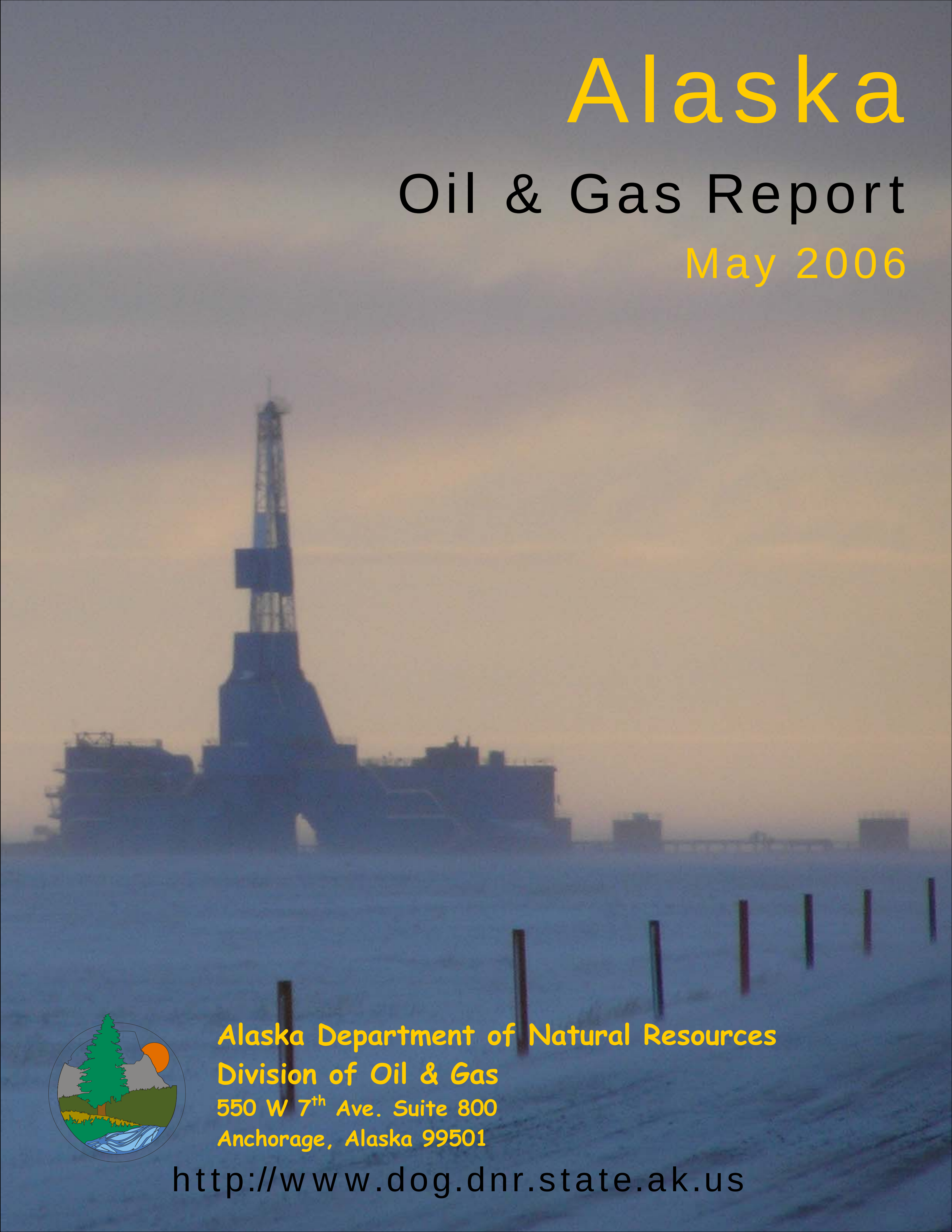

Alaska

Oil & Gas Report

May 2006

Alaska Department of Natural Resources
Division of Oil & Gas
550 W 7th Ave. Suite 800
Anchorage, Alaska 99501

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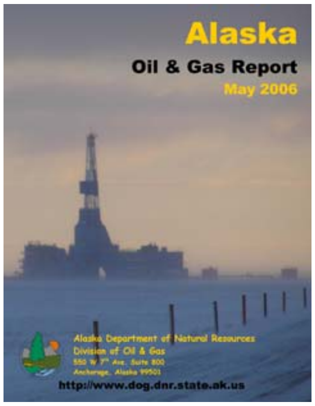

Front cover:
Arctic Rig on Alaska's North Slope.
Steve Schmitz

STATE OF ALASKA
Governor Frank H. Murkowski

ALASKA DEPARTMENT OF NATURAL RESOURCES
Michael L. Menge, Commissioner

DIVISION OF OIL AND GAS
William Van Dyke, Acting Director

This publication was released by the Division of Oil and Gas, Anchorage, Alaska. For more information, contact the Division of Oil and Gas, 550 W. 7th Ave., Suite 800, Anchorage, Alaska 99501. This report can be downloaded at www.dog.dnr.state.ak.us/oil//products/publications/annual/report.htm

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Forward

This 2006 Oil & Gas Report, released May 2006, includes production information through December 31, 2005, and contains the most recent Division of Oil and Gas oil production forecasts by field and reserve estimates. The division did not release an annual report in 2005 or 2001. Reports are available on the Division of Oil and Gas Web site at www.dog.dnr.state.ak.us/oil

2006 Oil and Gas Report

For the period ending December 31, 2005

Alaska Department of Natural Resources

Division of Oil and Gas

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Introduction

History and Outlook

This report is divided into five sections:

- This **Introduction** summarizes historic oil and gas production volume on Alaska's North Slope and Cook Inlet and discusses some of the methods and assumptions used in the report.
- **Section I** examines the state's oil and gas leasing, exploration licensing and incentive programs.
- **Section II** presents oil and gas units in Alaska and describes the individual units on the North Slope and in Cook Inlet and their producing reservoirs, sometimes called participating areas.
- **Section III** includes tables and charts depicting historic and forecast oil and gas production through 2025.
- **Section IV** presents tables describing historical royalty oil and gas production and royalty-in-kind sales contracts by volume and by customer for each unit, participating area, or field.

History of Oil and Gas Development in Alaska – The Early Years

Alaska's oil has long been the subject of interest and speculation. Historically, oil seeps were observed by Inupiat Eskimos and, according to archaeological evidence, oil shale was used for fuel by the indigenous peoples of the Arctic. 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 oil samples. In 1892 and 1896, explorers and prospectors staked oil claims along Cook Inlet.

Puale Bay, AK Peninsula
T. Ryherd

In 1896, oil claims were staked at Katalla approximately 50 miles southeast of Cordova. Oil was discovered there in 1902 and an on-site refinery near Controller Bay produced a total of 154,000 barrels over the 30 years it was in operation. The refinery burned down in 1933 and was not replaced.

In about 1903, Austin Lathrop drilled three wells in the Cold Bay area and entrepreneurs drilled several wells near Chignik and other coastal areas of Alaska in search of oil. In 1910, all oil lands in Alaska except Katalla were withdrawn from entry by the federal government. Since oil had been discovered at Katalla in commercial quantities, title was considered valid. Because of the land withdrawals, no oil drilling activity took place in Alaska for the next decade, 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 first formal descriptions were recorded by the U.S. Geological Survey 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.

Puale Bay, AK Peninsula
T. Ryherd

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 field, is being produced today for local consumption at Barrow.

Statehood - 1959

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 1950s, Congress was debating the Alaska Statehood Act. A major concern was how the potential new state, which was one of the poorest in the country, could support itself without a sufficient economic base. As a result, the Alaska Statehood Act allowed the state of Alaska to select 104 million acres of land from the federal public domain. 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 to the state of Alaska is addressed in Article VIII of the Alaska Constitution which became operative with the formal proclamation of statehood on January 3, 1959. Article. VIII, section. 1 states:

> *"[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 Alaska 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. It also recognized that other natural resources like coal and geothermal energy would play a major role in Alaska's future.

Cook Inlet Basin

Modern 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 the discovery well 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 onshore 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 more than $4 million in bonus bids.


Cook Inlet Platform
D. Colley

By 1960, further development of the Swanson River and Soldotna Creek Units raised annual oil production to 600,000 barrels. Five other Cook Inlet fields began production between 1965 and 1972. 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 1960s and 1970s. Chevron opened a refinery in 1963. The Tesoro refinery began operating in 1969. Cook Inlet production peaked at 83 million barrels per year in 1970 and declined to 7 million barrels per year in 2005. Most of the larger fields were found by the mid-1960s.

More recently, the West McArthur River field began production in 1993 and Redoubt oil field in 2002. All Cook Inlet oil is currently shipped to the Tesoro refinery at Nikiski on the Kenai Peninsula. Oil from fields on the west side 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.

By year-end 2005, the Cook Inlet tallied more than 1.3 billion barrels of cumulative oil production, including about 11 million barrels of natural gas liquids (NGLs).

Cook Inlet gas production began as a by-product of Swanson River oil development. The first major gas discovery occurred in the Kenai gas field in October 1959 by Union Oil Company of California and Ohio Oil Company. Gas production began the following year and continues today. Several additional large gas discoveries quickly followed. 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 1968 Unocal launched the ammonia-urea plant at Nikiski to take advantage of the abundance of cheap stranded natural gas. This plant was acquired in 2000 by Agrium Inc., of Calgary, Alberta. In 1969, Phillips and Marathon began operating the liquid natural gas (LNG) plant, also located at Nikiski.

Kenai Fertilizer Plant
D. Colley

LNG exports to Japan accounted for about a third of total Cook Inlet gas production. Total industrial use of Cook Inlet gas, including LNG exports, fertilizer manufacture, and oil field operations, has remained fairly constant at about 75 percent of total consumption since 1990. Cook Inlet natural gas production has remained relatively stable at an average of 203 Bcf per year from 2001 to 2005. In recent years, the steady increase in residential and commercial demand for space heating and electric power generation has been balanced by declines in field operations and reduced fertilizer production.

The history of Swanson River gas production differs from other Cook Inlet fields. Initially, gas was imported from other fields and injected into Swanson River to enhance oil recovery. In 1992 the operator began to “blow-down” the reservoir. In recent years, the Swanson River field became a major net gas producer in Cook Inlet and, since 2005, has been transformed into a federally approved gas storage facility with approximately 2 Bcf of annual storage capacity. The state has approved two gas storage facilities in Cook Inlet in depleted reservoirs at Pretty Creek and Kenai Field, which contribute 0.7 and 6 Bcf, respectively, annual storage capacity to the Cook Inlet gas pipeline system.

The North Slope

The U.S. Department of the Interior, Bureau of Land Management opened North Slope lands for competitive bidding in 1958 when 16,000 acres were offered in the area of the Gubik gas field. That same year, BLM opened 4 million acres in an area south and southeast of NPR-A (then named NPR-4). From 1962-64, industry exploration programs expanded rapidly. During this period, Sinclair and British Petroleum drilled a total of seven unsuccessful wildcat wells in the Arctic foothills in search of oil.

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 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. This proved successful, and in early 1968, Atlantic Richfield (ARCO) announced the discovery of what was to become 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.

After 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 more than $900 million in bonus bids on 164 tracts. The next North Slope sale was not held until 1979; however, during this time, more than 100 exploratory wells were drilled on the North Slope with 19 discovering oil or gas.


Arco Prudhoe Bay St #1 flare
G. Mull

Oil production on the North Slope began in 1969 at Prudhoe Bay. Production was initially restricted to small quantities used to fuel field operations until the trans-Alaska pipeline system (TAPS) was completed in July 1977. The operators injected surplus crude and residual oil back into the Prudhoe Bay reservoir. Similarly, oil production at the Endicott Field in the Duck Island Unit was re-injected into the reservoir until a pipeline linking Duck Island to TAPS was completed. From the beginning of Prudhoe Bay production, dissolved gas and water were separated from the crude oil and injected back into the reservoir. Over time, the proportion of both produced gas and water to oil increased. 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 miscible injectant (MI) project known as “MIX” also added to the field’s gas handling capacity.

Cumulative North Slope production has exceeded 15 billion barrels of oil and NGLs by the end of 2005; nearly all from the large Prudhoe Bay and Kuparuk fields. NGLs produced on the North Slope are blended with oil and shipped down TAPS or used to make MI for enhanced oil recovery projects. Since 1996, NGLs have been shipped from Prudhoe Bay to the Kuparuk River Unit via the Oliktok pipeline for MI in the large-scale enhanced oil recovery project at Kuparuk.

Exploration wells drilled on North Slope state leases since the Prudhoe Bay discovery have resulted in dozens of discoveries, many of which 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 Alpine, Northstar, Tarn, Meltwater, and West Sak. Although initial production on the North Slope was from onshore areas, seven fields produce at least some of their reserves from offshore areas including Endicott, Lisburne, Prudhoe Bay, Point McIntyre, Milne Point, Niakuk, and Northstar. Today, incremental oil production from new fields brought on line since 1995 account for 34 percent of total yearly Alaska North Slope production.

North Slope local gas production began near Barrow in the mid-1940s. 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 at the Prudhoe Bay industrial complex was 3.4 trillion cubic feet in 2005. Nearly all of this — about 3.2 trillion cubic feet (8.7 bcf per day) — was re-injected into oil-producing reservoirs. The remaining produced gas, 285 Bcf in 2005, was consumed locally on the North Slope to fuel oil-field equipment, operations, and pipelines (including TAPS). Yearly industrial local gas consumption on the North Slope is about 50 percent greater than yearly gas consumption for all uses, including industrial, in Southcentral Alaska.

Reserves and Production Summary and Outlook

The notion of reserves begins with original oil (or gas) in-place. Only a fraction of the original oil or gas in any reservoir can be extracted, depending on available technology and production economics. Recoverable reserves — those which are considered economically and technically feasible to extract — vary between 15 percent and 85 percent of oil or gas in-place, depending on the reservoir depth, rock and fluid type, technology and, to a lesser extent, market price. Total estimated recoverable and remaining recoverable reserves are the focus of this report, specifically Section III. Reserves can be calculated by many methods and there is often no consensus on which method is best to apply to each reservoir at any given point in time. Three state agencies are responsible for evaluating oil and gas reserves and production: the Alaska Oil and Gas Conservation Commission (AOGCC), the Alaska Department of Revenue's Tax Division, and the Department of Natural Resources' Division of Oil and Gas (DO&G). Each agency calculates reserves using slightly different methods. AOGCC emphasizes geologic and engineering factors to estimate the total recoverable resource. Department of Revenue calculations emphasize oil and gas production economics forecasted far into the future. These agencies cooperate and coordinate the preparation of reserves estimates and production forecasts. Reserves reported herein are based partly on Department of Revenue estimates and are calculated from the forecast of production from existing and planned developments that may reasonably be expected to occur in the near future. The forecast horizon is 30 years.

Ultimate recovery of hydrocarbons from large oil fields typically increases through their development years and is often greater than early predictions. In the 1970s, estimated reserves for the Prudhoe Bay Unit Initial Participating Area (PBU IPA) were between seven and nine billion barrels. By January 1986, ultimate recovery at the PBU IPA was projected to be 10.2 billion barrels; 4.4 billion produced and 5.8 billion remaining. By December 2002, estimated recovery increased to 13 billion barrels: 10.8 billion produced and 2.2 billion remaining reserves. By year-end 2005, we estimated the PBU IPA contains 2.5 billion recoverable barrels of oil plus another 426 million in reserves from satellite development. New investments, improved technologies, and careful cost management all have helped to increase the portion of oil or gas in-place extracted from the Prudhoe Bay and Kuparuk fields. Further improvements in technology may increase future reserve estimates. Other factors affecting ultimate recovery are energy prices, the cost of new investment and ongoing operations, the impact of fiscal incentives, and competing development opportunities available to the state's oil and gas operators in other parts of the world.

North Slope oil reserve estimates developed by DO&G are illustrated in detail in the oil forecast tables found in Section III. As indicated above, remaining reserves in any particular North Slope production unit are defined in terms of cumulative production projected for the next 30 years. Many of these units will likely produce well beyond the displayed forecast period that ends in 2025. This additional production will increase the ultimate recovery estimated in this report. Oil and gas reserve estimates for Cook Inlet fields also are based on cumulative forecast production. Reserves of undeveloped North Slope and Cook Inlet oil and gas fields are included in the forecast and, while speculative, they are based in part on the latest reports available from the producers as well as on DO&G in-house interpretation.

The State of Alaska's royalty reserves are calculated by finding the product of each field's reserves with the state's royalty ownership interest in the field. On average, the state retains a 1/8th royalty interest in most of the producing oil and gas fields in Alaska. There are third-party royalty owners in the Colville River and North Star Units on the North Slope, and the Beluga River, Cannery Loop, Kenai, Sterling, Ninilchik, Nicolai Creek, Deep Creek, and West Forelands fields in the Cook Inlet. These units and fields include federal and private Native Corporation acreage. Also, the state derives royalty from numerous non-unitized oil and gas leases. 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, Lone Creek, Moquawkie or Birch Hill fields in the Cook Inlet.

Oil Production and Natural Gas Development


State Oil and Gas Lease Sale

While production from the largest North Slope fields, Prudhoe and Kuparuk, is in decline, smaller and more numerous satellite oil and gas reservoirs are being developed and produced. New companies have entered the Alaska crude oil and gas upstream sector in recent years. Interest continues to grow, especially among independent exploration and production companies and in areas beyond the mature oil provinces of the North Slope and Cook Inlet.

Drilling activity has decreased since 2001, but the total number of feet drilled per year has been relatively steady since the mid-80s. Sustained drilling activity is a result of new discoveries, satellite field development in or near Prudhoe/Kuparuk infrastructure, in-field drilling, reworking of wells, and side-tracking of wells to reach "behind the pipe" oil and gas. Advances in drilling and completion efficiency (new fluids, technology, tools, and materials) at the main Prudhoe and Kuparuk fields is also recognized.

Nevertheless, the long-term outlook for oil production is one of gradual decline supplemented with smaller field-size oil development and with gas field development in or near existing infrastructure. The lion's share of Alaska oil production comes from Prudhoe Bay and Kuparuk, the nation's largest oil fields. The current production rate from the North Slope is about 900,000 barrels per day. We expect the rate of production to hold at about this level for at least the next five years with added production from state leases and from the NPR-A.

Cook Inlet oil production peaked at 230,000 barrels per day in 1970 and declined to 19,500 barrels per day in 2005. Oil production in Cook Inlet is expected to continue beyond 2025, including oil production from the Beaver Creek field and other non-state lands. Stepped-up oil and gas exploration drilling since 2000 in Cook Inlet is driven by strong demand and rising prices for both oil and gas, coupled with decline in production from existing fields. Details for both the North Slope and the Cook Inlet can be found in Section III.

Leasing, Exploration Licenses, and Incentives

Since 1959 the state has held more than one hundred competitive lease sales in which it has offered millions of acres throughout Alaska. By year-end 2005, 27 exploratory wells had been drilled in the federal waters of the Beaufort Sea resulting in four discoveries. These discoveries are Kuvlum, Hammerhead, Sandpiper, and Tern Island/Liberty.

Since 2001, the state of Alaska has seen a new surge in exploration interest with smaller, aggressive companies looking for gas, not just oil, in under-explored areas like the North Slope Foothills, other Interior Alaska basins and the Alaska Peninsula. This exploration is driven by increasing demand for energy in Alaska and across North America coupled with the availability of land and prospects in Alaska. Alaska oil and gas will continue to play a critical role in meeting the nation's energy needs.

The total number of separate producing reservoirs is increasing, yet they are smaller in size and may not offset the decline in overall North Slope production later this decade. In an attempt to avert the decline in oil production, the state has created new programs to attract explorers to areas of Alaska.

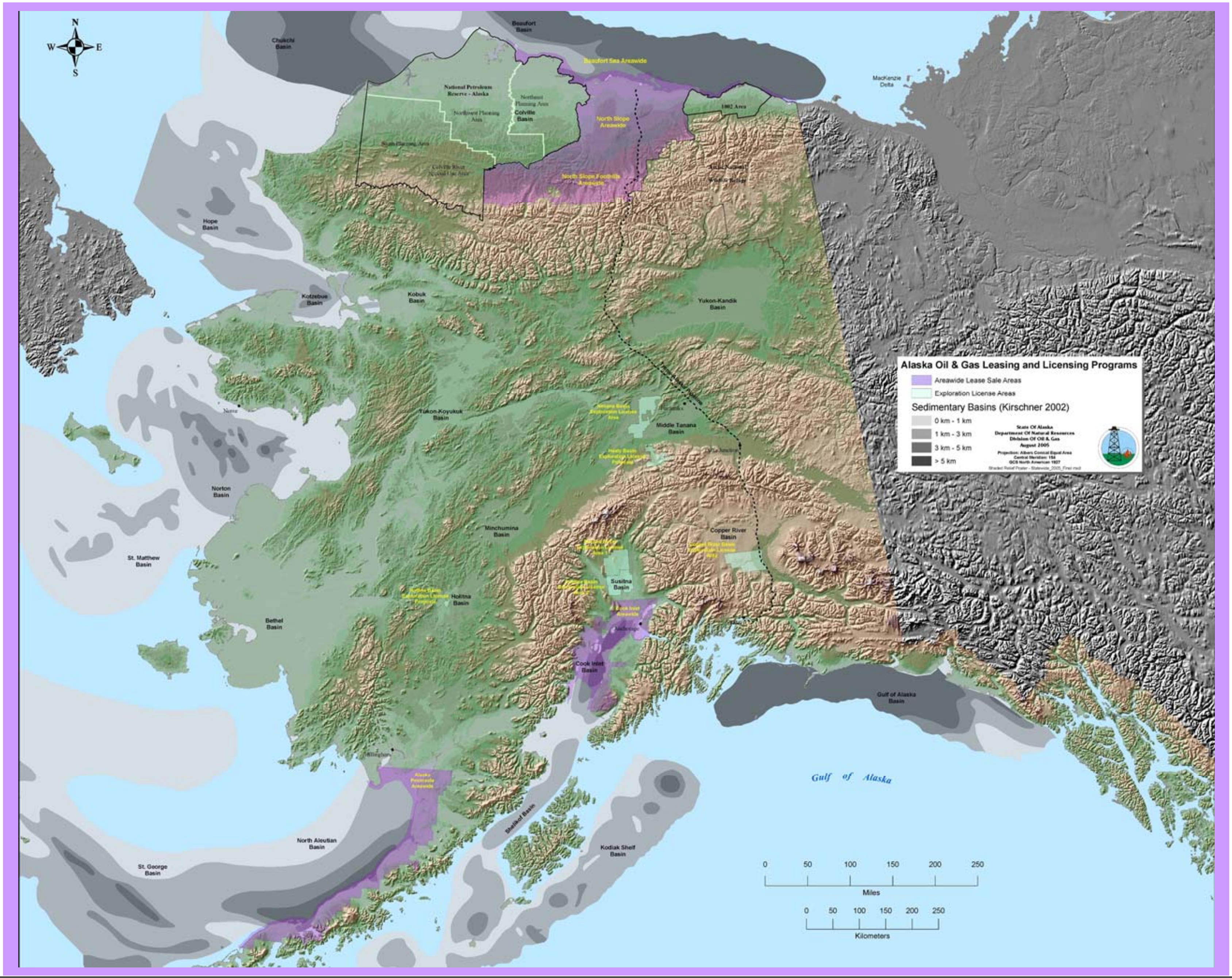
Outlook

The Division of Oil and Gas traditionally held four regularly scheduled, areawide oil and gas lease sales each year. In 2005 the Alaska Peninsula basin was added to the areawide leasing program. Also, the Division of Geological and Geophysical Survey is working to obtain geologic and geophysical data as well as to conduct fieldwork in new areas. DGGS and DO&G geologists completed fieldwork that will help companies in evaluating hydrocarbon potential in wildcat areas. In addition to areawide leasing, DO&G instituted an exploration licensing program to encourage exploration in oil and gas basins outside of Cook Inlet and the North Slope. The state has issued four exploration licenses covering 1.66 million acres and has received applications for three other areas. For details, see Section I.

The Alaska Department of Natural Resources remains committed to environmentally safe exploration and development of its oil and gas resources. The Division of Mining, Land and Water and the University of Alaska completed a study on tundra travel which resulted in a longer exploration season on the North Slope. The Division of Oil and Gas has worked closely with new Cook Inlet and North Slope explorers, including Pelican, Alliance, Pioneer Oil & Gas, Pioneer Natural Resources, AVCG, Kerr-McGee, and Armstrong to facilitate their exploration activities, and ADNR has made a special effort to disseminate information to new companies seeking to invest in Alaska. Steps have been taken to streamline permitting, including revising the Alaska Coastal Management Program and creating a large project permit office in ADNR.

Section One

Leasing
Licensing, and
Incentives



Alaska Oil & Gas Leasing and Licensing Programs
Areawide Lease Sale Areas
Exploration License Areas
Sedimentary Basins (Kirschner 2002)
0 km - 1 km
1 km - 3 km
3 km - 5 km
> 5 km
State Of Alaska
Department Of Natural Resources
Division Of Oil & Gas
August 2005
Projection: Albers Conical Equal Area
Central Meridian: 154
GCS North American 1927
N
S
W
E
Chukchi Basin
Beaufort Basin
Beaufort Sea Areawide
National Petroleum Reserve - Alaska
Colville Basin
North Slope Areawide
North Slope Foothills Areawide
1002 Area
MacKenzie Delta
Hope Basin
Kotzebue Basin
Kobuk Basin
Yukon-Kandik Basin
Yukon-Koyukuk Basin
Middle Tanana Basin
Norton Basin
St. Matthew Basin
Minchumina Basin
Copper River Basin
Susitna Basin
Holitna Basin
Bethel Basin
Cook Inlet Basin
Gulf of Alaska Basin
Alaska Peninsula Areawide
Shelikof Basin
North Aleutian Basin
Kodiak Shelf Basin
St. George Basin
Gulf of Alaska
0
50
100
150
200
250
Miles
Kilometers

Areawide Leasing

Oil and gas lease sales are the initial step in a process that generates nearly 80 percent of the state's general fund revenue. 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. Through lease sale bonus bids alone, the state has received more than $2 billion in revenue.

Since 1959 the state has held more than 100 competitive lease sales in which it has offered millions of acres throughout Alaska. Several leasing methods, authorized under the AS 38.05, were used to encourage responsible 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 lease terms generally involve an obligation to remit royalty payments in the form of a $12^{1/2}$ percent or $16^{2/3}$ percent share of gross production paid in-kind or in-value. Occasionally, the state has imposed a fixed royalty rate of 20 percent. The state has also used sliding-scale royalty terms in its leases based on production or oil price or gross revenue.

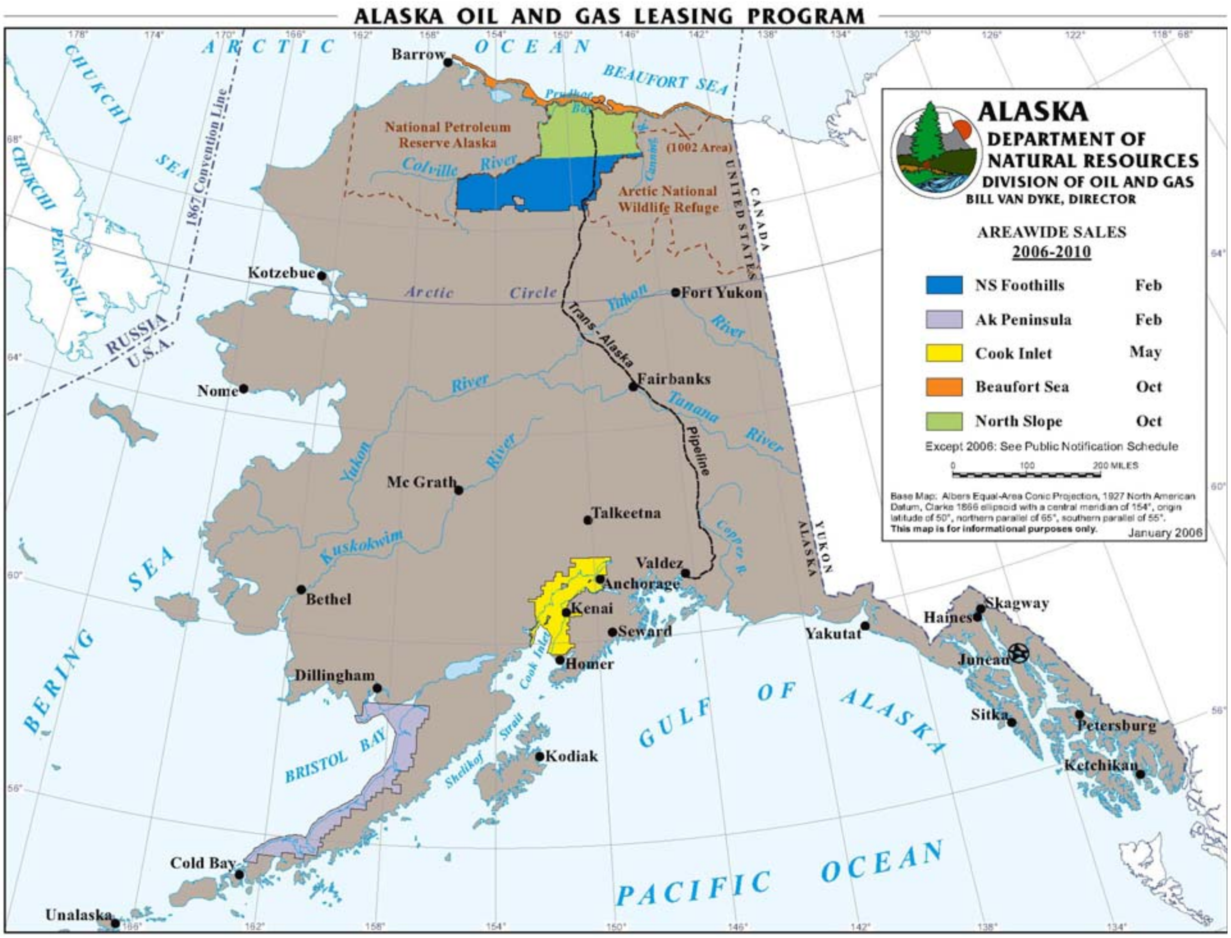
Areawide leasing
ADNR, DO&G

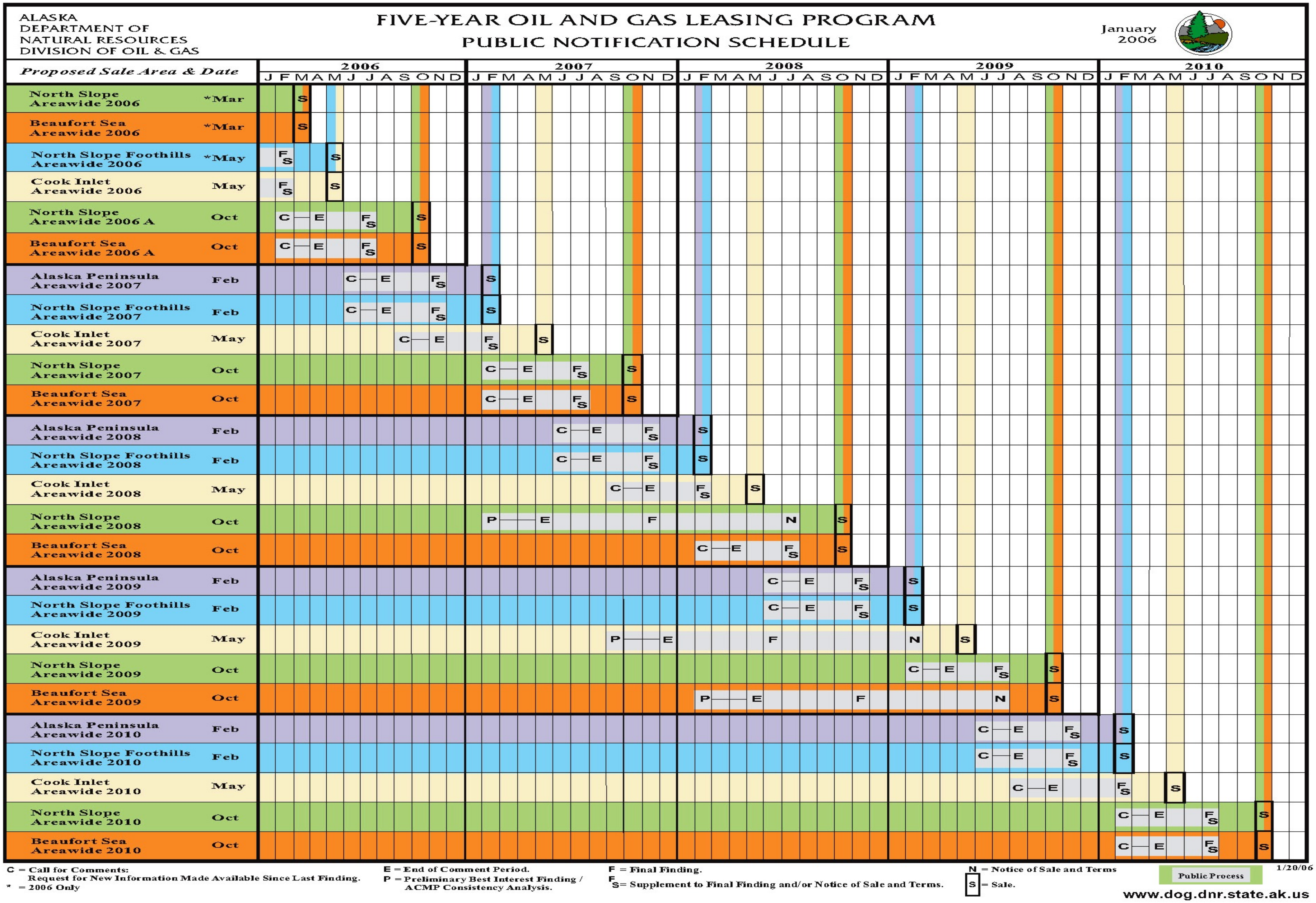
The most common bid variable used by the state is the cash bonus. The state may require minimum bids of $5 to $10 per acre (and sometimes higher). The state may also use the royalty rate or the net profit share as the bidding variable, though this has happened only rarely (Sale 30, the joint Federal-State Beaufort Sea sale held in 1979, was one of these occasions).

Since 1998, state oil and gas lease sales have been conducted on an areawide basis. This means that each sale includes all unleased state oil and gas resources within the lease sale area. The five geographic regions that have been subject to areawide leasing are the North Slope, North Slope Foothills, Beaufort Sea, Cook Inlet, and Alaska Peninsula. The first such sale was the North Slope Areawide Sale held in June 1998. Since then, areawide sales have been held in the other regions. In 2005, the state added the Alaska Peninsula Areawide Sale, located in Southwest Alaska. Areas outside these regions are available for exploration through exploration licensing, discussed later in this report.

Prior to an area being subject to an areawide lease sale, the commissioner must determine that it is in the state’s best interest to hold such a sale in the area. The best interest finding is effective for up to 10 years, however, prior to each sale, the commissioner must solicit public comment and determine if substantial new information has become available that justifies supplementing the best interest finding. If the decision is to proceed with a sale, a sale announcement — including the sale terms, bidding method, and tract map — will be issued at least 45 days prior to that sale. If a best interest finding or a supplement to a previous finding is required, it will be released at least 90 days prior to the sale.

The Division of Oil and Gas annually issues a new *Five-Year Oil and Gas Leasing Program* that sets out the sale schedule for the succeeding five years. Also included in this document are maps with results from the most recent areawide sales, a summary report of all previous state oil and gas lease sales, and an update on exploration licensing in the state. In addition, full information on each previous areawide lease sale is available on the division’s Web site.


ALASKA OIL AND GAS LEASING PROGRAM
ALASKA
DEPARTMENT OF
NATURAL RESOURCES
DIVISION OF OIL AND GAS
BILL VAN DYKE, DIRECTOR
AREAWIDE SALES
2006-2010
NS Foothills Feb
Ak Peninsula Feb
Cook Inlet May
Beaufort Sea Oct
North Slope Oct
Except 2006: See Public Notification Schedule
0 100 200 MILES
This map is for informational purposes only.
January 2006
ARCTIC OCEAN
BEAUFORT SEA
CHUKCHI SEA
BERING SEA
GULF OF ALASKA
PACIFIC OCEAN
BRISTOL BAY
National Petroleum Reserve Alaska
(1002 Area)
Arctic National Wildlife Refuge
1867 Convention Line
RUSSIA
U.S.A.
CANADA
UNITED STATES
YUKON
ALASKA
Arctic Circle
Trans-Alaska Pipeline
Barrow
Kotzebue
Nome
Fort Yukon
Fairbanks
Mc Grath
Talkeetna
Bethel
Valdez
Anchorage
Kenai
Seward
Homer
Dillingham
Kodiak
Yakutat
Haines
Skagway
Juneau
Sitka
Petersburg
Ketchikan
Cold Bay
Unalaska


ALASKA
DEPARTMENT OF
NATURAL RESOURCES
DIVISION OF OIL & GAS
FIVE-YEAR OIL AND GAS LEASING PROGRAM
PUBLIC NOTIFICATION SCHEDULE
January
2006
Proposed Sale Area & Date
2006
2007
2008
2009
2010
J F M A M J J A S O N D
North Slope Areawide 2006 *Mar
Beaufort Sea Areawide 2006 *Mar
North Slope Foothills Areawide 2006 *May
Cook Inlet Areawide 2006 May
North Slope Areawide 2006 A Oct
Beaufort Sea Areawide 2006 A Oct
Alaska Peninsula Areawide 2007 Feb
North Slope Foothills Areawide 2007 Feb
Cook Inlet Areawide 2007 May
North Slope Areawide 2007 Oct
Beaufort Sea Areawide 2007 Oct
Alaska Peninsula Areawide 2008 Feb
North Slope Foothills Areawide 2008 Feb
Cook Inlet Areawide 2008 May
North Slope Areawide 2008 Oct
Beaufort Sea Areawide 2008 Oct
Alaska Peninsula Areawide 2009 Feb
North Slope Foothills Areawide 2009 Feb
Cook Inlet Areawide 2009 May
North Slope Areawide 2009 Oct
Beaufort Sea Areawide 2009 Oct
Alaska Peninsula Areawide 2010 Feb
North Slope Foothills Areawide 2010 Feb
Cook Inlet Areawide 2010 May
North Slope Areawide 2010 Oct
Beaufort Sea Areawide 2010 Oct
C = Call for Comments: Request for New Information Made Available Since Last Finding.
* = 2006 Only
E = End of Comment Period.
P = Preliminary Best Interest Finding / ACMP Consistency Analysis.
F = Final Finding.
FS = Supplement to Final Finding and/or Notice of Sale and Terms.
N = Notice of Sale and Terms
S = Sale.
Public Process
1/20/06
www.dog.dnr.state.ak.us

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
12/10/1959	1	Cook Inlet	88,055	77,191	87.66%	$52.08	37	31	$4,020,342	Bonus; No Min	12.5% Royalty
7/13/1960	2	Cook Inlet	17,568	16,506	93.96%	$24.70	27	26	$407,655	Bonus; No Min	12.5% Royalty
12/7/1960	3	Mixed	73,048	22,867	31.30%	$1.54	26	9	$35,325	Bonus; No Min	12.5% Royalty
1/25/1961	4	Cook Inlet	400	400	100.00%	$679.04	3	3	$271,614	Bonus; No Min	12.5% Royalty
5/23/1961	5	Mixed	97,876	95,980	98.06%	$74.71	102	99	$7,170,465	Bonus; No Min	12.5% Royalty
8/4/1961	6	Gulf Ak	13,257	13,257	100.00%	$8.35	6	6	$110,672	Bonus; No Min	12.5% Royalty
12/19/1961	7	Mixed	255,708	187,118	73.18%	$79.43	88	53	$14,863,049	Bonus; No Min	12.5% Royalty
4/24/1962	8	Cook Inlet	1,062	1,062	100.00%	$4.80	8	8	$5,097	Bonus; No Min	12.5% Royalty
7/11/1962	9	Mixed	315,669	264,437	83.77%	$59.42	89	76	$15,714,113	Bonus; No Min	12.5% Royalty
5/8/1963	10	Cook Inlet	167,583	141,491	84.43%	$29.23	200	158	$4,136,225	Bonus; No Min	12.5% Royalty
12/11/1963	12	Cook Inlet	346,782	247,089	71.25%	$12.31	308	207	$3,042,681	Bonus; No Min	12.5% Royalty
12/9/1964	13	Mixed	1,194,373	721,224	60.39%	$7.68	610	341	$5,537,100	Bonus; No Min	12.5% Royalty
7/14/1965	14	North Slope	754,033	403,000	53.45%	$15.25	297	159	$6,145,473	Bonus; $1/acre Min	12.5% Royalty
9/28/1965	15	Cook Inlet	403,042	301,751	74.87%	$15.49	293	218	$4,674,344	Bonus; $1/acre Min	12.5% Royalty
7/19/1966	16	Mixed	184,410	133,987	72.66%	$52.55	205	153	$7,040,880	Bonus; $1/acre Min	12.5% Royalty
11/22/1966	17	Cook Inlet	19,230	18,590	96.67%	$7.33	36	35	$136,280	Bonus; $1/acre Min	12.5% Royalty
1/24/1967	18	Mixed	47,729	43,657	91.47%	$33.90	23	20	$1,479,906	Bonus; $1/acre Min	12.5% Royalty
3/28/1967	19	Kachemak Bay	2,560				RULED INVALID 12/9/74				
7/25/1967	20	Cook Inlet	311,250	256,447	82.39%	$73.14	295	220	$18,757,341	Bonus; $1/acre Min	12.5% Royalty
3/26/1968	21	Ak Pen	346,623	164,961	47.59%	$18.24	308	147	$3,009,224	Bonus; $1/acre Min	12.5% Royalty
10/29/1968	22	Cook Inlet	111,199	60,272	54.20%	$17.29	230	125	$1,042,220	Bonus; No Min	12.5% Royalty
9/10/1969	23	North Slope	450,858	412,548	91.50%	$2,181.66	179	164	$900,041,605	Bonus; No Min	12.5% Royalty
5/12/1971	24	Cook Inlet	196,635	92,618	47.10%	$4.92	244	106	$455,641	Bonus; No Min	12.5% Royalty
9/28/1972	25	Cook Inlet	325,401	178,245	54.78%	$7.43	259	152	$1,324,673	Bonus; No Min	12.5% Royalty
12/11/1972	26	Cook Inlet	399,921	177,973	44.50%	$8.75	218	105	$1,557,849	Bonus; No Min	12.5% Royalty
5/8/1973	27	Cook Inlet	308,401	113,692	36.93%	$9.92	210	86	$1,130,325	Bonus; No Min	12.5% Royalty
12/13/1973	28	Cook Inlet	166,648	97,804	58.69%	$253.77	98	62	$24,819,190	Bonus; No Min	16.67% Royalty
10/23/1974	29	Cook Inlet	278,269	127,120	45.68%	$8.19	164	82	$1,040,910	Bonus; No Min	16.67% Royalty
7/24/1979	29B	Copper Riv	34,678	34,678	100.00%	$4.56	20	20	$158,042	Bonus; No Min	20% Royalty
12/12/1979	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
9/16/1980	31	North Slope	196,268	196,268	100.00%	$63.12	78	78	$12,387,470	Bonus; No Min	20% Royalty; 30% NPS
5/13/1981	33	Cook Inlet	815,000	429,978	52.76%	$10.00	202	103	$4,299,782	Royalty; 20% Min	$10/acre Bonus
8/25/1981	32	Cook Inlet	202,837	152,428	75.15%	$10.00	78	59	$1,524,282	Royalty; 20% Min	$10/acre Bonus
2/2/1982	35	Cook Inlet	601,172	131,181	21.82%	$10.00	149	31	$1,311,807	Royalty; 12.5% Min	$10/acre Bonus
5/26/1982	*36	Beaufort Sea	56,862	56,862	100.00%	$573.02	13	13	$32,583,452	Bonus; No Min	12.5% Royalty & 40% NPS
8/24/1982	*37	Copper River	852,603	168,849	19.80%	$3.33	217	33	$562,944	Bonus; No Min	12.5% Royalty & 30% NPS
8/24/1982	37A	Cook Inlet	1,875	1,875	100.00%	$52.00	1	1	$97,479	Bonus; No Min	43% Royalty
9/28/1982	*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
5/17/1983	*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
9/28/1983	40	Cook Inlet	1,044,745	443,355	42.44%	$7.17	284	140	$3,177,178	Bonus; $1/acre Min	12.5% Royalty
5/22/1984	43	Beaufort Sea	298,074	281,794	94.53%	$114.32	69	66	$32,214,794	Bonus; $10/acre Min	16.67% Royalty
5/22/1984	*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
8/18/1984	41	Bristol Bay	1,437,930	278,939	19.40%	$3.03	308	63	$843,965	Bonus; No Min	12.5% Royalty
2/26/1985	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
9/24/1985	45A	North Slope	606,385	164,885	27.19%	$28.25	113	32	$4,657,478	Bonus; $5/acre Min	16.67% Royalty
9/24/1985	47	North Slope	192,569	182,560	94.80%	$63.79	50	48	$11,645,003	Bonus; $5/acre Min	12.5% Royalty
2/25/1986	48	North Slope	526,101	266,736	50.70%	$9.16	104	54	$2,444,342	Bonus; $5/acre Min	12.5% Royalty
2/25/1986	48A	Beaufort Sea	42,053	42,053	100.00%	$12.13	11	11	$510,255	Bonus; $5/acre Min	12.5% Royalty
6/24/1986	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
1/27/1987	51	North Slope	592,142	100,632	16.99%	$2.88	119	26	$289,625	Bonus; $2/acre Min	12.5% Royalty
6/30/1987	50	Beaufort Sea	118,147	118,147	100.00%	$56.05	35	35	$6,621,723	Bonus; $5/acre Min	16.67% Royalty
1/26/1988	*54	North Slope	421,809	338,687	80.29%	$13.83	89	72	$4,683,388	Bonus; $5/acre Min	12.5% Royalty
9/28/1988	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
9/28/1988	69A	North Slope	775,555	368,490	47.51%	$16.61	155	75	$6,119,135	Bonus; $5/acre Min	12.5% Royalty
1/24/1989	52	Beaufort Sea	175,981	52,483	29.81%	$33.12	43	15	$1,737,513	Bonus; $10/acre Min	12.5% Royalty
1/24/1989	72A	North Slope	677	677	100.00%	$671.90	1	1	$454,977	Bonus; $10/acre Min	12.5% Royalty
1/29/1991	*67A	Cook Inlet	549,364	191,568	34.87%	$28.77	140	55	$5,511,338	Bonus; $5/acre Min	12.5% Royalty
1/29/1991	*70A	North Slope	532,153	420,568	79.03%	$65.88	135	109	$27,707,541	Bonus; $5/acre Min	12.5% Royalty
6/4/1991	64	North Slope	754,542	34,143	4.52%	$7.10	141	6	$242,388	Bonus; $5/acre Min	12.5% Royalty
6/4/1991	*65	Beaufort Sea	491,091	172,865	35.20%	$40.46	108	36	$6,993,949	Bonus; $10/acre Min	16.67% Royalty
9/24/1991	*74A	Cook Inlet	605,851	26,605	4.39%	$12.06	134	5	$320,853	Bonus; $5/acre Min	12.5% Royalty
1/22/1992	61	North Slope	991,087	260,550	26.29%	$9.32	181	48	$2,429,551	Bonus; $5/acre Min	12.5% Royalty
6/2/1992	68	Beaufort Sea	153,445	0	0.00%	$0.00	36	0	$0	Bonus; $10/acre Min	12.5% Royalty
12/8/1992	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%
1/26/1993	76	Cook Inlet	393,025	141,504	36.00%	$461.25	86	36	$65,269,167	Bonus; $5/acre Min	12.5% Royalty
1/26/1993	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
5/25/1993	77	North Slope	1,260,146	45,727	3.63%	$25.47	228	8	$1,164,555	Bonus; $5/acre Min	12.5% Royalty
5/25/1993	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
9/21/1993	57	North Slope	1,033,248	0	0.00%	$0.00	196	0	$0	Bonus; $5/acre Min	12.5% Royalty
9/21/1993	75A	North Slope	14,343	14,343	100.00%	$31.36	11	11	$449,847	Bonus; $10/acre Min	16.67% Royalty
10/30/1994	78	Cook Inlet	396,760	136,307	34.36%	$12.14	90	34	$1,654,137	Bonus; $5/acre Min	12.5% Royalty
11/14/1995	67A-W2	Cook Inlet	152,768	13,804	9.04%	$7.29	36	3	$100,638	Bonus; $5/acre Min	12.5% Royalty
11/14/1995	74W	Cook Inlet	66,703	17,015	25.51%	$31.76	16	4	$540,406	Bonus; $5/acre Min	12.5% Royalty
11/14/1995	76W	Cook Inlet	251,614	14,220	5.65%	$5.61	50	4	$79,722	Bonus; $5/acre Min	12.5% Royalty
11/14/1995	78W	Cook Inlet	260,453	36,478	14.01%	$7.06	56	11	$257,583	Bonus; $5/acre Min	12.5% Royalty
12/5/1995	80	North Slope	951,302	151,567	15.93%	$22.02	202	42	$3,337,485	Bonus; $10/acre Min	12.5% Royalty
10/1/1996	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
12/18/1996	85A	Cook Inlet	1,061,555	173,503	16.33%	$17.92	234	44	$3,109,603	Bonus; $5/acre Min	12.5% Royalty
11/18/1997	86 **	Beaufort Sea	365,054	323,835	88.70%	$86.42	181	162	$27,985,125	Bonus; $10/acre Min	16.67% Royalty
2/24/1998	85A-W	Cook Inlet	757,878	98,011	12.90%	$8.46	157	24	$828,807	Bonus; $5/acre Min	12.5% Royalty
6/24/1998	87	North Slope	Areawide	518,689	N/A	$99.86	N/A	137	$51,794,173	Bonus; $5/acre Min	12.5% Royalty
2/24/1999	NS 1998	North Slope	Areawide	174,023	N/A	$14.85	N/A	40	$2,586,036	Bonus; $5/acre Min	12.5% Royalty
4/21/1999	CI 1999	Cook Inlet	Areawide	114,514	N/A	$10.75	N/A	41	$1,436,685	Bonus; $5/acre Min	12.5% Royalty
8/16/2000	CI 2000	Cook Inlet	Areawide	100,480	N/A	$9.15	N/A	27	$919,750	Bonus; $5/acre Min	12.5% Royalty
11/15/2000	BS 2000	Beaufort Sea	Areawide	25,840	N/A	$13.13	N/A	11	$338,922	Bonus; $10/acre Min	12.5% & 16.67% Royalty
11/15/2000	NS 2000	North Slope	Areawide	652,355	N/A	$15.41	N/A	145	$10,052,665	Bonus; $5/acre Min	12.5% & 16.67% Royalty
5/9/2001	CI 2001	Cook Inlet	Areawide	102,523	N/A	$9.05	N/A	29	$928,085	Bonus; $5/acre Min	12.5% Royalty
5/9/2001	NSF 2001	NS Foothills	Areawide	858,811	N/A	$11.41	N/A	170	$9,799,277	Bonus; $5/acre Min	12.5% Royalty
10/24/2001	BS 2001	Beaufort Sea	Areawide	36,331	N/A	$94.90	N/A	24	$3,447,734	Bonus; $10/acre Min	12.5% & 16.67% Royalty
10/24/2001	NS2001	North Slope	Areawide	434,938	N/A	$15.89	N/A	146	$6,911,572	Bonus; $5/acre Min	12.5% & 16.67% Royalty
5/1/2002	CI 2002	Cook Inlet	Areawide	64,923	N/A	$7.05	N/A	21	$421,841	Bonus; $5/acre Min	12.5% Royalty
5/1/2002	NSF 2002‡	NS Foothills	Areawide	213,374	N/A	$14.32	N/A	51	$2,889,532	Bonus; $5/acre Min	12.5% Royalty
10/24/2002	BS 2002	Beaufort Sea	Areawide	19,226	N/A	$26.34	N/A	15	$506,405	Bonus; $10&$100/ac Min	12.5%, 16.67% & 20% Royalty
10/24/2002	NS 2002	North Slope	Areawide	32,316	N/A	$17.94	N/A	12	$579,728	Bonus: $10/acre Min	12.5%,16.67%&16.67-33.33% Sliding Scale Rylty
5/7/2003	CI 2003	Cook Inlet	Areawide	73,869	N/A	$9.34	N/A	27	$689,949	Bonus; $5/acre Min	12.5% Royalty
5/7/2003	NSF 2003	NS Foothills	Areawide	5,760	N/A	$6.35	N/A	1	$36,576	Bonus; $5/acre Min	12.5% Royalty
10/29/2003	BS 2003	Beaufort Sea	Areawide	36,995	N/A	$36.71	N/A	20	$1,358,187	Bonus; $5 & $10/ac Min	12.5 % & 16.67% Royalty
10/29/2003	NS 2003**	North Slope	Areawide	210,006	N/A	$17.08	N/A	75	$3,586,400	Bonus; $10/acre Min	12.5 % & 16.67% Royalty
5/19/2004	CI 2004	Cook Inlet	Areawide	227,475	N/A	$7.33	N/A	72	$1,667,967	Bonus; $5/acre Min	12.5% Royalty
5/19/2004	NSF 2004	NS Foothills	Areawide	19,796	N/A	$5.37	N/A	5	$106,305	Bonus; $5/acre Min	12.5% Royalty
10/27/2004	BS 2004	Beaufort Sea	Areawide	113,570	N/A	$36.90	N/A	28	$4,190,782	Bonus; $10/acre Min	12.5 % & 16.67% Royalty
10/27/2004	NS 2004	North Slope	Areawide	197,915	N/A	$38.40	N/A	57	$7,599,192	Bonus; $10/acre Min	12.5 % & 16.67% Royalty
5/18/2005	CI 2005***	Cook Inlet	Areawide	245,120	N/A	$6.12	N/A	55	$1,501,152	Bonus; $5/acre Min	12.5% Royalty
5/18/2005	NSF 2005	NS Foothills	Areawide	55,505	N/A	$5.76	N/A	12	$319,959	Bonus; $5/acre Min	12.5% Royalty
10/26/2005	AK PEN 2005***	Alaska Peninsula	Areawide	213,120	N/A	$5.95	N/A	37	$1,268,122	Bonus; $5/acre Min	12.5% Royalty
TOTAL: 105 Sales				17,330,510		$119.42		6,245	$2,069,679,980		

*Economic Incentive Credits were offered for these sales.
** Sale 86A: State received $259,435; ASRC received $1,766,812.
‡ Sale NSF 2002 Bonus does not include 20% of Bonus bid ($1.25 million) retained by the state for relinquished tracts.
** NS 2003: State received $3,546,578; ASRC received $39,822.
*** Acres Leased, Average $/Acre, and Bonus Received are preliminary figures.

Exploration Licensing

Exploration licenses are designed to stimulate exploration in Alaska's frontier basins and complement the state's oil and gas leasing program. The North Slope, Cook Inlet, and Alaska Peninsula, which are subject to the state's competitive leasing program, remain off limits to exploration licensing.

Mat-Su coring program
C. Ruff

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 added costs by the state.

An area selected for exploration licensing must be between 10,000 and 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, and following satisfaction of the required work commitment, any portion of the licensed area may be converted to oil and gas leases. The term of the leases can extend beyond the original term of the license. If converted, annual lease rentals are set at $3 per acre.

Susitna basin
aeromagnetic survey
K. Dirks

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 any time, 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.

Submitted proposals must (1) describe the area proposed to be subject to the license, (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.

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.

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. If competing proposals are submitted and the commissioner determines that an exploration license should be awarded, the successful licensee will be determined by a sealed bid process.

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.

License Applications

The state has issued four exploration licenses covering 1.66 million acres and has received applications for three other areas.

Licenses Issued:

Copper River

Licensee:	Forest Oil Corporation
Size:	318,756.35 Acres
Exploration Commitment:	$1,420,000
Term:	5 years
Effective Date:	October 1, 2000
Status:	Lease conversion pending

Nenana Basin

Licensee:	Andex Resources
Size:	483,942 Acres
Exploration Commitment:	$2,525,000
Term:	7 years
Effective Date:	October 1, 2002
Status:	Active; work commitment has been met.

Susitna Basin I

Licensee:	Forest Oil Corporation
Size:	386,204 Acres
Exploration Commitment:	$2,520,000
Term:	7 years
Effective Date:	November 1, 2003
Status:	Active

Susitna Basin II

Licensee:	Forest Oil Corporation
Size:	471,474 Acres
Exploration Commitment:	$3,000,000
Term:	7 years
Effective Date:	November 1, 2003
Status:	Active

License Not Executed by Licensee:

Bristol Bay (Proposed)

Licensee:	Bristol Shores LLC
Size:	329,113 Acres
Exploration Commitment:	$3,200,000
Term:	7 years
Status:	License Issued but not executed by Licensee; file closed

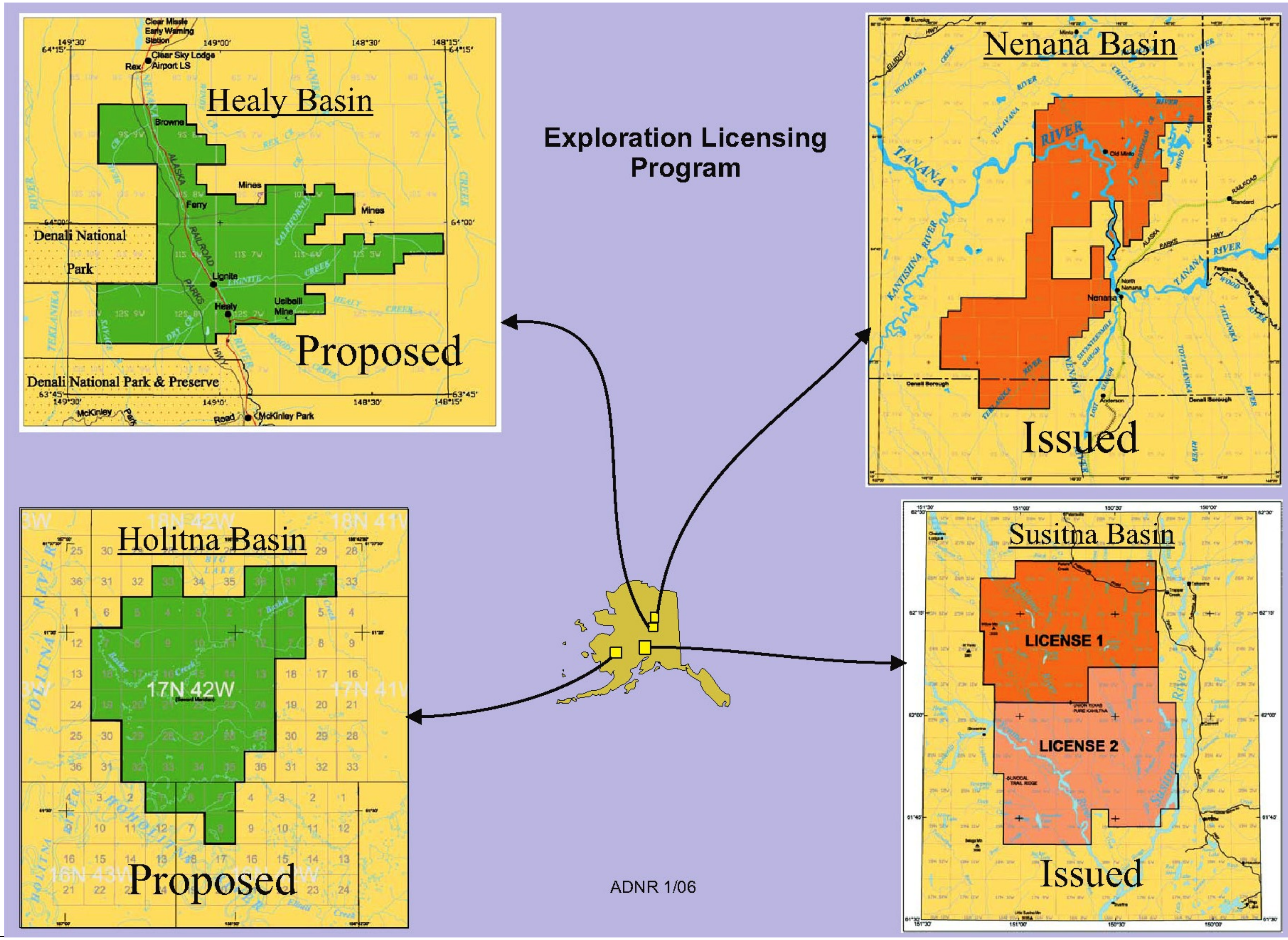
License Applications and Best Interest Finding Pending:

Healy Basin (Proposed)

Licensee:	Usibelli Coal Mine, Inc.

Holitna Basin (Proposed)

Licensee:	Holitna Energy Company LLC


Exploration Licensing Program
Healy Basin
Proposed
Denali National Park
Denali National Park & Preserve
Nenana Basin
Issued
Holitna Basin
17N 42W
Proposed
Susitna Basin
LICENSE 1
LICENSE 2
Issued
ADNR 1/06

Exploration Incentive Credit and Tax Credit Programs

AS 38.05.180(i): Exploration Incentive Credits (EIC)

This EIC may be included as a term of an oil and gas lease. AS 38.05.18(i) provides for a system in which a lessee of state land drilling an exploratory well may earn credits depending on the footage drilled and the region in which the well is located. 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 obtained is made public after the sale. Information is held confidential for two years, but confidentiality may be extended if the lessee meets certain requirements. The Department of Natural Resources commissioner grants credits as high as 50 percent of the costs. Credits may be applied against state royalty and rental payments or taxes, or they may be assigned. Since the state began offering this program, lessees have earned $54.7 million in credits for exploratory drilling.

AS 41.09.010: Exploration Incentive Credits

This EIC, adopted in 1994 under AS 41.09.010, allows the Natural Resources commissioner 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 minerals are 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, private, and Native corporation lands. As with the Title 38 program, the credits may be applied against oil and gas royalties, rentals, lease sale bonus bids and taxes, or they may be assigned. Drilling data 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 (measured depth) drilled. All activity qualifying for this EIC must be completed by July 1, 2007.

AS 43.55.025: Oil and Gas Exploration Tax Credit

This program, adopted in 2003, allows for a production tax credit of 20 percent of the cost of an exploratory well if the bottom hole location is three or more miles from the bottom hole location of a pre-existing well that was spudded more than 150 days but less than 35 years prior to the spud date of the eligible exploration well. The program also allows for an additional production tax credit of 20 percent of the cost of an exploratory well if the bottom hole location is 25 miles or more from the boundary of any unit under a plan of development as of July 1, 2003. The program also offers seismic exploration tax credits of 40 percent of eligible costs for those portions of activities outside of a unit that is under a plan of development or plan of exploration. Seismic data qualifying for this credit will be held confidential for 10 years and 30 days. This tax credit is transferable. This program only applies to exploration expenditures incurred prior to July 1, 2007, for the North Slope, or July 1, 2010, for elsewhere.

Imnaitchiak Cherts
P. Decker

AS 43.20.043: Gas Exploration and Development Tax Credit

This program, adopted in 2003, is applicable only to operators and working interest owners engaged in exploration for and development of gas resources and reserves south of 68 degrees North Latitude (excludes North Slope and Beaufort Sea). The program allows for a 10 percent tax credit equivalent of qualified capital investments made after June 30, 2003, and 10 percent of the annual cost of activity in the state during each tax year. The total allowable yearly tax credit may not exceed 50 percent of the taxpayer's total tax liability. Unused tax credits may be carried forward for up to five years. Credit is transferable only as part of a conveyance, assignment, or transfer of the taxpayer's business. Credit under this program may be used in conjunction with any other credit authorized by

AS 43.20, but not for tax credit or royalty modification provided under any other title. This program expires January 1, 2013.

Royalty Reduction

Since 1995, AS 38.05.180(j) has 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 5 percent. In an existing producing field or pool, the royalty may be reduced to as low as 3 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

Alaska law permits the granting of reduced 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 legislation granting a 5 percent temporary royalty rate on the first 25 million barrels of oil and the first 35 billion cubic feet of gas produced in the first 10 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 had been undeveloped or shut in. The fields identified in the law are Falls Creek; Nicolai Creek; North Fork; Point Starichkof; Redoubt Shoal; and West Foreland. Production from these fields had to begin before January 1, 2004, to be eligible for the royalty reduction.

Tree Row
S. Schmitz

Polar Resolution
PTI

Cook Inlet platform
D. Colley

Permitting in Alaska

The Division of Oil and Gas is responsible for issuing permits for operations and development activities on state lands and waters, oil and gas leases, or within state-managed oil and gas units. The division's approval process is generally a 30-day comment and review period for plans of operation or for multi-permit projects. The extent of review time usually depends on the complexity of the project, the environmental sensitivity of the area of activity, and the number of state, federal, and local permits required for the project.

Gas Storage

Gas storage is a new area of interest in the Cook Inlet basin. Gas storage is used when the rate and timing of production of natural gas does not match the local demand. When production exceeds demand, the gas can be injected back into the ground to be later extracted when demand exceeds production. Depleted gas reservoirs with good seals are ideal candidates for use as gas storage locations. The Division of Oil and Gas has issued two gas storage leases in Cook Inlet at Pretty Creek and Kenai gas fields.

Section Two

Oil and Gas Units

North Slope
Cook Inlet
Non-Unitized Lease Production
Alaska Fields and Pools

TABLE II.1 OIL & GAS UNITS

NORTH SLOPE	COOK INLET
Badami	Beaver Creek
Colville River	Beluga River
Cronus	Birch Hill
Duck Island	Cannery Loop
Jacob's Ladder	Cosmopolitan
Kuparuk River	Deep Creek
Milne Point	Ivan River
NE Storms	Kasilof
Nikaitchuq	Kenai River
Northstar	Lewis River
Oooguruk	Lone Creek
Point Thomson	Moquawkie
Prudhoe Bay	Nicolai Creek
Rock Flour	Nikolaevsk
Tuvaaq	Ninilchik
Whiskey Gulch	North Cook Inlet
	North Fork
	North Trading Bay
	Pretty Creek
	Redoubt
	South Granite Point
	South Middle Ground Shoal
	South Ninilchik
	Sterling
	Stump Lake
	Swanson River
	Three Mile Creek
	Trading Bay
	West McArthur River
	LEASE PRODUCTION
	Granite Point
	Kustatan
	Middle Ground Shoal
	North Trading Bay
	West Foreland
	Wolf Lake

Notes: All unit and participating area ownership and acreage figures are current as of March 6, 2006. Ownership percentages are based on leased surface acreage and may not represent ownership at depth.

Unit acreage figures may differ from previous annual reports because prior years included total leased acres held by the unit, not just acreage within the unit boundary that is reported herein.

The State of Alaska is sole royalty owner where ownership is not indicated.

* indicates working interest ownership is aligned over most of the unit leased area.

Oil and Gas Units

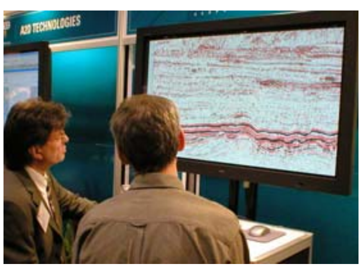
Unitization

Unitization is the grouping or pooling of working interest and royalty ownership in oil and gas leases that overlay a common petroleum reservoir. It is a method for developing an oil or gas pool that maximizes ultimate recovery, prevents economic and physical waste, and protects the rights of all parties with an ownership interest in the accumulation. A unit agreement defines a contractual relationship between the state, the royalty owners, and the working interest owners of the oil and gas leases included in the unit area. When leases are unitized, operators can eliminate redundancy and waste by sharing infrastructure and facilities, splitting development costs, and adopting unified reservoir management plans. Without unitization, competitive development can result in overly dense drilling, rapid loss of reservoir pressure, and undesired production of formation fluids. Unitization minimizes impacts to the environment, protects the value of leases, and ensures efficient and equitable recovery of hydrocarbons. Unitization can optimize value from public resources. The unit agreement entrusts the unit operator with duties, responsibilities, and obligations. A unit operator must be qualified to hold a lease and to fulfill the duties and obligations prescribed in the unit agreement. A performance bond is normally required before commencing drilling operations in Alaska.

Unit Formation

The unitization process begins when lessees identify a prospect or pool. The lessees in the proposed unit area select a unit operator. The unit application includes a plan of exploration and other terms for developing the entire unit area safely and responsibly (11 AAC 83.341). All lessees who hold an interest in the reservoir must be invited to join the unit. The commissioner of the Alaska Department of Natural Resources then publishes a Decision and Finding approving or disapproving the unit application. Unitization extends a lease beyond its initial primary term. After delineation drilling and testing, the unit operator may propose a participating area within the boundaries of the unit.

Osprey Platform
J. Patrick



TGS at North American Prospect Expo 2004

Participating Areas

At least 90 days before sustained production from a reservoir, the unit operator must apply to form a participating area. The participating area may include only those lands that are reasonably estimated to be underlain with hydrocarbons in quantities sufficient to pay well costs (11 AAC 83.351).The unit operator and state agree on a tract allocation schedule for the participating area that divides production shares fairly. An oil and gas unit can have one or more participating areas within its boundaries, depending on the geology of the area. Participating areas are described laterally and limited or defined by depth. The boundaries of the participating area should conform as closely as possible to the boundaries of the oil or gas pool.

Unitization Criteria

The director of the Division of Oil and Gas considers the following criteria when evaluating a unit or participating area application. The application should:

- promote conservation of all natural resources, including all or part of an oil or gas pool, field, or like area;
- promote the prevention of economic and physical waste; and
- provide for the protection of all parties of interest, including the state.

In evaluating the above criteria, the director considers:

- the environmental costs and benefits of unitized exploration or development;
- the geological and engineering characteristics of the potential hydrocarbon accumulation or reservoir proposed for unitization;
- prior exploration activities in the proposed unit area;
- the applicant's plans for exploration or development of the unit area;
- the economic costs and benefits to the state; and
- any other relevant factors, including measures to mitigate impacts identified above, the commissioner determines necessary or advisable to protect the public interest.

Unit Application

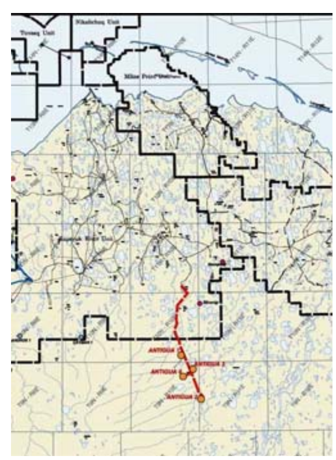
Before a 30-day public review of the unit application can begin, it must be complete and include the following:

1) the unit agreement, including exhibits required under 11 AAC 83.341 or 11 AAC 83.343, executed by the proper parties;
2) the unit operating agreement executed by the working-interest owners, which is submitted for information only and does not require the commissioner's approval for adoption or amendment;
3) evidence of reasonable effort made to obtain joinder of any proper party who has refused to join the unit agreement;
4) all pertinent geological, geophysical, engineering, and well data, and interpretations of those data directly supporting the application;
5) an explanation of proposed modifications, if any, of the standard state unit agreement form; and
6) the application fee prescribed by 11 AAC 05.010.

Within 10 days of receipt of a complete application, a public notice initiates a 30-day comment period. The Division of Oil and Gas will issue a decision within 60 days of the close of the comment period.

Plans of Exploration and Development

The unit operator and state must also agree on an initial unit plan of exploration or development 11 AAC 83. In concert with the unit agreement and plans of exploration, development, and operation, a unit operating agreement is drafted describing how expenses and revenues are distributed or paid among the working interest owners in the unit. Unit operators must submit an annual plan of exploration or development for approval (11 AAC 83.341-.343). Often unit areas are explored and developed at the same time. Failure to meet the goals, objectives, and commitments in the plan of exploration or development can result in default and unit termination.



ConocoPhillips Antigua Exploration Plan

Alaska has more than 50 units in various stages of exploration, development, production, and post-production field life stages.

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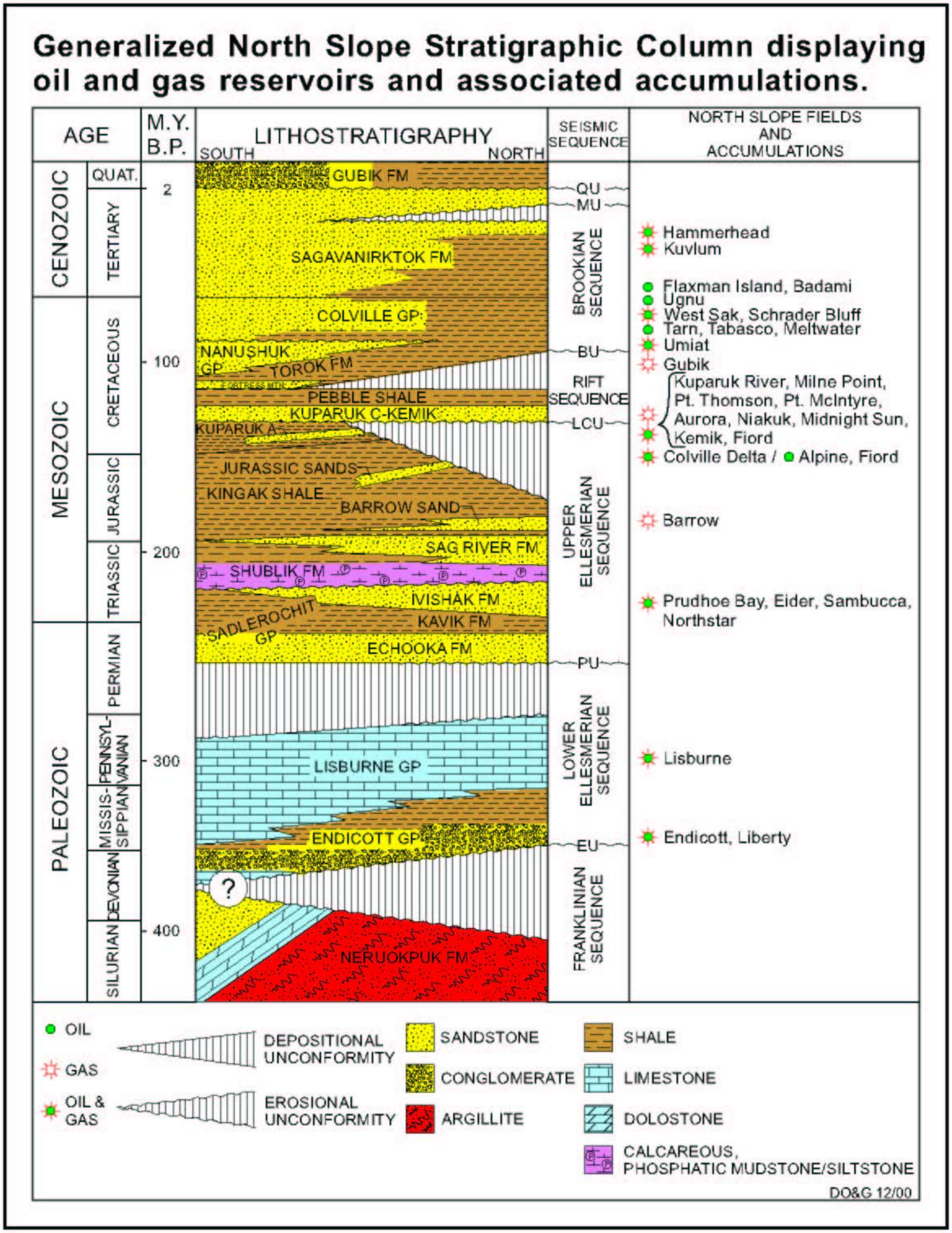
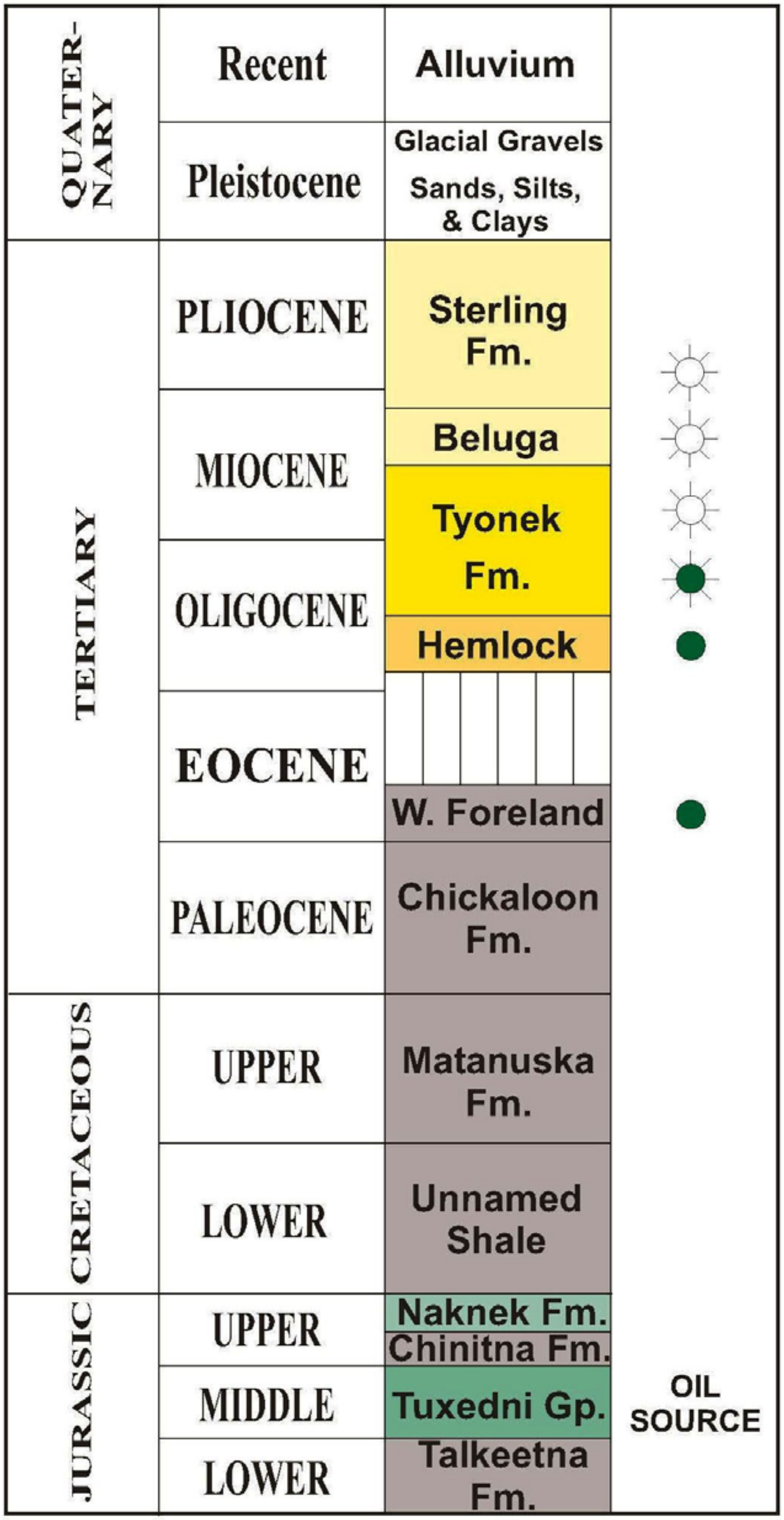
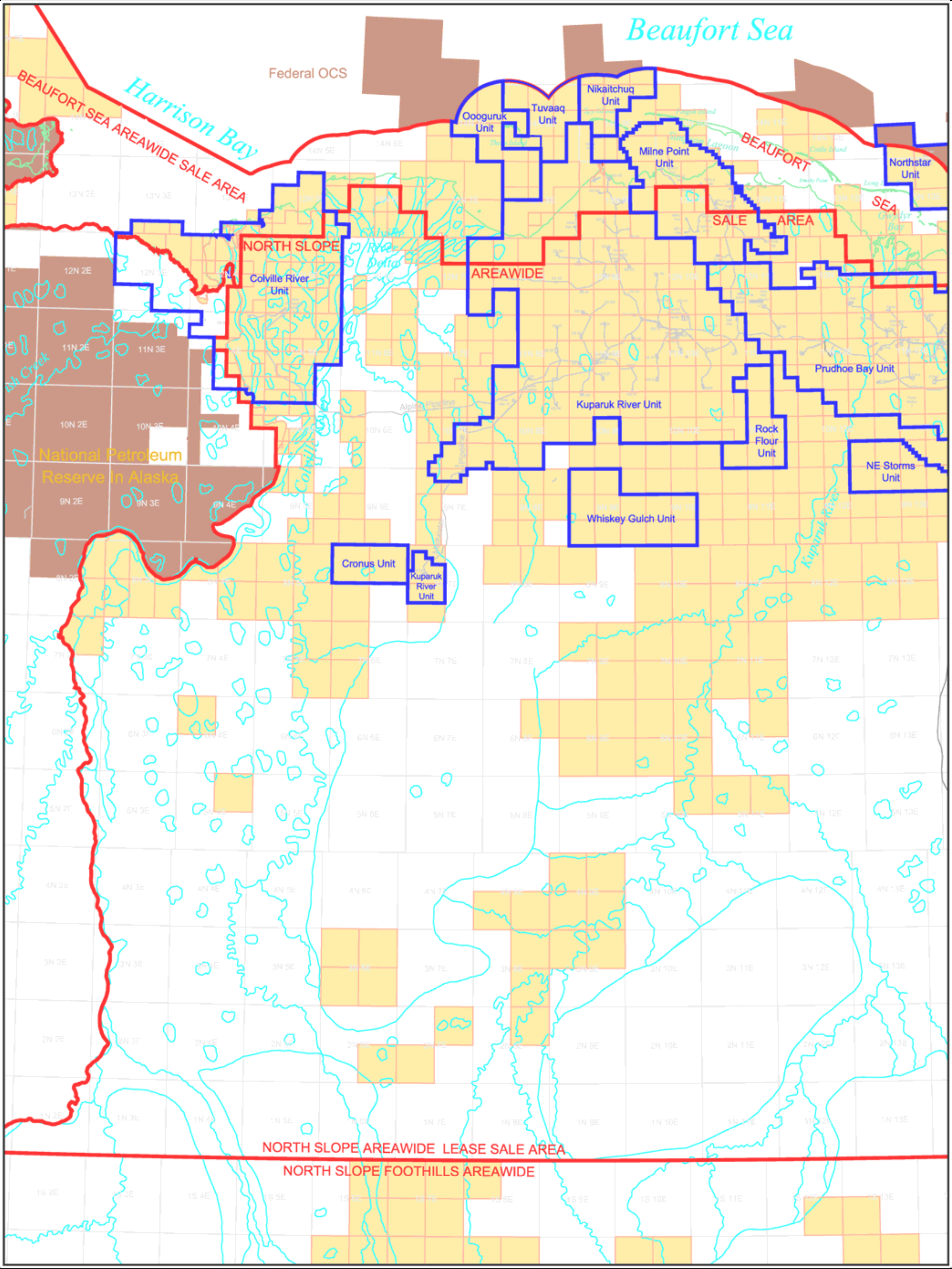
Generalized North Slope Stratigraphic Column

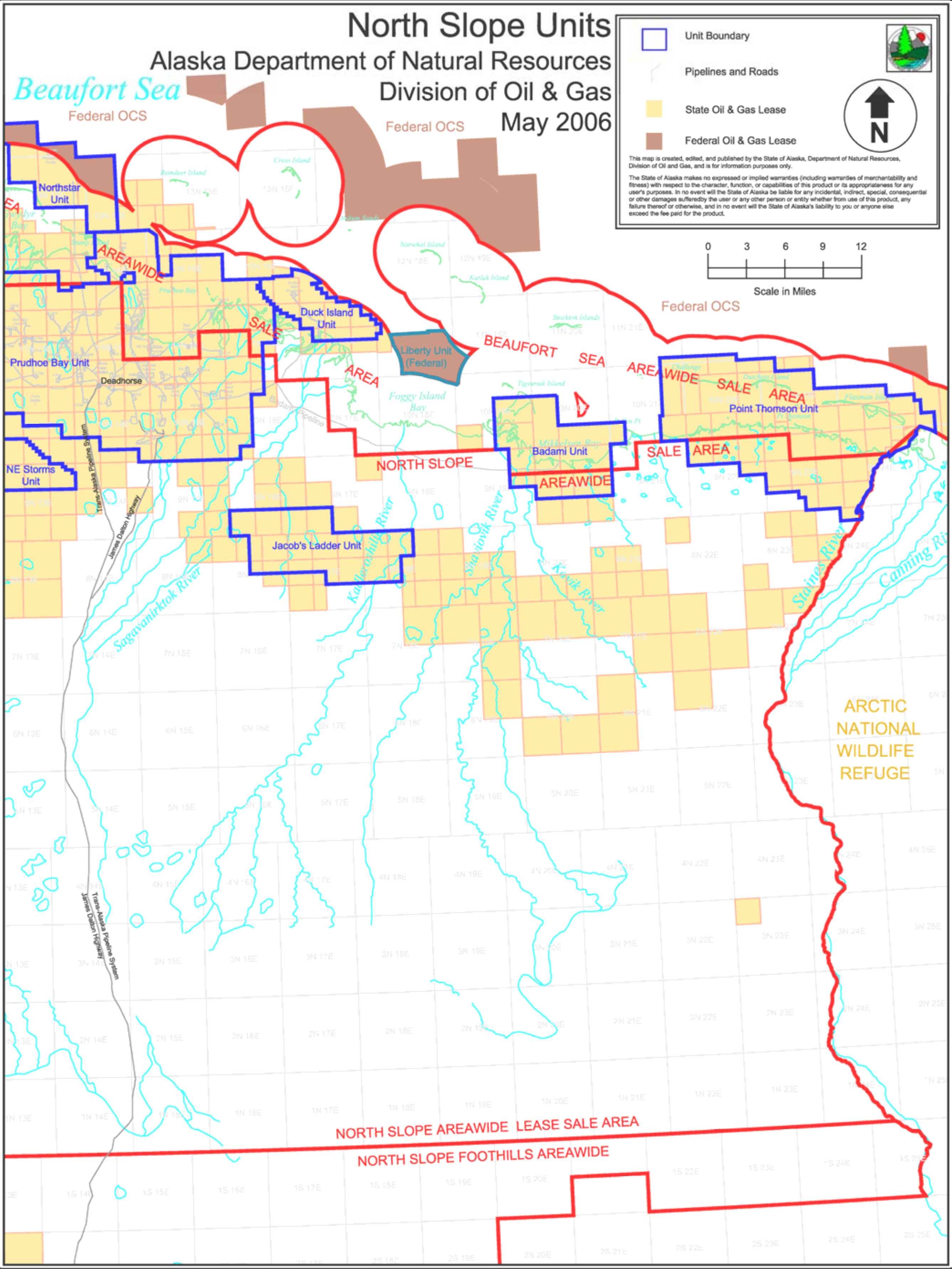


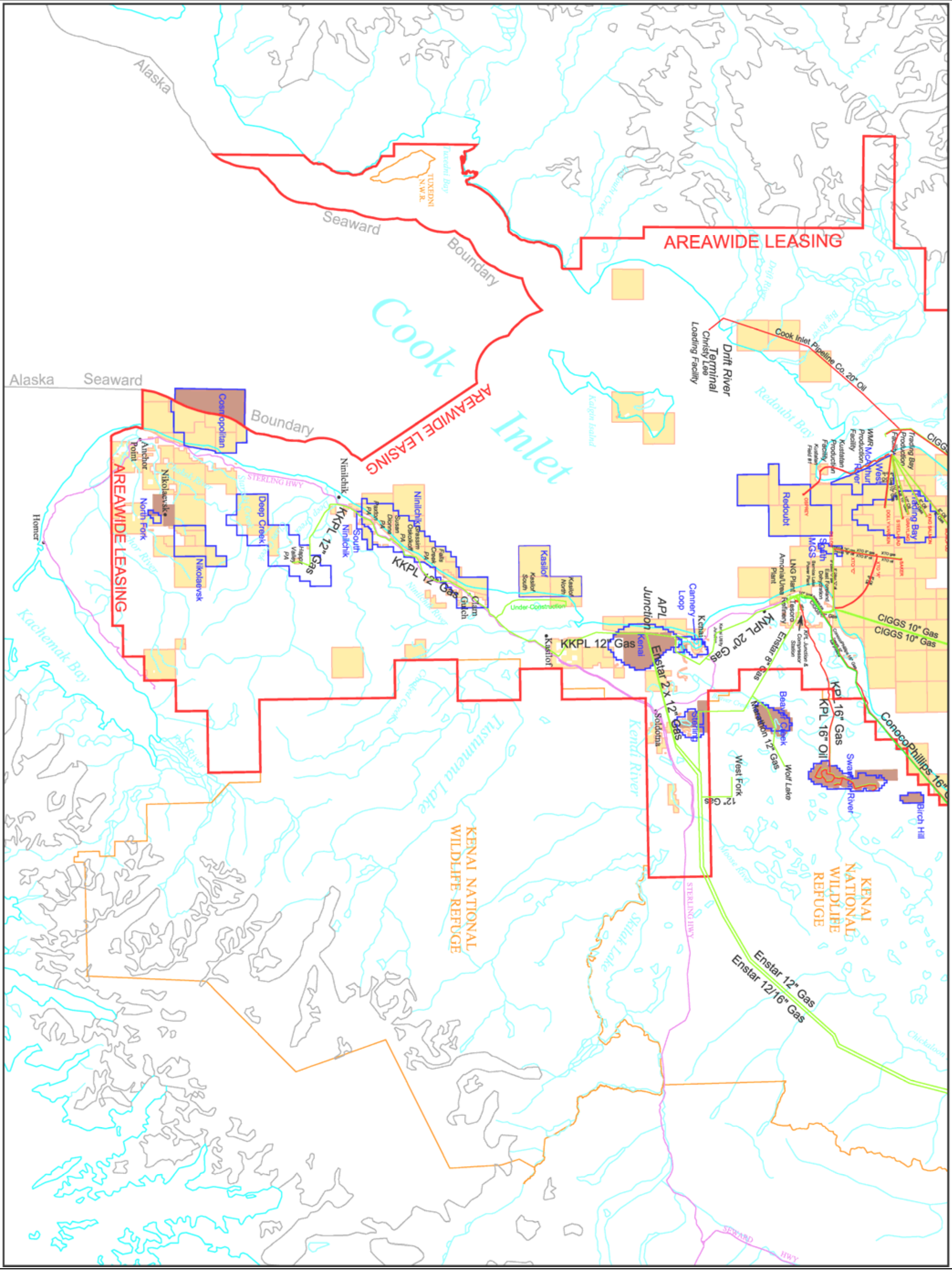
Generalized Cook Inlet Stratigraphic Column



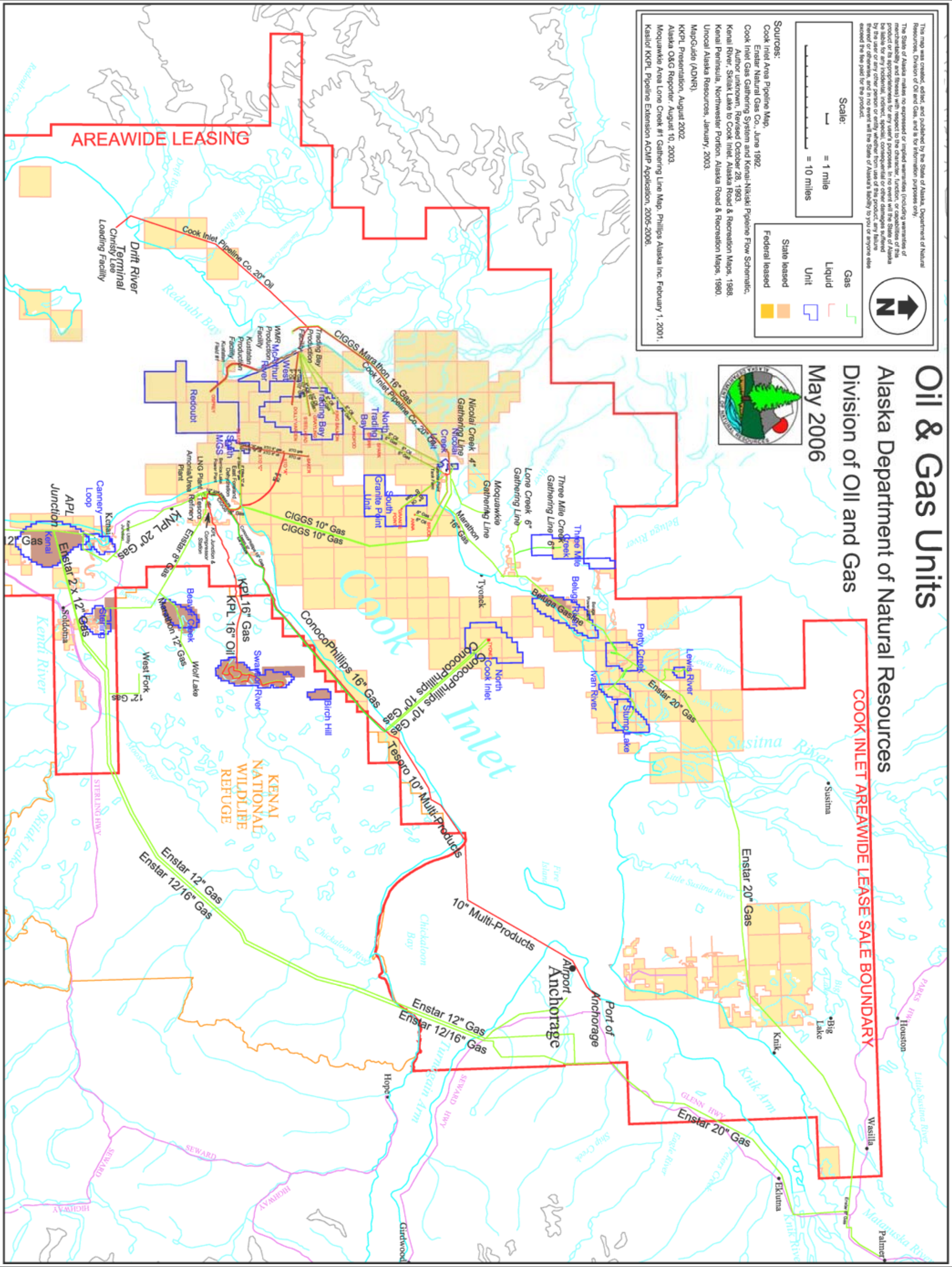
T. Ryherd, DO&G


Beaufort Sea
Federal OCS
Harrison Bay
BEAUFORT SEA AREAWIDE SALE AREA
Oooguruk Unit
Tuvaaq Unit
Nikaitchuq Unit
Milne Point Unit
Northstar Unit
NORTH SLOPE
AREAWIDE
SALE
AREA
BEAUFORT
SEA
Colville River Unit
Colville River Delta
Kuparuk River Unit
Prudhoe Bay Unit
Rock Flour Unit
NE Storms Unit
Whiskey Gulch Unit
Cronus Unit
Kuparuk River Unit
Kuparuk River
National Petroleum Reserve In Alaska
NORTH SLOPE AREAWIDE LEASE SALE AREA
NORTH SLOPE FOOTHILLS AREAWIDE


North Slope Units
Alaska Department of Natural Resources
Division of Oil & Gas
May 2006
Unit Boundary
Pipelines and Roads
State Oil & Gas Lease
Federal Oil & Gas Lease
N
0 3 6 9 12
Scale in Miles
Beaufort Sea
Federal OCS
Federal OCS
Federal OCS
Northstar Unit
Duck Island Unit
Liberty Unit (Federal)
Prudhoe Bay Unit
Deadhorse
NE Storms Unit
Badami Unit
Point Thomson Unit
Jacob's Ladder Unit
Foggy Island Bay
BEAUFORT SEA AREAWIDE SALE AREA
NORTH SLOPE AREAWIDE SALE AREA
Sagavanirktok River
Kadleroshilik River
Shaviovik River
Kavik River
Staines River
Canning River
Trans-Alaska Pipeline System
James Dalton Highway
ARCTIC NATIONAL WILDLIFE REFUGE
NORTH SLOPE AREAWIDE LEASE SALE AREA
NORTH SLOPE FOOTHILLS AREAWIDE



AREAWIDE LEASING
Cook Inlet
Seaward Boundary
Alaska
Cosmopolitan
Anchor Point
Nikolaevsk
North Fork
Deep Creek
Ninilchik
South Ninilchik
KKPL 12" Gas
Kasilof
Kenai
KKPL 12" Gas
Drift River Terminal
Christy Lee Loading Facility
Cook Inlet Pipeline Co. 20" Oil
Redoubt
Trading Bay
CIGGS 10" Gas
KNPL 20" Gas
Enstar 8" Gas
Enstar 2 x 12" Gas
KPL 16" Gas
KPL 16" Oil
ConocoPhillips 16"
Beaver Creek
Swanson River
Birch Hill
West Fork
Wolf Lake
Soldotna
Kenai River
Tustumena Lake
Skilak Lake
KENAI NATIONAL WILDLIFE REFUGE
Enstar 12" Gas
Enstar 12/16" Gas
Kachemak Bay
Homer
Under Construction
LNG Plant
APL Junction
Cannery Loop


Oil & Gas Units
Alaska Department of Natural Resources
Division of Oil and Gas
May 2006
COOK INLET AREAWIDE LEASE SALE BOUNDARY
AREAWIDE LEASING
Scale:
= 1 mile
= 10 miles
Gas
Liquid
Unit
State leased
Federal leased
Sources:
Cook Inlet Area Pipeline Map, Enstar Natural Gas Co., June 1992.
KKPL Presentation, August 2002.
Alaska O&G Reporter: August 10, 2003.
Cook Inlet
KENAI NATIONAL WILDLIFE REFUGE
Anchorage
Enstar 20" Gas
Enstar 12" Gas
Enstar 12/16" Gas
ConocoPhillips 16" Gas
ConocoPhillips 10" Gas
Tesoro 10" Multi-Products
10" Multi-Products
KPL 16" Gas
KPL 16" Oil
KNPL 20" Gas
CIGGS 10" Gas
Drift River Terminal
Redoubt
Trading Bay
North Cook Inlet
Beluga River
Swanson River
Birch Hill
Kenai
Soldotna
Tyonek
Susitna
Knik
Wasilla
Palmer
Eklutna
Hope
Girdwood

North Slope

Badami Pad
B. Webb

Badami Unit

Status:	Producing
Operator:	BP Exploration (Alaska), Inc.
Working Interest:	BP Exploration (Alaska), Inc. 100%
Total Acres:	37,402
First Production:	1998

Badami Sands PA

Status:	Producing
Discovery:	1990, Conoco Badami #1
Reservoir:	Tertiary Canning Formation Badami sandstone (-9,900 ft)

Alpine expansion loop
S. Schmitz

Colville River Unit

Status:	Producing Oil and Gas
Operator:	ConocoPhillips Alaska, Inc.
*Working Interest:	ConocoPhillips Alaska, Inc. 77.99% Anadarko Petroleum Corp. 22% Others 0.01%
Total Acres:	127,827
State Acres:	100,844
Royalty Ownership:	State of Alaska Arctic Slope Regional Corporation
First Production:	2000

Alpine PA

Status:	Producing
Discovery:	1994, ARCO Bergschrund #1
Reservoir:	Jurassic Kingak Formation, Alpine sandstone (-6,850 ft.)

CD 3 Pad, Doyon Rig 19
S. Schmitz

Nanuk Tract Operation

Status:	Test production
Discovery:	2000, ARCO Nanuk #2
Reservoir:	Cretaceous Torok Fm., Nanuq sandstone (-6,140 ft.)

Fiord Discovery

Status:	Undeveloped
Discovery:	1992, ARCO Fiord #1
Reservoir:	Kuparuk/Nechelik sandstones (-6,890 ft. and -7,400 ft.)

North Slope

Cronus Unit

Status:	Exploration
Operator:	Pioneer Natural Resources AK, Inc.
Working Interest:	Pioneer Natural Resources AK, Inc. 90%
	AVCG LLC 10%
Total Acres:	11,343

Duck Island Unit

Tundra Moss Campion
S. Schmitz

Status:	Producing Oil and Gas
Operator:	BP Exploration (Alaska), Inc.
Working Interest:	BP Exploration (Alaska), Inc. 52.7%
	ExxonMobil AK Production Inc. 31.9%
	Chevron (Unocal) 12.0%
	ConocoPhillips Alaska, Inc. 3.0%
	NANA Regional Corporation, Inc. 0.3%
	Doyon Ltd. 0.08%
Total Acres:	17,588
First Production:	1994

Eider PA

Status:	Producing
Discovery:	1998, BP Duck Island Unit MPI #2-56/EID
Reservoir:	Triassic Ivishak Sandstone (-9,700' subsea)

Endicott PA

Status:	Producing
Discovery:	1978, Sohio Sag Delta 34633 #4
Reservoir:	Mississippian Kekiktuk Conglomerate (-10,000 ft subsea)

Sag Delta North PA

Status:	Producing
Discovery:	1982, Sohio Sag Delta #9
Reservoir:	Triassic Ivishak (-10,000' subsea)

Jacob's Ladder Unit

Status:	Exploration
Operator:	Anadarko Petroleum Corporation
Working Interest:	Anadarko Petroleum Corp. 100%
Total Acres:	37,982

Kuparuk River Unit

Meltwater Pad
S. Schmitz

Status:	Producing Oil and Gas
Operator:	ConocoPhillips Alaska, Inc.
*Working Interest:	ConocoPhillips Alaska, Inc. 55.29%
	BP Exploration (Alaska), Inc. 39.28%
	Chevron (Unocal) 5.00%
	ExxonMobil AK Production Co. 0.36%
	Chevron U.S.A. 0.11%
Total Acres:	252,894
First Production:	1981

Kuparuk PA

Status:	Producing
Discovery:	1969, Sinclair Ugnu #1
Reservoir:	Cretaceous Kuparuk Formation (-5,600 ft subsea)

Meltwater PA

Status:	Producing
Discovery:	2000, ARCO Meltwater North #1
Reservoir:	Late Cretaceous Seabee Fm. Bermuda/Cairn sand)

Palm Flowlines
C. Ruff

Tabasco PA

Status:	Producing
Discovery:	1986, ARCO Kuparuk River Unit #2T-02
Reservoir:	Cretaceous Colville Group Tabasco sand

Tarn PA

Status:	Producing
Discovery:	1991, ARCO KRU Bermuda #3
Reservoir:	Late Cretaceous Seabee Fm., Bermuda sand (-4,376 to -5,990 ft)

West Sak PA

Status:	Producing
Discovery:	West Sak River State #1
Reservoir:	Cretaceous Colville Group Tabasco sand

Milne Point Unit F-Pad
S. Schmitz

Milne Point Unit

Status:	Producing Oil and Gas
Operator:	BP Exploration (Alaska), Inc.
Working Interest:	BP Exploration (Alaska), Inc. 100%
Total Acres:	49,668
First Production:	1985

Kuparuk PA

Status:	Producing
Discovery:	1969, Chevron Kavearak Pt. #32-25 1993, BP Cascade #1
Reservoir:	Cretaceous Kuparuk Formation (-7,200 ft subsea)

Schrader Bluff PA

Status:	Producing
Discovery:	1969, Chevron Kavearak Pt. #32-25
Reservoir:	Cretaceous Colville Group Schrader Bluff Fm.

Sag River Tract Operations (Undefined Pool)

Status:	Producing
Discovery:	1969, Chevron Kavearak Pt. #32-25
Reservoir:	Sag River and Ivishak formations

NE Storms Unit

Status:	Exploration
Operator:	Pioneer Natural Resources AK, Inc.
Working Interest:	Pioneer Natural Resources AK, Inc. 50% ConocoPhillips Alaska, Inc. 50%
Total Acres:	16,456

Nabors Rig 27E
C. Ruff

Nikaitchuq Unit

Status:	Exploration
Operator:	Kerr-McGee Oil & Gas Corp.
Working Interest:	Kerr-McGee Oil & Gas Corp. 70% ENI Petroleum US LLC 30%
Total Acres:	12,968

North Slope

Northstar Unit

Northstar Facility
S. Schmitz

Status:	Producing Oil and Gas
Operator:	BP Exploration (Alaska), Inc.
Working Interest:	BP Exploration (Alaska), Inc. 98.13%
	Murphy Exploration (Alaska), Inc. 1.87%
Total Acres:	28,024
State Acres:	17,599
Royalty Ownership:	State of Alaska/United States
First Production:	2001

Northstar PA

Status:	Producing
Discovery:	1984, Shell BF-47 (Seal Island) #1
Reservoir:	Ivishak and Shublik “D” Formations (-11,000 ft. subsea)

Northstar Production Island
S. Schmitz

Oooguruk Unit

Status:	Exploration
Operator:	Pioneer Natural Resources AK, Inc.
Working Interest:	Pioneer Natural Resources, AK 70%
	ENI Petroleum US LLC 30%
Total Acres:	20,394

Point Thomson Unit

Arctic Coastal Plain
B. Webb

Status:	Development
Operator:	ExxonMobil
Working Interest:	ExxonMobil 52.58%
	BP Exploration Alaska, Inc. 29.19%
	Chevron U.S.A., Inc. 14.31%
	ConocoPhillips Alaska, Inc. 2.82%
	Others 1.10%
Total Acres:	106,201

Point Thomson Sands

Status:	Undeveloped
Discovery:	1977, Exxon Pt. Thomson #1
Reservoir:	Lower Cretaceous Thomson sandstone (-12,834 ft.)

Exploration pad
B. Webb

Flaxman Discovery

Status:	Undeveloped
Discovery:	1975, Exxon Alaska State A #1
Reservoir:	Tertiary Flaxman sand (-12,565 ft.)

Sourdough Discovery

Status:	Undeveloped
Discovery:	1994, BP Sourdough #2

Arctic Drilling Rig
A. Motschenbacher

Prudhoe Bay Unit

Status:	Producing Oil and Gas
Operator:	BP Exploration (Alaska), Inc.
Working Interest:	ExxonMobil AK Production, Inc. 36.39%
(*Aligned for all PA's*	ConocoPhillips Alaska, Inc. 36.07%
~December 2001)	BP Exploration (Alaska), Inc. 26.36%
	Chevron U.S.A., Inc. 1.16%
	Forest Oil Corporation 0.02%
Total Acres:	248,677
First Production:	1977

Aurora PA

Status:	Producing
Discovery:	1969, Mobil North Kuparuk State #1
Reservoir:	Cretaceous Kuparuk Formation

Borealis PA

Status:	Producing
Discovery:	1969, Mobil West Kuparuk State #1
Reservoir:	Cretaceous Kuparuk Formation

Gas Cap PA

Status:	Producing
Discovery:	1968, Richfield Prudhoe Bay State #1
Reservoir:	Triassic Ivishak Sandstone (-8,800 ft subsea)

Lisburne PA

Status:	Producing
Discovery:	1968, Richfield Prudhoe Bay State #1
Reservoir:	Mississippian Lisburne Group

Midnight Sun PA

Status:	Producing
Discovery:	1997, BP Prudhoe Bay Un MDS #E-100
Reservoir:	Cretaceous Kuparuk Formation

Niakuk PA

Status:	Producing
Discovery:	1985, BP Niakuk #5
Reservoir:	Cretaceous Kuparuk Formation (-9,350 ft.)

Oliktok Point STP
S. Schmitz

Prudhoe Bay Unit, Cont.

North Prudhoe Bay PA

Status:	Producing
Discovery:	1970, ARCO North Prudhoe Bay State #1
Reservoir:	Triassic Sadlerochit Group

Oil Rim PA

Status:	Producing
Discovery:	1968, Richfield Prudhoe Bay State #1
Reservoir:	Triassic Ivishak sandstone (-8,800 ft subsea)

Polaris PA

Status:	Producing
Discovery:	1969, Mobil North Kuparuk State #1
Reservoir:	Cretaceous Colville Group, Schrader Bluff Fm.

Point McIntyre PA

Status:	Producing
Discovery:	1988, ARCO Pt. McIntryre #3A
Reservoir:	Cretaceous Kuparuk Formation

Prudhoe Bay Oilfield
A. Motschenbacher

West Beach PA

Status:	Producing
Discovery:	1976, ARCO West Beach #3
Reservoir:	Cretaceous Kuparuk Formation

Western Niakuk PA

Status:	Producing
Discovery:	1985, BP Niakuk #5
Reservoir:	Cretaceous Kuparuk Formation (-9,350 ft.)

Orion PA

Status:	Producing
Discovery:	1968, Mobil Kuparuk State #1
Reservoir:	Cretaceous Schrader Bluff Fm (-4,500 ft.ss)

Rock Flour Unit

Status:	Exploration
Operator:	ENI Petroleum US LLC
Working Interest:	ENI Petroleum US LLC 100%
Total Acres:	10,843

Tuvaaq Unit

Status:	Exploration
Operator:	ENI Petroleum US LLC
Working Interest:	ENI Petroleum US LLC 100%
Total Acres:	14,561

Meter Turbine
S. Schmitz

Whiskey Gulch Unit

Status:	Exploration
Operator:	AVCG LLC
Working Interest:	AVCG LLC 100%
Total Acres:	30,651

Arktos train
S. Schmitz

Beaver Creek Unit

Status:	Producing Oil and Gas
Operator:	Marathon Oil Company
Working Interest:	Marathon Oil Company 100%
Total Acres:	3,680
Royalty Ownership:	United States/CIRI
First Production:	1973

Sterling Gas, Beluga Gas, and Beaver Creek Oil Pools

Status:	Producing oil and gas
Discovery:	1972, Marathon Beaver Creek #4
Reservoir:	Tertiary Hemlock, Lower Tyonek and Beluga formations

Beluga River Unit


B. Havelock

Status:	Producing Gas
Operator:	ConocoPhillips Alaska, Inc.
Working Interest:	ConocoPhillips Alaska, Inc. 33.33%
	Chevron USA, Inc. 33.33%
	Municipality of Anchorage 33.33%
Total Acres:	8,228
State Acres:	6,099
Royalty Ownership:	State of Alaska/United States/Fee
First Production:	1968

Beluga-Sterling Gas Pool PA

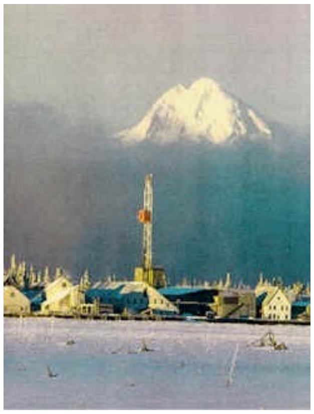
Status:	Producing gas
Discovery:	1962, Chevron Beluga River Unit 212-35 #1
Reservoir:	Tertiary Sterling Formation

Birch Hill Unit

Status:	Suspended
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 78.71%
	CIRI Production Company 19.68%
	Marathon Oil Company 1.61%
Total Acres:	1,240
Royalty Ownership:	United States/CIRI
First Production:	Shut-in 1965

Gas Pool #1 PA

Status:	Shut-in
Discovery:	1965, Chevron Birch Hill Unit #22-25
Reservoir:	Tertiary Tyonek Formation
Working Interest:	Chevron (Unocal) 78.7%



Cannery Loop #3
Redoubt Volcano
L. Ibele

Cannery Loop Unit

Status:	Producing Gas
Operator:	Marathon Oil Company
Working Interest:	Marathon Oil Company 100%
Total Acres:	2,640
State Acres:	916
Royalty Ownership:	State of Alaska/United States/Fee
First Production:	1988
:	

Beluga Gas Sands PA

Status:	Producing
Discovery:	1979, UNOCAL Cannery Loop Unit #1
Reservoir:	Tertiary Beluga Formation

Sterling Undefined Sands PA

Status:	Shut-in
Discovery:	1979, UNOCAL Cannery Loop Unit #1
Reservoir:	Tertiary Sterling Formation

Tyonek D Zone Gas Sands PA

Status:	Shut-in
Discovery:	1979, UNOCAL Cannery Loop Unit #1
Reservoir:	Tertiary Tyonek Formation

Upper Tyonek Gas Sands PA

Status:	Producing
Discovery:	1979, UNOCAL Cannery Loop Unit #1
Reservoir:	Tertiary Tyonek Formation

Cosmopolitan Unit

Status:	Exploration
Operator:	ConocoPhillips Alaska, Inc.
Working Interest:	ConocoPhillips Alaska, Inc. 60%
	Devon Energy Production Co. 17.5%
	Forest Oil Corporation 12.5%
	Pioneer Natural Resources AK, Inc. 10%
Total Acres:	24,600
State Acres:	14,835
Royalty Ownership:	State of Alaska/United States

Starichkof Discovery

Status:	Exploration
Discovery:	1967, Penzoil Starichkof St. #1
Reservoir:	Tertiary Hemlock Conglomerate

Deep Creek Unit

Nikolaevsk Pad
C. Ruff

Status:	Exploration
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	22,657
State Acres:	9,146
Royalty Ownership:	State of Alaska/CIRI
First Production:	October 2004

Happy Valley Participating Area

Status:	Producing gas
Discovery:	1963, Superior Oil Happy Valley Unit 31-22
First Production:	October 2004

Ivan River Unit

Status:	Producing Gas
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	2,291
First Production:	1990

Ivan River Gas Pool #1 PA

Status:	Producing Gas
Discovery:	1966, Chevron Ivan River Unit #44-1
Reservoir:	Tertiary Tyonek Formation

Kenai River
B. Havelock

Kasilof Unit

Status:	Exploration
Operator:	Marathon Oil Company
Working Interest:	Marathon Oil Company 100%
Total Acres:	13,289

Caribou at Kenai Gas Field
L. Ibele

Kenai River Unit

Status:	Producing Gas
Operator:	Marathon Oil Company
Working Interest:	Marathon Oil Company ~100%
Total Acres:	13,238
State Acres:	2,191
Royalty Ownership:	State of Alaska/United States/Fee
First Production:	1961

Sterling Formation Gas Zone PA (A Zone PA)

Status:	Producing
Discovery:	1959, UNOCAL Kenai Unit #14-6
Reservoir:	Tertiary Sterling Formation Pool 2, 3,4, 5, 5.2 and 6

Beluga PA (Beluga Formation Gas Zones PA)

Status:	Producing
Discovery:	1959, UNOCAL Kenai Unit #14-6
Reservoir:	Tertiary Beluga Formation (-4,595 to -5,108 ft. subsea)

Tyonek Undefined PA

Status:	Producing
Discovery:	--
Reservoir:	--

Beluga-Tyonek Commingled PA

Status:	Producing
Discovery:	--
Reservoir:	Beluga and Tyonek Formation

Pool 6 Gas Storage Reservoir

Status:	Active State Gas Storage Lease
First Injection:	May 2006
Annual cycle capacity:	6-11 bcf
Max daily deliverability:	60 MMCF
Reservoir:	Nearly Depleted Sterling formation Pool 6

Lewis River Pad
B. Havelock

Lewis River Unit

Status:	Producing
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	720
First Production:	1984

Lewis River PA #1

Status:	Producing
Discovery:	1975, Cities Lewis River #1
Reservoir:	Tertiary Tyonek and Beluga formations

Lewis River PA #2

Status:	Suspended
Discovery:	1975, Cities Lewis River #1
Reservoir:	Tertiary Tyonek and Beluga formations

Lone Creek Unit

Status:	Producing Gas
Operator:	Aurora Gas, LLC
Working Interest:	Aurora Gas, LLC 100%
Total Acres:	4,607
Discovery:	Anadarko Lone Creek #1
Reservoir:	Tertiary Beluga and Tyonek formation
Royalty Ownership:	Cook Inlet Region, Inc.
First Production:	June 2003

Moquawkie Unit

Status:	Producing Oil and Gas
Operator:	Aurora Gas, Inc.
Working Interest:	Aurora Gas, LLC 100%
Total Acres:	2,902
Discovery:	Moquawkie No. 1
Reservoir:	Tyonek Undefined
Royalty Ownership:	Cook Inlet Region, Inc.
First Production:	May 1967, November 2003

Nicloai Creek drilling
B. Havelock

Nicolai Creek Unit

Status:	Producing Gas
Operator:	Aurora Gas, LLC
Working Interest:	Aurora Gas, LLC100%
Total Acres:	411
State Acres:	365
Royalty Ownership:	State of Alaska/United States
First Production:	Shut-in 1977, Restart 2001

Nicolai Creek South Gas Pool “A” PA

Status:	Shut-In
Discovery:	1966, Texaco Nicolai Creek State #1A
Reservoir:	Tertiary Tyonek and Beluga formations

Unocal Red Well
C. Ruff

Nicolai Creek North Gas Pool "B" PA

Status:	Producing gas
Discovery:	1967, Texaco Nicolai Creek Unit #3
Reservoir:	Tertiary Tyonek and Beluga formations

Nicolai Creek Beluga PA

Status:	Producing gas
Discovery:	2003, Aurora Gas NCU #9
Reservoir:	Tertiary Beluga formations

Nikolaevsk Unit

Status:	Exploration
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	7,686
State Acres:	6,908
Royalty Ownership:	State of Alaska/CIRI

Marathon GO well
L. Ibele

Ninilchik Unit

Status:	Producing Gas
Operator:	Marathon Oil Company
Working Interest:	Marathon Oil Company 60% Chevron (Unocal) 40%
Total Acres:	25,807
State Acres:	19,583
Royalty Ownership:	State of Alaska/United States/ CIRI/University of Alaska/Fee
First Production:	2003

Falls Creek PA

Status:	Producing Gas
Discovery:	1961, Chevron Falls Creek Unit #43-1
Reservoir:	Tertiary Tyonek Formation

Ninilchik State #2
B. Havelock

Grassim Oskolkoff PA

Status:	Producing Gas
Discovery:	2000, Marathon Grassim Oskolkoff #1
Reservoir:	Tertiary Tyonek Formation

Susan Dionne PA

Status:	Producing Gas
Discovery:	2004, Marathon Susan Dionne #2
Reservoir:	Tertiary Tyonek Formation

Paxton Pool

Status:	Producing Gas
Discovery:	2004, Marathon Paxton #1
Reservoir:	Tertiary Tyonek Formation

Kenai LNG Plant
J. Rogers

North Cook Inlet Unit

Tyonek "A" Platform

Status:	Producing Gas
Operator:	ConocoPhillips Alaska, Inc.
Working Interest:	ConocoPhillips Petroleum Co. 100%
Total Acres:	9,782
First Production:	1970

North Cook Inlet Initial PA

Status:	Producing gas
Discovery:	1962, Pan Am Cook Inlet State 17589 #1
Reservoir:	Tertiary Tyonek, Beluga and Sterling formations

North Fork Unit

Status:	Shut-In
Operator:	Gas-Pro Alaska, LLC
Working Interest:	Gas Pro Alaska, LLC 60.3% IQ Gas, LLC 17.6% Alliance Energy Group LLC 13.7% Knoll Acres Assoc. LLC 4.7%
Total Acres:	640
State Acres:	400
Royalty Ownership:	State of Alaska/United States
First Production:	Shut-in in 1965

North Fork PA

Status:	Suspended
Discovery:	1965, Chevron North Fork Unit #41-35
Reservoir:	Tertiary Tyonek Formation

North Trading Bay Unit

Spark and Spurr Platforms

Status:	Intermittent gas production
Operator:	Marathon Oil Company
Working Interest (Gas):	Marathon Oil Company 100%
State Acres:	1,120
First Production:	1968, Oil Shut-in 1992

Spark Platform
L. Ibele

Hemlock and "G" Formation PA

Status:	Suspended
Discovery:	1965, Chevron Trading Bay #1A
Reservoir:	Tertiary Hemlock and Tyonek formations

Cook Inlet

Pretty Creek Unit

Status:	Shut-in
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	4,659
First Production:	1986

Beluga PA

Status:	Suspended
Discovery:	1979, Chevron Pretty Creek Unit #2
Reservoir:	Tertiary Beluga Formation
:	

Beluga Gas Storage Reservoir

Status:	Active State Storage Lease
First Injection:	November 2005
Annual cycle capacity:	0.7 BCF
Max daily deliverability:	20 MMCF
Reservoir:	Depleted Beluga 31-5 Sandstone

Redoubt Unit

Osprey Platform
J. Patrick

Osprey Platform

Status:	Producing
Operator:	Forest Oil Corporation
Working Interest:	Forest Oil Corporation 100%
Total Acres:	23,526
First Production:	2002

Hemlock PA

Status:	Producing Oil
Discovery:	1968, Pan Am Redoubt Shoal Unit #2
Reservoir:	Tertiary Hemlock Conglomerate

G-Ø Gas Sands PA

Status:	Suspended
Discovery:	n/a
Reservoir:	Tertiary Tyonek
:	

Cook Inlet Platforms
B.Webb

South Granite Point Unit

Granite Point Platform

Status:	Producing Oil and Gas
Operator:	Chevron (Unocal)
Working Interest:	ExxonMobil AK Production Co. 75%
	Chevron (Unocal) 25%
Total Acres:	10,209
First Production:	1967

South Granite Point Sands PA

Status:	Producing
Discovery:	1965, Mobil Granite Point 11965 #1
Reservoir:	Tertiary Tyonek Formation
:	

Hemlock PA

Status:	Producing
Discovery:	1965, Mobil Granite Point 11965 #1
Reservoir:	Tertiary Hemlock Conglomerate

South Middle Ground Shoal Unit

Dillon Platform

Status:	Suspended
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	1,160
First Production:	1967

South Middle Ground Shoal Tertiary System PA

Status:	Suspended
Discovery:	1962, Pan Am MGS State 17595 #1
Reservoir:	Tertiary Hemlock and Tyonek formations

South Ninilchik Unit

Status:	Exploration
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	1,266
State Acres:	823
Royalty Ownership:	State of Alaska/CIRI/Fee

Sterling Unit

Status:	Producing Gas
Operator:	Marathon Oil Company
Working Interest:	Marathon Oil Company 100%
Total Acres:	3,600
State Acres:	409
Royalty Ownership:	State of Alaska/United States/CIRI/Fee
First Production:	1962

"A" Zone PA (Sterling Formation Gas Zone PA)

Status:	Producing
Discovery:	1961, UNOCAL Sterling Unit #23-15
Reservoir:	Tertiary Sterling Formation

:

Lower Beluga PA

Status:	Producing
Discovery:	1999, UNOCAL Sterling Unit #41-15
Reservoir:	Tertiary Beluga Formation

Tyonek PA

Status:	Producing
Discovery:	1999, UNOCAL Sterling Unit #41-15
Reservoir:	Tertiary Tyonek Formation

Stump Lake Unit
B. Havelock

Stump Lake Unit

Status:	Suspended
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	4,800
First Production:	1990

Stump Lake Gas Pool #1 PA

Status:	Shut-in 1978, Restart 1990, Shut-in 2000
Discovery:	1978, Chevron Stump Lake Unit #41-33
Reservoir:	Tertiary Beluga Formation

:

Swanson River Unit

Status:	Producing Oil and Gas
Operator:	Chevron (Unocal)
Working Interest:	Chevron (Unocal) 100%
Total Acres:	8,021
Royalty Ownership:	United States/CIRI
First Production:	1960

Sterling Undefined G Zone Pool

Status:	Producing
Discovery:	1965, Chevron Birch Hill Unit #22-25
Reservoir:	Tertiary Tyonek Formation

Beluga Undefined Gas Pool

Status:	Producing
Discovery:	1965, Chevron Birch Hill Unit #22-25
Reservoir:	Tertiary Tyonek Formation

"B, C, D, & E" Zone Gas Pools #1 and #2 PA

Status:	Shut-in
Discovery:	1957, Richfield Swanson River Unit #34-10
Reservoir:	Tertiary Hemlock, Lower Tyonek and Beluga

Tyonek Storage Reservoirs

Status:	Active Federal Gas Storage Agreements
First Injection:	2001
Annual cycle capacity:	2 BCF
Max daily deliverability:	--
Reservoir:	Two depleted tertiary gas pools

Three Mile Creek Unit

Three Mile Creek well
Aurora Gas, LLC

Status:	Producing gas
Operator:	Aurora Gas, LLC
Working Interest:	Aurora Gas, LLC 79.21%
	Forest Oil Corporation 20.79%
Total Acres:	8,101
State Acres	3,840
Royalty Ownership:	State of Alaska/CIRI
First Production:	2005

Three Mile Creek PA

Status:	Producing Gas
Discovery:	1967, Superior Oil Three Mile Cr. State #1
Reservoir:	Tertiary Beluga Formation

Trading Bay Unit

King Salmon, Grayling, Steelhead, Dolly Varden Platforms

McArthur River Oilfield

Status:	Producing Oil and Gas
Operator:	Chevron (Unocal)
Working Interest (Gas):	Chevron (Unocal) 48.8%
	Marathon Oil Company 51.2%
Working Interest (Oil):	Forest Oil Corporation 53.2%
	Chevron (Unocal) 46.8%
Total Acres:	17,860
First Production:	1967

Grayling Gas Sands PA

Status:	Producing gas
Discovery:	1968, Trading Bay Unit #G-18
Reservoir:	Tertiary Tyonek Formation (-2,500 to -6,500 ft. subsea)

McArthur River Hemlock Oil Pool PA

Status:	Producing oil
Discovery:	1965, UNOCAL Grayling #1A
Reservoir:	Tertiary Hemlock Conglomerate

McArthur River Middle Kenai G Oil Pool PA

Status:	Producing oil
Discovery:	1965, UNOCAL Grayling #1A
Reservoir:	Tertiary Tyonek Formation

McArthur River West Foreland Oil Pool PA

Status:	Producing oil
Discovery:	1965, UNOCAL Grayling #1A
Reservoir:	Tertiary West Foreland Formation

West McArthur River Unit

West McArthur River
J. Patrick

Status:	Producing Oil and Gas
Operator:	Forest Oil Corporation
Working Interest:	Forest Oil Corporation 100%
Total Acres:	6,330
First Production:	1994

Area 1 PA

Status:	Producing Oil and Gas
Discovery:	1991, Stewart West McArthur River #1
Reservoir:	Tertiary Hemlock Conglomerate

Lease Production

Kustatan Production Facility
Forest Oil Corporation

Granite Point Field

Bruce and Anna Platforms

Status:	Producing Oil and Gas
Operator:	Chevron (Unocal)
Discovery:	1965, Mobil Granite Point 11965 #1
Reservoir:	Tertiary Hemlock and Tyonek formations
First Production:	1967

Kustatan Field

Status:	Producing Oil and Gas
Operator:	Forest Oil Corporation.
Discovery:	2000, Kustatan Field #1
Reservoir:	Undefined Tyonek Formation
First Production:	November 2005

Middle Ground Shoal Field

XTO Energy “A” and “C” Platforms

Status:	Producing Oil and Gas
Operator:	XTO Energy
Discovery:	1962, Pan Am MGS State 17595 #1
Reservoir:	Tertiary Hemlock and Tyonek formations
First Production:	1967

Monopod Platform
B. Webb

North Trading Bay Field

Monopod Platform

Status:	Producing Oil and Gas
Operator:	Chevron (Unocal)
Discovery:	1965, Mobil Granite Point 11965 #1
Reservoir:	Tertiary Hemlock and Tyonek formations
First Production:	1967

Lease Production

West Foreland Field

W. McArthur River Production Facility
Forest Oil Corporation

Status:	Producing Oil and Gas
Operator:	Forest Oil Corporation
Royalty Ownership:	Cook Inlet Region, Inc.
Discovery:	1962, West Foreland No.1
Reservoir:	Tyonek Undefined 4.0 and 4.1
First Production:	April 2001

Wolf Lake Pool

Glacier Rig at Wolf Lake
L. Ibele

Status:	Producing Gas
Operator:	Marathon Oil Company
Discovery:	Wolf Lake Marathon 2
Reservoir:	Beluga-Tyonek Undefined
Royalty Ownership:	Cook Inlet Region, Inc.
First Production:	November 2001

Table II.2 Alaska Fields and Pools

FIELD NAME	TYPE OF FIELD	UNIT	DISCOVERED	OPERATOR	STATUS	LOCATION
ALBERT KALOA	GAS		1/4/1968	CIRI	shut-in 1971	CI, west side, onshore
ALPINE	OIL	Colville River	3/27/1994	ConocoPhillips	prod. began 2000, Nov.	NS, Colville Delta, onshore
AURORA	OIL	Prudhoe Bay	8/24/1969	BP	prod. began 2000	NS, central, onshore
BADAMI	OIL & GAS	Badami	4/27/1990	BP	prod. began 1998, Aug. shut in	NS, Canning R., onshore
BEAVER CREEK	OIL & GAS	Beaver Creek	12/17/1972	UNOCAL	prod. began 1973	CI, east side, onshore
BELUGA RIVER	GAS	Beluga River	12/1/1962	ConocoPhillips	prod. began 1968	CI, west side, onshore
BIRCH HILL	GAS	Birch Hill	6/9/1965	ConocoPhillips	shut-in 1965	CI, east side, onshore
BOREALIS	OIL	Prudhoe Bay	8/8/1969	BP	prod. began 2000	NS, central, onshore
BURGER	OIL & GAS		10/14/1989		undeveloped	OCS, Chukchi Sea, offshore
CANNERY LOOP	GAS	Cannery Loop	6/24/1979	Marathon	prod. began 1988	CI, east side, onshore
CANNERY LOOP BELUGA	GAS	Cannery Loop	6/24/1979	Marathon	prod. began 1988	CI, east side, onshore
CANNERY LOOP STERLING	GAS	Cannery Loop	10/23/2000	Marathon	prod. began 2000	CI, east side, onshore
CASCADE	OIL	Milne Point	3/14/1993	BP	prod. began 1996, Aug.	NS, central, onshore
COLVILLE DELTA	OIL		4/26/1985	ConocoPhillips	undeveloped	NS, Colville Delta, onshore
EAST BARROW	GAS	Barrow	5/4/1974	NS Borough	prod. began 1981	NS, western, onshore
EAST KURUPA	GAS		3/1/1976		undeveloped	NS, foothills, onshore
EAST UMIAT	GAS		3/28/1964	UMC Petroleum	shut-in, no production.	NS, foothills, onshore
EIDER	OIL	Duck Island	3/20/1998	BP	prod. began 1998, Jul.	NS, central, onshore
ENDICOTT	OIL	Duck Island	2/14/1978	BP	prod. began 1987	NS, central, onshore
FALLS CREEK	GAS	Falls Creek	4/10/1961	Marathon	shut-in 1961; prod began 2003	CI, east side, onshore
FIORD	OIL	Colville River	4/18/1992	ConocoPhillips	undeveloped	NS, Colville Delta, onshore
FISH CREEK	OIL		9/4/1949	ConocoPhillips	undeveloped	NS, NPRA, onshore
FLAXMAN	OIL	Point Thomson	9/6/1975	Exxon	undeveloped	NS, Canning R., offshore
GRANITE POINT	OIL & GAS		5/16/1965	UNOCAL	prod. began 1967	CI, west side, offshore
GRANITE POINT TYONEK	GAS		8/5/1965	UNOCAL	prod. began 1995	CI, west side, offshore
GRASSIM OSKOLKOFF	GAS	Ninilchik	7/31/2001	Marathon	prod began 2003	CI, east side, offshore
GUBIK	GAS		8/11/1951		undeveloped	NS, foothills, onshore
GWYDYR BAY	OIL	Prudhoe Bay	11/25/1969	BP	undeveloped	NS, central, onshore
HAMMERHEAD	OIL		10/11/1986	Anadarko	undeveloped	OCS, Beaufort Sea, offshore
HAPPY VALLEY	GAS	Deep Creek	7/9/2003	Unocal	prod began 2004	CI, east side, onshore
HEMI SPRINGS	OIL		4/3/1984		undeveloped	NS, central, onshore
IVAN RIVER	GAS	Ivan River	10/8/1966	UNOCAL	prod. began 1990	CI, west side, onshore
KALUBIK	OIL	Alpine	5/1/1992	ConocoPhillips	undeveloped	NS, Colville Delta, onshore
KASILOF	GAS	Kasilof	2004	Marathon	undeveloped	CI, east side, offshore
KATALLA	OIL		1/1/1902		abandoned 1933	Gulf of Alaska, onshore
KAVIK	GAS		11/5/1969	Phillips	undeveloped	NS, foothills, onshore
KEMIK	GAS		6/17/1972	BP	undeveloped	NS, foothills, onshore
KENAI	GAS	Kenai	10/11/1959	Marathon	prod. began 1961	CI, east side, onshore
KENAI STERLING	GAS	Kenai		Marathon		CI, east side, onshore
KUPARUK RIVER	OIL & GAS	Kuparuk River	4/7/1969	ConocoPhillips	prod. began 1981	NS, central, onshore
KUVLUM	OIL		10/1/1992	Union Texas Pet.	undeveloped	OCS, Beaufort Sea, offshore
LEWIS RIVER	GAS	Lewis River	10/1/1975	UNOCAL	prod. began 1984	CI, west side, onshore
LIBERTY	OIL		3/3/1983	BP	undeveloped	OCS, Beaufort Sea, offshore
LISBURNE	OIL & GAS	Prudhoe Bay	12/19/1967	BP	prod. began 1986	NS, central, onshore
LONE CREEK	GAS	Moquawkie	10/12/1998	Anadarko	prod began 2003	CI, west side, onshore
MCARTHUR RIVER	OIL & GAS	Trading Bay	9/29/1965	UNOCAL	prod. began 1967	CI, west side, offshore
MCARTHUR RIVER TYONEK	GAS	Trading Bay		UNOCAL		CI, west side, offshore
MEADE	GAS		8/21/1950		undeveloped	NS, NPRA, onshore
MELTWATER	OIL	Kuparuk River	4/26/2000	ConocoPhillips	prod. began 2001, Nov.	NS, central, onshore
MIDDLE GROUND SHOAL	OIL	N & S MGS	6/10/1962	UNOCAL/XTO	prod. began 1967	CI, mid channel, offshore
MIDNIGHT SUN	OIL	Prudhoe Bay	12/20/1997	BP	prod. began 1998, Oct.	NS, central, onshore
MIKKELSON	OIL		11/11/1978	ExxonMobil	undeveloped	NS, central, onshore
MILNE POINT	OIL	Milne Point	8/9/1969	BP	prod. began 1985	NS, central, onshore
MOQUAWKIE	GAS	Moquawkie	11/28/1965	CIRI	shut-in 1979	CIt, west side, onshore
NIKAITCHUQ	OIL	Nikaitchuq	4/1/2004	Kerr-McGee	undeveloped	NS, central, offshore
N MID GROUND SH (MGS)	GAS	N Mid Ground Sh	6/10/1962	UNOCAL	prod. began 1982	CI, mid channel, offshore
N MIDDLE GROUND SHOAL	GAS		11/15/1964	UNOCAL/Cross Timber	undeveloped	CI, mid channel, offshore
NANUQ	OIL	Colville River	5/7/2000	ConocoPhillips	prod. began 2000	NS, Colville Delta, onshore
NIAKUK	OIL	Prudhoe Bay	3/7/1985	BP	prod. began 1994	NS, central, offshore
NICOLAI CREEK	GAS	Nicolai Creek	4/28/1966	Aurora Gas LLC	production began 2001	CI, west side, onshore
NORTH COOK INLET	GAS	N Cook Inlet	8/21/1962	ConocoPhillips	prod. began 1970	CI, mid channel, offshore
NORTH FORK	GAS	North Fork	12/20/1965	Alliance LLC	shut-in 1965	CI, east side, onshore
NORTH PRUDHOE	OIL & GAS	Prudhoe Bay	3/31/1970	BP	prod. began 1993, 0ct.	NS, central, onshore
NORTHSTAR	OIL & GAS	Northstar	1/30/1984	BP	prod. began 2001, Oct.	NS, central, offshore
NPRA LOOKOUT	OIL/COND		4/30/2002	ConocoPhillips	undeveloped	NS, NPRA, onshore
NPRA RENDEZVOUS	OIL/COND		4/27/2001	ConocoPhillips	undeveloped	NS, NPRA, onshore
NPRA SPARK	OIL/COND		4/12/2000	ConocoPhillips	undeveloped	NS, NPRA, onshore

Table II.2 Alaska Fields and Pools

FIELD NAME	TYPE OF FIELD	UNIT	DISCOVERED	OPERATOR	STATUS	LOCATION
OOOGURUK	OIL	Oooguruk	3/29/2003	Pioneer	undeveloped	NS, central, offshore
PALM	OIL	Kuparuk River	2/21/2001	ConocoPhillips	prod began 2002	NS, central, onshore
PETE'S WICKED	OIL	Prudhoe Bay	2/24/1997	BP	undeveloped	NSe, central, onshore
POINT MCINTYRE	OIL & GAS	Prudhoe Bay	3/22/1988	BP	prod. began 1993	NS, central, offshore
POINT THOMSON	OIL & GAS	Point Thomson	12/8/1977	ExxonMobil	undeveloped	NS, Canning R., onshore
POLARIS	OIL	Prudhoe Bay	8/24/1969	BP	prod. began 2001	NS, central, onshore
PRETTY CREEK	GAS	Pretty Creek	2/20/1979	UNOCAL	prod. began 1986	CI, west side, onshore
PRUDHOE BAY	OIL & GAS	Prudhoe Bay	12/19/1967	BP	prod. began 1977	NS, central, onshore
REDOUBT SHOAL	OIL	Redoubt Shoal	9/21/1968	Forest	prod. began 2001	CI, west side, offshore
SAG DELTA NORTH	OIL	Duck Island	1/25/1982	BP	prod. began 1989	NS, central, onshore
SAG RIVER	OIL	Milne Point	8/9/1969	BP	prod. began 1994	NSe, central, onshore
SAMBUCCA	OIL	Prudhoe Bay	1/20/1998	BP		NS, central, onshore
SANDPIPER	OIL	Sandpiper	1/25/1986	Murphy	undeveloped	OCS, Beaufort Sea, offshore
SCHRADER BLUFF	OIL	Milne Point	8/9/1969	BP	prod. began 1991	NS, central, onshore
SIKULIK	GAS		4/18/1988	NS Borough	undeveloped	NS, western, onshore
SIMPSON	OIL		10/23/1950		undeveloped	NS, NPRA, onshore
SOURDOUGH	OIL	Point Thomson	4/27/1994	BP	undeveloped	NS, Canning R., onshore
SOUTH BARROW	GAS	Barrow	4/15/1949	NS Borough	prod. began 1950	NS, western, onshore
SQUARE LAKE	GAS		4/18/1952		undeveloped	NS, NPRA, onshore
STARICHKOF	OIL	Cosmopolitan	4/1/1967	ConocoPhillips Alaska	undeveloped	CI, east side, offshore
STERLING	GAS	Sterling	7/11/1961	Marathon	prod. began 1962	CI, east side, onshore
STERLING BELUGA	GAS	Sterling	1/19/1999	Marathon	prod. began 1999	CI, east side, onshore
STERLING TYONEK	GAS	Sterling	1/19/1999	Marathon		CI, east side, onshore
STINSON	confidential		8/20/1990	ConocoPhillips	undeveloped	NS, Canning R., offshore
STUMP LAKE	GAS	Stump Lake	5/14/1978	UNOCAL	prod. began 1990	CI, west side, onshore
SUSAN DIONNE	GAS	Ninilchik	1/23/2002	Marathon	prod began 2003	CI, east side, offshore
SWANSON RIVER	OIL & GAS	Swanson River	7/19/1957	UNOCAL	prod. began 1958	CI, east side, onshore
TABASCO	OIL	Kuparuk River	10/18/1986	ConocoPhillips	prod. began 1998, May	NS, central, onshore
TARN	OIL	Kuparuk River	2/2/1991	ConocoPhillips	prod. began 1998, Aug.	NS, central, onshore
THETIS ISLAND	OIL		4/28/1993	Anadarko	undeveloped	NS, central, offshore
TRADING BAY	OIL	N Trading Bay	6/17/1965	UNOCAL	prod. began 1967	CI, west side, offshore
TRADING BAY TYONEK	GAS	N Trading Bay		UNOCAL		CI, west side, offshore
TYONEK DEEP	OIL	N Cook Inlet	11/5/1991	ConocoPhillips	undeveloped	CI, mid channel, offshore
UGNU	OIL	Kuparuk River	8/9/1969	ConocoPhillips	prod began 2003	NS, central, onshore
UMIAT	OIL		12/26/1946	U.S. Dept Interior	undeveloped	NS, foothills, onshore
WALAKPA	GAS		2/7/1980	NS Borough	prod. began 1992	NS, western, onshore
WEST BEACH	OIL & GAS	Prudhoe Bay	7/22/1976	BP	prod. began 1994, Apr.	NS, central, onshore
WEST FORELAND	GAS		3/29/1962	ConocoPhillips	shut-in 1962; prod began 2001	CI, west side, onshore
WEST FORK	GAS		9/26/1960	CIRI	prod. began 1978	CI, east side, onshore
WEST MCARTHUR RIVER	OIL & GAS	W Mcarthur River	12/2/1991	Forest	prod. began 1994	CI, west side, onshore
WEST SAK	OIL	Kuparuk River	8/9/1969	ConocoPhillips	prod. began 1998	NS, central, onshore
WOLF CREEK	GAS		6/4/1951		undeveloped	NS, NPRA, onshore
WOLF LAKE	GAS		11/12/1983	Maratthon	prod. began 2001	CI east side, onshore

Section Three

Historic and Forecast Production

Introduction

This section enumerates historic and projected oil and gas production for all North Slope and Cook Inlet producing areas, unit participating areas, and lease pools.

Forecast production volumes are based on original oil and gas in-place estimates and expected recovery factors. Original in-place means total volume of oil and gas in-place in a three-dimensional reservoir container, regardless of recoverability. Recoverable means the physical limitations of the reservoir and limits of existing technology, and considering economic factors, like price, volume, and rate of return on capital. Original and recoverable estimates are revised with new data and information on recovery and characteristics of the reservoir. Revised estimates are used to calculate remaining reserves.

Remaining Reserves are oil or gas that are economic and technologically feasible to produce and are expected to produce revenue in the foreseeable future. Total North Slope and Cook Inlet oil and gas reserves are the sum of forecasted production from year end 2006 to 2035 based on year-end 2005 reporting. Most remaining reserves of oil and gas generate royalty and other revenue to the state.

Historic and Forecast Production is summarized by producing area or unit as follows:

	Producing Region	Hydrocarbon Type	Table or Figure
Reserves	North Slope	Oil/Gas	Table III.1
	Cook Inlet	Oil/Gas	Table III.2
Historic	North Slope	Oil	Table III.3
	Incremental Production	Oil	Figures III.1A & B
	Cook Inlet	Oil	Table III.4
	North Slope	Gas	Table III.5
	North Slope	Gas	Figure III.2
	Cook Inlet	Gas	Table III.6
	Cook Inlet	Gas	Table III.10 and Figure III.7
Forecast	North Slope	Oil	Table III.7 and Figures III.3A & B
	Cook Inlet	Oil	Table III.8 and Figure III.4
	North Slope	Gas	Figure III.5
	Cook Inlet	Gas	Table III.9 and Figures III.6

Historic information is based on data from the Alaska Oil and Gas Conservation Commission (AOGCC) and the Division of Oil and Gas (DO&G) Royalty Accounting Section. The oil forecasts for North Slope and Cook Inlet are based primarily on estimates prepared by the Alaska Department of Revenue. Forecast gas production is based on DO&G material balance reserve estimates and assumptions about anticipated production on a field-by-field basis. These are enumerated in footnotes to the following tables and charts.

Table III.1 Oil and Gas Reserves

North Slope

Unit or Area	Oil Reserves (MMBO)[1]	Gas Reserves (Bcf)[1]	Royalty Percent	Royalty Oil Reserves (MMBO)	Royalty Gas Reserves (Bcf)
Badami Unit[2]	2	0	14.6%	0	-
Barrow					
East Barrow	-	5	0.0%	-	-
South Barrow	-	4	0.0%	-	-
Walakpa	-	25	0.0%	-	-
TOTAL Barrow	-	34		-	-
Colville River Unit					
Alpine	280	-	9.85%	28	-
CRU Satellite	230	-	14.2%[3]	33	-
TOTAL CRU	510	400		60	60
Duck Island Unit	117	843	12.5-14.4%	15	121
Kuparuk River Unit					
Kuparuk	864	1,000	12.5%	108	125
West Sak[4]	461	100	12.5%	58	13
Tabasco	14	-	12.5%	2	-
Tarn	47	50	12.5%	6	6
Meltwater	14	-	12.5%	2	
Other Kuparuk Satellite	-		12.5%	-	-
TOTAL KRU	1,401	1,150		175	144
Milne Point Unit[4]	391	14	14.6%	57	2
North Star	115	450	16.0%	18	72
Prudhoe Bay Unit					
Prudhoe IPAs[5]	2,497	23,000	12.5%	312	2,875
PBU Satellites[4], [6]	426	-	12.5%	53	-
Greater Point McIntyre Area					
Lisburne	43	1,000	12.5%	5	125
Niakuk	21	26	12.5%	3	3
North Prudhoe Bay State	-	-	12.5%	-	-
Pt. McIntyre	205	500	13.8%	28	69
West Beach	-	-	12.5%	-	-
TOTAL GPMA	269	1,526		36	197
TOTAL PBU	3,192	24,526		402	3,072
Point Thomson	243	8,000	12.5-16.0%	30	1,000
Other Undeveloped[7]	488	-	6%[8]	29	-
TOTAL North Slope (State Lands)	6,460	35,417		757	3,471
NPRA	255				
TOTAL North Slope Alaska	6,715	35,417	-	757	3,471

Notes:

[1] Remaining recoverable oil reserves based on the sum of Alaska Department Revenue forecasted production from 2006 through 2035. Gas reserves estmates from DNR. MMBO = Million Barrels of Oil; Bcf = Billion Cubic Feet.

[2] The Badami field was put in warm shut-in in August, 2003; production resumed in 2005.

[3] Average of royalty rates on State of Alaska lands.

[4] Based on a aggressive heavy oil component.

[5] Oil Rim and Gas Cap.

[6] Includes Midnight Sun, Aurora, Borealis, Orion and Polaris.

[7] Includes Liberty and other known on- and off-shore accumulations.

[8] Estimated combined rate for State and Federal on- and off-shore accumulations.

Table III.2 Oil and Gas Reserves

Cook Inlet

Unit or Area	Oil Reserves (MMBO)[1]	Gas Reserves (Bcf)[1]	Royalty Percent	Royalty Oil Reserves (MMBO)	Royalty Gas Reserves (Bcf)
Proved, Developed, Producing					
Beaver Creek	1.2	36.4	-	-	-
Beluga River	-	539.4	12.5%	-	67.4
Cannery Loop	-	68.5	12.6%	-	8.6
Deep Creek		22.6	12.5 - 18%		
Ninilchik[2]		50.8	5 - 12.5%	-	6.3
Granite Point	26.4	13.3	12.5%	3.3	1.7
Ivan River, Lewis River, Pretty Creek, Stump Lake	-	12.6	14.3 - 17.7%	-	1.8
Kenai	-	140.4	12.5%	-	17.6
Lone Creek/Moquawkie[3]	-	3.4	-	-	-
McArthur River	16.3	110.2	12.5%	2.0	13.8
Middle Ground Shoal	17.5	2.3	12.5%	2.2	0.3
Nicolai Creek	-	2.2	5 - 12.5%	-	0.3
North Cook Inlet	-	320.8	12.5%	-	40.1
North Trading Bay[3]	-	1.1	12.5%	-	0.1
Redoubt	1.1	0.3	5 - 12.5%		-
Sterling	-	5.5	12.5%	-	0.7
Swanson River	0.5	9.3	-	-	-
Three Mile Creek	-	4.1	12.5 - 18%		
Trading Bay	3.0	0.5	12.5%	0.4	0.1
West Foreland[3]	-	8.3	9.4%	-	0.8
West MacArthur River	3.1	-	12.5%	0.4	-
Wolf Lake[4]	-	0.3	-	-	-
					-
Probable, Undeveloped					-
Birch Hill	-	-	-	-	-
Tyonek Deep[5]	25.0	30.0	12.5%	3.1	3.8
Other Probable/ Under-development[6]		266.2	12.5%		33.3
TOTAL COOK INLET	94.1	1,648.4		11.4	196.5

Notes:

[1] Remaining recoverable reserves are based on the sum of forecasted production from 2006-2035. MMBO = Million Barrels of Oil; Bcf = Billion Cubic Feet.

[2] Ninilchik Unit includes Falls Creek, Grassim Oskolkoff, Susan Dionne, and Paxton PAs.

[3] Lone Creek, Nicolai Creek, North Trading Bay are point estimates. West Foreland royalty is 5% on State acreage and 12.5% on Federal acreage.

[4] Subsurface lands owned by Cook Inlet Region, Incorporated.

[5] DNR Estimate.

[6] Includes DNR estimates of non-producing, probable reserves based primarily on gas prospectivity in the Kasilof, Nikolaevsk and North Fork exploration areas. Also includes probable reserves estimates for the developed-producing fields: Deep Creek, McArthur River, Ninilchik, NCIU, and Three-Mile Creek.

North Slope (Millions of Barrels per Year)

	Badami	Colville River				Northstar	Duck Island								
		Alpine	Nanuk	Fiord	TOTAL Colville River	Northstar (Ivishak)	Eider[1]	Endicott				Sag Delta North[1]			TOTAL Duck Island Unit
	oil	oil	oil	oil		oil	oil	oil	ngl	inj	net	oil	ngl	net	
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	-	-	-	0.004
1987	-	-	-	-	-	-	-	8.796	0.003	0.014	8.785	-	-	-	8.785
1988	-	-	-	-	-	-	-	37.441	0.492	-	37.933	-	-	-	37.933
1989	-	-	-	-	-	-	-	35.746	0.839	-	36.585	0.349	0.005	0.354	36.939
1990	-	-	-	-	-	-	-	36.181	0.845	-	37.026	1.542	0.028	1.570	38.596
1991	-	-	-	-	-	-	-	38.996	1.170	-	40.166	2.309	0.048	2.357	42.523
1992	-	-	-	-	-	-	-	40.603	1.468	-	42.071	1.002	0.011	1.013	43.084
1993	-	-	-	-	-	-	-	38.433	1.551	-	39.984	0.761	0.007	0.768	40.752
1994	-	-	-	-	-	-	-	33.916	1.481	-	35.397	0.368	0.003	0.371	35.768
1995	-	-	-	-	-	-	-	32.998	1.203	-	34.201	0.235	0.001	0.236	34.437
1996	-	-	-	-	-	-	-	26.450	1.013	-	27.463	0.199	0.001	0.200	27.663
1997	-	-	-	-	-	-	-	21.121	1.550	-	22.671	0.255	0.002	0.257	22.928
1998	0.731	-	-	-	-	-	0.395	16.775	1.265	-	18.040	0.193	0.001	0.194	18.629
1999	1.150	-	-	-	-	-	0.605	13.529	1.371	-	14.900	0.179	0.001	0.180	15.685
2000	0.930	2.231	-	-	2.231	-	0.248	11.622	1.436	-	13.058	0.148	0.001	0.149	13.455
2001	0.675	31.932	0.019	-	31.951	1.266	0.660	9.637	1.324	-	10.961	0.142	0.001	0.143	11.764
2002	0.579	35.041	-	-	35.041	17.903	0.422	8.509	1.202	-	9.711	0.145	0.001	0.146	10.280
2003	0.282	35.582	-	-	35.582	22.968	0.242	9.104	1.189	-	10.293	0.092	0.001	0.092	10.627
2004	-	36.095	0.000	-	36.095	25.078	0.115	7.368	0.971	-	8.339	0.030	0.000	0.030	8.484
2005	0.000	43.797	-	0.016	43.813	22.421	0.032	6.398	0.979	-	7.377	0.043	0.000	0.043	7.451
TOTAL	4.347	184.678	0.020		184.714	89.636	2.719	433.634	21.354	0.021	454.966	7.992	0.112	8.104	465.789

Notes:

[1]AOGCC combined 1999 production volumes for Eider and Sag Delta North and reported these data in the "Ivishak Pool." Sag Delta North PA includes all oil and NGL production from Ivishak formation sands in the area. Eider also produces oil from the prolific Ivishak sandstone.

North Slope (Millions of Barrels per Year)

	Prudhoe Bay Unit Initial Participating Areas (IPAs) and Satellites										
	Prudhoe Bay[2]				Midnight Sun	Polaris (Schrader Bluff)	Aurora	Borealis	Orion	Raven	TOTAL PBU IPAs + Satellites
	oil	ngl	inj	net	oil	oil	oil	oil	oil	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	221.781	30.983	-	252.764	0.061	-	-	-	-	-	252.825
1999	194.338	29.423	-	223.761	1.696	0.027	-	-		-	225.484
2000	187.056	30.145	-	217.200	1.441	0.414	0.261	-	-	-	219.317
2001	166.718	27.526	-	194.244	1.305	0.419	1.738	1.346	-	-	199.052
2002	150.975	26.640	-	177.615	3.157	0.766	2.397	8.439	0.097	-	192.471
2003	141.302	24.972	-	166.274	1.719	0.918	3.782	11.791	0.368	-	184.856
2004	127.610	25.629	-	153.239	1.641	0.995	3.219	9.274	1.844	-	170.213
2005	118.552	21.420	-	139.972	2.132	1.248	3.452	7.077	2.897	0.291	157.069
TOTAL	10,817.070	466.613	13.011	11,270.672	13.154	4.786	14.850	37.926	5.207	0.291	11,346.889

Notes:
[2]Production for the Prudhoe Bay IPAs includes oil and condensates.

North Slope (Millions of Barrels per Year)

	Greater Point McIntyre Area (GPMA)																TOTAL Prudhoe Bay Unit (IPA+GPMA)
	Lisburne			Niakuk[3]			North Prudhoe Bay			Point McIntyre			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	0.008	0.001	0.009	33.460	0.831	34.291	0.603	0.067	0.670	47.486	272.970
2000	3.203	0.601	3.804	7.336	0.101	7.437	0.003	0.001	0.003	23.737	0.675	24.413	0.401	0.053	0.454	36.111	255.428
2001	3.054	0.622	3.675	6.978	0.109	7.087	-	-	-	18.094	0.600	18.693	0.110	0.014	0.125	29.580	228.632
2002	3.065	0.484	3.549	5.814	0.055	5.868	-	-	-	14.744	0.472	15.216	0.004	0.000	0.004	24.638	217.109
2003	3.335	0.480	3.816	4.599	0.039	4.638	-	-	-	13.320	0.518	13.838	0.010	0.001	0.011	22.302	207.154
2004	3.300	0.373	3.673	3.803	0.044	3.848	-	-	-	13.322	0.744	14.066	0.005	0.000	0.005	21.592	191.804
2005	3.050	0.320	3.370	2.621	0.048	2.670	0.001	0.000	0.001	11.789	0.844	12.633	0.001	0.000	0.001	18.675	175.745
TOTAL	142.759	14.230	156.989	82.954	1.004	83.958	1.985	0.086	2.071	387.895	8.876	396.771	3.421	0.220	3.641	643.431	11,990.315

Notes:

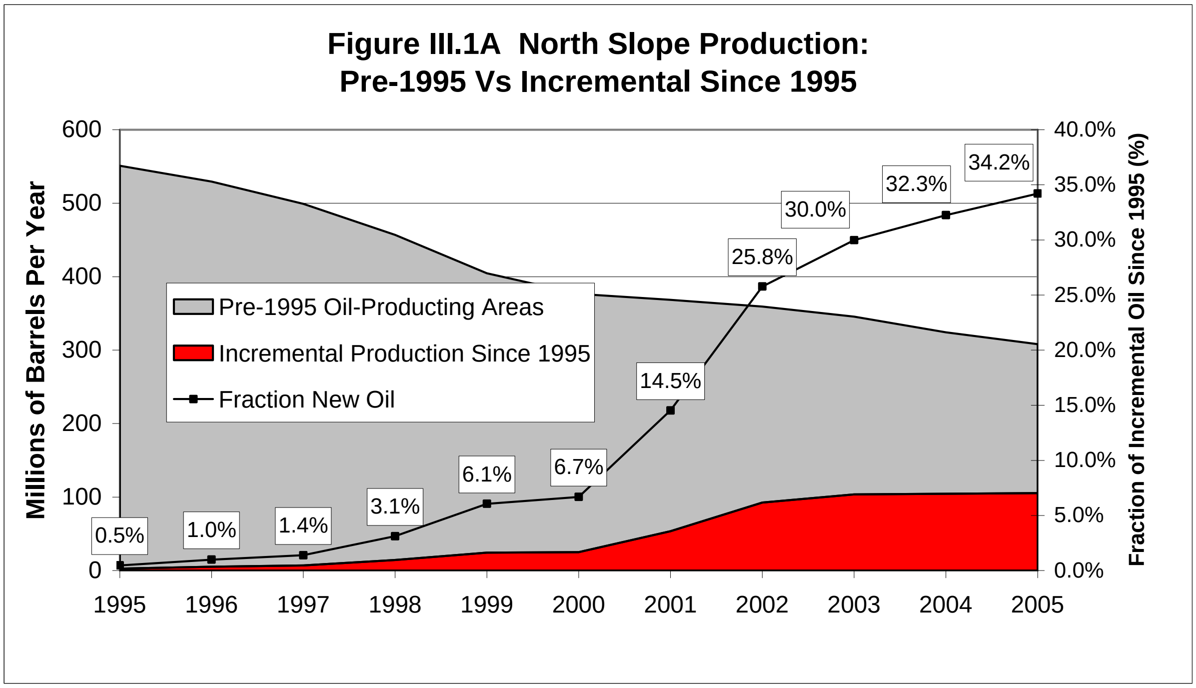
[3]Niakuk production volumes for 1994-1998 include production from all Niakuk wells. AOGCC lists 1999 volumes as "Niakuk Pool."

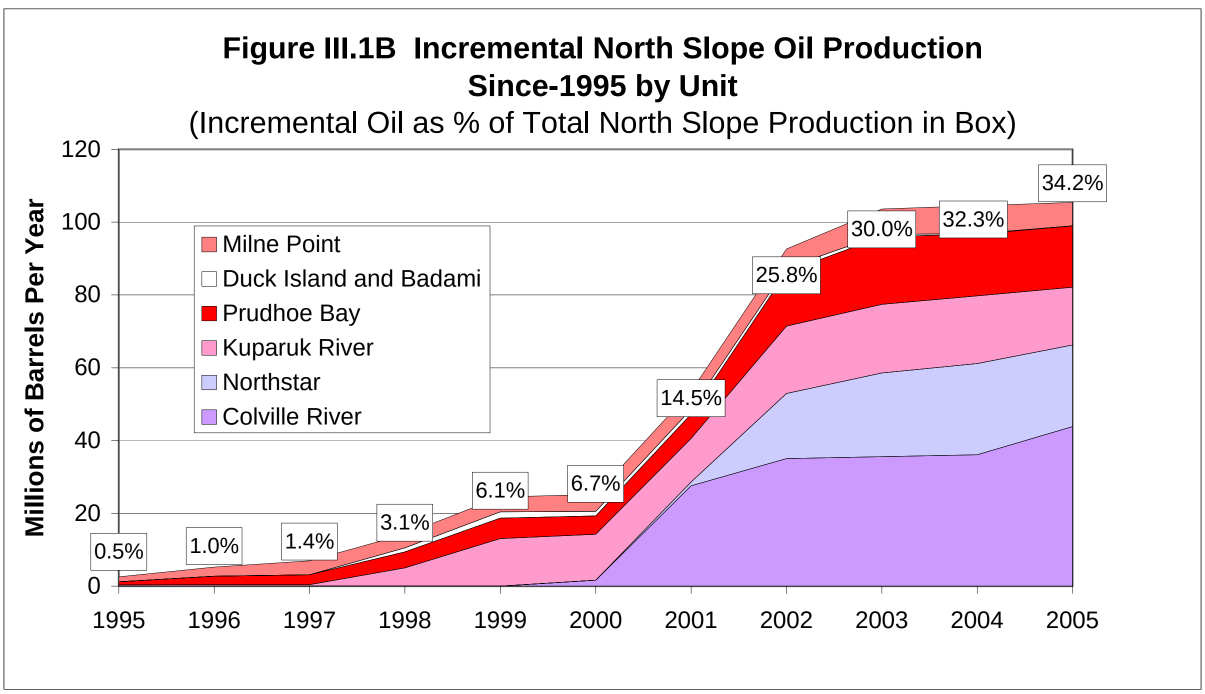
North Slope (Millions of Barrels per Year)

	Kuparuk River Unit								Milne Point Unit				NORTH SLOPE			
	Kuparuk			Tabasco	Tarn	West Sak	Melt-water	TOTAL Kuparuk River Unit	Milne Point	Sag River	Schrader Bluff	TOTAL Milne Point Unit	TOTAL OIL	TOTAL NGL	TOTAL INJECT-ED	TOTAL NET
	oil	ngl	net	oil	oil	oil	oil		oil	oil	oil					
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1969	-	-	-	-	-	-	-	-	-	-	-	-	0.277	-	0.217	0.060
1970	0.006	-	0.006	-	-	-	-	0.006	-	-	-	-	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	1.092	-	1.092	-	-	-	-	1.092	-	-	-	-	556.264	0.450	-	556.714
1982	32.406	-	32.406	-	-	-	-	32.406	-	-	-	-	591.503	0.500	-	592.003
1983	39.876	-	39.876	-	-	0.006	-	39.882	-	-	-	-	600.806	0.311	-	601.117
1984	46.084	-	46.084	-	-	0.124	-	46.208	-	-	-	-	608.454	0.317	-	608.771
1985	78.926	0.761	79.687	-	-	0.326	-	80.013	0.704	-	-	0.704	649.613	0.817	-	650.430
1986	93.900	1.072	94.972	-	-	0.300	-	95.272	4.709	-	-	4.709	664.052	1.302	0.007	665.347
1987	102.448	1.257	103.705	-	-	-	-	103.705	0.040	-	-	0.040	699.528	16.328	0.014	715.842
1988	110.891	0.256	111.147	-	-	-	-	111.147	-	-	-	-	722.839	21.030	-	743.869
1989	109.770	-	109.770	-	-	-	-	109.770	3.715	-	-	3.715	669.257	18.865	-	688.122
1990	107.206	-	107.206	-	-	-	-	107.206	6.624	-	0.004	6.628	636.366	18.171	-	654.537
1991	113.571	-	113.571	-	-	-	-	113.571	6.701	-	0.756	7.457	641.048	23.862	-	664.910
1992	118.506	-	118.506	-	-	-	-	118.506	5.812	-	1.135	6.947	612.162	26.845	-	639.007
1993	115.166	-	115.166	-	-	-	-	115.166	5.704	-	1.060	6.764	564.093	26.828	-	590.921
1994	111.795	-	111.795	-	-	-	-	111.795	5.648	-	1.030	6.678	553.402	25.867	-	579.269
1995	106.999	-	106.999	-	-	-	-	106.999	7.352	0.173	1.167	8.692	526.101	29.632	-	555.733
1996	99.459	-	99.459	-	-	-	-	99.459	12.665	0.346	1.090	14.101	496.197	33.198	-	529.395
1997	95.970	-	95.970	-	-	0.001	-	95.971	17.055	0.363	1.536	18.954	460.806	34.753	-	495.559
1998	91.702	-	91.702	0.483	3.534	0.562	-	96.281	18.314	0.162	1.943	20.419	417.110	33.724	-	450.834
1999	82.394	-	82.394	1.920	9.541	1.190	-	95.045	17.488	0.018	2.178	19.684	372.383	32.151	-	404.534
2000	74.133	-	74.133	1.911	8.767	1.520	-	86.330	16.572	-	2.498	19.069	344.431	33.013	-	377.444
2001	68.265	-	68.265	1.318	8.052	1.998	0.149	79.782	15.273	0.248	3.818	19.339	343.213	30.195	-	373.408
2002	58.903	-	58.903	1.089	12.011	2.472	2.902	77.378	13.314	0.130	5.219	18.663	348.098	28.854	-	376.952
2003	58.536	-	58.536	1.542	12.343	2.857	2.125	77.402	11.604	0.101	7.001	18.707	345.527	27.200	-	372.727
2004	53.215	-	53.215	1.471	10.337	4.281	2.478	71.781	10.996	0.048	7.693	18.737	324.218	27.762	-	351.980
2005	50.442	-	50.442	1.531	8.085	4.175	2.103	66.336	9.508	0.088	6.408	16.004	308.159	23.612	-	331.771
TOTAL	2,021.662	3.346	2,025.008	11.263	72.671	19.811	9.757	2,138.510	189.797	1.677	44.535	236.010	14,606.516	515.841	13.032	15,109.325

Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by FIeld and Pool" (Monthly Reports).

North Slope (Millions of Barrels per Year)





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Cook Inlet (Millions of Barrels per Year)

	Beaver Creek	Cannery Loop[1]	Granite Point[2]	Kenai[1]	McArthur River[3]			Middle Ground Shoal[4]	North Trading Bay Unit[5]	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	-	-
2000	0.092	-	1.742	-	4.822	-	4.822	1.894	-	0.002
2001	0.085	-	1.620	-	5.353	-	5.353	2.032	-	0.001
2002	0.079	-	1.527	-	5.510	-	5.510	1.959	-	0.046
2003	0.076	-	1.440	-	4.323	-	4.323	1.497	-	0.911
2004	0.068	-	1.433	-	3.373	-	3.373	1.323	-	0.559
2005	0.061	-	1.263	-	2.895	-	2.895	1.318	-	0.312
TOTAL	5.788	-	143.012	0.011	621.996	8.979	630.975	193.047	23.703	1.834

Notes:

[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. XTO Energy produces oil from "A" and "C" Platforms. All production is suspended at Baker and Dillon Platforms on the north and south flanks of the field.

[5]North Trading Bay Unit/Field Spark and Spurr Platform oil production has been shut-in since 1992, but some gas is produced from Spark

Cook Inlet (Millions of Barrels per Year)

	Swanson River[5]			Trading Bay[6]			West McArthur River	COOK INLET TOTAL OIL	COOK INLET TOTAL NGL	COOK INLET TOTAL
	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
2000	0.638	-	0.638	0.637	-	0.637	0.893	10.720	-	10.720
2001	0.609	-	0.609	0.574	-	0.574	1.222	11.497	-	11.497
2002	0.477	-	0.477	0.666	-	0.666	1.018	11.284	-	11.284
2003	0.425	-	0.425	0.537	-	0.537	0.849	10.059	-	10.059
2004	0.320	-	0.320	0.462	-	0.462	0.669	8.208	-	8.208
2005	0.330	-	0.330	0.414	-	0.414	0.517	7.110	-	7.110
TOTAL	229.000	1.400	230.400	78.289	0.360	78.649	11.006	1,307.675	10.750	1,318.425

Notes:

[5]Includes Hemlock pool.

[6]Includes Hemlock, Undefined, and B, C, D, and E pools.

Source: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports) and Alaska Department of Revenue.

No NGLs were produced in Cook Inlet in 2004.

North Slope (Billion Cubic Feet per Year)

	Badami			Barrow			Colville River						
	Badami			East Barrow	South Barrow	Walakpa	Alpine			Nanuq			TOTAL Colville
	gas	inj	net	gas	gas	gas	gas	inj	net	gas	inj	net	
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	-	-	-				-
1999	1.693	1.718	-0.025	0.123	0.055	1.281	-		-				-
2000	4.557	4.020	0.537	0.090	0.037	1.352	2.091	-	2.091				2.091
2001	5.312	0.479	4.834	0.086	0.042	1.348	33.604	-	33.604	-	-		33.604
2002	7.172	6.126	1.045	0.093	0.061	1.251	39.872	35.009	4.863	0.298	-	-	4.863
2003	3.698	3.363	0.335	0.093	0.089	1.235	41.594	36.315	5.279	-	-	-	5.279
2004	-	-	-	0.101	0.069	1.245	44.728	39.014	5.714	0.001	-	0.001	5.716
2005	1.120	0.959	0.161	0.080	0.053	1.255	49.433	43.112	6.321	-	-	-	6.321
TOTAL	24.011	16.669	7.341	8.162	22.538	15.168	211.322	153.449	57.872	0.300	-	0.001	57.873

North Slope (Billion Cubic Feet per Year)

	Duck Island								Prudhoe Bay Satellites									
	Eider			Endicott[1]			Sag Delta	TOTAL Duck Island	Midnight Sun	Aurora			Borealis			Orion	Polaris	Raven
	gas	inj	net	gas	inj	net	gas		gas	gas	inj	net	gas	inj	net	gas	gas	gas
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	2.122	-	2.122	119.981	109.440	10.541	0.122	12.785	0.130	-	-	-	-			-	-	
1999	4.879	-	4.879	126.274	116.944	9.331	0.120	14.329	3.781	-	-	-	-			-	-	
2000	2.428	-	2.428	140.704	128.599	12.105	0.095	14.628	9.288	1.083	-	1.083	-			-	-	
2001	6.494	-	6.494	134.122	125.915	8.208	0.093	14.794	6.750	12.052	-	12.052	0.936			-	-	
2002	3.658	-	3.658	134.693	124.402	10.291	0.096	14.044	9.879	12.609	3.486	9.123	9.681			0.058	1.182	
2003	2.813	-	2.813	141.556	129.458	12.098	0.064	14.975	3.500	11.971	0.357	11.614	9.466			0.312	1.000	
2004	0.930	-	0.930	130.206	117.797	12.410	0.020	13.359	6.191	9.869	5.395	4.474	6.997			1.624	0.993	-
2005	1.160	-	1.160	139.143	126.081	13.062	0.032	14.254	5.759	8.663	3.007	5.656	5.610	2.342	3.268	3.703	1.280	1.015
TOTAL	24.483	-	24.483	1,963.744	1,757.234	206.510	6.539	237.532	45.278	56.246	12.245	44.001	32.689	2.342	3.268	5.697	4.455	1.015

North Slope (Billion Cubic Feet per Year)

	Prudhoe Bay Initial Oil PA				Greater Point McIntyre Area (GPMA)[1]												
	Prudhoe Bay[2]			Total Prudhoe Bay IPA & Satellites	Lisburne			Niakuk[2]	North Prudhoe Bay	Point McIntyre			West Beach			TOTAL GPMA	TOTAL Prudhoe Bay Unit
	gas	inj	net		gas	inj	net	gas	gas	gas	inj	net	gas	inj	net		
1958	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1963	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1964	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1965	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1966	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1967	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1968	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-
1969	0.243	-	0.243	0.243	-	-	-	-	-	-	-	-	-		-	-	0.243
1970	1.037	-	1.037	1.037	-	-	-	-	-	-	-	-	-		-	-	1.037
1971	0.889	-	0.889	0.889	-	-	-	-	-	-	-	-	-		-	-	0.889
1972	0.658	-	0.658	0.658	-	-	-	-	-	-	-	-	-		-	-	0.658
1973	0.699	-	0.699	0.699	-	-	-	-	-	-	-	-	-		-	-	0.699
1974	2.022	-	2.022	2.022	-	-	-	-	-	-	-	-	-		-	-	2.022
1975	3.046	-	3.046	3.046	-	-	-	-	-	-	-	-	-		-	-	3.046
1976	5.077	-	5.077	5.077	-	-	-	-	-	-	-	-	-		-	-	5.077
1977	94.936	68.118	26.818	26.818	-	-	-	-	-	-	-	-	-		-	-	26.818
1978	307.966	271.854	36.112	36.112	-	-	-	-	-	-	-	-	-		-	-	36.112
1979	432.475	390.136	42.339	42.339	-	-	-	-	-	-	-	-	-		-	-	42.339
1980	597.148	546.510	50.638	50.638	-	-	-	-	-	-	-	-	-		-	-	50.638
1981	647.768	595.106	52.662	52.662	0.003	-	0.003	-	-	-	-	-	-		-	0.003	52.665
1982	756.884	697.812	59.072	59.072	0.374	-	0.374	-	-	-	-	-	-		-	0.374	59.446
1983	818.993	754.044	64.949	64.949	0.154	-	0.154	-	-	-	-	-	-		-	0.154	65.103
1984	846.674	768.899	77.775	77.775	0.343	-	0.343	-	-	-	-	-	-		-	0.343	78.118
1985	936.613	846.786	89.827	89.827	1.902	-	1.902	-	-	-	-	-	-		-	1.902	91.729
1986	970.290	882.882	87.408	87.408	8.677	-	8.677	-	-	-	-	-	-		-	8.677	96.085
1987	1,228.527	1,105.023	123.504	123.504	64.906	56.741	8.165	-	-	-	-	-	-		-	8.165	131.669
1988	1,404.992	1,248.094	156.898	156.898	94.670	87.815	6.855	-	-	-	-	-	-		-	6.855	163.753
1989	1,412.853	1,244.284	168.569	168.569	104.746	102.248	2.498	-	-	-	-	-	-		-	2.498	171.067
1990	1,481.462	1,317.106	164.356	164.356	107.592	101.542	6.050	-	-	-	-	-	-		-	6.050	170.406
1991	1,768.837	1,583.472	185.365	185.365	124.360	112.457	11.903	-	-	-	-	-	-		-	11.903	197.268
1992	1,951.156	1,761.397	189.759	189.759	154.468	141.598	12.870	-	-	-	-	-	-		-	12.870	202.629
1993	2,116.808	1,921.633	195.175	195.175	130.882	122.991	7.891	-	1.103	5.392	3.979	1.413	0.592		0.592	10.999	206.174
1994	2,402.584	2,204.235	198.349	198.349	101.260	99.748	1.512	2.471	2.646	38.795	34.461	4.334	1.119		1.119	12.082	210.431
1995	2,716.959	2,497.702	219.257	219.257	80.866	104.272	-23.406	7.241	2.482	46.637	21.687	24.950	0.446		0.446	11.713	230.970
1996	2,750.907	2,535.603	215.304	215.304	67.013	93.000	-25.987	8.757	0.206	56.584	30.444	26.140	2.720		2.720	11.836	227.140
1997	2,794.735	2,577.617	217.118	217.118	39.999	75.249	-35.250	10.523	-	70.009	35.945	34.064	2.739		2.739	12.076	229.194
1998	2,801.402	2,588.527	212.875	213.005	33.111	50.399	-17.288	8.381	0.018	70.828	49.276	21.552	0.545		0.545	13.208	226.213
1999	2,772.147	2,566.580	205.567	209.360	33.214	52.187	-18.973	8.469	0.114	62.586	41.672	20.915	4.452		4.452	14.976	219.884
2000	2,913.985	2,716.721	197.265	207.953	52.322	62.621	-10.299	5.069	0.049	57.664	43.549	14.115	5.638		5.638	14.572	216.887
2001	2,757.974	2,577.173	180.801	200.539	57.490	55.529	1.961	5.836	-	56.251	43.549	12.702	1.453		1.453	21.952	221.038
2002	2,761.753	2,570.664	191.090	211.199	63.745	52.214	11.531	4.287	-	57.465	55.078	2.387	0.048	2.606	-2.558	15.647	226.846
2003	2,840.910	2,617.182	223.728	249.619	66.748	52.165	14.583	3.386	-	51.777	64.363	-12.587	0.201	-	0.201	5.584	255.203
2004	2,885.902	2,651.341	234.562	254.219	56.340	48.826	7.514	3.022	-	64.808	72.967	-8.159	0.059	-	0.059	2.436	256.655
2005	2,823.514	2,602.692	220.822	241.503	57.695	42.929	14.765	2.481	0.035	76.822	74.727	2.095	0.017	-	0.017	19.393	260.896
TOTAL	51,010.826	46,709.192	4,301.634	4,422.323	1,502.880	1,514.531	-11.651	69.923	6.652	715.617	571.697	143.920	20.030	2.606	17.424	226.268	4,637.048

Notes:

[1]Liquids from the Greater Point McIntyre Area flows to both the Lisburne Production Center (LPC) and the Prudhoe Bay Field facilities. 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.

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

North Slope (Billion Cubic Feet per Year)

	Kuparuk River Unit													
	Kuparuk			Tabasco	Tarn			West Sak[1]			Meltwater			TOTAL Kuparuk River Unit
	gas	inj	net	gas	gas	inj	net	gas	inj	net	gas	inj	net	
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	-	-	-	-	-	6.114
1984	57.389	47.930	9.459	-	-	-	-	0.079	-	-	-	-	-	9.459
1985	104.279	85.909	18.370	-	-	-	-	0.134	-	-	-	-	-	18.370
1986	114.889	90.449	24.440	-	-	-	-	0.108	-	-	-	-	-	24.440
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	-	-	-	-	-	17.306
1999	117.193	98.330	18.863	0.305	13.395	16.502	-3.107	0.385	-	-	-	-	-	16.061
2000	109.638	97.762	11.875	0.203	17.777	16.552	1.225	0.399	-	-	-	-	-	13.304
2001	105.305	91.823	13.482	0.180	15.538	15.039	0.499	0.429	-	-	0.081	-	0.081	14.241
2002	100.938	81.157	19.782	0.159	13.101	16.755	-3.654	0.635	-	0.635	4.145	6.345	-2.200	14.721
2003	107.454	86.331	21.123	0.188	12.835	18.430	-5.596	0.813	0.171	0.642	5.595	5.562	0.033	16.391
2004	101.523	78.363	23.160	0.183	14.284	17.357	-3.073	2.069	0.121	1.948	7.322	11.596	-4.274	17.944
2005	97.292	71.011	26.281	0.345	13.366	19.331	-5.965	2.743	0.067	2.676	5.368	6.778	-1.410	21.927
TOTAL	2,483.202	1,974.537	508.665	1.674	104.772	121.162	-16.390	8.012	0.359	5.901	22.510	30.281	-7.770	492.080

Notes:
[1] KRU West Sak and Meltwater gas production only reported prior to 2002.

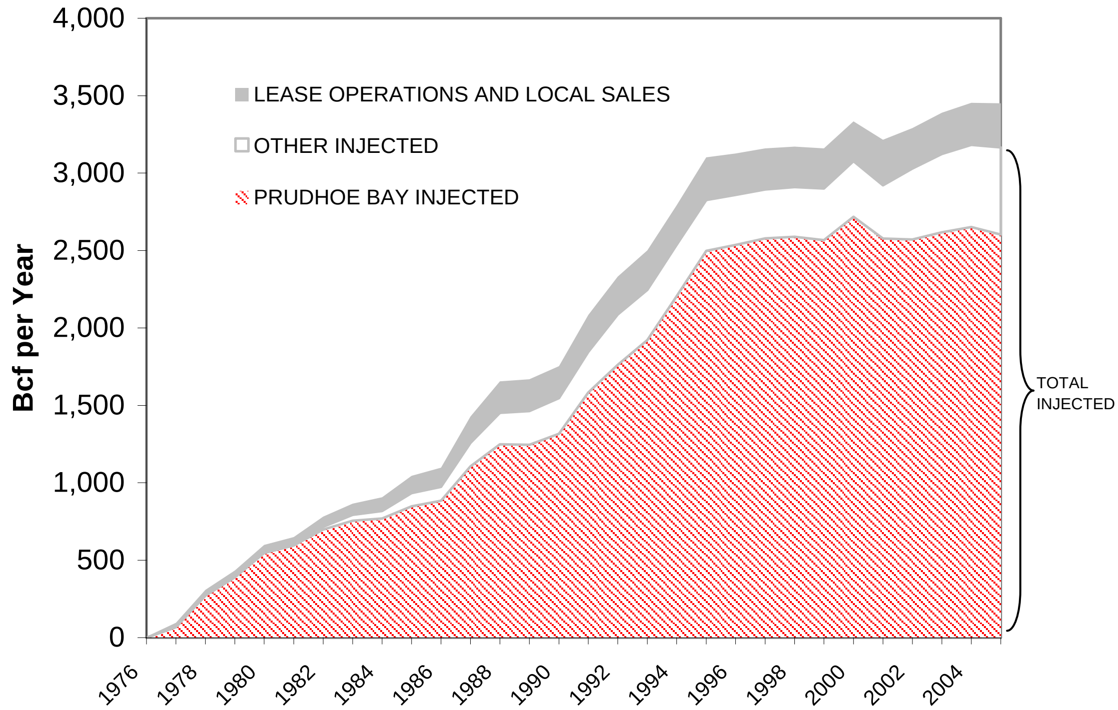
North Slope (Billion Cubic Feet per Year)

	Milne Popint Unit										Northstar			NORTH SLOPE		
	Kuparuk River PA			Sag River			Schrader Bluff			TOTAL Milne Point Unit	Northstar Oil Reservoir[1]			TOTAL GAS	TOTAL INJECTED	TOTAL NET
	gas	inj	net	gas	inj	net	gas	inj	net		gas	inj	net			
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	-	0.244	2.055	-	-	-	2,084.001	1,844.751	239.250
1992	3.015	1.632	1.383	-	-	-	0.536	-	0.536	1.919	-	-	-	2,331.011	2,086.334	244.677
1993	2.967	1.836	1.131	-	-	-	0.518	-	0.518	1.649	-	-	-	2,500.791	2,245.460	255.331
1994	3.524	2.305	1.219	-	-	-	0.515	-	0.515	1.734	-	-	-	2,791.598	2,536.571	255.027
1995	4.340	3.399	0.941	0.113	-	-	0.656	-	0.656	1.597	-	-	-	3,100.761	2,825.216	275.545
1996	6.120	4.307	1.813	0.299	-	-	0.464	-	0.464	2.277	-	-	-	3,126.223	2,858.624	267.599
1997	9.463	6.998	2.465	0.437	-	-	0.644	-	0.644	3.109	-	-	-	3,160.368	2,893.197	267.171
1998	8.949	6.351	2.598	0.179	-	-	1.008	-	1.008	3.606	-	-	-	3,170.890	2,908.797	262.093
1999	8.371	6.137	2.234	0.019	-	-	1.199	-	1.199	3.433	-	-	-	3,160.054	2,900.069	259.985
2000	8.207	6.195	2.012	-	-	-	1.480	-	1.480	3.492	-	-	-	3,334.155	3,076.018	258.137
2001	8.631	7.498	1.133	0.228	-	-	2.380	-	2.380	3.513	2.686	3.697	-1.011	3,215.301	2,920.702	294.599
2002	7.054	8.697	-1.643	0.179	0.653	-0.474	9.272	0.927	8.345	6.227	47.616	64.396	-16.781	3,290.999	3,028.516	262.483
2003	5.337	7.757	-2.420	0.121	0.179	-0.058	6.095	-	6.095	3.617	70.862	101.268	-30.407	3,389.711	3,122.902	266.810
2004	6.554	7.964	-1.410	0.028	0.179	-0.042	5.108	-	5.108	3.656	104.383	131.501	-27.118	3,454.559	3,182.420	272.139
2005	5.894	7.610	-1.717	0.125	0.075	0.050	5.285	-	5.285	3.619	142.131	165.712	-23.581	3,451.417	3,166.434	284.983
TOTAL	97.544	82.308	15.236	1.727	1.087	-0.524	35.404	0.927	34.477	49.189	367.678	466.575	-98.897	58,870.099	53,417.201	5,452.898

Note:
[1] Gas from Prudhoe Bay Field is imported to Northstar for injection.

North Slope

Figure III.2 ANS Gas Production 1977 - 2005



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

Cook Inlet (Billion Cubic Feet per Year)

	Albert Kaloa	Beaver Creek			Beluga River	Birch Hill	Cannery Loop[1]	Deep Creek	Ninilchik[2]	Granite Point	Ivan River	Kenai[3]	Lewis River	McArthur River (TBU)[4]	Middle Ground Shoal	Moquaw-kie Lone Cr	Nicolai Creek
	gas	gas	inj	net	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas	gas
1958	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1959	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1960	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1961	-	-	-	-	-	-	-	-	-	-	-	0.215	-	-	-	-	-
1962	-	-	-	-	-	-	-	-	-	-	-	1.460	-	-	-	-	-
1963	-	-	-	-	0.014	-	-	-	-	-	-	3.106	-	-	-	-	-
1964	-	-	-	-	0.137	-	-	-	-	-	-	4.493	-	-	-	-	-
1965	-	-	-	-	-	0.065	-	-	-	-	-	5.985	-	-	-	-	-
1966	-	-	-	-	-	-	-	-	0.019	-	-	33.375	-	-	1.200	-	-
1967	-	-	-	-	0.168	-	-	-	-	4.890	-	39.624	-	0.220	3.215	0.034	-
1968	-	-	-	-	2.018	-	-	-	-	10.036	-	46.014	-	6.155	6.654	0.353	0.026
1969	-	-	-	-	3.038	-	-	-	-	8.043	-	59.340	-	14.194	6.006	0.514	0.387
1970	0.095	-	-	-	3.571	-	-	-	-	9.211	-	80.612	-	19.688	6.137	0.083	0.202
1971	0.024	-	-	-	4.055	-	-	-	-	7.753	-	72.184	-	19.304	5.147	-	0.141
1972	-	0.002	-	0.002	4.142	-	-	-	-	5.773	-	76.007	-	19.722	4.075	-	0.066
1973	-	0.207	-	0.207	4.929	-	-	-	-	4.518	-	71.345	-	19.063	4.826	-	0.006
1974	-	0.150	0.019	0.131	5.596	-	-	-	-	3.265	-	68.485	-	19.599	4.260	-	0.011
1975	-	0.322	-	0.322	6.980	-	-	-	-	3.390	-	77.175	-	21.471	4.199	-	0.083
1976	-	0.261	0.091	0.170	11.211	-	-	-	-	3.205	-	79.467	-	19.027	4.347	-	0.108
1977	-	0.203	0.100	0.103	13.353	-	-	-	-	3.634	-	81.886	-	19.706	4.108	-	0.032
1978	-	0.329	0.144	0.185	14.253	-	-	-	-	3.860	-	97.290	-	18.585	3.290	-	-
1979	-	0.182	0.079	0.103	16.994	-	-	-	-	3.287	-	97.029	-	16.605	2.744	-	-
1980	-	0.180	0.029	0.151	17.002	-	-	-	-	3.233	-	98.846	-	15.590	2.628	-	-
1981	-	0.217	0.020	0.197	17.248	-	-	-	-	3.509	-	105.800	-	15.206	2.502	-	-
1982	-	0.396	0.037	0.359	18.653	-	-	-	-	2.780	-	115.913	-	16.240	2.374	-	-
1983	-	8.344	0.031	8.313	18.084	-	-	-	-	2.578	-	112.978	-	14.375	2.663	-	-
1984	-	9.335	-	9.335	19.833	-	-	-	-	2.340	-	110.109	0.696	15.076	2.726	-	-
1985	-	10.927	-	10.927	22.571	-	-	-	-	2.147	-	115.842	1.644	10.676	2.622	-	-
1986	-	17.773	-	17.773	25.357	-	-	-	-	2.415	-	82.470	1.338	13.560	1.593	-	-
1987	-	15.528	-	15.528	23.971	-	-	-	-	2.431	-	90.014	0.345	13.277	1.586	-	-
1988	-	14.346	-	14.346	25.586	-	9.400	-	-	2.543	-	76.299	0.045	16.722	1.635	-	-
1989	-	12.321	-	12.321	30.126	-	11.255	-	-	2.251	-	65.706	0.095	31.000	1.965	-	-
1990	-	12.474	-	12.474	39.512	-	12.502	-	-	1.431	0.676	38.393	1.485	51.456	2.579	-	-
1991	-	10.403	-	10.403	38.494	-	12.318	-	-	1.586	2.132	25.581	1.420	61.196	1.587	-	-
1992	-	7.368	-	7.368	36.534	-	10.635	-	-	2.246	1.774	24.187	0.706	70.070	2.377	-	-
1993	-	6.336	-	6.336	31.739	-	9.516	-	-	2.444	8.238	23.826	0.383	62.512	2.941	-	-
1994	-	1.304	-	1.304	34.212	-	6.361	-	-	2.077	15.996	18.853	0.244	50.027	3.025	-	-
1995	-	1.915	-	1.915	35.645	-	5.535	-	-	1.942	12.027	16.484	0.126	54.914	2.138	-	-
1996	-	3.042	-	3.042	36.930	-	2.072	-	-	2.251	6.605	13.294	0.114	67.275	0.852	-	-
1997	-	4.626	-	4.626	35.002	-	3.130	-	-	2.551	5.297	12.672	0.066	66.838	1.051	-	-
1998	-	3.743	-	3.743	33.391	-	3.021	-	-	2.635	4.532	9.736	0.102	73.822	1.882	-	-
1999	-	3.288	-	3.288	35.987	-	2.871	-	-	2.464	3.579	9.916	0.246	68.997	2.751	-	-
2000	-	4.793	-	4.793	38.750	-	4.692	-	-	2.209	2.620	12.833	0.134	65.016	1.485	-	-
2001	-	5.340	-	5.340	41.786	-	6.304	-	-	1.936	3.799	19.964	0.220	62.264	1.319	-	0.278
2002	-	8.548	-	8.548	44.039	-	5.016	-	-	1.658	4.303	22.154	0.898	51.515	0.918	-	0.605
2003	-	7.868	-	7.868	56.252	-	6.143	-	3.044	1.378	2.471	28.586	0.575	39.216	0.654	1.015	0.262
2004	0.439	8.338	-	8.338	57.618	-	13.640	0.299	12.367	1.332	1.670	24.217	0.369	34.408	0.415	2.548	0.983
2005	1.433	5.413	-	5.413	55.860	-	14.822	3.737	14.252	1.191	1.190	22.008	0.322	30.777	0.397	1.935	0.188
TOTAL	1.991	185.824	0.550	185.274	960.640	0.065	139.233	4.036	29.682	128.422	76.909	2,291.774	11.573	1,285.364	108.872	6.482	3.377

Notes:

[1] Cannery Loop includes CLU Beluga, CLU Upper Tyonek, CLU Tyonek D, and CLU Sterling Undefined in the Kenai formation.

[2] Ninilchik includes Falls Creek, Grassim Oskolk, Susan Dionne, and Paxton Pools.

[3] Kenai produced from Sterling # 3, 4, 5.1, and 6 Pools; and from Tyonek gas pool.

[4] Includes dry gas from Middle Kenai Gas (Grayling Gas Sands), and casing gas from the Hemlock, W Foreland, and Mid Kenai G Oil Pools.

Cook Inlet (Billion Cubic Feet per Year)

	North Cook Inlet	North Fork	North Trading Bay Gas Sands[3]	Pretty Creek	Re- Doubt	Sterling	Stump Lake	Swanson River[4]			Trading Bay[5]	West Fork	West Fore-land	West McArthur River	Wolf Lake	TOTAL GROSS	TOTAL INJECTED	TOTAL NET
	gas	gas	gas	gas	gas	gas	gas	gas	inj	net	gas	gas	gas	gas	gas			
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	-	0.105	-	-	-	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	-	-	0.045	-	-	0.198	-	25.434	58.316	-	2.916	-	-	-	-	99.849	58.316	41.533
1969	7.881	-	1.175	-	-	0.265	-	40.756	67.215	-	5.944	-	-	-	-	147.543	67.215	80.328
1970	40.947	-	0.725	-	-	0.265	-	50.396	73.139	-	6.430	-	-	-	-	218.362	73.139	145.223
1971	45.024	-	0.419	-	-	0.267	-	66.569	73.892	-	8.678	-	-	-	-	229.565	73.892	155.673
1972	41.580	-	0.635	-	-	0.172	-	67.441	76.133	-	5.033	-	-	-	-	224.648	76.133	148.515
1973	42.709	-	0.588	-	-	0.027	-	74.067	87.482	-	2.951	-	-	-	-	225.236	87.482	137.754
1974	44.238	-	0.600	-	-	0.032	-	80.869	86.793	-	2.712	-	-	-	-	229.817	86.812	143.005
1975	45.622	-	0.478	-	-	0.035	-	90.665	97.976	-	2.134	-	-	-	-	252.554	97.976	154.578
1976	45.091	-	0.318	-	-	0.035	-	101.427	113.279	-	2.155	-	-	-	-	266.652	113.370	153.282
1977	47.201	-	0.272	-	-	0.029	-	106.911	118.279	-	2.619	-	-	-	-	279.954	118.379	161.575
1978	46.757	-	0.217	-	-	0.024	-	106.934	114.557	-	2.211	0.052	-	-	-	293.802	114.701	179.101
1979	49.448	-	0.153	-	-	0.025	-	116.266	120.268	-	1.560	0.770	-	-	-	305.063	120.347	184.716
1980	41.540	-	0.197	-	-	0.026	-	118.855	120.636	-	1.355	0.476	-	-	-	299.928	120.665	179.263
1981	49.486	-	0.264	-	-	0.023	-	103.592	106.137	-	1.160	0.030	-	-	-	299.037	106.157	192.880
1982	45.368	-	0.445	-	-	0.024	-	105.654	113.023	-	1.187	0.086	-	-	-	309.120	113.060	196.060
1983	47.877	-	0.660	-	-	0.022	-	97.505	95.353	2.152	0.896	0.067	-	-	-	306.049	95.384	210.665
1984	46.981	-	0.649	-	-	0.018	-	96.710	93.687	3.023	0.911	0.037	-	-	-	305.421	93.687	211.734
1985	45.819	-	0.526	-	-	0.012	-	92.104	89.025	3.079	1.005	0.022	-	-	-	305.917	89.025	216.892
1986	43.838	-	0.513	0.067	-	0.002	-	95.083	93.602	1.481	0.866	-	-	-	-	284.875	93.602	191.273
1987	42.889	-	0.537	0.776	-	-	-	84.063	87.013	-2.950	0.897	-	-	-	-	276.314	87.013	189.301
1988	44.989	-	0.270	0.871	-	-	-	102.600	99.734	2.866	1.041	-	-	-	-	296.347	99.734	196.613
1989	45.287	-	0.217	0.641	-	-	-	104.094	107.802	-3.708	1.215	-	-	-	-	306.173	107.802	198.371
1990	45.014	-	0.060	0.607	-	-	0.528	104.395	106.031	-1.636	0.407	-	-	-	-	311.519	106.031	205.488
1991	44.695	-	0.079	0.742	-	-	1.608	105.057	105.157	-0.100	0.865	0.460	-	-	-	308.223	105.157	203.066
1992	44.411	-	0.013	0.762	-	-	1.504	104.533	104.724	-0.191	0.692	1.364	-	-	-	309.176	104.724	204.452
1993	45.529	-	-	0.333	-	0.007	0.778	97.701	93.052	4.649	0.619	0.625	-	0.031	-	293.558	93.052	200.506
1994	52.689	-	-	0.203	-	0.224	0.454	124.420	97.148	27.272	0.648	0.206	-	0.216	-	311.159	97.148	214.011
1995	53.541	-	-	0.256	-	0.184	0.288	101.781	73.086	28.695	0.526	0.016	-	0.231	-	287.549	73.086	214.463
1996	55.976	-	0.023	0.301	-	0.037	0.185	76.159	42.820	33.339	0.386	-	-	0.309	-	265.811	42.820	222.991
1997	52.466	-	0.511	0.383	-	0.005	0.132	51.898	23.163	28.735	1.122	-	-	0.152	-	237.902	23.163	214.739
1998	53.964	-	0.695	0.435	-	-	0.080	36.917	11.089	25.828	0.843	-	-	0.241	-	226.039	11.089	214.950
1999	51.629	-	0.241	0.028	-	0.125	0.054	37.483	7.731	29.752	0.445	-	-	0.212	-	220.318	7.731	212.587
2000	52.841	-	0.152	-	-	0.329	0.032	32.421	2.729	29.692	0.469	-	-	0.211	-	218.988	2.729	216.258
2001	55.531	-	-	0.080	-	0.149	0.000	30.405	8.356	22.049	0.420	-	-	0.288	0.114	230.197	8.356	221.841
2002	54.574	-	-	1.359	0.008	0.552	-	14.687	1.910	12.777	0.449	-	0.060	0.239	0.300	211.882	1.910	209.972
2003	47.920	-	0.101	0.428	0.673	0.358	0.000	9.292	2.720	6.571	0.263	-	0.940	0.200	0.240	207.877	2.720	205.157
2004	41.012	-	0.027	0.658	0.138	0.300	-	6.266	0.448	5.818	0.205	-	1.025	0.158	0.073	208.504	0.448	208.056
2005	45.560	-	0.416	0.411	0.077	1.874	-	4.349	1.297	3.052	0.313	0.286	2.604	0.125	0.093	209.631	1.297	208.335
TOTAL	1,707.924	0.105	12.222	9.341	0.896	6.230	5.644	2,909.974	2,905.199	269.238	65.270	4.497	4.628	2.612	0.821	9,964.407	2,905.749	7,105.021

Notes:

3 Includes dry gas quantities from Trading Bay Undefined Gas sands initially produced from Spurr Platform; later from Spark Platform.

4 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.

5 Includes only casing gas produced from the following oil pools: Hemlock, Middle Kenai B through E, and Undefined.

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

North Slope (Millions of Barrels per Year)

					Prudhoe Bay Unit				Kuparuk River Unit							
	Badami	Colville River	Northstar	Duck Island Unit	Prudhoe Bay IPAs[2]	Prudhoe Bay Satellites	Greater Pt McIntyre Area[3]	PBU IPA+Sat+G PMA	Kuparuk IPA	Kuparuk Satellites	KRU IPA+Sat	Milne Point Unit	Pt Thomson Unit	Other North Slope[4]	NPRA[5]	North Slope
1975	-	-	-	-	0.7	-	-	0.7	-	-	-	-	-	-	-	0.7
1976	-	-	-	-	1.0	-	-	1.0	-	-	-	-	-	-	-	1.0
1977	-	-	-	-	113.2	-	-	113.2	-	-	-	-	-	-	-	113.2
1978	-	-	-	-	397.7	-	-	397.7	-	-	-	-	-	-	-	397.7
1979	-	-	-	-	468.4	-	-	468.4	-	-	-	-	-	-	-	468.4
1980	-	-	-	-	555.6	-	-	555.6	-	-	-	-	-	-	-	555.6
1981	-	-	-	-	555.6	-	0.0	555.6	1.1	-	1.1	-	-	-	-	556.7
1982	-	-	-	-	559.4	-	0.2	559.6	32.4	-	32.4	-	-	-	-	592.0
1983	-	-	-	-	561.1	-	0.1	561.2	39.9	0.0	39.9	-	-	-	-	601.1
1984	-	-	-	-	562.3	-	0.3	562.6	46.1	0.1	46.2	-	-	-	-	608.8
1985	-	-	-	-	568.6	-	1.1	569.7	79.7	0.3	80.0	0.7	-	-	-	650.4
1986	-	-	-	0.0	561.8	-	3.6	565.4	95.0	0.3	95.3	4.7	-	-	-	665.3
1987	-	-	-	8.8	586.7	-	16.7	603.3	103.7	-	103.7	0.0	-	-	-	715.8
1988	-	-	-	37.9	578.7	-	16.1	594.8	111.1	-	111.1	-	-	-	-	743.9
1989	-	-	-	36.9	522.9	-	14.8	537.7	109.8	-	109.8	3.7	-	-	-	688.1
1990	-	-	-	38.6	486.2	-	15.9	502.1	107.2	-	107.2	6.6	-	-	-	654.5
1991	-	-	-	42.5	486.7	-	14.7	501.4	113.6	-	113.6	7.5	-	-	-	664.9
1992	-	-	-	43.1	456.5	-	14.0	470.5	118.5	-	118.5	6.9	-	-	-	639.0
1993	-	-	-	40.8	409.7	-	18.5	428.2	115.2	-	115.2	6.8	-	-	-	590.9
1994	-	-	-	35.8	374.3	-	50.7	425.0	111.8	-	111.8	6.7	-	-	-	579.3
1995	-	-	-	34.4	340.4	-	65.2	405.6	107.0	-	107.0	8.7	-	-	-	555.7
1996	-	-	-	27.7	312.6	-	75.6	388.2	99.5	-	99.5	14.1	-	-	-	529.4
1997	-	-	-	22.9	284.0	-	73.7	357.7	96.0	0.0	96.0	19.0	-	-	-	495.6
1998	0.7	-	-	18.6	252.8	0.061	61.9	314.8	91.7	4.6	96.3	20.4	-	-	-	450.8
1999	1.2	-	-	15.7	223.8	1.723	47.5	273.0	82.4	12.7	95.0	19.7	-	-	-	404.5
2000	0.9	2.2	-	13.5	217.2	2.117	36.1	255.4	74.1	12.2	86.3	19.1	-	-	-	377.4
2001	0.7	32.0	1.3	11.8	194.2	4.808	29.6	228.6	68.3	11.5	79.8	19.3	-	-	-	373.4
2002	0.6	35.0	17.9	10.3	177.6	14.856	24.6	217.1	58.9	18.5	77.4	18.7	-	-	-	377.0
2003	0.3	35.6	23.0	10.6	166.3	18.582	22.3	207.2	58.5	18.9	77.4	18.7	-	-	-	372.7
2004	-	36.1	25.1	8.5	153.2	16.973	21.6	191.8	53.2	18.6	71.8	18.7	-	-	-	352.0
2005	0.0	43.8	22.4	7.5	140.0	17.1	18.7	175.7	50.4	15.9	66.3	16.0	-	-	-	331.8
2006	0.4	40.1	18.1	6.5	135.5	18.1	17.1	170.8	47.4	18.5	65.9	16.1	-	-	-	317.8
2007	0.4	46.1	14.5	5.7	131.1	20.3	15.6	167.0	44.5	22.2	66.7	16.0	-	2.1	-	318.5
2008	0.4	49.2	11.6	5.3	126.4	23.1	14.6	164.1	42.3	24.5	66.8	15.9	-	7.9	-	321.1
2009	0.4	48.4	9.3	5.2	122.4	25.1	13.7	161.2	40.3	25.9	66.3	16.1	-	15.2	-	322.0
2010	0.2	44.7	7.4	5.2	116.6	25.7	12.9	155.1	38.6	27.5	66.1	16.0	-	25.5	4.3	324.3
2011	-	38.4	6.0	5.2	112.2	25.0	12.2	149.3	37.0	28.9	65.9	15.5	-	33.3	11.1	324.8
2012	-	30.9	5.0	5.3	108.1	23.5	11.5	143.1	35.5	30.1	65.6	15.0	-	33.7	17.2	315.8
2013	-	25.0	4.2	5.4	104.5	21.8	11.0	137.2	34.1	30.8	65.0	14.6	-	29.5	23.1	304.1
2014	-	21.1	3.7	5.5	101.1	20.3	10.5	131.9	32.9	31.2	64.1	14.6	-	28.1	24.4	293.4
2015	-	18.6	3.3	5.7	96.3	18.9	10.0	125.2	31.8	31.2	63.0	14.4	14.9	28.6	21.9	295.6
2016	-	16.7	3.0	5.9	93.5	17.6	9.6	120.8	30.7	29.3	60.0	14.4	24.2	29.8	19.4	294.1
2017	-	14.7	2.7	5.9	92.3	16.5	9.2	118.0	29.7	26.5	56.2	14.8	22.0	30.1	17.1	281.7
2018	-	12.9	2.5	5.7	90.5	15.5	8.8	114.8	28.8	24.0	52.7	15.5	20.1	28.0	15.1	267.2
2019	-	11.5	2.3	5.4	87.7	14.5	8.5	110.6	27.9	21.6	49.6	16.2	18.3	25.0	13.4	252.2
2020	-	10.4	2.2	4.9	77.5	13.5	8.2	99.2	27.1	19.5	46.7	16.9	16.6	22.1	11.8	230.9
2021	-	9.4	2.0	4.5	74.8	12.6	7.9	95.3	26.4	17.7	44.0	16.5	15.1	19.7	10.5	217.0
2022	-	8.4	1.9	4.0	72.2	11.8	7.6	91.6	25.7	16.0	41.6	15.6	13.8	17.6	9.3	203.7
2023	-	7.6	1.8	3.6	69.7	11.1	7.3	88.1	25.0	14.4	39.4	14.6	12.5	15.7	8.2	191.5
2024	-	6.9	1.6	2.9	67.4	10.4	7.1	84.8	24.4	13.1	37.4	13.8	11.4	14.0	7.3	180.1
2025	-	6.3	1.5	2.3	65.2	9.7	6.9	81.8	23.8	11.8	35.6	12.8	10.4	12.5	6.4	169.6

Notes:

[1] Actual reported production from AOGCC Monthly Production Reports through 2005. Figures include NGLs.
Forecast production is based on sum of remaining recoverable reserves. Forecast horizon is 2006-2035, shown to 2025 in table and related chart.

[2] Oil Rim and Gas Cap.

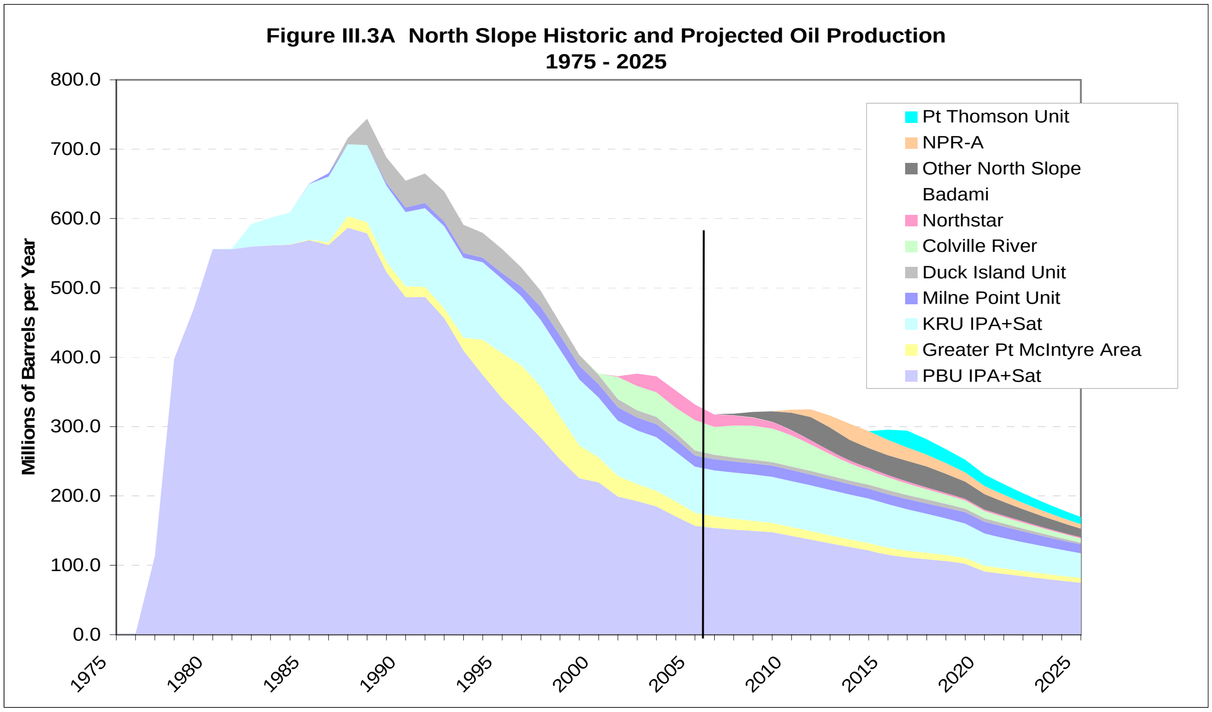
[3] Includes Lisburne, Niakuk, North Prudhoe Bay, Point MacIntyre PA, and West Beach.

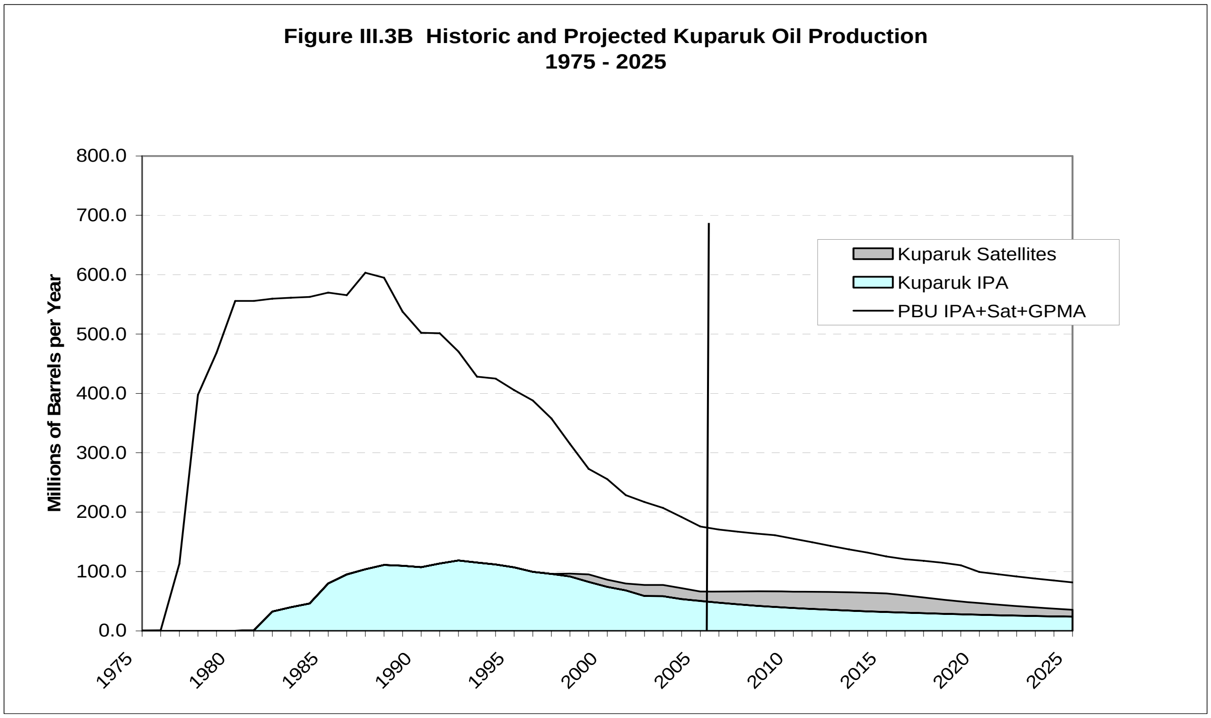
[4] Includes Liberty and other known onshore and offshore.

[5] Based on U.S.G.S. estimates.

Sources: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by FIeld and Pool" (monthly reports)
and Alaska Department of Revenue (forecast)

North Slope (Millions of Barrels per Year)



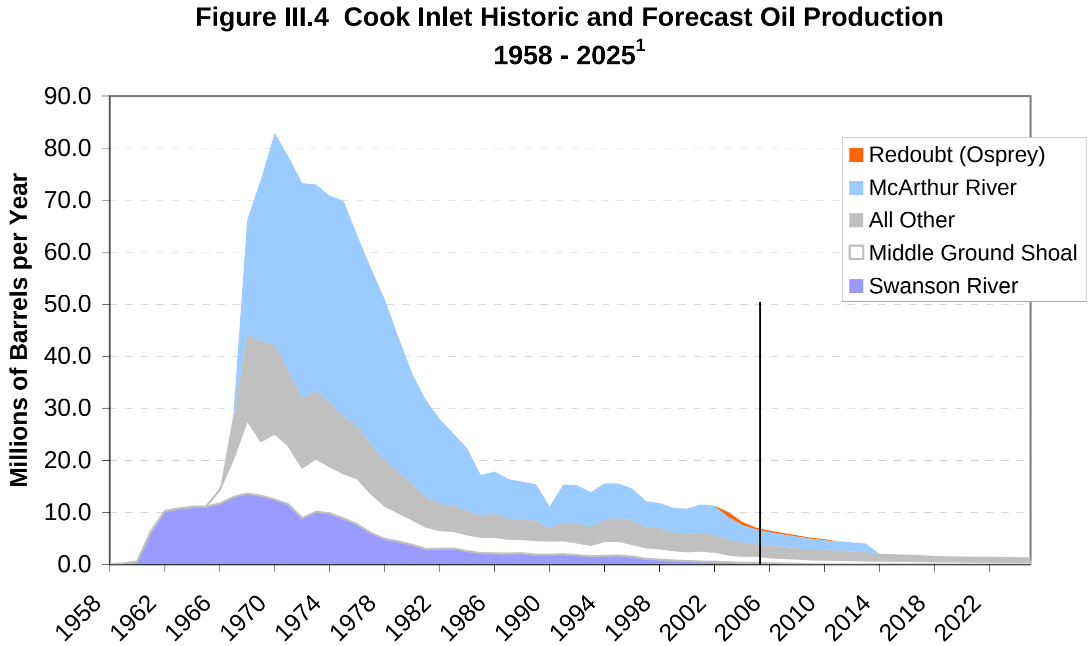


Note:
Figures III.3A and III.3B correspond to Table III.7.

Cook Inlet (Millions of Barrels per Year)

	Beaver Creek	Granite Point	McArthur River	Middle Ground Shoal	Redoubt (Osprey)	Swanson River	Trading Bay	West McArthur River	Kenai and North Trading Ba	TOTAL OIL and NGL[2]
1958	-	-	-	-	-	0.036	-	-	-	0.036
1959	-	-	-	-	-	0.187	-	-	-	0.187
1960	-	-	-	-	-	0.558	-	-	-	0.558
1961	-	-	-	-	-	6.327	-	-	-	6.327
1962	-	-	-	-	-	10.259	-	-	-	10.259
1963	-	-	-	-	-	10.740	-	-	-	10.740
1964	-	-	-	-	-	11.054	-	-	-	11.054
1965	-	0.002	0.001	0.027	-	11.099	0.002	-	-	11.131
1966	-	-	0.003	2.649	-	11.712	-	-	-	14.364
1967	-	7.052	0.749	7.404	-	12.980	0.727	-	0.002	28.914
1968	-	13.131	21.782	14.134	0.002	13.623	3.292	-	0.185	66.149
1969	-	9.183	31.301	10.467	-	13.221	5.626	-	4.312	74.110
1970	-	7.522	40.591	12.719	-	12.471	6.374	-	3.267	82.944
1971	-	5.577	41.130	11.304	-	11.543	6.753	-	2.030	78.337
1972	0.002	4.663	41.344	9.719	-	8.908	6.058	-	2.555	73.249
1973	0.416	4.767	39.545	10.239	-	10.162	5.854	-	2.023	73.006
1974	0.375	4.237	39.799	9.001	-	9.861	5.468	-	2.127	70.868
1975	0.322	4.361	41.520	8.670	-	8.843	4.629	-	1.531	69.876
1976	0.302	4.471	36.463	8.864	-	7.681	4.296	-	1.097	63.174
1977	0.276	4.711	33.968	7.617	-	6.067	3.350	-	0.970	56.959
1978	0.223	4.867	30.953	6.382	-	4.935	2.789	-	0.798	50.947
1979	0.211	4.613	25.981	5.545	-	4.424	2.298	-	0.609	43.681
1980	0.214	4.394	21.306	4.854	-	3.788	1.800	-	0.372	36.728
1981	0.180	3.975	18.506	4.291	-	2.986	1.440	-	0.235	31.613
1982	0.182	3.467	16.255	3.573	-	3.047	1.253	-	0.132	27.909
1983	0.170	3.550	13.896	3.381	-	3.062	0.968	-	0.117	25.144
1984	0.159	3.287	12.024	3.238	-	2.556	1.000	-	0.080	22.344
1985	0.146	3.052	7.648	3.098	-	2.191	0.919	-	0.113	17.167
1986	0.158	3.169	8.170	3.211	-	2.109	0.828	-	0.220	17.865
1987	0.185	2.803	7.571	2.834	-	2.089	0.690	-	0.246	16.418
1988	0.141	2.677	7.305	2.742	-	2.160	0.691	-	0.195	15.911
1989	0.227	2.275	6.955	2.769	-	1.899	1.085	-	0.179	15.389
1990	0.212	1.462	4.265	2.688	-	1.897	0.522	-	0.121	11.167
1991	0.179	2.064	7.247	2.670	-	1.985	1.048	0.002	0.168	15.363
1992	0.175	2.522	7.397	2.423	-	1.792	0.856	0.002	0.030	15.197
1993	0.153	2.488	6.636	2.160	-	1.594	0.742	0.098	-	13.871
1994	0.140	2.209	7.091	2.785	-	1.695	0.743	0.921	-	15.584
1995	0.132	2.580	6.622	2.823	-	1.729	0.722	0.922	-	15.530
1996	0.125	2.556	6.102	2.396	-	1.540	0.589	1.296	-	14.604
1997	0.119	2.432	5.059	2.223	-	1.077	0.602	0.645	-	12.157
1998	0.103	2.079	4.817	2.156	-	0.920	0.700	1.037	-	11.812
1999	0.100	1.787	4.697	1.968	-	0.794	0.645	0.914	-	10.905
2000	0.092	1.742	4.822	1.894	0.002	0.638	0.637	0.893	-	10.720
2001	0.085	1.620	5.353	2.032	0.001	0.609	0.574	1.222	-	11.497
2002	0.079	1.527	5.510	1.959	0.046	0.477	0.666	1.018	-	11.284
2003	0.076	1.440	4.323	1.497	0.911	0.425	0.537	0.849	-	10.059
2004	0.068	1.433	3.373	1.323	0.559	0.320	0.462	0.669	-	8.208
2005	0.061	1.263	2.895	1.318	0.312	0.330	0.414	0.517	-	7.110
2006	0.085	1.285	2.643	1.192	0.233	0.207	0.413	0.440	-	6.496
2007	0.081	1.280	2.399	1.106	0.261	0.152	0.399	0.378	-	6.058
2008	0.078	1.236	2.204	1.032	0.232	0.124	0.387	0.332	-	5.624
2009	0.075	1.196	2.042	0.967	0.211	-	0.375	0.296	-	5.161
2010	0.072	1.160	1.905	0.910	0.184	-	0.363	0.267	-	4.862
2011	0.070	1.128	1.788	0.858	-	-	0.353	0.243	-	4.439
2012	0.068	1.099	1.685	0.812	-	-	0.343	0.223	-	4.229
2013	0.065	1.072	1.594	0.771	-	-	0.333	0.206	-	4.041
2014	0.063	1.047	-	0.733	-	-	-	0.191	-	2.034
2015	0.061	1.024	-	0.699	-	-	-	0.179	-	1.963
2016	0.059	1.003	-	0.668	-	-	-	0.168	-	1.897
2017	0.058	0.983	-	0.639	-	-	-	0.158	-	1.837
2018	0.056	0.964	-	0.612	-	-	-	-	-	1.633
2019	0.055	0.947	-	0.588	-	-	-	-	-	1.589
2020	0.053	0.930	-	0.565	-	-	-	-	-	1.549
2021	0.052	0.915	-	0.544	-	-	-	-	-	1.511
2022	0.050	0.900	-	0.525	-	-	-	-	-	1.475
2023	0.049	0.886	-	0.507	-	-	-	-	-	1.442
2024	0.048	0.873	-	0.490	-	-	-	-	-	1.411
2025	0.047	0.860	-	0.474	-	-	-	-	-	1.381

Cook Inlet (Millions of Barrels per Year)



Notes (from previous page):

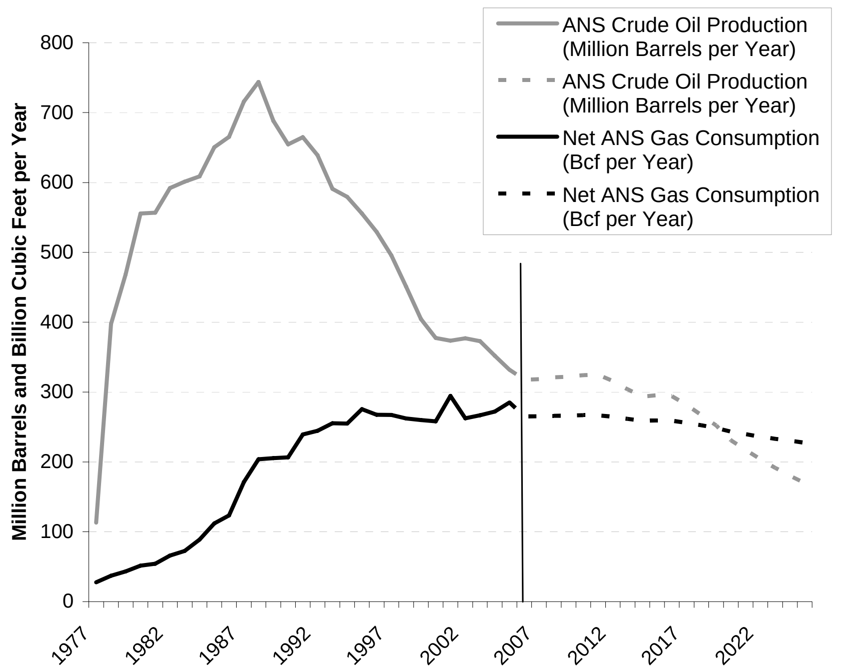
[1] Forecast horizon 2006-35; forecast based on field-by-field economic assessment prepared by Alaska Department of Revenue. Figure IV.4 (shown to 2025) corresponds to Table IV.8.

Source: Historic data: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool" (monthly reports). Forecast prepared by Alaska DNR.

North Slope

Year	Net Gas Consumption on the North Slope (Bcf per Year)
2006	265.2
2007	265.3
2008	266.0
2009	266.2
2010	266.8
2011	266.9
2012	264.6
2013	261.7
2014	259.0
2015	259.5
2016	259.2
2017	256.0
2018	252.3
2019	248.5
2020	243.1
2021	239.6
2022	236.2
2023	233.1
2024	230.3
2025	227.6

Figure III.5 Forecast of Net ANS Gas Consumption for Lease Operations and Local Gas Sales



Notes: Net ANS Gas consumption refers to gas produced for lease operations and for local sales to North Slope utilities and pipelines. Most gas produced is re-injected into the field for enhanced oil recovery and recycling. Historic quantities of injected gas are shown in Table IV.5. Gas injection is expected to remain fairly constant at about 8 Bcf per day for the foreseeable future. Many factors influence the quantity of gas used for lease operations, including demand for power, oil field compression and pipeline pump stations. New field and satellite development will, to some extent, offset the decline in gas used for lease operations and pipelines in mature fields. Also, many North Slope fields are "gas constrained" meaning that oil production is limited by gas handling capacity.

The forecast of net ANS gas consumption is based on an ordinary least squares regression of the historic relationship between net ANS gas consumption and ANS crude oil production, taking into account major additions to gas handling capacity in 1990 (GHX1), 1995 (GHX2), and 2001 (MIX). Detailed estimation results are available on request.

Cook Inlet (Billion Cubic Feet per Year)

Year	Beluga River[1]	McArthur River (TBU)[1]	North Cook Inlet[1]	Swanson River[1, 2]	Kenai/ Cannery Loop[1, 3]	Ninilchik/ Deep Creek[1]	All Other[1, 4]	Under-Development[5]	TOTAL NET[6]
1958	-	-	-	0.0	-	-	-	-	0.0
1959	-	-	-	0.0	-	-	-	-	0.0
1960	-	-	-	-	-	-	-	-	-
1961	-	-	-	1.3	0.2	-	-	-	1.5
1962	-	-	-	1.8	1.5	-	0.0	-	3.3
1963	0.0	-	-	1.2	3.1	-	0.0	-	4.3
1964	0.1	-	-	1.6	4.5	-	0.1	-	6.2
1965	-	-	-	1.1	6.0	-	0.2	-	7.3
1966	-	-	-	-	33.4	0.0	1.5	-	12.4
1967	0.2	0.2	-	-	39.6	-	9.0	-	24.7
1968	2.0	6.2	-	-	46.0	-	20.2	-	41.5
1969	3.0	14.2	7.9	-	59.3	-	22.3	-	80.3
1970	3.6	19.7	40.9	-	80.6	-	23.1	-	145.2
1971	4.1	19.3	45.0	-	72.2	-	22.4	-	155.7
1972	4.1	19.7	41.6	-	76.0	-	15.8	-	148.5
1973	4.9	19.1	42.7	-	71.3	-	13.1	-	137.8
1974	5.6	19.6	44.2	-	68.5	-	11.0	-	143.0
1975	7.0	21.5	45.6	-	77.2	-	10.6	-	154.6
1976	11.2	19.0	45.1	-	79.5	-	10.3	-	153.3
1977	13.4	19.7	47.2	-	81.9	-	10.8	-	161.6
1978	14.3	18.6	46.8	-	97.3	-	9.8	-	179.1
1979	17.0	16.6	49.4	-	97.0	-	8.6	-	184.7
1980	17.0	15.6	41.5	-	98.8	-	8.1	-	179.3
1981	17.2	15.2	49.5	-	105.8	-	7.7	-	192.9
1982	18.7	16.2	45.4	-	115.9	-	7.3	-	196.1
1983	18.1	14.4	47.9	2.2	113.0	-	15.2	-	210.7
1984	19.8	15.1	47.0	3.0	110.1	-	16.7	-	211.7
1985	22.6	10.7	45.8	3.1	115.8	-	18.9	-	216.9
1986	25.4	13.6	43.8	1.5	82.5	-	24.6	-	191.3
1987	24.0	13.3	42.9	(3.0)	90.0	-	22.1	-	189.3
1988	25.6	16.7	45.0	2.9	85.7	-	20.8	-	196.6
1989	30.1	31.0	45.3	(3.7)	77.0	-	18.7	-	198.4
1990	39.5	51.5	45.0	(1.6)	50.9	-	20.2	-	205.5
1991	38.5	61.2	44.7	(0.1)	37.9	-	20.9	-	203.1
1992	36.5	70.1	44.4	(0.2)	34.8	-	18.8	-	204.5
1993	31.7	62.5	45.5	4.6	33.3	-	22.7	-	200.5
1994	34.2	50.0	52.7	27.3	25.2	-	24.6	-	214.0
1995	35.6	54.9	53.5	28.7	22.0	-	19.6	-	214.5
1996	36.9	67.3	56.0	33.3	15.4	-	14.1	-	223.0
1997	35.0	66.8	52.5	28.7	15.8	-	15.9	-	214.7
1998	33.4	73.8	54.0	25.8	12.8	-	15.2	-	215.0
1999	36.0	69.0	51.6	29.8	12.8	-	13.4	-	212.6
2000	38.7	65.0	52.8	29.7	17.1	-	12.4	-	215.8
2001	41.8	62.3	55.5	22.0	24.1	-	13.9	-	219.7
2002	44.0	51.5	54.6	12.8	27.2	-	19.9	0.0	210.0
2003	56.3	39.2	47.9	6.6	34.7	3.0	17.4	3.0	208.2
2004	57.6	34.4	41.0	5.8	37.9	12.7	18.7	-	208.1
2005	55.9	30.8	45.6	3.1	36.8	18.0	18.7	-	208.8
2006	57.1	26.9	42.7	2.3	37.7	17.8	20.6	1.1	206.2
2007	57.0	19.6	37.1	1.2	31.1	12.3	14.5	16.8	189.6
2008	57.0	15.0	32.3	0.5	25.4	9.2	10.8	20.9	171.0
2009	49.1	11.5	28.0	1.5	20.7	6.9	8.2	26.1	151.8
2010	46.3	8.8	24.3	1.1	16.9	5.2	6.5	24.6	133.7
2011	39.7	6.8	21.1	0.8	13.9	4.0	5.2	23.5	114.9
2012	34.1	5.3	18.4	0.6	11.4	3.1	4.3	22.9	100.1
2013	29.2	4.1	15.9	0.4	9.3	2.4	3.6	21.1	86.0
2014	25.0	3.2	13.9	0.3	7.6	1.9	3.0	18.0	72.9
2015	21.5	2.5	12.0	0.2	6.3	1.5	2.4	15.5	62.0
2016	18.5	1.9	10.5	0.2	5.2	1.2	2.0	13.5	53.0
2017	15.8	1.5	9.1	0.1	4.3	1.0	1.7	11.2	44.6
2018	13.5	1.1	7.9	0.1	3.5	0.9	1.5	9.2	37.7
2019	11.6	0.8	6.9	0.1	2.9	0.7	1.3	7.7	32.0
2020	10.0	0.6	6.0	0.0	2.4	0.6	1.1	6.4	27.1
2021	8.5	0.4	5.2	0.0	2.0	0.6	1.0	5.4	23.1
2022	7.3	0.3	4.5	-	1.6	0.5	0.6	4.5	19.4
2023	6.3	-	3.9	-	1.3	0.4	0.6	4.1	16.6
2024	5.4	-	3.4	-	1.1	0.4	0.5	3.4	14.2
2025	4.6	-	2.9	-	0.9	0.3	0.5	2.8	12.1

Notes:

[1] Production forecasts based on decline and material balance analysis of proved, developed reserves. Forecast horizon is 2035; shown through 2025 in table and related chart.

[2] Net gas injections reported for Swanson River 1966-82.

[3] Includes Kenai pools: Sterling #3, 4, 5.1, 5.2, 6, and Upper Tyonek-Beluga, Tyonek, and Beluga Undefined; plus all Cannery Loop pools.

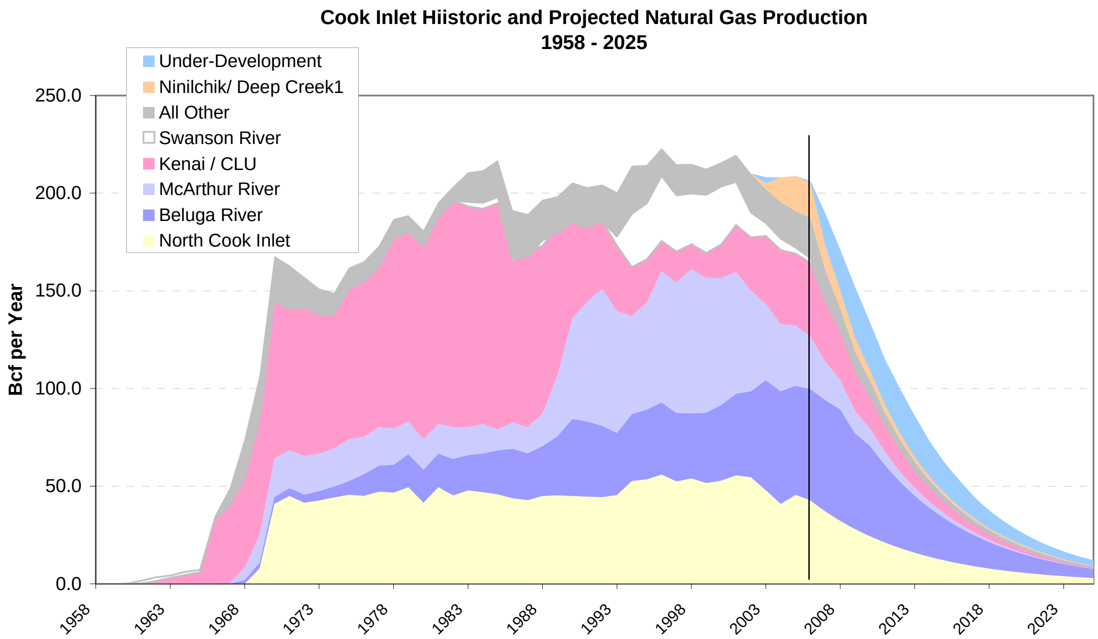
[4] All Other includes proved developed producing reserves of Albert Kaloa, Beaver Creek, Granite Point, Ivan River, Lewis River, Pretty Creek, Stump Lake, Lone Creek, MGS, Moquawkie, Nicolai Creek, North Fork, North Trading Bay, Redoubt, Sterling, Three-Mile Creek, Trading Bay, West Foreland, West Fork, West McArtur River and Wolf Lake.

[5] Includes DNR estimates of non-producing, probable reserves based primarily on gas prospectivity in the Kasilof, Nikolaevsk, and North Fork exploration areas. Also includes probable reserves estimates for the developed-producing fields: Deep Creek, McArthur River, Ninilchik, NCIU, and Three-Mile Creek.

[6] Total does not include Tyonek Deep project.

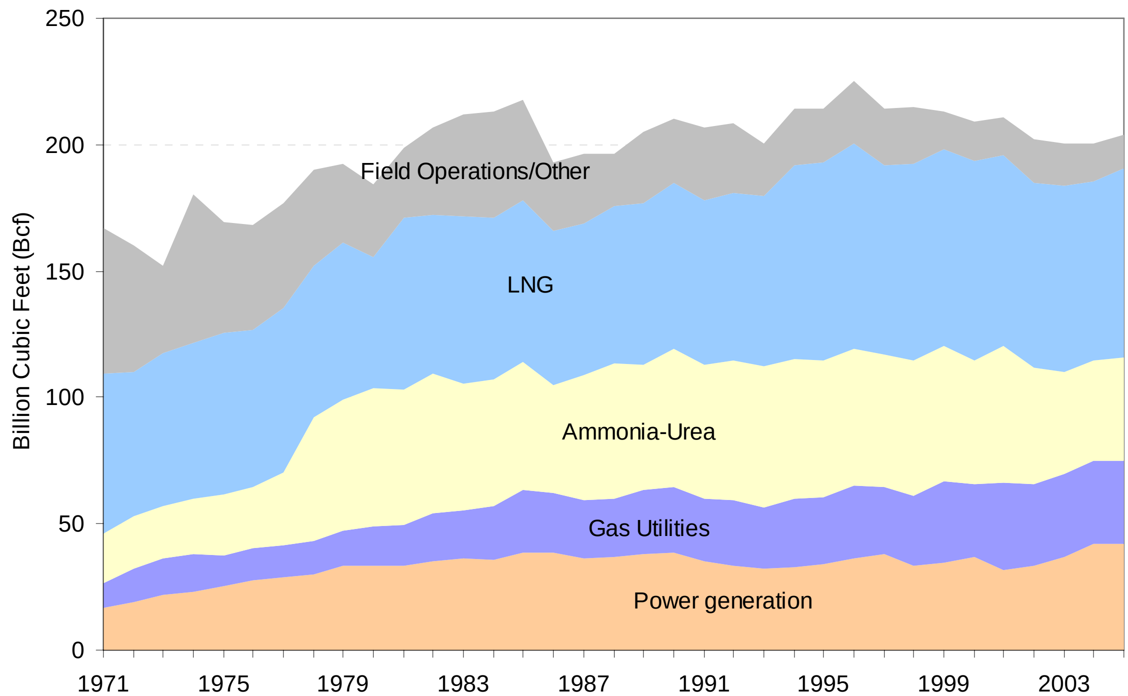
Source of Historic Data 1985-2005: Alaska Oil and Gas Conservation Commission, "Alaska Production Summary by Field and Pool", Monthly Reports.

Cook Inlet (Billion Cubic Feet per Year)



Note:
Figure III.6 corresponds to Table III.9.

Cook Inlet (Billion Cubic Feet per Year)



	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Average 1990-96	Average 1997-00	Average 2001-05
Power generation	38.9	35.3	33.5	32.0	33.0	34.0	36.1	37.7	33.4	34.6	36.8	31.6	33.7	36.6	42.1	41.8	34.5	35.7	37.2
Gas Utilities	25.9	24.7	25.9	24.2	26.6	26.7	29.0	26.6	27.4	32.0	29.1	34.9	32.0	33.0	33.1	33.3	25.7	28.9	33.3
LNG	65.1	65.4	66.2	67.3	76.7	78.1	81.4	75.4	78.1	78.0	78.5	75.2	73.0	74.0	71.1	74.9	69.8	78.3	73.6
Ammonia-Urea	54.8	52.6	55.0	56.2	55.4	54.0	54.0	52.3	53.6	53.9	49.0	53.9	46.3	40.2	39.5	40.4	54.7	52.6	44.1
Field Ops and Other	25.8	28.6	27.6	20.7	22.3	21.6	24.8	22.4	22.5	14.9	15.5	15.2	17.2	16.6	14.5	13.5	24.4	20.0	15.4
	210.4	206.6	208.2	200.5	214.0	214.5	225.4	214.5	215.0	213.4	208.9	210.8	202.2	200.4	200.2	203.9	209.0	215.4	203.5
Power generation	18.5%	17.1%	16.1%	16.0%	15.4%	15.8%	16.0%	17.6%	15.5%	16.2%	17.6%	15.0%	16.7%	18.3%	21.0%	20.5%	16.5%	16.6%	18.3%
Gas Utilities	12.3%	12.0%	12.5%	12.1%	12.4%	12.5%	12.9%	12.4%	12.8%	15.0%	13.9%	16.6%	15.8%	16.5%	16.5%	16.3%	12.3%	13.4%	16.3%
LNG	31.0%	31.7%	31.8%	33.6%	35.8%	36.4%	36.1%	35.1%	36.3%	36.5%	37.6%	35.7%	36.1%	36.9%	35.5%	36.7%	33.4%	36.3%	36.2%
Ammonia-Urea	26.0%	25.5%	26.4%	28.0%	25.9%	25.2%	24.0%	24.4%	24.9%	25.3%	23.4%	25.6%	22.9%	20.1%	19.7%	19.8%	26.1%	24.4%	21.6%
Field Ops and Other	12.3%	13.8%	13.2%	10.3%	10.4%	10.1%	11.0%	10.4%	10.4%	7.0%	7.4%	7.2%	8.5%	8.3%	7.2%	6.6%	11.7%	9.3%	7.6%

Section Four

Royalty Production and Revenue

Introduction

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 noncompetitive 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 remit cash payments on a monthly basis for the 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 Alaska's refining industry by providing long-term supplies of oil to each of the state's four refineries. Over the years, state RIK sales 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 Company merged with the Tesoro Petroleum Company. Tesoro subsequently built a new refinery in Nikiski on the Kenai Peninsula next to Chevron's refinery, built in 1964. Between 1969 and 1985 the state sold all of its Cook Inlet royalty oil to the Tesoro refinery. By 1980, the production decline in 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 Cook Inlet RIK oil to the Chinese Petroleum Company. These volumes were produced from fields on the west side of the 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 1991 deliveries under the last Chinese Petroleum contract were halted under force majeure following the December 1989 eruption of the Mount Redoubt volcano. There have been no Cook Inlet RIK sales since (See Table IV.8.).

[1] The state also sold 10.4 Bcf of RIK gas in a contract to Alaska Pipeline Company (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 percent, 50 percent, and 25 percent, respectively, of Prudhoe Bay Unit RIK gas. The contracts terminated in May 1978 when the proposed El Paso Trans-Alaska Gas Pipeline did not receive federal certification.

North Slope

Over the past 25 years, the state has held nine RIK sales involving portions of its Alaska North Slope (ANS) royalty oil production. These sales are summarized in Table IV.7 and Figure IV.3. In 1976, the state signed a six-year contract with Golden Valley Electric Association (GVEA), the electric utility in Fairbanks, to sell approximately 3,300 barrels of ANS crude 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 Alaska) in exchange for refined fuel. The state subsequently sold RIK ANS to GVEA in two other contracts until 1992. As in the first contract, GVEA traded these volumes with Mapco.

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

In September 2003, the state negotiated a temporary contract with Williams for the period January 1, 2004, through March 31, 2004. The state also negotiated a new 10-year contract with Flint Hills Resources Alaska, LLC (FHR), signed by the Governor on March 9, 2004, enabling FHR to take over the Williams' North Pole refinery on March 31. Deliveries of royalty oil under the new RIK contract began April 1, 2004. The state sold approximately 62,476 barrels per day to FHR, or more than 54 percent of the total royalty oil produced on the North Slope for the period January 1 through December 31, 2005.

The contract contained special conditions which serve as additional consideration for FHR's purchase of the state's royalty oil. FHR will maintain gasoline wholesale rack price parity between Anchorage and Fairbanks. FHR will invest approximately $100 million to install clean fuels processing equipment and facilities in the North Pole Refinery and/or elsewhere in Alaska, fulfill and enhance the previous commitments made by Williams to the Government Hill Community Council in Anchorage to address concerns about gasoline storage tanks near Government Hill and undertake additional projects to improve the Anchorage Tank Farm Facility. FHR will also continue to ship refined products to Anchorage via the Alaska Railroad, (FHR shipments represented 48 percent of the total freight loadings for the Alaska Railroad for 2005). In Fairbanks, FHR will study the use and viability of the hydrant fueling system at the Fairbanks International airport (FIA), concentrate on promoting FIA to cargo carriers, evaluate and possibly upgrade FIA fuel distribution facilities, and charge a jet fuel customer in Fairbanks the same or lower price as FHR charges that same customer in Anchorage. FHR met all of these conditions for 2005.

Tesoro has been an important 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. In one of these contracts Chevron took RIK barrels from Tesoro in exchange. Petro Star Inc. 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 1980s as part of a program to routinely offer RIK short-term contracts. Winners of these sales included in-state refineries but also several refineries located outside the state. Many of these buyers were also ANS producers. About 46 million barrels of Alaska North Slope RIK crude oil were sold in these auctions but the program was interrupted after the general collapse of oil prices in the mid-1980s. 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. The sale was subsequently held in August 2000 but no bids were offered.

Royalty-in-Kind Policy

The earliest RIK sales, notably Tesoro's first Cook Inlet contract, the first GVEA contract, and the Alpetco contract, generated 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? What kind of oversight should be required? The debates of these questions led to the present program as set out in statutes and regulations.

When disposing royalty oil or gas, the commissioner is bound by AS 38.05.182 and AS 38.05.183. Further, 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 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 royalty rather than take 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 of 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.

Table IV.1 Recent Royalty Oil Production and Revenues

North Slope, 1996-2005

	Badami	Colville River Unit	Duck Island Unit	Kuparuk River Unit	Milne Point Unit	Northstar Unit	Prudhoe Bay Unit RIV	Prudhoe Bay Unit RIK	TOTAL Prudhoe Bay Unit	**TOTAL North Slope**
Production (Thousands of Barrels)										
1996	-	-	3,679.6	11,366.3	1,800.6	-	19,133.3	25,081.1	44,214.3	61,060.8
1997	-	-	3,324.4	10,978.3	2,657.0	-	18,399.6	26,139.6	44,539.2	61,498.8
1998	106.1	-	2,692.5	10,886.2	2,833.4	-	11,810.5	27,981.6	39,792.1	56,310.2
1999	179.2	1.3	2,263.3	10,822.0	2,699.2	-	15,508.5	19,070.7	34,579.2	50,544.1
2000	144.6	196.6	1,943.1	9,897.9	2,613.9	-	13,053.5	19,290.3	32,343.8	47,140.0
2001	104.0	2,785.5	1,696.9	9,076.4	2,687.9	212.9	13,643.5	15,187.0	28,830.6	45,394.3
2002	87.0	3,403.4	1,483.5	8,944.0	2,570.7	4,009.3	11,789.3	15,509.6	27,298.9	47,796.8
2003	42.1	3,777.1	1,535.1	8,916.0	2,569.5	5,236.7	5,480.7	20,638.8	26,119.5	48,196.7
2004	-	3,642.4	1,220.2	8,255.5	2,572.6	5,664.9	5,638.7	18,480.5	24,119.2	45,474.8
2005	22.2	4,262.1	1,073.5	7,636.6	2,198.4	5,065.9	5,539.2	16,551.2	22,090.4	42,349.2
Revenues (Thousands of Dollars)										
1996	-	-	$57,988	$188,462	$28,404	-	$296,101	$436,377	$732,478	$1,007,332
1997	-	-	$42,866	$150,137	$33,777	-	$242,341	$383,701	$626,042	$852,822
1998	-	-	$18,147	$82,772	$18,608	-	$69,281	$227,032	$296,313	$415,841
1999	-	$57	$26,461	$136,802	$31,596	-	$170,204	$259,246	$429,450	$624,366
2000	$2,612	$4,539	$42,350	$220,539	$56,730	-	$275,928	$461,464	$737,392	$1,064,162
2001	$1,051	$47,972	$31,796	$160,694	$47,356	$1,584	$236,464	$279,804	$516,268	$806,722
2002	$108	$62,818	$27,128	$173,379	$48,818	$75,797	$201,726	$320,378	$522,104	$910,151
2003	$46	$89,684	$35,753	$211,369	$61,255	$123,753	$114,558	$507,952	$622,509	$1,144,385
2004	-	$122,667	$38,674	$266,699	$82,258	196,698	$172,637	$631,864	$804,501	$1,511,496
2005	$876	$201,866	$54,197	$346,186	$99,424	243,199	$239,535	$805,939	$1,045,474	$1,991,222

Revenues include principal and interest from revisions and settlements in the year received.

Cook Inlet & Statewide, 1996-2005

	Granite Point Field	South Granite Point Unit	Cannery Loop Field	North Middle Ground Shoal	Middle Ground Shoal	South Middle Ground Shoal	Trading Bay Field	Trading Bay Unit	West McArthur Unit	Redoubt Unit	Un-defined	**TOTAL Cook Inlet**	**TOTAL STATE**
Production (Thousands of Barrels)													
1996	320.3	-	0.01	50.6	216.5	32.5	73.6	762.7	162.0	-	-	1,618.2	62,679.0
1997	303.5	-	-	42.0	150.6	26.8	75.1	632.4	80.6	-	-	1,311.0	62,809.8
1998	259.8	-	-	44.7	196.0	28.8	87.1	602.4	116.2	-	-	1,335.0	57,645.2
1999	172.4	51.0	-	38.2	181.9	24.6	82.7	587.2	114.3	-	-	1,252.2	51,796.3
2000	119.2	98.5	-	43.5	170.5	22.8	79.6	602.8	111.6	-	-	1,248.6	48,388.5
2001	109.3	92.9	-	39.7	194.4	19.8	72.3	671.1	152.9	-	-	1,352.4	46,746.7
2002	105.2	86.1	-	27.1	197.1	20.8	76.0	704.3	120.3	2.3	-	1,339.2	49,136.0
2003	98.8	79.8	-	11.8	175.4	-	68.7	538.6	105.9	45.5	1.0	1,125.4	49,322.1
2004	84.0	77.1	-	-	165.3	-	58.0	424.6	83.7	28.0	-	920.5	46,395.3
2005	75.2	67.5	-	-	164.7	-	51.8	340.3	64.6	15.6	-	779.7	43,128.9
Revenues (Thousands of Dollars)													
1996	$5,825	-	-$6	$1,000	$4,266	$613	$1,188	$13,330	$2,257	-	-	$28,474	$1,035,805
1997	$5,175	-	-	$764	$3,655	$490	$1,192	$10,561	$1,795	-	-	$23,633	$876,456
1998	$2,813	-	-	$544	$2,244	$346	$853	$5,902	$1,107	-	-	$13,809	$429,650
1999	$2,090	$1,388	-	$662	$3,073	$406	$1,261	$8,917	$1,583	-	-	$19,380	$643,746
2000	$4,201	$3,840	-	$1,491	$4,647	$821	$2,632	$17,073	$2,790	-	-	$37,495	$1,101,657
2001	$2,515	$2,051	-	$959	$4,338	$476	$1,522	$13,908	$2,941	-	-	$28,710	$835,432
2002	$2,337	$1,850	-	$619	$5,428	$494	$1,609	$14,992	$2,680	$54	-	$30,062	$940,214
2003	$2,633	$2,249	-	$349	$5,103	-	$1,876	$14,693	$2,736	$1,140	$19	$30,798	$1,175,183
2004	$3,066	$2,764	-	-	$11,544	-	$2,021	$14,732	$2,807	$900	-	$37,835	$1,549,331
2005	$3,712	$3,354	-	-	$8,710	-	$2,509	$16,641	$3,089	$802	-	$38,819	$2,030,041

Revenues include principal and interest from revisions and settlements in the year received.

Table IV.2 Recent Royalty Oil Production by Lessee

North Slope

Production (Thousands of Barrels)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Amerada Hess	-	-	-	-	-	-	-	-	-	-
Amoco	360	297	237	199	119	-	-	-	-	-
Anadarko	-	-	-	0	43	613	749	831	801	938
Arco	12,394	11,120	9,522	10,729	-	-	-	-	-	-
Armstrong Resources	-	-	-	-	-	-	-	0	0	1
BPAmerica Prod Co.	-	-	-	-	-	-	-	165	-	-
BP	18,375	16,683	13,595	14,233	11,869	11,075	14,546	13,898	9,555	8,527
Chevron	116	99	64	91	77	81	117	66	60	59
CIRI	36	30	1	-	-	-	-	-	-	-
ConocoPhillips AK	-	-	-	-	-	-	11,244	9,250	9,145	7,910
DOYON	7	6	5	4	4	3	3	3	1	0
Exxon	6,364	5,571	3,563	4,815	-	-	-	-	-	-
ExxonMobil	-	-	-	-	4,596	5,287	-	-	-	-
ExxonMobil AK Prod	-	-	-	-	-	-	4,282	1,918	1,910	1,886
Forcenergy/Forest Oil	-	5	3	4	2	2	2	1	1	1
Kerr McGee	-	-	-	-	-	-	-	-	1	1
Louisiana Land & Expl.	5	-	-	-	-	-	-	-	-	-
Mapco 1978 Contract	13,037	12,652	11,148	12,442	12,718	12,522	12,167	12,583	-	-
Mapco 1997 Contract	-	466	4,451	-	-	-	-	-	-	-
Marathon	6	-	-	-	-	-	-	-	-	-
Mobil	280	237	155	195	-	-	-	-	-	-
NANA	22	18	14	12	11	8	8	8	4	0
Oxy	155	208	224	212	189	-	-	-	-	-
Petrofina	-	-	32	54	43	31	-	-	-	-
Phillips	231	190	113	151	10,201	12,482	-	-	-	-
Phillips Alpine Alaska	-	-	-	-	-	-	749	831	352	-
Pioneer	-	-	-	-	-	-	-	0	-	-
Shell	7	-	-	-	-	-	-	-	-	-
Tesoro	14,346	13,022	11,498	-	-	-	-	-	-	-
Texaco	63	52	31	41	35	38	18	-	-	-
TotalFina ELF	-	-	-	-	-	-	-	-	-	-
Union Texas Petroleum	-	-	-	-	-	-	-	-	-	-
Unocal	976	842	771	732	659	587	570	586	468	227
Williams 98 Conts	-	-	884	6,628	6,572	2,665	3,342	8,056	5,582	-
Flint Hills	-	-	-	-	-	-	-	-	17,632	22,797
XTO Energy	-	-	-	-	-	-	-	-	2	2
Undefined	-	-	-	-	-	-	-	-	1	-
North Slope TOTAL	**66,779**	**61,499**	**56,312**	**50,544**	**47,140**	**45,394**	**47,797**	**48,197**	**45,516**	**42,349**

Cook Inlet

Production (Thousands of Barrels)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Conoco Phillips AK	-	-	-	-	-	-	-	1	-	-
Cross Timbers/XTO	-	-	-	182	170	194	197	175	165	165
Devon	-	-	-	-	-	-	-	0	-	-
Forcenergy/Forest Oil	-	377	436	425	428	495	488	436	337	264
Marathon	386	-	-	-	-	-	-	-	-	-
Mobil/Exxon Mobil AK Prod	100	110	91	76	74	70	65	60	58	51
Shell	216	151	196	-	-	-	-	-	-	-
Stewart	162	30	-	-	-	-	-	-	-	-
Unocal	754	643	612	569	576	593	590	454	360	301
Cook Inlet TOTAL	**1,618**	**1,311**	**1,335**	**1,252**	**1,249**	**1,352**	**1,339**	**1,125**	**921**	**780**

Revenues include principal and interest from revisions and settlements in the year received.

Table IV.3 Recent Royalty Oil Revenue by Lessee

North Slope

Revenues (Thousands of Dollars)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Amerada Hess	-$118	$34	-	-	-	-	-	-	-	-
Amoco	$5,403	$3,674	$1,556	$2,404	$2,562	-$0	-	-	-	-
Anadarko	-	-	-	$12	$982	$10,374	$14,180	$20,057	$27,427	$45,375
Arco	$190,182	$155,281	$72,786	$135,879	-	-	-	-	-	-
Armstrong Resources	-	-	-	-	-	-	-	$4	-	$26
BPAmerica Prod Co.	-	-	-	-	-	-	-	$3,934	-	-
BP	$256,839	$216,022	$85,232	$158,955	$249,682	$208,250	$267,287	$325,241	$301,848	$391,141
Chevron	$1,712	$1,274	$368	$1,044	$1,608	$1,422	$2,070	$1,437	$1,745	$2,650
CIRI	$518	$423	$12	-	-	-	$1,549	$0	-	-
ConocoPhillips AK	-	-	-	-	-	-	$211,239	$214,806	$297,445	$353,413
DOYON	$103	$83	$41	$39	$82	$54	$44	$64	$40	$4
Exxon	$90,516	$71,707	$19,733	$52,342	-	-	-	-	-	-
ExxonMobil	-	-	-	-	$98,415	$83,945	-	-	-	-
ExxonMobil AK Prod	-	-	-	-	-	-	$69,780	$37,737	$54,093	$81,549
Forcenergy/Forest Oil	-	$63	$17	$43	$50	$38	$37	$18	$29	$43
Kerr McGee	-	-	-	-	-	-	-	-	$22	$60
Louisiana Land & Expl.	$68	-	-	-	-	-	-	-	-	-
Mapco 1978 Contract	$207,138	$185,000	$90,752	$166,427	$304,389	$223,123	$247,246	$316,072	-$179	-
Mapco 1997 Contract	-	$6,032	$38,590	-$60	$90	$1,075	-	-	-	-
Marathon	$84	$1	-	-	-	-	-	-	-	-
Mobil	$4,035	$3,026	$851	$2,166	-	-	-	-	-	-
NANA	$310	$255	$122	$120	$220	$163	$131	$221	$121	$12
Oxy	$2,248	$2,778	$1,533	$2,626	$4,290	-	-	-	-	-
Petrofina	-	-	$168	$616	$807	$284	-	-	-	-
Phillips	$3,175	$2,377	$752	$1,379	$228,306	$211,865	-	-	-	-
Phillips Alpine Alaska	-	-	-	-	-	-	$13,718	$19,628	$10,244	-
Pioneer	-	-	-	-	-	-	-	$10	-	-
Shell	$102	-$5	-	-	-	-	-	-	-	-
Tesoro	$229,239	$192,669	$92,288	$191	-$623	$1,632	$887	-	-	-
Texaco	$880	$664	$149	$398	$842	$653	$270	-	-	-
TotalFina ELF	-	-	-	-	-	-	-	-	-	-
Union Texas Petroleum	-	-	-	$12	-	-	-	-	-	-
Unocal	$14,896	$11,463	$6,013	$9,078	$14,851	$9,868	$10,858	$13,265	$14,250	$8,962
Williams 1998 Contract	-	-	$5,402	$92,688	$157,608	$53,975	$72,245	$196,991	$162,716	-
Flint Hills	-	-	-	-	-	-	-	-	$641,607	$1,107,909
XTO Energy	-	-	-	-	-	-	-	-	$87	$78
Undefined	-	-	-	-	-	-	-	-	$22	-
North Slope TOTAL	**$1,007,332**	**$852,822**	**$416,365**	**$626,358**	**$1,064,162**	**$806,722**	**$911,540**	**$1,149,487**	**$1,511,518**	**$1,991,222**

Cook Inlet

Revenues (Thousands of Dollars)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Conoco Phillips AK	-	-	-	-	-	-	-	$13	-	-
Cross Timbers/XTO	-	-	-	$3,073	$4,647	$4,338	$5,428	$5,103	$6,406	$8,710
Devon	-	-	-	-	-	-	-	$1	-	-
Forcenergy/Forest Oil	-	$6,166	$4,209	$6,296	$10,950	$9,831	$10,522	$11,521	$11,509	$12,867
Marathon	$6,620	-$7	-	-	-	-	-	-	-	-
Mobil/Exxon Mobil AK Prod	$1,810	$1,882	$1,094	$1,165	$1,824	$1,525	$1,348	$1,692	$2,068	$2,511
Shell	$4,266	$3,655	$2,244	-	-	-	-	-	$5,138	-
Stewart	$2,257	$1,104	-	-	-	-	-	-	-	-
Unocal	$13,521	$10,834	$6,262	$8,846	$20,074	$13,016	$12,764	$12,471	$12,714	$14,731
Cook Inlet TOTAL	**$28,474**	**$23,633**	**$13,809**	**$19,380**	**$37,495**	**$28,710**	**$30,062**	**$30,801**	**$37,835**	**$38,819**

Table IV.4 Recent Royalty Gas Production and Revenues

North Slope, 1996-2005

	Duck Island Unit	Kuparuk River Unit	Milne Point Unit	Prudhoe Bay Unit	**TOTAL North Slope**
Production (Thousand Cubic Feet)					
1996	32,446	107,807	9,466	1,467,794	1,617,513
1997	35,605	90,487	26,034	1,337,301	1,489,427
1998	36,255	79,552	27,156	1,178,761	1,321,724
1999	168,919	78,783	27,611	1,092,217	1,367,530
2000	31,785	135,929	27,436	1,061,761	1,256,911
2001	30,780	98,806	28,978	1,341,442	1,500,006
2002	32,108	83,021	29,718	3,711,292	3,856,140
2003	33,191	79,039	28,844	5,707,165	5,848,240
2004	29,424	76,647	29,639	5,260,659	5,396,369
2005	36,976	70,082	29,362	4,872,422	5,008,841
Revenues (Thousands of Dollars)					
1996	$30	$96	$30	$1,318	$1,475
1997	$31	$63	$28	$1,155	$1,278
1998	$28	$32	$24	$950	$1,033
1999	$150	$51	$26	$938	$1,165
2000	$40	$161	$34	$1,156	$1,390
2001	$33	$119	$32	$1,114	$1,298
2002	$37	$79	$34	$3,592	$3,742
2003	$45	$91	$40	$6,508	$6,685
2004	$57	$123	$54	$8,296	$8,529
2005	$87	$163	$72	$10,801	$11,123

Revenues include principal and interest from revisions and settlements in the year received.

Cook Inlet, 1996-2005

	Beluga River Unit	Cannery Loop Unit	South Granite Point Unit	Granite Point Field	Ivan River Unit	Kenai Unit	Lewis River Unit	Nicolai Creek	North Middle Ground Shoal Unit	Middle Ground Shoal
Production (Thousand Cubic Feet)										
1996	2,777,105	122,528	-	109,798	1,167,827	159,084	11,389	-	403	996
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	-
2000	2,913,658	236,492	55,787	73,754	461,437	149,187	16,232	-	72,167	-
2001	3,143,083	318,033	5,491	59,671	667,307	234,786	26,852	32,297	52,739	-
2002	3,313,302	286,118	3,859	34,936	756,028	233,375	111,535	31,792	14,404	
2003	4,236,316	390,962	2,042	10,580	432,649	323,139	71,284	8,464	11,612	-
2004	4,339,069	745,310	596	15,353	289,865	191,573	45,255	18,476		
2005	4,206,401	769,835	-	5,743	213,165	170,820	38,065	5,369		
Revenues (Thousands of Dollars)										
1996	$3,943	$206	-	$180	$1,995	$250	$20	-	$15	$1
1997	$4,598	$325	-	$192	$1,319	$249	$10	-	$24	-
1998	$4,265	$232	$1	$221	$1,071	$157	$16	-	$160	-
1999	$3,783	$272	$30	$82	$758	$294	$36	-	$301	-
2000	$4,657	$483	$58	$215	$5,339	$298	$508	-	$808	-
2001	$6,947	$1,216	$6	$82	$933	$476	$38	$62	$89	-
2002	$7,586	$748	$4	$50	$1,057	$454	$160	$18	$21	
2003	$9,479	$836	$6	$179	$2,904	$701	$335	$17	$60	-
2004	$11,706	$1,984	$1	$44	$814	$460	$126	$38	-	-
2005	$15,257	$2,837	$0	$20	$742	$534	$139	$35	-	-

	South Middle Ground Shoal	North Cook Inlet Unit	Pretty Creek Unit	Spark Platform	Sterling Unit	North Trading Bay Unit	Stump Lake Unit	Trading Bay Field	Trading Bay Unit	Redoubt Unit	Ninilchik Unit	West Mcarthur River Unit	Deep Creek Unit	Three Mile Creek Unit	**TOTAL Cook Inlet**	**TOTAL State**
Production (Thousand Cubic Feet)																
1996	489	6,910,165	41,347	2,814	558	57	44,183	-	7,248,017	-	-	-	-	-	18,596,759	20,214,272
1997	-	6,490,318	53,928	62,872	81	-	30,942	19,031	6,982,452	-	-	-	-	-	17,697,067	19,186,494
1998	-	6,665,243	61,640	85,882	4	-	18,332	-	7,841,950	-	-	-	-	-	18,564,277	19,886,001
1999	-	6,372,036	3,982	28,044	15	-	11,978	-	7,333,019	-	-	-	-	-	17,736,489	19,104,019
2000	-	6,548,758	-	-	4,384	18,632	6,839	-	6,802,700	-	-	-	-	-	17,360,027	18,616,938
2001	-	6,732,002	11,471	-	8,820	-	56	-	6,509,275	-	-	-	-	-	17,801,883	19,301,889
2002	-	6,537,260	189,692	-	11,655	-	-	-	5,198,621	-	-	-	-	-	16,722,576	20,578,716
2003	-	5,773,799	60,292	-	7,195	11,954	69	-	3,867,554	12,356	289,627	-	-	-	15,509,893	21,358,133
2004	-	5,012,401	93,122	-	7,111	2,130	-	-	3,342,175	-	1,135,488	17,096	4,191	-	15,259,211	20,655,579
2005	-	5,457,333	57,945	-	60,491	50,818	-	-	3,142,669	5,299	1,231,333	37,836	54,849	48,533	15,556,504	20,565,345
Revenues (Thousands of Dollars)																
1996	$0	$11,616	$69	$4	$2	$0	$32	-	$10,287	-	-	-	-	-	$28,618	$30,094
1997	-	$12,054	$76	$94	$0	-	-	$23	$10,148	-	-	-	-	-	$29,112	$30,390
1998	-	$8,874	$82	$118	$8	-	$0	-	$10,769	-	-	-	-	-	$25,974	$27,007
1999	-	$8,914	$5	$32	$0	-	$13	-	$8,918	-	-	-	-	-	$23,436	$24,601
2000	-	$14,058	$678	-	$7	$26	$1,254	$2	$10,743	-	-	-	-	-	$39,134	$40,524
2001	-	$14,301	$18	-	$16	$6	$0	-	$12,636	-	-	-	-	-	$36,826	$38,124
2002	-	$12,562	$276	-	$26	-	-	-	$9,632	-	-	-	-	-	$32,595	$36,337
2003	-	$12,159	$379	-	$16	$28	$5	-	$14,806	$16	$681	-	-	-	$42,606	$49,290
2004	-	$11,600	$263	-	$19	$5	-	-	$9,042	-	$3,165	$90	$17	-	$39,373	$47,903
2005	-	$14,987	$196	-	$209	$161	-	-	$10,787	$19	$4,302	$117	$235	$143	$50,721	$61,844

Revenues include principal and interest from revisions and settlements in the year received.

Table IV.5 Recent Royalty Gas Production by Lessee

North Slope

Production (Thousand Cubic Feet)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Arco	387,761	400,895	393,981	412,016	-	-	-	-	-	-
BP Am Prod. Co	-	-	-	-	-	-	-	1,852	-	-
BPXA	761,862	657,646	560,854	627,551	488,604	735,945	3,134,638	4,985,434	4,706,644	4,311,221
Chevron	17,786	16,561	5,070	-	-	1	2	2	1	-
ConocoPhillips AK	-	-	-	-	-	-	461,188	598,612	428,446	414,914
Exxon	297,260	284,187	264,969	241,821	-	-	-	-		-
ExxonMobil	-	-	-	-	298,217	293,045	260,247	262,275	259,052	282,640
Forest Oil	-	-	-	-	-	3	-	-	-	-
Mobil	101,256	84,433	78,519	74,713	-	-	-	-	-	-
NANA	32,446	25,930	-	-	-	-	-	-	-	-
Oxy	1,512	1,988	2,134	2,203	1,997	-	-	-	-	-
Phillips	17,630	17,786	16,197	9,226	468,093	470,986	-	-	-	-
Unocal	-	-	-	-	-	27	65	65	61	66
North Slope TOTAL	**1,617,513**	**1,489,427**	**1,321,724**	**1,367,530**	**1,256,911**	**1,500,007**	**3,856,140**	**5,848,240**	**5,394,204**	**5,008,841**

Cook Inlet

Production (Thousand Cubic Feet)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Arco	930,529	812,591	760,156	902,501	-	-	-	-	-	-
Aurora Power	-	-	-	-	-	32,296	31,792	8,464	18,476	39,342
Chevron	809,536	830,436	843,072	1,026,724	1,002,570	1,303,514	1,459,992	1,697,961	1,721,900	1,768,844
ConocoPhillips AK	-	-	-	-	-	-	1,287,322	1,949,494	1,983,167	1,808,634
Conoco Phillips Co.	-	-	-	-	-	-	-	5,773,799	5,012,401	5,457,333
Danco	85	-	-	-	-	-	-	-	-	-
Forest Oil	-	-	-	-	-	-	-	12,356	7,103	57,695
Marathon	4,475,074	3,995,784	4,062,765	4,347,695	4,358,280	4,234,315	3,356,118	3,077,325	3,550,106	3,545,572
ExxonMobil	22,815	50,177	55,372	21,509	52,341	4,118	2,894	1,532	188	-
Anchorage M, L & P	-	-	905,557	775,755	677,169	617,794	565,988	588,860	633,877	628,924
Phillips	6,910,165	6,490,318	6,665,243	6,372,036	7,782,678	7,953,777	6,537,260	-	-	-
Shell	1,038,035	985,270	-	-	-	-	-	-	-	-
Unocal	4,410,520	4,532,490	5,272,111	4,290,269	3,486,988	3,656,068	3,481,210	2,400,102	2,324,136	2,250,161
Cook Inlet TOTAL	**18,596,759**	**17,697,067**	**18,564,277**	**17,736,489**	**17,360,026**	**17,801,882**	**16,722,576**	**15,509,893**	**15,251,352**	**15,556,504**

Revenues include principal and interest from revisions and settlements in the year received.

Table IV.6 Recent Royalty Gas Revenues by Lessee

North Slope

Revenue (Thousands of Dollars)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Arco	$327	$325	$297	$344	-	-	-	-	-	-
BP Am Prod. Co	-	-	-	-	-	-	-	$3	-	-
BPXA	$658	$543	$451	$540	$539	$593	$3,054	$5,844	$7,527	$9,750
Chevron	$47	$33	$7	-	-	$0	$0	$0	$0	-
ConocoPhillips AK	-	-	-	-	-	-	$446	$538	$643	$865
Exxon	$230	$207	$183	$185	-	-	-	-	-	-
ExxonMobil	-	-	-	-	$318	$265	$242	$300	$360	$508
Forest Oil	-	-	-	-	-	-	-	-	-	-
Mobil	$168	$128	$80	$87	-	-	-	-	-	-
NANA	$31	$23	-	-	-	-	-	-	-	-
Oxy	$1	$2	$2	$2	$2	-	-	-	-	-
Phillips	$13	$15	$13	$7	$531	$440	-	-	-	-
XTO Energy	-	-	-	-	-	-	-	-	-	-
Unocal	-	-	-	-	-	-	-	<1	<1	<1
North Slope TOTAL	**$1,475**	**$1,278**	**$1,033**	**$1,165**	**$1,390**	**$1,298**	**$3,742**	**$6,685**	**$8,529**	**$11,123**

Cook Inlet

Revenue (Thousands of Dollars)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Arco	$1,352	$1,411	$1,262	$1,170	-	-	-	-	-	-
Aurora Power	-	-	-	-	-	$62	$18	$17	$38	$135
Chevron	$1,074	$1,551	$1,560	$1,605	$1,698	$3,136	$3,740	$4,373	$5,020	$6,293
ConocoPhillips AK	-	-	-	-	-	-	$2,530	$3,747	$4,562	$6,766
Conoco Phillips Co.				-	-	-	-	$12,159	$11,600	$14,987
Danco	$1	-	-	-	-	-	-	-	-	-
Forest Oil	-	-	-	-	-	-	-	$16	$90	$179
Marathon	$6,181	$6,061	$5,737	$5,557	$6,795	$10,429	$7,433	$6,777	$8,761	$12,113
ExxonMobil	$19	$47	$55	$22	-$0	$4	$3	$2	$0	-
Anchorage M, L & F	-	-	$1,443	$1,008	$1,082	$1,416	$1,316	$1,358	$2,022	$2,198
Phillips	$11,616	$12,054	$8,874	$8,914	$15,934	$16,697	$12,562	-	-	-
Shell	$1,517	$1,636	-	-	-	-	-	-	$103	-
Unocal	$6,858	$6,351	$7,035	$5,161	$13,624	$5,083	$4,993	$14,157	$7,178	$8,050
Cook Inlet TOTAL	**$28,618**	**$29,112**	**$25,966**	**$23,436**	**$39,134**	**$36,826**	**$32,595**	**$42,606**	**$39,373**	**$50,721**

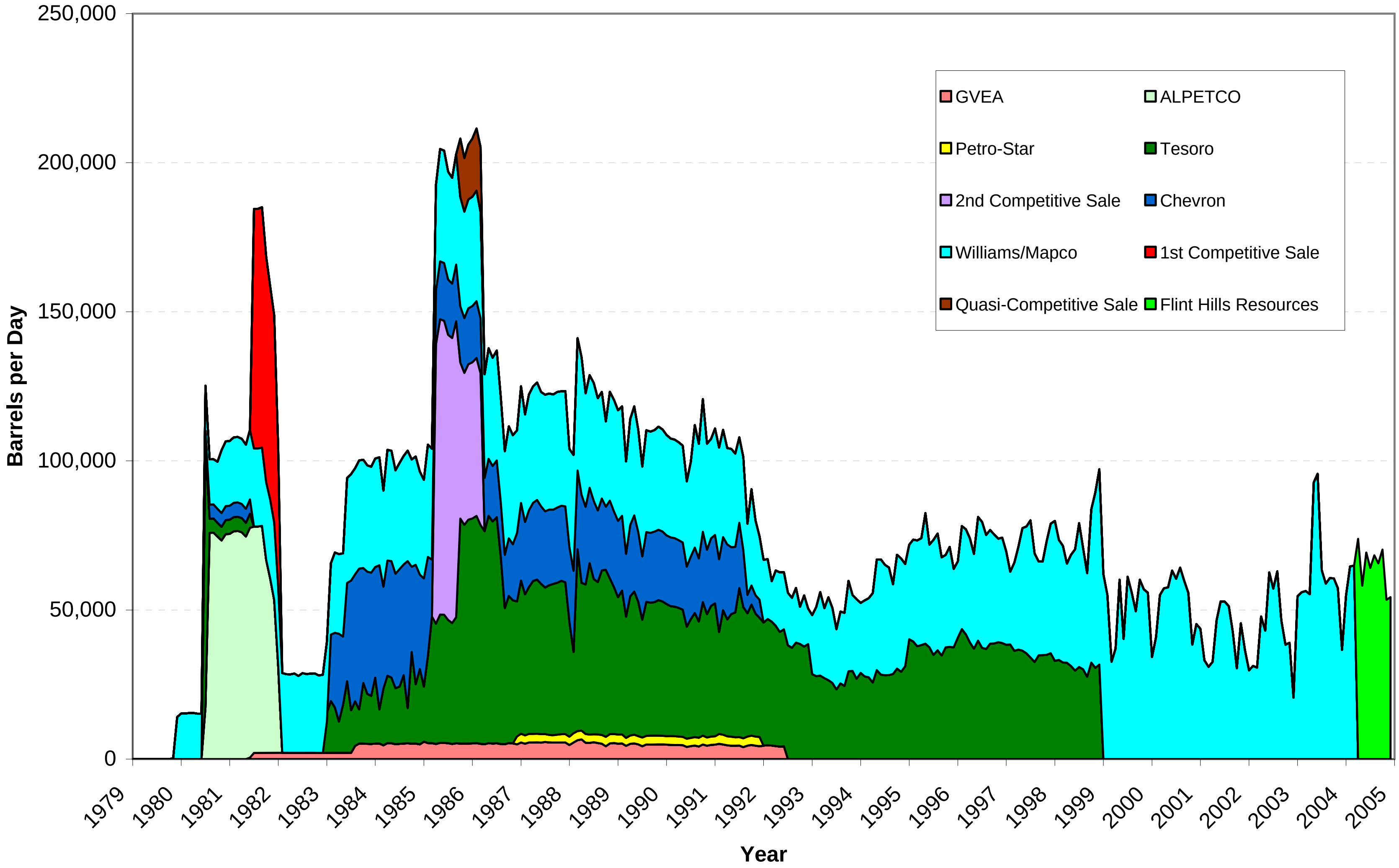
Revenues include principal and interest from revisions and settlements in the year received.

Table IV.7 North Slope Royalty in-Kind Sales

1979-2005 (Barrels per Year)

	Alpetco	Chevron	Williams (Mapco)	Flint Hills Resources, (FHR)	Golden Valley Elec Assoc	Tesoro	Petro Star	1st Comp Sale	2nd Comp Sale	Quasi-Comp Sale	**ANS TOTAL RIK**	**ANS TOTAL RIV**	**ANS TOTAL RIK + RIV**
1979	-	-	446,996		-	-	-	-	-	-	446,996	10,584,481	11,031,477
1980	12,020,950	882,414	5,976,024		-	3,427,388	-	-	-	-	22,306,777	47,047,583	69,354,360
1981	26,046,878	859,928	8,808,400		398,051	1,661,385	-	14,046,953	-	-	51,821,595	17,666,128	69,487,724
1982	898,714	-	9,632,099		764,762	36,841	-	1,432,108	-	-	12,764,524	61,136,212	73,900,737
1983	-	11,674,998	11,723,755		1,208,406	5,793,973	-	-	-	-	30,401,132	44,599,235	75,000,367
1984	-	14,053,279	13,093,397		1,870,505	7,531,155	-	-	-	-	36,548,337	39,396,031	75,944,369
1985	-	7,804,392	13,260,754		1,928,544	17,218,912	-	-	22,511,409	1,716,754	64,440,765	16,633,246	81,074,011
1986	-	6,934,482	13,168,483		1,881,232	23,538,192	52,667	-	4,686,801	1,862,051	52,123,908	30,262,661	82,386,569
1987	-	9,330,563	14,094,537		2,013,539	18,404,806	539,575	-	-	-	44,383,020	43,899,312	88,282,333
1988	-	9,315,264	13,814,522		1,981,998	18,307,014	590,832	-	-	-	44,009,631	44,068,970	88,078,602
1989	-	8,611,606	12,529,175		1,784,782	16,387,093	607,468	-	-	-	39,920,122	40,833,647	80,753,768
1990	-	8,099,292	12,735,412		1,670,494	15,368,565	621,220	-	-	-	38,494,983	37,242,490	75,737,473
1991	-	6,290,546	11,183,462		1,670,699	15,336,301	618,247	-	-	-	35,099,255	42,537,362	77,636,617
1992	-	-	6,285,005		803,407	14,412,460	-	-	-	-	21,500,872	52,754,222	74,255,094
1993	-	-	9,086,280		-	9,812,084	-	-	-	-	18,898,367	49,269,042	68,167,409
1994	-	-	11,986,495		-	10,452,726	-	-	-	-	22,439,220	50,657,903	73,097,124
1995	-	-	12,680,470		-	13,703,946	-	-	-	-	26,384,415	43,664,553	70,048,968
1996	-	-	13,027,646		-	14,345,621	-	-	-	-	27,373,267	39,396,515	66,769,782
1997	-	-	13,117,502		-	13,021,628	-	-	-	-	26,139,130	35,359,848	61,498,979
1998	-	-	16,483,695		-	11,497,629	-	-	-	-	27,981,324	28,316,894	56,298,218
1999	-	-	19,070,664		-	-	-	-	-	-	19,070,664	31,473,201	50,543,865
2000	-	-	19,290,298		-	-	-	-	-	-	19,290,297	27,784,503	47,074,800
2001	-	-	15,187,012		-	-	-	-	-	-	15,187,012	30,208,578	45,395,590
2002	-	-	15,509,592		-	-	-	-	-	-	15,509,591	32,264,920	47,774,511
2003	-	-	22,749,221		-	-	-	-	-	-	22,749,221	27,547,697	50,296,918
2004	-	-	5,582,299	17,639,277	-	-	-	-	-	-	23,221,576	22,287,470	45,509,046
2005	-	-	-	22,796,740	-	-	-	-	-	-	22,796,740	19,552,581	42,349,321
	38,966,543	83,856,765	320,523,194	40,436,018	17,976,419	230,257,719	3,030,009	15,479,061	27,198,210	3,578,804	781,302,744	966,445,287	1,747,748,031

Figure IV-1 ANS Royalty - In - Kind Crude Oil Volumes By Contract, 1979-2005



North Slope and Cook Inlet

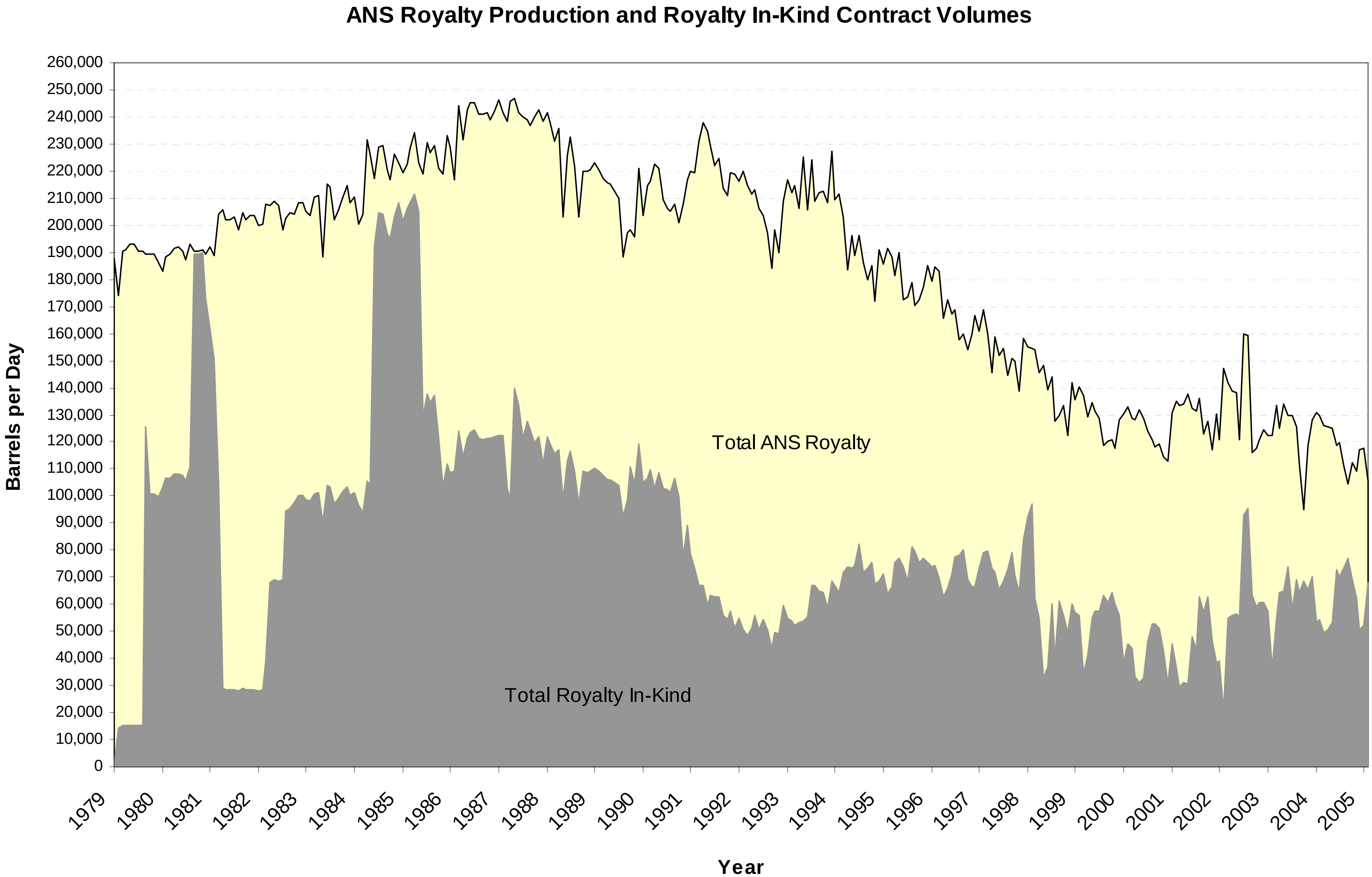


Table IV.8 Cook Inlet Royalty in-Kind Sales

1979-2005 (Barrels per Year)

	Tesoro[1]	Chinese Petroleum[2]	**CI TOTAL RIK**	**CI TOTAL RIV**	**CI TOTAL 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	73,048,460
1982	3,065,159	-	3,065,159	-	3,065,159	15,829,683	61,136,212	76,965,896
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	65,823,505	17,095,491	82,918,997
1986	-	-	-	1,922,101	1,922,101	52,123,908	32,184,762	84,308,670
1987	-	615,305	615,305	1,113,805	1,729,110	44,998,325	45,013,118	90,011,443
1988	-	799,938	799,938	917,208	1,717,146	44,809,570	44,986,178	89,795,748
1989	-	1,274,479	1,274,479	392,313	1,666,792	41,194,601	41,225,960	82,420,561
1990	-	566,825	566,825	522,456	1,089,282	39,061,808	37,764,946	76,826,755
1991	-	330,540	330,540	1,357,687	1,688,227	35,429,795	43,895,049	79,324,844
1992	-	-	-	1,661,526	1,661,526	21,500,872	54,415,749	75,916,620
1993	-	-	-	1,514,651	1,514,651	18,898,367	50,783,693	69,682,060
1994	-	-	-	1,717,758	1,717,758	22,439,220	52,375,662	74,814,882
1995	-	-	-	1,718,805	1,718,805	26,384,415	45,383,358	71,767,773
1996	-	-	-	1,618,157	1,618,157	27,373,267	41,014,672	68,387,939
1997	-	-	-	1,369,478	1,369,478	26,139,130	36,729,326	62,868,456
1998	-	-	-	1,335,030	1,335,030	27,981,324	29,651,924	57,633,248
1999	-	-	-	1,252,231	1,252,231	19,070,664	32,725,432	51,796,096
2000	-	-	-	1,248,564	1,248,564	19,290,297	29,033,067	48,323,364
2001	-	-	-	1,273,518	1,273,518	15,187,012	31,482,096	46,669,108
2002	-	-	-	1,320,281	1,320,281	15,509,591	33,585,201	49,094,792
2003	-	-	-	1,127,749	1,127,749	22,749,221	28,675,445	51,424,667
2004	-	-	-	920,431	920,431	23,221,576	23,207,900	46,429,476
2005	-	-	-	779,697	779,697	22,796,740	20,332,278	43,129,018
	22,103,526	3,587,088	25,690,614	25,545,691	51,236,305	806,993,358	991,990,978	1,798,984,336

Notes:

[1] East and west side.

North Slope and Cook Inlet

Figure IV.2A Composition of Total North Slope Royalty Dispositions 1979-2005

Royalty-In-Kind (RIK) and Royalty-in Value (RIV)

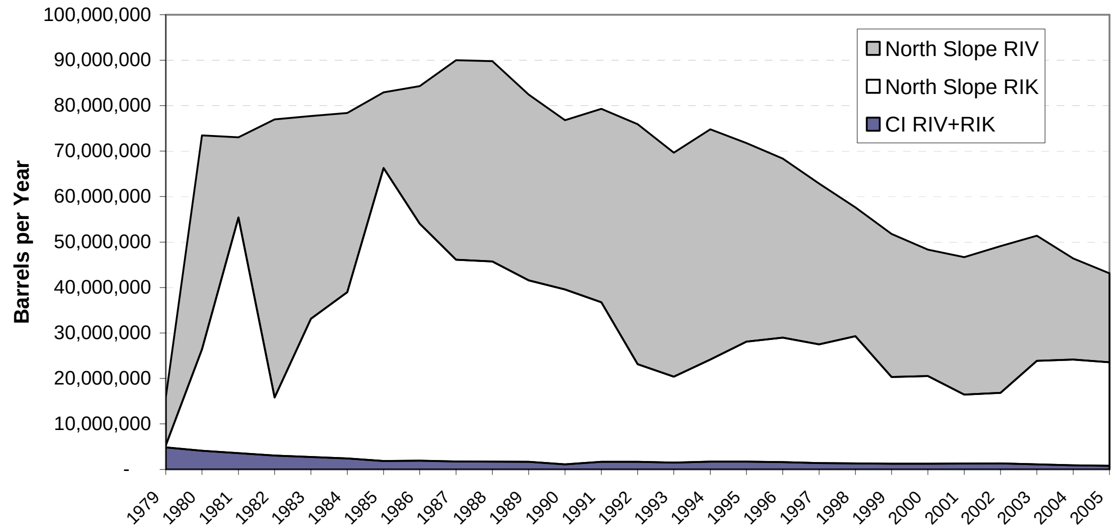


Figure IV2.B Composition of Cook Inlet Royalty Dispositions 1979-2005

Royalty-In-Kind (RIK) and Royalty-in Value (RIV)

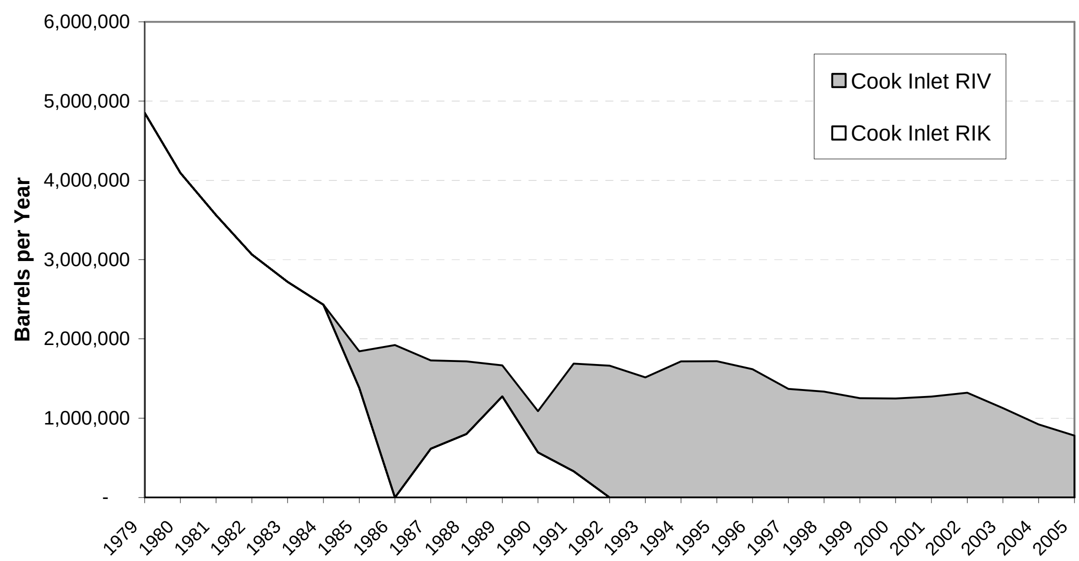


Figure IV.3 Major North Slope Royalty in-Kind Sales Contracts

1979-2005