89	$68.71
WELLHEAD OIL PRICE	37.90	39.76	41.83	43.66	45.38	46.48	47.05	48.69	46.99	47.88
GROSS REVENUE	$548	$488	$437	$387	$342	$298	$256	$0	$0	$0
TOTAL OPERATING COST	186	186	186	186	186	186	186	0	0	0
COST SHARING FEE	0	0	0	0	0	0	0	0	0	0
OPERATING COST IN CONSTANT $	113	109	105	102	98	95	92	0	0	0
CUM OP COST IN CONST $	904	1,013	1,119	1,221	1,319	1,414	1,506	1,506	1,506	1,506
ROYALTY	105	94	84	74	66	57	49	0	0	0
SEVERANCE TAX	9	8	7	6	5	4	4	0	0	0
AD VALOREM	26	25	25	24	23	22	21	0	0	0
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	1	0	0	0	0	0	0	0	0	0
STATE NET PROFIT INTEREST	150	119	92	66	43	19	-2	0	0	0
STATE INCOME TAX	0	0	0	0	0	0	0	0	0	0
TOTAL STATE	291	247	208	170	136	103	71	0	0	0
FEDERAL INCOME TAX	0	0	0	0	0	0	0	0	0	0
OPERATING CASH FLOW	70	56	43	31	20	9	-1	0	0	0
TOTAL INVESTMENT	0	0	0	0	0	0	0	0	0	0
CUM INVESTMENT IN CONST $	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405
TOTAL CASH FLOW	$70	$56	$43	$31	$20	$9	$-1	$0	$0	$0

NOMINAL DISCOUNT RATE IS 10%

CUM PW TOTAL CASH FLOW	$-828	$-815	$-807	$-801	$-797	$-796	$-796	$-796	$-796	$-796
CUM PW STATE REVENUE	908	964	1,007	1,039	1,062	1,078	1,089	1,089	1,089	1,089
CUM PW FEDERAL REVENUE	0	0	0	0	0	0	0	0	0	0

Northstar Proposal

Forecast of Supplemental Royalties and Rates

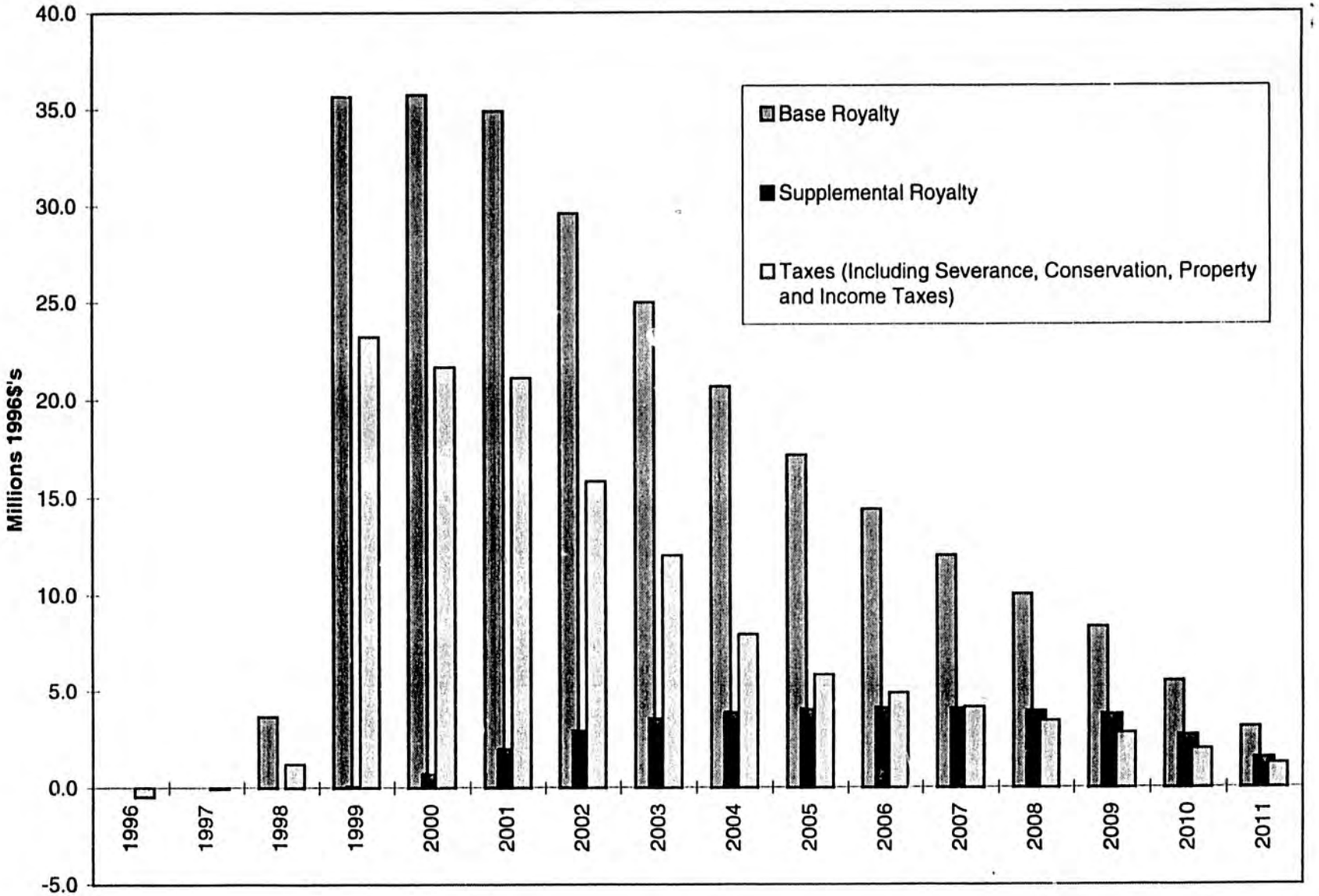


(This chart is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

BPNSU8B.311, SR&SRR

3/18/96, 10:27 AM

Northstar Proposal
Forecast of State Revnues



(This chart is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

Northstar Economic Evaluation

Alaska Department of NATURAL RESOURCES

Estimated Total Revenues

	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
		(Real 1996 Dollars)	
State Revenues			
State Royalty	256	256	257
State Supplemental Royalty	37	0	0
NPSL	0	85	41
State Share of Federal Royalty	16	16	16
Severance Tax	58	58	59
Spill & Conserv. Tax	3	3	3
Ad Valorem Tax	42	42	46
Income Tax	24	22	23
Total	435	481	444
Federal Revenues			
Royalty (Net of State Share)	44	44	44
Income Tax	215	198	213
Total	259	243	258
BPXA Cash Flow			
After Tax Funds Flow	349	318	346
Real Rate of Return	20.0%	19.9%	20.4%

Totals may not add due to rounding.

BPNSU9A.320, Revenue

(This table is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

3/29/96, 9:44 AM

Northstar Economic Evaluation

Alaska Department of NATURAL RESOURCES

Estimated Total Revenues

	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
		(Nominal Dollars*)	
State Revenues			
State Royalty	317	317	350
State Supplemental Royalty	51	0	0
NPSL	0	127	69
State Share of Federal Royalty	20	20	22
Severance Tax	67	67	75
Spill & Conserv. Tax	3	4	4
Ad Valorem Tax	53	53	63
Income Tax	30	27	32
Total	541	615	615
Federal Revenues			
Royalty (Net of State Share)	55	55	61
Income Tax	273	247	295
Total	328	302	356
BPXA Cash Flow			
After Tax Funds Flow	478	429	516
Real Rate of Return	20.0%	19.9%	20.4%

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

(This table is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

Northstar Economic Evaluation

Alaska Department of NATURAL RESOURCES

Estimated Total Revenues

	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
	(Discounted Net Present Value*)		
State Revenues			
State Royalty	169	169	140
State Supplemental Royalty	20	0	0
NPSL	0	37	14
State Share of Federal Royalty	11	11	9
Severance Tax	43	43	36
Spill & Conserv. Tax	2	2	1
Ad Valorem Tax	27	27	25
Income Tax	15	14	12
Total	286	303	237
Federal Revenues			
Royalty (Net of State Share)	29	29	44
Income Tax	133	127	213
Total	162	156	258
BPXA Cash Flow			
After Tax Funds Flow	167	155	139

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

(This table is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

Northstar Economic Evaluation

Alaska Department of NATURAL RESOURCES

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)	
State Revenues			
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
Total	444	502	444
Federal Revenues			
Royalty (Net of State Share)	44	44	44
Income Tax	218	198	213
Total	262	242	258
BPXA Cash Flow			
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.

(This table is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

Northstar Economic Evaluation

Alaska Department of NATURAL RESOURCES

Estimated Total Revenues

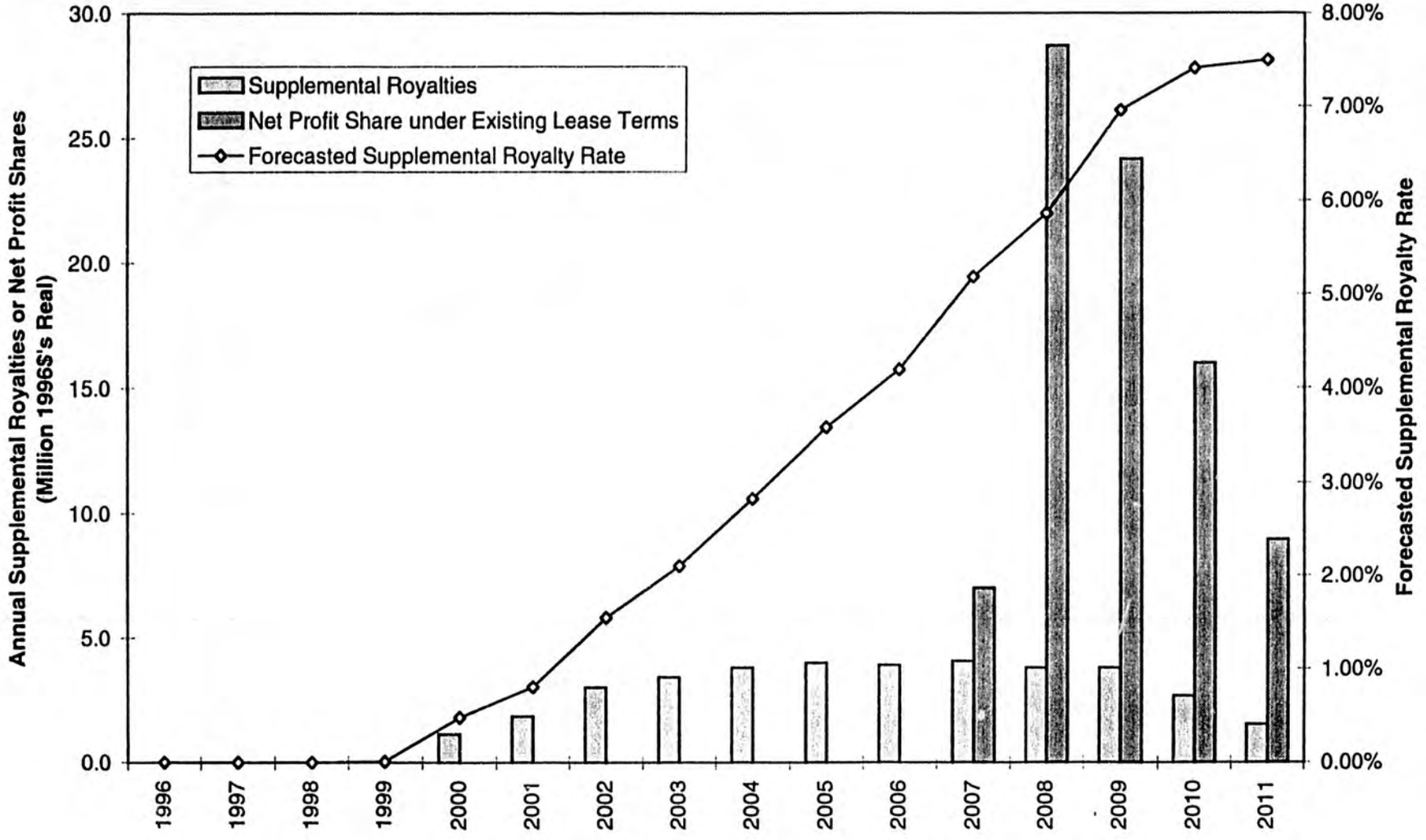
Accounting for the effects of "Price Volatility"	With Supplemental Royalty and Early Development	With Net Profit Share and Early Development	With Net Profit Share and Delayed Development
		(Nominal Dollars*)	
State Revenues			
State Royalty	317	318	350
State Supplemental Royalty	64	0	0
NPSL	0	158	69
State Share of Federal Royalty	20	20	22
Severance Tax	65	67	75
Spill & Conserv. Tax	3	4	4
Ad Valorem Tax	50	50	63
Income Tax	30	27	32
Total	551	643	615
Federal Revenues			
Royalty (Net of State Share)	55	55	61
Income Tax	277	245	295
Total	332	300	356
BPXA Cash Flow			
After Tax Funds Flow	486	427	516
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.

(This table is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

Northstar Proposal

Forecast of Net Profit Shares, Supplemental Royalties and Rates



(This chart is based on BPXA's most likely estimate of reserves, capital and operating costs, and DOR's Fall '95 Base Price Forecast.)

MEMORANDUM

State of Alaska
Department of Law

TO: Honorable John T. Shively
Commissioner
Department of Natural Resources

DATE: March 26, 1996

FILE NO.: 663-96-0441

TELEPHONE NO.: 465-3600

FROM: James L Baldwin
Assistant Attorney General
Governmental Affairs - Section

SUBJECT: Necessity for legislation to implement net profit share reduction

We were asked whether the Commissioner of Natural Resources has the statutory authority to reduce the net profit share payments required under the Northstar leases held by BP Exploration (Alaska) Inc. After considering that question, we conclude it would be prudent to seek express statutory authority for this action. We also discuss other legal issues that bear on proposed remedial legislation.

1. Authority Under Existing Law.

Alaska Statute 38.05.180 is a comprehensive statute which sets out the Commissioner of Natural Resources' authority regarding oil and gas leasing. Section 180 contains express authority in two subsections for the commissioner to modify the royalty provisions of an oil and gas lease. However, neither section 180 nor the Alaska Land Act (AS 38.05) defines the meaning of the term "royalty." To add to the difficulty of statutory construction, section 180 lacks express authority for reduction of a net profit share interest.

The Northstar leases are within the Northstar unit. To implement unitization of a field,

> The commissioner may, with the consent of the holders of the leases involved . . . change . . . royalty requirements of the leases . . . .

AS 38.05.180(p); (emphasis added). Section 180(p) provides that a change may be made "in connection with the institution and operation of a cooperative unit plan." The Department of Natural Resources (department) interprets section 180(p) to be applied only at the institution of a unit. For this reason, section 180(p) is not germane to the instant transaction. In any case, section 180(p) was amended during the first session of the Nineteenth Alaska State legislature to provide in part that the commissioner

> "may not decrease royalty on leases in connection with a cooperative or unit plan except as provided in (j) of this section.

Sec. 3 , ch. 85, SLA 1995. Section 180 (j) permits the commissioner to

> provide for an increase or decrease or otherwise modify royalty, to allow for production that would not otherwise be economically feasible. . . .

Section 180(j) contains intrinsic evidence that the legislature meant only to cover the royalty share in amount or value of production removed from the lease. For example, in section 180(j)(3)(C)(i) and (4)(A) limits are imposed on the commissioner's power to reduce a royalty using the terms "royalty percentage" or "royalty rate." The use of these terms is evidence that the legislature meant section 180 (j) to apply only to a share in the amount or value of production, not to a reduction of a share of the net profit derived from the lease. The foregoing intrinsic evidence of meaning is consistent with your testimony given when section 180(j) was under consideration before enactment by the legislature. You testified, "there was no reference made in [SB 207] to 'net profits leases'. . . . There could be negotiation on the base royalty, but not the net profit portion ." Senate Finance Committee Minutes, SB 207, May 11, 1995 . Senate Bill 207 was never subsequently amended to cover the omission highlighted by the commissioner. Senate Bill 207 was passed by the legislature was signed into law by the governor and became ch. 85, SLA 1995.

There is no commonly understood definition of a net profit share.[1] A net profits interest may be interpreted to be either the equivalent of a royalty which is an interest in land, or it could be considered only a contract right which is severable from an interest in realty. We would be remiss if we did not acknowledge that the department has without discussion, on occasion, interpreted the term "royalty requirements" in section 180 (p) to include a net profit share interest. Similarly, the Minerals Management Service, the federal agency equivalent to the Division of Oil & Gas, has interpreted the term "royalty," in the context of a royalty reduction, to include net profit share payments. See 30 C.F.R. § 203.50. The past administrative interpretations of the department are limited in number and of fairly recent origin. For this reason, we are unable to conclude there has been a contemporaneous construction that a net profit share is included within the meaning of "royalty." For these reasons and the analysis of the relevant provisions discussed above, we believe there is substantial doubt that section 180 prescribes a method for reducing a net profit share interest.

We believe that it would not be prudent to assume that the term "royalty," as used in subsection (p), includes net profit share payments. If that were the case, the commissioner's only statutory authority to reduce the net profit share payments required under the Northstar Unit leases

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[1] See Christy v. Petrol Resources Corp., 691 P.2d 59, 61 (N.M. App. 1984)("net profits interest" has no independent meaning, and nature of the interest must be determined from provisions of the instrument creating it).

is set out in AS 38.05.180(j). For the reasons stated above, we believe that a decision to reduce a net profit share using the authority contained in section 180(j) would be vulnerable to a judicial challenge. Further, under section 180 (j), the commissioner may reduce royalty on unitized leases if the lessee makes a "clear and convincing showing that a modification of royalty meets the requirements of this section and is in the best interests of the state." AS 38.05.180(j)(2). The purpose of subsection (j) is "to allow for production that would not otherwise be economically feasible." You have informed us that the Northstar Unit development does not meet this standard. It would be preferable to seek independent authority for the Northstar net profit share reduction in a way that would bring certainty to the state and the leaseholder while avoiding these difficult legal issues.[2]

2. Local or Special Legislation

The department intends to seek the narrowest possible provision to specifically authorize amendments to only the Northstar leases. Consistent with your instructions, we have prepared a bill to accomplish this goal. You ask whether such a bill would violate the Alaska Constitution. The prohibition against local or special legislation provides:

> The legislature shall pass no local or special act if a general act can be made applicable. Whether a general act can be made applicable shall be subject to judicial determination.

Alaska Const. Art. II, Sec. 19.

Section 19 has not been recently applied by the Alaska Supreme Court. In 1975, section 19 was applied to invalidate a statute that mandated the creation of an Eagle River-Chugiak Borough. Abrams v. State, 534 P.2d 91 (Alaska 1975). In Abrams, the court recognized that a statute may affect only one of a few areas and yet relate to a matter of statewide concern or common interest.

In 1977, section 19 was again applied to validate a statute authorizing a trade of land between the federal government, the state, and a Native regional corporation. State v. Lewis, 559 P.2d 630 (Alaska 1977), cert. denied, 432 U.S. 901 (1977). The court found that the land trade was unique, but of statewide concern. The Lewis, court propounded a test to be used in determining whether a statute violates the special or local prohibition. It was substantially the same as the test used to determine the validity of nonsuspect classifications challenged as violative of equal protection. The state merely had to show a rational basis, a good reason, to justify the special treatment.

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[2] There may be implied authority to amend the net profit share term of an oil and gas lease granted under AS 38.05.180. While that authority may exist, it has never been used to reduce a net profit lease. On a matter of such significance, this transaction should not become the test case.

In 1978, the court articulated a unified equal protection analysis that avoids distinguishing between suspect and nonsuspect classifications by using a sliding scale to weigh the interests involved in any classification. State v. Erickson, 574 P.2d 1 (Alaska 1978). The court applies a single test that is flexible and dependent on the importance of the rights involved. The more fundamental the right involved, the more compelling the interest the state must have for preferring one classmember over another. Commercial Fisheries Entry Commission v. Apokedak, 606 P.2d 1255 (Alaska 1980).

There has not been a case involving the local or special legislation prohibition since the unified equal protection test was adopted by the court. It remains to be seen how the court will apply an equal protection analysis to a statute claimed to violate section 19.

According to the department, there are approximately 39 leases carrying net profit share provisions. It is possible that other leaseholders will claim discrimination if they are not also given relief from a corresponding net profit share provision. We doubt that a leaseholder would prevail in a claim that a statute permitting the reduction of a leaseholder's net profit share interest implicates a fundamental right. It is not a foregone conclusion that the other leaseholders are similarly situated to the Northstar leaseholder. We doubt there is a class of similarly situated leaseholders who would be discriminated against by a bill that only applies to the Northstar leases. The effect of a net profit share on a specific field will be subject to different economic assumptions (except price).

The state's interest advanced by the proposed statute is to bring the Northstar leases into production in a way that also encourages other employment and economic activity in the state. The state depends on petroleum revenues for approximately 85 percent of its general fund revenues. For this reason, a statute specifically directed to the Northstar leases can be said to have statewide significance. The reduction in net profit sharing is tied to promises of local manufacture and assembly of facilities to develop the leases. This will lead to substantial economic activity in the railbelt region of the state in which over half of the population of the state resides. There will be a direct economic benefit to the North Slope Borough derived from increased tax revenues. Production from the Northstar Unit will decrease the TAPS tariff for all existing North Slope fields and will likely extend the life of TAPS thereby making it more likely that fields not currently in production can be brought into production.

It will be the department's responsibility to carefully articulate the state's interest during legislative hearings on the bill proposing the net profit share reduction. This must be done with the goal in mind of establishing a detailed legislative history supporting the interests of the state. The legislative history will be important because the ultimate decision "whether a general act can be made applicable" rests with the Alaska Supreme Court.

3. Public Purpose.

The proposed reduction in the net profits share provisions of the Northstar leases raises the question of whether there might be an expenditure of future state revenues without a valid public purpose. It is debatable how much revenue, if any, would be foregone if the reduction in net profit share takes effect. The amount is dependent on when the leases go into production, the value of oil and other production from the lease, and when the leases become profitable under 11 A.A.C. 83.210 - .295.

The Alaska Constitution requires that state money be expended only for public purposes. Alaska Const. art. IX, sec. 6. To satisfy the public purpose doctrine, the benefit to the public must be the direct and primary purpose of an expenditure. It is permissible if the expenditure also has an indirect private benefit. However, the reverse (direct private benefit with only secondary, indirect public benefit) constitutes violation of the public purpose doctrine.

The analysis is similar to a determination whether there is adequate consideration to support a contract. If there is valuable consideration received by both the state and the leaseholder, the benefit to the state may be characterized as direct. In the case of the Northstar leases, there is a trade-off between expedited development of the leases and the loss of uncertain future revenue. The expedited development comes combined with in-state manufacture and assembly of production facilities. The magnitude of the loss in revenue is highly speculative because the value of production from the leases depends on the whims of the marketplace.

Because the State leased the oil rights at the Northstar field pursuant to the constitutional mandate to obtain the maximum public benefit, an effort to expedite production vitally affects the public interest. See Swindel v. Kelly, 499 P.2d 291, 298 n.27 (Alaska 1972)(ruling that State Constitution recognizes value of all public lands); Alyeska Ski Corp. v. Holdsworth, 426 P.2d 1006, 1011 (Alaska 1967)(ruling that "our constitution reflects . . . the importance of our land resources and of the concomitant necessity for observance of legal safeguards in the disposal or leasing of state lands.") See also Trustees For Alaska v. State, 736 P.2d 324, 335 (Alaska 1987)(finding that State was granted large land holdings under the Statehood Act to "ensure the economic and social well-being of the new state.") Given the public's vital interest in deriving the maximum benefit from the leasing of state lands, the court would likely liberally construe the proposed net profit share reduction provisions in the State's favor. See State v. Moncrief, 720 P.2d 470, 475 (Wyo. 1986)(stating that if a governmental mineral lease is ambiguous, a court must then recognize that the government officials' duty "to realize the largest possible proceeds is a surrounding circumstance which must be considered when interpreting these leases.")

The Alaska Supreme Court tends to give a certain amount of deference to the judgment of the legislature concerning whether and how state resources may be expended for a particular purpose. See, DeArmond v. Alaska State Development Corporation, 376 P.2d 717, 721

(Alaska 1962)(court will not set aside finding of public purpose unless it clearly appears that such finding is arbitrary and without any reasonable basis in fact). To be sure, there will be some uncertainty if this question is litigated. The Alaska Supreme Court has stated that the phrase "public purpose" represents a concept which is not capable of precise definition. DeArmond, 376 P.2d at 721; Walker v. Alaska State Mortgage Association, 416 P.2d 245 (Alaska 1966). The concept is an evolving one for which "it would be a disservice to future generations for [the Supreme Court] to attempt to define . . . ." Id. The court will examine the "entire factual and governmental context to determine whether a particular plan of action serves a public purpose." Wright v. City of Palmer, 468 P.2d 326, 330 (Alaska 1970)(citation omitted). In essence, a determination of public purpose must be made in each case on the basis of the particular facts and circumstances. DeArmond, 376 P.2d at 721.

We believe that a compelling case can be made that there is adequate consideration to support a finding of a direct and substantial public benefit flowing from the reduction of the net profit share. We assign a low probability to the possibility of a successful challenge based on the public purpose doctrine.

4. Competitive Bidding Principles

It may be possible to consider a net profit share to be a contract right of the leaseholder. A public contract can be amended by the contracting parties. The power to amend a public contract is a necessary element of contract administration. It is not certain that judicial constructions of the ability of an administrative officer to amend a public contract will apply to the power to amend a contract right conveyed along with an oil and gas lease.

The power of amendment has its limits. The ability to amend is greatly restricted if the contract was awarded through the competitive bidding process. The reason for this is the premise that a material change in a competitively bid contract amounts to a new contract. McKinnon v. ALPETCO, 633 P.2d 281, 287 (Alaska 1981). A new contract can only be awarded through another round of competitive bids. Id.

The rule against material amendments was applied in Kenai Lumber Co., Inc v. LeResche, 646 P.2d 215 (Alaska 1982). In Kenai Lumber, the Alaska Supreme Court offered factors for determining when an amendment is material. These factors include:

(1) the legitimacy of the reasons for the change;

(2) whether the reasons for the change were unforeseen at the time the contract was made;

(3) the timing of the change;

(4) whether the contract contains clauses authorizing modifications; and

(5) the extent of the change relative to the original contract.

646 P.2d at 221.

It may be possible to formulate an argument that the reasons for amending the Northstar leases are legitimate and were unforeseen at lease formation. The timing of the change is sufficiently distant from formation of the leases to negate any claim that it is a pretext to avoid resolicitation of the leases. However, the extent of the change is substantial enough to raise serious questions as to whether factor (5) above can be satisfied. Other persons who competed for the leases may claim that since the net profit share was the sole variable in the lease sale, it is such a material term that a change cannot be made without violating the competitive bidding statute. Uncertainty concerning the state's prospects for prevailing in any litigation on this issue gives an additional basis for our advice that the department seek independent statutory authority for the Northstar transaction. The Alaska Supreme Court has held that competitive bidding is not necessary unless "required by constitution, statute, ordinance or regulation." McKinnon, 633 P.2d at 287. If the legislature were to directly authorize the amendments to the Northstar leases, that authorization would take precedence over any other statute requiring competitive bids, just as section 180(j) takes precedence over any other competitive bidding statute.

We hope that the foregoing memorandum adequately addresses the reasons why it would be prudent to seek specific authority from the legislature to reduce the net profit share provisions applicable to the Northstar leases. We are prepared to assist the Department of Natural Resources in seeking passage of a bill to accomplish this purpose.

JLB/clh

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

(907) 465-3867 or 465-3870
FAX (907) 465-2029
Mail Stop 3101

120 Seward Street, Suite 409
Juneau, Alaska 99801-2105

MAR 2 5 1996

MEMORANDUM March 25, 1996

SUBJECT: Renegotiation of State Oil and Gas Lease

TO: Senator Drue Pearce
President of the Senate

FROM: Jack Chen[illegible]
Legislative C[illegible]

I am responding to three questions set out in your March 22 memo.

1. I have not found explicit statutory or regulatory authority to renegotiate an oil and gas lease as seems to be contemplated in the North Star field lease. See, by way of specific example, 11 AAC 71.205 authorizing amendment of timber and materials contracts except that the amendment "may not materially affect or change the meaning or intent of the contract," 11 AAC 71.205(b). The lease documents applicable to the North Star field lease may authorize or provide for renegotiation under specific circumstances, but I don't know this.

Even absent an explicit statute or regulation or provision in the lease, as a matter of general law, negotiations may be initiated to amend a competitively bid public contract. 72 C.J.S. Supp., "Public Contracts," sec. 24. However, amendments to competitively bid contracts are prohibited if the amendments proposed are "material," that is to say, competitively bid contracts may not be materially amended. McKinnon v. Alpetco, 633 P.2d 281, 287 (Alaska 1981), Kenai Lumber Company v. LeResche, 646 P.2d 215, 221 (Alaska 1982). Amendments to a contract are "material" if they involve the alteration of factors that influence the judgment or decision on the award of the contract. Brown v. Ward, 593 P.2d 247, 250 (Alaska 1979), Creedmen v. Walker, 613 P.2d 608, 613 (Alaska 1980). Based on the pre-lease analysis, the state's choice of leasing method--including the decision to take net profit share using the amount reserved as the bid variable (which I think is what is at work in the award of the original N[illegible]h Star field lease)--seems to be "material" by any measure.

2. Without having a notion of what the administration may choose to offer, still, I think the administration will, in one way or another, ask the legislature to ratify or validate modifications proposed to the North Star lease.

An Act or public enactment to validate the modification of a public contract is a form of curative legislation. Yellon v. Plants, 89 N.E.2d 540 (Indiana 1950); C. Sands, Sutherland Statutory Construction, sec. 71.07. As a general rule, curative legislation is valid (1) when the legislature originally had power to authorize the acts that were done and (2) the curative legislation does not impair a vested right in violation of constitutional provisions prohibiting impairment of contract. Fairbanks North Star Borough v. State, 753 P.2d 1158, 1160 (Alaska 1988). The legislature might have authorized renegotiation of public contracts, and, depending on what is submitted, it is more probable than not that the proposed legislation would not impair a vested right (assuming that the state administration is prepared to waive the right to receive revenue under the original lease by shifting from one choice of leasing method to another).

A validating or curative act is usually subject to the "local or special" act limitations of a state constitution. C. Sands, Sutherland Statutory Construction, secs. 41.11 - 41.13. Even if it was a consideration in this instance, there is, it seems to me, good chance that the court would find the test of Abrams v. State, 534 P.2d 91 (Alaska 1975) to control and determine that the modification of an oil and gas lease with significant potential revenue-producing capacity is a matter of common interest to the whole state, having, through the contributions to the state treasury, probable statewide interest and impact, and therefore not subject to the local and special legislation prohibition provision.

It is also possible, of course, that the legislation sponsored by the administration will be general, in that it will authorize renegotiations of all or some types of oil and gas leases. That type of legislation, potentially applying to other leases as well as the North Star lease, would avoid the "local or special act" question altogether.

3. Your memo describes legislation that addresses the possibility that the state may receive less revenue than originally anticipated. It does not propose to withdraw money from the state treasury, therefore an act addressing renegotiation of the lease is not to be regarded as an appropriation.

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waived, either expressly[12] or impliedly.[13] We have no difficulty finding a waiver under the facts of this case. The plaintiffs diligently sought adjudication of the class action issues by twice moving for certification. The defendants initiated summary judgment proceedings while plaintiffs' second motion for certification of the class action was pending. Under these circumstances, the trial court did not err in ruling on the merits and then certifying the class.

B. *Did the Trial Court Err in Finding that the Named Plaintiffs Provided Adequate Representation for the Class?*

Civil Rule 23(a)(4) provides that a class action can be maintained only if "the representative parties will fairly and adequately protect the interests of the class." The defendants contend that the plaintiffs could not provide adequate representation for the class because they had interests antagonistic to other members of the class.

[7] First, the determination of the adequacy of representation in a class action is a question of fact. *Gueriue v. J & W Investment, Inc.*, 544 F.2d 863, 864 (5th Cir. 1977); 7 C. Wright & A. Miller, Federal Practice and Procedure § 1765, at 622–23 (1972). As a question of fact, the trial court's finding will not be reversed unless clearly erroneous; in other words, the trial court will not be reversed unless, in light of the whole record, it can be said with a definite and firm conviction that the trial judge was clearly mistaken. *Alaska Foods, Inc. v. American Mfrs. Mut. Ins. Co.*, 482 P.2d 842, 848 (Alaska 1971).

[8] Second, in order to bar a suit, the antagonism "must be as to the subject matter of the suit." *Berman v. Narragansett Racing Ass'n*, 414 F.2d 311, 317 (1st Cir. 1969), *cert. denied*, 396 U.S. 1037, 90 S.Ct. 682, 24 L.Ed.2d 681 (1970); 7 C. Wright & A. Miller, *supra*, § 1768, at 639; 3B J. Moore, *supra* note 8, ¶ 23.07[3], at 23–287.

Third, it should be noted that in a suit to strike down a statute as unconstitutional, the requirement of adequate representation loses vitality. The effect of a finding of unconstitutionality will affect everyone, not just the parties before the court. "Thus, even if [a] plaintiff is not a proper representative in the traditional sense, striking a class claim will not effectively change the end result if the party successfully proceeds on an individual basis." 7 C. Wright & A. Miller, *supra*, § 1771, at 664. *See also* 3B J. Moore, *supra note* 8, ¶ 23.40[3], at 23–299 n.15. In the present case, this would simply mean that the named plaintiffs would be burdened with the expenses of the suit without reimbursement from a class recovery. The effect of the action on the defendants and the rest of the class is the same whether the suit is brought as a class or as an individual action.

Finally, it should be noted that in a suit seeking to have a statute declared unconstitutional, there are only two sides to the argument; either the statute is constitutional or it is not. In such a case where there are no inherent conflicts *inter se* among class members (such as rights to differing shares in a limited fund), the interests of class members antagonistic to the representatives' constitutional attack will usually be adequately represented by the defendants.

[9] In the present case, the trial court was not clearly erroneous in finding the representation of the class to be adequate. First, the major antagonism claimed was that most of the fishermen in the region had supported, by their votes, mandatory assessments. Since the basis of this suit is the seeking of a declaration of the constitutionality of a statute, the rights of all class members are affected in the same way, whether or not it is brought as a class action. Moreover, the defendant associations and the state have vigorously opposed the constitutional attack of the plaintiffs and have thereby necessarily represented the interests of antagonistic class members to have the statute declared constitutional.

12. *Caldwell Co. v. Superior Court*, 50 Cal.App.3d 32, 123 Cal.Rptr. 228, 230 (1975). *Katz v. Carte Blanche Corp.*, 496 F.2d 747, 762 (3d Cir. 1974) (en banc), *cert. denied*, 419 U.S. 885, 95 S.Ct. 152, 42 L.Ed.2d 125 (1975).

13. *Civil Serv. Emps. Ins. Co. v. Superior Court*, 72 Cal.3d 362, 149 Cal.Rptr. 260, 584 P.2d 497, 502–04 (Cal.1978); *Peritz*, 523 F.2d at 354 n.4; 3B J. Moore, *supra* note 8, ¶ 23.50, at 23–425 to 23–428.

V. DID THE TRIAL COURT ERR IN FINDING THE DOCTRINE OF LACHES INAPPLICABLE?

The trial court held that the doctrine of laches was inapplicable on the facts of the present case. On appeal the defendants have contested this finding and both sides have extensively argued the traditional elements of laches, unreasonable delay and resulting prejudice. However, the discussion of the elements of laches is irrelevant since laches is simply inapplicable to any of the remedies sought in this case.

[10, 11] The suit seeks three basic forms of relief. First, a refund of all assessments paid under the statute is sought on a common count. Since this is a general assumpsit common-law cause of action for the refund of taxes wrongly paid, the six-year statute of limitations contained in AS 09.10.050(3) would apply to this action at law. *State v. Wakefield Fisheries, Inc.*, 495 P.2d 166, 172 (Alaska 1972). The other two types of relief sought, a declaratory judgment and a permanent injunction, are *prospective* in application and seek to prevent future threatened harm. A laches analysis is simply inappropriate, since each new assessment would give rise to a new cause of action.

VI. DID THE COURT ERR IN FINDING THE DOCTRINE OF EXHAUSTION OF ADMINISTRATIVE REMEDIES INAPPLICABLE?

[12] The trial court was correct in holding inapplicable the doctrine requiring the exhaustion of administrative remedies before seeking relief in the superior court. See Davis, Administrative Law Treatise § 20.04 (1st ed. 1958). This was not an administrative adjudicatory proceeding which had various routes of administrative appeal. Rather, the implementation of the salmon assessment was administrative legislative action not subject to appeal. The only action which the fishermen could take in the administrative process was to vote in the election on a proposed assessment. There simply were no administrative remedies to exhaust.

The judgment of the superior court is AFFIRMED in all respects.

KENAI LUMBER COMPANY, INC., Appellant,

v.

Robert LeRESCHE, Commissioner of Dept. of Natural Resources of the State of Alaska; Geoffrey Haynes, Director of Division of Lands of Dept. of Natural Resources; Frederick H. Boness, Deputy Commissioner of Dept. of Natural Resources; and South-Central Timber Development, Inc., Appellees.

SOUTH-CENTRAL TIMBER DEVELOPMENT, INC., Cross-Appellant and Appellee,

v.

KENAI LUMBER COMPANY, INC., Cross-Appellee and Appellant.

Nos. 5733, 5755.

Supreme Court of Alaska.

June 11, 1982.

Competitor timber company brought action challenging amendment to timber harvesting contract. The Superior Court, Third Judicial District, J. Justin Ripley, J., entered summary judgment, and appeal was taken. The Supreme Court, Matthews, J., held that: (1) rule prohibiting material modifications in competitively bid contracts did not apply to amendment to timber harvesting contract insofar as the amendment

waived primary manufacturing requirement and altered harvesting economics by removing certain lands from contract area and substituted other lands; (2) timber harvesting contract amendment substituting land for land originally included in contract area was not "material" for purposes of rule prohibiting material changes in public contracts let under competitive bidding, even though substituted land was never subject of competitive bidding process; (3) fact that losing party's attorney fees amounted to far less than sum prevailing party paid its attorneys did not demonstrate that award to prevailing party of attorney fees was manifestly unreasonable; and (4) competitor timber company's economic incentive to bring action challenging amendment of public timber harvesting contract, even if suit did not involve issue of alleged circumvention of competitive bidding process prevented claimed public interest from precluding award of attorney fees.

Affirmed.

Rabinowitz, C. J., dissented and filed opinion.

1. States ⇐106

Rule prohibiting material modifications in competitively bid contracts did not apply to amendment to timber harvesting contract insofar as the amendment waived primary manufacturing requirement and altered harvesting economics by removing certain lands from contract area and substituting other lands where price of timber harvested was, at time of amendment, to be determined by state appraisals, such appraisals were to be based on current market and cost condition and were not indexed to original bid price, primary manufacturing requirement detracted from rather than added to value of end product, and changes in harvesting economics were conditions to be reflected in price reappraisals to be made under the contract. AS 38.05.115, 38.05.120.

2. States ⇐106

Timber harvesting contract amendment substituting land for land originally included in contract area was not "material" for purposes of rule prohibiting material changes in public contracts let under competitive bidding, even though substituted land was never subject of competitive bidding process, where reason for amendment was discovery by Department of Fish and Game that included area contained important winter habitat for mountain goats, the Department requested the sale be modified by deleting such area, and importance of the deleted area as wildlife habitat was not appreciated when original contract was made. AS 38.05.115, 38.05.120.

3. Public Contracts ⇐18

Not all amendments to competitively bid contracts are prohibited, only those regarded as material. AS 38.05.115, 38.05.120.

4. Appeal and Error ⇐984(5)

The determination of court-awarded attorney fees is committed to discretion of trial court and reviewable on appeal only for abuse of discretion; such abuse is regarded as present only where trial court's decision appears to be manifestly unreasonable or motivated by inappropriate purpose.

5. Costs ⇐172

Fact that losing party's attorney fees amounted to far less than sum prevailing party paid its attorneys did not demonstrate that award to prevailing party of attorney fees was manifestly unreasonable.

6. Costs ⇐172

Competitor timber company's economic incentive to bring action challenging amendment of public timber harvesting contract, even if suit did not involve issue of alleged circumvention of competitive bidding process, prevented public interest from precluding award of attorney fees.

Richard Helm and Mark L. Figura, Burr, Pease & Kurtz, Inc., Anchorage, for appellant.

Shelley J. Higgins, Asst. Atty. Gen., Anchorage and Wilson L. Condon, Atty. Gen., Juneau, for appellees.

Leroy DeVeaux and James N. Wanamaker, Wanamaker, DeVeaux & Crabtree, Anchorage, for cross-appellant, South-Central.

Before RABINOWITZ, C. J., and CONNOR, BURKE, MATTHEWS and COMPTON, JJ.

OPINION

MATTHEWS, Justice.

In this case we are asked to review the legality of a negotiated amendment to a long term timber sale contract between the State of Alaska and South-Central Timber Development, Inc. The amendment has been challenged by Kenai Lumber Company, Inc., which operates a currently underutilized sawmill in Seward, and competes with South-Central in the purchase of timber. The basis for Kenai's claim is that the changes which the amendment makes are so significant that they amount to a circumvention of the competitive bidding process under which the original contract was let. The trial court on cross motions for summary judgment ruled that the amendment was lawful. We agree for the reasons expressed herein.

I

The original timber sale contract, designated Icy Cape No. 1, was made on December 1, 1969 following advertisement for public bids pursuant to AS 38.05.120. South-Central was the only bidder at the auction and received the award at the minimum stumpage prices established by the state.[1]

The sale area consists of approximately 33,760 acres in a remote location on the coast of south-central Alaska adjacent to Icy Bay. The contract estimates that some 206,800,000 board feet of timber can be taken from this area.[2] The contract requires all timber within the boundaries of the sale area meeting certain minimum specifications to be cut. The contract is to expire 20 years from the date of execution unless extended by the state. It contains a provision concerning the primary manufacture of the timber cut as follows:

> Timber cut under this contract shall not be transported for primary manufacture outside the State of Alaska without written approval of the state. Primary manufacture shall be as defined under Section 406.104 of the "Timber Sale Regulations" and as further defined in the Governor's Policy Statement for primary manufacture dated April 8, 1968, a copy of which is attached hereto and hereby made a part of this contract.[3]

1. The prices were $7.00 per 1,000 board feet (m.b.f.) for Sitka spruce saw logs and $2/m.b.f. for hemlock saw logs.

2. Of this amount approximately 106,200 m.b.f. were Sitka spruce saw logs and 100,600 m.b.f. were hemlock saw logs.

3. Section 406.104 of the Timber Sale Regulations in existence as of the date of execution of the contract provides:

> Primary Manufacture.
>
> The Director may require that primary manufacture of logs, cordwood, bolts, or other similar products be accomplished within the State of Alaska.
>
> The term primary manufacture means manufacture which is first in order of time or development. When used in relation to sawmilling, it means:
>
> (a) The breakdown process wherein logs have been reduced in size by a headsaw or gang saw to the extent that the residual cants, slabs, or planks can be processed by resaw equipment of the type customarily used in log processing plants, or
>
> (b) Manufacture of a product for use without further processing, such as structural timbers (subject to a firm showing of an order or orders for this form of product.)
>
> Primary manufacture, when used in reference to pulp ventures, means the breakdown process to a point where the wood fibers have been separated. Chips made from timber processing wastes shall be considered to have received primary manufacture. With respect to veneer or plywood productions, it means the production of green veneer. Poles and piling, whether treated or untreated, when manufactured to American Standards Association specifications are considered to have received primary manufacture.

The Governor's Policy Statement for primary manufacture, referred to in the contract, provides:

> Cants may be manufactured from all species for export and shall be considered to have received primary manufacture when sawed up to a maximum thickness of 12 inches and may be of any width. Timber cut thicker than 12 inches must be squared on four sides along their entire length with allowances for one-third of each dimension (thickness and width) allowed in waste.

The contract calls for reappraisal of the prices of the timber at the end of five years after the effective date of the contract and thereafter in three year intervals.[1] A section of the contract incorporates by reference the state timber sale regulations. Of interest here is section 156 of the regulations pertaining to amendments and modifications:

> Amendments to and modifications of the contract may be made in writing and become a part of the contract upon mutual agreement of the director and the purchaser; provided that such amendment or modification does not materially affect or change the meaning or intent of the contract.[2]

From 1970 through 1978 South-Central cut timber from the sale, squared it in compliance with the primary manufacturing requirement at its mill on Jakolof Bay, several hundred miles from the sale area, and exported the squared timber, called "cants," to Japanese markets. During this period the contract was amended on six occasions. These amendments included two price changes under the reappraisal provision of the contract,[3] and one amendment allowing 3,200,000 board feet of spruce and hemlock to be exported as round logs, that is, logs not subjected to primary manufacture.

The 7th amendment, agreed to in January of 1979, is the amendment in question in this case. The most important change it makes is that it waives the primary manufacturing requirement. Another important change deletes from the sale area all lands at an elevation above 400 feet and substitutes additional acreage. The deleted lands contain approximately 40,000,000 board feet of timber. About 14,000,000 board feet may be cut from the added acreage. The amendment also changes the stumpage prices, increasing the price of spruce to $80.00/m.b.f. and of hemlock to $28.00/m.b.f. Other aspects of amendment No. 7 include a provision that South-Central must also take logs suitable only for the manufacture of wood pulp or pay a fine; a provision which on the whole increases the penalty imposed on South-Central for failing to remove trees meeting the contract specifications; a provision increasing the penalty for leaving high stumps; and a provision making the new state Forest Resources and Practices Act, AS 41.17.010.950, applicable to the sale immediately rather than one year following the amendment as would otherwise be the case. At the time of the amendment it was estimated that the total harvestable timber remaining was some 87,000,000 board feet.

Due to a change in the administration of the air pollution control laws it became apparent in 1978 that South-Central's Jakolof Bay mill could not continue to operate beyond June of 1979 without making extensive changes in the burner used to dispose of the slabs created by primary manufacture. These changes were judged by South-Central to be economically unfeasible. South-Central therefore sought a waiver of the primary manufacture requirement from the state. The state granted the waiver, making the following findings:

FINDINGS AND WAIVER OF PRIMARY MANUFACTURE

Based on a review of the experience since this sale was let in 1969, the following findings are made:

(1) Actually, only four jobs, those of sawyer, off-bearer (of slab), millwright and night watchman, are added by the primary manufacture milling operations.

(2) That the waiver of primary manufacture will provide economic incentive for the more intense utilization of additional timber and will create at least as many jobs in the woods as were created through the milling operation.

(3) That given the limited volume in this sale, it will not be economic to install chipping operations or pneumatic shiploading facilities. Also, there is no other economic method of salvaging the slab created by primary manufacture.

(4) The one known economic method of disposing of the slab is by burning in a wigwam burner.

(5) That since Icy Bay is an area of pristine air quality at present, it is doubtful that the required permit could be obtained (see the case of *National Asphalt Pavement Assoc. v. Train* [D.C. Cir.], 539 F.2d 776 (1976).

(6) That, rather than continue a practice which requires waste of commercially valuable sapwood (by slabbing) and also causes potential air quality deterioration (by burning), it is submitted that it may be preferable to permit round-log export.

(7) That the outer ring, or sapwood, of the log is the most commercially valuable portion because of close grain, freedom from knots and consistent color and grain.

(9)[7] That under present pri manufacture requirements, a si percentage of the valuable sapwo cut, burned, and wasted.

(10) It is further found that th a strong market for the valuable wood and because of that strong ket there will be a higher utilizati the forest products from this sa round log export is permitted.

(11) Also a higher price wil obtained for the state's timbe sources if primary manufactu waived.

(12) Also, there will be benefi the long term management of Ala forest lands resulting from higher zation.

The justification for deleting those tions of the sale area lying above 400 and for making a partial substitutio adjacent low lands is also expressed in nal findings made by the state:

REDUCTION OF SALE AREA F PROTECTION OF GOAT HABIT

Based upon the representations of Habitat Division of the Alaska Dep ment of Fish & Game, the following f ings are made:

(1) That at the time this Cont was let in 1969, there had been lim funds for studying the fish and g habitat protection. Accordingly, area received less intensive study t might otherwise have been the c

(2) That subsequent investigat has revealed that timber stands at tain elevations and along certain st are vital to the protection of the p population at Icy Bay.

(3) That these designated slopes necessary for providing a proper s tering habitat for the goat popula of Icy Bay.

(4) That it will support the ac conservation of wildlife resources Icy Bay if these needed habitat a are deleted from the Timber Sale.

Chips made from timber processing wastes shall be considered to have received primary manufacture and export will be permissive on action of the Commissioner. Timber processing wastes is hereby defined as all timber, mill residue, logging residue or other material not presently being utilized or in demand for higher-valued products.
With the advance approval of the Commissioner, limited quantities of all species, excluding spruce and hemlock, may be exported in the form of round logs for experimental purposes only, e.g. to introduce a new product to market. Round logs may not be exported as a marketable commodity.
The above statement is intended to clarify and/or define Section 608.104 of the "Timber Sale Regulations" and supersedes all previous policy statements and/or resolutions.

1. Apparently the intent of the contract was to allow two years for construction of the roads and loading facilities which would be needed before timber cutting and transportation could take place. A special provision of the contract required that a minimum of ten million board feet be cut and paid for by the end of the third year.

2. 11 A.A.C. 76.155.

3. The first, effective December 1, 1974 changed spruce saw logs to $16.25/m.b.f. and hemlock saw logs to $12.00/m.b.f. and the second effective December 1, 1977 changed the price for spruce saw logs to $25.00/m.b.f. and hemlock saw logs to $18.00/m.b.f.

7. There is no finding numbered 8.

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(5) That although the timber purchaser has made certain capital investments based on the volume of timber within the contracted sale area, the purchaser is willing to amend the sale area by deleting the area essential to goat habitat if the stumpage is amortized over the lower volume.

II

Kenai's challenge to amendment No. 7 in this court is based solely on the ground that the amendment violates the rule that material modifications may not be made to a contract let under a competitive bidding statute. This sale was made pursuant to AS 38.05.120 which requires that timber sales larger than 500,000 board feet be made by competitive bidding.[8] We alluded to the rule relied on by Kenai in *McKinnon v. Alpeter Co.*, 633 P.2d 281, 287 (Alaska 1981):

> [G]enerally a government contract that was initially competitively bid cannot be materially amended because that is tantamount to forming a new contract, which should be accomplished by starting all over again with competitive bidding.

This rule has been judicially imposed in order to guard against circumvention of competitive bidding requirements. Competitive bidding itself is designed to ensure that government obtains the most favorable terms possible in its contracts, and to protect the public from the possibility of favoritism, fraud, and corruption on the part of public officials. *Libby v. City of Dillingham*, 612 P.2d 35, 42 (Alaska 1980) (plurality opinion); *id.* at 44 (Rabinowitz, C. J., concurring).

[1] Under the terms of this contract, competitive bidding can only be effective to accomplish these purposes for the first five years of the contract. Thereafter, the price of the timber is to be determined by state appraisals. These appraisals are based on current market and cost conditions and are not indexed to the original bid price. Kenai has not challenged this aspect of the contract and we therefore assume it to be legal for the purposes of this case. Based on this assumption we believe that, with one exception which we will discuss later, the rule prohibiting material modifications of competitively bid contracts has no application to amendment No. 7. That rule could not operate to ensure that the state receive the best price possible because price under this contract is determined privately; nor could it prevent favoritism, fraud or corruption on the part of state officials for the same reason.[9]

The evidence in this case indicates that the primary manufacture requirement detracts from rather than adds to the value of the end product. Thus a prospective purchaser of state timber would be willing to pay a higher stumpage price if there were no such requirement. If, therefore, an amendment to the contract had been made eliminating primary processing within the initial five year period a persuasive argument could be made that the protections which are meant to be afforded by competitive bidding had been by-passed. However, once the initial period is over the competitively established price is no longer effective and the removal of the primary processing requirement is merely another market condition to be taken into account during reappraisal.

Essentially the same observations can be made with respect to the economic aspects of the change removing from the sale lands above 400 feet and substituting adjacent low lands. Kenai contends, quite plausibly, that the costs of harvest are less and the product value is higher in the newly substituted acreage than in the lands deleted from the sale. If those changes had been made during the first five years of the contract a legitimate question whether competitive bidding had been improperly circumvented would be presented. As it is, however, those changes are now simply new conditions to be reflected in each reappraisal.

[2] The one aspect of amendment No. 7 to which the rule prohibiting material changes potentially applies is the physical addition of timber land in partial substitution for the deleted acreage. The additional land has never been subject to the competitive bidding process. However, for the following reasons, the rule does not prohibit this change.

[3] Not all amendments to competitively bid contracts are prohibited, only those regarded as material. The concept of materiality in this context has not been satisfactorily captured in a single phrase. One court has spoken of "an essential change of such magnitude as to be incompatible with the general scheme" of competitive bidding;[11] another has phrased the question to be whether the amendment "so varied from the original plan, was of such importance, or so altered the essential identity purpose of the contract, that it con new undertaking."[12] These for simply recognize that the materi cept prohibits those changes whic be subversive of the purposes of tive bidding. In determining wh amendment has this tendency, co found the following factors to be tance:

(1) the legitimacy of the reason change;[13]

(2) whether the reasons for th were unforeseen at the time the was made;[14]

(3) the timing of the change;[15]

(4) whether the contract contain authorizing modifications;[16]

(5) the extent of the change, rel the original contract.[17]

Applying these factors to the sub of timber lands in this case lead conclusion that the substitution material for purposes of the rule ing material changes.

The reason for the change was Department of Fish and Game hav ered after the contract was awar the mountainside included in the contained important winter habi mountain goats. The Department fore requested that the sale be mod deleting this area. Since this would eliminate an area containin 40,000,000 board feet which the st contractually committed to South It was necessary in order to obt agreement of South-Central to pro stitute timberland

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8. AS 38.05.120 provides in relevant part:
Timber and other materials shall be sold either by sealed bids or public auction, depending on which method is determined by the commissioner to be in the best interests of the state, to the highest qualified bidder as determined by the director.
The 500 m.b.f. exception is expressed in AS 38.05.115.

9. This does not mean that the state officials are entirely free to modify long term timber sale contracts after the first reappraisal date has passed. As we have previously noted, 11 A.A.C. 76.156 prohibits contract amendments which "materially affect or change the meaning or intent of the contract." Kenai, however, did not brief in its opening brief the question whether amendment No. 7 violates this regulation and we therefore do not pass on this point. In its reply brief it made no more than a conclusory assertion that § 156 prohibits material modifications, with no analysis or citation of authority. Under these circumstances we consider this point to have been waived. *See Hitt v. J. B. Coghill, Inc.*, 641 P.2d 211, 213 n.4 (Alaska 1982); *State v. O'Neill Investigations, Inc.*, 609 P.2d 520, 528 (Alaska 1980).

10. *Morse v. City of Boston*, 253 Mass. 247, 148 N.E. 813, 815 (1925), *on later appeal*, 260 Mass. 255, 157 N.E. 523 (1927).

11. *Albert Elia Building Co., Inc. v. New York State Urban Development Corp.*, 54 A.D.2d 337, 388 N.Y.S.2d 462, 467 (1976).

12. *See Myers v. Wood*, 173 Mo.App. 564, 158 S.W. 909, 912 (1913).

13. *See Sekerez v. Lake County Board of Commissioners*, 345 N.E.2d 865, 868-69 (Ind.App. 1976); *Myers v. Wood*, 158 S.W. at 912.

14. *See Albert Elia Building Co., Inc. v. New York State Urban Development Corp.*, 388 N.Y.S.2d at 467.

15. *Myers v. Wood*, 158 S.W. at 913 [illegible] a clause authorizing modifications may so broadly read as to negate the statutory requirement of competitive bidding. *City of Boston*, 148 N.E. at 816.

16. *See Albert Elia Building Co., Inc. v. New York State Urban Development Corp.*, 388 N.Y.S.2d at 467.

This appears to be a legitimate rather than a pretextual reason for modifying the contract. It furthers the state's strong interest in maintaining or increasing existing population levels of game animals.[17] Nor was the importance of the deleted area as wildlife habitat appreciated when the original contract was made. There is nothing suspicious about the timing of the change since it was made more than nine years after the initial contract was entered into, and timber cutting had taken place under the contract for seven years with about 58% of the total estimated volume in the original sale having by then been cut.[18] While the contract does not specifically authorize replacing one timber area with another, the change here was relatively small, the substituted timber amounting to less than 7% of the total originally sold.

In a contract of this magnitude and duration it is to be expected that changes in circumstances will occur and that new perceptions concerning needed environmental protections will develop. A measure of flexibility is obviously required to be able to respond intelligently to the needs created by those changes. The substitution of timber here does not exceed permissible bounds.

III

The court awarded attorney's fees to South-Central of $40,000.00. Kenai challenges this as unreasonable, and contends further that no attorney's fees should have been awarded since this case is within the public interest exception to the rule that the prevailing party is entitled to an award of partial attorney's fees.[19]

[4, 5] The determination of court awarded attorney's fees is committed to the discretion of the trial court and reviewable on appeal only for an abuse of discretion. Such an abuse is regarded as present only where the trial court's decision appears to be manifestly unreasonable or motivated by an inappropriate purpose. *Alaska State Bank v. General Insurance Co.*, 579 P.2d 1362, 1370 (Alaska 1978). South-Central's attorneys expended some 845.8 hours in the defense of this case and South-Central paid them $75,624.00. The only argument made by Kenai that the court's award of $40,000.00 is unreasonable is that Kenai's actual attorney's fees were less than that sum. This, however, does not demonstrate that South-Central's attorneys' billings were unreasonable for opposing sides in a lawsuit do not necessarily have equal burdens. We therefore conclude that Kenai has not demonstrated that the court's award was manifestly unreasonable.

[6] We have recognized that in cases involving issues of genuine public interest an unsuccessful plaintiff should not be burdened with payment of a part of his opponent's attorney's fees under Civil Rule 82. *Thomas v. Bailey*, 611 P.2d 536, 539 (Alaska 1980); *Horowitz v. Alaska Bar Association*, 609 P.2d 39, 42 (Alaska 1980); *Gilbert v. State*, 526 P.2d 1131, 1136 (Alaska 1974). This exception has been made because of a fear that "awarding fees in this type of controversy will deter citizens from litigating questions of general public concern for fear of incurring the expense of the other party's attorney's fees." *Id.* at 1136. *Accord, Anchorage v. McCabe*, 568 P.2d 986, 990 (Alaska 1977).

In *Anchorage v. McCabe*, we identified three criteria useful in identifying public interest litigation:

(1) Is the case designed to effectuate strong public policies?

(2) If the plaintiff succeeds will numerous people receive benefits from the lawsuit?

(3) Can only a private party have been expected to bring the suit?

17. *See Frank v. State*, 604 P.2d 1065, 1073 (Alaska 1979); *State v. Tanana Valley Sportsmen's Ass'n*, 583 P.2d 854, 859 n.16 (Alaska 1978).

18. *See* p. 218 *supra*.

19. Kenai argues that the public interest it has sought to vindicate lies in protecting the integrity of the competitive bidding process.

568 P.2d at 991. *Accord, Thomas v. Bailey*, 611 P.2d at 539 n.7. The foregoing can arguably be answered favorably to Kenai in this case. However, our cases establish what can be regarded as a fourth criterion which excludes this case from the public interest exception.

In *Weaver Bros., Inc. v. Alaska Transportation Commission*, 588 P.2d 819, 823 (Alaska 1978); *Lynden Transport, Inc. v. State*, 532 P.2d 700, 717 (Alaska 1975), and *Mobil Oil Corp. v. Local Boundary Commission*, 518 P.2d 92, 104 (Alaska 1974), we upheld attorney's fees awards against parties who had raised important questions of public interest but did not prevail. In *Mobil* we stated:

> Because the sums at stake in this controversy are large enough to prompt a suit without consideration of the public interest, the superior court could have concluded that the property owners were acting in their private interests and not in behalf of the public.

Id. at 104. In *Lynden* we quoted with approval the foregoing language, 532 P.2d at 717, and in *Weaver Bros.* we stated, citing *Lynden* and *Mobil Oil*:

> [I]t appears to us that the competitive advantage sought by appellant in this litigation takes the case outside of the notion of public interest litigation.

588 P.2d at 823. Based on these authorities what we have called the fourth criterion may be expressed as whether the litigant claiming public interest status would have had sufficient economic incentive to bring the lawsuit even if it involved only narrow issues lacking general importance. Such a litigant is less apt than a party lacking this incentive to be deterred from bringing a good faith claim by the prospect of an adverse award of attorney's fees.

On this record, since Kenai was a competitor of South-Central and was seeking a continuing source of timber to process in its mill, the court could have concluded had sufficient economic reasons to lenge the amendment regardless grounds for the challenge. Under circumstances we decline to hold th award of attorney's fees to South-C was an abuse of discretion.

AFFIRMED.

RABINOWITZ, Chief Justice, diss

I do not agree with the court's ruli the state and South-Central were f eliminate the primary manufacture r ment of their timber sale contract. view the court places its imprimatu precisely the kind of modification to petitively bid contract that the judi imposed rule against material modifi is designed to prevent.

The Alaska legislature has decree an important state resource and asse ber, is to be disposed of only by comp bidding.[1] This legislative mandate underlying policies are rendered ineff if the state and South-Central may their competitively bid contract and tute in its stead a significantly dif agreement. On the record presented case I must conclude that the primary ufacture requirement was an imp term of the timber sale contract an waiver of that requirement wrought permissible material change in the co I so conclude for several reasons. Fir primary manufacture requirement w express condition of the state's requ bids, and the state candidly admits th requirement was "a significant part consideration for the State's agreeme sell timber to South-Central." Secon administrative regulation authorizing mary manufacture requirement in sale contracts[2] and the governor's statement urging primary manufa both of which were incorporated int contract between the state and South

1. AS 38.05.115, .120.

2. *See* Section 406.104 of the timber sale regulations, 11 AAC 76.130, the full text of which is reproduced at note 3 of the court's opinion.

3. This policy statement, which provides that "[r]ound logs may not be exporte marketable commodity," is set forth at of the court's opinion.

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tral, were undoubtedly designed to further the strong state interest in not exporting jobs in the often depressed forest products industry;[4] this state policy is subverted by elimination of the primary manufacture requirement. Third, Kenai Lumber plausibly suggests that the timber sale might have attracted different bidders and bids had the primary manufacture requirement not been included in the state's request for bids,[5] and the court concedes that such a requirement affects the price that potential bidders are willing to pay for state-owned timber. In light of these factors I am unable to agree that the state and South-Central were at liberty to waive the primary manufacture requirement of their competitively bid contract.

I further disagree with the majority's conclusion that the question of the materiality of the primary manufacture requirement need not be reached because the original contract authorized renegotiation of its terms after five years and at regular intervals thereafter. If the statutory competitive bidding requirements are to have any continuing viability, the parties to a competitive bid contract may not circumvent the legislature's mandate by including in their contract a provision which authorizes any and all modifications.[6] I recognize that the parties to a long-term contract for the sale of state-owned timber must be afforded a fair degree of latitude to make good faith modifications to their agreement in order to account for inevitable fluctuations in the market for timber and to respond to a myriad of factors which may not have been foreseeable at the time the timber was placed on bid. It does not follow, however, that the parties must be afforded unfettered license to rewrite their agreement; the judicially-imposed rule proscribing material modifications limits the power to alter a competitively bid contract and, in my view, that limit was exceeded when the state and South-Central removed the primary manufacture requirement from their contract.

4. I note also that both California and Oregon prohibit the export of state owned timber without primary manufacture. *See* Cal Pub.Res Code § 4650) (West Supp 1982); Or.Rev.Stat. § 526.805 (1979).

5. South-Central was the only bidder on the contract in question

6. The court recognizes that "a clause authorizing modification may not be so broadly read as to negate the statutory requirement of competitive bidding" but in my view fails to apply this rule to the state's and South-Central's power to alter their competitively bid contract.

Leslie NEWELL, Appellant,

v.

NATIONAL BANK OF ALASKA, Appellee.

No. 5437.

Supreme Court of Alaska.

June 18, 1982.

Plaintiff brought suit in connection with default on promissory note which purchasers had executed in favor of plaintiff when they purchased his mobile home. The Superior Court, Third Judicial District, Anchorage, James K. Singleton, J., granted summary judgment in favor of defendant bank, and plaintiff appealed. The Supreme Court, Dimond, Senior Justice, assigned, held that mobile home, which was moved once, from dealer's lot to mobile home park, was not within exemption in Motor Vehicle Act for vehicles which "crossed the highway," and therefore, was subject to registration under that Act, and filing and notation on certificate of title provisions of Act were exclusive method of perfecting security interest in mobile home.

Affirmed.

Burke, J., concurred in result.

Automobiles ⇐37

Mobile home, which was moved once, from dealer's lot to mobile home park, was not within exemption in Motor Vehicle Act for vehicles which "crossed the highway," and therefore, was subject to registration under that Act, and filing and notation on certificate of title provisions of Act were exclusive method of perfecting security interest in mobile home. AS 28.10.040, 28.10.040(1), 28.10.480, 28.10.510, 28.10.530 (Repealed).

M. Ashley Dickerson, Anchorage, for appellant.

Thomas R. Tulka, Anchorage, for appellee.

Before RABINOWITZ, C. J., CONNOR, BURKE and MATTHEWS, JJ., and DIMOND, Senior Justice.*

OPINION

DIMOND, Senior Justice.

Appellant Leslie Newell brought this action against Ray and Samantha Charlton, the National Bank of Alaska (NBA), and one other party in connection with the default by the Charltons on a promissory note which they had executed in favor of Newell when they purchased his mobile home or house trailer[1] in 1978. The suit against the Charltons sought judgment against them on the note, and asserted a lien against the mobile home which, Newell contended, served as security on the promissory note. NBA was later joined as a party in the suit when Newell learned that NBA also claimed a security interest in the mobile home.

The sole issue between Newell and NBA concerns which party has the superior security interest. NBA sought to perfect its interest by filing the requisite documents with the Motor Vehicle Division, according to the certificate of title provisions of the Motor Vehicle Code. Newell sought to perfect his interest by filing the promissory note with the Anchorage district recorder several months later.[2] Each party claims that its method of filing its respective security interest was the exclusive method of perfecting a security interest in the mobile home. Summary judgment was granted in favor of NBA, and Newell has appealed.

Perfection of security interests and priority of perfected interests in personal property and fixtures is generally governed by the provisions of the Uniform Commercial Code—Secured Transactions.[3] Under the UCC, the filing of a financing statement to perfect a security interest in property covered by the code would properly be made in the office of the recorder in the recording district of the debtor's residence, or in the case of fixtures, in the office where a mortgage on the real estate concerned would be filed or recorded. AS 45.09.401 (formerly AS 45.05.768).

There are certain exceptions to the filing provisions of the UCC. AS 45.09.302 (formerly AS 45.05.734) provides in part:

> (c) The filing provisions of AS 45.09.101–45.09.507 do not apply to a security interest in property subject to a statute

> . . .

> (2) of this state which provides for a central filing of, or which requires indication on a certificate of title of, the security interests in the property, unless the property is inventory held for sale by a dealer which has not been previously sold at retail and for which no certificate of title has been issued.

* Dimond, Senior Justice, sitting by assignment made pursuant to article IV, section 11 of the Constitution of Alaska, and Alaska R.Admin P. 23(a).

1. Newell, throughout his brief, refers to the mobile home as a trailer or house trailer.

2. Although the validity of Newell's security interest, a promissory note, was challenged by NBA in the superior court, this issue is not raised on appeal.

3. At the time of the transactions in question UCC—Secured Transactions was set out in AS 45.05.690—.794. The article has since been renumbered and is now AS 45.09.101–.507.

FIRST AMENDMENT TO THE NORTHSTAR UNIT LEASES BETWEEN THE STATE OF ALASKA AND BP EXPLORATION (ALASKA) INC.

The State of Alaska ("State") and BP Exploration (Alaska) Inc. ("BPXA") are parties to the following leases in the Northstar Unit: ADL 312798, effective February 1, 1980; ADL 312799, effective February 1, 1980; ADL 312808, effective February 1, 1980; and ADL 312809, effective February 1, 1980 (collectively the "1980 Leases"); as well as ADL 355001, effective August 1, 1983 (the "1983 Lease"). The parties agree to amend the 1980 Leases and the 1983 Lease as set forth in this first amendment to the Northstar Unit leases.

1980 Leases

1) Paragraph 6(b) is replaced in its entirety as follows:

(b) Annual rental paid in advance is a credit on the royalty or supplemental royalty due under this lease for that year.

2) Paragraph 7 is replaced in its entirety as follows:

7. SUPPLEMENTAL ROYALTY. (a) In addition to the royalty paid and computed under paragraphs 8, 10, and 11 below, Lessee shall pay to the State a supplemental royalty ("supplemental royalty"). Lessee shall pay the supplemental royalty, if owed, upon the same production volume for which royalty is paid ("production volume"). The supplemental royalty payment for a given month equals the supplemental royalty value times the supplemental royalty percentage rate ("percentage rate") times the production volume for that month. The percentage rate shall be calculated monthly by reference to: (1) an ANS West Coast spot price ("spot price"); and (2) a supplemental royalty trigger price ("trigger price"). If the spot price is equal to or less than the trigger price, then the percentage rate equals zero. If the spot price is greater than the trigger price, then the percentage rate equals [the spot price per barrel minus the

trigger price per barrel] times 1.5 per cent per dollar per barrel. The percentage rate may never exceed 7.5 per cent.

(b) The spot price is the price per barrel calculated in Article 3.3 of and Exhibit 4 to the ANS Royalty Litigation Settlement Agreement ("ANS Agreement"), dated December 31, 1991, between the State and BPXA, for the crude oil referred to as "ANS (USWC)" in the ANS Agreement. The trigger price is $17.35 per barrel through April 30, 1997. On May 1, 1997, and each May 1 thereafter, the trigger price shall be adjusted by an inflation factor equal to fifty percent of the "inflation rate" defined as the Producer Price Index for Industrial Commodities ("PPI") for December of the previous year, as reported by April 30 of the current year, divided by the PPI for December of 1995, as reported by April 30, 1996. The supplemental royalty value for oil, gas, natural gas liquids and associated substances is defined in paragraphs 10 and 11 below. Exhibit B is a sample calculation to demonstrate the method of calculating supplemental royalty for oil.

3) Paragraph 9 is replaced in its entirety as follows:

9. REDUCTION OF ROYALTY. Except as provided in paragraph 7 above, Lessee shall not be entitled to any reduction of royalty paid under paragraph 8 above or supplemental royalty paid under paragraph 7 above based on any current or future agreement, State statute, or State regulation.

4) Paragraph 10 is replaced in its entirety as follows:

10. ROYALTY IN VALUE. Unless the State elects to receive all or a portion of its royalty or supplemental royalty in kind as provided in paragraph 12 below, Lessee shall pay to the State the value of all royalty and supplemental royalty oil, gas and associated substances as determined under paragraph 11 below. Royalty and supplemental royalty paid in value shall be free and clear of all lease expenses (and any portion of such expenses which is incurred away from the leased area), including, but not limited to, expenses for separation, cleaning dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substances for transportation off the leased area. All royalty and supplemental royalty that may become payable in money to the State shall be paid on or before the last day of the calendar month following the month in which the oil, gas or associated substances are produced. Royalty and supplemental royalty payments shall be accompanied by copies of run tickets or such other information relating to valuation of royalty and supplemental royalty as the State may require, which may include, but is not limited to, evidence of sales, shipments, and amounts of gross oil, gas and associated substances produced.

5) Paragraph 11 is replaced in its entirety as follows:

11. VALUE. For purposes of computing supplemental royalty due under this lease. the value of supplemental royalty oil, gas, natural gas liquids and associated substances shall be the value used in computing royalty on said substances.

(a) To compute the value of oil for royalty and supplemental royalty purposes, this lease shall be deemed an "ANS Lease" under the terms of the ANS Agreement, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(b) To compute the value of gas and natural gas liquids for royalty and supplemental royalty purposes, this lease shall be deemed a "Lease" under the terms of the 1995 ANS Gas Royalty Litigation Settlement Agreement between BPXA and the State dated as of April 1, 1995, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(c) To compute the value of associated substances (which shall be deemed to exclude oil, gas, and natural gas liquids) for royalty and supplemental royalty purposes, the value of such associated substances shall not be less than the highest of:

(1) the field price actually received be Lessee for such associated substances;

(2) Lessee's posted price in the field for such associated substances;

(3) the volume weighted average field price actually received by other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area; or

(4) the volume weighted average posted price in the field of other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area.

If associated substances are sold away from the leased or unit area, the term "field price" above shall be the actual price for such associated substances received from the purchaser thereof less the actual cost of transportation away from the leased or unit area to the point of delivery.

Minimum Value Determinations. The State may establish minimum values for purposes of computing royalties on associated substances obtained from this lease, with consideration being given to the price actually received by Lessee, to the price or prices paid in the same field or area for production of like quality, to posted prices, to prices received by Lessee and/or other producers from

sales occurring away from the leased area, and to other relevant matters. Each such determination will be made only after Lessee has been given notice and a reasonable opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty associated substances under this lease may not necessarily equal the price of such associated substances.

6) The following provision shall be added to the end of paragraph 12:

(e) Supplemental royalty under paragraph 7 above may be taken in kind under the same terms and conditions as royalty may be taken in kind under this paragraph 12.

7) Paragraph 14 is replaced in its entirety as follows:

14. APPORTIONMENT OF ROYALTY FROM APPROVED UNIT. The landowner's royalty and supplemental royalty share of the unit production allocated to each separately owned tract shall be regarded as royalty to be distributed to and among, or the proceeds of it paid to, the landowners, free and clear of all unit expense and free of any lien for it. Under this provision, the State's royalty and supplemental royalty share of any unit production allocated to the leased area shall be regarded as royalty to be distributed to, or the proceeds of it paid to, the State, free and clear of all unit expenses (and any portion of such expenses which is incurred away from the unit area), including, but not limited to, expenses for separation, cleaning, dehydration, gathering, saltwater disposal, and preparing oil, gas or associated substances for transportation off the unit area, and free of any lien for it.

8) Paragraph 28 (c) is added as follows:

(c) Notwithstanding any other provisions of this lease, the Northstar Unit Agreement, State statute, or State regulation, this lease shall terminate automatically without notice, an opportunity to be heard, or judicial proceeding, if the Lessee fails to comply with the project schedule set forth in Exhibit C ("project schedule"), attached and incorporated by reference. Automatic termination shall occur whether or not there is a well on the leased area capable of producing oil or gas in paying quantities, the lease is committed to a unit agreement, or the Lessee is drilling or conducting reworking operations, on the date performance under the schedule is due. Furthermore, upon termination BPXA shall promptly file of record appropriate lease relinquishments. The automatic termination shall occur at 11:59 P.M., Alaska Time, on the day performance of an obligation under the project schedule is due. The State may waive performance of an obligation required under the project schedule by prior written consent. The performance of any obligation

required under the project schedule is subject to the provisions of paragraph 32.

9) Paragraph 32 is replaced in its entirety as follows:

32. FORCE MAJEURE. If the State determines that Lessee has been prevented, after diligent efforts made in good faith, from complying with any express or implied promise, term, condition or covenant of this lease, from conducting drilling operations, or from producing or marketing oil or gas from the leased area, by reason of war, riots, acts of God, unusually severe weather, or any other cause beyond Lessee's reasonable ability to foresee or control (including delays caused by judicial decision or lack thereof or inability to obtain local, State, or federal permits or environmental impact statements), whether similar to those enumerated or not, Lessee's obligation to comply with such provision shall be suspended, but not voided, and Lessee shall not be liable for damages for failure to comply therewith. If Lessee's obligations to conduct drilling or reworking operations are suspended under this paragraph and the continuation of such operations without suspension would have had the effect of preventing the expiration or termination of this lease, this lease shall not terminate during the period which the obligation to perform such operations is suspended. Nothing in this paragraph shall be construed to suspend the obligation to pay rentals, or to suspend the obligation to pay royalties, supplemental royalties or other production payments from operations on the lease area which are not suspended or from operations which are not affected by any such suspension, to the State.

10) Paragraph 41 is replaced in its entirety as follows:

41. EMPLOYMENT OF ALASKAN RESIDENTS. Lessee shall comply with all valid federal, State and local laws in hiring Alaska residents and contractors and shall not discriminate against Alaska residents or contractors. Within the constraints of law, Lessee shall employ Alaska residents and contractors to the extent they are available and qualified. Subject to the foregoing:

Lessee voluntarily agrees to adopt a program to hire residents of Alaska. Lessee shall advertise for available positions locally and use Alaska job service organizations to notify the Alaskan public. For work in connection with this lease, Lessee shall use best efforts to contract with Alaska firms and fabricate modules in Alaska, whenever feasible. Lessee shall encourage its contractors to employ and train, when necessary, residents of Alaska. In determining feasibility, Lessee shall consider commercial, health, safety, and environmental conditions and requirements to ensure maintenance of Lessee's operational standards. Lessee shall submit annually to the Director, Division of Oil and Gas, for transmission to the Department of

Labor. a report that details the specific measures Lessee and its contractors and subcontractors have taken or are planning to take to recruit qualified Alaska residents for available jobs, describes on-the-job training opportunities, and describes Lessee's efforts to hire Alaska firms for work in connection to this lease. Lessee shall furnish the Department of Labor a quarterly report regarding the employment of Alaska residents on the leased area in compliance with regulations by the Commissioner of Labor. The report must also include statistical data concerning the number of resident personnel hired within the past year for this lease.

1983 Lease

1) Paragraph 4(f) and paragraph 34(7) are deleted and replaced in their entirety with the following paragraph 4(f):

(f) FORCE MAJEURE. If the state determines that lessee has been prevented, after diligent efforts made in good faith, from complying with any express or implied promise, term, condition or covenant of this lease, from conducting drilling operations, or from producing or marketing oil or gas from the leased area, by reason of war, riots, acts of God, unusually severe weather, or any other cause beyond lessee's reasonable ability to foresee or control (including delays caused by judicial decision or lack thereof or inability to obtain local, state, or federal permits or environmental impact statements), whether similar to those enumerated or not, lessee's obligation to comply with such provision shall be suspended, but not voided, and lessee shall not be liable for damages for failure to comply therewith. If lessee's obligations to conduct drilling or reworking operations are suspended under this paragraph and the continuation of such operations without suspension would have had the effect of preventing the expiration or termination of this lease, this lease shall not terminate during the period which the obligation to perform such operations is suspended. Nothing in this paragraph shall be construed to suspend the obligation to pay rentals, or to suspend the obligation to pay royalties, supplemental royalties or other production payments from operations on the lease area which are not suspended or from operations which are not affected by any such suspension, to the state.

2) Paragraph 5(b) is replaced in its entirety as follows:

(b) Annual rental paid in advance is a credit on the royalty or supplemental royalty due under this lease for that year.

3) Paragraph 7 is replaced in its entirety as follows:

7. APPORTIONMENT OF ROYALTY FROM APPROVED UNIT. The state's royalty and supplemental royalty share of the unit production allocated to each separately owned tract must be regarded as royalty to be distributed to or among, or the proceeds of it paid to, the state, free and clear of all unit expenses and free of any lien for them. Under this provision, the state's royalty and supplemental royalty share of any unit production allocated to the leased area will be regarded as royalty to be distributed to, or the proceeds of it paid to, the state, free and clear of all unit expenses (and any portion of those expenses incurred away from the unit area), including, but not limited to, expenses for separating, cleaning, dehydration, gathering, saltwater disposal, and preparing oil, gas, or associated substances for transportation off the unit area, and free of any lien for them.

4) A new paragraph 20(c) is added as follows:

(c) Notwithstanding any other provisions of this lease, the Northstar Unit Agreement, state statute, or state regulation, this lease shall terminate automatically without notice, an opportunity to be heard, or judicial proceeding, if the lessee fails to comply with the project schedule set forth in Exhibit C ("project schedule"), attached and incorporated by reference. Automatic termination shall occur whether or not there is a well on the leased area capable of producing oil or gas in paying quantities, the lease is committed to a unit agreement, or the lessee is drilling or conducting reworking operations, on the date performance under the schedule is due. Furthermore, upon termination BPXA shall promptly file of record appropriate lease relinquishments. The automatic termination shall occur at 11:59 P.M., Alaska Time, on the day performance of an obligation under the project schedule is due. The state may waive performance of an obligation required under the project schedule by prior written consent. The performance of any obligation required under the project schedule is subject to the provisions of paragraph 4(f).

5) Paragraph 31 is replaced in its entirety as follows:

31. EMPLOYMENT OF ALASKAN RESIDENTS. Lessee shall comply with all valid federal, state and local laws in hiring Alaska residents and contractors and shall not discriminate against Alaska residents or contractors. Within the constraints of law, lessee shall employ Alaska residents and contractors to the extent they are available and qualified. Subject to the foregoing:

Lessee voluntarily agrees to adopt a program to hire residents of Alaska. Lessee shall advertise for available positions locally and use Alaska job

service organizations to notify the Alaskan public. For work in connection with this lease, lessee shall use best efforts to contract with Alaska firms and fabricate modules in Alaska, whenever feasible. Lessee shall encourage its contractors to employ and train, when necessary, residents of Alaska. In determining feasibility, lessee shall consider commercial, health, safety, and environmental conditions and requirements to ensure maintenance of lessee's operational standards. Lessee shall submit annually to the Director, Division of Oil and Gas, for transmission to the Department of Labor, a report that details the specific measures lessee and its contractors and subcontractors have taken or are planning to take to recruit qualified Alaska residents for available jobs, describes on-the-job training opportunities, and describes lessee's efforts to hire Alaska firms for work in connection to this lease. Lessee shall furnish the Department of Labor a quarterly report regarding the employment of Alaska residents on the leased area in compliance with regulations by the Commissioner of Labor. The report must also include statistical data concerning the number of resident personnel hired within the past year for this lease.

6) Paragraph 35 is replaced in its entirety as follows:

35. ROYALTY ON PRODUCTION. Except for oil, gas, and associated substances used on the leased area for development and production or unavoidably lost, the lessee shall pay to the state as a royalty 20 percent in amount or value of the oil, gas, and associated substances saved, removed, or sold from the leased area and of the gas used on the leased area for extraction of natural gasoline or other products from the leased area.

7) Paragraph 36 is replaced in its entirety as follows:

36. VALUE. For purposes of computing supplemental royalty due under this lease, the value of supplemental royalty oil, gas, natural gas liquids, and associated substances shall be the value used in computing royalty on said substances.

(a) To compute the value of oil for royalty and supplemental royalty purposes, this lease shall be deemed an "ANS Lease" under the terms of the ANS Agreement, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(b) To compute value of gas and natural gas liquids for royalty and supplemental royalty purposes, this lease shall be deemed a "Lease" under the terms of the 1995 ANS Gas Royalty Litigation Settlement Agreement between BPXA and the State dated as of April 1, 1995, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(c) To compute the value of associated substances (which shall be deemed to exclude oil, gas, and natural gas liquids) for royalty and supplemental royalty purposes, the value of such associated substances shall not be less than the highest of:

(1) the field price actually received be lessee for such associated substances:

(2) Lessee's posted price in the field for such associated substances;

(3) the volume weighted average field price actually received by other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area; or

(4) the volume weighted average posted price in the field of other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area.

If associated substances are sold away from the leased or unit area, the term "field price" above shall be the actual price for such associated substances received from the purchaser thereof less the actual cost of transportation away from the leased or unit area to the point of delivery.

Minimum Value Determinations. The state may establish minimum values for purposes of computing royalties on associated substances obtained from this lease, with consideration being given to the price actually received by lessee, to the price or prices paid in the same field or area for production of like quality, to posted prices, to prices received by lessee and/or other producers from sales occurring away from the leased area, and to other relevant matters. Each such determination will be made only after lessee has been given notice and a reasonable opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty associated substances under this lease may not necessarily equal the price of such associated substances.

8) Paragraph 37 is replaced in its entirety as follows:

37. ROYALTY IN VALUE. Unless the state elects to receive all or a portion of its royalty or supplemental royalty in kind as provided in paragraph 38, lessee shall pay to the state the value of all royalty and supplemental royalty oil, gas and associated substances as determined under paragraph 36. Royalty and supplemental royalty paid in value shall be free and clear of all lease expenses (and any portion of such expenses which is incurred away from the leased area), including, but not limited to, expenses for separation, cleaning

dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substances for transportation off the leased area. All royalty and supplemental royalty that may become payable in money to the state shall be paid on or before the last day of the calendar month following the month in which the oil, gas or associated substances are produced. Royalty and supplemental royalty payments shall be accompanied by copies of run tickets or such other information relating to valuation of royalty and supplemental royalty as the state may require, which may include, but is not limited to, evidence of sales, shipments, and amounts of gross oil, gas and associated substances produced.

9) The following provision shall be added to the end of paragraph 38:

(f) Supplemental royalty under this lease may be taken in kind under the same terms and conditions as royalty may be taken in kind under this paragraph 38.

10) Paragraph 39 is replaced in its entirety as follows:

39. REDUCTION OF ROYALTY. Except as provided in paragraph 40 below, lessee shall not be entitled to any reduction of royalty paid under paragraph 35 above or supplemental royalty paid under paragraph 40 below based on any current or future agreement, state statute, or state regulation.

11) Paragraph 40 is replaced in its entirety as follows:

40. SUPPLEMENTAL ROYALTY. (a) In addition to the royalty paid and computed under paragraph 35, 36, 37 above, lessee shall pay to the state a supplemental royalty ("supplemental royalty"). Lessee shall pay the supplemental royalty, if owed, upon the same production volume for which royalty is paid ("production volume"). The supplemental royalty payment for a given month equals the supplemental royalty value times the supplemental royalty percentage rate ("percentage rate") times the production volume for that month. The percentage rate shall be calculated monthly by reference to: (1) an ANS West Coast spot price ("spot price"); and (2) a supplemental royalty trigger price ("trigger price"). If the spot price is equal to or less than the trigger price, then the percentage rate equals zero. If the spot price is greater than the trigger price, then the percentage rate equals [the spot price per barrel minus the trigger price per barrel] times 1.5 per cent per dollar per barrel. The percentage rate may never exceed 7.5 per cent.

(b) The spot price is the price per barrel calculated in Article 3.3 of and Exhibit 4 to the ANS Royalty Litigation Settlement Agreement ("ANS Agreement"), dated December 31, 1991, between the State and BPXA, for the crude oil referred to

as "ANS (USWC)" in the ANS Agreement. The trigger price is $17.35 per barrel through April 30, 1997. On May 1, 1997, and each May 1 thereafter, the trigger price shall be adjusted by an inflation factor equal to fifty percent of the "inflation rate" defined as the Producer Price Index for Industrial Commodities ("PPI") for December of the previous year, as reported by April 30 of the current year, divided by the PPI for December of 1995, as reported by April 30, 1996. The supplemental royalty value for oil, gas, natural gas liquids and associated substances is defined in paragraphs 36 and 37 above. Exhibit B is a sample calculation to demonstrate the method of calculating supplemental royalty for oil.

These amendments do not affect: (1) any future agreements which may be reached for the handling of outside substances as that term is used in the Northstar Unit Agreement effective January 24, 1990 or (2) the current valuation methodology for royalty for any other Alaska Net Profit Share leases between the State and BPXA or any affiliates or any future agreements which may be reached regarding a future valuation methodology for Alaska Net Profit Share leases. These amendments take effect when and if an Act(s) substantially similar to the act, attached as Exhibit D and incorporated by reference, takes effect. This amendment is dated for reference purposes as of March 22, 1996.

LESSEE:

BP EXPLORATION (ALASKA), INC.

E. M. Luttrell, Vice President

LESSOR:

STATE OF ALASKA

John T. Shively, Commissioner
Department of Natural Resources

STATE OF ALASKA)
) ss.
Third Judicial District)

On March 22, 1996, before me appeared John T. Shively, Commissioner, State of Alaska, Department of Natural Resources, and who executed this lease and acknowledged voluntarily signing it on behalf of the State of Alaska, as lessor.

Dianne A. Pitts

Notary Public in and for the State of Alaska
My Commission Expires: 1/16/99

DIANNE A. PITTS NOTARY PUBLIC STATE OF ALASKA

STATE OF ALASKA)
) ss.
Third Judicial District)

On March 22, 1996, before me appeared E. M. Lutrell, Vice President of BP Exploration (Alaska), Inc., and who executed this lease and acknowledged voluntarily signing it on behalf of the BP Exploration (Alaska), Inc., as lessee.

Dianne A. Pitts

Notary Public in and for the State of Alaska
My Commission Expires: 1/16/99

DIANNE A. PITTS NOTARY PUBLIC STATE OF ALASKA

Exhibit B
Calculation of the Supplemental Royalty Payment for Oil

1) The calculation of the ANS West Coast spot price is derived from Platt's "Oilgram Price Report" Spot Crude Price Assessments:

Date	Platt's Reported Daily Assessment ($/barrel) ANSWC Low	ANSWC High	ANSWC Daily Average	ANSWC Daily Average (After Rounding)[1]
01/02/96	$17.97	$18.06	$18.015	$18.02
01/03/96	$17.94	$18.03	$17.985	$17.98
01/04/96	$17.96	$18.03	$17.995	$18.00
01/05/96	$18.60	$18.64	$18.620	$18.62
01/09/96	$18.23	$18.29	$18.260	$18.26
01/10/96	$17.99	$18.05	$18.020	$18.02
01/11/96	$17.10	$17.17	$18.135	$17.14
01/12/96	$16.64	$16.71	$18.675	$16.68
01/15/96	$16.75	$16.83	$16.690	$16.79
01/16/96	$16.60	$16.66	$16.730	$16.63
01/17/96	$16.91	$16.97	$16.940	$16.94
01/18/96	$17.46	$17.54	$17.500	$17.50
01/19/96	$17.28	$17.37	$17.325	$17.32
01/22/96	$17.02	$17.08	$17.050	$17.05
01/23/96	$17.10	$17.16	$17.150	$17.13
01/24/96	$17.35	$17.41	$17.380	$17.38
01/25/96	$16.76	$16.81	$17.785	$16.78
01/26/96	$16.43	$16.53	$17.480	$16.48
01/29/96	$16.16	$16.24	$16.200	$16.20
01/30/96	$16.30	$16.38	$16.340	$16.34
01/31/96	$16.46	$16.56	$16.510	$16.51

Monthly Average calculated from ANSWC Daily Average (After Rounding) = $17.2271 per barrel

ANS West Coast spot price for the January 1996 month of production = $17.23 per barrel

2) The inflation factor shall be calculated as follows: Assume that by April 30, 1996, the U.S. Department of Labor reports a PPI for December 1995 as 126.2. Assume that by April 30, 1998, the PPI for December 1997 is 134.2. The inflation factor for 1998 is calculated according to the following formula:

[1] All source and calculated numbers shall be rounded as required in the ANS Agreement.

Inflation Factor for May 1, 1998 through April 30, 1999
= [(PPI December of the previous year ÷ PPI December 1995) - 1] x 0.5

= [(134.2 ÷ 126.2) - 1] x 0.5 = 0.0317 = 3.17 percent

3) The trigger price for May 1, 1998 through April 30, 1999 is calculated by adjusting $17.35 per barrel by the inflation factor as follows:

Trigger price for the current year = $17.35 per barrel x (1 + inflation factor)

= $17.35 per barrel x (1+ 3.17 percent)

= $17.35 x 1.0317

= $17.90 per barrel

4) Assuming the current month ANSWC spot price is $21.40, the supplemental royalty percentage rate is calculated as:

Supplemental royalty percentage rate = (ANSWC spot price - trigger price for the current year) x (1.5 percent per dollar per barrel)

= ($21.40 per barrel - $17.90 per barrel) x 1.5 percent per dollar per barrel

= (21.40 -17.90) x 0.015

= 0.05250 = 5.25 percent

5) The calculation of the supplemental royalty payment for the current month is the product of the production volume times the royalty value and the supplemental royalty percentage rate. Assume that 1,550,000 barrels of oil were produced in the Northstar unit in the current month and that the royalty value is $17.71. The supplemental royalty is:

Supplemental royalty payment = production volume x royalty value x supplemental royalty percentage rate

= 1,550,000 barrels x $17.71 per barrel x 5.25 percent

= $1,441,151.25

EXHIBIT C

PROJECT SCHEDULE

The Northstar Development Project ("the Project") is described in the document titled "Northstar Development Project, Conceptual Engineering Report" dated February 1996. BPXA shall comply with the following schedule for the Project and shall provide satisfactory evidence of compliance within fifteen days of the date performance is due under the schedule:

BPXA shall receive Project sanction within twelve (12) months after passage by the legislature of an Act approving the First Amendments to the Northstar Unit Leases for the Project. "Project sanction" means approval in writing by the highest appropriate authority in BPXA or its parent entity necessary for the total amount of expenditures required for the Project. Satisfactory evidence of receipt of sanction shall be tendered to the State in the form of the sanctioning entity's documents approving the expenditure of funds for the Project. If Project sanction is withdrawn for any reason whatsoever, BPXA shall notify the State within three working days by letter from an authorized officer and BPXA shall be deemed to have failed to comply with this schedule.

EXHIBIT D

ACT

____ BILL NO.

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINETEENTH LEGISLATURE - SECOND SESSION

BY THE ____ RULES COMMITTEE BY REQUEST OF THE GOVERNOR

Introduced:
Referred:

A BILL

FOR AN ACT ENTITLED

"An Act authorizing, approving, and ratifying the amendment of Northstar Unit oil and gas leases between the State of Alaska and BP Exploration (Alaska) Inc.; and providing for an effective date."

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

* Section 1. The legislature finds that

(1) the production of oil and gas from state land is a matter of statewide interest and effect because it is an important source of revenue to the state and job opportunities for the people of the state;

(2) BP Exploration (Alaska) Inc. holds state oil and gas leases in the Northstar Unit that include net profit share provisions;

(3) with the current and projected price of oil, BP Exploration (Alaska) Inc. maintains that the net profit share provisions of the Northstar Unit leases prevent the timely development of the unit;

(4) existing law set out in AS 38.05 does not provide the commissioner of the

NEW TEXT UNDERLINED [DELETED TEXT BRACKETED]

Department of Natural Resources with sufficient express authority to amend the net profit share provisions of the Northstar Unit leases held by BP Exploration (Alaska) Inc.;

(5) unless the net profit share provisions of the Northstar Unit leases are amended, production of oil and gas from the unit is unlikely to begin until the year 2002;

(6) the Department of Revenue currently forecasts that production will not begin from the unit until the year 2002;

(7) if the net profit share provisions of the Northstar Unit leases are amended, full production of oil and gas from the unit may begin as early as the year 1999;

(8) amending the net profit share provisions of the Northstar Unit leases to provide for a supplemental royalty will maximize the economic benefits of oil and gas production to the people of the state by encouraging timely production from the unit;

(9) the development of the unit and the associated construction of unit facilities within the state will provide additional revenue to the state and increased job opportunities;

(10) BP Exploration (Alaska) Inc. has committed to use its best efforts to hire Alaska residents and contractors and to fabricate modules for the unit in Alaska;

(11) the timely development of the unit may result in increased state revenue in future lease sales;

(12) the timely development of the unit may result in technological breakthroughs and other cost savings that may make other development opportunities in Alaska economically feasible; and

(13) the development of the unit will include the first truly offshore Arctic Island construction and Arctic subsea pipeline for oil.

* Sec. 2. (a) The State of Alaska and BP Exploration (Alaska) Inc. are parties to the following leases in the Northstar Unit:

(1) ADL 312798, effective February 1, 1980;

(2) ADL 312799, effective February 1, 1980;

(3) ADL 312808, effective February 1, 1980;

(4) ADL 312809, effective February 1, 1980; and

(5) ADL 355001, effective August 1, 1983.

(b) The commissioner of the Department of Natural Resources may amend the Northstar Unit leases described in (a) of this section to the extent set out in the "First

DRAFT DRAFT - DEPARTMENT OF LAW DRAFT

Amendment to the Northstar Unit Leases Between the State of Alaska and BP Exploration (Alaska) Inc.", dated March ___, 1996.

(c) Notwithstanding any other provision of law, the "First Amendment to the Northstar Unit Leases Between the State of Alaska and BP Exploration (Alaska) Inc.", dated March ___, 1996, is approved and ratified.

* Sec. 3. This Act takes effect immediately under AS 01.10.070(c).

FIRST AMENDMENT TO THE NORTHSTAR UNIT LEASES BETWEEN THE STATE OF ALASKA AND BP EXPLORATION (ALASKA) INC.

The State of Alaska ("State") and BP Exploration (Alaska) Inc. ("BPXA") are parties to the following leases in the Northstar Unit: ADL 312798, effective February 1, 1980; ADL 312799, effective February 1, 1980; ADL 312808, effective February 1, 1980; and ADL 312809, effective February 1, 1980 (collectively the "1980 Leases"); as well as ADL 355001, effective August 1, 1983 (the "1983 Lease"). The parties agree to amend the 1980 Leases and the 1983 Lease as set forth in this first amendment to the Northstar Unit leases.

1980 Leases

1) Paragraph 6(b) is replaced in its entirety as follows:

(b) Annual rental paid in advance is a credit on the royalty or supplemental royalty due under this lease for that year.

2) Paragraph 7 is replaced in its entirety as follows:

7. SUPPLEMENTAL ROYALTY. (a) In addition to the royalty paid and computed under paragraphs 8, 10, and 11 below, Lessee shall pay to the State a supplemental royalty ("supplemental royalty"). Lessee shall pay the supplemental royalty, if owed, upon the same production volume for which royalty is paid ("production volume"). The supplemental royalty payment for a given month equals the supplemental royalty value times the supplemental royalty percentage rate ("percentage rate") times the production volume for that month. The percentage rate shall be calculated monthly by reference to: (1) an ANS West Coast spot price ("spot price"); and (2) a supplemental royalty trigger price ("trigger price"). If the spot price is equal to or less than the trigger price, then the percentage rate equals zero. If the spot price is greater than the trigger price, then the percentage rate equals [the spot price per barrel minus the

trigger price per barrel] times 1.5 per cent per dollar per barrel. The percentage rate may never exceed 7.5 per cent.

(b) The spot price is the price per barrel calculated in Article 3.3 of and Exhibit 4 to the ANS Royalty Litigation Settlement Agreement ("ANS Agreement"), dated December 31, 1991, between the State and BPXA, for the crude oil referred to as "ANS (USWC)" in the ANS Agreement. The trigger price is $17.35 per barrel through April 30, 1997. On May 1, 1997, and each May 1 thereafter, the trigger price shall be adjusted by an inflation factor equal to fifty percent of the "inflation rate" defined as the Producer Price Index for Industrial Commodities ("PPI") for December of the previous year, as reported by April 30 of the current year, divided by the PPI for December of 1995, as reported by April 30, 1996. The supplemental royalty value for oil, gas, natural gas liquids and associated substances is defined in paragraphs 10 and 11 below. Exhibit B is a sample calculation to demonstrate the method of calculating supplemental royalty for oil.

3) Paragraph 9 is replaced in its entirety as follows:

9. REDUCTION OF ROYALTY. Except as provided in paragraph 7 above, Lessee shall not be entitled to any reduction of royalty paid under paragraph 8 above or supplemental royalty paid under paragraph 7 above based on any current or future agreement, State statute, or State regulation.

4) Paragraph 10 is replaced in its entirety as follows:

10. ROYALTY IN VALUE. Unless the State elects to receive all or a portion of its royalty or supplemental royalty in kind as provided in paragraph 12 below, Lessee shall pay to the State the value of all royalty and supplemental royalty oil, gas and associated substances as determined under paragraph 11 below. Royalty and supplemental royalty paid in value shall be free and clear of all lease expenses (and any portion of such expenses which is incurred away from the leased area), including, but not limited to, expenses for separation, cleaning dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substances for transportation off the leased area. All royalty and supplemental royalty that may become payable in money to the State shall be paid on or before the last day of the calendar month following the month in which the oil, gas or associated substances are produced. Royalty and supplemental royalty payments shall be accompanied by copies of run tickets or such other information relating to valuation of royalty and supplemental royalty as the State may require, which may include, but is not limited to, evidence of sales, shipments, and amounts of gross oil, gas and associated substances produced.

5) Paragraph 11 is replaced in its entirety as follows:

11. VALUE. For purposes of computing supplemental royalty due under this lease, the value of supplemental royalty oil, gas, natural gas liquids and associated substances shall be the value used in computing royalty on said substances.

(a) To compute the value of oil for royalty and supplemental royalty purposes, this lease shall be deemed an "ANS Lease" under the terms of the ANS Agreement, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(b) To compute the value of gas and natural gas liquids for royalty and supplemental royalty purposes, this lease shall be deemed a "Lease" under the terms of the 1995 ANS Gas Royalty Litigation Settlement Agreement between BPXA and the State dated as of April 1, 1995, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(c) To compute the value of associated substances (which shall be deemed to exclude oil, gas, and natural gas liquids) for royalty and supplemental royalty purposes, the value of such associated substances shall not be less than the highest of:

(1) the field price actually received be Lessee for such associated substances;

(2) Lessee's posted price in the field for such associated substances;

(3) the volume weighted average field price actually received by other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area; or

(4) the volume weighted average posted price in the field of other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area.

If associated substances are sold away from the leased or unit area, the term "field price" above shall be the actual price for such associated substances received from the purchaser thereof less the actual cost of transportation away from the leased or unit area to the point of delivery.

Minimum Value Determinations. The State may establish minimum values for purposes of computing royalties on associated substances obtained from this lease, with consideration being given to the price actually received by Lessee, to the price or prices paid in the same field or area for production of like quality, to posted prices, to prices received by Lessee and/or other producers from

sales occurring away from the leased area, and to other relevant matters. Each such determination will be made only after Lessee has been given notice and a reasonable opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty associated substances under this lease may not necessarily equal the price of such associated substances.

6) The following provision shall be added to the end of paragraph 12:

(e) Supplemental royalty under paragraph 7 above may be taken in kind under the same terms and conditions as royalty may be taken in kind under this paragraph 12.

7) Paragraph 14 is replaced in its entirety as follows:

14. APPORTIONMENT OF ROYALTY FROM APPROVED UNIT. The landowner's royalty and supplemental royalty share of the unit production allocated to each separately owned tract shall be regarded as royalty to be distributed to and among, or the proceeds of it paid to. the landowners, free and clear of all unit expense and free of any lien for it. Under this provision, the State's royalty and supplemental royalty share of any unit production allocated to the leased area shall be regarded as royalty to be distributed to, or the proceeds of it paid to. the State, free and clear of all unit expenses (and any portion of such expenses which is incurred away from the unit area), including, but not limited to, expenses for separation, cleaning, dehydration, gathering, saltwater disposal, and preparing oil, gas or associated substances for transportation off the unit area, and free of any lien for it.

8) Paragraph 28 (c) is added as follows:

(c) Notwithstanding any other provisions of this lease, the Northstar Unit Agreement, State statute, or State regulation, this lease shall terminate automatically without notice, an opportunity to be heard, or judicial proceeding, if the Lessee fails to comply with the project schedule set forth in Exhibit C ("project schedule"), attached and incorporated by reference. Automatic termination shall occur whether or not there is a well on the leased area capable of producing oil or gas in paying quantities, the lease is committed to a unit agreement, or the Lessee is drilling or conducting reworking operations, on the date performance under the schedule is due. Furthermore, upon termination BPXA shall promptly file of record appropriate lease relinquishments. The automatic termination shall occur at 11.59 P.M., Alaska Time, on the day performance of an obligation under the project schedule is due. The State may waive performance of an obligation required under the project schedule by prior written consent. The performance of any obligation

required under the project schedule is subject to the provisions of paragraph 32.

9) Paragraph 32 is replaced in its entirety as follows:

32. FORCE MAJEURE. If the State determines that Lessee has been prevented, after diligent efforts made in good faith, from complying with any express or implied promise, term, condition or covenant of this lease, from conducting drilling operations, or from producing or marketing oil or gas from the leased area, by reason of war, riots, acts of God, unusually severe weather, or any other cause beyond Lessee's reasonable ability to foresee or control (including delays caused by judicial decision or lack thereof or inability to obtain local, State, or federal permits or environmental impact statements), whether similar to those enumerated or not, Lessee's obligation to comply with such provision shall be suspended, but not voided, and Lessee shall not be liable for damages for failure to comply therewith. If Lessee's obligations to conduct drilling or reworking operations are suspended under this paragraph and the continuation of such operations without suspension would have had the effect of preventing the expiration or termination of this lease, this lease shall not terminate during the period which the obligation to perform such operations is suspended. Nothing in this paragraph shall be construed to suspend the obligation to pay rentals, or to suspend the obligation to pay royalties, supplemental royalties or other production payments from operations on the lease area which are not suspended or from operations which are not affected by any such suspension, to the State.

10) Paragraph 41 is replaced in its entirety as follows:

41. EMPLOYMENT OF ALASKAN RESIDENTS. Lessee shall comply with all valid federal, State and local laws in hiring Alaska residents and contractors and shall not discriminate against Alaska residents or contractors. Within the constraints of law, Lessee shall employ Alaska residents and contractors to the extent they are available and qualified. Subject to the foregoing:

Lessee voluntarily agrees to adopt a program to hire residents of Alaska. Lessee shall advertise for available positions locally and use Alaska job service organizations to notify the Alaskan public. For work in connection with this lease, Lessee shall use best efforts to contract with Alaska firms and fabricate modules in Alaska, whenever feasible. Lessee shall encourage its contractors to employ and train, when necessary, residents of Alaska. In determining feasibility, Lessee shall consider commercial, health, safety, and environmental conditions and requirements to ensure maintenance of Lessee's operational standards. Lessee shall submit annually to the Director, Division of Oil and Gas, for transmission to the Department of

Labor, a report that details the specific measures Lessee and its contractors and subcontractors have taken or are planning to take to recruit qualified Alaska residents for available jobs, describes on-the-job training opportunities, and describes Lessee's efforts to hire Alaska firms for work in connection to this lease. Lessee shall furnish the Department of Labor a quarterly report regarding the employment of Alaska residents on the leased area in compliance with regulations by the Commissioner of Labor. The report must also include statistical data concerning the number of resident personnel hired within the past year for this lease.

1983 Lease

1) Paragraph 4(f) and paragraph 34(7) are deleted and replaced in their entirety with the following paragraph 4(f):

(f) FORCE MAJEURE. If the state determines that lessee has been prevented, after diligent efforts made in good faith, from complying with any express or implied promise, term, condition or covenant of this lease, from conducting drilling operations, or from producing or marketing oil or gas from the leased area, by reason of war, riots, acts of God, unusually severe weather, or any other cause beyond lessee's reasonable ability to foresee or control (including delays caused by judicial decision or lack thereof or inability to obtain local, state, or federal permits or environmental impact statements), whether similar to those enumerated or not, lessee's obligation to comply with such provision shall be suspended, but not voided, and lessee shall not be liable for damages for failure to comply therewith. If lessee's obligations to conduct drilling or reworking operations are suspended under this paragraph and the continuation of such operations without suspension would have had the effect of preventing the expiration or termination of this lease, this lease shall not terminate during the period which the obligation to perform such operations is suspended. Nothing in this paragraph shall be construed to suspend the obligation to pay rentals, or to suspend the obligation to pay royalties, supplemental royalties or other production payments from operations on the lease area which are not suspended or from operations which are not affected by any such suspension, to the state.

2) Paragraph 5(b) is replaced in its entirety as follows:

(b) Annual rental paid in advance is a credit on the royalty or supplemental royalty due under this lease for that year.

3) Paragraph 7 is replaced in its entirety as follows:

7. APPORTIONMENT OF ROYALTY FROM APPROVED UNIT. The state's royalty and supplemental royalty share of the unit production allocated to each separately owned tract must be regarded as royalty to be distributed to or among, or the proceeds of it paid to, the state, free and clear of all unit expenses and free of any lien for them. Under this provision, the state's royalty and supplemental royalty share of any unit production allocated to the leased area will be regarded as royalty to be distributed to, or the proceeds of it paid to, the state, free and clear of all unit expenses (and any portion of those expenses incurred away from the unit area), including, but not limited to, expenses for separating, cleaning, dehydration, gathering, saltwater disposal, and preparing oil, gas, or associated substances for transportation off the unit area, and free of any lien for them.

4) A new paragraph 20(c) is added as follows:

(c) Notwithstanding any other provisions of this lease, the Northstar Unit Agreement, state statute, or state regulation, this lease shall terminate automatically without notice, an opportunity to be heard, or judicial proceeding, if the lessee fails to comply with the project schedule set forth in Exhibit C ("project schedule"), attached and incorporated by reference. Automatic termination shall occur whether or not there is a well on the leased area capable of producing oil or gas in paying quantities, the lease is committed to a unit agreement, or the lessee is drilling or conducting reworking operations, on the date performance under the schedule is due. Furthermore, upon termination BPXA shall promptly file of record appropriate lease relinquishments. The automatic termination shall occur at 11:59 P.M., Alaska Time, on the day performance of an obligation under the project schedule is due. The state may waive performance of an obligation required under the project schedule by prior written consent. The performance of any obligation required under the project schedule is subject to the provisions of paragraph 4(f).

5) Paragraph 31 is replaced in its entirety as follows:

31. EMPLOYMENT OF ALASKAN RESIDENTS. Lessee shall comply with all valid federal, state and local laws in hiring Alaska residents and contractors and shall not discriminate against Alaska residents or contractors. Within the constraints of law, lessee shall employ Alaska residents and contractors to the extent they are available and qualified. Subject to the foregoing:

Lessee voluntarily agrees to adopt a program to hire residents of Alaska. Lessee shall advertise for available positions locally and use Alaska job

service organizations to notify the Alaskan public. For work in connection with this lease, lessee shall use best efforts to contract with Alaska firms and fabricate modules in Alaska, whenever feasible. Lessee shall encourage its contractors to employ and train, when necessary, residents of Alaska. In determining feasibility, lessee shall consider commercial, health, safety, and environmental conditions and requirements to ensure maintenance of lessee's operational standards. Lessee shall submit annually to the Director, Division of Oil and Gas, for transmission to the Department of Labor, a report that details the specific measures lessee and its contractors and subcontractors have taken or are planning to take to recruit qualified Alaska residents for available jobs, describes on-the-job training opportunities, and describes lessee's efforts to hire Alaska firms for work in connection to this lease. Lessee shall furnish the Department of Labor a quarterly report regarding the employment of Alaska residents on the leased area in compliance with regulations by the Commissioner of Labor. The report must also include statistical data concerning the number of resident personnel hired within the past year for this lease.

6) Paragraph 35 is replaced in its entirety as follows:

35. ROYALTY ON PRODUCTION. Except for oil, gas, and associated substances used on the leased area for development and production or unavoidably lost, the lessee shall pay to the state as a royalty 20 percent in amount or value of the oil, gas, and associated substances saved, removed, or sold from the leased area and of the gas used on the leased area for extraction of natural gasoline or other products from the leased area.

7) Paragraph 36 is replaced in its entirety as follows:

36. VALUE. For purposes of computing supplemental royalty due under this lease, the value of supplemental royalty oil, gas, natural gas liquids, and associated substances shall be the value used in computing royalty on said substances.

(a) To compute the value of oil for royalty and supplemental royalty purposes, this lease shall be deemed an "ANS Lease" under the terms of the ANS Agreement, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(b) To compute value of gas and natural gas liquids for royalty and supplemental royalty purposes, this lease shall be deemed a "Lease" under the terms of the 1995 ANS Gas Royalty Litigation Settlement Agreement between BPXA and the State dated as of April 1, 1995, irrespective of any provision(s) of such agreement which would otherwise exclude this lease therefrom.

(c) To compute the value of associated substances (which shall be deemed to exclude oil, gas, and natural gas liquids) for royalty and supplemental royalty purposes, the value of such associated substances shall not be less than the highest of:

(1) the field price actually received be lessee for such associated substances;

(2) Lessee's posted price in the field for such associated substances;

(3) the volume weighted average field price actually received by other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area; or

(4) the volume weighted average posted price in the field of other producers in the same field or area for associated substances of like kind and quality at the time such associated substances are removed from the leased or unit area.

If associated substances are sold away from the leased or unit area, the term "field price" above shall be the actual price for such associated substances received from the purchaser thereof less the actual cost of transportation away from the leased or unit area to the point of delivery.

Minimum Value Determinations. The state may establish minimum values for purposes of computing royalties on associated substances obtained from this lease, with consideration being given to the price actually received by lessee, to the price or prices paid in the same field or area for production of like quality, to posted prices, to prices received by lessee and/or other producers from sales occurring away from the leased area, and to other relevant matters. Each such determination will be made only after lessee has been given notice and a reasonable opportunity to be heard. Under this provision, it is expressly agreed that the minimum value of royalty associated substances under this lease may not necessarily equal the price of such associated substances.

8) Paragraph 37 is replaced in its entirety as follows:

37. ROYALTY IN VALUE. Unless the state elects to receive all or a portion of its royalty or supplemental royalty in kind as provided in paragraph 38, lessee shall pay to the state the value of all royalty and supplemental royalty oil, gas and associated substances as determined under paragraph 36. Royalty and supplemental royalty paid in value shall be free and clear of all lease expenses (and any portion of such expenses which is incurred away from the leased area), including, but not limited to, expenses for separation, cleaning

dehydration, gathering, saltwater disposal, and preparing the oil, gas or associated substances for transportation off the leased area. All royalty and supplemental royalty that may become payable in money to the state shall be paid on or before the last day of the calendar month following the month in which the oil, gas or associated substances are produced. Royalty and supplemental royalty payments shall be accompanied by copies of run tickets or such other information relating to valuation of royalty and supplemental royalty as the state may require, which may include, but is not limited to, evidence of sales, shipments, and amounts of gross oil, gas and associated substances produced.

9) The following provision shall be added to the end of paragraph 38:

(f) Supplemental royalty under this lease may be taken in kind under the same terms and conditions as royalty may be taken in kind under this paragraph 38.

10) Paragraph 39 is replaced in its entirety as follows:

39. REDUCTION OF ROYALTY. Except as provided in paragraph 40 below, lessee shall not be entitled to any reduction of royalty paid under paragraph 35 above or supplemental royalty paid under paragraph 40 below based on any current or future agreement, state statute, or state regulation.

11) Paragraph 40 is replaced in its entirety as follows:

40. SUPPLEMENTAL ROYALTY. (a) In addition to the royalty paid and computed under paragraph 35, 36, 37 above, lessee shall pay to the state a supplemental royalty ("supplemental royalty"). Lessee shall pay the supplemental royalty, if owed, upon the same production volume for which royalty is paid ("production volume"). The supplemental royalty payment for a given month equals the supplemental royalty value times the supplemental royalty percentage rate ("percentage rate") times the production volume for that month. The percentage rate shall be calculated monthly by reference to: (1) an ANS West Coast spot price ("spot price"); and (2) a supplemental royalty trigger price ("trigger price"). If the spot price is equal to or less than the trigger price, then the percentage rate equals zero. If the spot price is greater than the trigger price, then the percentage rate equals [the spot price per barrel minus the trigger price per barrel] times 1.5 per cent per dollar per barrel. The percentage rate may never exceed 7.5 per cent.

(b) The spot price is the price per barrel calculated in Article 3.3 of and Exhibit 4 to the ANS Royalty Litigation Settlement Agreement ("ANS Agreement"), dated December 31, 1991, between the State and BPXA, for the crude oil referred to

as "ANS (USWC)" in the ANS Agreement. The trigger price is $17.35 per barrel through April 30, 1997. On May 1, 1997, and each May 1 thereafter, the trigger price shall be adjusted by an inflation factor equal to fifty percent of the "inflation rate" defined as the Producer Price Index for Industrial Commodities ("PPI") for December of the previous year, as reported by April 30 of the current year, divided by the PPI for December of 1995, as reported by April 30, 1996. The supplemental royalty value for oil, gas, natural gas liquids and associated substances is defined in paragraphs 36 and 37 above. Exhibit B is a sample calculation to demonstrate the method of calculating supplemental royalty for oil.

These amendments do not affect: (1) any future agreements which may be reached for the handling of outside substances as that term is used in the Northstar Unit Agreement effective January 24, 1990 or (2) the current valuation methodology for royalty for any other Alaska Net Profit Share leases between the State and BPXA or any affiliates or any future agreements which may be reached regarding a future valuation methodology for Alaska Net Profit Share leases. These amendments take effect when and if an Act(s) substantially similar to the act, attached as Exhibit D and incorporated by reference, takes effect. This amendment is dated for reference purposes as of March 22, 1996.

LESSEE:

BP EXPLORATION (ALASKA), INC.

E. M. Luttrell, Vice President

LESSOR:

STATE OF ALASKA

John T. Shively, Commissioner
Department of Natural Resources

STATE OF ALASKA)
) ss.
Third Judicial District)

On March 22, 1996, before me appeared John T. Shively, Commissioner, State of Alaska, Department of Natural Resources, and who executed this lease and acknowledged voluntarily signing it on behalf of the State of Alaska, as lessor.

Notary Public in and for the State of Alaska
My Commission Expires: 1/16/99



STATE OF ALASKA)
) ss.
Third Judicial District)

On March 22, 1996. before me appeared E. M. Lutrell, Vice President of BP Exploration (Alaska), Inc., and who executed this lease and acknowledged voluntarily signing it on behalf of the BP Exploration (Alaska), Inc., as lessee.

Notary Public in and for the State of Alaska
My Commission Expires: 1/16/99



Exhibit B
Calculation of the Supplemental Royalty Payment for Oil

1) The calculation of the ANS West Coast spot price is derived from Platt's "Oilgram Price Report" Spot Crude Price Assessments:

Date	Platt's Reported Daily Assessment ($/barrel) ANSWC Low	ANSWC High	ANSWC Daily Average	ANSWC Daily Average (After Rounding)[1]
01/02/96	$17.97	$18.06	$18.015	$18.02
01/03/96	$17.94	$18.03	$17.985	$17.98
01/04/96	$17.96	$18.03	$17.995	$18.00
01/05/96	$18.60	$18.64	$18.620	$18.62
01/09/96	$18.23	$18.29	$18.260	$18.26
01/10/96	$17.99	$18.05	$18.020	$18.02
01/11/96	$17.10	$17.17	$18.135	$17.14
01/12/96	$16.64	$16.71	$18.675	$16.68
01/15/96	$16.75	$16.83	$16.690	$16.79
01/16/96	$16.60	$16.66	$16.730	$16.63
01/17/96	$16.91	$16.97	$16.940	$16.94
01/18/96	$17.46	$17.54	$17.500	$17.50
01/19/96	$17.28	$17.37	$17.325	$17.32
01/22/96	$17.02	$17.08	$17.050	$17.05
01/23/96	$17.10	$17.16	$17.150	$17.13
01/24/96	$17.35	$17.41	$17.380	$17.38
01/25/96	$16.76	$16.81	$17.785	$16.78
01/26/96	$16.43	$16.53	$17.480	$16.48
01/29/96	$16.16	$16.24	$16.200	$16.20
01/30/96	$16.30	$16.38	$16.340	$16.34
01/31/96	$16.46	$16.56	$16.510	$16.51

Monthly Average calculated from ANSWC Daily Average (After Rounding) = $17.2271 per barrel

ANS West Coast spot price for the January 1996 month of production = $17.23 per barrel

2) The inflation factor shall be calculated as follows: Assume that by April 30, 1996, the U.S. Department of Labor reports a PPI for December 1995 as 126.2. Assume that by April 30, 1998, the PPI for December 1997 is 134.2. The inflation factor for 1998 is calculated according to the following formula:

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[1] All source and calculated numbers shall be rounded as required in the ANS Agreement.

Inflation Factor for May 1, 1998 through April 30, 1999
= [(PPI December of the previous year ÷ PPI December 1995) - 1] x 0.5

= [(134.2 ÷ 126.2) - 1] x 0.5 = 0.0317 = 3.17 percent

3) The trigger price for May 1, 1998 through April 30, 1999 is calculated by adjusting $17.35 per barrel by the inflation factor as follows:

Trigger price for the current year = $17.35 per barrel x (1 + inflation factor)

= $17.35 per barrel x (1+ 3.17 percent)

= $17.35 x 1.0317

= $17.90 per barrel

4) Assuming the current month ANSWC spot price is $21.40, the supplemental royalty percentage rate is calculated as:

Supplemental royalty percentage rate = (ANSWC spot price - trigger price for the current year) x (1.5 percent per dollar per barrel)

= ($21.40 per barrel - $17.90 per barrel) x 1.5 percent per dollar per barrel

= (21.40 -17.90) x 0.015

= 0.05250 = 5.25 percent

5) The calculation of the supplemental royalty payment for the current month is the product of the production volume times the royalty value and the supplemental royalty percentage rate. Assume that 1,550,000 barrels of oil were produced in the Northstar unit in the current month and that the royalty value is $17.71. The supplemental royalty is:

Supplemental royalty payment = production volume x royalty value x supplemental royalty percentage rate

= 1,550,000 barrels x $17.71 per barrel x 5.25 percent

= $1,441,151.25

EXHIBIT C

PROJECT SCHEDULE

The Northstar Development Project ("the Project") is described in the document titled "Northstar Development Project, Conceptual Engineering Report" dated February 1996. BPXA shall comply with the following schedule for the Project and shall provide satisfactory evidence of compliance within fifteen days of the date performance is due under the schedule:

BPXA shall receive Project sanction within twelve (12) months after passage by the legislature of an Act approving the First Amendments to the Northstar Unit Leases for the Project. "Project sanction" means approval in writing by the highest appropriate authority in BPXA or its parent entity necessary for the total amount of expenditures required for the Project. Satisfactory evidence of receipt of sanction shall be tendered to the State in the form of the sanctioning entity's documents approving the expenditure of funds for the Project. If Project sanction is withdrawn for any reason whatsoever, BPXA shall notify the State within three working days by letter from an authorized officer and BPXA shall be deemed to have failed to comply with this schedule.

EXHIBIT D

ACT

____ BILL NO.

IN THE LEGISLATURE OF THE STATE OF ALASKA

NINETEENTH LEGISLATURE - SECOND SESSION

BY THE ____ RULES COMMITTEE BY REQUEST OF THE GOVERNOR

Introduced:
Referred:

A BILL

FOR AN ACT ENTITLED

"An Act authorizing, approving, and ratifying the amendment of Northstar Unit oil and gas leases between the State of Alaska and BP Exploration (Alaska) Inc.; and providing for an effective date."

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

* Section 1. The legislature finds that

(1) the production of oil and gas from state land is a matter of statewide interest and effect because it is an important source of revenue to the state and job opportunities for the people of the state;

(2) BP Exploration (Alaska) Inc. holds state oil and gas leases in the Northstar Unit that include net profit share provisions;

(3) with the current and projected price of oil, BP Exploration (Alaska) Inc. maintains that the net profit share provisions of the Northstar Unit leases prevent the timely development of the unit;

(4) existing law set out in AS 38.05 does not provide the commissioner of the

NEW TEXT UNDERLINED [DELETED TEXT BRACKETED]

Department of Natural Resources with sufficient express authority to amend the net profit share provisions of the Northstar Unit leases held by BP Exploration (Alaska) Inc.;

(5) unless the net profit share provisions of the Northstar Unit leases are amended, production of oil and gas from the unit is unlikely to begin until the year 2002;

(6) the Department of Revenue currently forecasts that production will not begin from the unit until the year 2002;

(7) if the net profit share provisions of the Northstar Unit leases are amended, full production of oil and gas from the unit may begin as early as the year 1999;

(8) amending the net profit share provisions of the Northstar Unit leases to provide for a supplemental royalty will maximize the economic benefits of oil and gas production to the people of the state by encouraging timely production from the unit;

(9) the development of the unit and the associated construction of unit facilities within the state will provide additional revenue to the state and increased job opportunities;

(10) BP Exploration (Alaska) Inc. has committed to use its best efforts to hire Alaska residents and contractors and to fabricate modules for the unit in Alaska;

(11) the timely development of the unit may result in increased state revenue in future lease sales;

(12) the timely development of the unit may result in technological breakthroughs and other cost savings that may make other development opportunities in Alaska economically feasible; and

(13) the development of the unit will include the first truly offshore Arctic island construction and Arctic subsea pipeline for oil.

* Sec. 2. (a) The State of Alaska and BP Exploration (Alaska) Inc. are parties to the following leases in the Northstar Unit:

(1) ADL 312798, effective February 1, 1980;

(2) ADL 312799, effective February 1, 1980;

(3) ADL 312808, effective February 1, 1980;

(4) ADL 312809, effective February 1, 1980; and

(5) ADL 355001, effective August 1, 1983.

(b) The commissioner of the Department of Natural Resources may amend the Northstar Unit leases described in (a) of this section to the extent set out in the "First

DRAFT DRAFT - DEPARTMENT OF LAW DRAFT

Amendment to the Northstar Unit Leases Between the State of Alaska and BP Exploration (Alaska) Inc.", dated March ___, 1996.

(c) Notwithstanding any other provision of law, the "First Amendment to the Northstar Unit Leases Between the State of Alaska and BP Exploration (Alaska) Inc.", dated March ___, 1996, is approved and ratified.

* Sec. 3. This Act takes effect immediately under AS 01.10.070(c).