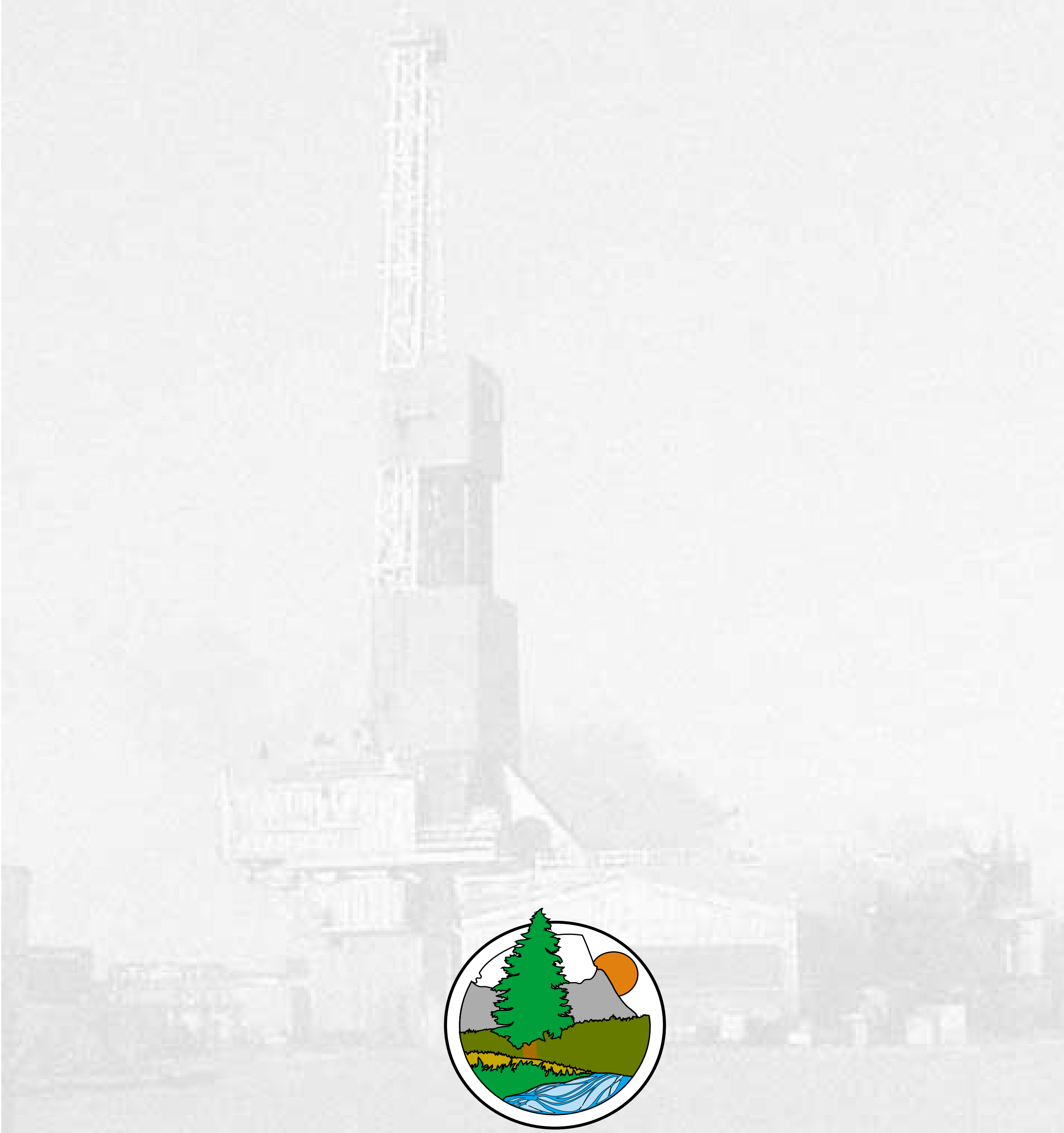
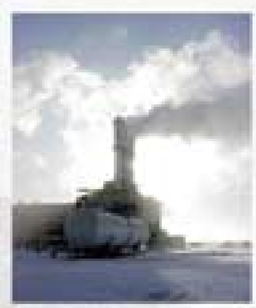




2000 Annual Report

Department of Natural Resources
Division of Oil and Gas

This publication was released by the Department of Natural Resources, Division of Oil and Gas. It was produced at a cost of $7.50 per copy. The purpose of this publication is to meet the mandate of Alaska Statute 38.05.182. The publication was printed in Anchorage, Alaska.

2000 Annual Report

Department of Natural Resources
Division of Oil and Gas

Table of Contents

INTRODUCTION

DATA

UNITS

ROYALTY-IN-KIND
AND ALASKA REFINING

LEASING PROGRAM

GOVERNMENT OIL & GAS
MANAGEMENT AGENCIES
IN ALASKA

Introduction

1999 was a tumultuous year for Alaska's oil and gas industry. In December, 1998, Alaska North Slope (ANS) oil sold on the West Coast dropped to its lowest monthly average price on record. By December, 1999, the price of ANS soared to $24.54 and continued to rise to $28 by March, 2000. This whipsaw in prices of the state's most valuable commodity again underscored the volatility of the world oil market and the dependence of the state on events outside its control.

Alaska was also rocked by the announcement in March 1999 that BP Amoco would acquire Atlantic Richfield (ARCO) and all of ARCO Alaska Inc.'s Alaska oil and gas production. The ensuing public debate and controversy over jobs and control of the state's resources occupied the attention of state government and the oil industry and its support sectors. The uncertainty generated by low oil prices and the pending merger led to a reevaluation of several capital projects on the North Slope. As the dust continues to settle, a new player in the state's oil industry—Phillips Alaska, Inc.—has emerged in a dramatic realignment of ownership in the Prudhoe Bay Unit. The importance of these changes in the industry will not be completely evident for some time. In fact, the forecast of oil production by lessee that is usually included in this report will not be reported this year.

1999 also saw the completion of the Miscible Injection Expansion (MIX) project. New projects are underway. The development of the Alpine field in the Colville River Unit will see first oil by summer, 2000. Pipeline and island construction of the Northstar project is nearly complete and development drilling is expected to begin next winter. Modules for each these projects were built (or are now under construction) in Alaska.

Reserves

Only a fraction of the original oil or gas in any reservoir can be extracted, depending on available technology and production economics. The lessee's decision whether or not to develop a new reservoir or to continue production from a developed field depends on the difference between the present and forecasted cost of extracting the oil or gas and its value.

Reserves are an estimate of how much oil and gas can be economically produced from a given reservoir. Reserves can be calculated by many methods and there is often no consensus on which method is best to apply to each reservoir. Three state agencies are responsible for predicting reserves or future oil and gas production, the Alaska Oil and Gas Conservation Commission (AOGCC), the Department of Revenue, Tax Division (DOR), and the Department of Natural Resources, Division of Oil and Gas (DOG). Each of these agencies calculates reserves by slightly different methods for their different requirements. AOGCC emphasizes geologic and engineering factors and look to an estimate of the total resource. DOR calculations emphasize oil and gas production economics and the impact of oil prices fore-

This report replaces the annual "Historical and Projected Oil and Gas Consumption" report that the Division of Oil and Gas has published since 1979. It includes the same data on historical production, the division's most recent oil production forecasts by field, and reserve estimates. It also expands on Alaska's royalty-in-kind program and adds a section summarizing the many active oil and gas units. The report briefly describes the state's oil and gas leasing program.

This report lacks a comprehensive update of statewide fuel and natural gas consumption. Data tables from last year's report may be found at the end of Section 2, "Data." Next year's report will include a comprehensive review of energy consumption in the state combined with a new energy consumption forecast.

casted far into future. DOG reserves are calculated from the forecast of production from existing and planned developments that may reasonably be expected to occur in the near future. These agencies cooperate fully in the preparation of these forecasts.

Recovery estimates of large oil fields typically increase through their development years and ultimate recoveries are often greater than early predictions. In the early 1980's, Prudhoe Bay's reserves were estimated between seven and nine billion barrels. By January 1986 Prudhoe Bay's projected ultimate recovery was 10.2 billion barrels, 4.4 billion produced and 5.8 billion reserves, and by January 2000 the estimate for the Prudhoe Bay Unit Initial Participating Areas is 13 billion barrels, 10.2 billion barrels produced and reserves of 2.9 billion barrels (see chart below). New investments, improved technologies, and strict management of operating costs, contribute to a large portion of these increases.

North Slope oil reserve estimates developed by DOG are illustrated below and are derived from the oil forecast tables in Section 4. Each unit's remaining reserves are equal to the total ANS production predicted for the next 21 years. Many of these units will likely produce well beyond the forecast period that ends in 2021 and this additional production will increase the ultimate recovery listed in this report. Reserves of each of the Cook Inlet fields were calculated by whichever method was most appropriate for that field. Oil reserves from the producing Cook Inlet oil fields were calculated in the same way as the North Slope oil fields except that only a five-year remaining life was assumed. Gas reserves for each of the producing Cook Inlet gas fields are calculated by subtracting 1999 production from the reserve estimates listed by DOG in last year's report.

The state's royalty reserves are calculated by multiplying each field's reserves times the state royalty ownership interest in the field. The state owns 100 percent of the royalty interest in most of the producing oil and gas fields in Alaska. It owns a partial interest in the Colville River Unit, North Star Unit, and Liberty on the North Slope and Beluga Rive, Cannery Loop, Kenai, Sterling and West Forelands in the Cook Inlet. The state has no royalty interest in the reserves in the East Barrow, South Barrow and Walakpa fields on the North Slope nor does the state have any royalty interest in the Swanson River, Beaver Creek, or Birch Hill fields in Cook Inlet. Future production form these field will contribute revenues to the state through severance and property taxes.

Oil Production Forecast

North Slope production of oil, condensate, and natural gas liquids (NGLs), which peaked at 2.0 million barrels per day in 1988, declined to 1.1 million barrels per day in 1999. By the end of the forecast period in 2021, ANS production will fall to about 408,000 barrels per day. Cook Inlet fields probably will continue to produce beyond the DOG forecast period ending in 2004. The projection includes oil production forecast from Swanson River and Beaver Creek even though the state holds no leases in these fields. It does not include forecasts for Redoubt Shoal and Tyonek Deep. Although platform construction and placement is nearly complete for the Redoubt Shoal its development potential, like the potential for Tyonek Deep, is still uncertain.

Cook Inlet oil production peaked at 230,000 barrels per day in 1970, declined to 30,000 barrels per day in 1999, and will decline to 20,440 barrels per day by 2004. Cumulative production over the next five years in the Cook Inlet will be an estimated 47 million barrels (from fields now in production).

History

Pre-1950's Activity

Alaska's oil has long been the subject of interest and speculation. Historically, oil seeps were observed by the Eskimos, and according to archaeological evidence, oil shale was used for fuel by the early Eskimos. As early as 1853, during the Russian period, oil was reported on the west side of Cook Inlet in the vicinity of the Iniskin Peninsula and in 1882, a Russian named Paveloff took the first samples of oil. Early traders on the North Slope also reported seeps along the coast. Claims were first staked along Cook Inlet in 1892 and 1896. In about 1903, Austin Lathrop drilled three wells in the Cold Bay area.

In 1896, oil claims were staked at Katalla approximately 50 miles southeast of Cordova. Oil was discovered there in 1902. An on-site refinery near Controller Bay produced a total of 154,000 bbl over the thirty years it was in operation. The refinery burned down in 1933 and was not replaced.

In 1910, the federal government withdrew all oil lands in Alaska from entry with the exception of Katalla. Since oil had been discovered there in commercial quantities, title was considered valid. Because of the land withdrawals, no oil drilling activity took place in Alaska with the exception of Katalla. Drilling resumed after the Mineral Leasing Act of 1920 provided for two-year prospecting permits.

On the North Slope, the first geologic and topographic studies date back to 1901 and the U.S. Geological Survey recorded the first formal descriptions in 1919. By 1921, prospecting permits were filed and in 1923 President Harding established by executive order the Naval Petroleum Reserve No. 4 (NPR-4), now known as the National Petroleum Reserve-Alaska (NPR-A). The Geological Survey conducted reconnaissance mapping from 1923 through 1926 and published the results in 1930.

The first exploration phase of NPR-4 started in 1943 and ended in 1953. Between 1923 and 1953, the United States Navy drilled 37 test wells and found three oil accumulations and six gas accumulations within the reserve. Only two of these discoveries were considered sizable, namely Umiat, with an estimated 50 million barrels of recoverable oil, and Gubik, with an estimated 600 billion cubic feet of recoverable gas. Gas from another of the discoveries during that period, the small South Barrow gas field, is being produced today for local consumption at Barrow.

Statehood

At the time of statehood, both Congress and Alaskans recognized the importance of the state's natural resources, specifically, oil and gas. In the late 1950's, Congress was debating the Alaska Statehood Act. A major concern expressed was how the potential new state, which was one of the poorest in the country, could support itself since it did not have an economic base sufficient to support the new state. As a result, the Alaska Statehood Act allowed the state of Alaska to select from the federal public domain 104 million acres of land. The Act also granted to Alaska the right to all minerals underlying these selections and specifically required the state to retain this mineral interest when conveying interests in the surface estate. The mineral estate was seen as so important to Alaska's financial survival that the Statehood Act provided that if Alaska disposed of its mineral estate contrary to the Act, it would forfeit that mineral estate to the federal government.

The importance of natural resources is addressed in art. VIII of the Alaska Constitution which became operative with the formal proclamation of statehood, January 3, 1959. Art. VIII, sec. 1 states that "[i]t is the policy of the State to encourage the settlement of its land and the development of its resources by making them available for maximum use consistent with the public interest." The early legislature realized the importance of oil and gas in Alaska's future. The Alaska Land Act of 1959 included a section specifically addressing the leasing and administration of the state's oil and gas resources. Between 1959 and when Prudhoe Bay was discovered the state conducted 19 competitive oil and gas lease sales.

Cook Inlet

Modern day exploration in Cook Inlet began in 1955 when Richfield Oil Corporation began exploration on the Kenai Peninsula in the Swanson River area. Oil was discovered on July 23, 1957, at a depth of 11,000 feet and flowed at a rate of about 900 barrels a day. This discovery began an oil rush in southcentral Alaska.

Shortly after the Swanson River discovery, Standard Oil Company of California and Richfield formed a joint venture to explore for oil. Additional wells were drilled in the Swanson River area, and more leases were taken on both sides of Cook Inlet. Several other oil companies moved in to participate in leasing and drilling activities on the Kenai Peninsula. By 1959, 187,000 barrels of crude oil were produced annually. The state's first competitive sale was held December 10, 1959 bringing the state over $4 million in bonus bids. Between 1959 and 1969, 17 competitive lease sales were held which included Cook Inlet acreage.

In 1960, following further development of the Swanson River and Soldotna Creek Units, annual production rose to 600,000 barrels. In 1962, Pan American Petroleum Corporation discovered the first offshore oil in Cook Inlet. This led to extensive exploration throughout the Cook Inlet region in the 1960's and 1970's. Chevron opened a refinery in 1963 which eventually closed, and in 1969, the Tesoro refinery began operating. Production peaked at 83 million barrels per year in 1970 and had declined to 11 million barrels per year by 1999. Most of the larger fields were found by the mid-1960's.

The first major gas discovery occurred in October 1959 by Union Oil Company of California and Ohio Oil Company in the Kenai gas field. Gas production began the following year. Several additional large gas discoveries quickly followed and the Phillips/Marathon LNG project stared operating in 1969. The Unocal fertilizer plant began operation in 1968. By 1984, net annual natural gas production had reached 217 bcf per year and has remained near this level to this date.

Production from Alaska's first significant oil field, Swanson River, began in 1959. Five other fields began production between 1965 and 1972. Most recently, West McArthur River began production in 1993. All Cook Inlet oil is currently shipped to the Tesoro refinery at Nikiski on the Kenai Peninsula. Oil from fields on the westside of Cook Inlet is transported by pipeline to the Drift River terminal, then transported to Nikiski. Oil from the eastside fields is shipped by pipeline directly to the refinery. The Cook Inlet has produced almost 1.3 billion barrels of oil including 10 million barrels of NGLs.

Cook Inlet gas production began in 1959 as a by-product of Swanson River oil development. As more oil and gas fields were discovered nearby markets for the gas were developed in Anchorage and Kenai to supply space heat and electricity generation. In 1969 Unocal built an ammonia-urea plant (a sale of the plant to Agrium is pending) and Phillips-Marathon built a liquid natural gas (LNG) plant at Nikiski. Since 1983 net gas production in the Cook Inlet has fluctuated only 5-7 percent annually, constrained by the capacity of the plants and the growth of in-state demand. Gross gas production peaked in 1992 at 309 Bcf per year and has declined to 218 Bcf per year in 1999.

The history of Swanson River gas production differs from other Cook Inlet fields. Swanson River injected gas imported from other fields to enhance oil production. In 1992 the operator began to "blow-down" the reservoir. Now no gas is imported from other fields and Swanson River has become a major net gas supplier in Cook Inlet.

The North Slope

The U.S. Department of the Interior, Bureau of Land Management opened North Slope lands for competitive bidding in 1958 when 16 thousand acres were offered in the area of the Gubik gas field. That same year, BLM opened four million acres in an area south and southeast of NPR-4 for simultaneous filing and subsequent drawing. From 1962-1964, industry exploration programs expanded rapidly. During this period, Sinclair and British Petroleum (now BP Amoco) drilled a total of seven unsuccessful wildcat wells in the arctic foothills.

In 1964, in conjunction with the Statehood Act, the state of Alaska selected some 80 townships across the northern tier of lands between the Colville and Canning Rivers and received tentative approvals on the 1.6 million acres from the federal government in October of the same year. In December 1964, the state held the first North Slope Competitive Sale. Lease Sale 13 covered 625,000 acres in the area east of the Colville River Delta. In July 1965, the state held Lease Sale 14 which included the onshore area in the vicinity of Prudhoe Bay. In Lease Sale 18, held January 1967, the offshore Prudhoe Bay tracts were offered and leased.

After drilling several dry holes in the area immediately surrounding the Prudhoe Bay structure, a rig was moved to the Prudhoe Bay State No. 1 location near the mouth of the Sagavanirktok River in early 1967. The "last effort" proved successful, and in early 1968, Atlantic Richfield (ARCO) announced the discovery of the first commercial North Slope oil field at Prudhoe Bay. In 1969, Atlantic Richfield and British Petroleum agreed to jointly operate Prudhoe Bay. Prudhoe Bay Field did not begin production until 1977 after the construction of the 800-mile Trans-Alaska Pipeline.

Following the Prudhoe Bay discovery, exploration activity on the North Slope increased dramatically. Thirty-three exploration wells were completed in 1969 as industry prepared for Lease Sale 23 in September of that year. The state offered more than 450,000 acres along the Arctic coast between the Canning and Colville rivers and earned over $900 million in bonus bids on 164 tracts. The next North Slope sale was not held until 1979, however, during this time, over 100 exploratory wells were drilled on the North Slope with 19 of those wells discovering oil or gas.

Since 1979, six federal lease sales have been held in the Beaufort Sea and 32 state lease sales offering both onshore and submerged offshore acreage have been held. In addition, a joint state-federal sale was held in 1979. To date, 27 exploratory wells have been drilled in the federal waters of the Beaufort Sea resulting in four discoveries. These discoveries are Kuvlum, Hammerhead, Sandpiper, and Tern Island/Liberty. In 1999, a sale was held in NPR-A and several exploration wells were drilled.

Exploration wells drilled on North Slope state leases since the Prudhoe Bay discovery have resulted in 36 discoveries. Many of these accumulations were found in the vicinity of Prudhoe Bay. Most of the post-Prudhoe Bay discoveries are currently producing oil because of the existence of Prudhoe Bay infrastructure and their relatively close location to the Trans-Alaska Pipeline. Five of these, Lisburne, Kuparuk, Milne Point, Endicott, and Point McIntyre are major fields. Fields recently brought into production are Badami, Tarn, and West Sak. Although initial production on the North Slope was from onshore areas, six fields produce at least some of their reserves from offshore areas including Endicott, Lisburne, Prudhoe Bay, Point McIntyre, Milne Point, and Niakuk.

Oil production on the North Slope began in 1969 in Prudhoe Bay but was restricted to small amounts used to fuel field operations. The operators injected surplus crude and residual oil back into the reservoir. Similarly, Endicott oil produced in the Duck Island Unit was injected back into the reservoir before the pipeline between Duck Island and the Trans-Alaska Pipeline System (TAPS) was completed.

From the beginning of Prudhoe Bay production, the dissolved gas and water have been separated from the crude oil and, augmented with seawater, injected back into the reservoir. Inevitably, the reservoir's proportion of both gas-and-water to oil increased and eventually, oil production was constrained by the rate at which the separating plants could process gas and water. To alleviate this constraint the gas and water handling facilities were expanded in 1986, 1991, and 1993-94. The 1999 MIX project also adds to the field's gas handling capacity.

The North Slope has produced nearly 13 billion barrels of oil and NGLs by the end of 1999, 80 percent of it, Prudhoe Bay and 13 percent from Kuparuk. The NGLs produced on the North Slope have been blended with oil and shipped down TAPS or used to make miscible injectant (MI) in enhance oil recovery projects. Since 1996, NGLs have been shipped via the Oliktok pipeline to the Kuparuk River Unit for MI for the Large-Scale Enhance Oil Recovery projest there.

A small amount of gas has been produced near Barrow since the mid-1940's though records are available only from 1949. This gas initially was used to fuel a nearby military base. Gas service was extended to the village after World War II. The East Barrow and Walakpa fields were developed in 1980 to provide gas to Barrow.

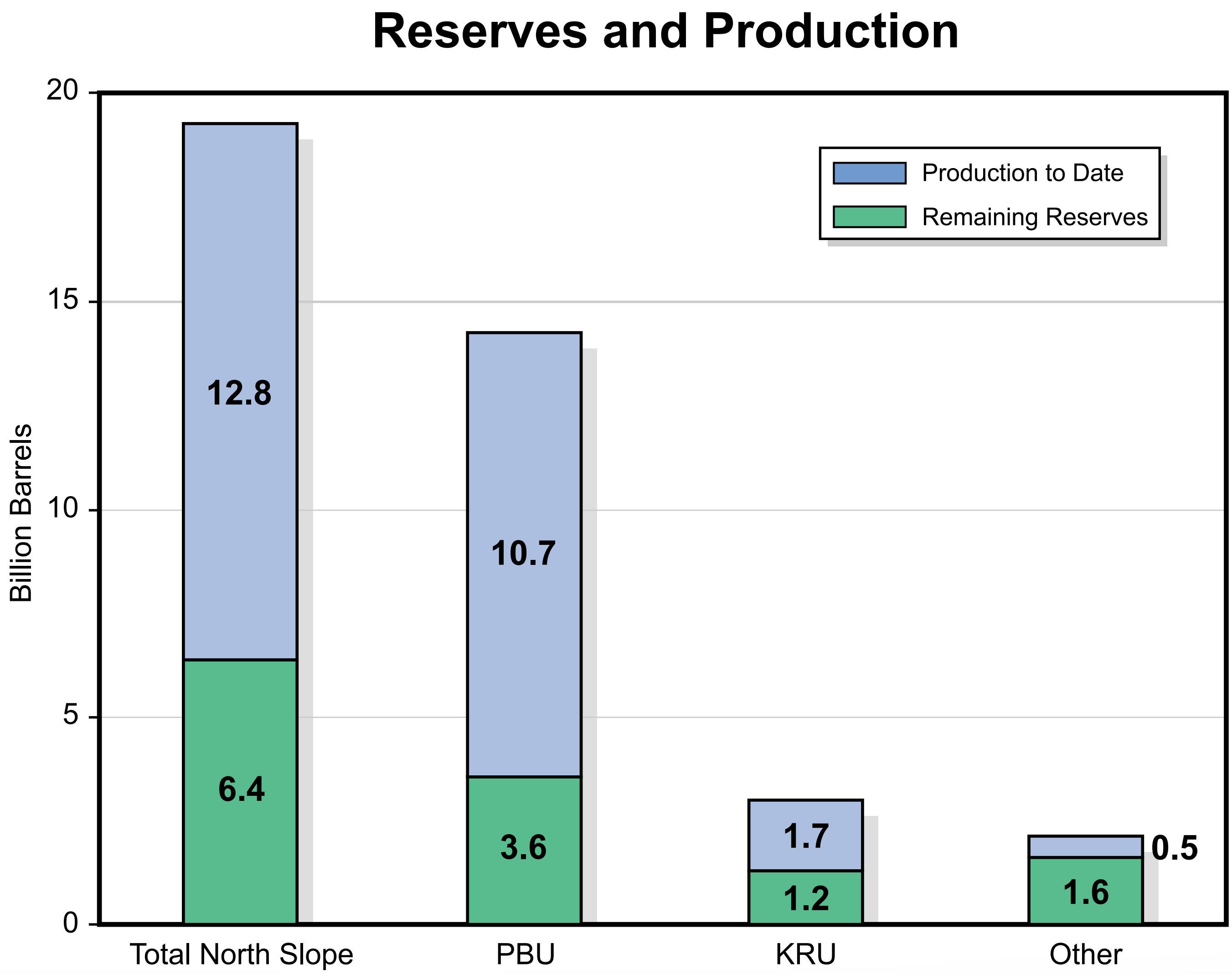
Gross gas production on the North Slope in 1999 was 3.2 trillion cubic feet (8.7 billion cubic feet (bcf)) per day but 93 percent of this volume was injected. Net gas production fuels the regional oil field equipment, operations, and pipelines (including the first four TAPS pump stations). Net gas production of 219 bcf consumed on the North Slope rivals the total gas produced in the Cook Inlet.

The Present

In 1994, ARCO and partners discovered the Alpine accumulation on state and Native Corporation land along the Colville River and adjacent to the northeastern boundary of NPRA and announced plans to develop the field the following year. Alaska's newest oil development is estimated to contain 381 million barrels of economically recoverable oil. Alpine is scheduled to go into production in summer 2000. Additional fields proposed for development but not yet producing include Northstar and Liberty.

Interest in Alaska's oil and gas resources continues today. In 1999, BP Amoco announced that it would acquire ARCO. As a result of the proposed merger, Phillips Petroleum bought ARCO Alaska Inc. and ARCO's marine tranportation and Alaska pipeline assets.

In addition to competitive leasing, the Department of Natural Resources has instituted an exploration licensing program to encourage exploration in oil basins outside of Cook Inlet and the North Slope. Also, the department has recently initiated a shallow natural gas leasing program, which allows the Division of Oil and Gas to issue non-competitive leases to explore for and develop natural gas reservoirs, including coalbed methane, located within 3,000 feet of the surface.


Reserves and Production
Billion Barrels
20
15
10
5
0
Production to Date
Remaining Reserves
12.8
6.4
10.7
3.6
1.7
1.2
0.5
1.6
Total North Slope
PBU
KRU
Other

BACKGROUND

DATA

UNITS

ROYALTY-IN-KIND AND ALASKA REFINING

LEASING PROGRAM

GOVERNMENT OIL & GAS MANAGEMENT AGENCIES IN ALASKA

Oil and Gas Reserves

North Slope

Oil and Gas Reserves

	Oil Reserves (MMBO)	Gas Reserves (Bcf)	Royalty Percent	Royalty Oil Reserves (MMBO)	Royalty Gas Reserves (Bcf)
North Slope					
Badami Unit	9	39	14.60%	1	6
Barrow					
East Barrow	-	5	0.00%	-	-
South Barrow	-	4	0.00%	-	-
Walakpa	-	25	0.00%	-	-
TOTAL Barrow	-	34		-	-
Colville River Unit					
Alpine	381	-	10.00%	38	-
CRU Satellite	55	-	-	-	-
TOTAL CRU	437	60		38	60
Duck Island Unit					
Endicott/Sag Delta	201	843	14.40%	29	121
Eider	5	-	12.50%	1	-
TOTAL DIU	207	843		30	121
Kuparuk River Unit					
Kuparuk	960	590	12.50%	120	74
West Sak	103	-	12.50%	13	-
Tabasco	27	-	12.50%	3	-
Tarn	63	21	12.50%	8	3
Kuparuk Satellite	50	-	12.50%	6	-
TOTAL KRU	1,202	611		150	76
Milne Point Unit					
Kuparuk	292	14	14.60%	43	2
Schrader Bluff	105	-	14.60%	15	-
Sag River	7	-	14.60%	1	-
TOTAL MPU	404	14		59	2
North Star	204	450	16.00%	33	72
Prudhoe Bay Unit					
Initial Participating Areas					
Prudhoe IPAs	2,865	-	12.50%	358	-
Midnight Sun	23	-	12.50%	3	-
PBU Satellites	311	-	12.50%	39	-
TOTAL PBU IPA	3,199	23,000	12.50%	400	2,875
Greater Point McIntyre Area					
Lisburne	40	276	12.50%	5	35
Niakuk	63	26	12.50%	8	3
North Prudhoe Bay State	1	-	12.50%	0	-
Pt. McIntyre	251	577	13.80%	35	80
West Beach	6	-	12.50%	1	-
TOTAL GPMA	361	879		48	117
TOTAL PBU	3,559	23,879		448	2,992
Other Undeveloped					
Liberty	138	-	0.00%	-	-
Known Onshore	202	5,000	12.50%	25	625
TOTAL Other	340	5,000		25	625
TOTAL North Slope	6,362	30,930		784	3,955

Cook Inlet and State Total

Oil and Gas Reserves

	Oil Reserves (MMBO)	Gas Reserves (Bcf)	Royalty Percent	Royalty Oil Reserves (MMBO)	Royalty Gas Reserves (Bcf)
Cook Inlet					
Beaver Creek	-	97	0.00%	-	-
Beluga River	-	600	7.50%	-	45
Cannery Loop	-	20	4.00%	-	1
Granite Point	8	19	12.50%	1	2
Ivan River, Lewis River, Pretty Creek, Stump Lake	-	20	12.50%	-	3
Kenai	-	225	2.10%	-	5
MacArthur River	22	383	12.50%	3	48
Middle Ground Shoal	8	8	12.50%	1	1
North Cook Inlet	-	917	12.50%	-	115
North Trading Bay	-	19	12.50%	-	2
Sterling	-	30	12.40%	-	4
Swanson River	2	108	0.00%	<1	-
Trading Bay	3	27	12.50%	<1	3
West Fork	-	3	0.00%	-	-
West MacArthur River	3	-	12.50%	<1	-
Other Undeveloped					
Birch Hill	-	11	0.00%	-	-
Falls Creek	-	13	12.50%	-	2
Lone Creek	-	-	0.00%	-	-
Nicolai Creek	-	2	12.50%	-	0
North Fork	-	12	12.50%	-	2
Tyonek Deep	25	30	12.50%	3	4
West Foreland	-	20	12.50%	-	3
TOTAL COOK INLET	72	2,564		8	238
TOTAL STATE	6,434	33,494		792	4,193

Badami Unit

Production Forecast (barrels per day)

	Badami Unit
	Badami
2000	3,065
2001	3,000
2002	3,000
2003	3,000
2004	3,000
2005	3,000
2006	3,000
2007	3,000
2008	1,500
2009	-
2010	-
2011	-
2012	-
2013	-
2014	-
2015	-
2016	-
2017	-
2018	-
2019	-
2020	-
2021	-

Colville River Unit

Production Forecast (barrels per day)

	Colville River Unit		
	Alpine	CRU Satellite	TOTAL CRU
2000	40,000	-	40,000
2001	80,000	-	80,000
2002	80,000	-	80,000
2003	80,000	-	80,000
2004	76,500	3,500	80,000
2005	70,500	9,500	80,000
2006	65,500	13,500	79,000
2007	60,750	14,500	75,250
2008	56,073	13,500	69,573
2009	51,256	12,500	63,756
2010	47,013	11,500	58,513
2011	43,337	10,500	53,837
2012	39,971	9,500	49,471
2013	36,912	8,550	45,462
2014	34,152	7,695	41,847
2015	31,788	6,926	38,714
2016	29,484	6,233	35,717
2017	27,550	5,610	33,160
2018	26,050	5,049	31,099
2019	24,525	4,544	29,069
2020	22,375	4,152	26,527
2021	20,500	4,013	24,513

Duck Island Unit

Production Forecast (barrels per day)

Duck Island Unit

	Endicott/ Sag Delta	Eider	TOTAL DIU
2000	39,142	1,073	40,215
2001	37,450	1,568	39,018
2002	36,175	1,411	37,586
2003	34,950	1,270	36,220
2004	33,800	1,143	34,943
2005	32,728	1,028	33,756
2006	31,317	926	32,242
2007	29,542	833	30,375
2008	27,872	750	28,621
2009	26,255	675	26,930
2010	24,743	607	25,351
2011	23,330	547	23,877
2012	22,009	492	22,500
2013	20,773	443	21,216
2014	19,618	398	20,016
2015	18,538	359	18,896
2016	17,528	323	17,850
2017	16,583	290	16,874
2018	15,700	261	15,962
2019	14,875	235	15,110
2020	14,238	211	14,449
2021	13,700	100	13,800

Kuparuk River Unit

Production Forecast (barrels per day)

Kuparuk River Unit

	Kuparuk	West Sak	Tabasco	Tarn	Kuparuk Satellite	TOTAL KRU
2000	206,263	3,425	6,094	25,233	-	241,015
2001	193,750	3,682	6,625	21,850	-	225,907
2002	185,000	8,724	8,160	18,475	7,500	227,859
2003	178,500	8,745	7,795	15,800	18,750	229,590
2004	174,250	9,720	6,125	13,175	20,250	223,520
2005	167,200	9,798	4,740	10,875	16,200	208,813
2006	157,800	10,357	4,055	9,000	12,960	194,172
2007	149,600	11,428	3,525	7,350	10,368	182,271
2008	139,400	13,357	3,135	6,100	8,294	170,286
2009	129,200	14,673	2,850	5,150	6,636	158,509
2010	118,800	15,533	2,615	4,500	5,382	146,830
2011	109,600	16,093	2,405	3,900	4,501	136,499
2012	101,800	17,194	2,195	3,550	3,878	128,617
2013	94,000	18,681	2,010	3,450	3,411	121,552
2014	86,200	18,710	1,790	3,350	3,027	113,076
2015	78,950	17,592	1,600	3,250	2,708	104,100
2016	72,900	16,639	1,500	3,150	2,450	96,639
2017	67,500	15,694	1,400	3,050	2,241	89,885
2018	62,100	14,446	1,300	2,900	2,073	82,818
2019	56,700	13,267	1,200	2,700	1,938	75,805
2020	52,000	12,475	1,075	2,500	1,739	69,789
2021	47,000	11,395	900	2,300	1,580	63,175

Milne Point Unit

Production Forecast (barrels per day)

Milne Point Unit

	Kuparuk	Schrader Bluff	Sag River	TOTAL MPU
2000	47,033	6,425	554	54,012
2001	48,181	6,682	1,500	56,363
2002	48,753	8,724	1,900	59,377
2003	48,269	8,745	1,710	58,724
2004	48,324	9,720	1,547	59,590
2005	47,522	9,798	1,408	58,727
2006	46,040	10,357	1,281	57,678
2007	45,256	11,428	1,166	57,850
2008	43,447	13,357	1,061	57,864
2009	41,612	14,673	970	57,255
2010	39,908	15,533	893	56,334
2011	37,459	16,093	821	54,373
2012	35,000	17,194	756	52,950
2013	32,537	18,681	695	51,913
2014	30,250	18,710	643	49,602
2015	28,126	17,592	598	46,315
2016	26,153	16,639	556	43,348
2017	24,320	15,694	517	40,531
2018	22,617	14,446	481	37,543
2019	21,035	13,267	450	34,752
2020	19,637	12,475	418	32,529
2021	17,800	11,395	400	29,595

North Star Unit

Production Forecast (barrels per day)

	North Star Unit
	North Star
2000	-
2001	10,000
2002	65,000
2003	65,000
2004	65,000
2005	57,876
2006	50,375
2007	44,875
2008	39,000
2009	33,500
2010	31,750
2011	27,350
2012	23,200
2013	19,350
2014	14,750
2015	10,440
2016	-
2017	-
2018	-
2019	-
2020	-
2021	-

Prudhoe Bay Unit

IPAs and GPMA

Production Forecast (barrels per day)

Prudhoe Bay Unit											
	Initial Participating Areas				Greater Point McIntyre Area						
	Prudhoe IPAs	Midnight Sun	PBU Satellites	TOTAL PBU IPA	Lisburne	Point McIntyre	Niakuk	North Prudhoe Bay State	West Beach	TOTAL GPMA	TOTAL PBU
2000	573,249	4,367	3,338	580,953	7,933	77,176	23,835	126	2,043	111,112	692,064
2001	535,500	4,150	9,000	548,650	9,100	68,982	20,335	350	2,163	100,930	649,580
2002	504,680	5,250	18,000	527,930	9,750	58,093	16,845	500	2,088	87,275	615,205
2003	478,926	6,175	32,250	517,351	8,750	49,271	14,355	500	1,800	74,676	592,027
2004	454,830	5,411	47,000	507,241	7,750	42,999	12,365	500	1,523	65,136	572,377
2005	431,751	4,600	56,250	492,600	7,000	38,270	10,625	250	1,348	57,492	550,092
2006	411,888	4,015	60,900	476,803	6,250	34,552	9,385	-	1,188	51,375	528,178
2007	389,722	3,614	65,050	458,386	5,750	31,565	8,395	-	1,063	46,772	505,158
2008	368,830	3,252	68,550	440,632	5,250	29,117	7,478	-	938	42,782	483,414
2009	352,938	2,927	69,000	424,865	4,750	27,054	6,673	-	813	39,289	464,154
2010	337,925	2,634	65,500	406,059	4,375	25,286	5,959	-	688	36,307	442,366
2011	313,749	2,371	60,100	376,220	4,158	23,751	5,331	-	563	33,802	410,022
2012	300,368	2,134	54,100	356,602	3,927	22,405	4,772	-	438	31,541	388,143
2013	297,743	1,921	47,000	346,663	3,639	21,214	4,273	-	318	29,442	376,106
2014	292,527	1,728	40,150	334,405	3,361	20,148	3,822	-	205	27,536	361,942
2015	287,620	1,556	34,700	323,875	3,110	19,189	3,420	-	75	25,793	349,668
2016	276,239	1,400	29,900	307,539	2,851	18,320	3,065	-	-	24,236	331,774
2017	265,360	1,260	25,350	291,970	2,594	17,529	2,748	-	-	22,871	314,841
2018	254,962	1,134	21,275	277,371	2,361	16,803	2,465	-	-	21,628	298,999
2019	245,573	1,021	17,675	264,269	2,148	16,135	2,212	-	-	20,494	284,763
2020	237,133	833	14,500	252,466	1,923	15,407	1,996	-	-	19,326	271,793
2021	231,500	550	13,000	245,050	1,790	14,750	1,050	-	-	17,590	262,640

Other Undeveloped

Production Forecast (barrels per day)

	Other Undeveloped		
	Liberty	Known Onshore	TOTAL Other
2000	-	-	-
2001	-	-	-
2002	-	-	-
2003	-	-	-
2004	17,500	-	17,500
2005	45,000	10,000	55,000
2006	47,500	35,000	82,500
2007	46,800	55,000	101,800
2008	37,856	58,200	96,056
2009	31,554	53,280	84,834
2010	26,821	47,652	74,473
2011	22,797	42,887	65,684
2012	19,902	38,598	58,500
2013	17,911	34,738	52,650
2014	16,120	31,264	47,385
2015	14,508	28,138	42,646
2016	13,057	25,324	38,382
2017	11,752	22,792	34,543
2018	9,567	20,513	30,079
2019	-	18,461	18,461
2020	-	16,245	16,245
2021	-	14,387	14,387

Cook Inlet

Production Forecast (barrels per day)

	Cook Inlet							
	Beaver Creek	Granite Point	MacArthur River	Middle Ground Shoal	Swanson River	Trading Bay	West MacArthur River	TOTAL COOK INLET
2000	280	5,000	14,000	5,300	1,830	1,730	2,200	30,340
2001	270	4,800	13,820	4,800	1,560	1,640	2,060	28,950
2002	250	4,600	12,230	4,300	1,320	1,560	1,750	26,010
2003	230	4,300	10,670	3,900	1,130	1,480	1,490	23,200
2004	200	3,900	9,280	3,500	940	1,390	1,230	20,440

Royalty Oil Production Forecast

North Slope

Royalty Oil Production Forecast (barrels per day)

	NORTH SLOPE											Royalty-in-Kind			
	Badami Unit	Colville River Unit	Duck Island Unit	Kuparuk River Unit	Milne Point Unit	North Star Unit	Prudhoe Bay Unit	Total North Slope	PBU Royalty NGLs Delivered to KRU via the Oliktok Pipeline	KRU NGLs Royalty Credit	Field Cost Credit	Available Royalty Volume for Sale as Royalty-in-Kind	Mapco No. 1	Mapco No. 3	Remaining RIK Volumes
Royalty:	14.6%	10.0%	14.3%	12.5%	14.6%	16.0%	12.6%	12.7%							
2000	447	4,000	5,771	30,127	7,886	0	87,544	135,774	3,750	3,013	6,021	122,990	35,000	24,950	63,040
2001	438	8,000	5,589	28,238	8,229	1,600	82,123	134,217	3,750	2,824	5,656	121,987	35,000	24,637	62,350
2002	438	8,000	5,386	28,482	8,669	10,400	77,680	139,055	3,750	2,848	5,435	127,022	35,000	24,858	67,164
2003	438	8,000	5,192	28,699	8,574	10,400	74,664	135,966	3,750	2,870	5,284	124,062	35,000	25,013	64,050
2004	438	8,000	5,010	27,940	8,700	10,400	72,124	132,612	3,750	2,794	5,114	120,954	0	0	120,954
2005	438	8,000	4,841	26,102	8,574	9,260	69,275	126,490	3,750	2,610	4,880	115,250	0	0	115,250
2006	438	7,900	4,625	24,272	8,421	8,060	66,486	120,202	3,750	2,427	4,648	109,377	0	0	109,377
2007	438	7,525	4,358	22,784	8,446	7,180	63,568	114,299	3,750	2,278	4,422	103,849	0	0	103,849
2008	219	6,957	4,107	21,286	8,448	6,240	60,817	108,075	3,750	2,129	4,204	97,992	0	0	97,992
2009	0	6,376	3,865	19,814	8,359	5,360	58,382	102,156	3,750	1,981	4,004	92,420	0	0	92,420
2010	0	5,851	3,639	18,354	8,225	5,080	55,635	96,784	3,750	1,835	3,790	87,409	0	0	87,409
2011	0	5,384	3,428	17,062	7,938	4,376	51,571	89,760	3,750	1,706	3,518	80,786	0	0	80,786
2012	0	4,947	3,231	16,077	7,731	3,712	48,818	84,516	3,750	1,608	3,326	75,832	0	0	75,832
2013	0	4,546	3,047	15,194	7,579	3,096	47,298	80,760	3,750	1,519	3,201	72,290	0	0	72,290
2014	0	4,185	2,875	14,135	7,242	2,360	45,513	76,309	3,750	1,413	3,055	68,090	0	0	68,090
2015	0	3,871	2,714	13,012	6,762	1,670	43,966	71,997	3,750	1,301	2,920	64,026	0	0	64,026
2016	0	3,572	2,564	12,080	6,329	0	41,718	66,262	3,750	1,208	2,758	58,546	0	0	58,546
2017	0	3,316	2,424	11,236	5,918	0	39,590	62,484	3,750	1,124	2,606	55,004	0	0	55,004
2018	0	3,110	2,294	10,352	5,481	0	37,600	58,837	3,750	1,035	2,461	51,592	0	0	51,592
2019	0	2,907	2,171	9,476	5,074	0	35,812	55,439	3,750	948	2,326	48,416	0	0	48,416
2020	0	2,653	2,077	8,724	4,749	0	34,181	52,383	3,750	872	2,205	45,555	0	0	45,555
2021	0	2,451	1,985	7,897	4,321	0	33,028	49,682	3,750	790	2,106	43,037	0	0	43,037

Historical Oil Production (million barrels/year)

	NORTH SLOPE									
	Badami	Duck Island								
		Eider[1]	Endicott	Endicott	Endicott	Endicott	Sag Delta North[1]	Sag Delta North[1]	Sag Delta North[1]	Ivishak[1]
	oil	oil	oil	ngl	inj	net	oil	ngl	net	oil
1958	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	-	-	-	-	-	-
1970	-	-	-	-	-	-	-	-	-	-
1971	-	-	-	-	-	-	-	-	-	-
1972	-	-	-	-	-	-	-	-	-	-
1973	-	-	-	-	-	-	-	-	-	-
1974	-	-	-	-	-	-	-	-	-	-
1975	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-
1977	-	-	-	-	-	-	-	-	-	-
1978	-	-	-	-	-	-	-	-	-	-
1979	-	-	-	-	-	-	-	-	-	-
1980	-	-	-	-	-	-	-	-	-	-
1981	-	-	-	-	-	-	-	-	-	-
1982	-	-	-	-	-	-	-	-	-	-
1983	-	-	-	-	-	-	-	-	-	-
1984	-	-	-	-	-	-	-	-	-	-
1985	-	-	-	-	-	-	-	-	-	-
1986	-	-	0.011	-	0.007	0.004	-	-	-	-
1987	-	-	8.796	0.003	0.014	8.785	-	-	-	-
1988	-	-	37.441	0.492	-	37.933	-	-	-	-
1989	-	-	35.746	0.839	-	36.585	0.349	0.005	0.354	-
1990	-	-	36.181	0.845	-	37.026	1.542	0.028	1.570	-
1991	-	-	38.996	1.170	-	40.165	2.309	0.048	2.357	-
1992	-	-	40.603	1.468	-	42.071	1.002	0.011	1.013	-
1993	-	-	38.433	1.551	-	39.984	0.761	0.007	0.768	-
1994	-	-	33.916	1.481	-	35.397	0.368	0.003	0.371	-
1995	-	-	32.998	1.203	-	34.201	0.235	0.001	0.236	-
1996	-	-	26.450	1.013	-	27.463	0.199	0.001	0.200	-
1997	-	-	21.121	1.550	-	22.671	0.255	0.002	0.257	-
1998	0.731	0.395	16.775	1.265	-	18.040	0.193	0.001	0.194	-
1999	1.150	-	13.529	1.480	-	15.009	-	-	-	0.216
TOTAL	1.881	0.395	380.996	14.360	0.021	395.334	7.213	0.107	7.320	0.216

Prudhoe Bay Unit IPAs and Satellites

Historical Oil Production (million barrels/year)

NORTH SLOPE							
	Prudhoe Bay Unit Initial Participating Areas (IPAs) and Satellites						
	Midnight Sun	Prudhoe Bay[2] IPAs	Prudhoe Bay IPAs	Prudhoe Bay IPAs	Prudhoe Bay[2] IPAs	Schrader Bluff	TOTAL PBU IPAs + Satellites
	oil	oil	ngl	inj	net	oil	
1958	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-
1969	-	0.277	-	0.217	0.060	-	0.060
1970	-	1.193	-	0.879	0.314	-	0.314
1971	-	1.157	-	0.833	0.324	-	0.324
1972	-	0.922	-	0.792	0.130	-	0.130
1973	-	0.944	-	0.817	0.127	-	0.127
1974	-	2.170	-	1.640	0.530	-	0.530
1975	-	2.870	-	2.147	0.723	-	0.723
1976	-	4.604	-	3.611	0.993	-	0.993
1977	-	115.258	-	2.075	113.183	-	113.183
1978	-	397.679	-	-	397.679	-	397.679
1979	-	468.412	-	-	468.412	-	468.412
1980	-	555.394	0.254	-	555.648	-	555.648
1981	-	555.170	0.450	-	555.620	-	555.620
1982	-	558.889	0.500	-	559.389	-	559.389
1983	-	560.837	0.311	-	561.148	-	561.148
1984	-	561.952	0.317	-	562.269	-	562.269
1985	-	568.534	0.056	-	568.590	-	568.590
1986	-	561.538	0.230	-	561.768	-	561.768
1987	-	572.045	14.610	-	586.655	-	586.655
1988	-	559.412	19.274	-	578.686	-	578.686
1989	-	505.940	16.928	-	522.868	-	522.868
1990	-	470.140	16.094	-	486.234	-	486.234
1991	-	465.399	21.307	-	486.706	-	486.706
1992	-	432.587	23.902	-	456.489	-	456.489
1993	-	385.811	23.879	-	409.690	-	409.690
1994	-	351.493	22.825	-	374.318	-	374.318
1995	-	313.629	26.810	-	340.439	-	340.439
1996	-	282.060	30.549	-	312.609	-	312.609
1997	-	252.421	31.580	-	284.001	-	284.001
1998	0.061	221.781	30.983	-	252.764	-	252.825
1999	2.017	194.338	29.423	-	223.761	0.022	225.800
TOTAL	2.078	9,924.856	310.282	13.011	10,222.127	0.022	10,224.227

Historical Oil Production

Greater Point McIntyre Area

Historical Oil Production (million barrels/year)

NORTH SLOPE																	
	Greater Point McIntyre Area (GPMA)																TOTAL Prudhoe Bay Unit (IPA+GPMA)
	Lisburne	Lisburne	Lisburne	Niakuk[2]	Niakuk[2]	Niakuk[2]	North Prudhoe Bay State	North Prudhoe Bay State	North Prudhoe Bay State	Point McIntyre	Point McIntyre	Point McIntyre	West Beach	West Beach	West Beach	TOTAL GPMA	
	oil	ngl	net	oil	ngl	net	oil	ngl	net	oil	ngl	net	oil	ngl	net		
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.060
1970	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.314
1971	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.324
1972	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.130
1973	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.127
1974	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.530
1975	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.723
1976	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.993
1977	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	113.183
1978	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	397.679
1979	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	468.412
1980	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	555.648
1981	0.002	-	0.002	-	-	-	-	-	-	-	-	-	-	-	-	0.002	555.622
1982	0.208	-	0.208	-	-	-	-	-	-	-	-	-	-	-	-	0.208	559.597
1983	0.087	-	0.087	-	-	-	-	-	-	-	-	-	-	-	-	0.087	561.235
1984	0.294	-	0.294	-	-	-	-	-	-	-	-	-	-	-	-	0.294	562.563
1985	1.123	-	1.123	-	-	-	-	-	-	-	-	-	-	-	-	1.123	569.713
1986	3.594	-	3.594	-	-	-	-	-	-	-	-	-	-	-	-	3.594	565.362
1987	16.199	0.458	16.657	-	-	-	-	-	-	-	-	-	-	-	-	16.657	603.312
1988	15.095	1.008	16.103	-	-	-	-	-	-	-	-	-	-	-	-	16.103	594.789
1989	13.737	1.093	14.830	-	-	-	-	-	-	-	-	-	-	-	-	14.830	537.698
1990	14.669	1.204	15.873	-	-	-	-	-	-	-	-	-	-	-	-	15.873	502.107
1991	13.316	1.337	14.653	-	-	-	-	-	-	-	-	-	-	-	-	14.653	501.359
1992	12.517	1.464	13.981	-	-	-	-	-	-	-	-	-	-	-	-	13.981	470.470
1993	8.473	1.277	9.750	-	-	-	0.418	0.015	0.433	7.543	0.090	7.633	0.724	0.009	0.733	18.549	428.239
1994	6.846	0.939	7.785	3.383	0.028	3.411	0.727	0.031	0.758	37.684	0.548	38.232	0.512	0.012	0.524	50.710	425.028
1995	5.454	0.823	6.277	7.004	0.077	7.081	0.702	0.034	0.736	50.225	0.679	50.904	0.163	0.005	0.168	65.166	405.605
1996	4.465	0.674	5.139	10.937	0.108	11.045	0.126	0.003	0.129	57.926	0.825	58.751	0.474	0.025	0.499	75.563	388.172
1997	3.002	0.416	3.418	10.265	0.136	10.401	-	-	-	58.498	1.042	59.540	0.319	0.027	0.346	73.705	357.706
1998	2.468	0.331	2.799	10.356	0.128	10.484	0.001	0.001	0.002	47.553	1.009	48.562	0.096	0.006	0.102	61.949	314.774
1999	2.203	0.326	2.529	9.857	0.131	9.988	-	-	-	33.426	0.830	34.256	0.603	0.067	0.670	47.443	273.243
TOTAL	123.752	11.350	135.102	51.802	0.608	52.410	1.974	0.084	2.058	292.855	5.023	297.878	2.891	0.151	3.042	490.490	10,714.717

KRU and Milne Point Units

Historical Oil Production (million barrels/year)

	NORTH SLOPE										
	Kuparuk River Unit							Milne Point Unit			
	Kuparuk	Kuparuk	Kuparuk	Tabasco	Tarn	West Sak	TOTAL Kuparuk River Unit	Milne Point	Sag River	Schrader Bluff	TOTAL Milne Point Unit
	oil	ngl	net	oil	oil	oil		oil	oil	oil	
1958	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	-	-	-	-	-	-	-
1970	-	-	-	-	-	-	-	-	-	-	-
1970	0.006	-	0.006	-	-	-	0.006	-	-	-	-
1971	-	-	-	-	-	-	-	-	-	-	-
1972	-	-	-	-	-	-	-	-	-	-	-
1973	-	-	-	-	-	-	-	-	-	-	-
1974	-	-	-	-	-	-	-	-	-	-	-
1975	-	-	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-	-	-
1977	-	-	-	-	-	-	-	-	-	-	-
1978	-	-	-	-	-	-	-	-	-	-	-
1979	-	-	-	-	-	-	-	-	-	-	-
1980	-	-	-	-	-	-	-	-	-	-	-
1981	1.092	-	1.092	-	-	-	1.092	-	-	-	-
1982	32.406	-	32.406	-	-	-	32.406	-	-	-	-
1983	39.876	-	39.876	-	-	0.006	39.882	-	-	-	-
1984	46.084	-	46.084	-	-	0.124	46.208	-	-	-	-
1985	78.926	0.761	79.687	-	-	0.326	80.013	0.704	-	-	0.704
1986	93.900	1.072	94.972	-	-	0.300	95.272	4.709	-	-	4.709
1987	102.448	1.257	103.705	-	-	-	103.705	0.040	-	-	0.040
1988	110.891	0.256	111.147	-	-	-	111.147	-	-	-	-
1989	109.770	-	109.770	-	-	-	109.770	3.715	-	-	3.715
1990	107.206	-	107.206	-	-	-	107.206	6.624	-	0.004	6.628
1991	113.571	-	113.571	-	-	-	113.571	6.701	-	0.756	7.457
1992	118.506	-	118.506	-	-	-	118.506	5.812	-	1.135	6.947
1993	115.166	-	115.166	-	-	-	115.166	5.704	-	1.060	6.764
1994	111.795	-	111.795	-	-	-	111.795	5.648	-	1.030	6.678
1995	106.999	-	106.999	-	-	-	106.999	7.352	0.173	1.167	8.692
1996	99.459	-	99.459	-	-	-	99.459	12.665	0.346	1.090	14.101
1997	95.970	-	95.970	-	-	0.001	95.971	17.055	0.363	1.536	18.954
1998	91.702	-	91.702	0.483	3.534	0.562	96.281	18.314	0.162	1.943	20.419
1999	82.394	-	82.394	1.920	9.541	1.190	95.045	17.408	-	2.178	19.586
TOTAL	1,658.167	3.346	1,661.513	2.403	13.075	2.509	1,679.500	112.451	1.044	11.899	125.394

Historical Oil Production

North Slope Totals

Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool", monthly reports.

NORTH SLOPE (million barrels/year)

	TOTAL OIL	TOTAL NGL	TOTAL INJECTED	TOTAL NET
1958	-	-	-	-
1959	-	-	-	-
1960	-	-	-	-
1961	-	-	-	-
1962	-	-	-	-
1963	-	-	-	-
1964	-	-	-	-
1965	-	-	-	-
1966	-	-	-	-
1967	-	-	-	-
1968	-	-	-	-
1969	0.277	-	0.217	0.060
1970	1.199	-	0.879	0.320
1971	1.157	-	0.833	0.324
1972	0.922	-	0.792	0.130
1973	0.944	-	0.817	0.127
1974	2.170	-	1.640	0.530
1975	2.870	-	2.147	0.723
1976	4.604	-	3.611	0.993
1977	115.258	-	2.075	113.183
1978	397.679	-	-	397.679
1979	468.412	-	-	468.412
1980	555.394	0.254	-	555.648
1981	556.264	0.450	-	556.714
1982	591.503	0.500	-	592.003
1983	600.806	0.311	-	601.117
1984	608.454	0.317	-	608.771
1985	649.613	0.817	-	650.430
1986	664.052	1.302	0.007	665.347
1987	699.528	16.328	0.014	715.842
1988	722.839	21.030	-	743.869
1989	669.257	18.865	-	688.122
1990	636.366	18.171	-	654.537
1991	641.048	23.862	-	664.910
1992	612.162	26.845	-	639.007
1993	564.093	26.828	-	590.921
1994	553.402	25.867	-	579.269
1995	526.101	29.632	-	555.733
1996	496.197	33.198	-	529.395
1997	460.806	34.753	-	495.559
1998	417.110	33.724	-	450.834
1999	371.992	32.257	-	404.249
TOTAL	12,592.479	345.311	13.032	12,924.758

[1]AOGCC combined 1999 production volumes for Eider and Sag Delta North and reported these data in the "Ivishak Pool."

[2]Production for the Prudhoe Bay Initial Participating Areas (IPAs) includes oil and condensates.

[3]Niakuk production volumes for 1994-1998 include production from all Niakuk wells. AOGCC lists 1999 volumes as "Niakuk Pool."

Historical Oil Production (million barrels/year)

	COOK INLET									
	Beaver Creek	Cannery Loop[1]	Granite Point[2]	Kenai[1]	McArthur River[3]	McArthur River[3]	McArthur River[3]	Middle Ground Shoal[4]	North Trading Bay Unit	Redoubt Shoal
	oil	ngl	oil	ngl	oil	ngl	net	oil	oil	oil
1958	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-
1965	-	-	0.002	-	0.001	-	0.001	0.027	-	-
1966	-	-	-	-	0.003	-	0.003	2.649	-	-
1967	-	-	7.052	-	0.749	-	0.749	7.404	0.002	-
1968	-	-	13.131	-	21.782	-	21.782	14.134	0.185	0.002
1969	-	-	9.183	0.002	31.301	-	31.301	10.467	4.310	-
1970	-	-	7.522	0.002	40.165	0.426	40.591	12.719	3.265	-
1971	-	-	5.577	0.001	40.537	0.593	41.130	11.304	2.029	-
1972	0.002	-	4.663	0.002	40.774	0.570	41.344	9.719	2.553	-
1973	0.416	-	4.767	0.001	38.884	0.661	39.545	10.239	2.022	-
1974	0.375	-	4.237	-	39.145	0.654	39.799	9.001	2.127	-
1975	0.322	-	4.361	0.001	40.876	0.644	41.520	8.670	1.530	-
1976	0.302	-	4.471	0.001	35.810	0.653	36.463	8.864	1.096	-
1977	0.276	-	4.711	-	33.235	0.733	33.968	7.617	0.970	-
1978	0.223	-	4.867	0.001	30.223	0.730	30.953	6.382	0.797	-
1979	0.211	-	4.613	-	25.440	0.541	25.981	5.545	0.609	-
1980	0.214	-	4.394	-	20.894	0.412	21.306	4.854	0.372	-
1981	0.180	-	3.975	-	18.022	0.484	18.506	4.291	0.235	-
1982	0.182	-	3.467	-	15.806	0.449	16.255	3.573	0.132	-
1983	0.170	-	3.550	-	13.564	0.332	13.896	3.381	0.117	-
1984	0.159	-	3.287	-	11.707	0.317	12.024	3.238	0.080	-
1985	0.146	-	3.052	-	7.454	0.194	7.648	3.098	0.113	-
1986	0.158	-	3.169	-	7.942	0.228	8.170	3.211	0.220	-
1987	0.185	-	2.803	-	7.375	0.196	7.571	2.834	0.246	-
1988	0.141	-	2.677	-	7.143	0.162	7.305	2.742	0.195	-
1989	0.227	-	2.275	-	6.955	-	6.955	2.769	0.179	-
1990	0.212	-	1.462	-	4.265	-	4.265	2.688	0.121	-
1991	0.179	-	2.064	-	7.247	-	7.247	2.670	0.168	-
1992	0.175	-	2.522	-	7.397	-	7.397	2.423	0.030	-
1993	0.153	-	2.488	-	6.636	-	6.636	2.160	-	-
1994	0.140	<.001	2.209	-	7.091	-	7.091	2.785	-	-
1995	0.132	<.001	2.580	-	6.622	-	6.622	2.823	-	-
1996	0.125	<.001	2.556	-	6.102	-	6.102	2.396	-	-
1997	0.119	-	2.432	-	5.059	-	5.059	2.223	-	-
1998	0.103	-	2.079	-	4.817	-	4.817	2.156	-	-
1999	0.100	-	1.787	-	4.697	-	4.697	1.968	-	-
TOTAL	5.327	<.001	133.985	0.011	595.720	8.979	604.699	183.024	23.703	0.002

Cook Inlet

Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool", monthly report.

Historical Oil Production (million barrels/year)

	COOK INLET							COOK INLET		
	Swanson River[5]	Swanson River[5]	Swanson River[5]	Trading Bay[6]	Trading Bay[7]	Trading Bay[8]	West McArthur River	TOTAL OIL	TOTAL NGL	TOTAL INJECTED
	oil	ngl	net	oil	ngl	net	oil			
1958	0.036	-	0.036	-	-	-	-	0.036	-	0.036
1959	0.187	-	0.187	-	-	-	-	0.187	-	0.187
1960	0.558	-	0.558	-	-	-	-	0.558	-	0.558
1961	6.327	-	6.327	-	-	-	-	6.327	-	6.327
1962	10.259	-	10.259	-	-	-	-	10.259	-	10.259
1963	10.740	-	10.740	-	-	-	-	10.740	-	10.740
1964	11.054	-	11.054	-	-	-	-	11.054	-	11.054
1965	11.099	-	11.099	0.002	-	0.002	-	11.131	-	11.131
1966	11.712	-	11.712	-	-	-	-	14.364	-	14.364
1967	12.980	-	12.980	0.727	-	0.727	-	28.914	-	28.914
1968	13.619	0.004	13.623	3.292	-	3.292	-	66.145	0.004	66.149
1969	13.151	0.070	13.221	5.626	-	5.626	-	74.038	0.072	74.110
1970	12.408	0.063	12.471	6.335	0.039	6.374	-	82.414	0.530	82.944
1971	11.466	0.077	11.543	6.714	0.039	6.753	-	77.627	0.710	78.337
1972	8.896	0.012	8.908	6.033	0.025	6.058	-	72.640	0.609	73.249
1973	10.064	0.098	10.162	5.803	0.051	5.854	-	72.195	0.811	73.006
1974	9.765	0.096	9.861	5.425	0.043	5.468	-	70.075	0.793	70.868
1975	8.754	0.089	8.843	4.598	0.031	4.629	-	69.111	0.765	69.876
1976	7.591	0.090	7.681	4.270	0.026	4.296	-	62.404	0.770	63.174
1977	5.981	0.086	6.067	3.306	0.044	3.350	-	56.096	0.863	56.959
1978	4.870	0.065	4.935	2.770	0.019	2.789	-	50.132	0.815	50.947
1979	4.344	0.080	4.424	2.284	0.014	2.298	-	43.046	0.635	43.681
1980	3.724	0.064	3.788	1.794	0.006	1.800	-	36.246	0.482	36.728
1981	2.938	0.048	2.986	1.435	0.005	1.440	-	31.076	0.537	31.613
1982	2.999	0.048	3.047	1.251	0.002	1.253	-	27.410	0.499	27.909
1983	3.017	0.045	3.062	0.964	0.004	0.968	-	24.763	0.381	25.144
1984	2.517	0.039	2.556	0.995	0.005	1.000	-	21.983	0.361	22.344
1985	2.165	0.026	2.191	0.915	0.004	0.919	-	16.943	0.224	17.167
1986	2.055	0.054	2.109	0.826	0.002	0.828	-	17.581	0.284	17.865
1987	2.059	0.030	2.089	0.689	0.001	0.690	-	16.191	0.227	16.418
1988	2.127	0.033	2.160	0.691	-	0.691	-	15.716	0.195	15.911
1989	1.875	0.024	1.899	1.085	-	1.085	-	15.365	0.024	15.389
1990	1.878	0.019	1.897	0.522	-	0.522	-	11.148	0.019	11.167
1991	1.962	0.023	1.985	1.048	-	1.048	0.002	15.340	0.023	15.363
1992	1.773	0.019	1.792	0.856	-	0.856	0.002	15.178	0.019	15.197
1993	1.576	0.018	1.594	0.742	-	0.742	0.098	13.853	0.018	13.871
1994	1.672	0.023	1.695	0.743	-	0.743	0.921	15.561	0.023	15.584
1995	1.712	0.017	1.729	0.722	-	0.722	0.922	15.513	0.017	15.530
1996	1.521	0.019	1.540	0.589	-	0.589	1.296	14.585	0.019	14.604
1997	1.065	0.012	1.077	0.602	-	0.602	0.645	12.145	0.012	12.157
1998	0.911	0.009	0.920	0.700	-	0.700	1.037	11.803	0.009	11.812
1999	0.794	-	0.794	0.645	-	0.645	0.914	10.905	-	10.905
TOTAL	226.201	1.400	227.601	74.999	0.360	75.359	5.837	1,248.798	10.750	1,259.548

[1]These gas fields temporarily produced NGLs.
[2]Includes Middle Kenai and Undefined Hemlock pools.
[3]Includes Hemlock, Middle Kenai G, and West Foreland Pools.
[4]Includes A, B, C, D, E, F, and G pools.
[5]Includes Hemlock pool.
[6]Includes Hemlock, Undefined, and B, C, D, and E pools

North Slope

Historical Gas Production (billion cubic feet/year)

	NORTH SLOPE								
	Badami			Barrow			Duck Island		
		Badami	Badami	East Barrow	South Barrow	Walakpa	Eider	Eider	Eider
	gas	inj	net	gas	gas	gas	gas	inj	net
Pre-1958	-	-	-	-	0.830	-	-	-	-
1958	-	-	-	-	0.119	-	-	-	-
1959	-	-	-	-	0.132	-	-	-	-
1960	-	-	-	-	0.172	-	-	-	-
1961	-	-	-	-	0.172	-	-	-	-
1962	-	-	-	-	0.197	-	-	-	-
1963	-	-	-	-	0.211	-	-	-	-
1964	-	-	-	-	0.249	-	-	-	-
1965	-	-	-	-	0.389	-	-	-	-
1966	-	-	-	-	0.438	-	-	-	-
1967	-	-	-	-	0.475	-	-	-	-
1968	-	-	-	-	0.504	-	-	-	-
1969	-	-	-	-	0.582	-	-	-	-
1970	-	-	-	-	0.619	-	-	-	-
1971	-	-	-	-	0.627	-	-	-	-
1972	-	-	-	-	0.675	-	-	-	-
1973	-	-	-	-	0.707	-	-	-	-
1974	-	-	-	-	0.765	-	-	-	-
1975	-	-	-	-	0.799	-	-	-	-
1976	-	-	-	-	0.832	-	-	-	-
1977	-	-	-	-	0.879	-	-	-	-
1978	-	-	-	-	0.893	-	-	-	-
1979	-	-	-	-	0.913	-	-	-	-
1980	-	-	-	-	1.027	-	-	-	-
1981	-	-	-	0.037	1.009	-	-	-	-
1982	-	-	-	0.717	0.532	-	-	-	-
1983	-	-	-	0.689	0.541	-	-	-	-
1984	-	-	-	0.693	0.650	-	-	-	-
1985	-	-	-	0.632	0.678	-	-	-	-
1986	-	-	-	0.589	0.589	-	-	-	-
1987	-	-	-	0.590	0.622	-	-	-	-
1988	-	-	-	0.661	0.598	-	-	-	-
1989	-	-	-	0.475	0.758	-	-	-	-
1990	-	-	-	0.488	0.733	-	-	-	-
1991	-	-	-	0.583	0.662	-	-	-	-
1992	-	-	-	0.439	0.628	0.252	-	-	-
1993	-	-	-	0.259	0.441	0.585	-	-	-
1994	-	-	-	0.223	0.261	0.858	-	-	-
1995	-	-	-	0.099	0.052	1.109	-	-	-
1996	-	-	-	0.064	0.051	1.160	-	-	-
1997	-	-	-	0.114	0.041	1.126	-	-	-
1998	0.459	0.005	0.454	0.146	0.081	1.110	2.122	-	2.122
1999	2.240	1.718	0.521	0.123	0.055	1.281	4.879	4.480	0.399
TOTAL	2.699	1.723	0.975	7.621	22.188	7.481	7.001	4.480	2.521

Historical Gas Production (billion cubic feet/year)

	NORTH SLOPE				
	Duck Island				
	Endicott[1]	Endicott[1]	Endicott[1]	Sag Delta	TOTAL Duck Island
	gas	inj	net	gas	
Pre-1958	-	-	-	-	-
1958	-	-	-	-	-
1959	-	-	-	-	-
1960	-	-	-	-	-
1961	-	-	-	-	-
1962	-	-	-	-	-
1963	-	-	-	-	-
1964	-	-	-	-	-
1965	-	-	-	-	-
1966	-	-	-	-	-
1967	-	-	-	-	-
1968	-	-	-	-	-
1969	-	-	-	-	-
1970	-	-	-	-	-
1971	-	-	-	-	-
1972	-	-	-	-	-
1973	-	-	-	-	-
1974	-	-	-	-	-
1975	-	-	-	-	-
1976	-	-	-	-	-
1977	-	-	-	-	-
1978	-	-	-	-	-
1979	-	-	-	-	-
1980	-	-	-	-	-
1981	-	-	-	-	-
1982	-	-	-	-	-
1983	-	-	-	-	-
1984	-	-	-	-	-
1985	-	-	-	-	-
1986	0.195	-	0.195	-	0.195
1987	8.237	5.615	2.622	-	2.622
1988	34.834	28.023	6.811	-	6.811
1989	41.194	33.033	8.161	0.236	8.397
1990	42.490	35.523	6.967	1.416	8.383
1991	60.246	51.136	9.110	2.347	11.457
1992	97.047	85.082	11.965	0.703	12.668
1993	120.116	100.682	19.434	0.529	19.963
1994	116.810	102.534	14.276	0.259	14.535
1995	127.191	113.839	13.352	0.152	13.504
1996	123.968	111.638	12.330	0.099	12.429
1997	124.737	111.495	13.242	0.157	13.399
1998	119.981	109.440	10.541	0.122	12.785
1999	126.274	112.467	13.807	0.120	14.326
TOTAL	1,143.320	1,000.507	142.813	6.140	151.474

Historical Gas Production (billion cubic feet/year)

	NORTH SLOPE				
	Prudhoe Bay Unit Initial Participating Areas				
	Midnight Sun gas	Prudhoe Bay gas	Prudhoe Bay inj	Prudhoe Bay net	TOTAL Prudhoe Bay Unit IPA
Pre-1958	-	-	-	-	-
1958	-	-	-	-	-
1959	-	-	-	-	-
1960	-	-	-	-	-
1961	-	-	-	-	-
1962	-	-	-	-	-
1963	-	-	-	-	-
1964	-	-	-	-	-
1965	-	-	-	-	-
1966	-	-	-	-	-
1967	-	-	-	-	-
1968	-	-	-	-	-
1969	-	0.243	-	0.243	0.243
1970	-	1.037	-	1.037	1.037
1971	-	0.889	-	0.889	0.889
1972	-	0.658	-	0.658	0.658
1973	-	0.699	-	0.699	0.699
1974	-	2.022	-	2.022	2.022
1975	-	3.046	-	3.046	3.046
1976	-	5.077	-	5.077	5.077
1977	-	94.936	68.118	26.818	26.818
1978	-	307.966	271.854	36.112	36.112
1979	-	432.475	390.136	42.339	42.339
1980	-	597.148	546.510	50.638	50.638
1981	-	647.768	595.106	52.662	52.662
1982	-	756.884	697.812	59.072	59.072
1983	-	818.993	754.044	64.949	64.949
1984	-	846.674	768.899	77.775	77.775
1985	-	936.613	846.786	89.827	89.827
1986	-	970.290	882.882	87.408	87.408
1987	-	1,228.527	1,105.023	123.504	123.504
1988	-	1,404.992	1,248.094	156.898	156.898
1989	-	1,412.853	1,244.284	168.569	168.569
1990	-	1,481.462	1,317.106	164.356	164.356
1991	-	1,768.837	1,583.472	185.365	185.365
1992	-	1,951.156	1,761.397	189.759	189.759
1993	-	2,116.808	1,921.633	195.175	195.175
1994	-	2,402.584	2,204.235	198.349	198.349
1995	-	2,716.959	2,497.702	219.257	219.257
1996	-	2,750.907	2,535.603	215.304	215.304
1997	-	2,794.735	2,577.617	217.118	217.118
1998	0.130	2,801.402	2,588.527	212.875	213.005
1999	4.355	2,772.147	2,572.252	199.895	204.250
TOTAL	4.485	34,026.787	30,979.092	3,047.695	3,052.180

Historical Gas Production (billion cubic feet/year)

	NORTH SLOPE										
	Greater Point McIntyre Area (GPMA)[2]										
	Lisburne	Lisburne	Lisburne	Niakuk[3]	. Prudhoe Bay S	Point McIntyre	Point McIntyre	Point McIntyre	West Beach	TOTAL GPMA	TOTAL Prudhoe Bay Unit IPA
	gas	inj	net	gas	gas	gas	inj	net	gas		
Pre-1958	-	-	-	-	-	-	-	-	-	-	-
1958	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	-	-	-	-	-	-	0.243
1970	-	-	-	-	-	-	-	-	-	-	1.037
1971	-	-	-	-	-	-	-	-	-	-	0.889
1972	-	-	-	-	-	-	-	-	-	-	0.658
1973	-	-	-	-	-	-	-	-	-	-	0.699
1974	-	-	-	-	-	-	-	-	-	-	2.022
1975	-	-	-	-	-	-	-	-	-	-	3.046
1976	-	-	-	-	-	-	-	-	-	-	5.077
1977	-	-	-	-	-	-	-	-	-	-	26.818
1978	-	-	-	-	-	-	-	-	-	-	36.112
1979	-	-	-	-	-	-	-	-	-	-	42.339
1980	-	-	-	-	-	-	-	-	-	-	50.638
1981	0.003	-	0.003	-	-	-	-	-	-	0.003	52.665
1982	0.374	-	0.374	-	-	-	-	-	-	0.374	59.446
1983	0.154	-	0.154	-	-	-	-	-	-	0.154	65.103
1984	0.343	-	0.343	-	-	-	-	-	-	0.343	78.118
1985	1.902	-	1.902	-	-	-	-	-	-	1.902	91.729
1986	8.677	-	8.677	-	-	-	-	-	-	8.677	96.085
1987	64.906	56.741	8.165	-	-	-	-	-	-	8.165	131.669
1988	94.670	87.815	6.855	-	-	-	-	-	-	6.855	163.753
1989	104.746	102.248	2.498	-	-	-	-	-	-	2.498	171.067
1990	107.592	101.542	6.050	-	-	-	-	-	-	6.050	170.406
1991	124.360	112.457	11.903	-	-	-	-	-	-	11.903	197.268
1992	154.468	141.598	12.870	-	-	-	-	-	-	12.870	202.629
1993	130.882	122.991	7.891	-	1.103	5.392	3.979	1.413	0.592	10.999	206.174
1994	101.260	99.748	1.512	2.471	2.646	38.795	34.461	4.334	1.119	12.082	210.431
1995	80.866	104.272	-23.406	7.241	2.482	46.637	21.687	24.950	0.446	11.713	230.970
1996	67.013	93.000	-25.987	8.757	0.206	56.584	30.444	26.140	2.720	11.836	227.140
1997	39.999	75.249	-35.250	10.523	-	70.009	35.945	34.064	2.739	12.076	229.194
1998	33.111	50.399	-17.288	8.381	0.018	70.828	49.276	21.552	0.545	13.208	226.213
1999	33.214	93.859	-60.645	8.468	-	62.556	41.672	20.884	4.452	-26.841	177.409
TOTAL	1,148.540	1,241.919	-93.379	45.841	6.455	350.801	217.464	133.337	12.613	104.867	3,157.047

Historical Gas Production (billion cubic feet/year)

	NORTH SLOPE								
	Kuparuk River Unit								
	Kuparuk	Kuparuk	Kuparuk	Tabasco	Tarn	Tarn	Tarn	West Sak	TOTAL Kuparuk River Unit
	gas	inj	net	gas	gas	inj	net	gas	
Pre-1958	-	-	-	-	-	-	-	-	-
1958	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	-	-	-	-	-
1970	-	-	-	-	-	-	-	-	-
1971	-	-	-	-	-	-	-	-	-
1972	-	-	-	-	-	-	-	-	-
1973	-	-	-	-	-	-	-	-	-
1974	-	-	-	-	-	-	-	-	-
1975	-	-	-	-	-	-	-	-	-
1976	-	-	-	-	-	-	-	-	-
1977	-	-	-	-	-	-	-	-	-
1978	-	-	-	-	-	-	-	-	-
1979	-	-	-	-	-	-	-	-	-
1980	-	-	-	-	-	-	-	-	-
1981	0.615	-	0.615	-	-	-	-	-	0.615
1982	22.989	17.822	5.167	-	-	-	-	-	5.167
1983	44.391	38.277	6.114	-	-	-	-	0.005	6.119
1984	57.389	47.930	9.459	-	-	-	-	0.079	9.538
1985	104.279	85.909	18.370	-	-	-	-	0.134	18.504
1986	114.889	90.449	24.440	-	-	-	-	0.108	24.548
1987	125.089	89.191	35.898	-	-	-	-	-	35.898
1988	119.883	87.906	31.977	-	-	-	-	-	31.977
1989	107.519	83.323	24.196	-	-	-	-	-	24.196
1990	116.579	91.273	25.306	-	-	-	-	-	25.306
1991	123.207	95.982	27.225	-	-	-	-	-	27.225
1992	122.767	96.625	26.142	-	-	-	-	-	26.142
1993	120.599	94.339	26.260	-	-	-	-	-	26.260
1994	120.273	93.288	26.985	-	-	-	-	-	26.985
1995	112.418	84.317	28.101	-	-	-	-	-	28.101
1996	107.811	83.632	24.179	-	-	-	-	-	24.179
1997	105.644	85.893	19.751	-	-	-	-	-	19.751
1998	117.517	103.604	13.913	0.112	4.476	1.195	3.281	0.213	17.519
1999	117.204	93.859	23.345	0.305	13.396	16.502	-3.106	0.377	20.921
TOTAL	1,861.062	1,463.619	397.443	0.417	17.872	17.697	0.175	0.916	398.951

North Slope

Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool", monthly report

Historical Gas Production (billion cubic feet/year)

	NORTH SLOPE						NORTH SLOPE		
	Milne Point Unit						TOTAL	TOTAL	TOTAL
	Milne Point	Milne Point	Milne Point	Sag River	Schrader Bluff	TOTAL Milne Point Unit	GAS	INJECTED	NET
	gas	inj	net	gas	gas				
Pre-1958	-	-	-	-	-	-	0.830	-	0.830
1958	-	-	-	-	-	-	0.119	-	0.119
1959	-	-	-	-	-	-	0.132	-	0.132
1960	-	-	-	-	-	-	0.172	-	0.172
1961	-	-	-	-	-	-	0.172	-	0.172
1962	-	-	-	-	-	-	0.197	-	0.197
1963	-	-	-	-	-	-	0.211	-	0.211
1964	-	-	-	-	-	-	0.249	-	0.249
1965	-	-	-	-	-	-	0.389	-	0.389
1966	-	-	-	-	-	-	0.438	-	0.438
1967	-	-	-	-	-	-	0.475	-	0.475
1968	-	-	-	-	-	-	0.504	-	0.504
1969	-	-	-	-	-	-	0.825	-	0.825
1970	-	-	-	-	-	-	1.656	-	1.656
1971	-	-	-	-	-	-	1.516	-	1.516
1972	-	-	-	-	-	-	1.333	-	1.333
1973	-	-	-	-	-	-	1.406	-	1.406
1974	-	-	-	-	-	-	2.787	-	2.787
1975	-	-	-	-	-	-	3.845	-	3.845
1976	-	-	-	-	-	-	5.909	-	5.909
1977	-	-	-	-	-	-	95.815	68.118	27.697
1978	-	-	-	-	-	-	308.859	271.854	37.005
1979	-	-	-	-	-	-	433.388	390.136	43.252
1980	-	-	-	-	-	-	598.175	546.510	51.665
1981	-	-	-	-	-	-	649.432	595.106	54.326
1982	-	-	-	-	-	-	781.496	715.634	65.862
1983	-	-	-	-	-	-	864.773	792.321	72.452
1984	-	-	-	-	-	-	905.828	816.829	88.999
1985	0.253	-	0.253	-	-	0.253	1,044.491	932.695	111.796
1986	1.644	0.197	1.447	-	-	1.447	1,096.981	973.528	123.453
1987	0.011	-	0.011	-	-	0.011	1,427.982	1,256.570	171.412
1988	-	-	-	-	-	-	1,655.638	1,451.838	203.800
1989	0.978	0.320	0.658	-	-	0.658	1,668.759	1,463.208	205.551
1990	2.718	1.401	1.317	-	-	1.317	1,753.478	1,546.845	206.633
1991	3.515	1.704	1.811	-	0.244	2.055	2,084.001	1,844.751	239.250
1992	3.015	1.632	1.383	-	0.536	1.919	2,331.011	2,086.334	244.677
1993	2.967	1.836	1.131	-	0.518	1.649	2,500.791	2,245.460	255.331
1994	3.524	2.305	1.219	-	0.515	1.734	2,791.598	2,536.571	255.027
1995	4.340	3.399	0.941	0.113	0.656	1.710	3,100.761	2,825.216	275.545
1996	6.120	4.307	1.813	0.299	0.464	2.576	3,126.223	2,858.624	267.599
1997	9.463	6.998	2.465	0.437	0.644	3.546	3,160.368	2,893.197	267.171
1998	8.949	6.351	2.598	0.179	1.008	3.785	3,170.890	2,908.797	262.093
1999	9.588	6.137	3.451	-	1.198	4.649	3,162.232	2,942.947	219.285
TOTAL	57.085	36.587	20.498	1.028	5.783	27.309	38,736.135	34,963.089	3,773.046

[1]The small Endicott dry gas volume for 1996 was an injection of processed gas into Endicott when the field resumed operation.

[2]Liquids from the Greater Point McIntyre Area flow to the Lisburne Production Center (LPC). At the LPC gas from these liquids is returned and reinjected into the GPMA fields. Consequently, production and injection data may appear to be anomolous.

[3]Niakuk production volumes for 1994-1999 include production from all Niakuk wells. AOGCC lists 1999 volumes as "Niakuk Pool."

Historical Gas Production

Cook Inlet

Historical Gas Production (billion cubic feet/year)

COOK INLET	Albert Kaloa	Beaver Creek	Beaver Creek	Beaver Creek	Beluga River	Birch Hill	Cannery Loop	Falls Creek	Granite Point	Ivan River
	gas	gas	inj	net	gas	gas	gas	gas	gas	gas
Pre-1958	-	-	-	-	-	-	-	-	-	-
1958	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	0.014	-	-	-	-	-
1964	-	-	-	-	0.137	-	-	-	-	-
1965	-	-	-	-	-	0.065	-	-	-	-
1966	-	-	-	-	-	-	-	0.019	-	-
1967	-	-	-	-	0.168	-	-	-	4.890	-
1968	-	-	-	-	2.018	-	-	-	10.036	-
1969	-	-	-	-	3.038	-	-	-	8.043	-
1970	0.095	-	-	-	3.571	-	-	-	9.211	-
1971	0.024	-	-	-	4.055	-	-	-	7.753	-
1972	-	0.002	-	0.002	4.142	-	-	-	5.773	-
1973	-	0.207	-	0.207	4.929	-	-	-	4.518	-
1974	-	0.150	0.019	0.131	5.596	-	-	-	3.265	-
1975	-	0.322	-	0.322	6.980	-	-	-	3.390	-
1976	-	0.261	0.091	0.170	11.211	-	-	-	3.205	-
1977	-	0.203	0.100	0.103	13.353	-	-	-	3.634	-
1978	-	0.329	0.144	0.185	14.253	-	-	-	3.860	-
1979	-	0.182	0.079	0.103	16.994	-	-	-	3.287	-
1980	-	0.180	0.029	0.151	17.002	-	-	-	3.233	-
1981	-	0.217	0.020	0.197	17.248	-	-	-	3.509	-
1982	-	0.396	0.037	0.359	18.653	-	-	-	2.780	-
1983	-	8.344	0.031	8.313	18.084	-	-	-	2.578	-
1984	-	9.335	-	9.335	19.833	-	-	-	2.340	-
1985	-	10.927	-	10.927	22.571	-	-	-	2.147	-
1986	-	17.773	-	17.773	25.357	-	-	-	2.415	-
1987	-	15.528	-	15.528	23.971	-	-	-	2.431	-
1988	-	14.346	-	14.346	25.586	-	9.400	-	2.543	-
1989	-	12.321	-	12.321	30.126	-	11.255	-	2.251	-
1990	-	12.474	-	12.474	39.512	-	12.502	-	1.431	0.676
1991	-	10.403	-	10.403	38.494	-	12.318	-	1.586	2.132
1992	-	7.368	-	7.368	36.534	-	10.635	-	2.246	1.774
1993	-	6.336	-	6.336	31.739	-	9.516	-	2.444	8.238
1994	-	1.304	-	1.304	34.212	-	6.361	-	2.077	15.996
1995	-	1.915	-	1.915	35.645	-	5.535	-	1.942	12.027
1996	-	3.042	-	3.042	36.930	-	2.072	-	2.251	6.605
1997	-	4.626	-	4.626	35.002	-	3.130	-	2.551	5.297
1998	-	3.743	-	3.743	33.391	-	3.021	-	2.635	4.532
1999	-	3.315	-	3.315	35.987	-	2.871	-	2.465	3.579
TOTAL	0.119	145.549	0.550	144.999	666.336	0.065	88.616	0.019	118.720	60.856

Historical Gas Production (billion cubic feet/year)

COOK INLET	Kenai	Lewis River	McArthur River (TBU)	Middle Ground Shoal	Moquawkie	Nicolai Creek	North Cook Inlet	North Fork	North Trading Bay Unit	Pretty Creek
	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas
Pre-1958	-	-	-	-	-	-	-	-	-	-
1958	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-
1961	0.215	-	-	-	-	-	-	-	-	-
1962	1.460	-	-	-	-	-	-	-	-	-
1963	3.106	-	-	-	-	-	-	-	-	-
1964	4.493	-	-	-	-	-	-	-	-	-
1965	5.985	-	-	-	-	-	-	-	-	-
1966	33.375	-	-	1.200	-	-	-	0.105	-	-
1967	39.624	-	0.220	3.215	0.034	-	-	-	-	-
1968	46.014	-	6.155	6.654	0.353	0.026	-	-	0.045	-
1969	59.340	-	14.194	6.006	0.514	0.387	7.881	-	1.175	-
1970	80.612	-	19.688	6.137	0.083	0.202	40.947	-	0.725	-
1971	72.184	-	19.304	5.147	-	0.141	45.024	-	0.419	-
1972	76.007	-	19.722	4.075	-	0.066	41.580	-	0.635	-
1973	71.345	-	19.063	4.826	-	0.006	42.709	-	0.588	-
1974	68.485	-	19.599	4.260	-	0.011	44.238	-	0.600	-
1975	77.175	-	21.471	4.199	-	0.083	45.622	-	0.478	-
1976	79.467	-	19.027	4.347	-	0.108	45.091	-	0.318	-
1977	81.886	-	19.706	4.108	-	0.032	47.201	-	0.272	-
1978	97.290	-	18.585	3.290	-	-	46.757	-	0.217	-
1979	97.029	-	16.605	2.744	-	-	49.448	-	0.153	-
1980	98.846	-	15.590	2.628	-	-	41.540	-	0.197	-
1981	105.800	-	15.206	2.502	-	-	49.486	-	0.264	-
1982	115.913	-	16.240	2.374	-	-	45.368	-	0.445	-
1983	112.978	-	14.375	2.663	-	-	47.877	-	0.660	-
1984	110.109	0.696	15.076	2.726	-	-	46.981	-	0.649	-
1985	115.842	1.644	10.676	2.622	-	-	45.819	-	0.526	-
1986	82.470	1.338	13.560	1.593	-	-	43.838	-	0.513	0.067
1987	90.014	0.345	13.277	1.586	-	-	42.889	-	0.537	0.776
1988	76.299	0.045	16.722	1.635	-	-	44.989	-	0.270	0.871
1989	65.706	0.095	31.000	1.965	-	-	45.287	-	0.217	0.641
1990	38.393	1.485	51.456	2.579	-	-	45.014	-	0.060	0.607
1991	25.581	1.420	61.196	1.587	-	-	44.695	-	0.079	0.742
1992	24.187	0.706	70.070	2.377	-	-	44.411	-	0.013	0.762
1993	23.826	0.383	62.512	2.941	-	-	45.529	-	-	0.333
1994	18.853	0.244	50.027	3.025	-	-	52.689	-	-	0.203
1995	16.484	0.126	54.914	2.138	-	-	53.541	-	-	0.256
1996	13.294	0.114	67.275	0.852	-	-	55.976	-	0.023	0.301
1997	12.672	0.066	66.838	1.051	-	-	52.466	-	0.511	0.383
1998	9.736	0.102	73.822	1.882	-	-	53.964	-	0.695	0.435
1999	9.916	0.246	67.772	2.751	-	-	51.643	-	0.241	-
TOTAL	2,162.011	9.055	1,000.943	103.685	0.984	1.062	1,410.500	0.105	11.525	6.377

Cook Inlet

Historical Gas Production (billion cubic feet/year)

COOK INLET	Sterling	Stump Lake	Swanson River	Swanson River[1]	Swanson River[1]	Trading Bay	West Fork	West McArthur River	TOTAL GROSS	TOTAL INJECTED	TOTAL NET
	gas	gas	gas	inj	net	gas	gas	gas			
Pre-1958	-	-	-	-	-	-	-	-	-	-	-
1958	-	-	0.006	-	0.006	-	-	-	0.006	-	0.006
1959	-	-	0.027	-	0.027	-	-	-	0.027	-	0.027
1960	-	-	0.119	46.482	-	-	-	-	0.119	46.482	-
1961	-	-	1.293	-	1.293	-	-	-	1.508	-	1.508
1962	0.025	-	2.071	0.259	1.812	-	-	-	3.556	0.259	3.297
1963	0.046	-	7.646	6.478	1.168	-	-	-	10.812	6.478	4.334
1964	0.058	-	7.176	5.620	1.556	-	-	-	11.864	5.620	6.244
1965	0.120	-	5.973	4.843	1.130	-	-	-	12.143	4.843	7.300
1966	0.157	-	6.363	28.770	-	-	-	-	41.219	28.770	12.449
1967	0.180	-	13.541	37.944	-	0.722	-	-	62.594	37.944	24.650
1968	0.198	-	25.434	58.316	-	2.916	-	-	99.849	58.316	41.533
1969	0.265	-	40.756	67.215	-	5.944	-	-	147.543	67.215	80.328
1970	0.265	-	50.396	73.139	-	6.430	-	-	218.362	73.139	145.223
1971	0.267	-	66.569	73.892	-	8.678	-	-	229.565	73.892	155.673
1972	0.172	-	67.441	76.133	-	5.033	-	-	224.648	76.133	148.515
1973	0.027	-	74.067	87.482	-	2.951	-	-	225.236	87.482	137.754
1974	0.032	-	80.869	86.793	-	2.712	-	-	229.817	86.812	143.005
1975	0.035	-	90.665	97.976	-	2.134	-	-	252.554	97.976	154.578
1976	0.035	-	101.427	113.279	-	2.155	-	-	266.652	113.370	153.282
1977	0.029	-	106.911	118.279	-	2.619	-	-	279.954	118.379	161.575
1978	0.024	-	106.934	114.557	-	2.211	0.052	-	293.802	114.701	179.101
1979	0.025	-	116.266	120.268	-	1.560	0.770	-	305.063	120.347	184.716
1980	0.026	-	118.855	120.636	-	1.355	0.476	-	299.928	120.665	179.263
1981	0.023	-	103.592	106.137	-	1.160	0.030	-	299.037	106.157	192.880
1982	0.024	-	105.654	113.023	-	1.187	0.086	-	309.120	113.060	196.060
1983	0.022	-	97.505	95.353	2.152	0.896	0.067	-	306.049	95.384	210.665
1984	0.018	-	96.710	93.687	3.023	0.911	0.037	-	305.421	93.687	211.734
1985	0.012	-	92.104	89.025	3.079	1.005	0.022	-	305.917	89.025	216.892
1986	0.002	-	95.083	93.602	1.481	0.866	-	-	284.875	93.602	191.273
1987	-	-	84.063	87.013	-2.950	0.897	-	-	276.314	87.013	189.301
1988	-	-	102.600	99.734	2.866	1.041	-	-	296.347	99.734	196.613
1989	-	-	104.094	107.802	-3.708	1.215	-	-	306.173	107.802	198.371
1990	-	0.528	104.395	106.031	-1.636	0.407	-	-	311.519	106.031	205.488
1991	-	1.608	105.057	105.157	-0.100	0.865	0.460	-	308.223	105.157	203.066
1992	-	1.504	104.533	104.724	-0.191	0.692	1.364	-	309.176	104.724	204.452
1993	0.007	0.778	97.701	93.052	4.649	0.619	0.625	0.031	293.558	93.052	200.506
1994	0.224	0.454	124.420	97.148	27.272	0.648	0.206	0.216	311.159	97.148	214.011
1995	0.184	0.288	101.781	73.086	28.695	0.526	0.016	0.231	287.549	73.086	214.463
1996	0.037	0.185	76.159	42.820	33.339	0.386	-	0.309	265.811	42.820	222.991
1997	0.005	0.132	51.898	23.163	28.735	1.122	-	0.152	237.902	23.163	214.739
1998	-	0.080	36.917	11.089	25.828	0.843	-	0.241	226.039	11.089	214.950
1999	0.125	0.054	36.742	7.642	29.100	0.426	-	0.212	218.345	7.642	210.703
TOTAL	2.669	5.611	2,811.813	2,887.649	188.626	63.132	4.211	1.392	8,675.355	2,888.199	5,833.519

Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool", monthly report.

[1]Gas from other fields was injected into the Swanson River field to maintain reservoir pressure. Consequently, production and injection volumes may appear anomalous. The very high gas injection volume for 1960 was an accounting adjustment.

Historical Royalty Oil Production

NORTH SLOPE								TOTAL North Slope
	Colville River Unit	Duck Island Unit	Kuparuk River Unit	Milne Point Unit	Prudhoe Bay Unit RIV	Prudhoe Bay Unit RIK	TOTAL Prudhoe Bay Unit	
Production (barrels)								
1996	-	4,005,134	12,403,783	2,028,806	20,958,791	27,382,712	48,341,503	115,120,730.480
1997	-	3,324,412	10,978,270	2,656,966	18,399,640	26,139,553	44,539,193	106,038,034.230
1998	-	2,692,532	10,887,893	2,833,414	11,810,493	27,981,560	39,792,053	95,997,945.090
1999	1,266	2,263,296	10,821,950	2,699,198	15,508,533	19,070,657	34,579,190	84,944,088.650
Revenues								
1996	-	$57,987,542	$188,462,048	$28,403,789	$296,101,427	$436,376,846	$732,478,273	$1,739,809,925
1997	-	$42,866,427	$150,137,432	$33,776,789	$242,341,066	$383,700,713	$626,041,779	$1,478,864,205
1998	-	$18,147,072	$82,772,342	$18,608,378	$69,280,597	$227,032,160	$296,312,757	$712,153,305
1999	$57,185	$26,460,806	$136,801,806	$31,596,437	$170,204,367	$259,245,781	$429,450,148	$1,053,816,530

Historical Royalty Oil Production

COOK INLET	Granite Point Field	South Granite Point Unit	Cannery Loop Field	North Middle Ground Shoal	Middle Ground Shoal	South Middle Ground Shoal	Trading Bay Filed	Trading Bay Unit	West McArthur Unit	TOTAL Cook Inlet
Production (barrels)										
1996	320,281	-	9	50,622	216,475	32,460	73,629	762,714	161,967	1,618,158
1997	303,533	-	-	41,959	150,614	26,795	75,064	632,387	80,650	1,311,001
1998	259,839	-	-	44,699	195,976	28,783	87,128	602,381	116,223	1,335,030
1999	172,411	51,017	-	38,201	181,913	24,583	82,668	587,176	114,262	1,252,231
Revenues										-
1996	$5,824,597	-	-$5,528	$1,000,134	$4,266,126	$613,057	$1,188,184	$13,330,480	$2,256,556	$28,473,607
1997	$5,175,340	-	-	$764,403	$3,654,590	$490,468	$1,192,008	$10,561,261	$1,795,197	$23,633,267
1998	$2,813,480	-	-	$544,472	$2,244,325	$345,745	$852,521	$5,901,622	$1,106,984	$13,809,148
1999	$2,089,980	$1,387,751	-	$661,562	$3,072,935	$405,548	$1,261,303	$8,917,412	$1,583,092	$19,379,581

Historical Royalty Gas Production

North Slope

Historical Royalty Gas Production

	NORTH SLOPE				TOTAL
	Duck Island Unit	Kuparuk River Unit	Milne Point Unit	Prudhoe Bay Unit	**North Slope**
Production (mcf)					
1996	32,446	107,807	9,466	1,467,794	1,617,512.600
1997	35,605	90,487	26,034	1,337,301	1,489,426.660
1998	36,255	79,552	27,156	1,178,761	1,321,724.380
1999	168,919	78,783	27,611	1,092,217	1,367,530.200
Revenues					
1996	$30,497	$96,452	$29,676	$1,318,431	$1,475,056
1997	$31,402	$63,482	$28,326	$1,154,595	$1,277,804
1998	$27,554	$32,473	$23,723	$949,674	$1,033,424
1999	$150,373	$50,763	$26,108	$937,602	$1,164,845

Historical Royalty Gas Production

Cook Inlet

Historical Royalty Gas Production

COOK INLET	Beluga River Unit	Cannery Loop Unit	South Granite Point Unit	Granite Point Field	Ivan River Unit	Kenai Unit	Lewis River Unit	North Middle Ground Shoal Unit	Middle Ground Shoal	South Middle Ground Shoal
Production (mcf)										
1996	2,777,105	122,528	-	109,798	1,167,827	159,084	11,389	403	996	489
1997	2,628,297	186,477	-	141,763	935,228	140,655	7,057	17,965	-	-
1998	2,508,785	163,775	1,127	162,690	800,046	111,751	11,959	131,092	-	-
1999	2,704,980	167,759	28,102	67,573	631,597	111,459	29,916	246,030	-	-
Revenues										
1996	$3,942,906	$205,833	-	$180,076	$1,995,187	$250,307	$19,865	$14,576	$613	$72
1997	$4,598,164	$325,190	-	$191,592	$1,318,780	$249,102	$9,943	$23,979	-	-
1998	$4,264,931	$231,820	$1,353	$221,096	$1,070,859	$156,838	$15,585	$160,470	-	-
1999	$3,782,832	$271,607	$30,115	$82,135	$757,916	$294,223	$35,899	$300,841	-	-

Historical Royalty Gas Production

Cook Inlet

Historical Royalty Gas Production

	COOK INLET								TOTAL Cook Inlet
	North Cook Inlet Unit	Pretty Creek Unit	Spark Platform	Sterling Unit	North Trading Bay Unit	Stump Lake Unit	Trading Bay Field	Trading Bay Unit	
Production									
1996	6,910,165	41,347	2,814	558	57	44,183	-	7,248,017	18,596,759.3
1997	6,490,318	53,928	62,872	81	-	30,942	19,031	6,982,452	17,697,066.9
1998	6,665,243	61,640	85,882	4	-	18,332	-	7,841,950	18,564,276.8
1999	6,372,036	3,982	28,044	15	-	11,978	-	7,333,019	17,736,489.3
Revenues									
1996	$11,615,706	$69,483	$3,796	$1,514	$77	$31,502	-	$10,286,938	28,618,452.9
1997	$12,054,437	$75,855	$94,178	$140	-	-	$22,797	$10,147,976	29,112,133.9
1998	$8,874,018	$82,099	$118,197	$8	-	$71	-	$10,768,856	25,966,200.3
1999	$8,914,102	$4,778	$31,511	$19	-	$12,836	-	$8,917,539	23,436,353.2

North Slope

Historical Royalty Oil Production by Payor

NORTH SLOPE	Amerada Hess	Amoco	Anadarko	Arco	BP	Chevron	CIRI	DOYON	Exxon
Production (barrels)									
1996	-	360,245	-	12,393,570	18,374,599	116,487	36,393	7,282	6,364,423
1997	-	297,395	-	11,120,403	16,683,338	98,673	30,474	6,093	5,571,147
1998	-	236,813	-	9,521,816	13,595,127	64,349	918	4,837	3,563,010
1999	-	199,393	279	10,729,354	14,233,417	91,429	-	4,044	4,814,677
Revenues									
1996	-$118,215	$5,403,122	-	$190,182,380	$256,838,544	$1,712,485	$517,798	$103,471	$90,516,387
1997	$34,097	$3,674,233	-	$155,280,555	$216,022,314	$1,273,612	$422,666	$83,399	$71,706,852
1998	-	$1,556,244	-	$72,785,595	$85,232,060	$367,964	$11,864	$40,870	$19,733,115
1999	-	$2,403,577	$12,427	$135,879,335	$158,955,268	$1,043,504	-	$38,606	$52,341,733

North Slope

Historical Royalty Oil Production by Payor

NORTH SLOPE

	Forcenergy	L L & E	Mapco 1978 Contract	Mapco 1997 Contract	Marathon	Mobil	NANA	Oxy	Petrofina	Phillips
Production										
1996	-	$4,592	$13,037,159	-	$5,862	$279,928	$21,761	$154,526	-	$230,737
1997	$4,726	-	$12,651,629	$465,988	-	$236,807	$18,286	$208,046	-	$190,355
1998	$2,795	-	$11,148,190	$4,451,369	-	$155,396	$14,402	$224,250	$31,815	$112,917
1999	$3,704	-	$12,442,407	-	-	$195,257	$12,043	$212,159	$53,760	$151,416
Revenues										
1996	-	$68,283	$207,138,217	-	$84,474	$4,034,866	$309,800	$2,247,692	-	$3,175,436
1997	$63,207	-	$184,999,869	$6,032,134	$1,392	$3,026,169	$254,616	$2,778,344	-	$2,377,433
1998	$16,920	-	$90,752,306	$38,590,098	-	$851,166	$122,367	$1,532,623	$168,424	$752,421
1999	$42,828	-	$166,427,319	-$60,370	-	$2,165,787	$120,277	$2,625,708	$616,199	$1,378,898

Historical Royalty Oil Production

North Slope

Historical Royalty Oil Production by Payor

	NORTH SLOPE						TOTAL North Slope
	Shell	Tesoro	Texaco	Union Texas Petroleum	Unocal	Williams 1998 Contract	
Production							
1996	7,176	14,345,554	63,325	-	975,611	-	66,779,227
1997	-	13,021,937	51,931	-	841,614	-	61,498,841
1998	-	11,497,733	30,723	-	771,215	884,268	56,311,943
1999	-	-	40,708	279	731,527	6,628,250	50,544,102
Revenues							
1996	101,774	229,238,629	880,081	-	14,896,427	-	1,007,331,652
1997	-4,601	192,668,709	664,035	-	11,463,390	-	852,822,426
1998	-	92,287,552	148,657	-	6,012,926	5,402,204	416,365,377
1999	-	190,874	398,008	12,403	9,077,675	92,687,958	626,358,014

Cook Inlet

Historical Royalty Oil Production by Payor

	COOK INLET							TOTAL
	Cross Timbers	Forcenergy	Marathon	Mobil	Shell	Stewart	Unocal	Cook Inlet
Production (barrels)								
1996	-	-	385,568	99,659	216,475	161,967	754,488	1,618,158
1997	-	376,962	-	109,677	150,614	30,263	643,486	1,311,001
1998	-	436,498	-	90,973	195,976	-	611,583	1,335,030
1999	181,913	425,149	-	76,355	-	-	568,814	1,252,231
Revenues								
1996	-	-	$6,620,106	$1,809,619	$4,266,126	$2,256,556	$13,521,200	$28,473,607
1997	-	$6,165,972	-$7,004	$1,881,913	$3,654,590	$1,103,834	$10,833,962	$23,633,267
1998	-	$4,209,047	-	$1,093,789	$2,244,325	-	$6,261,988	$13,809,148
1999	$3,072,935	$6,295,651	-	$1,165,412	-	-	$8,845,583	$19,379,581

North Slope

Historical Royalty Gas Production by Payor

NORTH SLOPE	Arco	BP	Chevron	Exxon	Mobil	NANA	Oxy	Phillips	TOTAL North Slope
Production (mcf)									
1996	387,761	761,862	17,786	297,260	101,256	32,446	1,512	17,630	1,617,513
1997	400,895	657,646	16,561	284,187	84,433	25,930	1,988	17,786	1,489,427
1998	393,981	560,854	5,070	264,969	78,519	-	2,134	16,197	1,321,724
1999	412,016	627,551	-	241,821	74,713	-	2,203	9,226	1,367,530
Revenues									
1996	$326,746	$658,038	$47,435	$229,871	$168,198	$30,782	$964	$13,021	$1,475,056
1997	$325,488	$543,435	$33,157	$207,325	$127,870	$23,282	$1,929	$15,319	$1,277,804
1998	$297,465	$451,204	$7,165	$182,809	$79,937	-	$1,887	$12,957	$1,033,424
1999	$343,610	$539,789	-	$185,339	$86,789	-	$1,937	$7,381	$1,164,845

Historical Royalty Gas Production

Cook Inlet

by Payor

Historical Royalty Gas Production by Payor

	COOK INLET									TOTAL
	Arco	Chevron	Danco	Marathon	Mobil	Municipal Light & Power	Phillips	Shell	Unocal	Cook Inlet
Production (mcf)										
1996	930,529	809,536	85	4,475,074	22,815	-	6,910,165	1,038,035	4,410,520	18,596,759
1997	812,591	830,436	-	3,995,784	50,177	-	6,490,318	985,270	4,532,490	17,697,067
1998	760,156	843,072	-	4,062,765	55,372	905,557	6,665,243	-	5,272,111	18,564,277
1999	902,501	1,026,724	-	4,347,695	21,509	775,755	6,372,036	-	4,290,269	17,736,489
Revenues										-
1996	$1,352,425	$1,073,740	$799	$6,181,274	$19,482	-	$11,615,706	$1,517,354	$6,857,672	$28,618,453
1997	$1,411,208	$1,551,102	-	$6,061,206	$47,489	-	$12,054,437	$1,635,854	$6,350,838	$29,112,134
1998	$1,262,404	$1,559,786	-	$5,736,683	$55,372	$1,442,741	$8,874,018	-	$7,035,196	$25,966,200
1999	$1,169,971	$1,605,202	-	$5,557,091	$21,509	$1,007,659	$8,914,102	-	$5,160,819	$23,436,353

ROYALTY-IN-KIND OIL SALES CONTRACTS (barrels per year)

NORTH SLOPE											
	Alpetco (Charter Co.)			Chevron							
	Alpetco	Alpetco	TOTAL Alpetco	Chevron 1	Chevron 1-C	Chevron 2	Chevron 3	Chevron/ Petrostar Kuparuk	Chevron - Kuparuk Resid. Purchases	Chevron/ Tesoro Exchange	TOTAL Chevron
1979	-	-	-	-	-	-	-	-	-	-	-
1980	5,450,147	6,570,803	12,020,950	382,850	499,564	-	-	-	-	-	882,414
1981	25,227,290	819,589	26,046,878	808,704	51,224	-	-	-	-	-	859,928
1982	898,714	-	898,714	-	-	-	-	-	-	-	-
1983	-	-	-	-	-	3,963,604	-	-	-	7,711,395	11,674,998
1984	-	-	-	-	-	2,757,632	3,976,103	-	-	7,319,544	14,053,279
1985	-	-	-	-	-	-	6,819,804	-	-	984,588	7,804,392
1986	-	-	-	-	-	-	6,772,350	132,184	29,948	-	6,934,482
1987	-	-	-	-	-	-	7,251,438	1,611,815	467,310	-	9,330,563
1988	-	-	-	-	-	-	7,093,977	1,732,529	488,758	-	9,315,264
1989	-	-	-	-	-	-	6,450,345	1,703,946	457,315	-	8,611,606
1990	-	-	-	-	-	-	6,013,846	1,665,641	419,806	-	8,099,292
1991	-	-	-	-	-	-	4,040,480	1,765,133	484,933	-	6,290,546
1992	-	-	-	-	-	-	-	-	-	-	-
1993	-	-	-	-	-	-	-	-	-	-	-
1994	-	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-	-
1996	-	-	-	-	-	-	-	-	-	-	-
1997	-	-	-	-	-	-	-	-	-	-	-
1998	-	-	-	-	-	-	-	-	-	-	-
1999			-								-
Cumulative	31,576,151	7,390,392	38,966,543	1,191,553	550,788	6,721,236	48,418,344	8,611,247	2,348,070	16,015,527	83,856,765

ROYALTY-IN-KIND OIL SALES CONTRACTS (barrels per year)

NORTH SLOPE									
	Williams (Mapco)					Golden Valley Electric Association			
	North Pole	North Pole - Subject Federal Price Control	Williams 2	Williams 3	TOTAL Williams	GVEA 1	GVEA 2	GVEA 3	TOTAL GVEA
1979	446,996	-	-	-	446,996	-	-	-	-
1980	1,876,991	4,099,033	-	-	5,976,024	-	-	-	-
1981	8,572,768	235,632	-	-	8,808,400	398,051	-	-	398,051
1982	9,632,099	-	-	-	9,632,099	764,762	-	-	764,762
1983	11,723,755	-	-	-	11,723,755	1,208,406	-	-	1,208,406
1984	13,093,397	-	-	-	13,093,397	776,933	1,093,572	-	1,870,505
1985	13,260,754	-	-	-	13,260,754	34,130	1,417,491	476,923	1,928,544
1986	13,168,483	-	-	-	13,168,483	-	-	1,881,232	1,881,232
1987	14,094,537	-	-	-	14,094,537	-	-	2,013,539	2,013,539
1988	13,814,522	-	-	-	13,814,522	-	-	1,981,998	1,981,998
1989	12,529,175	-	-	-	12,529,175	-	-	1,784,782	1,784,782
1990	12,735,412	-	-	-	12,735,412	-	-	1,670,494	1,670,494
1991	11,183,462	-	-	-	11,183,462	-	-	1,670,699	1,670,699
1992	6,303,005	-	-	-	6,303,005	-	-	801,795	801,795
1993	9,086,280	-	-	-	9,086,280	-	-	-	-
1994	11,812,241	-	-	-	11,812,241	-	-	-	-
1995	12,680,470	-	-	-	12,680,470	-	-	-	-
1996	13,037,159	-	-	-	13,037,159	-	-	-	-
1997	12,651,629	-	465,988	-	13,117,616	-	-	-	-
1998	11,148,189	-	4,451,370	884,268	16,483,827	-	-	-	-
1999	12,442,407			6,628,250	19,070,657				-
Cumulative	225,293,730	4,334,664	4,917,358	7,512,518	242,058,270	3,182,282	2,511,063	12,281,462	17,974,807

ROYALTY-IN-KIND OIL SALES CONTRACTS (barrels per year)

NORTH SLOPE												
		Tesoro										
	Chevron/ Tesoro Exchange	Tesoro 1	Tesoro 1 - Subject to Federal Price Control	Tesoro 2	Tesoro 2 - Subject to Federal Price Control	Tesoro 3	Tesoro 4	Tesoro 5	Tesoro 5 Reservation Fee	Tesoro 6	Tesoro 7	Total Tesoro
1979	-	-	-	-	-	-	-	-	-	-	-	-
1980	-	381,232	496,157	821,100	1,728,900	-	-	-	-	-	-	3,427,388
1981	-	808,703	51,224	-	-	801,458	-	-	-	-	-	1,661,385
1982	-	-	-	-	-	36,841	-	-	-	-	-	36,841
1983	-7,711,383	-	-	-	-	-	13,505,356	-	-	-	-	5,793,973
1984	-7,319,532	-	-	-	-	-	14,850,687	-	-	-	-	7,531,155
1985	-984,586	-	-	-	-	-	15,723,463	2,480,035	-	-	-	17,218,912
1986	-	-	-	-	-	-	17,306,883	9,782,529	-3,551,220	-	-	23,538,192
1987	-	-	-	-	-	-	18,458,776	10,399,030	-10,453,000	-	-	18,404,806
1988	-	-	-	-	-	-	18,307,014	10,293,669	-10,293,669	-	-	18,307,014
1989	-	-	-	-	-	-	16,387,093	9,297,797	-9,297,797	-	-	16,387,093
1990	-	-	-	-	-	-	15,368,565	5,111,875	-5,111,875	-	-	15,368,565
1991	-	-	-	-	-	-	15,336,301	-	-	-	-	15,336,301
1992	-	-	-	-	-	-	14,412,451	-	-	-	-	14,412,451
1993	-	-	-	-	-	-	9,814,311	-	-	-	-	9,814,311
1994	-	-	-	-	-	-	10,312,487	-	-	-	-	10,312,487
1995	-	-	-	-	-	-	-	-	-	13,703,946	-	13,703,946
1996	-	-	-	-	-	-	-	-	-	-	14,345,554	14,345,554
1997	-	-	-	-	-	-	-	-	-	-	13,021,937	13,021,937
1998	-	-	-	-	-	-	-	-	-	-	11,497,733	11,497,733
1999												-
Cumulative	-16,015,501	1,189,935	547,381	821,100	1,728,900	838,299	179,783,385	47,364,935	-38,707,561	13,703,946	38,865,223	230,120,043

ROYALTY-IN-KIND OIL SALES CONTRACTS (barrels per year)

	NORTH SLOPE													
	Petrostar	First Competitive Sale												
	TOTAL Petro-Star	Alaska Petroleum Co. (Coastal)	Arco Products	Oasis Petroleum	Shell (Nonpriority)	Shell (Nonpriority) Dec-81	Shell (Priority)	Shell (Priority) Dec-81	Sohio	Union 1 (Nonpriority)	Union 1 (Nonpriority) Dec-81	Union 1 (Priority)	Union 1 (Priority) Dec-81	TOTAL 1st Comp Sale
1979	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1980	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1981	-	622,698	1,847,668	801,750	2,305,936	98,406	1,537,287	65,604	3,072,268	1,748,062	99,606	1,748,062	99,606	14,046,953
1982	-	-	-	36,855	110,522	-	73,681	-	577,421	316,815	-	316,815	-	1,432,108
1983	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1984	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1985	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1986	52,667	-	-	-	-	-	-	-	-	-	-	-	-	-
1987	539,575	-	-	-	-	-	-	-	-	-	-	-	-	-
1988	590,832	-	-	-	-	-	-	-	-	-	-	-	-	-
1989	607,468	-	-	-	-	-	-	-	-	-	-	-	-	-
1990	621,220	-	-	-	-	-	-	-	-	-	-	-	-	-
1991	618,247	-	-	-	-	-	-	-	-	-	-	-	-	-
1992	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1993	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1994	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1996	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1997	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1998	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1999														-
Cumulative	3,030,009	622,698	1,847,668	838,604	2,416,458	98,406	1,610,968	65,604	3,649,689	2,064,877	99,606	2,064,877	99,606	15,479,061

ROYALTY-IN-KIND OIL SALES CONTRACTS (barrels per year)

	NORTH SLOPE									
	Second Competitive Sale									
	Chevron 4-B	Chevron 5-C	Chevron 6-A	Chevron 7-A	Sohio C	Texaco 1-C	Texaco 2-B	Union 2-A	US Oil & Refining B	TOTAL 2nd Comp Sale
1979	-	-	-	-	-	-	-	-	-	-
1980	-	-	-	-	-	-	-	-	-	-
1981	-	-	-	-	-	-	-	-	-	-
1982	-	-	-	-	-	-	-	-	-	-
1983	-	-	-	-	-	-	-	-	-	-
1984	-	-	-	-	-	-	-	-	-	-
1985	4,297,939	955,688	1,135,518	1,135,518	955,688	2,867,172	7,163,179	1,135,522	2,865,186	22,511,409
1986	1,406,056	-	-	-	-	-	2,343,409	-	937,336	4,686,801
1987	-	-	-	-	-	-	-	-	-	-
1988	-	-	-	-	-	-	-	-	-	-
1989	-	-	-	-	-	-	-	-	-	-
1990	-	-	-	-	-	-	-	-	-	-
1991	-	-	-	-	-	-	-	-	-	-
1992	-	-	-	-	-	-	-	-	-	-
1993	-	-	-	-	-	-	-	-	-	-
1994	-	-	-	-	-	-	-	-	-	-
1995	-	-	-	-	-	-	-	-	-	-
1996	-	-	-	-	-	-	-	-	-	-
1997	-	-	-	-	-	-	-	-	-	-
1998	-	-	-	-	-	-	-	-	-	-
1999										-
Cumulative	5,703,996	955,688	1,135,518	1,135,518	955,688	2,867,172	9,506,588	1,135,522	3,802,521	27,198,210

North Slope

ROYALTY-IN-KIND OIL SALES CONTRACTS (barrels per year)

NORTH SLOPE	Quasi-competitive Sale						TOTAL NORTH SLOPE RIK	TOTAL NORTH SLOPE RIV	TOTAL NORTH SLOPE RIK + RIV
	Chevron 8	Union 3	US Oil & Refining 1	US Oil & Refining 2	US Oil & Refining 3	TOTAL Quasi-Comp Sale			
1979	-	-	-	-	-	-	446,996	10,584,481	11,031,477
1980	-	-	-	-	-	-	22,306,777	47,047,583	69,354,360
1981	-	-	-	-	-	-	51,821,595	17,666,128	69,487,723
1982	-	-	-	-	-	-	12,764,524	61,136,212	73,900,736
1983	-	-	-	-	-	-	30,401,132	44,599,235	75,000,367
1984	-	-	-	-	-	-	36,548,337	39,396,031	75,944,369
1985	457,801	343,350	343,351	343,351	228,901	1,716,754	64,440,764	16,633,246	81,074,010
1986	496,547	372,409	372,410	372,410	248,274	1,862,051	52,123,907	30,262,661	82,386,568
1987	-	-	-	-	-	-	44,383,020	43,899,311	88,282,331
1988	-	-	-	-	-	-	44,009,630	44,068,971	88,078,602
1989	-	-	-	-	-	-	39,920,122	40,833,646	80,753,768
1990	-	-	-	-	-	-	38,494,983	37,242,490	75,737,473
1991	-	-	-	-	-	-	35,099,255	42,537,362	77,636,617
1992	-	-	-	-	-	-	21,517,251	60,174,977	81,692,228
1993	-	-	-	-	-	-	18,900,591	55,796,583	74,697,174
1994	-	-	-	-	-	-	22,124,728	50,657,903	72,782,631
1995	-	-	-	-	-	-	26,384,415	43,664,553	70,048,968
1996	-	-	-	-	-	-	27,382,712	39,396,515	66,779,227
1997	-	-	-	-	-	-	26,139,553	35,359,288	61,498,841
1998	-	-	-	-	-	-	27,981,560	28,330,383	56,311,943
1999							19,070,657	31,473,445	50,544,102
Cumulative	954,349	715,759	715,761	715,761	477,174	3,578,804	662,262,512	820,761,006	1,483,023,517

Cook Inlet / State

ROYALTY-IN-KIND OIL SALES CONTRACTS (barrels per year)

	COOK INLET					STATE		
	Tesoro East and West Side	Chinese Petroleum West Side Export	TOTAL COOK INLET RIK	TOTAL COOK INLET RIV	TOTAL COOK INLET RIK + RIV	TOTAL RIK	TOTAL RIV	TOTAL RIK + RIV
1979	4,849,631	-	4,849,631	-	4,849,631	5,296,627	10,584,481	15,881,108
1980	4,094,229	-	4,094,229	-	4,094,229	26,401,006	47,047,583	73,448,589
1981	3,560,736	-	3,560,736	-	3,560,736	55,382,331	17,666,128	73,048,459
1982	3,065,159	-	3,065,159	-	3,065,159	15,829,683	61,136,212	76,965,895
1983	2,719,044	-	2,719,044	-	2,719,044	33,120,176	44,599,235	77,719,411
1984	2,431,987	-	2,431,987	-	2,431,987	38,980,324	39,396,031	78,376,356
1985	1,382,740	-	1,382,740	462,245	1,844,985	65,823,504	17,095,491	82,918,995
1986	-	-	-	1,922,102	1,922,102	52,123,907	32,184,763	84,308,671
1987	-	625,099	625,099	1,104,010	1,729,109	45,008,119	45,003,321	90,011,440
1988	-	798,885	798,885	912,193	1,711,078	44,808,515	44,981,164	89,789,680
1989	-	1,274,480	1,274,480	388,888	1,663,368	41,194,602	41,222,534	82,417,136
1990	-	579,337	579,337	480,570	1,059,908	39,074,320	37,723,061	76,797,381
1991	-	330,540	330,540	1,354,524	1,685,064	35,429,795	43,891,886	79,321,681
1992	-	-	-	1,661,526	1,661,526	21,517,251	61,836,503	83,353,754
1993	-	-	-	1,514,651	1,514,651	18,900,591	57,311,234	76,211,825
1994	-	-	-	1,717,759	1,717,759	22,124,728	52,375,662	74,500,390
1995	-	-	-	1,718,805	1,718,805	26,384,415	45,383,358	71,767,773
1996	-	-	-	1,618,158	1,618,158	27,382,712	41,014,673	68,397,385
1997	-	-	-	1,311,001	1,311,001	26,139,553	36,670,289	62,809,842
1998	-	-	-	1,335,030	1,335,030	27,981,560	29,665,413	57,646,973
1999				1,252,231	1,252,231	19,070,657	32,725,676	51,796,333
Cumulative	22,103,526	3,608,341	25,711,867	18,753,693	44,465,560	687,974,379	839,514,698	1,527,489,077

Fuel Consumption History (million gallons)

	Exempt[1]									
	Foreign Flights	Heating Fuel	Bulk Sales (Jet Fuel)	Gasohol	Public Utilities	State and Local Government	Federal Government	Exported as Cargo	Exempt Power Plants	Charitable Institutions
1983	163.100	93.269	3.624	-	92.894	29.891	23.730	20.571	0.847	0.137
1984	230.044	99.191	-	-	96.311	28.624	21.773	21.776	6.691	0.105
1985	141.862	105.469	-	-	102.425	44.207	24.820	100.840	14.098	0.116
1986	192.596	114.318	-	0.171	111.157	44.054	24.281	372.853	12.968	0.115
1987	225.607	97.277	-	0.416	109.167	24.361	25.852	458.016	18.718	0.175
1988	242.202	103.136	-	0.215	95.960	24.971	50.587	436.760	14.426	0.120
1989	258.757	113.602	-	0.022	69.472	24.576	29.813	457.604	11.637	0.196
1990	303.044	113.159	-	6.045	157.955	21.293	36.242	358.678	12.104	0.195
1991	257.623	110.922	-	-	104.764	28.937	24.057	298.407	9.714	1.153
1992	236.556	128.800	-	17.118	116.262	28.317	25.397	194.442	5.260	0.254
1993	198.916	144.387	87.422	17.157	69.026	30.859	25.976	221.140	5.790	0.360
FY 1994	338.188	159.170	-	-	33.208	27.625	98.653	82.205	4.321	0.632
FY 1995	407.515	164.061	-	30.296	28.365	24.032	64.180	81.854	4.236	0.659
FY 1996	346.505	151.795	-	79.327	28.265	23.272	69.014	112.151	1.893	0.838
FY 1997	329.820	154.387	-	91.663	47.580	25.919	68.403	57.895	7.648	0.555
FY 1998	352.208	138.239	-	7.004	61.285	27.766	79.491	162.432	2.094	0.692

Fuel Consumption History

Fuel Consumption History (million gallons)

	Exempt[1]			Not categorized on monthly Fuel Sales report			
	Consigned to Foreign Countries	Losses	Other	Oil and Gas Operations[2]	Foreign Trade Zone[3]	Domestic - Non-Alaska Air Miles[4]	Other
1983	78.280	0.001	1.796	-	-	-	
1984	59.722	0.605	0.466	-	-	-	
1985	84.655	0.225	0.042	-	-	-	
1986	0.021	0.338	-	-	-	-	
1987	42.960	0.335	-	-	-	-	
1988	0.035	0.345	-	-	-	-	
1989	62.835	0.003	-	-	-	-	
1990	0.001	0.000	-	-	-	-	
1991	-	0.003	1.559	-	-	-	
1992	0.800	0.001	28.011	-	-	-	
1993	6.092	0.000	16.092	-	-	-	
FY 1994	-	-	0.205	2.357	-	-	
FY 1995	0.378	-	18.325	1.945	-	-	
FY 1996	-	0.032	0.236	2.731	8.451	17.038	
FY 1997	-	-	0.803	18.106	47.280	17.787	
FY 1998	-	-	3.775	20.998	90.251	3.381	3.775

Fuel Consumption History

Fuel Consumption History (million gallons)

	Taxable							TOTAL Fuel Sales[1]	TOTAL Fuel Sales Consumed in Alaska[5]
	Aviation Gas	Aviation Jet	Highway Diesel	Highway Gas	Marine Diesel	Marine Gas	Gasohol		
1983	14.746	274.760	241.785	187.081	72.174	8.516	-	1,307.203	1,208.352
1984	16.825	299.494	245.113	212.150	73.542	8.835	-	1,421.266	1,339.768
1985	17.482	294.457	274.151	219.728	88.851	14.413	-	1,527.840	1,342.345
1986	16.957	311.966	338.557	212.924	95.121	10.173	-	1,858.570	1,485.696
1987	18.108	326.128	259.740	203.718	88.650	11.327	-	1,910.554	1,409.578
1988	18.571	351.207	282.097	207.122	115.199	10.479	-	1,953.432	1,516.638
1989	18.493	370.434	281.435	200.017	147.725	10.008	-	2,056.630	1,536.191
1990	19.788	449.753	273.083	235.157	182.600	10.238	-	2,179.338	1,820.658
1991	18.887	374.475	285.625	209.228	178.342	9.662	-	1,913.356	1,614.949
1992	19.481	379.448	272.294	232.386	188.041	12.938	-	1,885.805	1,690.563
1993	18.463	346.049	230.301	225.960	162.226	10.535	-	1,816.750	1,589.519
FY 1994	20.657	242.930	197.813	225.327	155.424	10.416	-	1,599.131	1,516.926
FY 1995	21.165	251.603	200.591	219.220	144.293	10.262	-	1,672.980	1,590.748
FY 1996	20.951	225.375	219.650	166.742	160.742	10.771	-	1,645.779	1,533.628
FY 1997	20.252	224.098	179.038	161.977	135.491	10.526	-	1,599.228	1,541.333
FY 1998	19.731	139.474	166.562	186.749	177.576	11.112	49.913	1,704.508	1,542.076

Source: Alaska Department of Revenue (DOR), "Motor Fuel Activity Report." Data from 1977 to 1982 are available but are incompatible with recent data. Data for 1983-1993 are summations of monthly reports. Data for 1995-1997 are fiscal year (FY) summaries. Data for FY 1998 are estimates. This table appeared in last year's "Historical and Projected Oil and Gas Consumption" report. N.B. "-" = zero or no data; "0.000" = less than 0.001.

[1]Bonded category is not included.
[2]Fuel used in conjunction with oil and gas drilling operations.

[3]Fuel voluntarily reported on tax returns.

[4]Fuel claimed by taxpayers under their interpretation of the foreign flight exemption.

[4]Net of "Exported as Cargo" and "Consigned to Foreign Countries."

Revised 6/30/99

Gas Consumption History

Gas Consumption History (billion cubic feet)

	NORTH SLOPE									TOTAL NORTH SLOPE
	Field Operations[1]		TOTAL Field Operations	Sold[1]					TOTAL Sold	
	Vented and Flared	Used on Lease		Power Generation[2]	Gas Utilties[2]	TAPS[3]	NGL[4]	Unaccounted[5]		
1971	-	-	-	-	-	-	-	-	-	-
1972	-	-	-	-	-	-	-	-	-	-
1973	-	-	-	-	-	-	-	-	-	-
1974	1.076	1.574	2.650	-	-	-	-	-	-	2.650
1975	1.061	1.747	2.808	-	-	-	-	-	-	2.808
1976	1.254	2.602	3.856	-	-	-	-	-	-	3.856
1977	10.882	13.562	24.444	-	-	1.754	-	-	1.754	26.198
1978	2.313	26.918	29.231	0.219	0.291	6.949	-	-	7.459	36.690
1979	1.840	31.923	33.763	0.235	0.317	8.648	-	0.312	9.512	43.275
1980	1.801	37.896	39.697	0.235	0.400	10.686	0.305	0.381	12.007	51.704
1981	2.485	39.122	41.607	0.315	0.435	11.106	0.540	0.395	12.791	54.398
1982	3.490	48.431	51.921	0.404	0.539	11.952	0.600	0.505	14.000	65.921
1983	2.524	55.686	58.210	0.482	0.407	13.277	0.373	0.050	14.589	72.799
1984	5.814	68.918	74.732	0.480	0.508	12.856	0.380	0.864	15.088	89.820
1985	3.437	87.951	91.388	0.486	0.453	14.381	0.980	3.789	20.089	111.477
1986	5.802	95.920	101.722	0.559	0.486	15.166	1.562	2.228	20.001	121.723
1987	12.952	130.320	143.272	0.544	0.493	16.624	19.594	5.464	42.719	185.991
1988	5.747	146.811	152.558	0.620	0.519	17.855	25.235	4.058	48.287	200.845
1989	6.792	157.163	163.955	0.620	0.484	16.147	22.637	-0.342	39.546	203.501
1990	8.753	160.590	169.343	0.644	0.495	14.543	21.805	-0.420	37.067	206.410
1991	6.795	176.916	183.711	0.667	0.486	15.349	28.633	0.340	45.475	229.186
1992	10.092	185.963	196.055	0.721	0.530	14.583	32.276	0.292	48.402	244.457
1993	19.081	189.458	208.539	0.676	0.508	12.342	32.209	0.467	46.202	254.741
1994	10.585	200.435	211.020	0.680	0.541	12.017	31.098	-0.146	44.190	255.210
1995	6.968	211.088	218.056	0.680	0.522	11.426	35.558	-0.316	47.870	265.926
1996	5.616	210.779	216.395	0.661	0.519	10.624	39.836	1.767	53.407	269.802
1997	6.255	215.807	222.063	0.640	0.554	9.616	41.704	1.875	54.389	276.451
1998	6.052	213.859	219.911	0.691	0.536	8.395	40.469	1.761	51.852	271.763

Source: Various. This table appeared in last year's "Historical and Projected Oil and Gas Consumption" report. N.B. "-" = zero or no data; "0.000" = less than 0.00.

[1]Alaska Oil and Gas Conservation Commission (AOGCC), "Report of Gas Disposition." AOGCC modified its consumption classification in 1994 but the classes in this table are equivalent throughout the time series.
[2]Barrow Utilities and Electric Cooperative, Inc.
[3]Royalty reports from ARCO to Division of Oil and Gas, sales to TAPS from Prudhoe Bay Unit.
[4]Alaska Oil an Gas Conservation Commission, "Alaska Production Summary by Field and Pool", monthly reports. NGLs are reported in barrels, here converted to billion cubic feet by: 1 barrel = 1.2 mcf.
[4]Calculated difference between "Sold" and sum of listed "Sold" items.

Revised 6/30/99

Gas Consumption History

Gas Consumption History (billion cubic feet)

COOK INLET	Field Operations[1]			Sold[1]												TOTAL COOK INLET
	Vented and Flared	Used on Lease	TOTAL Field Operations	Power Generation Public[2]	Power Generation Military[3]	TOTAL Power Generation	Gas Utilties Residential	Gas Utilities Commercial	TOTAL Gas Utilities[3]	LNG[4]	Ammonia Urea[5]	Rental Gas[6]	Unaccounted[7]	TOTAL Sold	
1971	33.180	12.070	45.250	9.980	6.549	16.529	5.440	4.798	10.238	63.240	19.490	-	12.220	121.717	166.967
1972	20.980	15.580	36.560	12.780	6.473	19.253	6.027	7.072	13.099	57.133	20.580	13.400	0.252	123.717	160.277
1973	6.930	13.970	20.900	15.683	6.069	21.752	6.519	8.238	14.757	60.570	20.640	12.590	0.628	130.937	151.837
1974	7.978	41.856	49.834	17.117	5.684	22.801	6.717	8.411	15.128	61.656	22.100	10.410	-1.586	130.509	180.343
1975	9.496	19.334	28.830	19.619	5.842	25.461	5.548	6.544	12.092	63.904	23.888	12.477	2.895	140.717	169.547
1976	5.421	19.046	24.467	22.204	5.424	27.628	5.916	6.635	12.551	62.090	24.257	11.588	5.596	143.710	168.177
1977	4.848	19.568	24.416	23.717	5.000	28.717	6.010	6.673	12.683	65.449	28.620	6.703	10.265	152.437	176.853
1978	3.870	22.079	25.949	24.757	5.126	29.883	6.536	6.918	13.454	60.102	48.879	10.523	1.459	164.300	190.249
1979	2.710	21.391	24.101	28.180	4.986	33.166	6.911	7.134	14.045	62.231	51.657	6.958	0.049	168.106	192.207
1980	3.045	19.259	22.304	28.763	4.763	33.526	7.773	7.748	15.521	51.915	54.699	5.190	1.350	162.201	184.505
1981	3.175	17.384	20.559	29.071	4.561	33.632	7.950	7.828	15.778	67.943	53.836	5.601	1.292	178.082	198.641
1982	3.494	17.463	20.957	30.113	4.830	34.943	9.981	9.044	19.025	62.853	55.220	11.383	2.489	185.913	206.870
1983	2.560	16.820	19.380	31.547	4.596	36.143	10.202	8.909	19.111	66.042	50.338	12.698	8.246	192.578	211.958
1984	3.260	17.256	20.516	31.571	4.338	35.909	10.999	9.904	20.903	64.229	50.083	18.362	3.266	192.752	213.268
1985	2.893	15.744	18.637	34.194	4.530	38.724	12.445	11.974	24.419	63.926	50.688	21.532	0.022	199.311	217.948
1986	3.095	15.313	18.408	34.243	4.531	38.774	11.935	11.300	23.235	61.062	43.052	14.785	-6.345	174.563	192.971
1987	2.746	15.783	18.529	31.583	4.657	36.240	12.027	11.036	23.063	60.111	49.450	16.733	-7.937	177.660	196.189
1988	3.244	15.898	19.142	32.038	4.816	36.854	12.292	10.957	23.249	62.168	53.140	8.722	-6.662	177.471	196.613
1989	2.940	16.493	19.433	32.917	5.016	37.933	13.564	11.674	25.238	63.836	49.965	6.705	2.090	185.767	205.200
1990	2.214	13.356	15.570	33.918	4.940	38.858	13.968	11.924	25.892	65.135	54.770	3.182	7.040	194.877	210.447
1991	3.900	16.356	20.256	30.629	4.700	35.329	13.440	11.260	24.700	65.429	52.609	3.683	4.616	186.366	206.622
1992	4.088	16.926	21.014	28.549	4.955	33.504	14.333	11.613	25.946	66.219	55.000	3.719	2.845	187.233	208.247
1993	3.419	15.545	18.964	27.361	4.684	32.045	13.413	10.829	24.242	67.328	56.210	-	1.717	181.542	200.506
1994	2.727	16.395	19.122	28.360	4.685	33.045	14.769	11.838	26.607	76.651	55.400	-	3.177	194.880	214.002
1995	1.815	16.024	17.839	29.255	4.710	33.965	14.847	11.862	26.709	78.144	54.000	-	3.809	196.627	214.466
1996	1.493	17.536	19.029	31.012	5.090	36.102	16.220	12.827	29.047	81.407	54.011	-	5.806	206.373	225.402
1997	2.058	15.079	17.137	32.773	4.974	37.747	14.872	11.773	26.645	75.382	52.318	-	5.231	197.323	214.460
1998	2.164	14.739	16.903	28.491	4.911	33.402	15.337	12.110	27.447	78.126	53.550	-	5.550	198.075	214.978

Source: Various. This table appeared in last year's "Historical and Projected Oil and Gas Consumption" report.
N.B. "-" = zero or no data; "0.000" = less than 0.00.

[1]Alaska Oil and Gas Conservation Commission (AOGCC), "Report of Gas Disposition." AOGCC modified its consumption classification in 1994 but the classes in this table are equivalent throughout the time series.
[2]1971-91: Alaska Energy Authority, "Alaska Electric Power Statistics, 1960-1991"
1992-98: Chugach Electric and Municipal Light & Power.
[3]1971-82: Annual reports from Alaska Pipeline Co., Enstar and Kenai Utility Service Co. to Alaska Public Utilities Commission.
1983-98: Enstar Natural Gas Co.
[4]Phillips Petroleum Co..
[5]1971-74: Stanford Research Institute, "Natural Gas Demand and Supply to the Year 2000 in the Cook Inlet Basin of South Central Alaska," Novemebr 1977.
1975-79: Sum of (1) sales from Kenai and Beaver Creek gas fields to Collier Chemical in : AOGCC, "Kenai Gas Sales" and (2) sales from McArthur River gas field in: AOGCC, "Monthly Report of Gas Disposition."
1980-85: Royalty reports from producers to Division of Oil and gas
1986-98: Unocla Corp.
[6]Gas produced and sold from other fields and injected into Swanson River field to maintain reservoir pressure.
1972-90: Royalty reports form Unocal to Division of Oil and Gas, item: Swnason River Rental Gas.
1991-92: Unocal Corp.
[7]Calculated difference between "Sold" and sum of listed "Sold" items.

Revised 6/30/99

Gas Consumption History

Gas Consumption History (billion cubic feet)

	STATE																TOTAL STATE
	Field Operations[1]			Sold[1]													
Year	Vented and Flared	Used on Lease	TOTAL Field Operations	Power Generation Public[2]	Power Generation Military[3]	TOTAL Power Generation	Gas Utilities Residential	Gas Utilities Commercial	TOTAL Gas Utilities[3]	LNG[4]	Ammonia Urea[5]	Rental Gas[6]	TAPS[7]	NGL[8]	Unaccounted[9]	TOTAL Sold	
1971	33.180	12.070	45.250	9.980	6.549	16.529	5.440	4.798	10.238	63.240	19.490	-	-	-	12.220	121.717	166.967
1972	20.980	15.580	36.560	12.780	6.473	19.253	6.027	7.072	13.099	57.133	20.580	13.400	-	-	0.252	123.717	160.277
1973	6.930	13.970	20.900	15.683	6.069	21.752	6.519	8.238	14.757	60.570	20.640	12.590	-	-	0.628	130.937	151.837
1974	9.054	43.430	52.484	17.117	5.684	22.801	6.717	8.411	15.128	61.656	22.100	10.410	-	-	-1.586	130.509	182.993
1975	10.557	21.081	31.638	19.619	5.842	25.461	5.548	6.544	12.092	63.904	23.888	12.477	-	-	2.895	140.717	172.355
1976	6.675	21.648	28.323	22.204	5.424	27.628	5.916	6.635	12.551	62.090	24.257	11.588	-	-	5.596	143.710	172.033
1977	15.730	33.130	48.860	23.717	5.000	28.717	6.010	6.673	12.683	65.449	28.620	6.703	1.754	-	10.265	154.191	203.051
1978	6.183	48.997	55.180	24.757	5.126	29.883	6.536	6.918	13.454	60.102	48.879	10.523	6.949	-	1.459	171.759	226.939
1979	4.550	53.314	57.864	28.180	4.986	33.166	6.911	7.134	14.045	62.231	51.657	6.958	8.648	-	0.361	177.618	235.482
1980	4.846	57.155	62.001	28.763	4.763	33.526	7.773	7.748	15.521	51.915	54.699	5.190	10.686	0.305	1.731	174.208	236.209
1981	5.660	56.506	62.166	29.071	4.561	33.632	7.950	7.828	15.778	67.943	53.836	5.601	11.106	0.540	1.687	190.873	253.039
1982	6.984	65.894	72.878	30.113	4.830	34.943	9.981	9.044	19.025	62.853	55.220	11.383	11.952	0.600	2.994	199.913	272.791
1983	5.084	72.506	77.590	31.547	4.596	36.143	10.202	8.909	19.111	66.042	50.338	12.698	13.277	0.373	8.296	207.167	284.757
1984	9.074	86.174	95.248	31.571	4.338	35.909	10.999	9.904	20.903	64.229	50.083	18.362	12.856	0.380	4.130	207.840	303.088
1985	6.330	103.695	110.025	34.194	4.530	38.724	12.445	11.974	24.419	63.926	50.688	21.532	14.381	0.980	3.811	219.400	329.425
1986	8.897	111.233	120.130	34.243	4.531	38.774	11.935	11.300	23.235	61.062	43.052	14.785	15.166	1.562	-4.117	194.564	314.694
1987	15.698	146.103	161.801	31.583	4.657	36.240	12.027	11.036	23.063	60.111	49.450	16.733	16.624	19.594	-2.473	220.379	382.180
1988	8.991	162.709	171.700	32.038	4.816	36.854	12.292	10.957	23.249	62.168	53.140	8.722	17.855	25.235	-2.604	225.758	397.458
1989	9.732	173.656	183.388	32.917	5.016	37.933	13.564	11.674	25.238	63.836	49.965	6.705	16.147	22.637	1.748	225.313	408.701
1990	10.967	173.946	184.913	33.918	4.940	38.858	13.968	11.924	25.892	65.135	54.770	3.182	14.543	21.805	6.620	231.944	416.857
1991	10.695	193.272	203.967	30.629	4.700	35.329	13.440	11.260	24.700	65.429	52.609	3.683	15.349	28.633	4.956	231.841	435.808
1992	14.180	202.889	217.069	28.549	4.955	33.504	14.333	11.613	25.946	66.219	55.000	3.719	14.583	32.276	3.137	235.635	452.704
1993	22.500	205.003	227.503	27.361	4.684	32.045	13.413	10.829	24.242	67.328	56.210	-	12.342	32.209	2.184	227.744	455.247
1994	13.312	216.830	230.142	28.360	4.685	33.045	14.769	11.838	26.607	76.651	55.400	-	12.017	31.098	3.031	239.070	469.212
1995	8.783	227.112	235.895	29.255	4.710	33.965	14.847	11.862	26.709	78.144	54.000	-	11.426	35.558	3.492	244.497	480.392
1996	7.109	228.315	235.424	31.012	5.090	36.102	16.220	12.827	29.047	81.407	54.011	-	10.624	39.836	7.573	259.780	495.204
1997	8.314	230.886	239.200	32.773	4.974	37.747	14.872	11.773	26.645	75.382	52.318	-	9.616	41.704	7.106	251.711	490.911
1998	8.216	228.598	236.814	28.491	4.911	33.402	15.337	12.110	27.447	78.126	53.550	-	8.395	40.469	7.311	249.927	486.741

Source: Various. This table appeared in last year's "Historical and Projected Oil and Gas Consumption" report.
N.B. "-" = zero or no data; "0.000" = less than 0.00.

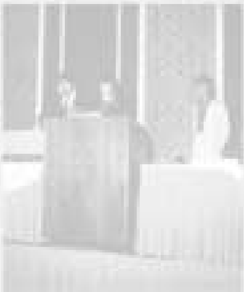
[1]Alaska Oil and Gas Conservation Commission (AOGCC), "Report of Gas Disposition." AOGCC modified its consumption classification in 1994 but the classes in this table are equivalent throughout the time series.
[2]Barrow Utilities and Electric Cooperative Inc.
1971-91: Alaska Energy Authority, "Alaska Electric Power Statistics, 1960-1991"
1992-98: Chugach Electric and Municipal Light & Power.
[3]Barrow Utilities and Electric Cooperative Inc.
1971-82: Annual reports from Alaska Pipeline Co., Enstar and Kenai Utility Service Co. to Alaska Public Utilities Commission.
1983-98: Enstar Natural Gas Co.
[4]Phillips Petroleum Co.
[5]1971-74: Stanford Research Institute, "Natural Gas Demand and Supply to the Year 2000 in the Cook Inlet Basin of South Central Alaska," Novemebr 1977.
1975-79: Sum of (1) sales from Kenai and Beaver Creek gas fields to Collier Chemical in : AOGCC, "Kenai Gas Sales" and (2) sales from McArthur River gas field in: AOGCC, "Monthly Report of Gas Disposition."
1980-85: Royalty reports from producers to Division of Oil and gas
1986-98: Unocla Corp.
[6]Gas produced and sold from other fields and injected into Swanson River field to maintain reservoir pressure.
1972-90: Royalty reports form Unocal to Division of Oil and Gas, item: Swnason River Rental Gas.
1991-92: Unocal Corp.
[7]Royalty reports from ARCO to Division of Oil and Gas, sales to TAPS from Prudhoe Bay Unit.
[8]Alaska Oil an Gas Conservation Commission, "Alaska Production Summary by Field and Pool", monthly reports. NGLs are reported in barrels, here converted to billion cubic feet by: 1 barrel = 1.2 mcf.
[9]Calculated difference between "Sold" and sum of listed "Sold" items.

Revised 6/30/99

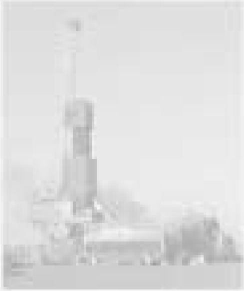
Historical Refinery Throughput

	Taps Flow[1]			Golden Valley Pipeline[2]			Petrostar Refinery[3]			Tesoro[4]
	Throughput at PS#1	Liftings at Valdez	Net	Deliveries	Receipts	Net	Deliveries	Receipts	Net	Thruput
1977	112.315	96.669	15.646	-	-	-	-	-	-	-
1978	397.149	394.080	3.069	-	-	-	-	-	-	-
1979	467.939	464.394	3.545	-	-	-	-	-	-	-
1980	554.934	548.895	6.039	-	-	-	-	-	-	-
1981	556.067	547.026	9.041	-	-	-	-	-	-	-
1982	591.142	583.370	7.772	-	-	-	-	-	-	-
1983	600.859	592.319	8.540	-	-	-	-	-	-	-
1984	608.836	596.588	12.248	-	-	-	-	-	-	-
1985	649.887	643.512	6.375	-	-	-	-	-	-	-
1986	665.435	653.028	12.407	-	-	-	-	-	-	-
1987	716.662	700.878	15.784	-	-	-	-	-	-	-
1988	744.108	731.663	12.445	-	-	-	-	-	-	-
1989	688.062	672.461	15.601	-	-	-	-	-	-	-
1990	654.551	636.199	18.352	-	-	-	-	-	-	-
1991	665.175	647.345	17.830	-	-	-	-	-	-	-
1992	639.390	623.217	16.173	-	-	-	-	-	-	-
1993	591.220	570.707	20.513	48.430	33.970	14.460	9.204	6.821	2.383	18.176
1994	579.320	559.082	20.238	48.267	33.705	14.562	10.597	8.021	2.576	16.848
1995	555.939	535.790	20.149	50.874	34.563	16.311	11.949	9.038	2.911	18.608
1996	525.565	503.726	21.839	52.901	35.124	17.777	14.062	10.514	3.548	17.693
1997	487.017	462.139	24.878	53.080	35.552	17.528	14.126	10.709	3.417	18.670
1998	440.482	419.495	20.987	NA	NA	NA	NA	NA	NA	NA

BACKGROUND



DATA



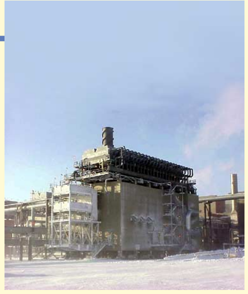
UNITS

ROYALTY-IN-KIND AND ALASKA REFINING

LEASING PROGRAM

GOVERNMENT OIL & GAS MANAGEMENT AGENCIES IN ALASKA

Units



The unitization of oil and gas reservoirs and the formation of participating areas within unit areas to develop hydrocarbon-bearing reservoirs are well-accepted means of hydrocarbon conservation. Without unitization, the unregulated development of reservoirs tends to be a race for possession by competing operators. That development can result in overly dense drilling, especially along property lines; rapid dissipation of reservoir pressure; and irregular advancement of displacing fluids. These all contribute to the loss of ultimate recovery or economic waste. The proliferation of surface activity, duplication of production, gathering, and processing facilities, and haste to get oil to the surface also increase the likelihood of environmental damage. Unitization provides a practical and efficient method for maximizing oil and gas recovery, and minimizes negative impacts on other resources.

Traditionally, under unitized operations, the assignment of undivided equity interests in the oil and gas reservoirs to each lease largely resolves the tension between lessees to compete for their share of production. In addition, unitization must equitably divide costs and production, and maximize physical and economic recovery from any reservoir. It must also treat the royalty owner fairly.

Under unitization, operators can eliminate redundancy and waste by sharing infrastructure and facilities, and by adopting unified reservoir management plans. These savings are in the best interest of the participating lessees, the royalty owner, and the public since they encourage development that is ultimately both more profitable for all entities concerned and less threatening to the environment than other production alternatives.

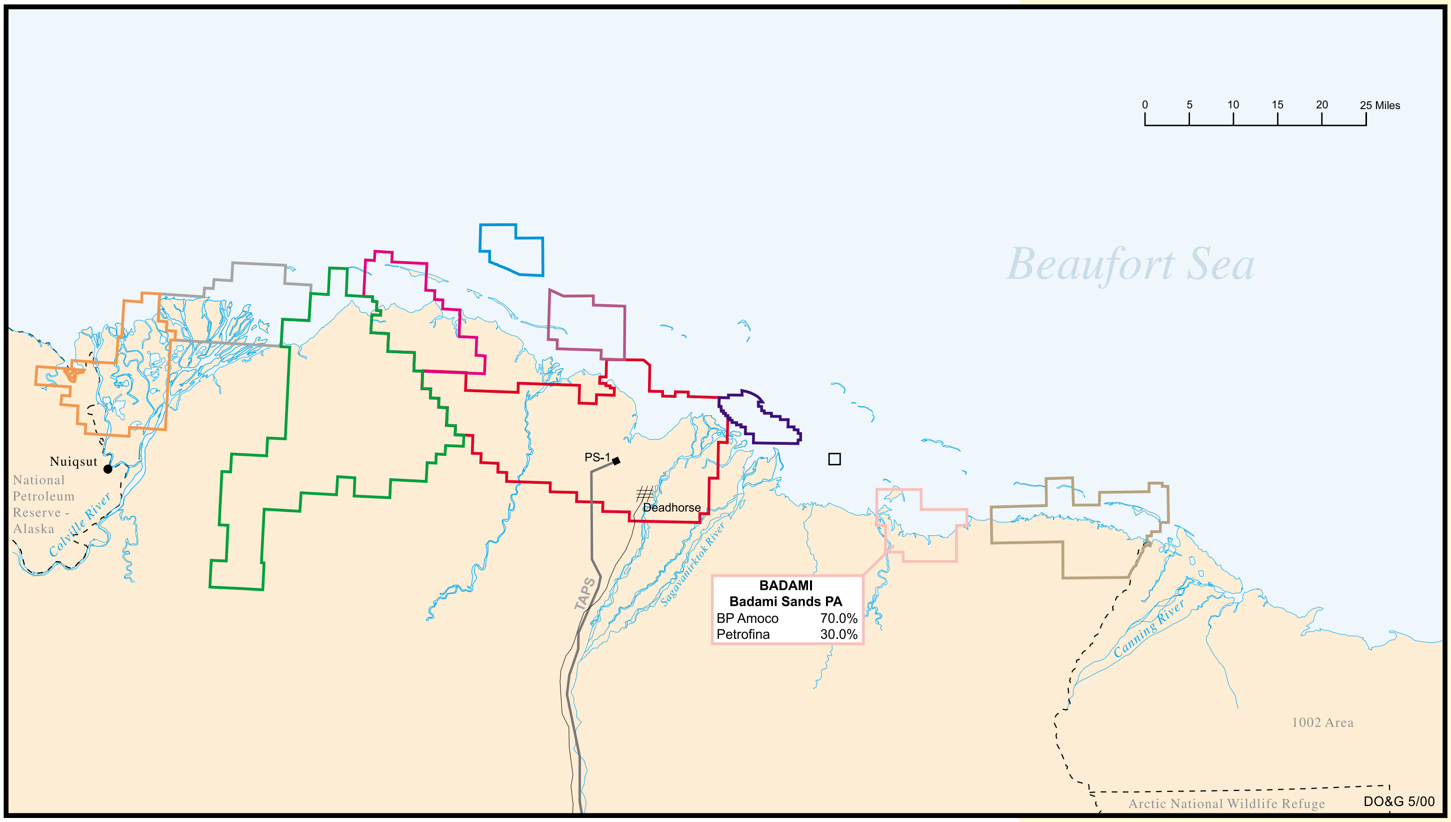
This section briefly describes current units in the state on the North Slope and in Cook Inlet. The Commissioner of the Department of Natural Resources (the Commissioner) reviews applications to form units and participating areas under AS 38.05.180(p) and 11 AAC 83.303 et. seq. The Commissioner will approve proposed units and the formation of participating areas upon a written finding that they will: 1) promote the conservation of all natural resources; 2) promote the prevention of economic and physical waste; and 3) provide for the protection of all parties of interest, including the state.

Badami Unit

Region:	North Slope
Status:	Producing
Type:	Oil
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	BP Exploration (Alaska), Inc. 70%
	Petrofina 30%
Operator:	BP Amoco
Discovery Date:	1990, Conoco Badami #1
Reservoir:	Tertiary Canning Formation, Badami Sandstone turbidite (9,900 ft. subsea)

Status: Production started in August 1998.

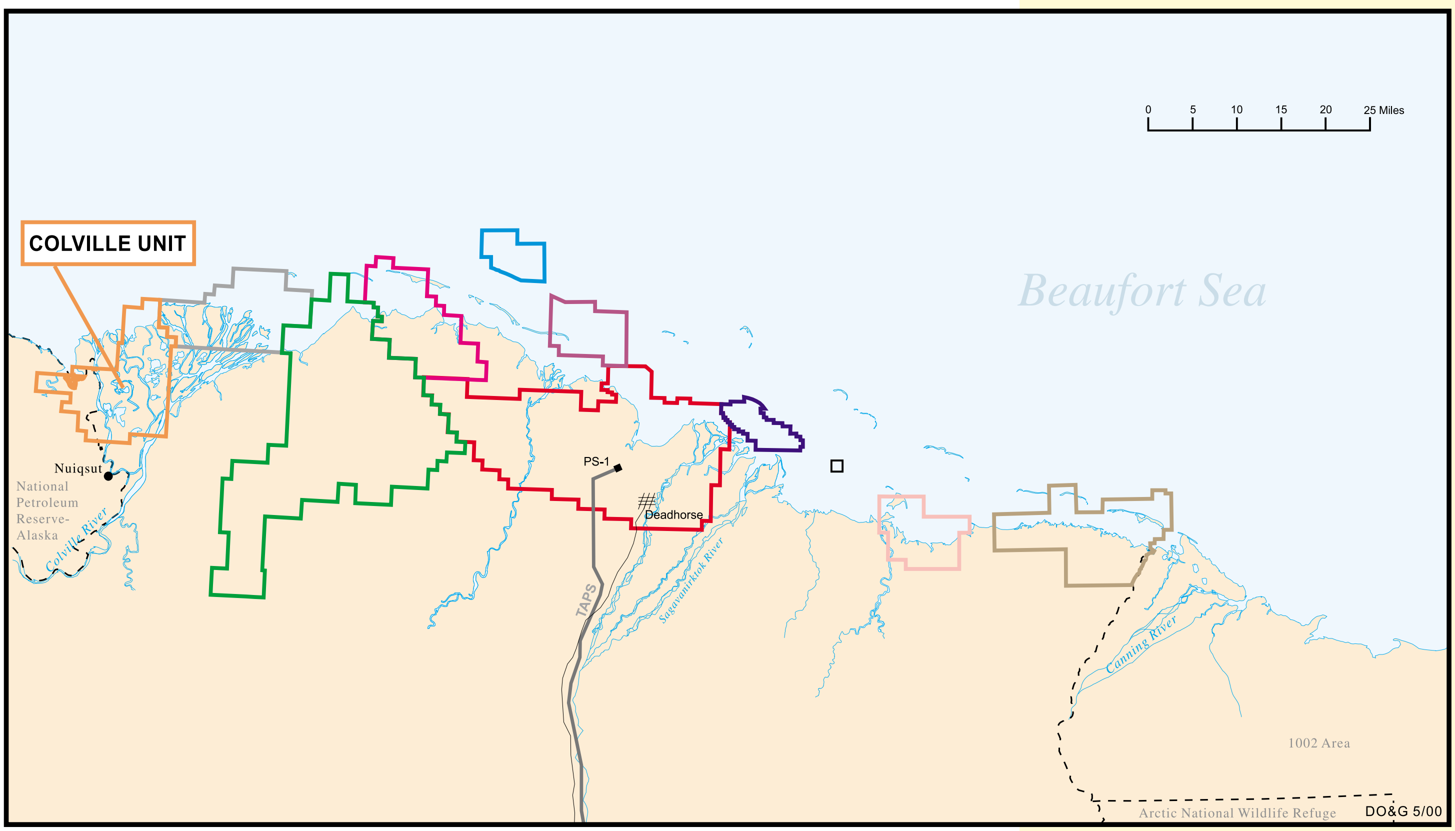
Badami Unit



Colville River Unit

Region:	North Slope
Status:	Exploration and Development
Type:	Oil and Gas
Royalty Ownership:	State of Alaska/Arctic Slope Regional Corp.
State of Alaska Ownership:	Alpine: 64.75%; others to be determined.
Working Interest Ownership:	Phillips Alaska 56% Anadarko 22% Union Texas Alaska (Phillips Alaska, Inc.) 22%
Operator:	Phillips Alaska, Inc.
Discovery Date:	Alpine: 1994, Bergschrund #1 Fiord: 1992, Fiord #1
Reservoir:	Jurassic Kingak Formation, Alpine sandstone (6,850 ft. subsea) Kuparuk/Nelchelik sandstones (Fiord)
Status:	Alpine: 3rd Quarter, 2000, start-up; peak production expected at 80,000 bpd by 2001; all horizontal well development.

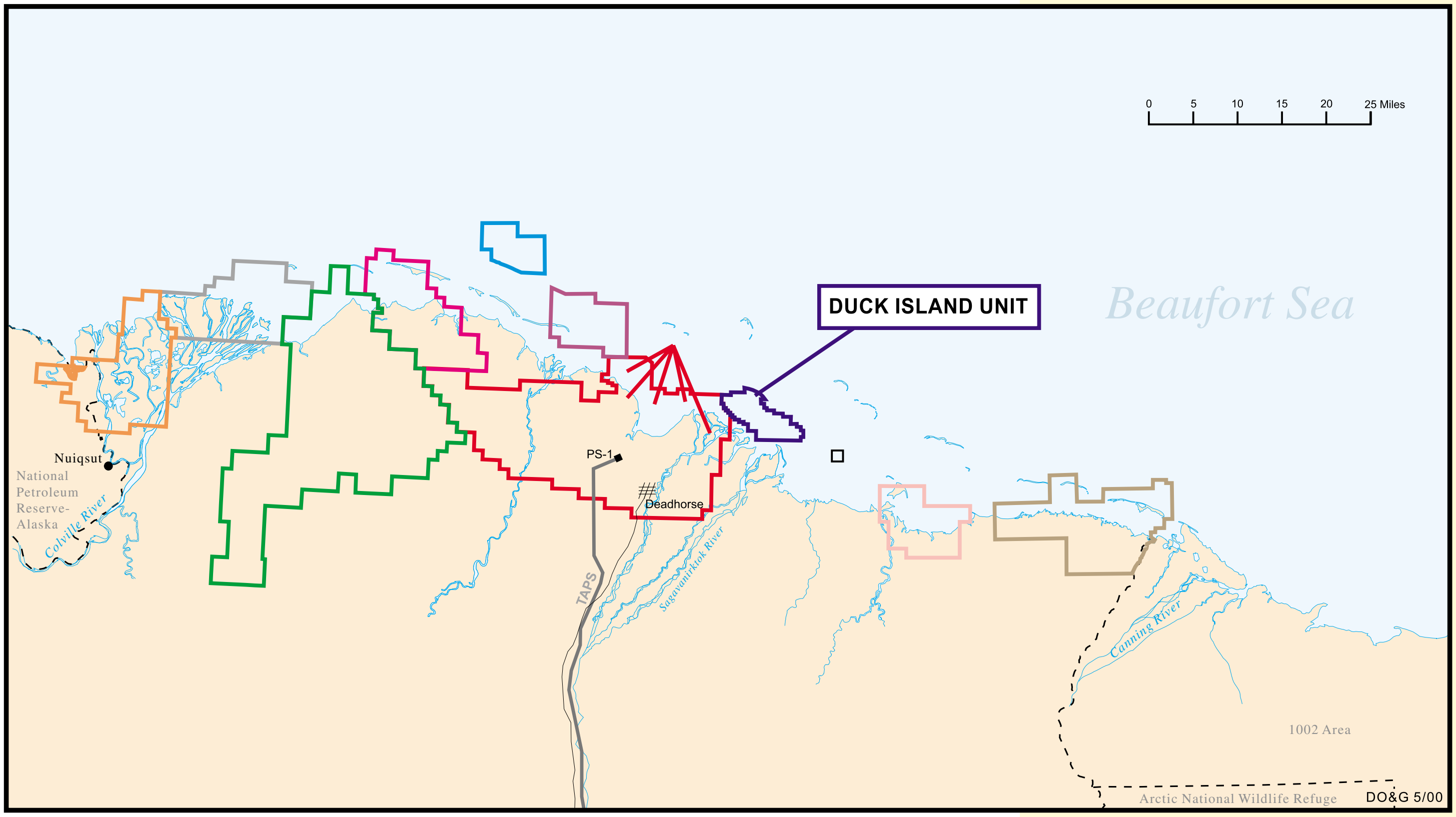
Colville Unit



Duck Island Unit

Region:	North Slope
Status:	Producing
Type:	Oil and Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	BP Exploration (Alaska), Inc. 68.78%, ExxonMobil 0.46%, Unocal 10.24%, Nana 0.38%, Doyon 0.13%, Phillips Alaska, Inc. 0.02%
Operator:	BP Exploration (Alaska), Inc.
Discovery Date:	Endicott; 1978, Sag Delta 34633 #4 Sag Delta North; 1982, Sag Delta #9 Eider; 1998, Duck Island Unit MPI #2-56/EID
Reservoir:	Endicott: Mississippian Kekiktuk Con glomerate (19,000 ft subsea) Sag Delta: Triassic Ivishak sandstone Eider: Mississippian Alaphah limestone
Status:	Three Participating Areas in the Unit. Eider PA formed in 1998.

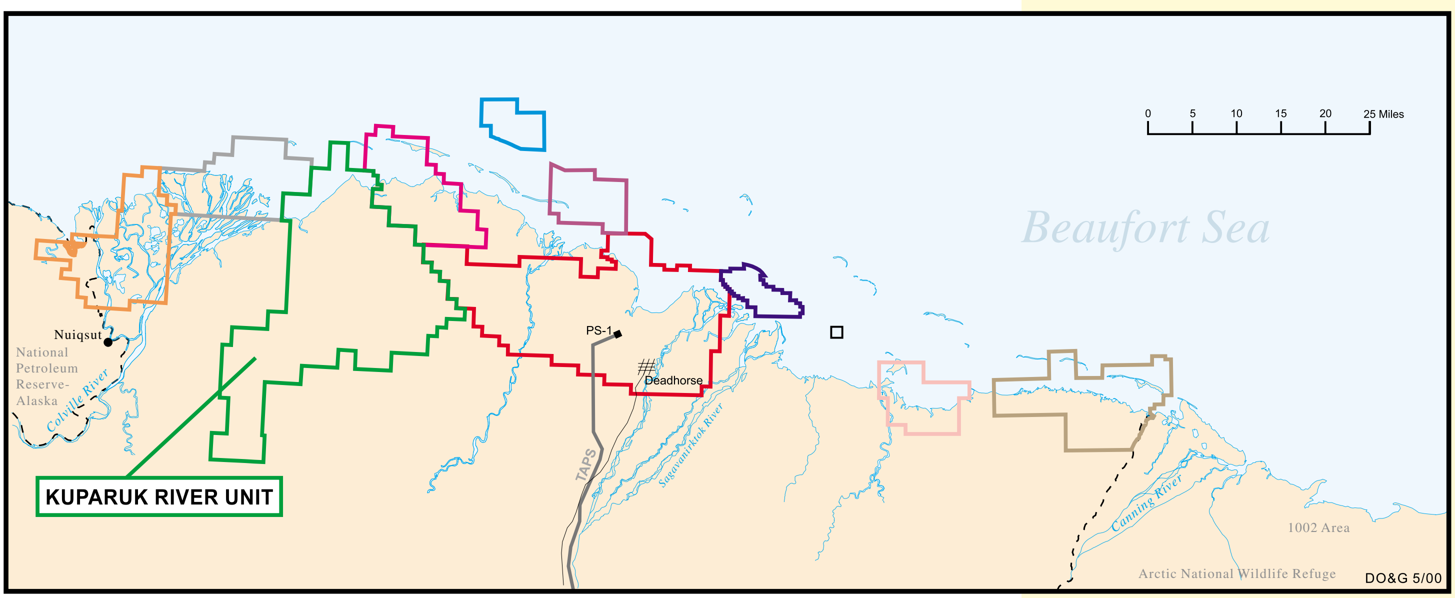
Duck Island Unit



Kuparuk River Unit

Region:	North Slope
Status:	Exploration and Develoment
Type:	Oil and Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Phillips Alaska, Inc. 54.95%, BP Exploration (Alaska), Inc. 39.05%, Unocal 5.32%, ExxonMobil 0.57%, Chevron 0.11%
Operator:	Phillips Alaska, Inc.
Discovery Date:	Kuparuk: 1969, Ugnu #1. West Sak: 1969, Kavearak Pt. #32-25. Ugnu: 1969, Kavearak Pt. #32-25. Tarn Satellite: 1991, KRU Bermuda 36-10-7 #1. Tabasco: 1992 (confirmation/delineation). Meltwater #2: Discovery announced 5/2000.
Reservoir:	Kuparuk Formation (5,6000 ft subsea) Tarn Satellite; Late Cretaceous Seabee Formation “Bermuda” sand (between 4,376 and 5,990 ft MD in the discovery well). Tabasco; Late Cretaceous Schrader Bluff Formation “Tabasco” sand, above Seabee Formation and below W.
Status:	With four participating areas and new alignment agreements, the KRU is now referred to as the Greater Kuparuk Area. Recent discovery announced: Meltwater.

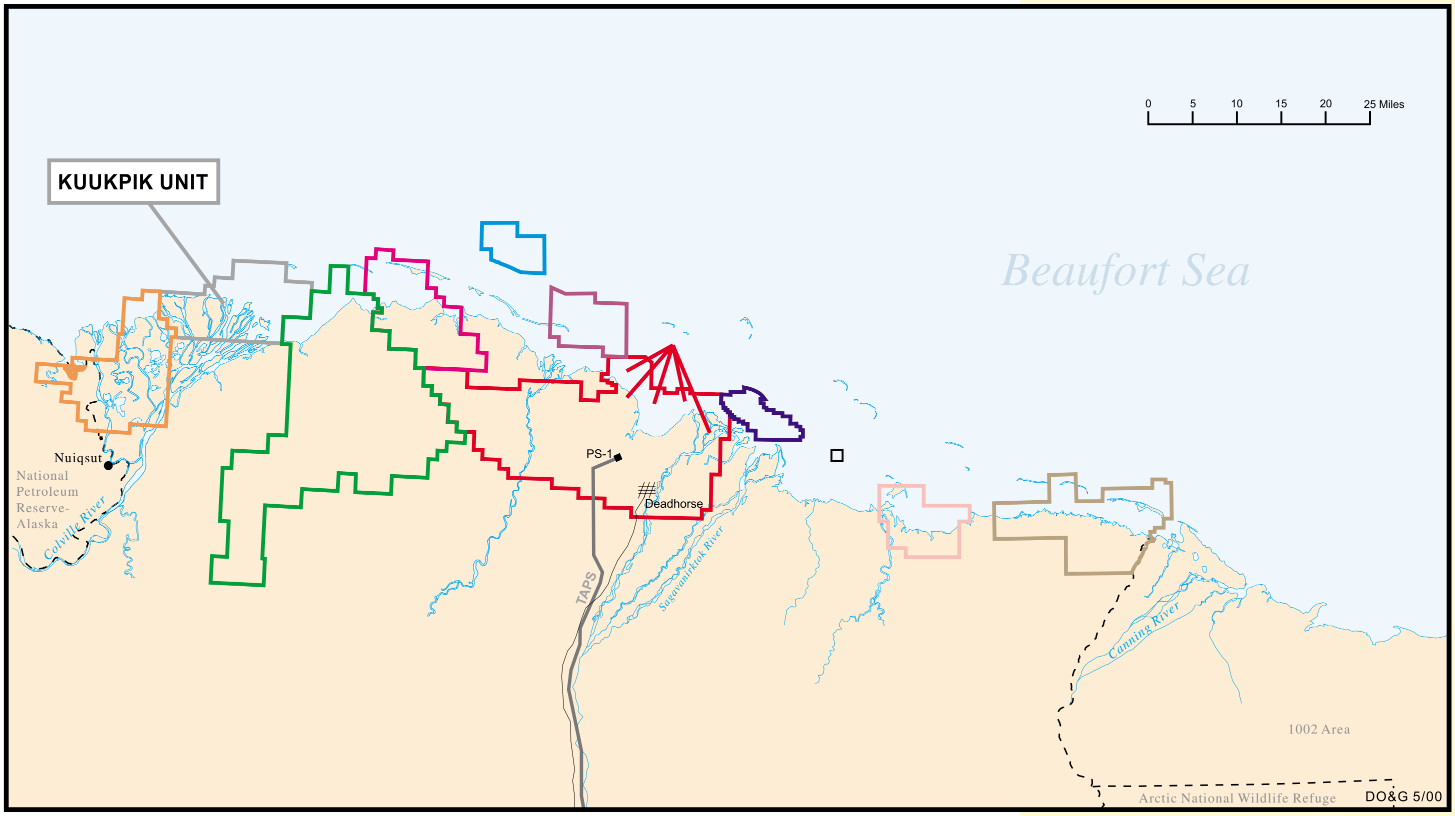
Kuparuk River Unit



Kuukpik Unit

Region:	North Slope
Status:	Exploration
Type:	Oil and Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Phillips Alaska, Inc., Union Texas Alaska, Anadarko, ExxonMobil
Operator:	Phillips Alaska, Inc.

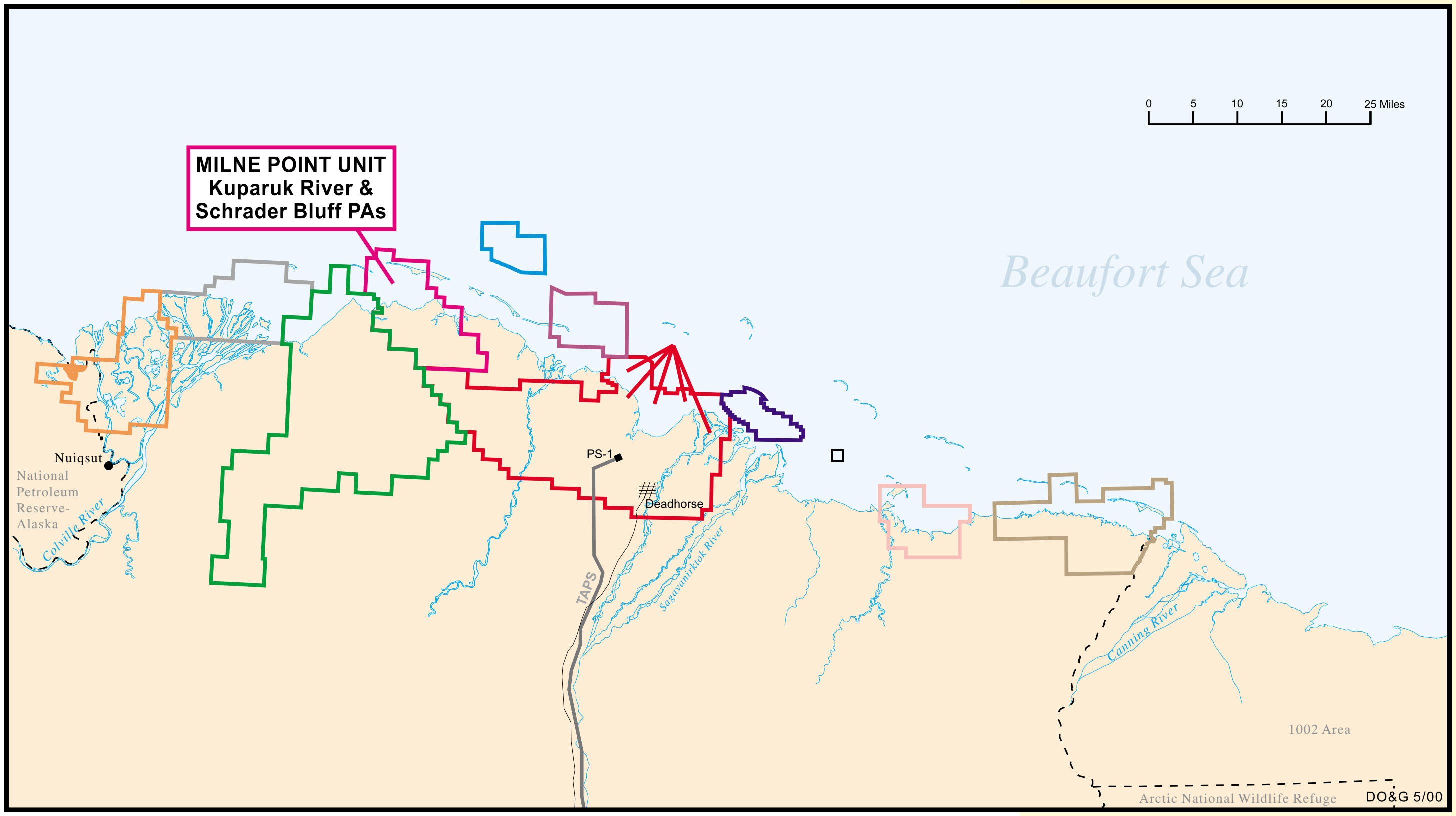
Kuukpik Unit



Milne Point Unit

Region:	North Slope
Status:	Producing
Type:	Oil and Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	BP Exploration (Alaska), Inc. 91.56%, Oxy 8.44%.
Operator:	BP Exploration (Alaska), Inc.
Discovery Date:	Milne Pt., Sag River and Schrader Bluff: 1969, Kavearak Pt. #32-25. Cascade: 1993, Cascade #1.
Reservoir:	Milne Pt.: Kuparuk Formation (7,200 ft subsea). Schrader Bluff: Cretaceous Colville Group. Sag River: Sag River/ Ivishak Formations. Cascade: Kuparuk Formation.
Status:	Production from Kuparuk and Schrader Bluff Formations. Miscible WAG EOR projected, estimated for 2nd quarter 2001.

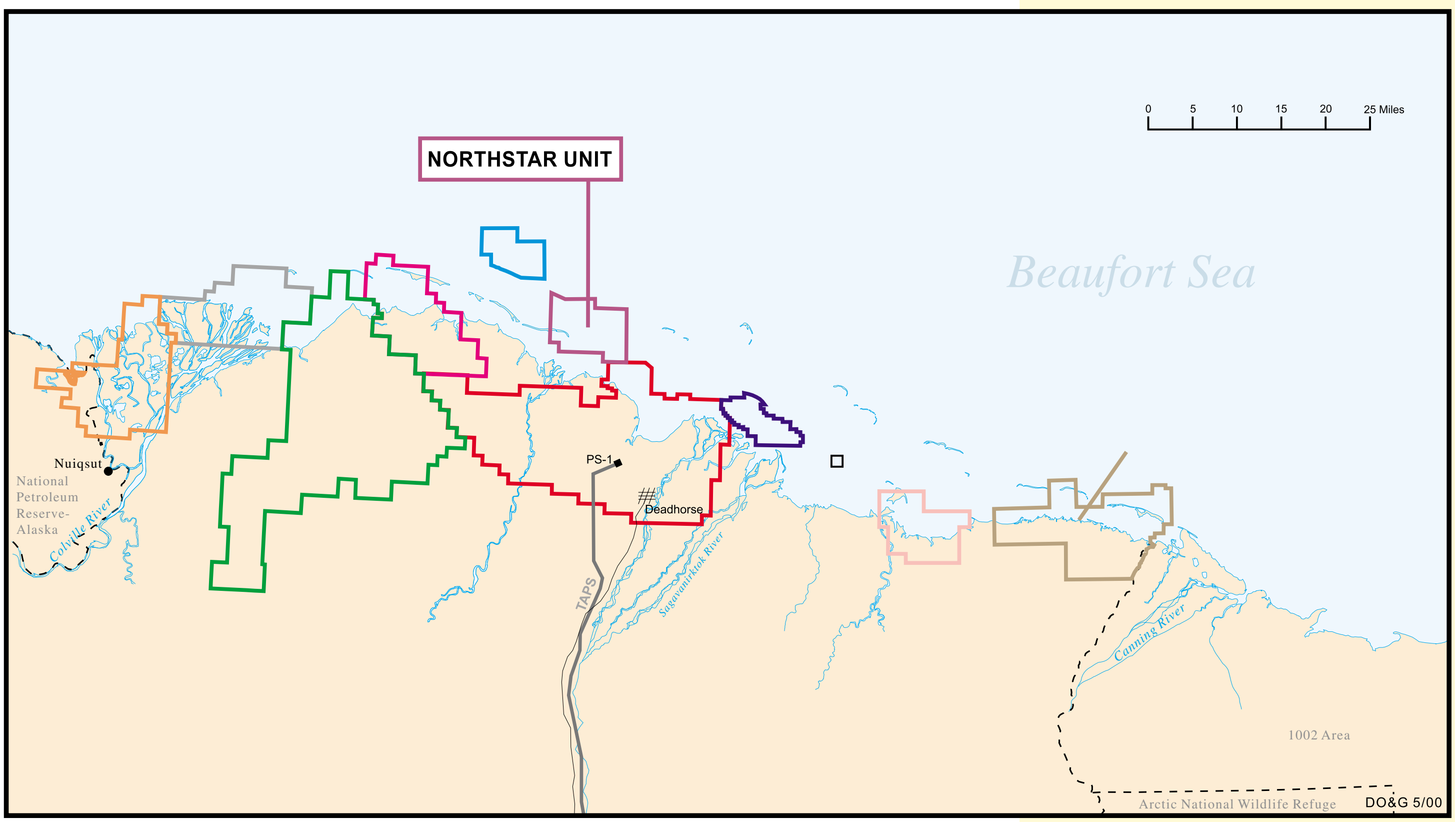
Milne Point Unit



Northstar Unit

Region:	North Slope
Status:	Development
Type:	Oil and Gas
Royalty Ownership:	State of Alaska/Federal
State of Alaska Ownership:	Ivishak: 80-85%
Working Interest Ownership:	BP Exploration (Alaska), Inc. 98%, Murphy 2%
Operator:	BP Exploration (Alaska), Inc.
Discovery Date:	1984, Shell BF-47 (Seal Island) #1
Reservoir:	Ivishak Sandstone (11,000 ft. subsea)
Status:	Pipeline and island construction commenced 1999/2000 Winter season.

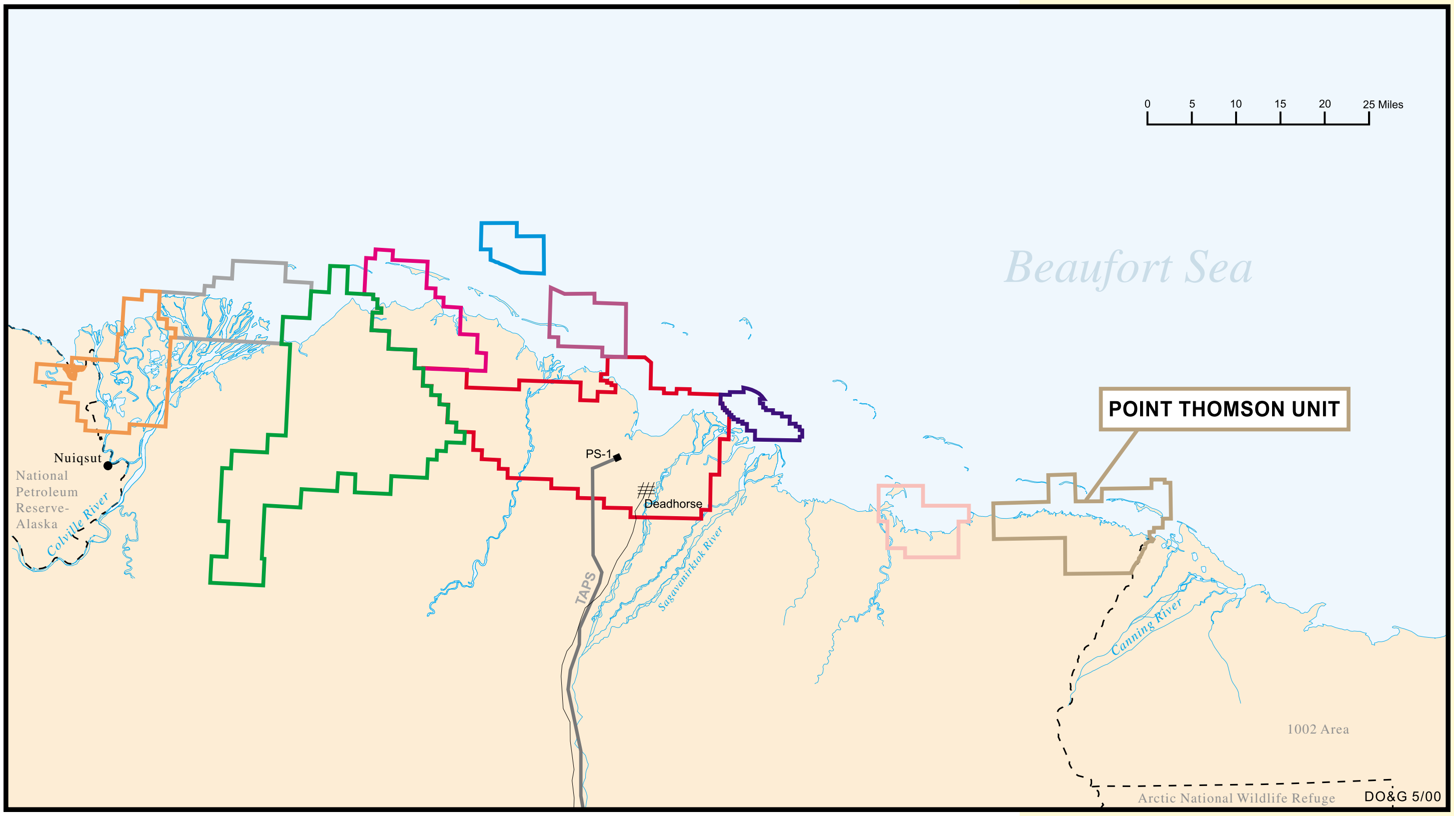
Northstar Unit



Pt. Thomson Unit

Region:	North Slope
Status:	Exploration and Development
Type:	Oil and Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	BP Amoco, ExxonMobil, Phillips, Inc., Chevron, Pennzoil
Operator:	Exxon
Discovery Date:	Pt. Thomson: 1977, Pt Thomson #1. Flaxman: 1975, Alaska State A #1. Sourdough: 1994, Sourdough #2.
Reservoir:	Lower Cretaceous Thomson sandstone, Tertiary Flaxman Turbidite

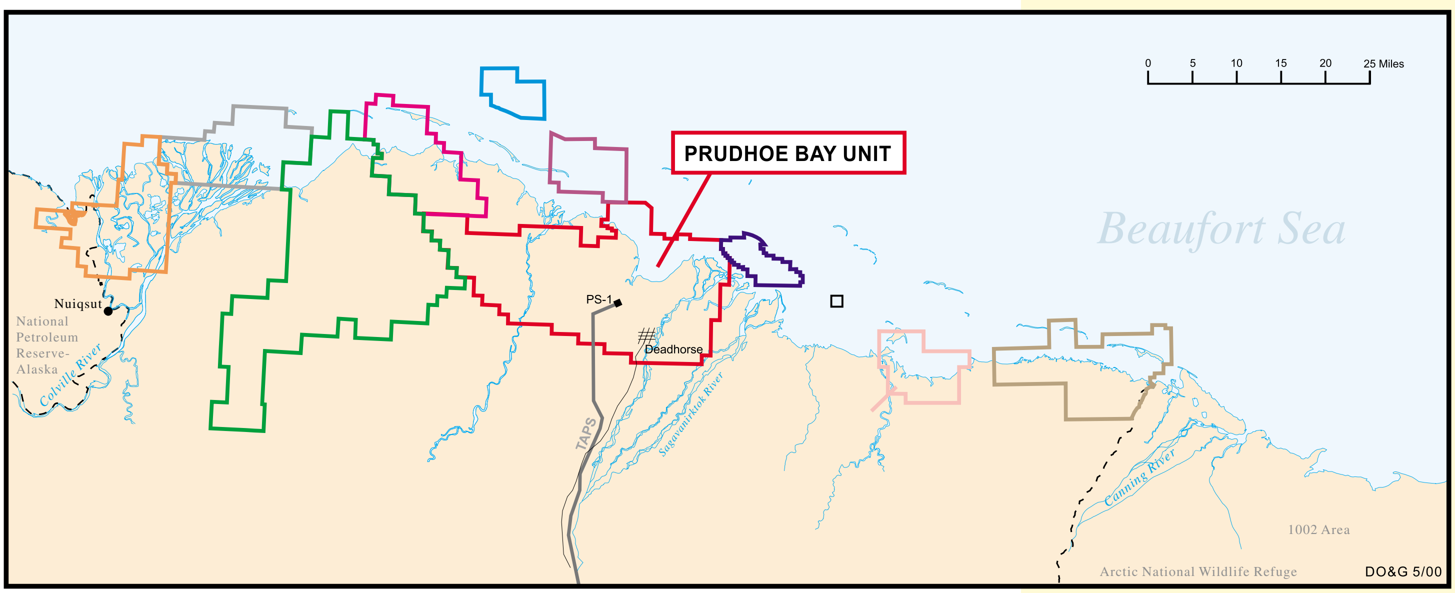
Point Thomson Unit



Prudhoe Bay Unit

Region:	North Slope
Status:	Exploration and Development
Type:	Oil and Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	ExxonMobil , Phillips Alaska, Inc., BP Exploration (Alaska), Inc., Chevron, Texaco, Forcenergy
Operator:	BP Exploration (Alaska), Inc.
Discovery Date:	PBU: 1968, Prudhoe Bay State #1. Lisburne: 1968, Prudhoe Bay State #1. North Prudhoe Bay: 1970, North Prudhoe Bay State #1. West Beach: 1976, West Beach State #3. Niakuk: 1985, Niakuk #5. Pt McIntyre: 1988, Pt. McIntyre #3.
Reservoir:	PBU: Ivishak sanstone (8,800 ft subsea). Lisburne: Lisburne Group. North Prudhoe Bay State: Sadlerochit Group. West Beach: Kuparuk. Niakuk: Kuparuk Formation. Pt McIntyre: Kuparuk Formation/Seabee Formation. Midnight Sun/Sambucca: Kuparuk Formation (Midnight Sun).
Status:	Now nine participating areas in the PBU. Plans for the new satellites: Aurora-develop ment planned for 2000; Polaris-Pilot testing in progress; NW Eileen-Two delineation wells planned for 2000.

Prudhoe Bay Unit



Beluga River

Region:	Cook Inlet
Status:	Producing
Type:	Gas
Royalty Ownership:	State of Alaska, Federal, and Fee
State of Alaska Ownership:	60%
Working Interest Ownership:	Municipality of Anchorage 33.3%, Phillips Alaska, Inc. 33.3%, Chevron 33.3%
Operator:	Phillips Alaska, Inc.
Discovery Date:	1962, Beluga River Unit 212-35 #1
Reservoir:	Beluga Formation

Cannery Loop

Region:	Cook Inlet
Status:	Producing
Type:	Gas
Royalty Ownership:	State of Alaska, Federal, and Fee
State of Alaska Ownership:	35.00%
Working Interest Ownership:	CIRI, Marathon
Operator:	Marathon
Discovery Date:	1979, Cannery Loop Unit #1
Reservoir:	Tyonek/Beluga/Sterling Formations
Status:	Three participating areas in the Cannery Loop Unit

Ivan River

Region:	Cook Inlet
Status:	Producing
Type:	Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Unocal
Operator:	Unocal
Discovery Date:	1966, Ivan River Unit #44-1
Reservoir:	Tyonek Formations

Kenai River

Region:	Cook Inlet
Status:	Producing
Type:	Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	Beluga: 100%
Working Interest Ownership:	Marathon, CIRI
Operator:	Marathon
Discovery Date:	1959, Kenai Unit #14-6
Reservoir:	Tyonek/Beluga/Sterling Formations

Lewis River

Region:	Cook Inlet
Status:	Producing
Type:	Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Unocal 100%
Operator:	Unocal
Discovery Date:	1975, Lewis River #1
Reservoir:	Tyonek and Beluga Formations

Nicolai Creek

Region:	Cook Inlet
Status:	Shut-in
Type:	Oil and Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Unocal, Marathon, Anadarko, Phillips
Operator:	Unocal
Discovery Date:	1966, Nicolai State #1A
Reservoir:	Tyonek and Beluga Formations

North Cook Inlet

Region:	Cook Inlet
Status:	Producing
Type:	Oil and Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Phillips Alaska, Inc. 100%
Operator:	Phillips Alaska, Inc.
Discovery Date:	1962, Cook Inlet State 17589 #1
Reservoir:	Tyonek/Beluga/Sterling Formations
Status:	Tyonek Deep project on hold. Royalty reduction application submitted by Phillips Alaska, Inc. is pending.

North Fork

Region:	Cook Inlet
Status:	Shut-in
Type:	Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Gas Pro, Marathon, Phillips Alaska, Inc.
Operator:	Gas Pro
Discovery Date:	1965, North Fork Unit #41-35
Reservoir:	Tyonek Formation

North Trading Bay

Region:	Cook Inlet
Status:	Producing
Type:	Oil and Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Marathon, Phillips, Anadarko, Union, Forcenergy
Operator:	Marathon
Discovery Date:	Trading Bay: 1965 Trading Bay
#1AReservoir:	Hemlock/Tyonek

Pioneer

Region:	Cook Inlet
Status:	Exploration
Type:	Coalbed Methane
Royalty Ownership:	State of Alaska (Federal/Cook Inlet Region Inc./, University of Alaska/Mental Health Trust/Fee)
State of Alaska Ownership:	52.00%
Working Interest Ownership:	Unocal, Ocean Energy
Operator:	Ocean Energy
Discovery Date:	—
Reservoir:	Tyonek Formation coal probable target
Status:	Disposal well drilled, three other "develop ment" wells planned for 2000. Water now being produced from coals. Assessment period expected to last three years.

Pretty Creek

Region:	Cook Inlet
Status:	Suspended
Type:	Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Unocal 100%
Operator:	Unocal
Discovery Date:	1979, Pretty Creek Unit #2
Reservoir:	Beluga Formation

Redoubt

Region:	Cook Inlet
Status:	Exploration
Type:	Oil
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Forcenergy 100%
Operator:	Forcenergy
Discovery Date:	1968, Redoubt Shoal Unit #2
Reservoir:	Hemlock Conglomerate (approximately 12,000 ft MD)
Status:	Platform construction underway with placement expected June 2000. Subject to 5% royalty relief under HB380.

South Granite Point

Region:	Cook Inlet
Status:	Producing
Type:	Oil and Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Mobil Rocky Mountain (ExxonMobil) 75%, Unocal 25%
Operator:	Unocal
Discovery Date:	1965, Granite Point #1
Reservoir:	Hemlock/Tyonek

South Middle Ground Shoal

Region:	Cook Inlet
Status:	Producing
Type:	Oil and Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Unocal
Operator:	Unocal
Discovery Date:	Middle Ground Shoal: 1962, MGS State 17595 #1
Reservoir:	Hemlock/Tyonek

Sterling

Region:	Cook Inlet
Status:	Producing
Type:	Gas
Royalty Ownership:	State of Alaska, Federal, and Cook Inlet Region, Inc.
State of Alaska Ownership:	12.00%
Working Interest Ownership:	Marathon 100%
Operator:	Marathon
Discovery Date:	1961, Sterling Unit 23-15
Reservoir:	Sterling Formation
Status:	Marathon plans expansion of the field.

Stump Lake

Region:	Cook Inlet
Status:	Producing
Type:	Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Unocal 100%
Operator:	Unocal
Discovery Date:	1978, Stump Lake Unit 41-33
Reservoir:	Beluga Formation

Trading Bay Unit (McArthur River Field)

Region:	Cook Inlet
Status:	Producing
Type:	Oil and Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Unocal, Forcenergy
Operator:	Unocal
Discovery Date:	McArthur River Field: 1965, W. Grayling #1A
Reservoir:	West Foreland/Hemlock/Tyonek

West McArthur River

Region:	Cook Inlet
Status:	Producing
Type:	Oil and Gas
Royalty Ownership:	State of Alaska
State of Alaska Ownership:	100.00%
Working Interest Ownership:	Forcenergy 100%
Operator:	Forcenergy
Discovery Date:	1991, West McArthur River #1
Reservoir:	Hemlock Conglomerate

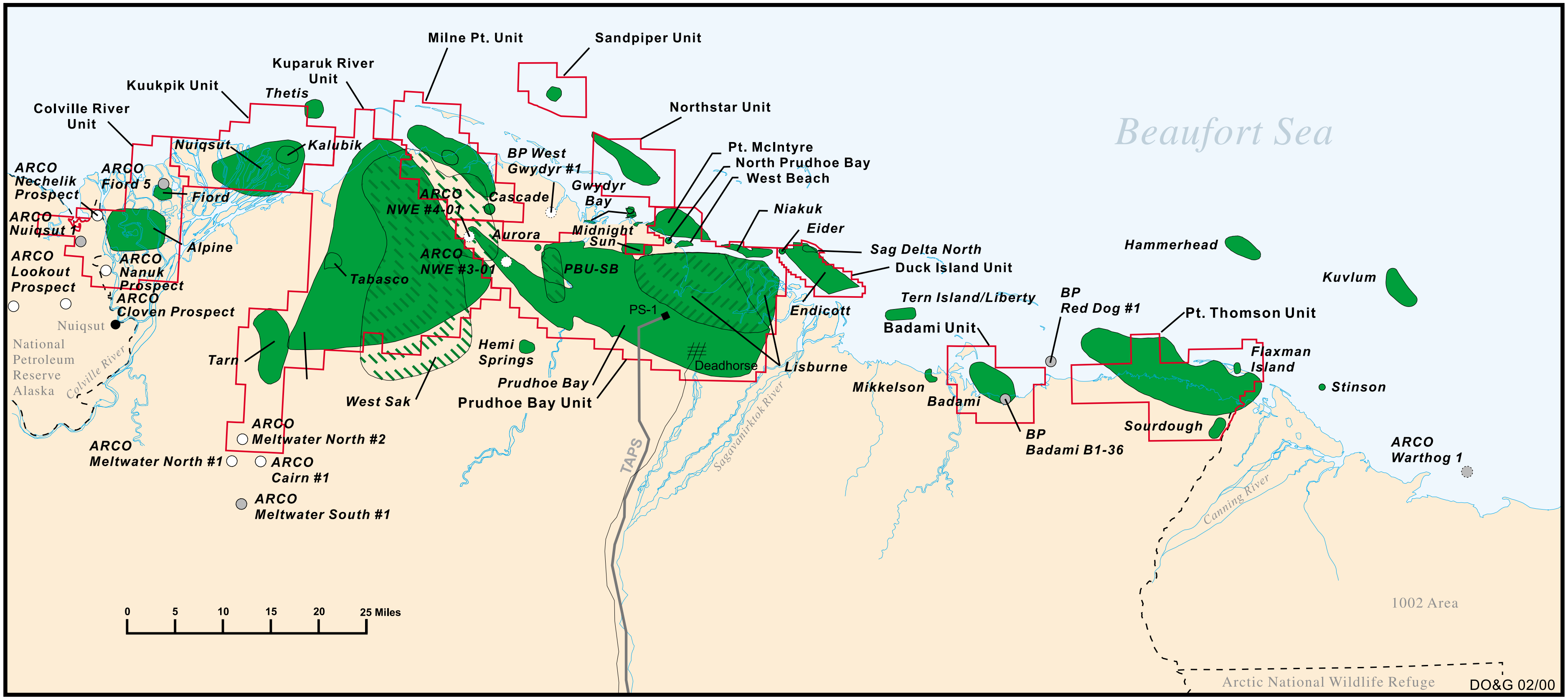
OIL AND GAS FIELDS

Field	Type	Region	Unit	Discovery	Operator	Production
ALBERT KALOA	Gas	Cook Inlet, west side, onshore		Jan-68	CIRI	shut-in 1971
ALPINE	Oil	North Slope, Colville Delta, onshore	Colville River	Mar-94	Phillips	underway
BADAMI	Oil & Gas	North Slope, Canning R., offshore	Badami	Apr-90	BP	prod. began 1998
BEAVER CREEK	Oil & Gas	Cook Inlet, east side, onshore	Beaver Creek	Dec-72	Marathon	prod. began 1973
BELUGA RIVER	Gas	Cook Inlet, west side, onshore	Beluga River	Dec-62	Phillips	prod. began 1968
BIRCH HILL	Gas	Cook Inlet, east side, onshore	Birch Hill	Jun-65	Phillips	shut-in 1965
BURGER	Oil & Gas	OCS, Beaufort Sea, offshore		Oct-89	Shell	undeveloped
CANNERY LOOP	Gas	Cook Inlet, east side, onshore	Cannery Loop	Jun-79	Marathon	prod. began 1988
CASCADE	Oil	North Slope, central, onshore.	Milne Point	Mar-93	BP	prod. began 1996
COLVILLE DELTA	Oil	North Slope, Colville Delta, onshore		Apr-85	Phillips	undeveloped
EAST BARROW	Gas	North Slope, western, onshore		May-74	NS Borough	prod. began 1981
EAST KURUPA	Gas	North Slope, foothills, onshore		Mar-76		undeveloped
EAST UMIAT	Gas	North Slope, foothills, onshore		Mar-64	UMC Pet.	shut-in, no production
EIDER	OIL	North Slope, Central, onshore	Duck Island	Mar-98	BP	prod. began 1998, Jul
ENDICOTT	Oil	North Slope, central, onshore	Duck Island	Feb-78	BP	prod. began 1987
FALLS CREEK	Gas	Cook Inlet, east side, onshore	Falls Creek	Apr-61	Marathon	shut-in 1961
FIORD	Oil	North Slope, Colville Delta, onshore		Apr-92	Phillips	undeveloped
FISH CREEK	Oil	North Slope, NPRA, onshore		Sep-49		undeveloped
FLAXMAN	Oil	North Slope, Canning R., offshore	Point Thomson	Sep-75	Exxon	undeveloped
GRANITE POINT	Oil & Gas	Cook Inlet, west side, offshore	N Trading Bay	May-65	Unocal	prod. began 1967
GUBIK	Gas	North Slope, foothills, onshore		Aug-51		undeveloped
GWYDYR BAY	Oil	North Slope, central, onshore		Nov-69	BP	undeveloped
HAMMERHEAD	Oil	OCS, Beaufort Sea, offshore		Oct-86	Chevron	undeveloped
HEMI SPRINGS	Oil	North Slope, central, onshore		Apr-84		undeveloped
IVAN RIVER	Gas	Cook Inlet, west side, onshore	Ivan River	Oct-66	Unocal	prod. began 1990
KALUBIK	Oil	North Slope, Colville Delta, offshore		May-92	Phillips	undeveloped
KATALLA	Oil	Gulf of Alaska, onshore		Jan-02		abandoned 1933
KAVIK	Gas	North Slope, foothills, onshore		Nov-69	Phillips	undeveloped
KEMIK	Gas	North Slope, foothills, onshore		Jun-72	BP	undeveloped
KENAI	Gas	Cook Inlet, east side, onshore	Kenai	Oct-59	Marathon	prod. began 1961
KUPARUK RIVER	Oil & Gas	North Slope, central, onshore	Kuparuk River	Apr-69	Phillips	prod. began 1981
KUVLUM	Oil	OCS, Beaufort Sea, offshore		Oct-92	Chevron	undeveloped
LEWIS RIVER	Gas	Cook Inlet, west side, onshore	Lewis River	Oct-75	Unocal	prod. began 1984
LIBERTY	Oil	OCS, Beaufort Sea, offshore		Mar-83	BP	undeveloped
LISBURNE	Oil & Gas	North Slope, central, onshore	Prudhoe Bay	Dec-67	Phillips	prod. began 1986
MCARTHUR RIVER	Oil & Gas	Cook Inlet, west side, offshore	Trading Bay	Sep-65	Unocal	prod. began 1967
MEADE	Gas	North Slope, NPRA, onshore		Aug-50		undeveloped
MIDDLE GROUND SHOAL	Oil & Gas	Cook Inlet, mid channel, offshore	N & S Middle Ground Shoal	Jun-62	Unocal/Shell	prod. began 1967
MIKKELSON	Oil	North Slope, central, onshore		Nov-78	Exxon/Phillips	undeveloped
MILNE POINT	Oil	North Slope, central, onshore	Milne Point	Aug-69	BP	prod. began 1985
MOQUAWKIE	Gas	Cook Inlet, west side, onshore		Nov-65	CIRI	shut-in 1979
NIAKUK	Oil	North Slope, central, offshore	Prudhoe Bay	Mar-85	BP/Phillips	prod. began 1994
NICOLAI CREEK	Gas	Cook Inlet, west side, onshore	Nicolai Creek	Apr-66	Unocal	shut-in 1977
NORTH COOK INLET	Gas	Cook Inlet, mid channel, offshore	N Cook Inlet	Aug-62	Phillips	prod. began 1970

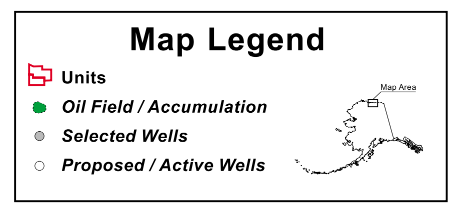
OIL AND GAS FIELDS

Field	Type	Region	Unit	Discovery	Operator	Production
NORTH FORK	Gas	Cook Inlet, east side, onshore	North Fork	Dec-65	Gas-Pro	shut-in 1965
N. MIDDLE GROUND SHOAL	Oil & Gas	Cook Inlet, mid channel, offshore		Nov-64	Unocal	undeveloped
NORTH PRUDHOE	Oil & Gas	North Slope, central, onshore	Prudhoe Bay	Mar-70	Phillips	prod. began 1993
NORTHSTAR	Oil & Gas	North Slope, central, offshore	Northstar	Jan-84	BP	underway
POINT MCINTYRE	Oil & Gas	North Slope, central, offshore		Mar-88	Phillips	prod. began 1993
POINT THOMSON	Oil & Gas	North Slope, Canning R., offshore		Dec-77	Exxon	undeveloped
PRETTY CREEK	Gas	Cook Inlet, west side, onshore		Feb-79	Unocal	prod. began 1986
PRUDHOE BAY	Oil & Gas	North Slope, central, onshore		Dec-67	BP/Phillips	prod. began 1977
REDOUBT SHOAL	Oil	Cook Inlet, west side, offshore		Sep-68	Forcenergy	proposed
SAG DELTA NORTH	Oil	North Slope, central, onshore		Jan-82	BP	prod. began 1989
SAG RIVER	Oil	North Slope, central, onshore		Aug-69	BP	prod. began 1994
SANDPIPER	Oil	OCS, Beaufort Sea, offshore		Jan-86	Murphy	undeveloped
SCHRADER BLUFF	Oil	North Slope, central, onshore		Aug-69	BP	prod. began 1991
SIKULIK	Gas	North Slope, western, onshore		Apr-88	NS Borough	undeveloped
SIMPSON	Oil	North Slope, NPRA, onshore		Oct-50		undeveloped
SOURDOUGH	Oil	North Slope, Canning R., offshore		Apr-94	BP	undeveloped
SOUTH BARROW	Gas	North Slope, western, onshore		Apr-49	NS Borough	prod. began 1950
SQUARE LAKE	Gas	North Slope, NPRA, onshore		Apr-52		undeveloped
STARICHKOF	Oil	Cook Inlet, east side, offshore		Apr-67	Forcenergy	undeveloped
STERLING	Gas	Cook Inlet, east side, onshore		Jul-61	Marathon	prod. began 1962
STINSON	Oil	North Slope, Canning R., offshore		Aug-90	Phillips	undeveloped
STUMP LAKE	Gas	Cook Inlet, west side, onshore		May-78	Unocal	prod. began 1990
SWANSON RIVER	Oil & Gas	Cook Inlet, east side, onshore		Jul-57	Unocal	prod. began 1958
TABASCO	Oil	North Slope, central, onshore		Jan-92	Phillips	prod. began 1999
TARN	Oil	North Slope, central, onshore		Feb-91	Phillips	prod. began 1999
THETIS ISLAND	Oil	North Slope, central, offshore		Apr-93	Anadarko	undeveloped
TRADING BAY	Oil & Gas	Cook Inlet, west side, offshore		Jun-65	Unocal	prod. began 1967
TYONEK DEEP	Oil & Gas	Cook Inlet, mid channel, offshore		Nov-91	Phillips	undeveloped
UGNU	Oil	North Slope, central, onshore		Aug-69	Phillips	undeveloped
UMIAT	Oil	North Slope, foothills, onshore		Jul-50	U.S. Dept Interior	undeveloped
WALAKPA	Gas	North Slope, western, onshore		Feb-80	NS Borough	prod. began 1992
WEST BEACH	Oil & Gas	North Slope, central, onshore		Jul-76	Phillips	prod. began 1994
WEST FORELAND	Gas	Cook Inlet, west side, onshore		Mar-62	Phillips	shut-in 1962
WEST FORK	Gas	Cook Inlet, east side, onshore		Sep-60	CIRI	prod. began 1978
WEST MCARTHUR RIVER	Oil & Gas	Cook Inlet, west side, onshore		Dec-91	Forcenergy	prod. began 1994
WEST SAK	Oil	North Slope, central, onshore		Aug-69	Phillips	prod. began 1998
WOLF CREEK	Gas	North Slope, NPRA, onshore		Jun-51		undeveloped

Source: ADNR, 5/00



North Slope Oil and Gas Activity
February 2000




Cook Inlet Region
Oil and Gas Activity
0 5 10 15 20 25 Miles
GRI
Houston 1
Pioneer Unit
(Generalized Bdry)
Palmer
Wasilla
Parks
Hwy
Knik Arm
Glenn
Forcenergy, Inc.
Coffee Creek 1
Pretty Creek
Stump Lake
Ivan River
Beluga River
Fire
Is.
ANCHORAGE
Anadarko
Lone Creek 1
North Cook Inlet
Moquawkie
Nicolai Creek
Albert Kaloa
Tyonek Deep
Turnagain Arm
Seward
Hwy
Chickaloon
Bay
Girdwood
Granite Point
Hope
Trading Bay
North Middle Ground Shoal
McArthur River
Birch Hill
W. McArthur River
Middle Ground Shoal
Whittier
West Forelands
Swanson River
Frontier
Pet. Corp.
Maverick
Redoubt
Shoal
Beaver Creek
Marathon
Wolf Lake 2RD
Nikiski
Drift River
Terminal
West Fork
Sterling
Kenai
Cannery Loop
Sterling
Hwy
Marathon
Sterling Unit 41-15
Kenai
Soldotna
Kalgin
Island
Seward
Hwy
Cook Inlet
Falls Creek
Seward
Ninilchik
Sterling
North Fork
Homer
Kachemak Bay
Seldovia
Gulf
of
Alaska
Map Legend
Unit Boundary
Oil Field / Accumulation
Gas Field / Accumulation
Selected Wells
Proposed / Active Wells
Platform
Pipelines
Production Facility
Map Area
DO&G 9/99

BACKGROUND

DATA

UNITS

ROYALTY-IN-KIND AND ALASKA REFINING

LEASING PROGRAM

GOVERNMENT OIL & GAS MANAGEMENT AGENCIES IN ALASKA

Royalty-In-Kind and Alaska Refining

The state of Alaska receives a royalty of approximately 12.5 percent of the oil and gas produced from its leases. The state may take its share of oil production "in-kind" or "in-value." When the state takes its royalty share in-kind (RIK), it assumes possession of the oil or gas. The commissioner of Natural Resources may sell the RIK oil or gas in a competitive auction or through a non-competitive sale negotiated with a single buyer. When the state takes its royalty in-value (RIV), the state's lessees who produce the oil or gas market the state's share along with their own share of production. The lessees then pay the state in money for state's RIV share.

Over the last 30 years the state has taken about one-half of its royalty oil as RIK.[1] The state has sold nearly 800 million barrels of RIK oil during this time, most of it in-state. These in-state sales provided an important stimulus to the Alaska's refining industry by providing long-term supplies of oil to each of the state's fledging refineries. The early RIK sales also fueled many controversies and policy debates over the appropriate use of the state's natural resources.

Cook Inlet

In 1969 the commissioner of Natural Resources negotiated a sale of 100 percent of the state's royalty from Cook Inlet to the Alaska Oil and Refining Company. Within months of signing the contract Alaska Oil and Refining Co. merged with the Tesoro Petroleum Company. Tesoro subsequently built a new refinery in Nikiski on the Kenai Peninsula next to the Chevron refinery. Between 1969 and 1985 the state sold all of its Cook Inlet royalty oil to the Tesoro refinery. By 1980 the production decline in the Cook Inlet prompted Tesoro to negotiate the first of several sales contracts with the state for supplies of RIK oil from the North Slope. By the end of 1985 Tesoro had replaced its Cook Inlet RIK volumes with supplies of RIK from the North Slope.

In 1987 the state began to export RIK oil to the Chinese Petroleum Company. These volumes were produced from fields on the West Side of Cook Inlet after the Federal government exempted Cook Inlet production from Export Administration regulations. The state sold 97 percent of the royalty production from the McArthur River, Trading Bay, North Trading Bay, and Granite Point fields in a series of one-year competitive auctions. In 1990, deliveries under the last Chinese Petroleum contract were halted under force majuere with the eruption of the Mount Redoubt volcano. There have been no Cook Inlet RIK sales since.

North Slope

In 1976, the state signed a six-year contract with Golden Valley Electric Association (GVEA, a Fairbanks electric utility) to sell approximately 3,300 barrels of oil per day as turbine fuel. GVEA did not exercise its option to take RIK until 1981 and it traded these volumes with Mapco (now Williams Co.) in exchange for refined fuel. The state subsequently sold RIK to GVEA in two other contracts until 1992. As in the first contract, GVEA traded these volumes with Mapco.

[1] The state also sold 10.4 Bcf of RIK gas in a contract to Alaska Pipeline Co (Enstar) from 1977 through 1984 from Cook Inlet royalty production. In a bid to encourage development of the gas resource in Prudhoe Bay, the state entered 20-year contracts in January 1977 to supply El Paso Natural Gas Co., Tenneco Alaska, Inc and Southern Natural Gas Co. with 25%, 50%, and 25%, respectively, of Prudhoe Bay Unit RIK gas. The contracts terminated in May 1978 when the proposed El Paso Trans-Alaska Gas Pipeline was not certified by the Federal government.

In 1978 the state contracted with Earth Resources Company of Alaska, predecessor to Mapco Alaska and now Williams Co., to supply 15 percent of Prudhoe Bay RIK oil production less the quantity dedicated to GVEA. This 25-year contract expires in December 2003. Williams Co. receives a maximum of 35,000 barrels per day of RIK oil produced from the Prudhoe Bay Unit under this contract and has since supplemented this supply with new agreements for another 28,000 barrels per day. Williams is now the only purchaser of state RIK.

As mentioned above, Tesoro has been a big North Slope RIK customer. Tesoro negotiated and bid for several contracts that supplied it with RIK supplies from 1980 to 1998. Chevron was another big purchaser of North Slope RIK for oil supplied to its Nikiski refinery from 1980 through 1991 when it finally shut down its Nikiski refinery. Petro Star purchased North Slope RIK from 1986 through 1991 for its new refinery at North Pole. In 1992 Petro Star negotiated a 10-year contract with the state for a supply of RIK from the Kuparuk River Unit. With this contract in hand, Petro Star was able to build the state's newest refinery in Valdez. As it happened, Petro Star elected to take no oil under this contract and the contract expired automatically nine months after it had been signed.

The state also held competitive auctions of RIK oil during the early 1980's as part of a program to routinely offer RIK short-term contracts. Winners of these sales included in-state refineries but also several outside refineries. Many of these buyers were also ANS producers. About 46 million barrels of North Slope RIK were sold in these sales but the program was interrupted after the general collapse of oil prices at the time.

The earliest RIK sales, notably Tesoro's first Cook Inlet contract, the first GVEA contract, and the Alpetco contract, generated quite a bit of controversy and debate in the state. Several issues arose as the RIK program evolved. Is the state better off negotiating sales one-on-one or auctioning RIK through competitive tenders? How much public input should be encouraged? Should the state subsidize the local refining industry through price breaks? Should it sell RIK only if it can get greater value. What kind of oversight should be required? The debates of these questions led to the present program as set out in statutes and regulations.

Royalty-in-Kind Policy

When disposing royalty oil or gas, the commissioner is bound by AS 38.05.182 and AS 38.05.183. Furthermore, the legislature established the Alaska Royalty Oil and Gas Development Board (Royalty Board) under AS 38.06 to oversee the department's RIK program. Regulations under Title 11, Chapters 3 and 26 govern the actual disposition of royalty and the sale of RIK. (See http://www.legis.state.ak.us/folhome.htm for more information.)

The rules that govern the sale of RIK may be reduced to a few principles.

- Any disposition of the state's royalty must be in the state's best interest. The state should sell its oil rather than keep it in-value as long as the best interests of the state are served.
- The state must receive a price for its RIK that is at least as much as it receives when the state takes its royalty in-value.
- Under certain circumstances, the state may sell its oil in a negotiated sale, but competitive sales are preferred.
- Although the price of RIK must equal or exceed the price of RIV, a review of each sale must consider economic, social, and environmental effects. In this way, benefits may be attributed to the sale of RIK to local refineries that would not be generated by sales to outside purchases.
- The public is a part of the process. Depending on the terms of the sale, the commissioner will publish best interest findings and solicit comments on the sale from the public.
- The Royalty Board must be notified of any disposition of RIK. For supply contracts for more than one year, the Royalty Board must evaluate the economic, social, and environmental effects of the sale, convene a public hearing, and recommend approval of the sale to the legislature.
- The legislature approves long-term contracts by enacting legislation.

In January 2000, the Division of Oil and Gas published a "Notice of Interest in Sale of State Royalty Oil." The response to this notice by prospective RIK purchasers prompted the division to plan for a competitive bid auction for volumes of RIK oil produced from several North Slope fields. If the sale is determined to be in the state's best interest, the sale may be held later this year.

The division estimates that approximately 60,000 barrels per day may be available for sale in 2000-2003. When the two Williams' contracts expire at the end of 2003, the royalty productio available for new sales will rise to 120,000 barrels per day. Available royalty will decline thereafter at about 5 percent per year.

Alaska Refineries

Alaska has four refineries owned by three firms that produce nearly all of the fuel sold in Alaska. The refineries are located in North Pole near Fairbanks, Nikiski on the Kenai Peninsula, and Valdez near the TAPS marine terminal.

Williams Co. operates one of the refineries at North Pole. This refinery was expanded in 1998 and has a throughput of 210,000 barrels per day of ANS shipped to the refinery via TAPS. Williams "rents" crude oil from several TAPS shippers and returns to the pipeline the residual oil after removing the lighter components used to make petroleum products. The refinery uses about 64,000 barrels per day to manufacture various fuels and returns the remaining 146,000 barrels per day to TAPS.

Williams purchases a maximum of 57,000 barrels per day of Alaska royalty oil and the balance of its needs from other North Slope producers. Williams reports they produce the following product slate:

Gasoline	19%
Jet Fuel	57
Diesel	19
Gas Oil	4
Asphalt	__1
Total	100%

A portion of the gasoline produced by Williams is naphtha that is mostly exported to the Far East. Williams transports jet fuel, naphtha, and about 2,000 barrels per day of gasoline by rail to South-central Alaska. Williams reports that they exchange gasoline for their Juneau station with an Outside oil company. About a third of Williams' gasoline is sold to other retailers.

Tesoro's Nikiski refinery is the state's most complex refinery and has a throughput of about 50,000 barrels per day. The refinery uses all of the oil produced in the Cook Inlet and supplements this supply with foreign crude oil and feedstock produced by its refineries in Hawaii and Washington.

Tesoro currently has no contracts with the state of Alaska to process royalty oil. Tesoro reports that they produce the following product slate:

Gasoline	25%
Jet, Diesel, Fuel Oil	40-45
VT Bottoms & Resid	_30
Total	100%

Tesoro exports nearly all of its heavy oil and some asphalt. The refinery sells all of its summer gasoline production in the state but must export gasoline during the slower, winter season.

Statewide Total Fuel Consumption

Only jet fuel and motor gasoline sales have increased in the last five years. Jet fuel consumption increased on average about 13% for 1996 and 1997, then slowed to average half that rate for the following two years. Motor gasoline sales in Alaska remained flat during 1995-1997, then increased 11% and 5.5% during 1998 and 1999, respectively. Total fuel sales increased by 19% during the period 1995-1999, led by a 44% increase in jet fuel.

Seasonal Fuel Sales

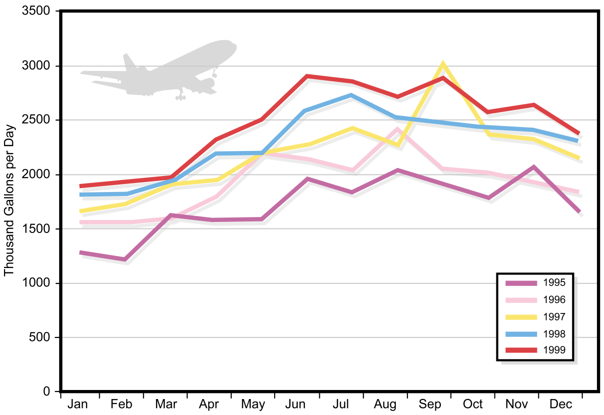
Alaska's extreme seasonal change promotes different consumption patterns of fuel use. Statewide sales of motor gasoline generally increase 30% to 40% during the summer months of May through September.

Jet fuel sales also demonstrate a seasonal pattern that has shifted upward each year from 1995 to 1999.

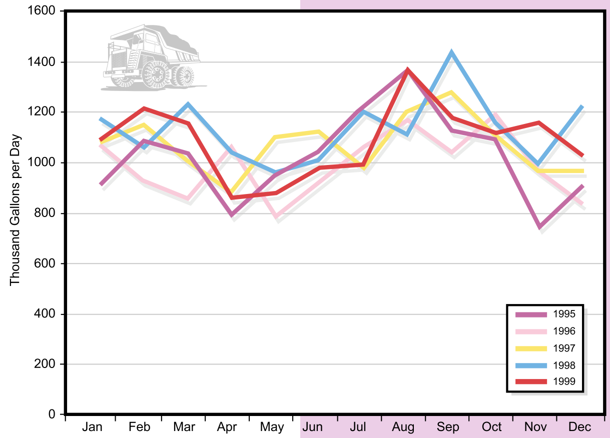
The seasonal pattern for aviation gasoline sales is markedly different than for diesel. Aviation gas sales more than double during the high activity in the summer months while diesel sales convert from distillate fuel oil to highway and marine diesel fuel.

Petro Star operates refineries in North Pole and Valdez and is owned by the Arctic Slope Regional Corporation (ASRC). The smaller, North Pole refinery has a 14,000 barrels per day throughput and Valdez refinery processes 40,000 barrels per day. Both refineries are located next to TAPS and process ANS. Only 25 percent of the throughput is retained as product and refinery fuel with the balance returned to TAPS in a similar manner as the Williams refinery. Petro Star manufactures jet fuel, diesel, and fuel oil.

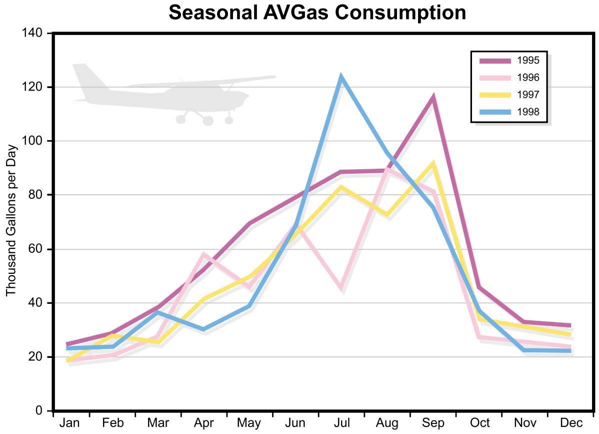
Seasonal Jet Fuel Consumption



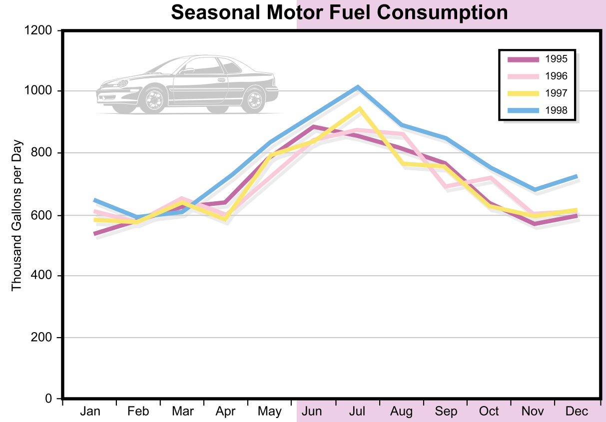
Seasonal Diesel Fuel Consumption



Seasonal AVGas Consumption



Seasonal Motor Fuel Consumption



Total Fuel Sales in Alaska (million gallons)

	Motor Gasoline[1]	Aviation Gasoline[2]	Jet Fuel[1]	Diesel[2]	Total Fuel Sold
1995	252.5	21.3	625.9	607.5	1,507.2
1996	255.1	21.2	706.4	606.3	1,588.9
1997	253.5	20.6	800.5	587.7	1,662.2
1998	281.6	19.5	834.1	574.9	1,710.1
1999	297.0	18.8	900.2	572.8	1,788.8

Source: USDOE, Energy Information Administration, EIA-782C and Alaska Department of Revenue annual reports.
[1]EIA. Complete monthly data for 1999 is unavailable.
[2]DOR. Converted from fiscal year (except 1999).

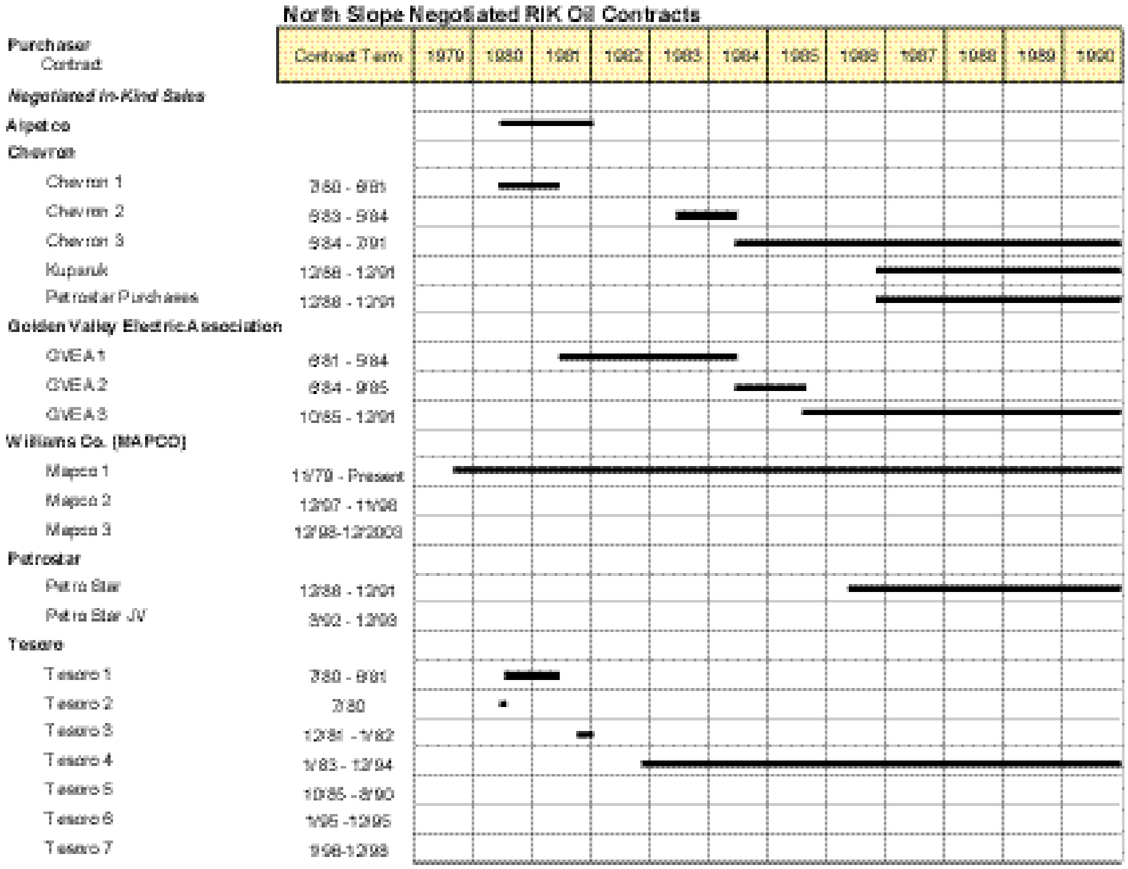
Value of Prudhoe Bay Unit Royalty Oil and ANS Spot Price

Production Month	ANS Spot Price	PS-1 PBU Royalty Value[1]
Jan-98	14.79	10.37
Feb-98	13.39	9.50
Mar-98	12.25	7.89
Apr-98	12.42	8.37
May-98	12.31	8.19
Jun-98	11.62	7.56
Jul-98	12.92	8.24
Aug-98	12.49	7.81
Sep-98	14.13	9.45
Oct-98	13.38	9.12
Nov-98	11.47	7.61
Dec-98	9.39	5.48
Jan-99	10.69	6.59
Feb-99	10.43	6.28
Mar-99	13.06	8.48
Apr-99	15.64	11.00
May-99	15.86	11.60
Jun-99	15.84	11.45
Jul-99	18.16	14.26
Aug-99	20.08	15.61
Sep-99	22.96	18.18
Oct-99	21.83	17.61
Nov-99	23.61	18.88
Dec-99	24.54	19.95

Source: ADNR.
[1]"PS-1 PBU Royalty Value" equals the volume-weighted average for royalty oil produced in the Prudhoe Bay Unit as revised in February 2000. Royalty Value equals the value of ANS oil at its destination minus marine transportation cost and tariffs.

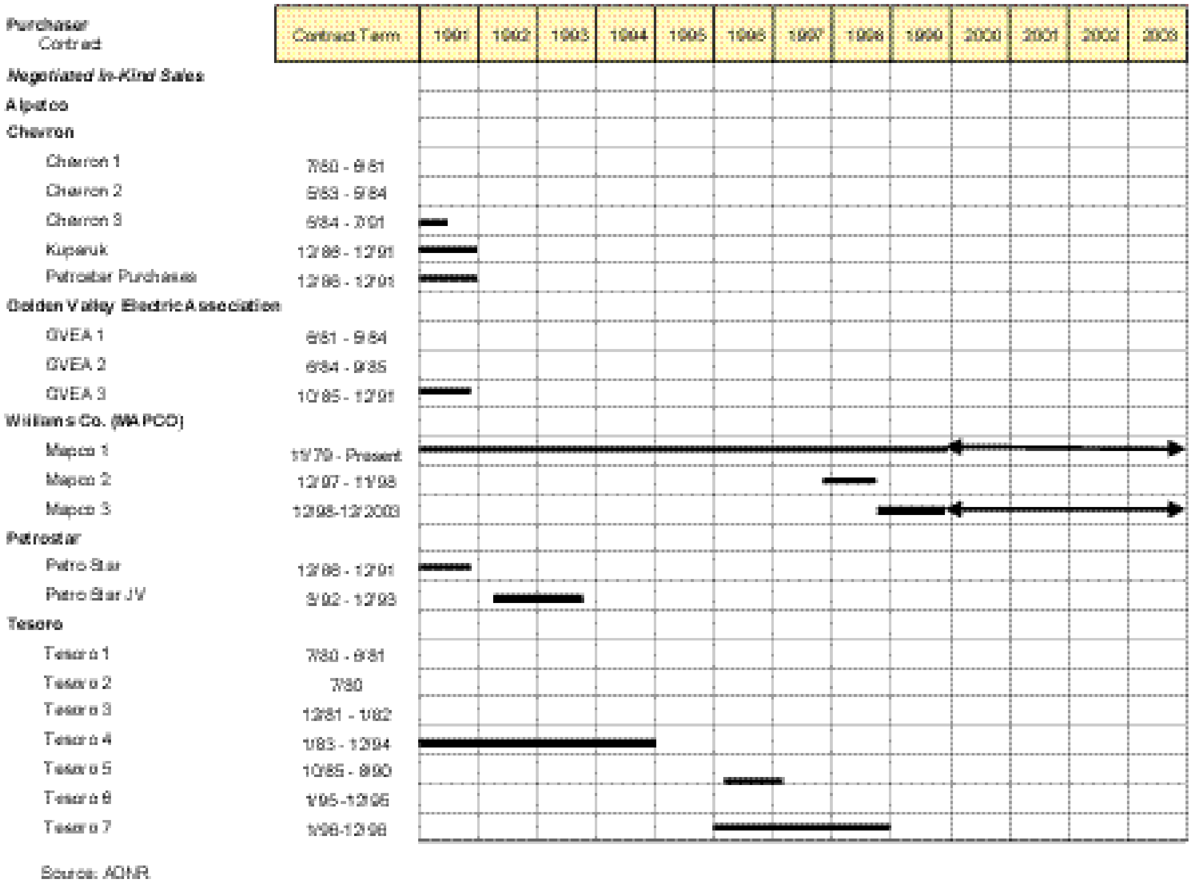
The price terms in the Williams RIK contracts are based on the value of oil received by the state for the RIV in the Prudhoe Bay Unit paid by the lessees (one contract requires an additional premium). This table compares the spot price of ANS oil sold on the U.S. West Coast versus the RIV price for in 1998-99 as reported by the lessees as of February 2000. Any new purchaser of Prudhoe Bay Unit RIK would have to expect to pay a price that exceeds the RIV price.

North Slope RIK Oil Contracts



Source: ADNR

North Slope RIK Oil Contracts



Source: ADNR

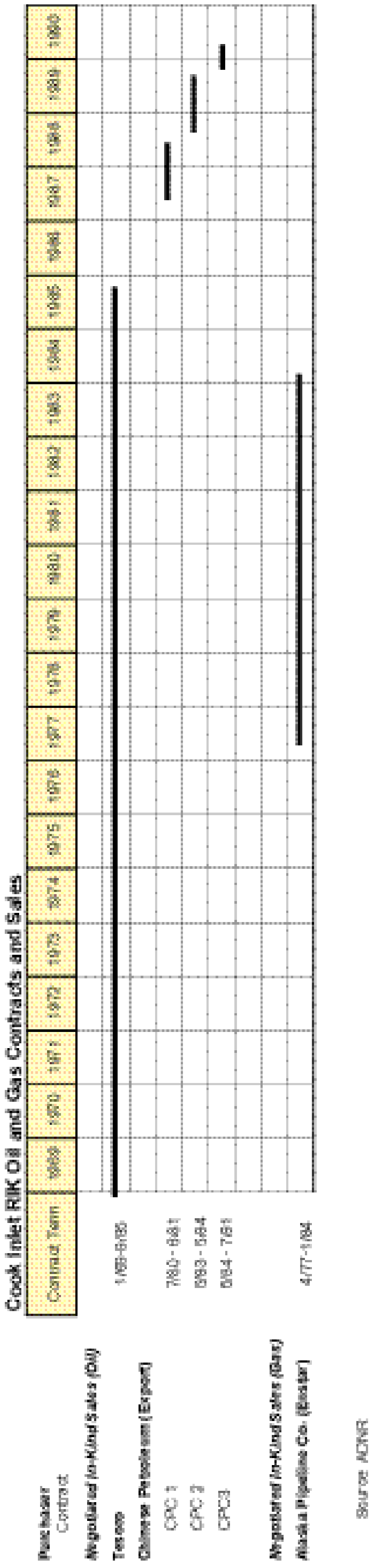
North Slope Competitive RIK Oil Sales

North Slope Competitive RIK Oil Sales

Purchaser Contract	Contract Term	1979	1980	1981	1982	1983	1984	1985	1986
First Competitive RIK Sale									
Alaska Petroleum Co.	7/81								
ARCO Products Co.	7/81 - 12/81								
Oasis Petroleum Co.	7/81 - 1/82								
Shell	7/81 - 1/82								
Sohio	8/81 - 1/82								
Union	7/81 - 1/82								
Second Competitive RIK Sale									
Chevron 4	4/85 - 3/88								
Chevron 5, 6, 7	4/85 - 9/85								
Sohio	4/85 - 12/85								
Texaco 1	4/85 - 12/85								
Texaco 2	4/85 - 3/86								
Union 2	4/85 - 9/85								
US Oil & Refining - B	4/85 - 3/86								
Quasi-Competitive RIK Sale									
Chevron 8	10/85 - 3/88								
Union 3	10/85 - 3/88								
US Oil & Refining - 1, 2, 3	10/85 - 3/88								

Source: ADNR

North Slope Competitive RIK Oil Sales



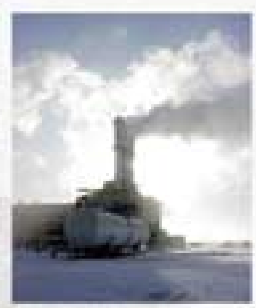
BACKGROUND

DATA

UNITS

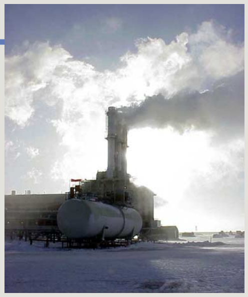
ROYALTY-IN-KIND
AND ALASKA REFINING

LEASING PROGRAM



GOVERNMENT OIL & GAS
MANAGEMENT AGENCIES
IN ALASKA

Leasing



Areawide Leasing

Oil and gas lease sales are the initial step in a process that generates nearly 80 percent of the state's income. Although the primary purpose of leasing state lands is to provide for oil and gas development and the subsequent economic benefits, the program in itself has been a significant revenue source. Fiscal Year 1998 (July 1, 1997 - June 30, 1998) was the state's biggest year for leasing in 25 years. The state sold 323 lease tracts in three sales resulting in $80.6 million in bonus bid income to the state.

Since 1959 the state has held 83 competitive lease sales in which it has offered tens of millions of acres throughout Alaska. Several leasing methods, authorized under the AS 38.05, were used to encourage oil and gas exploration and development and maximize state revenue. These methods include combinations of fixed and variable bonus bids, royalty shares and net profit shares. The fixed terms generally involve an obligation to remit royalty payments in the form of a 12.5 percent share of gross production paid in-kind or in-value. Occasionally, the state has imposed fixed royalty rates of 16-2/3 and 20 percent. The minimum royalty obligation is 12.5 percent. The state has also used sliding-scale royalty terms in its leases based on production or oil price or gross revenue. In several sales, the state has offered acreage and leased with a fixed net profit share in addition to a fixed royalty rate. Net profits are defined as the share of revenues from production from the lease net of investments and ongoing operating costs.

The most common bid variable used by the state is the cash bonus. The state may require minimum bids of $5 to $10 per acre (and sometimes higher). The state may also use the royalty rate or the net profit share as the bidding variable, though this has happened only rarely (Sale 30 was one of these occasions).

Biennially, the division issues a new *Five-Year Oil and Gas Leasing Program* that sets out the sale schedule for the succeeding five years. In 1997, the state changed the lease sale methodology. Formerly, the state offered areas for sale based on nominations by industry. Now all proposed lease sales are areawide sales held each year. An areawide sale is one in which all available state acreage within a geographic region is included. The three geographic regions are the North Slope, the Beaufort Sea, and the Cook Inlet area. The first such sale was the North Slope Areawide held in June 1998. Areas outside of these regions are available for exploration through other oil and gas programs.

Sale Areas: A total of 13 lease sales are currently scheduled over the next four years. The state proposes to conduct areawide sales on the North Slope, in the Cook Inlet area and in the Beaufort Sea.

State of Alaska
Five-Year Oil and Gas Leasing Program
2000 to 2003

2000 Sales	
North Slope Areawide 2000	November
Beaufort Sea Areawide 2000	November
Cook Inlet Areawide 2000	August

2001 Sales	
North Slope Areawide 2000	October
NS Foothills Areawide*	May
Beaufort Sea Areawide	October
Cook Inlet Areawide 2001	May

2002 Sales	
North Slope Areawide 2002	October
Beaufort Sea Areawide 2002	October
Cook Inlet Areawide 2002	May

2003 Sales	
North Slope Areawide 2003	October
Beaufort Sea Areawide 2003	October
Cook Inlet Areawide 2003	May

*Requires a Best Interest Finding

If the decision is to proceed with a sale, a Sale Announcement, including the sale terms, bidding method, tract map, and mitigation measures will be issued 90 days prior to that sale. If a best interest finding or a supplement to a previous finding is required, it will be released at the same time as the Sale Announcement.

Exploration Licensing

Exploration Licenses are designed to stimulate exploration in Alaska's frontier basins, and complement the state's oil and gas leasing program. Portions of the North Slope and Cook Inlet, which are the main thrust of the state's leasing program, remain off limits to Exploration Licensing.

There are, however, several large sedimentary basins within interior Alaska, some of which are virtually unexplored. The highly variable structural geology of these basins offers the potential for structural traps in overthrust belts and strike slip systems. Various types of clastic and carbonate stratigraphic traps may also be present. Exploration Licensing will allow companies to explore these frontier basins with minimal initial costs.

An area selected for Exploration Licensing must be between 10,000 to 500,000 acres. A license will be awarded to the applicant who has committed the most dollars to an exploration program. The recipient of a license will be required to post a bond in the amount of the work commitment and pay a $1 per acre license fee. There are no additional charges during the term of the license, which can be up to 10 years.

During its term any portion of the licensed area may be converted to oil and gas leases. The term of the leases can then extend beyond the original term of the license. There is a standard annual rental fee for leases of one dollar per acre for the first year, increasing to a maximum of three dollars per acre after the fourth year.

Licensing Process: The licensing process will be initiated in one of two ways; each year during the month of April applicants may submit to the Commissioner of the Department of Natural Resources a proposal to conduct exploratory activity within an area they have specified, or the commissioner, at anytime, can issue a notice requesting the submittal of proposals to explore an area designated by the commissioner. Once a request for proposals has been issued applicants will have 20 days to notify the commissioner of their intent to submit a proposal, and 60 days in which to submit.

Within 30 days of receiving any proposal the commissioner will either reject it in a written decision or give public notice of the intent to evaluate the proposal's acceptability. This notice will solicit public comments on the proposal(s) and request competing proposals. The commissioner may also modify any proposal and request a new one based on those modifications.

Submitted proposals must (1) describe the area proposed to be subject to licensing, (2) state the specific minimum work commitment expressed in dollars, (3) describe the amount and form of security to be posted based on the projected cost of the planned exploration work, (4) propose the term of the license (unless already established by the commissioner) and (5) verify that a prospective licensee meets minimum qualifications.

Best Interest Finding: After considering all submitted proposals and public comment on those proposals the commissioner shall issue a written finding determining whether or not granting the Exploration License is in the state's best interests. The finding must describe the limitations, conditions, stipulations or changes from the initiating proposal or competing proposals that are required to make the issuance of the license conform to the best interests of the state. If only one proposal was submitted, the finding must also identify the prospective licensee. If the finding concludes that an Exploration License should be awarded and there has only been a single applicant, that applicant will have 30 days after issuance of the finding to accept or reject the license award.

Bidding Process: If competing proposals are submitted and the commissioner determines that an Exploration License should be awarded, the commissioner will issue an invitation to submit a sealed bid. A bid deposit equal to 20 percent of the license fee must be submitted with the bid. The successful bidder will be the applicant who submits the highest bid in terms of exploration expenditures.

Once notified a successful bidder will have 10 days in which to accept or reject the license award. If the successful bidder fails to accept the award within the allotted time the bid deposit and the right to accept the award are forfeited. The next successive highest bidders will then have an opportunity to accept the award.

Relinquishment of Lands: If by the fourth anniversary of the Exploration License the licensee has completed less than 25 percent of the total work commitment the license will be terminated, with the remainder of the security forfeited to the state. If the licensee has completed less than 50 percent of the total work, then 25 percent of the licensed area will be relinquished, with an additional 10 percent relinquished each successive year until half of the original acreage has been relinquished.

Shallow Natural Gas Program

Alaska's newest leasing program allows the Division of Oil and Gas to issue non-competitive leases to explore for and develop natural gas reservoirs (including coalbed methane) located within 3,000 feet of the surface. The intent of this program is to locate local sources of gas, which can be delivered to consumers in remote areas of the state at less cost than alternative energy sources.

To encourage participation in this program, there is no bonus payment to the state for the right to explore a lease. The application fee is $500, and the annual rental payments remain at 50 cents per acre (rather than increasing from $1 to $3 per acre, as with a conventional oil and gas lease). The royalty is set at 6-1/4 percent unless the gas is produced "in direct competition" with conventional gas. Then the royalty is set at 12-1/2 percent. The term of a lease is limited to three years, with the lessee having the ability to extend the life of the lease so long as there is production. A shallow gas lease may consist of up to 5,760 acres, and a lessee may not hold more than 46,080 acres (two townships) of leased land under this program.

Because the shallow gas lease does not allow exploration for oil or for gas below 3,000 feet, the lessee need only post a bond of $25,000 (a $1 million bond is required for traditional exploratory drilling). If, however, a well penetrates a formation capable of producing gas from below 3,000 feet of the surface or penetrates a formation capable of producing oil, no further operations may be conducted until the facility complies with all applicable laws and regulations relating to oil and gas exploration and production.

Lands subject to an Exploration License, or the state's Five-Year Oil and Gas Leasing Program are not eligible for a shallow gas lease. Also, if the land is held under a coal lease, only that lessee may apply for a shallow gas lease. The Commissioner of Natural Resources may waive any of these limitations.

On February 29, 2000 at 8:30 a.m., the state held its first Non-Competitive Shallow Natural Gas Lease offering. This offering attracted 36 applicants submitting a total of 263 lease applications.

Exploration Incentive Credits

The state offers two programs authorizing an Exploration Incentive Credit (EIC).

Program I: This EIC is included as a term of the lease. AS 38.05.18(i) provides for a system in which a lessee of state land drilling an exploratory well may earn credits based upon the footage drilled and the region in which the well is situated. The statute also provides for an EIC for geophysical work on state land if that work is performed during the two seasons immediately preceding an announced lease sale and on land included within the sale area. The geophysical information must be made public following the sale. Drilling information is held confidential for two years. If demonstrated by the lessee as necessary, confidentiality may be extended. The Commissioner of Natural Resources grants credits, which can be as high as 50 percent of the costs. Credits may be applied against royalty and rental payments to the state or taxes, or they may be assigned. Since the state began offering this program, lessees have earned nearly over $50 million in credits for exploratory drilling.

Program II: This program, adopted in 1994 under AS 41.09.010 allows the Commissioner of Natural Resources to grant an EIC for exploratory drilling, the drilling of a stratigraphic test well and for geophysical work on land in the state, regardless of whether the land is state-owned. This program is designed to encourage oil and gas exploration within remote parts of the state and to provide a means for the state to obtain exploration data from federal lands and certain private lands. As with the first program, the credits may be applied against oil and gas royalties and rentals payable to the state or taxes, or they may be assigned. Data derived from drilling will be kept confidential for two years, with no extension of this period. Copies of geophysical data may be shown to interested parties by the state, but may not be transferred to third parties. Credits may be as high as 50 percent of eligible costs if performed on state land, and as high as 25 percent when performed on federal or private land. A credit may not exceed $5 million per eligible project, and the total of all credits may not exceed $30 million. Drilling credits are based upon the footage drilled. All activity qualifying for this EIC must be completed by July 1, 2004.

Royalty Reduction

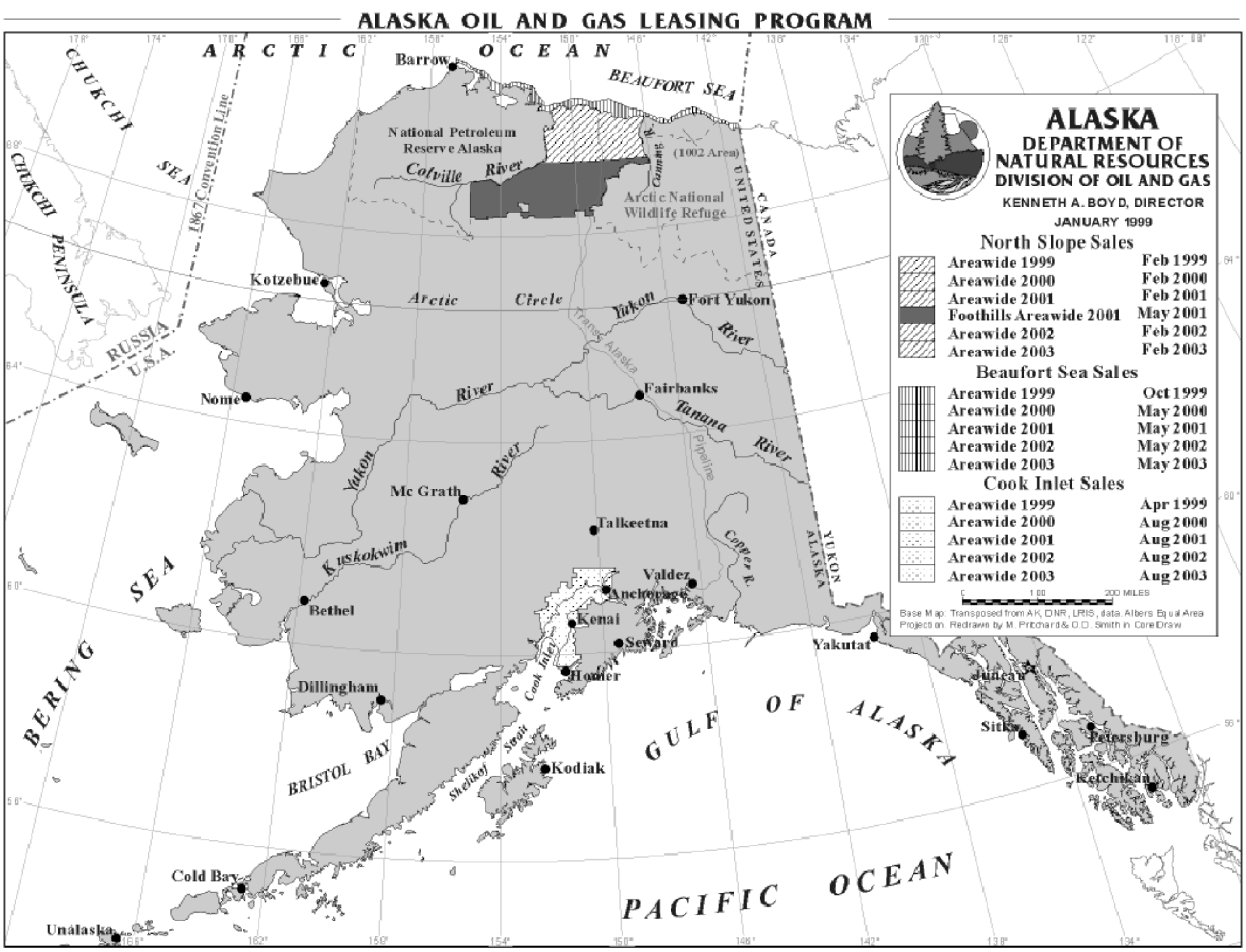
In 1995 the governor signed into law legislation that allowed the Commissioner of Natural Resources to adjust the royalty reserved to the state in order to encourage otherwise uneconomic production of oil and gas. If a delineated field or pool has not previously produced, the royalty can be lowered to five percent. If an existing producing field or pool, the royalty may be reduced to as low as three percent in order to prolong its economic life as costs per barrel or barrel equivalent increase. In order to establish production of shut-in oil or gas, the royalty may also be reduced to as low as 3 percent. These royalty reduction provisions expire on July 1, 2015.

Discovery Royalty

In 1996 the governor signed into law a measure that permits the granting of discovery royalty for wells in the Cook Inlet sedimentary basin that have discovered oil or gas in a previously undiscovered oil or gas pool, providing that the wells are capable of producing in paying quantities. The discovery royalty is established at 5 percent for 10 years following the discovery of a pool. The discovery royalty applies to all oil or gas from that pool that is attributable to the lease.

Cook Inlet Royalty Reduction

In 1998 the governor signed HB 380 that grants a 5 percent temporary royalty on the first 25 million barrels of oil and the first 35 billion cubic feet of gas produced in the first ten years of production from six specified fields in the Cook Inlet sedimentary basin. The six fields eligible for royalty reduction were discovered before January 1, 1988 and have been undeveloped or shut. The fields identified in the law are Falls Creek; Nicolai Creek; North Fork; Point Starichkof; Redoubt Shoal; and West Foreland. Production from these fields must begin before January 1, 2004.



SUMMARY OF STATE COMPETITIVE LEASE SALES

Sale Date	Sale	Sale Area	Acres Offered	Acres Leased	Percent Leased	Average $/Acre	Tracts Offered	Tracts Leased	Bonus Received	Bid Variable	Fixed Terms
12/10/59	1	Cook Inlet	88,055	77,191	87.66%	$52.08	37	31	$4,020,342	Bonus; No Min	12.5% Royalty
7/13/60	2	Cook Inlet	17,568	16,506	93.96%	$24.70	27	26	$407,655	Bonus; No Min	12.5% Royalty
12/7/60	3	Mixed	73,048	22,867	31.30%	$1.54	26	9	$35,325	Bonus; No Min	12.5% Royalty
1/25/61	4	Cook Inlet	400	400	100.00%	$679.04	3	3	$271,614	Bonus; No Min	12.5% Royalty
5/23/61	5	Mixed	97,876	95,980	98.06%	$74.71	102	99	$7,170,465	Bonus; No Min	12.5% Royalty
8/4/61	6	Gulf Ak	13,257	13,257	100.00%	$8.35	6	6	$110,672	Bonus; No Min	12.5% Royalty
12/19/61	7	Mixed	255,708	187,118	73.18%	$79.43	68	53	$14,863,049	Bonus; No Min	12.5% Royalty
4/24/62	8	Cook Inlet	1,062	1,062	100.00%	$4.80	8	8	$5,097	Bonus; No Min	12.5% Royalty
7/11/62	9	Mixed	315,669	264,437	83.77%	$59.42	89	76	$15,714,113	Bonus; No Min	12.5% Royalty
5/8/63	10	Cook Inlet	167,583	141,491	84.43%	$29.23	200	158	$4,136,225	Bonus; No Min	12.5% Royalty
12/11/63	12	Cook Inlet	346,782	247,089	71.25%	$12.31	308	207	$3,042,681	Bonus; No Min	12.5% Royalty
12/9/64	13	Mixed	1,194,373	721,224	60.39%	$7.68	610	341	$5,537,100	Bonus; No Min	12.5% Royalty
7/14/65	14	North Slope	754,033	403,000	53.45%	$15.25	297	159	$6,145,473	Bonus; $1/acre Min	12.5% Royalty
9/28/65	15	Cook Inlet	403,042	301,751	74.87%	$15.49	293	216	$4,674,344	Bonus; $1/acre Min	12.5% Royalty
7/19/66	16	Mixed	184,410	133,987	72.66%	$52.55	205	153	$7,040,880	Bonus; $1/acre Min	12.5% Royalty
11/22/66	17	Cook Inlet	19,230	18,590	96.67%	$7.33	36	35	$136,280	Bonus; $1/acre Min	12.5% Royalty
1/24/67	18	Mixed	47,729	43,657	91.47%	$33.90	23	20	$1,479,906	Bonus; $1/acre Min	12.5% Royalty
3/28/67	19	Kachemak Bay	2,560	RULED INVALID 12/9/74							
7/25/67	20	Cook Inlet	311,250	256,447	82.39%	$73.14	295	220	$18,757,341	Bonus; $1/acre Min	12.5% Royalty
3/26/68	21	Ak Pen	346,623	164,961	47.59%	$18.24	308	147	$3,009,224	Bonus; $1/acre Min	12.5% Royalty
10/29/68	22	Cook Inlet	111,199	60,272	54.20%	$17.29	230	125	$1,042,220	Bonus; No Min	12.5% Royalty
9/10/69	23	North Slope	450,858	412,548	91.50%	$2,181.66	179	164	$900,041,605	Bonus; No Min	12.5% Royalty
5/12/71	24	Cook Inlet	196,635	92,618	47.10%	$4.92	244	106	$455,641	Bonus; No Min	12.5% Royalty
9/26/72	25	Cook Inlet	325,401	178,245	54.78%	$7.43	259	152	$1,324,673	Bonus; No Min	12.5% Royalty
12/11/72	26	Cook Inlet	399,921	177,973	44.50%	$8.75	218	105	$1,557,849	Bonus; No Min	12.5% Royalty
5/9/73	27	Cook Inlet	308,401	113,892	36.93%	$9.92	210	96	$1,130,325	Bonus; No Min	12.5% Royalty
12/13/73	28	Cook Inlet	166,648	97,804	58.69%	$253.77	98	62	$24,819,190	Bonus; No Min	16.67% Royalty
10/23/74	29	Cook Inlet	278,269	127,120	45.68%	$8.19	164	82	$1,040,910	Bonus; No Min	16.67% Royalty
7/24/79	29B	Copper Riv	34,678	34,678	100.00%	$4.56	20	20	$158,042	Bonus; No Min	20% Royalty
12/12/79	30	Beaufort Sea	341,140	296,308	86.86%	$1,914.87	71	62	$567,391,497	Net Profit Share (NPS)	20% Royalty; $850 & $1750/acre
9/16/80	31	North Slope	196,268	196,268	100.00%	$63.12	78	78	$12,387,470	Bonus; No Min	20% Royalty; 30% NPS
5/13/81	33	Cook Inlet	815,000	429,978	52.76%	$10.00	202	103	$4,299,782	Royalty; 20% Min	$10/acre Bonus
8/25/81	32	Cook Inlet	202,837	152,428	75.15%	$10.00	78	59	$1,524,282	Royalty; 20% Min	$10/acre Bonus

SUMMARY OF STATE COMPETITIVE LEASE SALES (CONT'D)

Sale Date	Sale	Sale Area	Acres Offered	Acres Leased	Percent Leased	Average $/Acre	Tracts Offered	Tracts Leased	Bonus Received	Bid Variable	Fixed Terms
2/2/82	35	Cook Inlet	601,172	131,191	21.82%	$10.00	149	31	$1,311,907	Royalty; 12.5% Min	$10/acre Bonus
5/26/82	*36	Beaufort Sea	56,862	56,862	100.00%	$573.02	13	13	$32,583,452	Bonus; No Min	12.5% Royalty & 40% NPS
8/24/82	*37	Copper River	852,603	168,849	19.80%	$3.33	217	33	$562,944	Bonus; No Min	12.5% Royalty & 30% NPS
8/24/82	37A	Cook Inlet	1,875	1,875	100.00%	$52.00	1	1	$97,479	Bonus; No Min	43% Royalty
9/28/82	*34	North Slope	1,231,517	571,954	46.44%	$46.70	261	119	$26,713,018	Bonus; No Min	Royalty:16.67%-40%NPS; 12.5%-30%NPS
5/17/83	*39	Beaufort Sea	211,988	211,988	100.00%	$99.05	42	42	$20,998,101	Bonus; $10/acre Min	12.5% Royalty & 30% or 40% NPS
9/28/83	40	Cook Inlet	1,044,745	443,355	42.44%	$7.17	284	140	$3,177,178	Bonus; $1/acre Min	12.5% Royalty
5/22/84	43	Beaufort Sea	298,074	281,784	94.53%	$114.32	69	66	$32,214,794	Bonus; $10/acre Min	16.67% Royalty
5/22/84	*43A	North Slope	76,079	76,079	100.00%	$125.44	15	15	$1,612,583	Bonus; $10/acre Min	12.5% Royalty & 30% NPS
9/18/84	41	Bristol Bay	1,437,930	278,939	19.40%	$3.03	308	63	$843,965	Bonus; No Min	12.5% Royalty
2/26/85	46A	Cook Inlet	248,585	190,042	76.45%	$13.28	65	50	$2,523,334	Bonus; $1/acre Min	12.5% & 16.67% Royalty
9/24/85	45A	North Slope	606,385	164,885	27.19%	$28.25	113	32	$4,657,478	Bonus; $5/acre Min	16.67% Royalty
9/24/85	47	North Slope	192,569	182,560	94.80%	$63.79	50	48	$11,645,003	Bonus; $5/acre Min	12.5% Royalty
2/25/86	48	North Slope	526,101	266,736	50.70%	$9.16	104	54	$2,444,342	Bonus; $5/acre Min	12.5% Royalty
2/25/86	48A	Beaufort Sea	42,053	42,053	100.00%	$12.13	11	11	$510,255	Bonus; $5/acre Min	12.5% Royalty
6/24/86	49	Cook Inlet	1,189,100	394,881	33.21%	$2.40	260	98	$947,171	Bonus; $1/acre Min	12.5% & 16.67% Royalty
1/27/87	51	North Slope	592,142	100,632	16.99%	$2.88	119	26	$289,625	Bonus; $2/acre Min	12.5% Royalty
6/30/87	50	Beaufort Sea	118,147	118,147	100.00%	$56.05	35	35	$6,621,723	Bonus; $5/acre Min	16.67% Royalty
1/26/88	*54	North Slope	421,809	338,687	80.29%	$13.83	89	72	$4,683,388	Bonus; $5/acre Min	12.5% Royalty
9/28/88	55	Beaufort Sea	201,707	96,632	47.91%	$152.13	56	25	$14,700,602	Bonus; $10&$25/ac Min	12.5% & 16.67% Royalty
9/28/88	69A	North Slope	775,555	368,490	47.51%	$16.61	155	75	$6,119,135	Bonus; $5/acre Min	12.5% Royalty
1/24/89	52	Beaufort Sea	175,981	52,463	29.81%	$33.12	43	15	$1,737,513	Bonus; $10/acre Min	12.5% Royalty
1/24/89	72A	North Slope	677	677	100.00%	$671.90	1	1	$454,977	Bonus; $10/acre Min	12.5% Royalty
1/29/91	*67A	Cook Inlet	549,364	191,588	34.87%	$28.77	140	55	$5,511,338	Bonus; $5/acre Min	12.5% Royalty
1/29/91	*70A	North Slope	532,153	420,568	79.03%	$65.88	135	109	$27,707,541	Bonus; $5/acre Min	12.5% Royalty
6/4/91	64	North Slope	754,542	34,143	4.52%	$7.10	141	6	$242,389	Bonus; $5/acre Min	12.5% Royalty
6/4/91	*65	Beaufort Sea	491,091	172,865	35.20%	$40.46	108	36	$6,993,949	Bonus; $5/acre Min	16.67% Royalty
9/24/91	*74A	Cook Inlet	605,851	26,605	4.39%	$12.06	134	5	$320,853	Bonus; $5/acre Min	12.5% Royalty
1/22/92	61	North Slope	991,087	260,550	26.29%	$9.32	181	46	$2,429,551	Bonus; $5/acre Min	12.5% Royalty
6/2/92	68	Beaufort Sea	153,445	0	0.00%	$0.00	36	0	$0	Bonus; $10/acre Min	12.5% Royalty
12/8/92	75	North Slope	217,205	124,832	57.47%	$78.11	90	55	$9,750,111	Bonus; $10/acre Min	Royalty: State =12.5% & ASRC =16.67%

*Economic Incentive Credits were offered for these sales.

SUMMARY OF STATE COMPETITIVE LEASE SALES (CONT'D)

Sale Date	Sale	Sale Area	Acres Offered	Acres Leased	Percent Leased	Average $/Acre	Tracts Offered	Tracts Leased	Bonus Received	Bid Variable	Fixed Terms
1/26/93	76	Cook Inlet	393,025	141,504	36.00%	$461.25	86	36	$65,269,167	Bonus; $5/acre Min	12.5% Royalty
1/26/93	67 A-W	Cook Inlet	282,577	129,810	45.94%	$18.75	69	33	$2,433,864	Bonus; $5/acre Min	12.5% Royalty
5/25/93	77	North Slope	1,260,146	45,727	3.63%	$25.47	228	8	$1,164,555	Bonus; $5/acre Min	12.5% Royalty
5/25/93	70 A-W	North Slope	37,655	28,055	74.51%	$48.41	11	8	$1,358,027	Bonus; $10/acre Min	12.5% Royalty
9/21/93	57	North Slope	1,033,248	0	0.00%	$0.00	196	0	$0	Bonus; $5/acre Min	12.5% Royalty
9/21/93	75A	North Slope	14,343	14,343	100.00%	$31.36	11	11	$449,847	Bonus; $10/acre Min	16.67% Royalty
10/30/94	78	Cook Inlet	396,760	136,307	34.36%	$12.14	90	34	$1,654,137	Bonus; $5/acre Min	12.5% Royalty
11/14/95	67A-W2	Cook Inlet	152,768	13,804	9.04%	$7.29	36	3	$100,638	Bonus; $5/acre Min	12.5% Royalty
11/14/95	74W	Cook Inlet	66,703	17,015	25.51%	$31.76	16	4	$540,406	Bonus; $5/acre Min	12.5% Royalty
11/14/95	76W	Cook Inlet	251,614	14,220	5.65%	$5.61	50	4	$79,722	Bonus; $5/acre Min	12.5% Royalty
11/14/95	78W	Cook Inlet	260,453	36,478	14.01%	$7.06	56	11	$257,583	Bonus; $5/acre Min	12.5% Royalty
12/5/95	80	North Slope	951,302	151,567	15.93%	$22.02	202	42	$3,337,485	Bonus; $10/acre Min	12.5% Royalty
10/1/96	86A	North Slope	15,484	5,901	38.11%	$343.40	13	5	$2,026,247**	Bonus; $100/acre Min	16.67% & 16.67-33.33% Sliding Scale Rylty
12/18/96	85A	Cook Inlet	1,061,555	173,503	16.33%	$17.92	234	44	$3,109,603	Bonus; $5/acre Min	12.5% Royalty
11/18/97	86	Beaufort Sea	365,054	323,835	88.70%	$86.42	181	162	$27,985,125	Bonus, $10/acre Min	16.67% Royalty
2/24/98	85A-W	Cook Inlet	757,878	98,011	12.90%	$8.46	157	24	$828,807	Bonus, $5/acre Min	12.5% Royalty
6/24/98	87	North Slope	Areawide	518,689	N/A	$99.86	N/A	137	$51,794,173	Bonus, $5/acre Min	12.5% Royalty
2/24/99	NS 1999	North Slope	Areawide	174,923	N/A	$14.85	N/A	40	$2,596,838	Bonus; $5/acre Min	12.5% Royalty
4/21/99	CI 1999	Cook Inlet	Areawide	114,514	N/A	$10.75	N/A	41	$1,436,685	Bonus; $5/acre Min	12.5% Royalty
TOTAL: 83 Sales				**13,390,262**		**$150.15**		**5,205**	**$2,010,559,878**		

** Sale 86A: State received $259,435; ASRC received $1,766,812.

Shallow Natural Gas Lease Application Filing

February 29, 2000

Applicant	Number of Applications	Applicant Number	Priority Number[1]
Hollmann, Nancy A.	8	26	1
Hollmann, Elisabeth M.	8	27	2
Cominco Alaska Incorporated	4	3	3
Lapp Resources Inc.	8	9	4
Mills, Paula J.	8	31	5
Ocean Energy Resources, Inc. (Hank Wood, Agent)	9	24	6
Teich, John C.	9	22	7
Orell, Elizabeth A.	8	19	8
Carlton, Dennis R.	8	32	9
Collins, Kevin R.	8	33	10
Evergreen Resources Inc.	9	36	11
Orell, Jennifer	8	20	12
Growth Resources, Ltd.	3	8	13
Thomas, Lowell R.	8	29	14
Murray, Dennis A.	9	16	15
Lappi, Linda	8	11	16
Lappi, Troy	8	12	17
Schlenker, Kenneth A.	8	21	18
Emery, Pamela J.	8	28	19
Hollmann, Ronald D.	8	35	20
Latchem, Raymond R.	5	14	21
Hollmann, John P.	8	25	22
GRI, Inc.	6	7	23
Sexton, Mark S.	8	34	24
Latchem, Edna A.	2	13	25
Bradshaw, Caroline O.	8	1	26
Williams, Ted H.	7	23	27
Northern Eclipse, LLC	2	18	28
Bradshaw, Kory	8	2	29
Latchem, Shannon G.	10	15	30
Birkholt, Franklin A.	8	30	31
Fulton, William M.	6	6	32
Lappi, Cory	8	10	33
Fromson, Paul	10	5	34
Fitzpatrick, Karen	8	4	35
NANA Development Corporation	4	17	36

[1]The priority number is the order in which applications will be adjudicated.

BACKGROUND

DATA

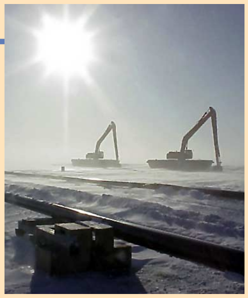
UNITS

ROYALTY-IN-KIND
AND ALASKA REFINING

LEASING PROGRAM

GOVERNMENT OIL & GAS MANAGEMENT AGENCIES IN ALASKA

Agencies



List of Oil and Gas Management Agencies in Alaska

Department of Natural Resource
Division of Oil and Gas

550 West Seventh Avenue, Suite 800
Anchorage, Alaska 99501-3560
Kenneth A. Boyd, Director
Phone: (907) 269-8800
Fax: (907) 269-8938
Website: http://www.dog.dnr.state.ak.us/oil/

The Division of Oil and Gas (DOG) encourages maximum responsible oil and gas exploration and development.

- Leases or licenses state land for oil and gas exploration and development.
- Sets the conditions under which state oil and gas leases may be developed.
- Monitors lease development for consistency with regulations and lease terms.
- Collects oil and gas royalty revenues and initiates audits of these revenues.
- Negotiates and administers oil and gas royalty-in-kind contracts.
- Estimates the volume and value of oil and gas reserves within proposed lease sale areas.
- Approves and administers oil and gas unit agreements to insure the greatest ultimate recovery and prevent waste.

Department of Revenue
Tax Division

550 West Seventh Avenue, Suite 500
Anchorage, Alaska 99501-3566
Dan Dickinson, Director
Phone: (907) 6620
Fax: (907) 269-6644
Website: http://www.revenue.state.ak.us/tax/

- Collects oil and gas severance taxes, property taxes, and corporate income taxes
- Audits oil and gas tax payments and royalty revenues.
- Estimates how much tax and royalty revenue the state will receive. This projection is used to prepare the state's annual budget.

Alaska Oil and Gas Conservation Commission

3001 Porcupine Drive
Anchorage, Alaska 99501-3192
Chair, Vacant
Phone: (907) 279-1433
Fax: (907) 276-7542
Website: http://www.state.ak.us/local/akpages/ADMIN/ogc/homeogc.htm

The Alaska Oil and Gas Conservation Commission (AOGCC) oversees the underground operation of the Alaska oil industry on private and public lands and waters.

- regulates drilling and production of oil and gas to ensure that physical waste does not occur, protects correlative rights of mineral interest owners
- ensures maximum ultimate resource recovery
- Manages the Class II Underground Injection Control program for oil and gas wells in Alaska as authorized by the U.S. Environmental Protection Agency on June 19, 1986.

Joint Pipeline Office

411 West Fourth Avenue, Suite 2-C
Anchorage, Alaska 99501
Phone: (907) 271-5070
Fax: 272-0690
Website: http://www.corecom.net/JPO/index.htm

The Joint Pipeline Office, a consortium of State and Federal agencies, regulates the Trans-Alaska Pipeline System and other Alaskan oil and gas pipelines.

Department of the Interior
Bureau of Land Management

Alaska State Office
227 West Seventh Avenue, #13
Anchorage, Alaska 99503
Fran Cherry, State Director
Phone: (907) 271-5080
Website: http://www.ak.blm.gov/

Leases and administers onshore federal oil and gas resources.

Department of the Interior
Minerals Management Service

Alaska OCS Region
949 East 36th Avenue, Room 308
Anchorage, Alaska 99508-4302
John Goll, Regional Director
Phone: (907) 261-6000
Fax: (907) 271-6805
Website: http://www.mms.gov/alaska

Leases and administers offshore federal oil and gas resources.