

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2351 SCOMM 99 HOUSE SPEC. WORLD TRADE. . RELATIONS, 1995-1996

Sta' of Alaska
30th COMPETITIVE OIL AND GAS LEASE SALE
 ** BEAUFORT SEA **

SALE RESULTS - BidRecap by Tract

TRACT NO.	JCS NO.	BLOCK NO.	ACRES	SUBDIVISION	ADL NO.
IF046	Z0C01	CCC470	4392.82	BLK 514	ADL 312798

312798

GRP NO.	NO.	PCT.	C O M P A N Y N A M E	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. CO			
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 COMP			
078	50%		CHEVRON USA INC			

OBFO47 ZU002 CCC471 4472.37 BLK 515 ADL 312799

ADL 312799

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		80.56769	3 OF 7
040	50%		TEXACO INC.			
235	50%		TEXAS EASTERN EXPLOR. CO			
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 COMP			
039	33%		MOBIL OIL COMPANY			
078	34%		CHEVRON USA INC			
003	100%		UNION OIL COMPANY OF CAL ROYALTY BID		32.00000	7 OF 7

TRACTS BF-48 →

-52

NO BID

GBF053 20003 000520 5241.36 ADL 312805

001 100% TENNECO OIL COMPANY

ROYALTY BID

21.58000 1 OF 1

GBF054 20004 000521 5693.29

ADL 312806

001 100% TENNECO OIL COMPANY

ROYALTY BID

59.00000 1 OF 1

GBF055 20005 000522 5058.40 ADL 312807

001 100% TENNECO OIL COMPANY

ROYALTY BID

31.67000 1 OF 1

GBF056 20006 000514 3432.92 BLK 515 552 559 ADL 312808

235 100% TEXAS EASTERN EXPLOR. CO ROYALTY BID

85.25978 1 OF 5

3

ROYALTY BID

36.12530 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 CAL ROYALTY BID

25.50000 3 OF 5

1

ROYALTY BID

10.14550 4 OF 5

078 50% CHEVRON USA INC.

056 50% PHILLIPS PETROLEUM CORP

7

ROYALTY BID

2.11111 5 OF 5

002 40% ATLANTIC RICHEFIELD CORP

108 10% MURPHY OIL CORPORATION

117 50% SHELL OIL COMPANY

GBF057 20007 000516 5301.38 BLK 560 ADL 312809

235 100% TEXAS EASTERN EXPLOR. CO ROYALTY BID

85.25978 1 OF 7

114 100% AMOCO PRODUCTION COMPANY ROYALTY BID

71.25009 2 OF 7

11

ROYALTY BID

61.83000 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 CAL ROYALTY BID

38.00000 5 OF 7

5

ROYALTY BID

34.23333 6 OF 7

056 33% PHILLIPS PETROLEUM CORP

9

ROYALTY BID

31.69117 7 OF 7

002 45% ATLANTIC RICHEFIELD CORP

BID TALLY LIST - O/G LEASE SALE 39

May 17, 1983

39-11

Tract #	No. of Bids	Bidder	% ownership	Bid amount	Bid/Acre	20% depo:
ADL 355001	3	Exxon Corp.	50%	60,300.00	10.49	12,060.00
		Sohio Alaska	50%			
		Kelley Everette	5%	64,620.00	11.25	13,000.00
		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	14,428.93
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
002	3	Kelley Everette	5%	50,343.75	11.25	11,000.00
		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%			
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. Andre. 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% deposit
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. Dieringer, Jr.	15%	69,013.42	15.56	13,801.68
		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%			
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%	64,307.20	12.56	12,861.44
		James F. Dieringer, Jr.	15%			
		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%	71,792.96	12.56	14,358.59
		James F. Dieringer, Jr.	15%			
		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	Bld/Acre	20% depos
007	3	Kelley Everette	5%	43,020.00	11.25	9,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Constance Cole POA	15%			
		Joe Burglin POA	45%			
		James F. Dierlinger, Jr.	15%	59,501.44	15.56	11,900.29
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
		Exxon Corp.	50%	70,300.00	18.38	14,060.00
		Sohio Alaska	50%			
		Kelley Everette	5%	59,343.75	11.25	12,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Bernard Shier POA	15%			
		Bruce Burglin POA	45%			
008	4	Shell Oil Co.	50%	73,457.00	13.92	14,691.40
		Amoco Production Co.	50%			
		James F. Dierlinger, 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
		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. Dierlinger, 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	13,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		Ed Carlson	15%			
		David Burglin	45%	89,625.60	15.56	17,925.12
		James F. Dieringer, Jr.	15%			
		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	11,000.00
		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	% ownership	Bid amount	Bid/Acre	20% depo:
021	3	Kelley Everette	5%	57,600.00	11.25	13,000.00
		C. Burglin	15%			
		K. K. Everette POA	20%			
		James Burglin POA	60%			
		Canoco Inc.	100%	73,165.00	14.29	14,633.00
		Amerada Hess Corp.	50%	257,177.60	50.23	51,435.50
		Diamond Shamrock Corp.	50%			
022	2	Kelley Everette	5%	64,507.50	11.25	13,000.00
		C. Burglin	15%			
		Gene Everette POA	20%			
		Bruce Burglin POA	60%			
		James F. Dieringer, Jr.	15%	89,221.04	15.56	17,844.20
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
023	4	Kelley Everette	5%	58,218.75	11.25	13,000.00
		C. Burglin	15%			
		Gene Everette POA	20%			
		Brian Burglin POA	60%			
		James F. Dieringer, Jr.	15%	80,523.00	15.56	16,104.60
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%			
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	Bld/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	12,831.30
		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	Bld/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%					
		Getty Oil Co.	25%	440,155.00	76.90	88,031.00		
		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	410,973.4
		Amerada Hess Corp.	25%			
		Diamond Shamrock	25%			
		Placid Oil	25%			
040	4	Kelley Everette	5%	57,802.50	11.25	13,000.00
		C. Burglin	15%			
		Paul Quist POA	20%			
		James Johnson POA	15%			
		Barbara Burglin	45%	79,942.77	15.56	15,988.55
		James F. Dieringer Jr.	15%			
		J. Andrew Bachner	30%			
		W. G. Stroecker	22.5%			
		Richard E. Wagner	32.5%	88,008.98	17.13	17,601.80
		Arco Alaska, Inc.	100%			
		Chevron U.S.A. Inc.	40%		19.97	20,516.00
		Getty Oil Co.	20%			
		Gulf Oil Corp.	40%			

Tract #	No. of Bids	Bidder	% ownership	Bid amount	Bid/Acre	20% deposit
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%			

0255b

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 N $\frac{1}{2}$ S $\frac{1}{2}$ (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 38.05.365(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.

11-1-79-80 05073-80

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 interfere 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.

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.

7. SHARE OF NET PROFIT. Lessee will pay to the State 20.0000% 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 D 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 accounts 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 resources 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 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 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 outweigh 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, 1980.

LESSEE
AMERADA HESS CORPORATION

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

STATE OF ALASKA

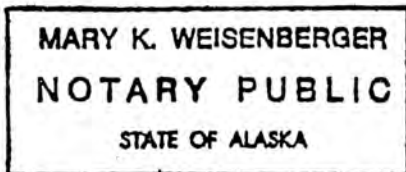
By: Ethel H. Nelson
ETHEL H. NELSON
Title: Leasing Manager

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

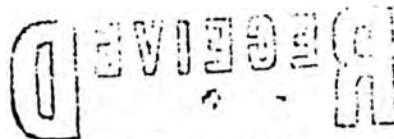
Acknowledgement of Lessor

This certifies that on the 14th day of January, 1980, before me, a notary public in and for the State of Alaska, duly commissioned and sworn, personally appeared 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



RECEIVED
JAN 29 1980
U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

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 archaeological 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 archaeological, 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-88, 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 management 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.

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., Uniat 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.

RECEIVED

JUN 4 1984

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 exercised 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.

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

3ss.

Third Judicial District)

STATE OF ALASKA

By: Kay Brown

Title: Kay Brown, Director, DMEM

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



TRACT 39-01

BOOK 40 PAGE 852
Barrow Recording District

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.

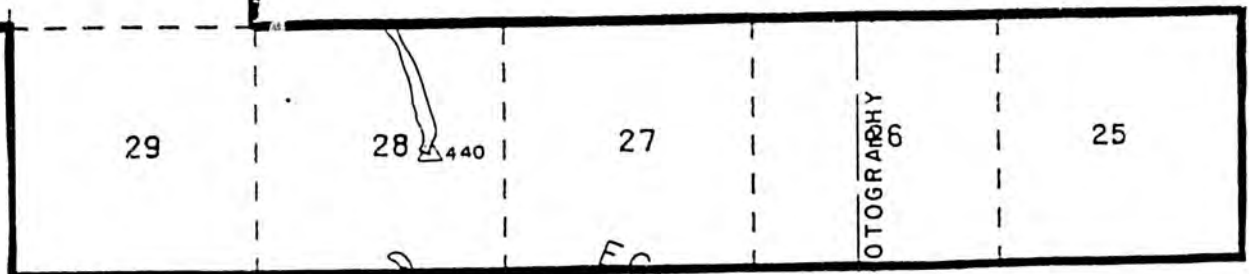
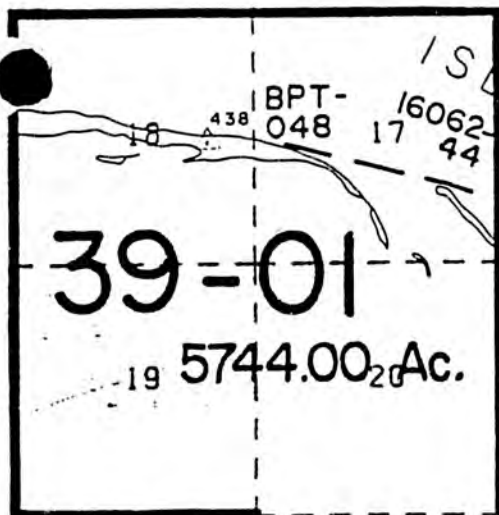
This tract contains 5744.00 acres more or less.

8 4 0 5 7 9
32.00

RECORDED-~~FILE~~
BARROW RECORDING
DISTRICT

MAY 16 12 00 PM '84
REQUESTED BY AS/DNR

REQUESTED BY _____
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.

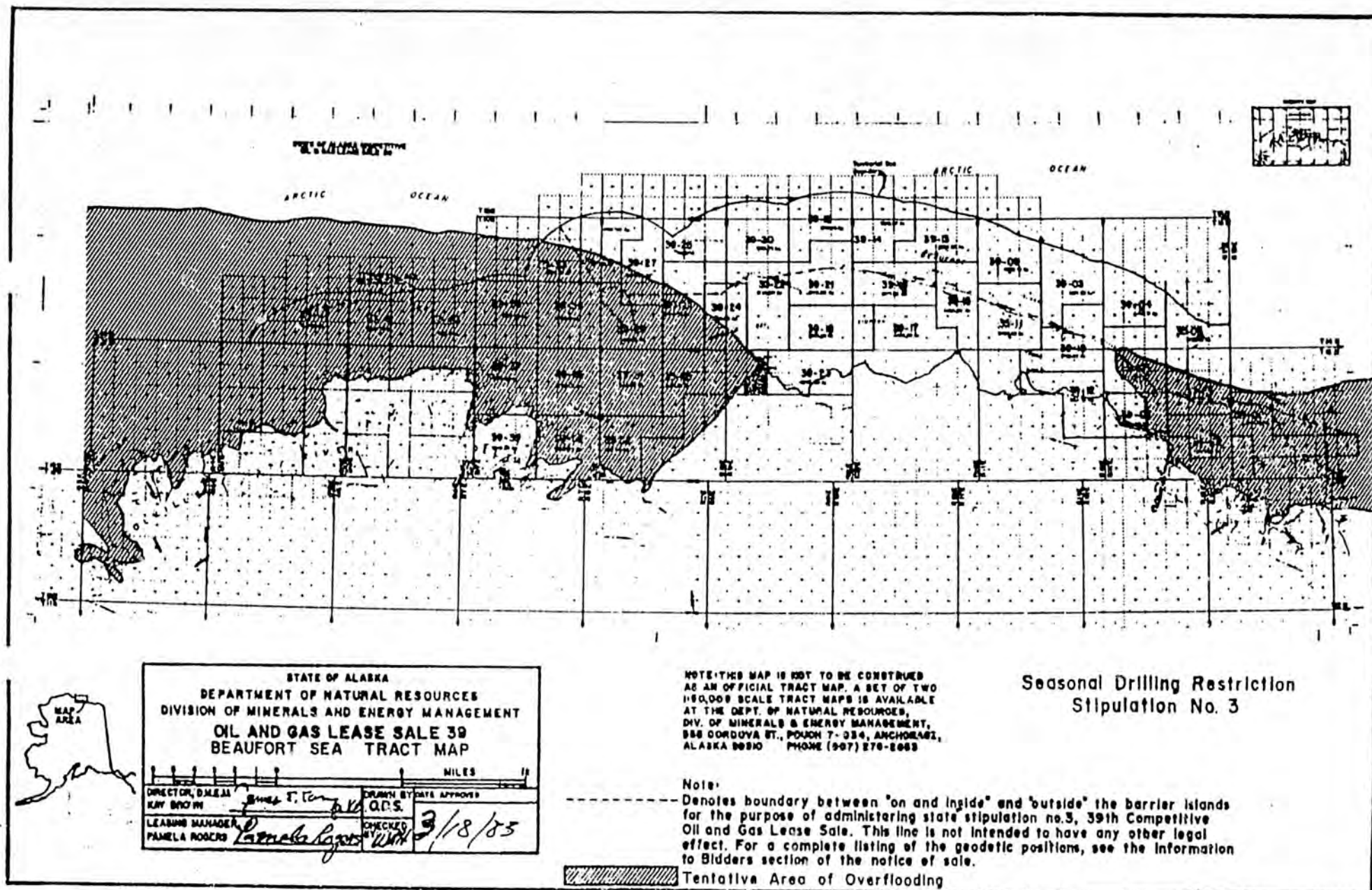


FIGURE 1

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.

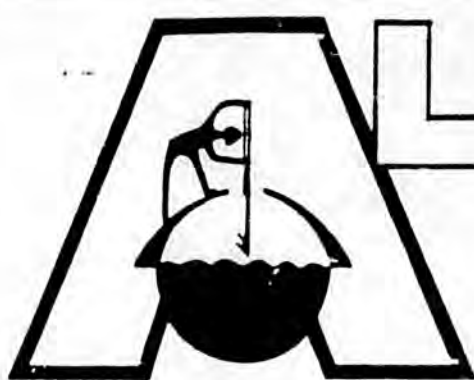
25. Routes of travel must avoid preferred polar bear denning habitat unless human safety dictates otherwise. Polar bears den on Pingok and Cottle islands and within 25 miles of the coastline in deeply drifted areas (6 ft. or greater) adjacent to the cutbanks of drainages. The use of explosives will be 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:

<u>Salient Pt. No.</u>	<u>Latitude</u>	<u>Longitude</u>
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°49'06.40" 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

<u>Salient Pt. No.</u>	<u>Latitude</u>	<u>Longitude</u>
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 treas-

ury 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-

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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 well-head 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.

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

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"	"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.

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) (March 1982 = 100)					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) (March 1982 = 100)					Crude-Oil Prices (1972 = 100) (March 1982 = 100)																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																					

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 the 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.

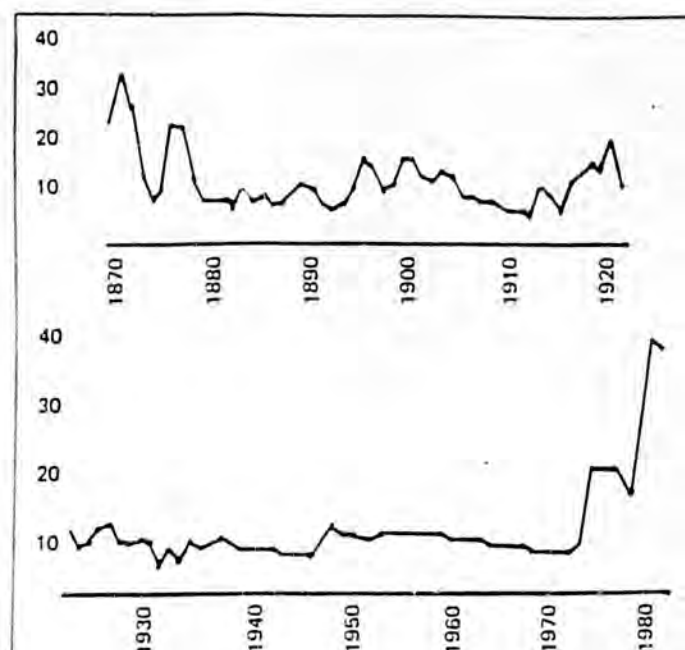


Figure 1. U.S. Crude Oil Price Trends, 1870-1981
(March 1982 constant dollars)

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 Prices¹³

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 draw-down of inventories, or political events. After some such contingency has caused a spot price 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 of 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 to changed energy-supply conditions also means that the all-time high oil prices of 1974-1982 will influence 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 are 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 Louisiana, 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 dol-

lars 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

¹None 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).

²Alaska 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.

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

⁴Charles 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.

⁶Acres 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'l 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.

⁷For 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.

⁸From 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 Alleghany 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.

⁹For 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.

¹⁰Lovejoy 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.

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

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

¹³On 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.

¹⁴Estimated 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.

¹⁵See, 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 Petroleum 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.

¹⁶As 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).

¹⁷Youssef 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.

¹⁹D. deBruyne, quoted in *Petroleum Intelligence Weekly*, June 14, 1982, p. 8.

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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 economic 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 assumptions 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.

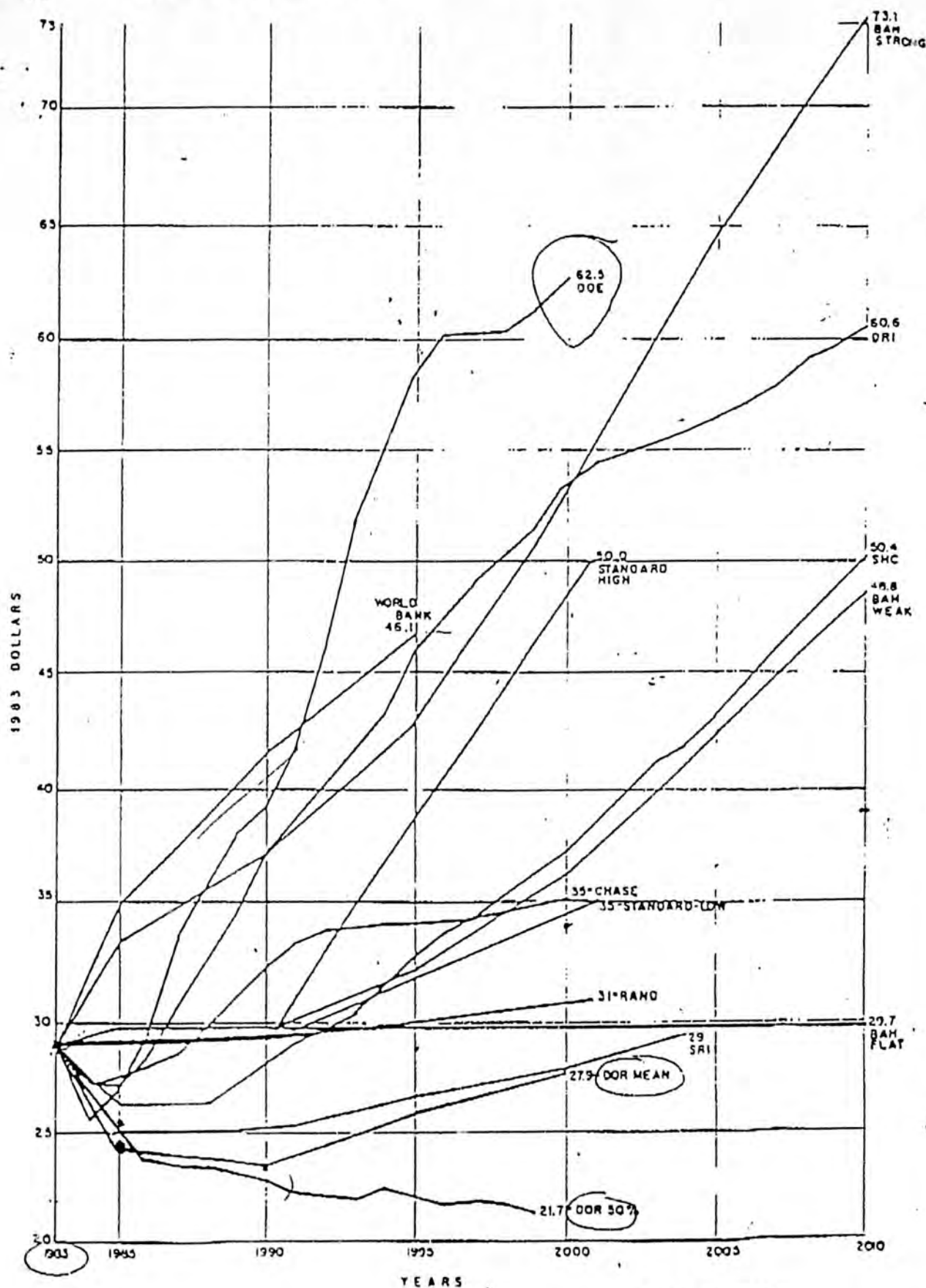
Domestic Price Trends

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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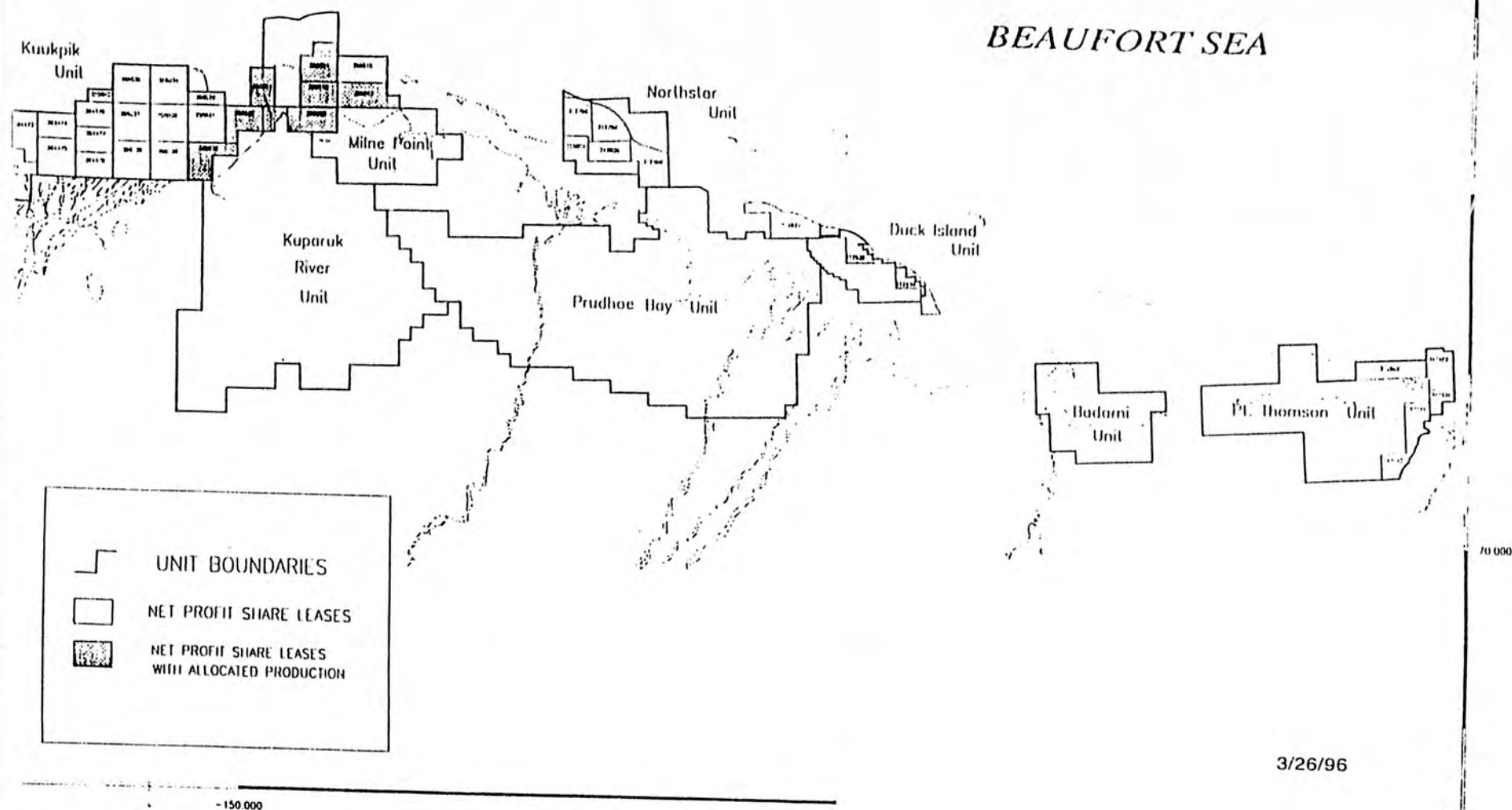
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 1983 - 2010

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?
<u>Duck Island Unit</u>									
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
<u>Kuupik Unit</u>									
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	
<u>Kuparuk River Unit</u>									
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
<u>Milne Point Unit</u>									
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
<u>Northstar Unit</u>									
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	5,301.39	
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 (NPSI.s)

Lease	Sale	Lease Date	Unit	Bonus Bid	NPS Percent	Royalty Percent	Bid Type	Unit Acres	Allocated Production?
<u>Pt. Thomson Unit</u>									
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	
<u>Not Utilized</u>									
ADL 312827	30	01-Feb-80		\$9,880,867.50	74.83000%	20.0%	Fixed Royalty and Variable NPS	0.00	

ALASKA NORTH SLOPE
NATIONAL ENERGY STRATEGY INITIATIVE

Analysis of Five Undeveloped Fields

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May 1993

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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.

Technical and Economic Analysis

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 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, it is 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 indications that 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