Alaska North Slope Oil and Gas
A Promising Future or an Area in Decline?

DOE/NETL-2007/1279

Full Report

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Summary Report

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Alaska North Slope Terrain

The map shows the geographical region of Arctic Alaska north of the Brooks Range, extending from the Canadian border on the east to the Chukchi Sea on the west. This region includes the Alaska National Wildlife Refuge (ANWR), the Central Arctic (area between the Colville and Canning Rivers), the National Petroleum Reserve Alaska (NPRA), the Beaufort Sea Outer Continental Shelf (OCS), and the Chukchi Sea OCS areas. Oil fields are depicted in a light green tint and gas fields with a pink.

Foreword

The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL), Arctic Energy Office; the U.S. Department of Interior's, Minerals Management Service, Alaska OCS Region; the U.S. Department of Interior's Bureau of Land Management, Alaska State Office jointly funded this Alaska North Slope oil and gas resource assessment. The purpose of the assessment is to provide a detailed assessment and analysis of Alaska North Slope oil and gas resources and the interrelated technical, economic, and environmental factors controlling development of those resources. Science Application International Corporation (SAIC), Alaska Energy Office, performed the study under contract to DOE–NETL.

An Advisory Committee was formed to review plans and provide input to the assessment. The committee members are listed below.

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U.S. Department of Interior, Office of the Secretary: Michael Baffrey
U.S. Department of Interior, Bureau of Land Management: Colleen McCarthy & Bob Fisk
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Alaska Department of Natural Resources, Division of Oil and Gas: Tim Ryherd & William Nebesky
Alaska Department of Revenue: Michael Williams
Alaska Oil and Gas Conservation Commission: Robert Crandall & Tom Maunder

The Summary Report, DOE/NETL-2007/1280 is intended to be a stand-alone report and summarizes the results of the detailed analysis contained in the Full Report, DOE/NETL-2007/1279. The Full Report consists of four main chapters: Chapter 1–Introduction; Chapter 2–Geological Assessment of the Alaska North Slope; Chapter 3–Engineering and Economic Assessment; and Chapter 4–Environmental and Regulatory Issues.

The Alaska Petroleum Production Tax that passed the Alaska Legislature on August 11, 2006 and was signed into law by the governor of Alaska on August 19, 2006 is not analyzed in the report.

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ALASKA NORTH SLOPE OIL AND GAS: A Promising Future or an Area in Decline?

Abstract

This report presents a detailed assessment and analysis of the oil and gas resources on Alaska's North Slope. It covers the geographical region of Arctic Alaska north of the Brooks Range, extending from the Canadian border on the east to the Chukchi Sea Outer Continental Shelf (OCS) on the west. Five sub-provinces are evaluated: the 1002 Area of the Arctic National Wildlife Refuge (ANWR), the Central Arctic (area between the Colville and Canning Rivers), the National Petroleum Reserve Alaska (NPRA), the Beaufort Sea OCS, and the Chukchi Sea OCS. Land ownership consists of a combination of federal lands, state lands, and Alaska native lands. The assessment includes: (a) a review of the regional geology relative to oil and gas resources; (b) an engineering and economic assessment of the currently producing fields, known fields with announced development plans, and known fields with potential for development in the next few years; (c) impact of major gas sales on oil and gas resource development; (d) estimates of the minimum economic field size for developments in each of the exploration areas; and (e) a discussion of economic value of sharing facilities when developing new resources.

The future projections were viewed from two perspectives, near term (2005 to 2015) and long term (2015 to 2050) with the near term being oil-centered and the long term marked by the emergence of gas as a major, if not dominant, factor in exploration and development activities. The future for Alaska North Slope oil and gas ranges from very promising to limited depending on how many of the following assumptions apply: (1) the 1002 Area of ANWR is opened for exploration and development soon, (2) exploration is allowed in the most prospective areas of NPRA, (3) the Beaufort Sea OCS and Chukchi Sea OCS are available for exploration and development without major restrictions on area or timing, (4) an Alaska North Slope natural gas pipeline is operational by 2015 to 2016, (5) oil and gas prices remain near the current high values, and (6) state of Alaska and federal fiscal policies remain stable and supportive of the huge investments that will be required. The future prospects become progressively less promising as these assumptions are removed.

Key findings are summarized below:

- Oil production from Alaska's North Slope began in 1977 and increased to 2.2 million barrels per day by 1988, representing 25% of the U.S. domestic production. Production has since declined to below 900,000 barrels per day in 2005, but still represents about 17% of the U.S. domestic production.

- All oil production to date has been from fields in the Central Arctic (Colville-Canning area) on state lands and adjacent waters of the Beaufort Sea (The Northstar Unit produces from both state and federal waters in the Beaufort Sea). Through 2004, Alaska North Slope oil fields had produced 15 billion barrels of oil, or about 70% of the estimated economically recoverable oil from the currently developed fields. The remaining economically recoverable oil from these fields is between 6 and 7 billion barrels.

- Discovered recoverable natural gas resources on the Alaska North Slope are estimated to be about 35 trillion cubic feet. No natural gas is currently exported off the North Slope because there is no gas pipeline to transport the gas to markets.

- From an exploration perspective, the North Slope and adjacent areas is not a mature petroleum province. The majority of the wells in both the state onshore and near-shore Beaufort Sea are clustered along the Barrow Arch trend, with a drilling density of approximately one exploration well per 22 square miles. Only forty-five of the 301 North Slope exploration wells have been located south of 70º north latitude. This area, which constitutes nearly 75% of the state acreage, has a well density of one well per 383 square miles.

- In the short term, 2005 to 2015, exploration efforts are forecast to result in the addition of about 2.9 billion barrels of economically recoverable oil and 12 trillion cubic feet of economically recoverable gas. Oil exploration is expected to target primarily oil resources in the Central Arctic on state lands and adjacent state waters, NPRA, and the Beaufort Sea OCS. Gas exploration is expected to begin in earnest when a gas pipeline is assured and will initially target the Central Arctic foothills area, south of the current oil producing area.

- In the long term, 2015 to 2050, exploration success and development is expected to involve activities in all five sub-provinces under the **optimistic assumptions** and is estimated to total 28 billion barrels of economically recoverable oil and 125 trillion cubic feet of economically recoverable gas. The expected oil and gas reserve additions are widely distributed in all the geographic areas.

- For the complete study interval from 2005 to 2050, the forecasts of economically recoverable oil and gas additions, including reserves growth in known fields, is 35 to 36 billion barrels of oil and 137 trillion cubic feet of gas. These **optimistic estimates** assume continued high oil and gas prices, stable fiscal policies, and **all areas** open for exploration and development. For this optimistic scenario, the productive life of the Alaska North Slope would be extended well beyond 2050 and could potentially result in the need to refurbish TAPS and add capacity to the gas pipeline.

- The forecasts become increasingly pessimistic if the assumptions are not met as illustrated by the following scenarios.
    1. If the ANWR 1002 area is removed from consideration, the estimated economically recoverable oil is 29 to 30 billion barrels of oil and 135 trillion cubic feet of gas.
    2. Removal of ANWR 1002 and the Chukchi Sea OCS results in a further reduction to 19 to 20 billion barrels of oil and 85 trillion cubic feet of gas.
    3. Removal of ANWR 1002, Chukchi Sea OCS, and the Beaufort Sea OCS results in a reduction to 15 to 16 billion barrels of oil and 65 trillion cubic feet of gas.
    4. Scenario 3 and no gas pipeline reduces the estimate to 9 to 10 billion barrels of oil (any gas discovered will likely remain stranded).

  Some combination of these hypothetical scenarios is more likely to occur than the optimistic estimates.

- The study examined two resource development cases related to the presence or absence of significant natural gas sales arising from construction of a gas pipeline.
    - The assessment for the **No-Major-Gas-Sales** case results in an estimate of remaining technically recoverable oil of 6.4 billion barrels of oil for the fields analyzed (i.e., currently producing fields, known fields with pending or announced development plans, and known fields with near-term development potential).
    - For the **Major-Gas-Sales** case, the development of the Point Thomson field is estimated to result in an additional 400 million barrels of recoverable oil. A reserve decline in the Prudhoe Bay field is estimated to be about 133 million barrels of oil, resulting in an estimate of about 6.8 billion barrels of remaining technically recoverable oil from the known Alaska North Slope fields.

- The estimated gas reserves in the Prudhoe Bay and Point Thomson fields will provide 32 trillion cubic feet of the 57.5 trillion cubic feet of natural gas required to support a gas pipeline project at 4.5 billion cubic feet per day for a 35-year life.

- The Trans Alaska Pipeline System's (TAPS) minimum flow rate of about 300,000 barrels of oil per day will be reached in 2025, absent new developments or reserves growth beyond the forecasted technically remaining reserves. An Alaska gas pipeline and gas sales from the Point Thomson field and the associated oil and condensate would provide another boost to oil production and extend the life of TAPS for about one year to 2026. A shut down of TAPS would potentially strand about 1 billion barrels of oil reserves from the fields analyzed.

- Exploration in the 1002 Area of ANWR (including native corporation in-holdings and state Beaufort Sea waters) is highly significant because this sub-province contains an estimated 10.4 billion barrels of oil in 1.9 million acres (5,475 barrels of oil per acre). In comparison, NPRA contains an estimated 10.6 billion barrels of oil in 24.2 million acres (440 barrels per acre). Opening the ANWR 1002 Area would significantly increase exploration activity and increase the potential for discovery of additional oil and gas reserves.

- The construction of a 4.5 billion cubic feet per day Alaska gas pipeline by 2015 and the ability to sell gas from the Prudhoe Bay and Point Thomson fields will nearly double the revenue to the stakeholders (state of Alaska, federal government, and industry). New oil and gas discoveries catalyzed by the gas pipeline will further increase revenues.

- The minimum economic field size estimates and the geological evidence for the Alaska North Slope areas indicate that oil and gas fields of sufficient size could be found to support development, provided oil and gas prices are adequate and the fiscal and regulatory environment are supportive of the large investments that will be required.

- Issues that have the *potential* for preventing development of a given field or set of fields on the Alaska North Slope include land access; extent of requirements for dismantlement, removal, and restoration of facilities and infrastructure; marine mammal protection with respect to development of offshore resources and potential impacts on bowhead whales, a species listed under the Endangered Species Act; water availability for constructing ice roads and exploration pads; and gravel availability for constructing development and production facilities and roads. Some may be solved by further advances in technology, while others may ultimately prevent development in a given location.

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ACRONYMS AND ABREVIATIONS

% .... Percent
2D.......... Two Dimensional
3D.......... Three Dimensional
ACE.......... Army Corps of Engineers
ACMP .... Alaska Coastal Management Program
ADEC.......... Alaska Department of Environmental Conservation
ADFG.......... Alaska Department of Fish and Game
ADGC .... Alaska Division of Governmental Coordination
ADNR .... Alaska Department of Natural Resources
ADOR .... Alaska Department of Revenue
ADOG .... Alaska Division of Oil and Gas
AIMS.......... Alaska Incident Management System
AIRFA.......... The American Indian Religious Freedom Act
ANCSA .... Alaska Native Claims Settlement Act
ANILCA .... Alaska National Interest Lands Conservation Act
ANS.......... Alaska North Slope
ANWR .... Alaska National Wildlife Refuge
AOGCC.......... Alaska Oil and Gas Conservation Commission
API .... American Petroleum Institution
ARCO .... Atlantic Richfield Oil Company
ASRC .... Arctic Slope Regional Corporation
BACT .... Best Available Control Technology
BAT.......... Best Available Technology
BBO .... Billions of Barrels of Oil
BCF .... Billions of Cubic Feet of Gas
BCFD .... Billion Cubic Feet per Day
BLM.......... Bureau of Land Management
BO .... Barrels of Oil
BOPD.......... Barrels of Oil per Day
BTU.......... British Thermal Unit
BWPD .... Barrels Water Per Day
CAA .... Clean Air Act
CAH .... Central Arctic Herd
CEQ.......... Council on Environmental Quality
CERCLA.......... Comprehensive Environmental Response Compensation and Liability Act
CFPB.......... Cubic Feet per Barrel
CH4 .... Methane
CO .... Carbon Monoxide
Crk.......... Creek
CRU .... Coleville River Unit
CWA .... Clean Water Act
CZMA .... Coastal Zone Management Act
DAQ .... Division of Air Quality
DGGS.......... Division of Geological and Geophysical Services

DHS	Department of Homeland Security
DIU	Duck Island Unit
DMLW	Alaska Department of Mining, Land and Water
DOE	U.S. Department of Energy
DOI	U.S. Department of Interior
DOT	Department of Transportation
DR&R	Dismantle Removal and Restoration
E&P	Exploration and Production
EIA	Energy Information Administration
EIS	Environmental Impact Statement
ELF	Economic Limit Factor
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ERR	Economically Remaining Reserves
ESA	Endangered Species Act
EUR	Economical Ultimate Reserves
FLIR	Forward Looking Infrared Photography
FLPMA	Federal Land Policy and Management Act
Fms	Formations
FOSC	Federal ON Scene Coordinator
ft	Feet
FWCA	Fish and Wildlife Coordination Act
FWPCA	Federal Water Pollution Control Act
FWS	U.S. Fish and Wildlife Service
GAO	U.S. General Accounting Office
GG&E	Geophysical, Geologic and Exploration
GOR	Gas Oil Ratio
GRZ/ HRZ	Condensed Radioactive Shale
H^2S	Hydrogen Sulfide
Hc	hydrocarbons
HI	Hydrogen Index
HMTA	Hazardous Materials Transportation Act
IPA	Initial Participating Area
KIC	The Kaktovik Inupiat Corporation
KRU	Kuparuk River Unit
LCU	Lower Cretaceous Unconformity
m	meters
m.y.	million years
Ma	Million of years ago
MB	Thousands of Barrels of Petroleum Liquids
MBO	Thousand Barrels of Oil
MBO	Thousands of Barrels of Oil
MBOPD	Thousands of Barrels of Oil Per Day
MCF	Thousand Cubic Feet
MD	Measured Depth
md	millidarcies

MEFS	Minimum Economic Field Size
MI	Miscible Rich Gas Injection
MMB	Millions of Barrels of Petroleum Liquids
MMBO	Million of Barrels of Oil
MMBOE	Million Barrels of Oil Equivalent
MMBOPD	Millions of Barrels of Oil Per Day
MMPA	Marine Mammal Protection Act
MMS	Minerals Management Service
MOU	Memorandum of Understanding
MPU	Milne Point Unit
MWAG	Miscible Water Alternating Gas Process
NAGPRA	Native American Graves Protection and Repatriation Act
NCP	National Oil and Hazardous Substances Pollution Contingency Plan
NEPA	National Environmental Policy Act
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NGL	Natural Gas Liquids
NHPA	National Historic Preservation Act
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPR	Naval Petroleum Reserve
NPRA	National Petroleum Reserve Alaska
NPRPA	Naval Petroleum Reserves Production Act
NPS	National Park Service
NRHP	National Register of Historic Places
NSB	North Slope Borough
NSU	North Star Unit
O^3	Ozone
OCS	Outer Continental Shelf
ODPCP	Oil Discharge Prevention and Contingency Plan
OGIP	Original Natural Gas in Place
OHSPC	Oil and Hazardous Substance Pollution Control
OOIP	Original Oil in Place
OPA	Oil Pollution Act
OPEC	Organization of Petroleum Exporting Countries
PA	Participating Area
Pb	Lead
PBU	Prudhoe Bay Unit
PCB	Polychlorinated Biphenyls
PM	Particulate matter
PPA	Pressure Point Analysis
PSD	Prevention of Significant Deterioration
RCRA	Resource Conservation and Recovery Act
RHA	Rivers and Harbors Act
Ro	Vitrinite Reflectance
S	Sulfur

SARA	Superfund Amendments and Reauthorization
SDWA	Safe Drinking Water Act
SEC	Security and Exchange Commission
SHPO	Alaska State Historic Preservation Office
SO^2	Sulfur Dioxide
SPCC	Spill Prevention Control and Countermeasure
SPE	Society of Petroleum Engineers
Ss	Sandstone
TAPS	Trans Alaska Pipeline System
TCF	Trillion Cubic Feet of Gas
TOC	Total Organic Carbon
TRR	Technical Remaining Recovery
TSCA	Toxic Substance Control Act
TSP	Total Suspended Particulates
TUR	Technical Ultimate Recovery
UAF	University of Alaska Fairbanks
UIC	Underground Injection Control
USCG	U.S. Coast Guard
USDA	U.S. Department of Agriculture
USGS	U.S. Geological Survey
VOC	Volatile Organic Compounds
WAG	Water Alternating Gas Process
Wt	Weight
WTI	West Texas Intermediate
yr	Year

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ALASKA NORTH SLOPE OIL AND GAS
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1. INTRODUCTION

The purpose of this report is to provide a detailed assessment and analysis of Alaska North Slope (ANS) oil and gas resources and the interrelated technical, economic, and environmental factors controlling development of those resources. The ANS region includes the area north of the Brooks Range to the Beaufort Sea and extends from the Chukchi Sea on the west to the Canadian border on the east. This area includes the National Petroleum Reserve-Alaska (NPRA), the Central Arctic, the Alaska National Wildlife Refuge (ANWR) and the Beaufort Sea and Chukchi Sea Outer Continental Shelf (OCS) areas as shown in Figure 1.1.

Figure 1.1. The North Slope, Alaska and adjacent Chukchi and Beaufort Seas. (map by Mapmakers Alaska, Palmer, AK)

The results provide a source of detailed information for planning and decision-making by the U.S. Department of Energy (DOE), other federal agencies, and state of Alaska agencies to improve the prospects for continued development of ANS oil and gas. The scope includes currently known onshore and offshore fields on the ANS (developed and undeveloped) and prospective development areas including NPRA, the Beaufort Sea and Chukchi Sea OCS areas, and the 1002 Area of ANWR. Exploration in the 1002 Area of ANWR will require approval by the U.S. Congress and the President. The onshore portion of this region is all within the North Slope Borough.

In prospective development areas, estimated characteristics, locations, and economic potential of the undiscovered oil and gas resources on state of Alaska, federal, and native lands are described using the latest geological information available and analytic reservoir engineering calculations to estimate recoverable oil and gas. The effects of infrastructure, access to infrastructure, environmental regulations, advanced technology development, and development of a gas pipeline on the future viability of ANS oil and gas production are described.

ANS development has been limited to the northern portion of the Central Arctic region, on state lands and near-shore in the Beaufort Sea between the Colville River on the west and the Canning River in the east, as seen in Figure S.2.[1] Successful exploration has progressed into eastern NPRA and has lead to pending development of three satellites fields near the Colville River Unit.

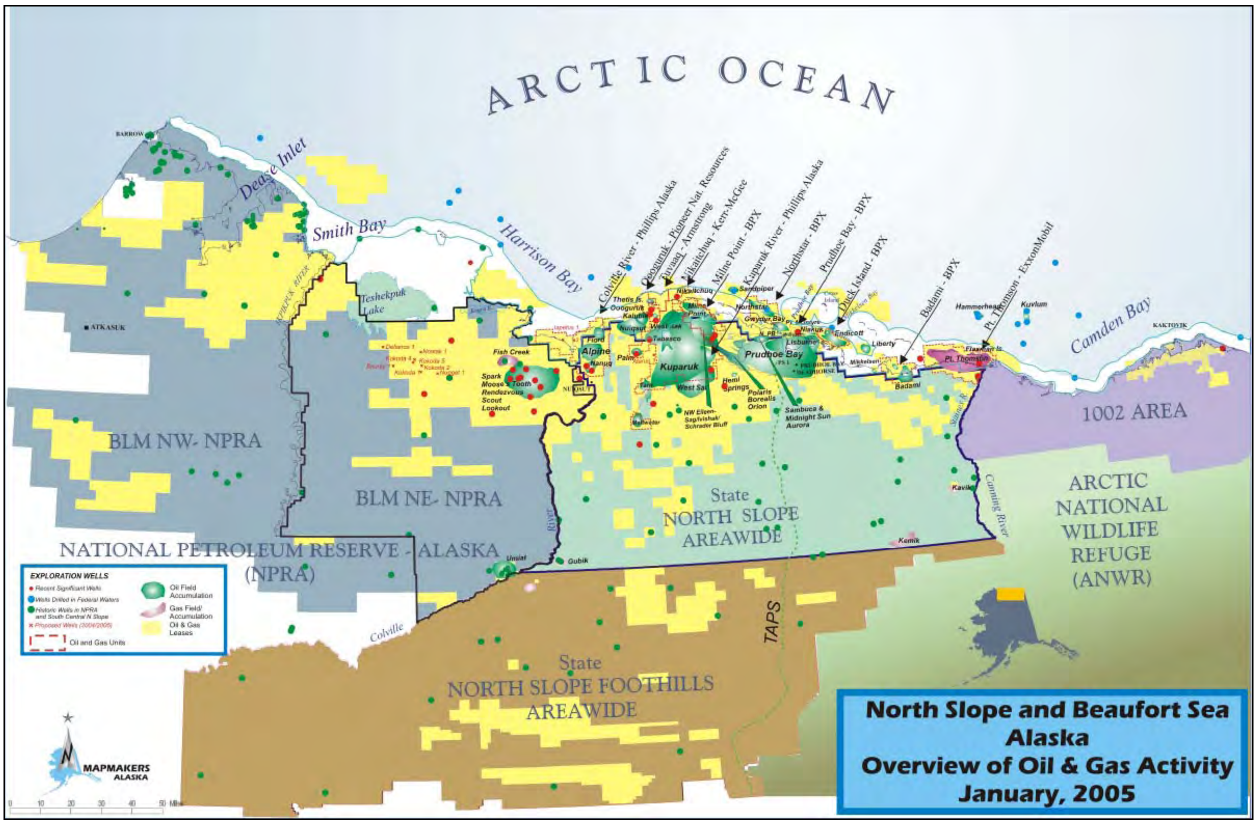

Figure 1.2 North Slope Oil and Gas Activity and Discoveries.

1.1 Oil

The state of Alaska currently receives almost 90% of its general fund revenues from petroleum revenues (royalties, production taxes, property taxes, and corporate income taxes) and will remain heavily dependent on these revenues for the foreseeable future. Production from Alaska is critical to the United States as illustrated in Figure 13. Since 1978, ANS fields, driven by the Prudhoe Bay and Kuparuk oil fields, have comprised up to 25% of U.S. domestic crude

[1] Additional maps at larger scale are available at the ADNR Division of Oil and Gas web site. http://www.dog.dnr.state.ak.us/oil/products/maps/northslope/northslope.htm

oil production and currently comprise about 17% of U.S. domestic production. The current production rate is less than 900,000 barrels of oil per day (BOPD) or about 45% of the peak production levels of the late 1980s.

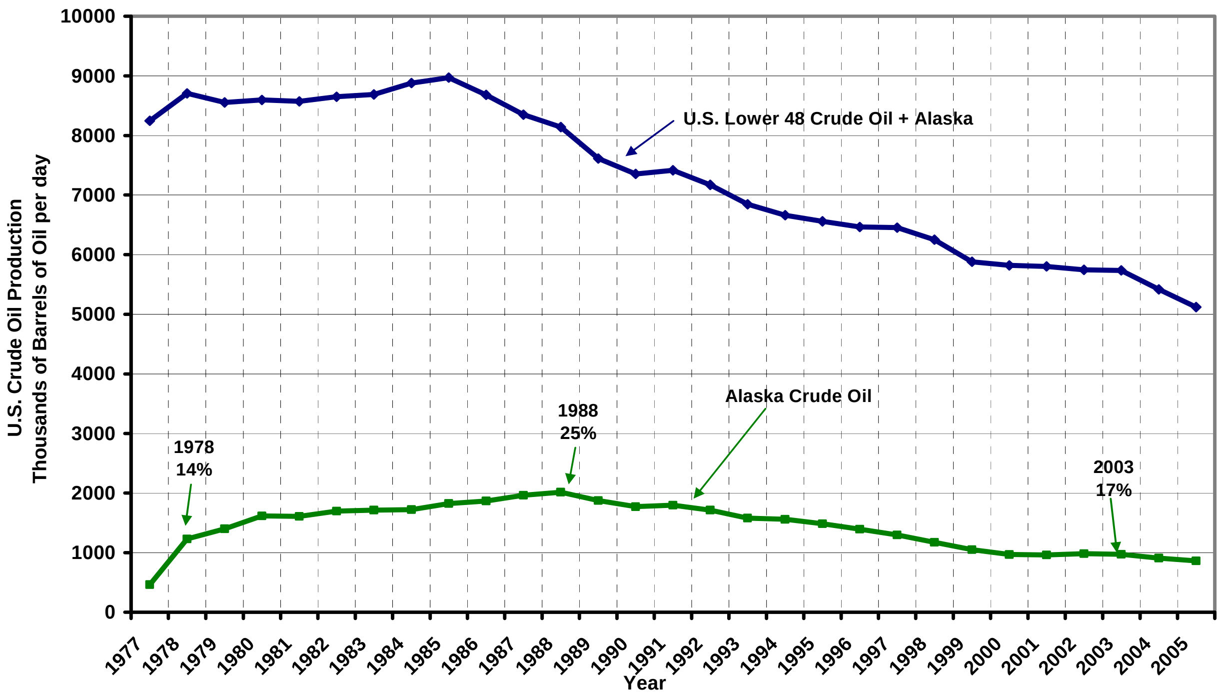

Figure 1.3. Lower 48 and Alaska crude oil production. (EIA 2003 http://tonto.eia.doe.gov/dnav/pet/pet_sum_crdsnd_adc_mbblpd_a.htm)

The ANS production decline has been dominated by the continuing decline of Prudhoe Bay production as shown in Figure 1.4. The discovery and development of the Alpine and Northstar fields and satellite fields near the existing infrastructure has tempered this decline. However, unless there are significant future discoveries and commercial development, ANS production could reach the estimated minimum Trans Alaska Pipeline System (TAPS) throughput rate of about 300,000 BOPD by 2025 as shown on Figure 1.4. This minimum flow rate would be achieved by reducing the number of pumps at the four required TAPS pump stations (PS) to one pump per station at PS 1, 3, 4, and 9. TAPS is currently configured with three pumps at these four stations, sufficient to support a throughput of 1.14 million barrels of oil per day (MMBOPD) (Alyeska, 2004). Throughput could be increased to about 2 MMBOPD by adding addition pump skids and returning additional pump stations to service. At the peak production rates in 1988, 10 pump stations were operating. The large number of small fields making up the current and projected production shows just how difficult it has been to find additional giant fields to replace declining Prudhoe Bay and Kuparuk River field production.

1.2 Natural Gas

No ANS natural gas has been sold except for field operations and local use on the ANS. This situation will continue until a gas pipeline is built to deliver the gas to U.S. Lower 48 or world markets. Gas-to-liquids (GTL) technology, which would allow the natural gas to be converted into a liquid petroleum product for transport in TAPS, has been studied, but a gas

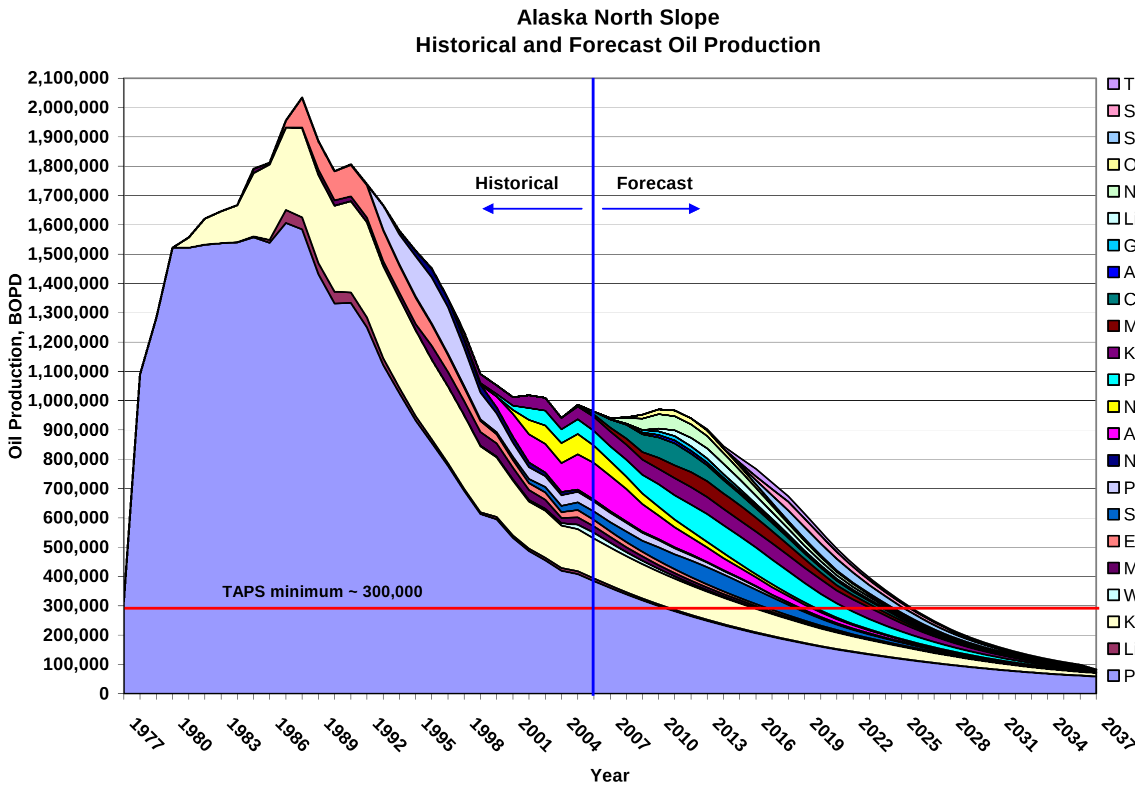

Figure 1.4. Alaska North Slope historical and forecast production. (AOGCC database for history and Section 3 for forecast.)

pipeline appears to be the most desirable option. In this report it is assumed that a gas pipeline will be in place by 2015 to 2016 and this will stimulate aggressive exploration for natural gas and oil.

Exportable hydrocarbon natural gas reserves (produced gas less CO_2 and lease use, local sales, and shrinkage) are estimated at 23.7 trillion cubic feet (TCF) for the Prudhoe Bay Unit (PBU) and 8 TCF for the Point Thomson Unit (PTU) for a total of 31.8 TCF. A higher recovery factor for PBU and PTU, or additional small amounts from other currently producing fields, will be required to provide the total of 35 TCF frequently referred to in discussions of ANS gas reserves.

Gas production for use in field operations is common on the ANS. Prudhoe Bay's gas production rate is currently about 7.8 billion cubic feet per day (BCFPD), of which about 7.2 BCFPD is reinjected. Natural gas re-injection has had a positive impact on recovery efficiency in PBU and in other producing fields. In addition, miscible injectant (MI), a combination of natural gas and natural gas liquids (NGLs), has been used effectively for enhanced oil recovery (EOR) processes in the Prudhoe Bay and Kuparuk River oil fields. Natural gas injection and waterflooding to enhance recovery from the huge viscous, heavy oil resource overlying the Prudhoe Bay, Kuparuk River, and Milne Point field areas (25 to 30 billion barrels of original oil in place (OOIP)) is proving to be economical when coupled with new technology for multilateral horizontal wells and new completion and production technology.

Enhanced oil recovery using ANS natural gas is expected to continue to be an important and profitable use for natural gas even after an Alaska gas pipeline is constructed to delivery ANS gas to market. Carbon dioxide (CO_2) that must be removed from Prudhoe Bay and Point Thomson natural gas prior to sale is expected to be used for EOR as well.

Technology advancements in the last 10 years, including 3-D seismic and extended reach and multi-lateral horizontal drilling, have made numerous small satellite fields near PBU and Kuparuk River Unit (KRU) economically viable and slowed the ANS production decline as illustrated in Figure 1.4. Incremental production developed since 1995 accounts for more than 30% of the total ANS production (Alaska Division of Oil and Gas (ADOG), 2004). The Alpine field in the Colville River Unit and the offshore Northstar field are recent examples of stand-alone fields that have been developed using advanced technology for drilling and production. These technology advancements have also reduced the footprint of the development and the resulting environmental impact. Northstar is offshore in state of Alaska and federal waters of the Beaufort Sea and is the first field to produce from federal waters in the Arctic. The discovery of the Alpine field and the play type it represents is in large part responsible for the recent increase in reserves estimated for NPRA. Although, these developments have slowed the decline of ANS production, continued leasing and development are essential to maintain the viability of TAPS and other infrastructure in the long term to support future development.

Exploration, development and operations on the North Slope has been dominated by a few major oil companies (BP, ConocoPhillips, and ExxonMobil), or their predecessors, which own varying proportions of the unitized fields, the facilities, and TAPS. Development of major ANS gas reserves will likely occur in a similar manner with the gas pipeline owned by a consortium of companies and possibly the state of Alaska. However, recent lease sales in NPRA, and on state lands, suggest independent operators and major operators other than the current big three companies may become important in the future and the decision-making process could change significantly. The increase in the number of companies will potentially increase the amount of investment that can occur on the ANS.

1.3 Scope and Approach

The **Geological Assessment, Section 2,** contains a comprehensive, region-by-region, description of the ANS oil and gas resource base and an assessment of oil and gas reserves, reserves growth in producing fields, reserves growth in discovered but undeveloped fields, and potential reserve additions through additional exploration. The assessment addresses two time frames **–** **near term** (2005 to 2015) and **long term** (2015 to 2050). The **near term** focuses on continued oil production, but begins the transition to oil and gas production in the **long term,** assuming a gas pipeline is constructed and becomes operational by 2015 to 2016. The ANS regional geological framework, petroleum geology, exploration history, and existing fields are first described to provide a basis for understanding prior exploration and development activities, to develop a framework for assessing current and future opportunities, and to estimate economically recoverable oil and gas that could be developed by 2050.

Historically, any treatment of petroleum geology of the North Slope has been strongly focused on its oil potential, with little attention to the area’s vast conventional gas resources and even less attention to unconventional resources such as coalbed natural gas (CBNG) and gas hydrates.

Because the ANS contains large quantities of coal, the potential for CBNG production is significant. A USGS assessment of undiscovered CBNG was completed in 2006, and a mean estimate of undiscovered, technically recoverable resources gives a potential of about 18 TCF of CBNG (Roberts and others, 2006). However, more attention is being focused on gas hydrates. DOE's National Energy Technology Laboratory (NETL) leads a major, inter-agency, research program underway to assess the nation's gas hydrate potential. One major project within hydrates research program is aimed at ANS gas hydrate reservoir characterization. According to MMS and USGS estimates (Petroleum News, 2005a; Collett, 2004), the ANS may contain as much as 590 TCF of in-place gas in permafrost-associated gas hydrates. Collett (2004) reports that the volume of gas within the known gas hydrates of the Prudhoe Bay-Kuparuk River infrastructure area alone may exceed 100 TCF of gas in place. Ongoing research efforts will attempt to resolve the numerous technical challenges that must be overcome before this potential resource can be considered an economically producible reserve (Collett, 2004).

At this time, because natural gas recovery from CBNG and gas hydrate resources has not been demonstrated, there is no basis upon which to assess their economic feasibility. Therefore, they are not discussed further.

The **Engineering and Economic Evaluation, Section 3,** contains the engineering and economic evaluation of the ANS oil and gas producing region. The goal of the economic analysis is use discounted cash flow analysis, together with the geologic and engineering findings and estimate the revenue generated for industry, the state of Alaska, and the federal government from ANS oil and gas production. A summary description of individual pool production history, field and reservoir performance observations, production forecasts, economic analyses for each pool and field, and estimated ultimate recovery (EUR) are presented for a range of oil and natural gas prices. This section is divided into currently producing fields, fields with announced development plans, known fields with potential for development in the near future, and minimum economic oil and gas field sizes (MEFS) for the different regions. A separate analysis is provided for major gas sales starting in 2015 from the Prudhoe Bay and Point Thomson fields.

Environmental and Regulatory Issues, Section 4, describes: (a) the regulatory, land management, resource agencies, and local governments agencies and their respective functions; (b) the acts, regulations, and permits that control oil and gas development; (c) the lease sale and regulatory permitting process; (d) the environmental issues, impacts, and mitigation measures currently in place; and (e) evaluates the effects of changes in technology and practices on ANS exploration and development. The costs of environmental regulations and compliance are discussed and issues that could present major road blocks to future exploration and development are described.

2. Geological Assessment of the Alaska North Slope

The oil resources of the North Slope of Alaska have been, are, and will be for the foreseeable future, critical to the United States and state of Alaska. Since 1978 these fields, driven by production from Prudhoe Bay and Kuparuk oil fields, have supplied as much as 25% of domestically produced oil. Current production is approximately 1.0 million barrels of oil per day (MMBOPD) or about half of the peak production levels of the late 1980's.

From discovery of the Prudhoe Bay field in 1968 and the start-up in 1977 until the present, all commercial oil production has been from the northern portion of the "Colville-Canning province", the area between the Colville and Canning rivers, and from the immediately adjacent offshore state and federal waters (Figure 2.1). Production is just commencing in the northeastern portion of the National Petroleum Reserve Alaska (NPRA). In the future, it is anticipated that oil exploration and production will expand westward and southward in NPRA, southward within the Colville-Canning area, offshore into state waters adjacent to NPRA and the Arctic National Wildlife Refuge (ANWR), Outer Continental Shelf (OCS) waters of the Beaufort and possibly Chukchi Seas, and perhaps into the 1002 Area of ANWR.

Figure 2.1. North Slope Alaska and adjacent Chukchi and Beaufort Seas.

To date, all commercial production has been oil. Gas has been produced and used for local field operations and enhanced recovery programs. The commercialization of the vast gas resources awaits the approval and construction of a gas pipeline. When this pipeline is a reality, extensive exploration of the southern portions of all the onshore areas will proceed at a more rapid pace, as these areas are widely believed to be gas-prone.

While the near term status of North Slope production appears to be relatively stable, the longer term future, beyond 10 to 15 years (2015 to 2020), is much more uncertain. The decline in production from the major early discoveries is being partially offset by more recently discovered but smaller fields (200 to 500 MMBO) and small proximal satellites (25 to 100 MMBO). Maintenance of future production at or above current rates will require some combination of intermediate-size discoveries (500 MMBO ±), continued development of satellite fields, and more intensive development of the heavy oil reservoirs such as West Sak, Schrader Bluff, and Ugnu. Exploration of the Federal OCS areas and the 1002 Area of ANWR would significantly increase the probability of long term (through 2050) production maintenance and even growth. If a gas pipeline is approved by mid-2006, gas production could be a reality by 2015 and provide impetus for the long-term exploration and development in the greater North Slope area.

To provide a basis for understanding prior exploration and development activities on the North Slope and to develop a framework for current and future exploration and development opportunities, Sections 2.1 to 2.3 presenting the regional geological framework, the petroleum geology, and the exploration history precede the discussions of the existing fields and future exploration/production potential in Section 2.4 and 2.5.

2.1 Geological Framework of the North Slope

The North Slope has three physiographic subdivisions as shown in Figure 2.2. From south to north, these subdivisions are the southern foothills of the Brooks Range, the northern foothills of the Brooks Range and the coastal plain. To a considerable extent, these areas reflect the nature of the underlying structure and stratigraphy of the North Slope. These three areas not only possess distinctive physiographies but also present different challenges to exploration and development. These include the availability of both water and gravel and more difficult off-road travel. Thus different technologies or plans of development are required where gravel is scarce for the construction of gravel production pads and roads and where an adequate water supply is lacking for building exploration ice roads and ice pads. To some considerable extent the physiography may constrain the ability to acquire seismic data and drill exploration wells.

The evolution of the structural elements and the associated sequences of the North Slope are essential to understanding the exploration opportunities not only for the currently explored and developed area of the Colville-Canning province but also for the greater onshore area and the adjacent shelfal areas of the Beaufort and Chukchi seas. The roles that the individual structural elements and the stratigraphic sequences play in the generation, migration, and accumulation of hydrocarbons varies from north to south and east to west in the area of interest.

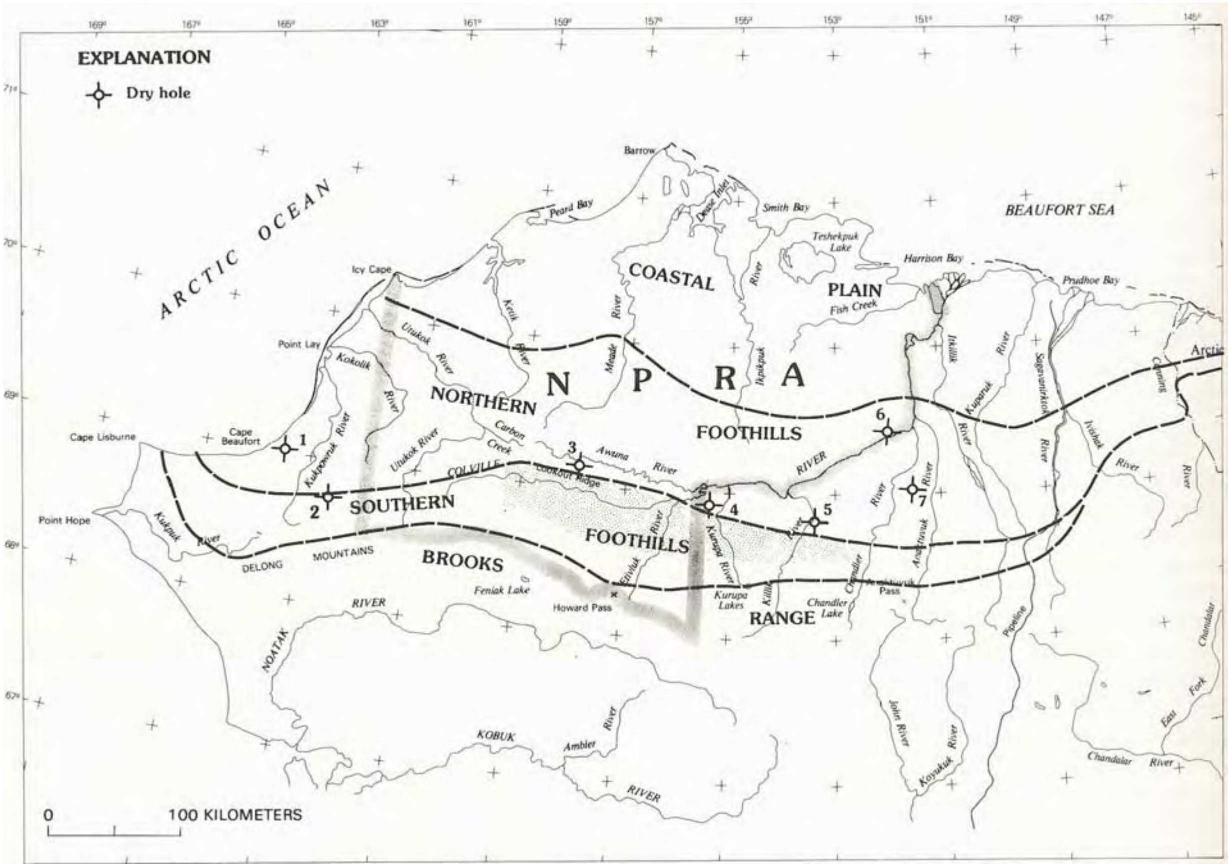

Figure 2.2 North Slope Physiographic Subdivisions; wells indicated on the map were drilled to the Lower Cretaceous Fortress Mountain Formation. (Source: Molenaar and others, 1988)

2.1.1 Structural Elements

Three or four distinct structural elements have played a major role in the evolution of the North Slope basin. Figure 2.3 shows these elements and the adjacent shelves of the Beaufort and Chukchi seas. The shelf margin is considered to lie just seaward of the 100-meter isobath. The Barrow Arch and Ellesmerian passive margin upon which it developed are in the north and the Colville basin/trough occupies much of the central portion of the North Slope with the Brooks Range, shown in a variety of lithologic patterns, to the south. The grid represents 1:250,000 scale quadrangle boundaries. Ks and Ts represent outcrop areas of Cretaceous and Tertiary rocks respectively.

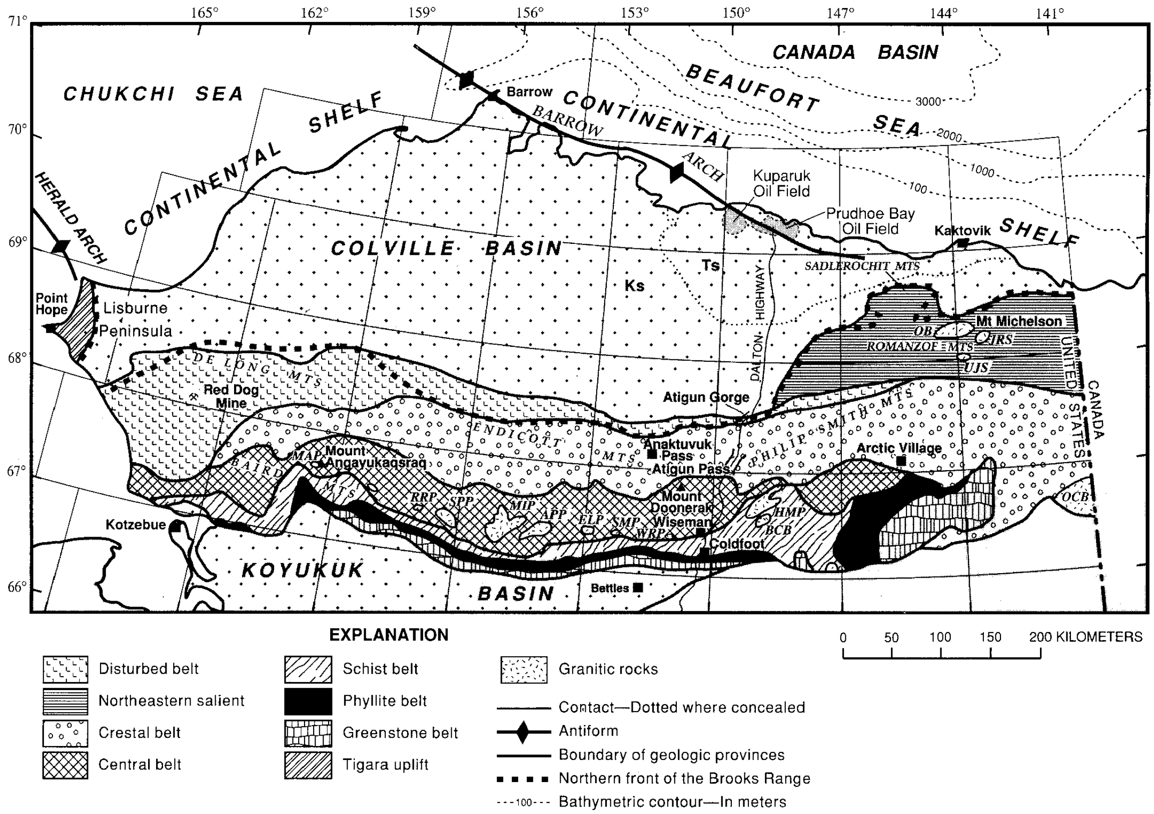

Figure 2.3. Geological provinces of northern Alaska. (Modified from Moore and others, 1994) The plutons are presented for reasons unrelated to this report.

APP	**Arrigetch Peak pluton;**	**OB**	**Okpilak batholith;**
BCB	**Baby Creek batholith;**	**OCB**	**Old Crow batholith;**
ELP	**Ernie Lake pluton;**	**RRP**	**Redstone River pluton;**
HMP	**Horace Mountain pluton;**	**SMP**	**Sixtymile pluton;**
JRS	**Jago River stock;**	**SPP**	**Shishakshinovik Pass pluton;**
MAP	**Mount Angayukaqsraq plutons;**	**UJS**	**Upper Jago River stock;**
MIP	**Mount Igikpuk pluton;**	**WRP**	**Wild River pluton**

Figure 2.4 is a regional north-south cross-section from the Brooks Range to the Beaufort Sea coast and shows regional stratigraphic relationships, which are discussed later in the report, as well as the major tectonic elements. The oldest element occurs in the northernmost portion of the area and is the Early Mississippian, or latest Devonian to Jurassic passive margin, which was overprinted by the Jurassic to Cretaceous rifting episodes that led to the opening of the Canada Basin and the development of the Barrow Arch. Concurrent, at least in part, with the rifting episode was the development of the fold and thrust belt of the ancestral Brooks Range to the south, and the subsidence of the intermediate area to form the Colville trough. The tectonic regimes responsible for the generation and perpetuation of these features strongly controlled the character and distribution of the sediments deposited during their development and subsequent history.

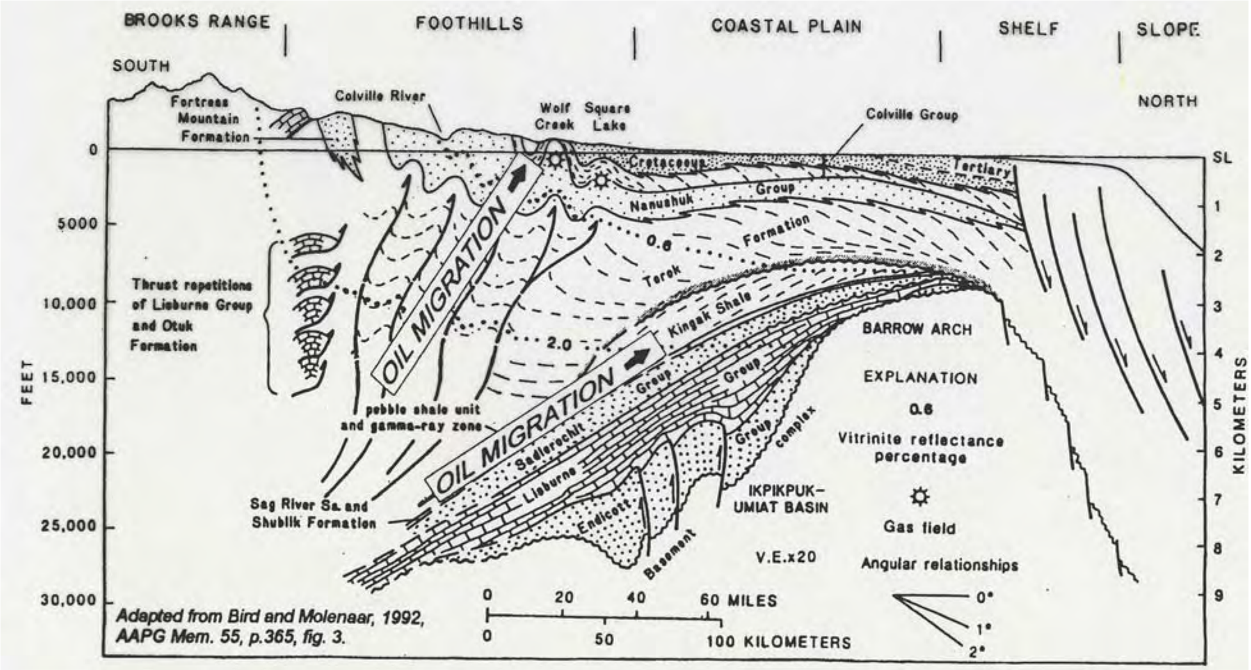

Figure 2.4. North Slope regional south to north cross-section from the Brooks Range to the Beaufort Sea. Also shows the hydrocarbon generation window, 0.6 to 2.0 % Ro – See Figure 2.23 (page 2-109) and oil migration pathways. (Source: Sherwood, and others, 1998)

2.1.1.1 Passive Margin/Barrow Arch

The oldest and longest lasting tectonic element of the North Slope was the passive margin that dominated deposition from the Early Mississippian to the close of the Triassic. It was overprinted in the Jurassic and Early Cretaceous by rifting associated with the opening of the Canada Basin. There were at least two rifting episodes, a failed episode in the Jurassic and the rifting responsible for the opening of the Canada Basin in the Early Cretaceous (Grantz and May, 1983 and Hubbard, and others, 1987). By the close of the Early Cretaceous, the northern area had ceased to be a positive sediment source and the North Slope area began to receive sediment from the newly emergent sources to the south and southwest.

2.1.1.1.1 Passive Margin

From the Early Mississippian through the Triassic, the northern portions of the North Slope and Beaufort Sea shelf (Figure 2.3) were part of a large continental mass that was co-extensive with the present-day Canadian Arctic Islands. This passive continental margin supplied large volumes of compositionally and texturally mature sediment to tectonically quiescent coastal plain and shallow marine environments across much of the present-day North Slope. The passive margin regime was disrupted and largely terminated by extensional rifting events that created the Canada Basin, which lies to the north of the present-day Beaufort Sea coastline. The formation of the Canada Basin separated the Mississippian through Triassic rocks of the North Slope from their more proximal facies now preserved in the Canadian Arctic Islands. These passive margin rocks comprise the major reservoirs at the Prudhoe Bay, Lisburne, and Endicott fields, as well as smaller satellite fields. Additionally, at least one major source rock was deposited during this time.

2.1.1.1.2 Barrow Arch

A failed rifting episode in the Early Jurassic was followed by a successful rifting event in the Early Cretaceous, which ultimately resulted in the creation of the Canada Basin and established the Barrow Arch (Figure 2.3) as an uplifted rift margin (Hubbard, 1988). The tectonic style north of the rift rim was dominantly extensional and large grabens and half-grabens are common within the Jurassic section seaward of the arch (see Figure 2.4). Sediments were derived from the uplifted rift rim and generally transported southward but locally to the west and north. The reservoirs for the Kuparuk, Milne Point, and Point McIntyre fields and a number of satellites are associated with these events. A major oil-prone source rock is also a product of this rifting episode. The arch ultimately became a major structural culmination that acted as a focusing mechanism for hydrocarbons migrating out of the mature source intervals lying both to the south in the Colville trough and to the north in the Canada Basin.

2.1.1.2 Brooks Range Fold and Thrust Belt

Convergence between the southern margin of northern Alaska and the Paleo-Pacific Basin gave rise to the ancestral Brooks Range fold and thrust belt (Figures 2.3 and 2.4) of the southern portion of the North Slope (Grantz, and others, 1994). There were several pulses of shortening and deformation throughout the Cretaceous and into the Cenozoic, during this Brookian orogenesis (Hubbard, and others, 1987). Total crustal shortening in the western Brooks Range is estimated to be on the order of 420 to 480 miles (700 to 800 km) or more (Mayfield, and others, 1988). The convergence commenced in the Early to Middle Jurassic and was largely completed by Albian time.

The onset of deformation was earliest in the west becoming progressively younger to the east. Direct geological evidence and apatite fission track dating indicate that there were at least three relatively widespread deformation events, that represent kilometer-plus uplift and denudation in the central Brooks Range during the late Early Cretaceous (~100 Ma), the Paleocene (~60±4 Ma), and the latest Oligocene or earliest Miocene (~25±3 Ma) (O'Sullivan, 1996 and O'Sullivan and others, 1997)). North of the central Brooks Range, in the southern portion of the Colville trough, the fission-track data indicate four episodes of kilometer-scale uplift and denudation (O'Sullivan, and others, 1997). These include the 60 Ma and 24 Ma events of the central Brooks Range and episodes in the middle Eocene (~46 Ma) and early Oligocene (~34 Ma) (O'Sullivan, and others, 1997 and Mull, and others, in press). To the east in the Canadian Beaufort Sea-Mackenzie Delta region the youngest events are Miocene and younger (Lane, 2002). The sediment eroded from the developing Brooks Range was shed north and east into the Colville trough and supplied both source rocks and reservoirs for oil and gas accumulations.

2.1.1.3 Colville Trough/Basin

The Colville trough is a structural trough trending east-northeast to west-southwest and flanked by the Barrow Arch to the north and the Brooks Range to the south. It is filled with sedimentary rocks that range in age from latest Jurassic to Pliocene. The sedimentary fill of the trough was derived from emergent uplands in the ancestral Brooks Range and the Hearld Arch to the south and west. The uplift, resulting from the collision of Arctic Alaska with the Paleo-Pacific Basin, is time transgressive. The resulting basin, the Colville Trough, was filled with sediment derived from high, active uplands to the south by short, high-gradient streams, supplying coarse, poorly sorted, and compositionally immature detritus. The westerly sourced material arrived at the depositional site via long, low-gradient streams carrying finer-grained, texturally and compositionally more mature (better sorted and more quartzose) detritus.

The short vigorous streams from the south caused the shoreline and shelf-margins to prograde rapidly northward and the west-to-east flowing streams shifted the shoreline and shelf-margin eastward through time. The result of the interaction of these two systems was a rapidly filled basin whose depocenter and depositional facies shifted northeast as the basin was filled with sediment. The ultimate result is that the sedimentary packages prograded northeastward and ultimately over-topped the Barrow Arch and were deposited on the north-flank of the arch and into the Canada Basin.

The sedimentary fill is less mature than that deposited in association with the passive margin and rifting stages of the North Slope. Consequently, the potential for development of good to high quality reservoirs is much lower than in the northerly sourced lithologic assemblages. Where these rocks have been more extensively evaluated, to the north where they lap onto or across the Barrow Arch, they have proven to host oil accumulations in reservoirs of diverse character. Fields such as Tarn, West Sak, Schrader Bluff, and Badami are developed in reservoirs of this nature and at least one major oil-prone source rock is known.

2.1.2 Stratigraphic Framework

The prospective sedimentary packages that underlie northern Alaska and the adjacent continental shelves span approximately 360 million years (m.y.) of geologic time and represent the deposits of two overlapping basins. The older basin abutted a continent that existed to the north of the present-day North Slope. The deposits of this basin grade from proximal in the north to distal in the south and have been generally assigned to the Ellesmerian sequence. The younger basin was formed as a deep trough (the Colville basin) in front of the rising Brooks Range. The Brookian sequence deposited in this basin consists of fluvial, deltaic, and shallow marine deposits to the south and coeval marine slope and basinal facies to the north or northeast. The transition period between these two overlapping tectonic events is represented by rocks of the Beaufortian sequence, which were derived from rifting of the Ellesmerian continental margin and deposited in grabens along the southern margin of the present Arctic Ocean basin and as a prograding series of deposits across the North Slope.

The stratigraphic succession of the North Slope has been subdivided into four sequences. These are the three cited above plus the older "basement" succession. Lerand (1973) originally identified three sequences, as shown in Figure 2.5, based on their provenances. The oldest being the Franklinian of Devonian and older age, and named for the Franklinian Geosyncline of the Arctic Archipelago. Where originally recognized (Lerand, 1973), the Ellesmerian sequence was considered to represent an Early Mississippian to late Early Cretaceous carbonate and clastic succession derived from present-day north as a product of the Ellesmerian orogeny. The youngest interval, the Brookian sequence was considered to be comprised of a predominantly clastic succession of Middle Jurassic to Pliocene age, sourced from the Brooks Range and Herald Arch lying to the south and southwest respectively. With detail derived from extensive seismic data acquisition and exploration drilling, Hubbard, and others (1987) recognized the Beaufortian sequence, comprised of middle to late Mesozoic strata derived from the uplifted rift margin.

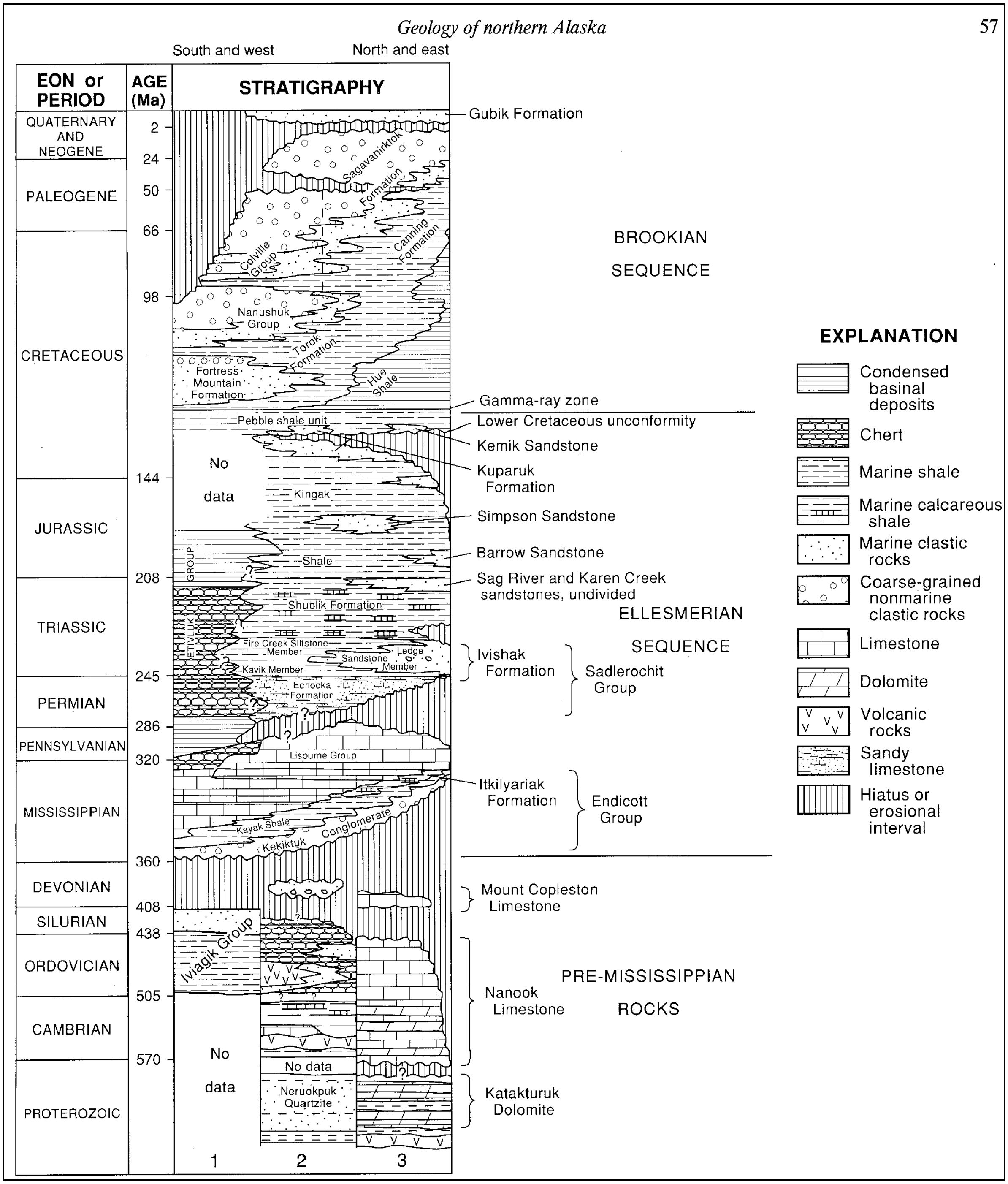

Figure 2.5. Generalized stratigraphic column of the North Slope, Alaska: Franklinian rocks are representative of three distinct areas; 1. Lisburne Peninsula, 2. Romanzof Mountains, and 3. Sadlerochit and Shublik Mountains. (Source: Moore, and others, 1994)

The relationships among the various sequences are not always simple and straight forward. Numerous unconformities may suprapose intervals as young as Eocene/Paleocene directly upon strata of Proterozoic age. Figures 2.6 and 2.7 demonstrate this relationship in west-east and south-north cross sections. Figure 2.6 trends from Prudhoe Bay eastward across the Endicott field, and Figure 2.7 parallels the Canning River from the northern foothills belt to the

Beaufort Sea. Both sections demonstrate the degree to which the areal distribution of known highly productive hydrocarbon-bearing units may be limited as a result of truncation and complete removal by erosional episodes.

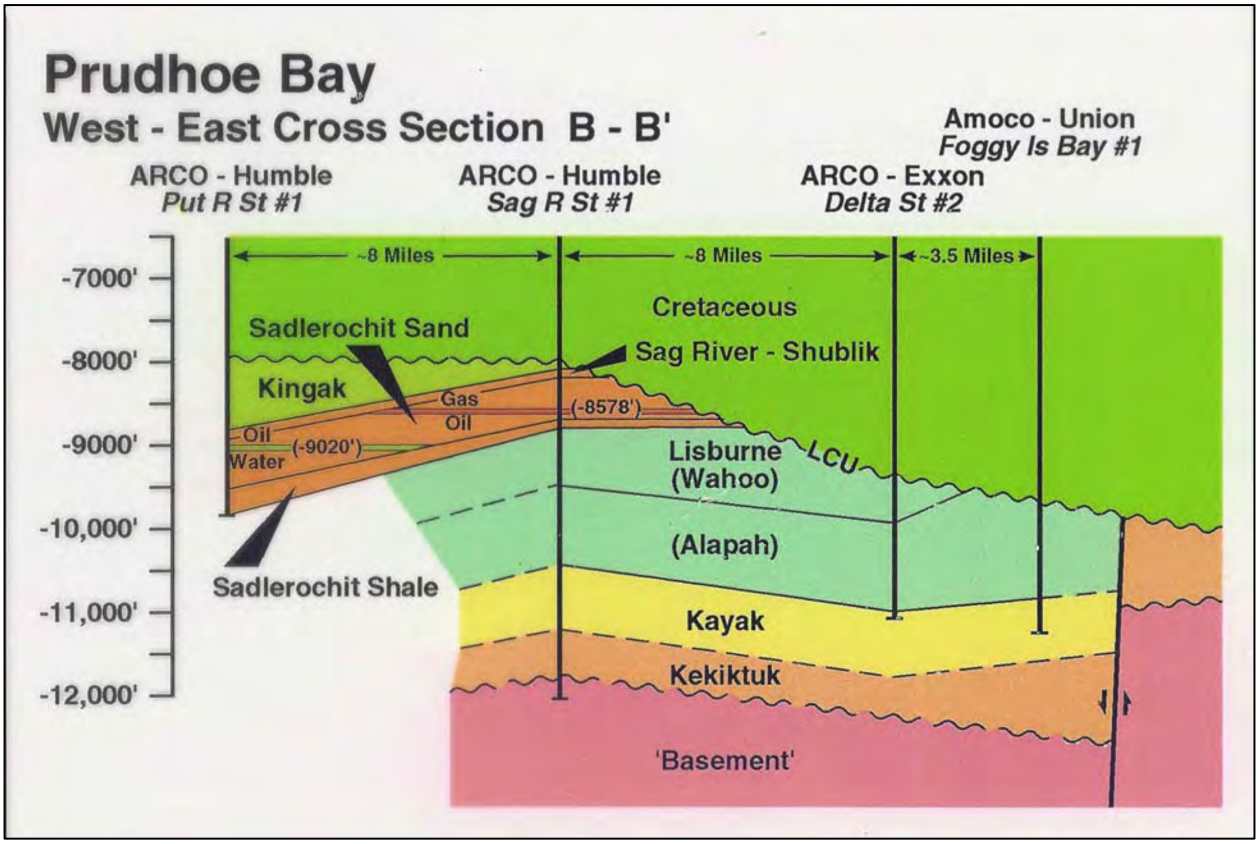

Figure 2.6. West to east cross-section from Prudhoe Bay to Foggy Island Bay St. No.1. Note truncation, by the Lower Cretaceous Unconformity (LCU), of the interval from the Jurassic Kingak Shale through the Mississippian Lisburne Group.

These four major stratigraphic sequences all have some degree of hydrocarbon potential. To date the Ellesmerian, Beaufortian, and Brookian sequences have all provided source rocks, reservoirs, and commercial accumulations of oil. The older and, in many places, metamorphosed rocks of the Franklinian have not yet been demonstrated to possess viable economic objectives.

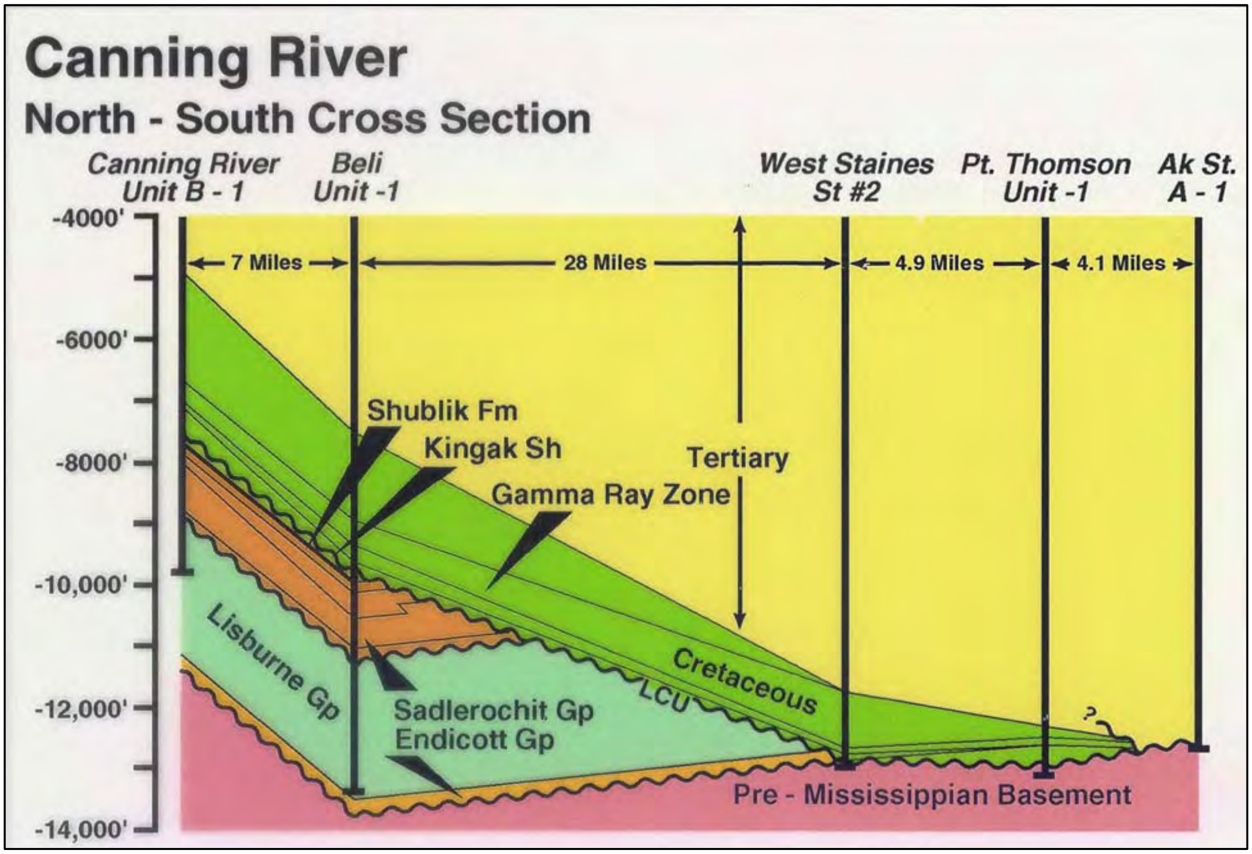

Figure 2.7. South to North cross-section along the west side of the Canning River. Note truncation, by LCU, of the Jurassic Kingak Shale through the Mississippian Endicott Group and into the pre-Mississippian "basement".

2.1.2.1 Franklinian Sequence

The rocks of the Franklinian sequence are the oldest units on the North Slope, ranging in age from Proterozoic to Late Devonian. These rocks have variously been referred to in the literature as pre-Mississippian, "the argillite', Neruokpuk, and "basement". Most of these terms are misleading or inadequately describe the rocks. All pre-Mississippian age units of the Brooks Range and subsurface of the North Slope are assigned to the Franklinian sequence (Lerand, 1973). The most complete, yet general, references regarding the Franklinian stratigraphy of the North Slope of Alaska and the Yukon Territory are Dutro and others (1972), Norris (1985), and Mull and Anderson (1991). The uppermost portion of the Franklinian sequence consists of the lower Paleozoic and upper Proterozoic formations depicted in Figure 2.5. In Alaska, the rocks of the Franklinian have generally been considered to be economic basement, although shows of oil and gas have been reported in the Point Thomson area.

The units of primary interest are carbonates of the Katakturuk Dolomite (late Proterozoic), Nanook Limestone (Cambrian-Ordovician), and Mt. Coplestone Limestone (Silurian). Each of these units is bounded by unconformities and has limited regional distribution. These three formations are largely restricted to the area of the Sadlerochit and Shublik Mountains and to the adjacent subsurface portions of the 1002 Area of ANWR and the northeastern portions of the Colville-Canning province.

2.1.2.1.1 Katakturuk Dolomite

The age of the Katakturuk Dolomite is Proterozoic, based on the 700 to 800 Ma age determined from volcanics interbedded in the basal portion of the Katakturuk (Clough, and others, 1990). The Katakturuk unconformably overlies the Neruokpuk Formation and is in turn unconformably overlain by rocks ranging in age from the Cambrian-Ordovician Nanook limestone to the Paleocene Sagavanirktok/Canning Formations (Figure 2.5). The Katakturuk is up to 8,000 ft (2,450 m) thick and consists of a shallowing upward carbonate succession. The bulk of the unit is comprised of partial cycles of intratidal to supratidal deposition (Clough, 1989).

2.1.2.1.2 Nanook Limestone

The Nanook Limestone (Cambrian to Early Ordovician) is defined as a 4,200 ft (1,300 m) thick succession of limestone, dolomite, and minor shale that unconformably overlies the Katakturuk Dolomite and is in turn unconformably overlain by the Mt. Coplestone Limestone and younger strata (Figure 2.5). Rocks of the Nanook represent a shallowing upward succession, proceeding from near-slope calcareous turbidites to limestone and vuggy dolomite of shallow-water origin. The uppermost Nanook Limestone consists of pelloidal and oolitic limestone and minor dolomite of subtidal to intertidal environments.

2.1.2.1.3 Mt. Coplestone Limestone

The Mt. Coplestone Limestone (late Early Devonian) rests unconformably upon the Nanook Limestone and is overlain unconformably by strata of the Ellesmerian sequence (see Figure 2.5). It has an approximate preserved thickness of 1,500 ft (460 m) and consists of mudstone, wackestone, and grainstone deposited in shallow subtidal to intertidal environments.

The other recognized units of the Franklinian megasequence are of little importance to this review and are not discussed, but interested readers can examine the references cited in the opening paragraphs of the Franklinian section for additional information.

2.1.2.2 Ellesmerian Sequence

As originally defined the Ellesmerian sequence (Legrand, 1973) spanned the Early Mississippian to late Early Cretaceous. Within the area circumscribed by this report, the recognition of the Beaufortian has restricted the upper limits of the Ellesmerian to the end of the Triassic. The Ellesmerian succession as redefined is bounded by the pre-Mississippian unconformity, associated with the Devonian Ellesmerian orogeny, and the initiation of the first failed rifting episode at the beginning of the Jurassic (see Figure 2.5). The sequence was initially present across the entire North Slope and throughout much of Arctic Canada. Multiple Late Paleozoic and Mesozoic uplifts and associated erosional episodes have limited the areal distribution and completeness of the depositional units of the Ellesmerian sequence (Figures 2.6 and 2.7).

The succession was deposited on a passive south-facing continental margin. The rocks present in the northern part of the area were deposited in a series of nonmarine to shallow-marine depositional environments related to repeated transgressions and regressions. In ascending order the succession is comprised of the Endicott Group, the Lisburne Group, the Salderochit Group, and the Shublik Formation - Karen Creek/Sag River Sandstone (Figure 2.5). Figure 2.5 and Figure 2.11 (page 2-28)[2] show the distal equivalents found in the foothills to the south.

Throughout most of the North Slope the Endicott Group comprises the basal depositional cycle of the Ellesmerian; however, at least locally a series of unmetamorphosed, nonmarine coal-bearing deposits termed "Eo-Ellesmerian" by Grantz, and others (1990) are found confined to grabens and halfgrabens and separated from true Ellesmerian by an unconformity with mild angular discordance. These graben-filling deposits are most common and well-preserved in NPRA, where they are present in thicknesses that range up to nearly 10,000 ft (3,000 m). The overlying typical Ellesmerian deposits transgress northward across these restricted packages and are much more widespread in their occurrence.

2.1.2.2.1 Endicott Group

The Endicott Group consists of two (Figure 2.5) and locally three recognized formations. In ascending order these are the Kekiktuk Conglomerate, Kayak Shale, and Itkilyariak Formation. The truncation of this group to the east and north is demonstrated on Figures 2.6 and 2.7. The contacts between the various formations of the Endicott and with the overlying Lisburne Group are gradational and time transgressive, with the base of each stratigraphic unit becoming progressively younger to the north.

Kekiktuk Conglomerate: The Kekiktuk Conglomerate (Figure 2.5) is the basal transgressive unit of the Endicott and is comprised of a quartz- and chert-rich, largely nonmarine conglomeratic sequence that is up to 1,200 ft (365 m) thick and fines upward through sandstone, siltstone, and coal interbeds into the gradationally overlying Kayak Shale. While the Kekiktuk is highly silica-cemented in outcrop, it has locally developed or preserved excellent reservoir characteristics in the subsurface. It is the principal oil-reservoir at the Endicott and Liberty fields. To the south and to some degree to the west, the Kekiktuk Conglomerate grades laterally into the Kayak Shale or Huntfork Formation.

Kayak Shale: The Kayak Shale conformably and gradationally overlies the Kekiktuk Conglomerate and grades upward into the Alapah Limestone of the Lisburne Group and northward into the Itkilyariak Formation (Figure 2.5). It is more widely distributed than the Kekiktuk and represents the first marine inundation of the Ellesmerian platform. The Kayak is up to 1,300 ft (400 m) thick. It is a marine shale with sandstone interbeds near the base and limestone and dolomite in the upper portion. East of the Sadlerochit Mountains and south of Leffingwell Ridge the Kayak is an organic-rich black shale with a few coals, locally up to 600 ft (180 m) thick (LePain and Crowder, 1991). Due to this characteristic of organic-rich facies, the Kayak may have some hydrocarbon generation potential.

Itkilyariak Formation: The Itkilyariak Formation is at least in part equivalent to the Kayak Shale and represents a more proximal facies deposited in shallow-marine to nonmarine depositional environments. In large part, these rocks are the product of tidal-flat deposition in an arid environment (Bird and Jordan, 1977). The Itkilyariak is typified by red and maroon sandy

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[2] This figure and several others are referenced out of sequence for completeness and will be discussed in the proper context later in the report at the referenced site.

limestone, siltstone, and shale. Although only 150 ft (45 m) thick in outcrop it is up to 1,000 ft (305 m) thick in the subsurface. Both the upper and lower contacts are gradational and conformable.

2.1.2.2.2 Lisburne Group

The Lisburne Group (Figure 2.5) is conformable upon the rocks of the Endicott Group and ranges in age from Early Mississippian to Early Permian. North of the Endicott onlap limit the Lisburne rests unconformably on the Franklinian. The upper contact with the Sadlerochit Group is unconformable (Figure 2.5). The pre-Echooka Unconformity represents a hiatus of more than 40 million years. The Lisburne is widely distributed on the North Slope, but is locally missing to the north and east as a consequence of erosion associated with the LCU (Figures 2.6 and 2.7), and consists mainly of shallow-marine carbonate rocks, with local deep-marine shale, chert and fine-grained limestone and dolomite. North of the Brooks Range, the Lisburne is comprised of platform carbonates with sporadic interbeds of organic-rich shale. In the central and western Brooks Range the Lisburne Group consists of the deep-water Kuna Formation (Figure 2.5) and is generally organic-rich. These organic facies may provide an oil-prone source rock. The Lisburne Group may exceed 5,000 ft (1,525 m) in thickness but the excessive thickness is probably a result of structural thickening. The Lisburne is generally in the range of 2,000 to 3,000 ft (600 to 900 m) thick with a probable maximum thickness of about 3,300 ft (1,000 m).There are three formations recognized, the Wachsmuth, Alapah, and Wahoo and a fourth unit (Early Permian in age) in NPRA is as yet unnamed. The Alapah and Wahoo are better understood and more important from a petroleum perspective.

Wachsmuth Limestone: The basal unit of the Lisburne is the Wachsmuth Limestone of Early and Late Mississippian age. Both the upper and lower contacts are conformable and gradational. It is a more distal facies of the Lisburne and ranges up to at least 700 ft (215 m) in thickness and perhaps as much as 1,150 ft (350 m). The unit consists of several thick packages of nodular or bedded chert and crinoid-bryozoan wackestone overlain by crinoid rudstones. These facies are taken to represent deposition below fair-weather wave base in a deep ramp environment with occasional shoaling (McGee, and others, 2001).

Alapah Limestone: The Alapah Limestone is Late Mississipian in age and is gradational with the underlying Wachsmuth and Itkilyariak/Kayak and the overlying Wahoo. The thickness of the Alapah varies but locally exceeds 1,000 ft (300 m). Three informal members have been recognized. The lower Alapah is comprised of numerous parasequences superimposed on an overall transgressive systems tract. These represent restricted lagoonal to intertidal to high energy shoal environments with cross-bedded grainstones. The fossiliferous limestones of the middle Alapah were deposited below wave base in open marine environments, and the upper Alapah is comprised of spiculitic dolomite and lime mud with evaporate nodules representing restricted-platforms that aggraded to sea level. Good porosity is locally developed in the dolomitic intervals.

Wahoo Limestone: The Wahoo Limestone is Late Mississippian to Early Pennsylvanian in age and ranges to 1,000 ft (300 m) or more in thickness. The basal contact is conformable and gradational with the Alapah and the upper contact is unconformable with the overlying Sadlerochit Group, except in some portions of NPRA where the contact is conformable with the unnamed Early Permian portion of the Lisburne. At least locally, two informal members are recognized. The lower Wahoo is a transgressive-regressive sequence composed primarily of bryozoan and pelmatozoan limestones formed in open marine settings. The upper Wahoo is characterized by numerous small-scale parasequences superimposed on an overall transgressive-regressive sequence. These rocks are equivalent to the oil-producing facies at the Lisburne field.

2.1.2.2.3 Sadlerochit Group

The Sadlerochit Group (Figure 2.5) is comprised of a succession of Early Permian to Early Triassic clastics assigned to the Echooka and Ivishak formations. The Sadlerochit Groups rests unconformably upon the Lisburne and is overlain disconformably to unconformably by the Shublik Formation. At the type section the Sadlerochit is 650 ft (200 m) thick but the thickness varies from zero to well over 1,000 ft (300 m). The Sadlerochit Formation is absent in the northeast portion of the Colville-Canning province and in at least portions of the 1002 Area of ANWR due to truncation by the LCU (Figures 2.6 and 2.7). To the south the Sadlerochit group becomes much finer-grained, and the distal equivalents are the Siksikpuk Formation and the basal portion of the Otuk Formation (Figure 2.5).

Echooka Formation: The Early to Late Permian Echooka Formation is comprised of the Joe Creek and Ikiakpaurak Members. The basal contact is unconformable (Figure 2.5) and, as noted in outcrop, there are a few tens of feet of relief developed where fluvial channels have been incised into the underlying Lisburne limestones. These channelized deposits are overlain by the more uniformly distributed marine calcarenites and associated facies of the Joe Creek Member and the quartz sandstone and siltstone of the Ikiakpaurak Member. In outcrop, the Echooka Formation ranges in thickness from 150 to 450 ft (45 to 135 m) and thicknesses of up to 700 ft (215 m) or more occur in the subsurface. To the south, the Siksikpuk Formation of the Etivluk Group is the Echooka equivalent (Figure 2.5).

The Joe Creek Member is Early to Late Permian in age and is 372 ft (113 m) thick at the type section. It is composed of marine facies. From the base upward it consists of limy mudstone and calcareous siltstone, chert and siliceous siltstone, and calcarenite and bioclastic limestone with quartz grains. This member rests unconformably upon the Lisburne Group and is gradational into the overlying Ikiakpaurak Member.

The Late Permian Ikiakpaurak Member is 280 ft (85 m) thick at the type section and elsewhere in outcrop ranges from 200 to 350 ft (60 to 107 m) thick. The basal contact with the underlying Joe Creek Member is generally conformable. The upper contact with the Kavik Member of the Ivishak Formation is conformable to disconformable, with the disconformity becoming more pronounced to the north of the type locality (Detterman, and others, 1975). The Ikiakpaurak Member is composed of dark-colored highly quartzose sandstone and siltstone with minor interbeds of silty shale.

Ivishak Formation: The Early Triassic Ivishak Formation conformably to disconformably overlies the Echooka Formation, and where the Echooka is absent, rests unconformably upon limestones of the Lisburne Group. The thickness ranges from about 590 ft (180 m) at Marsh Creek to more than 1,800 ft (550 m) on the Ivishak River. A thickness of more than 1,400 ft (427 m) has been noted in the subsurface.

The Ivishak is composed of three distinctive members: the Kavik Shale, the Ledge Sandstone, and Fire Creek Siltstone Members (Figure 2.5). These units respectively represent a transgressive marine phase, a deltaic/fan delta progradational phase, and a destructive delta-plain phase. The principal reservoir horizon at the Prudhoe Bay field is the more proximal equivalent of the Ledge Sandstone Member. Additionally, the Kavik Member may be a potential oil source rock.

The Early Triassic Kavik Shale Member is 278 ft (85 m) thick at the type locality and ranges from 120 to 700 ft (36 to 213 m). The contact with the Echooka Formation is usually disconformable, but locally there is evidence of a slight angular unconformity. The unconformity is present in the Sadlerochit Mountains and at Prudhoe Bay where the Kavik Shale rests directly upon the Lisburne Group. The contact with the overlying Ledge Sandstone Member is gradational and interfingering. The Kavik Shale is comprised of black fissile shale interbedded with widespread units of coarsening upward siltstone and very fine-grained argillaceous sandstone. These prodelta shales represent the culmination of the Sadlerochit Group transgressive episode.

The Early Triassic Ledge Sandstone Member is conformable with both the underlying Kavik Shale and overlying Fire Creek Siltstone members. The member is 189 ft (58 m) thick at the type section where it is unconformably overlain by Cretaceous strata. The Ledge equivalent is up to 650 ft (200 m) thick at Prudhoe Bay field, where it is the primary reservoir and informally termed the "Ivishak Sandstone". Lithologically, the Ledge Sandstone is composed of thick-bedded to massive, fine- to coarse-grained sandstone and conglomerate with minor shale and siltstone. The sandstone is a well sorted, subrounded to well rounded, siliceously cemented quartz and chert arenite. The conglomeratic component increases to the north. The thin siltstone and silty shale beds that are present in outcrop thicken to the south.

The Ledge Sandstone equivalent at Prudhoe Bay has been interpreted to have been deposited in a large fan-delta system. In ANWR and other areas south of Prudhoe Bay field, the Ledge Sandstone is thought to represent a sequence of delta-front sheet sands, distributary channels and proximal mouth-bar deposits. The Ledge Sandstone Member represents the most regressive interval of the Sadlerochit Group. To the south in the Brooks Range foothills the lower portion of the Otuk Formation of the Etivluk Group is considered to be equivalent to the Ledge Sandstone and most of the Ivishak Formation (Figures 2.5 and 2.11).

While the reservoir quality is poor where observed in outcrop samples and in the subsurface of the southern portions of the North Slope, it is excellent at the Prudhoe Bay field. The producing interval contains porosities of up to 35% and permeabilities of more than 4,000 md (Jamison, and others, 1980). This interval may be a primary objective in some parts of the North Slope where conditions similar to those at Prudhoe Bay may be expected to exist. The Northstar field also produces from this unit.

The Fire Creek Siltstone is the uppermost member of the Ivishak Formation, is Early Triassic in age, and lies conformably upon the Ledge Sandstone Member. In ANWR it appears to have a disconformable to conformable contact with the overlying Shublik Formation. The Sadlerochit-Shublik contact is distinctly unconformable at the Prudhoe Bay field. The thickness at the type section is 110 ft (33 m) and the thickness in outcrop ranges from 0 to 440 ft (0 to 134 m), with some of this variation related to pre-Shublik erosion. The Fire Creek Siltstone is a thin-bedded to massive, medium to dark gray to black siltstone, with minor silty shale and argillaceous sandstone and is interpreted to represent the reworking of the lower delta-plain during the destructive phase of the Ivishak delta system. The member thickens and becomes more shale-rich to the south. To the north, as at Prudhoe Bay, the Fire creek Siltstone is absent or has become lithologically indistinguishable from the upper portion of the Ledge Sandstone.

2.1.2.2.4 Shublik Formation

The Shublik Formation (Figure 2.5) is a Middle-to-Late Triassic unit that rests unconformably atop the Sadlerochit Group in northern ANWR and at the Prudhoe Bay field. This unconformity dies out to the south and the basal contact with the Sadlerochit becomes gradational. The contact with the overlying Karen Creek Sandstone is conformable and gradational. The approximate maximum thickness is about 650 ft (200 m) with outcrop sections generally ranging from 300 to 450 ft (91 to 137 m). In the subsurface west of ANWR, the Shublik Formation has a maximum known thickness of 283 ft (86 m) in the Kemik No. 1 well. The Shublik, as many other Ellesmerian units, is absent in the northeastern portion of the Colville-Canning province and the adjacent northwest part of the 1002 Area as the result of erosion associated with development of the LCU.

The Shublik Formation is composed of phosphatic, organic-rich, fossiliferous limestones, calcareous shales, siltstones, and thin sandstones. Four informal members or subunits have been recognized. The formation is rich in organic carbon and is an important source rock for the Prudhoe Bay area oil fields. The bulk of the Otuk Formation of the Etivluk Group (Figure 2.5) is the distal equivalent of the Shublik Formation. The Shublik Formation is thought to represent continued subsidence of the basin after Sadlerochit deposition. A minor regression at the top resulted in the deposition of the overlying Karen Creek Sandstone.

2.1.2.2.5 Karen Creek Sandstone/Sag River Sandstone

Late Triassic Karen Creek Sandstone or Sag River Sandstone of the subsurface (Figure 2.5) is 70 ft (21 m) thick at the type section and outcrop thickness ranges from 10 to 125 ft (3 to 38 m). The maximum thickness in the subsurface is 330 ft (100 m) in northeastern NPRA. These sandstone packages are discontinuous, southward thinning units. In the foothills to the south it is represented by the Karen Creek Member of the Otuk Formation, generally a sandstone bed about 1 to 2 ft (0.3 to 0.6 m) thick (Figure 2.5). Like the other units of the Ellesmerian its distribution is limited by the LCU.

The unit is very fine-grained, calcareous and locally phosphatic and glauconitic quartzitic sandstone. It conformably overlies the Shublik Formation and appears to be onlapped by the Kingak Shale of the overlying Beaufortian sequence. The Karen Creek Sandstone is termed the Sag River Sandstone in the subsurface of the Prudhoe Bay and Colville Delta areas. The presence of marine fossils, bioturbation, glauconite and phosphate, bedding characteristics, and widespread distribution indicate deposition on a broad shallow-marine shelf, with a northern source area. In surface exposures, the unit is very fine-grained, well cemented and has limited thickness, but it is an oil-producing interval (Sag River Sandstone) at Prudhoe Bay and other fields and contains gas at the Kemik gas field.

2.1.2.3 Beaufortian Sequence

The Beaufortian sequence, as defined by Hubbard, and others (1987), includes the Jurassic and the bulk of Early Cretaceous deposition in the northern portion of the North Slope (Figure 2.8). In a regional sense the Beaufortian sediments were derived from the north and from uplifted elements associated with the several rifting episodes that ultimately culminated in the opening of the Canada Basin and formation of the Barrow Arch. The Beaufortian of the northern portion of the North Slope is comprised of the Kingak Shale with included sandstone members (Barrow, Simpson, Nechelik, Nuiqsut, and Alpine), Kuparuk River Formation (Kemik Sandstone), Pebble Shale/highly radioactive zone (HRZ)[3] or "condensed radioactive shale", and Thomson Sandstone. In the southern foothills, the Blankenship Member of the Otuk Formation is equivalent to at least the lower portion of the Kingak Shale.

2.1.2.3.1 Kingak Shale

The Kingak Shale (Jurassic and Early Cretaceous?) is up to 4,000 ft (1,220 m) thick in outcrop and 3,748 ft (1,140 m) in the subsurface (Pessel, and others, 1978). The nature of the contact with the underlying Karen Creek is uncertain. Bird and Molenaar (1987) consider the contact to be conformable and Robinson, and others (1989) assert that it is disconformable. In this report, the contact is represented as being conformable (Figure 2.5).

The Kingak Shale consists of calcareous and pyritic shale and siltstone with minor fine-grained sandstone intervals. Seismic and outcrop data indicate that the Kingak is composed of at least four southward-prograding, offlapping, and downlapping wedges of sedimentary rock (Bruynzeel, and others, 1982). These cycles consist of shelf and slope sequences that grade southward into basinal facies, which were deposited at depths of 1,300 to 3,300 ft (400 to 1,000 m) or greater (Molenaar, 1988). Each cycle demonstrates a coarsening upward character, from shale to siltstone with shelfal sandstones of limited areal extent at the top. These sandstones are developed as bar or shelf sands during the maximum regressive phase of the cycle and generally are fine- grained, bioturbated, and glauconitic. They grade laterally into the shales of the Kingak both to the north and south. At least five such sandstone packages have been recognized to date (Figure 2.8).

Barrow Sandstone: The Barrow Sandstone (Early Jurassic) in northwestern NPRA is the oldest of these sandstone packages. It occurs near the base of the Kingak Shale and is gas bearing in the vicinity of Barrow.

Simpson Sandstone: The Simpson Sandstone of Middle or Late Jurassic age is a glauconitic sandstone found in the subsurface in north-central NPRA. Like the Barrow Sandstone it appears to be a shallow-marine, bar sandstone.

Nechelik Sandstone: The Nechelik Sandstone is an early Late Jurassic sandstone found in the subsurface of the Colville Delta and northeastern NPRA. Much like the older Simpson and Barrow sandstones, it is interpreted to be a shallow-marine, inner shelf sandstone, probably

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[3] The HRZ is also referred to as the GRZ (gamma ray zone) in some of the writings on North Slope petroleum geology

deposited in a lower shoreface depositional setting (Kornbrath, and others, 1997). The Nechelik Sandstone is 65 ft (20 m) thick in the Nechelik No. 1 well.

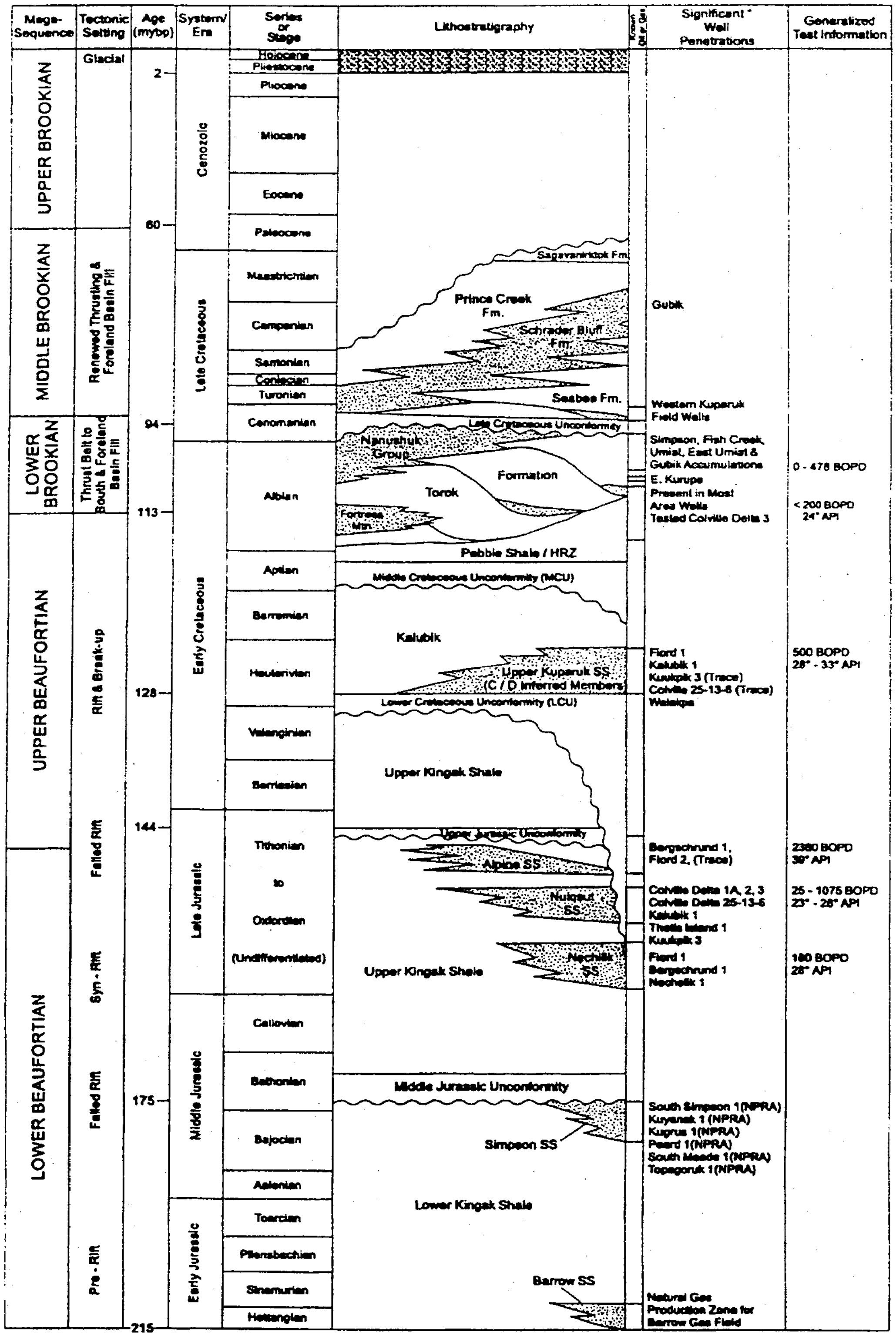

Figure 2.8. Beaufortian and Brookian megasequences of northern NPRA and the western Colville-Canning area. (Source: Kornbrath, and others, 1997)

Nuiqsut Sandstone: The Late Jurassic Nuiqsut Sandstone is found in the Colville Delta/northeastern NPRA area. It is somewhat younger than the Nechelik Sandstone but appears to have a similar origin and distribution. The Nuiqsut Sandstone is well developed in the Colville Delta No. 1 well, where is has an aggregate thickness of at least 152 ft (46 m). To the east, it is 224 ft (68 m) thick in the Kalubik No. 1 well (Kornbrath, and others, 1997).

Alpine Sandstone: The Late Jurassic Alpine Sandstone is the youngest of the shallow-marine bar sandstones of the Kingak. It is present in the subsurface of the Colville Delta and northeastern NPRA and is another of the sequence of shallow-marine bars at the top of the regressive cycles of the Kingak. It is 52 ft (16 m) thick in the Bergschrund No. 1 well and appears to thin and onlap the Colville high. The thinning appears to be due to both onlap and truncation. Truncation related to the development of intra-Kingak unconformities may be a feature associated with all of these sandstones; thus, these sandstones or age equivalent packages may be relatively widespread but preserved as somewhat discontinuous and isolated bodies.

The uppermost Kingak in NPRA is considered to be Early Cretaceous. The Miluveach Formation of Carman and Hardwick (1983), in the area of the Kuparuk River field, may be the equivalent of this upper-most unit of the Kingak.

2.1.2.3.2 Kuparuk River Formation and Kemik Sandstone

The Kingak is overlain in many areas by one or more Early Cretaceous sandstones. In the outcrop areas of ANWR and the eastern portion of the Colville-Canning province, the Kemik Sandstone rests unconformably upon the Kingak. In the subsurface to the west in the Prudhoe Bay and Kuparuk areas the Kuparuk River Formation is partially equivalent to the Kemik. The lower portion of the Kuparuk River, the Kuparuk A-and B-intervals are preserved beneath the LCU and the upper Kuparuk C-Interval lies above it. The Kuparuk C is considered equivalent to the Kemik. Molenaar, and others (1987) consider the Walakpa, Put River, and Thomson sandstones equivalents of the Kemik/Kuparuk C-interval (biostratigraphic control places the Thomson in the Albian or considerably younger than the Hauterivian Kemik). These sedimentary packages are derived from rift-related highs and sediments were dispersed in a variety of directions, not just to the south, as may be suggested by the regional framework.

Kuparuk River Formation: The Kuparuk River Formation of Valanginian to Hauterivian age consists of two informal members separated by the LCU. The lower member is comprised of subunits A and B (Carman and Hardwick, 1983) and lies immediately below the LCU and atop the Kingak as shown in Figure 2.5. Unit A has a maximum thickness of approximately 120 ft (36 m) and is comprised of a heterolithic assemblage of sandstones, siltstones, and mudstones in regressive cycles. Unit B is similar to unit A, and it also coarsens upward but with less sandstone. The maximum thickness is about 150 ft (46 m). Both units thin westward due at least in part to truncation by the LCU.

The upper member (Figures 2.5 and 2.8) is comprised of subunits C and D (Carman and Hardwick, 1983), is principally Hauterivian, and is equivalent to the Kemik Sandstone in the exposures to the east. The C-interval is comprised of a variety of shallow-marine facies ranging from debris-flow(?) deposits at Pt. McIntyre to inner-shelf shoreface deposits. The maximum thickness is in excess of 400 ft (122 m). The D-interval is predominantly mudstone and has a more restricted areal distribution. The basal contact of the Kuparuk River Formation with the underlying Miluveach or Kingak is conformable and gradational. The upper contact with the Pebble Shale or Kalubik Formation is also conformable and gradational (Figure 2.8).

Kemik Sandstone: The Kemik Sandstone of the eastern Colville-Canning province and adjacent areas to the east and south is equivalent to the upper member of the Kuparuk River Formation (C- and D-intervals) (Figure 2.5). The Kemik is Hauterivian to Barremian in age and ranges for 30 to 100 ft (9 to 30 m) in outcrop to nearly 300 ft (91 m) in the subsurface. Where present, the Kemik is directly atop the LCU and rests unconformably upon the Kingak Shale. The upper contact with the Pebble Shale unit is conformable and sharp. The Kemik is composed of three distinct facies (Mull, 1987). These facies are: 1) a shoreface to foreshore bar facies of cross-bedded and hummocky bedded sandstone with minor conglomerate and siltstone; 2) a back barrier lagoonal facies comprised of interbedded bioturbate and pebbly mudstone, siltstone, and fine-grained sandstone; and 3) an offshore marine facies of bioturbated mudstone/shale with thinly laminated siltstones.

2.1.2.3.3 Pebble Shale Unit

The Pebble Shale unit (Figure 2.8) is an informal designation for a series, of Hauterivian to Barremian, noncalcareous, clayey to silty shales. The shales are characterized by minor scattered rounded and frosted quartz grains, common to rare matrix-supported chert and quartzite pebbles or granules, and rare cobbles (Detterman, and others, 1975). The Pebble Shale is conformable on the Kemik and its equivalents and unconformable on the Kingak and older rocks where the Kemik or its equivalents are absent (Figure 2.5). The upper contact with the HRZ is disconformable. The lower portions of the Pebble Shale may be in part age-equivalent to the younger portions of the Kemik. These rocks appear to have been deposited in slope to basin environments. The organic-carbon content is typically 1 to 3% total organic carbon (TOC) and capable of generating hydrocarbons (Magoon, and others, 1987).

2.1.2.3.4 Thomson Sandstone

The uppermost Beaufortian unit is known only from the subsurface of the Point Thomson-Mikkelsen Bay area. The Thomson Sandstone rests unconformably upon Franklinian or Ellesmerian sequence rocks and grades laterally, as well as vertically, into the south-sourced HRZ of the Brookian Sequence. The unit ranges from 0 to 300 ft (0 to 92 m) thick. The Aptian to Albian Thomson Sandstone is considerably younger than the Kemik Sandstone, with which it has been correlated by several authors (Bird and Molenaar, 1987 and Banet, 1990). The Thomson Sandstone is a lenticular body composed of quartzose and dolomitic sandstone and angular conglomerate (breccia?). These lithologies suggest a local source from the underlying Franklinian carbonates and clastics. The rocks appear to have been deposited in a high energy shallow marine environment in close proximity to a northern source, probably exposed along or near the crest of the then emergent Barrow arch. Similar age coarse clastics may be present in the subsurface to the south.

2.1.2.4 Brookian Sequence

The Brookian sequence of Lerand (1973) is comprised of rocks of Late Jurassic or Early Cretaceous through Tertiary age (Figure 2.8). For much of the Early Cretaceous, rocks assigned to the upper portion of the “northerly-sourced” Beaufortian are age equivalents to the basal portions of the “southerly-sourced” Brookian (Figure 2.5). A primary example of this is the relationship between the Barrow arch-sourced Thomson Sandstone and the distal, starved-basin Brookian units of the HRZ and Hue Shale. The base of the rock package assigned to the

Brookian Sequence is time-transgressive. The onset of Brookian deposition began approximately 140 Ma, at the start of the Cretaceous, in the south or southwest with the initiation of Okpikruak Formation/Kongakut Formation deposition and about 115 Ma in the north or northeast (the base of the HRZ).

The Brookian Sequence is comprised of approximately 25,000 ft (7,500 m) of clastic sedimentary rocks derived from the Brookian orogenic belt. The source area was the newly emergent ancestral Brooks Range, and the Herald arch of the Chukchi Sea, to the south and southwest respectively. The Brookian sequence depositional pattern reflects a simple basin-filling process in which the depositional system prograded northeastward through the bulk of Cretaceous and Tertiary time (Molenaar, 1983 and Bird and Molenaar, 1987). In a vertical succession, the depositional pattern (megacycle) consists of basal deep-marine basinal deposits overlain by prodelta slope shales, and finally by deltaic and nonmarine deposits that prograded to the east or northeast.

The Brookian megasequence can be subdivided into five megacycles. In ascending order these are 1) the Berriasian to Valanginain Okpikruak Formation; 2) the Hauterivian(?) to Albian megacycle of the Fortress Mountain Formation and lower part of the Torok Formation; 3) the Albian to Cenomanian megacycle of the Torok and Nanushuk Formations; 4) the Cenomanian to Eocene megacycle consisting of the Colville Group and parts of the Hue Shale, Canning Formation, and Sagavanirktok Formation; and 5) the Eocene to Holocene megacycle consisting of the upper parts of the Hue Shale, Canning Formation, and Sagavanirktok Formation (Moore, and others, 1994). The two older megacycles are generally restricted to the southern flank of the Colville trough while the three younger megacycles are shingled from southwest to northeast along the length of the Colville trough.

The following discussions treat the lithologic units of the southern Brooks Range foothills belt and southernmost flank of the Colville trough as the proximal suite of rocks and then relates these to the more distal, northern facies. Several units, most notably the Torok Formation through the Colville Group, are widespread and recognized from the foothills in the south to the Prudhoe Bay area in the north (Figure 2.5). The oldest proximal units of the Brookian are limited in their distribution, especially in respect to their northerly extent and contribute little to the filling of the Colville trough. The Okpikruak and Fortress Mountain formations are the primary examples. The partially equivalent and intervening Torok Formation and the successively younger Nanushuk Formation and Colville Group (Figure 2.8) are much more widespread and constitute much of the sedimentary fill of the western and central portions of the Colville trough.

Mull, and others (2003) revised the Cretaceous and Tertiary stratigraphic nomenclature of the Colville basin and in so doing demoted the Nanushuk Group to formation status and abandoned the use of the six formations of the Nanushuk. The Colville Group was also abandoned and four formations were revised (the Sagavanirktok, Prince Creek, Schrader Bluff and Seabee), and the Tuluvak Tongue was elevated to formation status (Figures 2.9 and 2.10). Some of the figures used in this report are adapted from older references and still retain the pre-2003 revision nomenclature. In the text, an effort has been made to relate the two sets of nomenclature where appropriate, and for most of the Cretaceous section, figures utilizing the Mull and others (2003) revisions will be used (Figures 2.9 and 2.10).

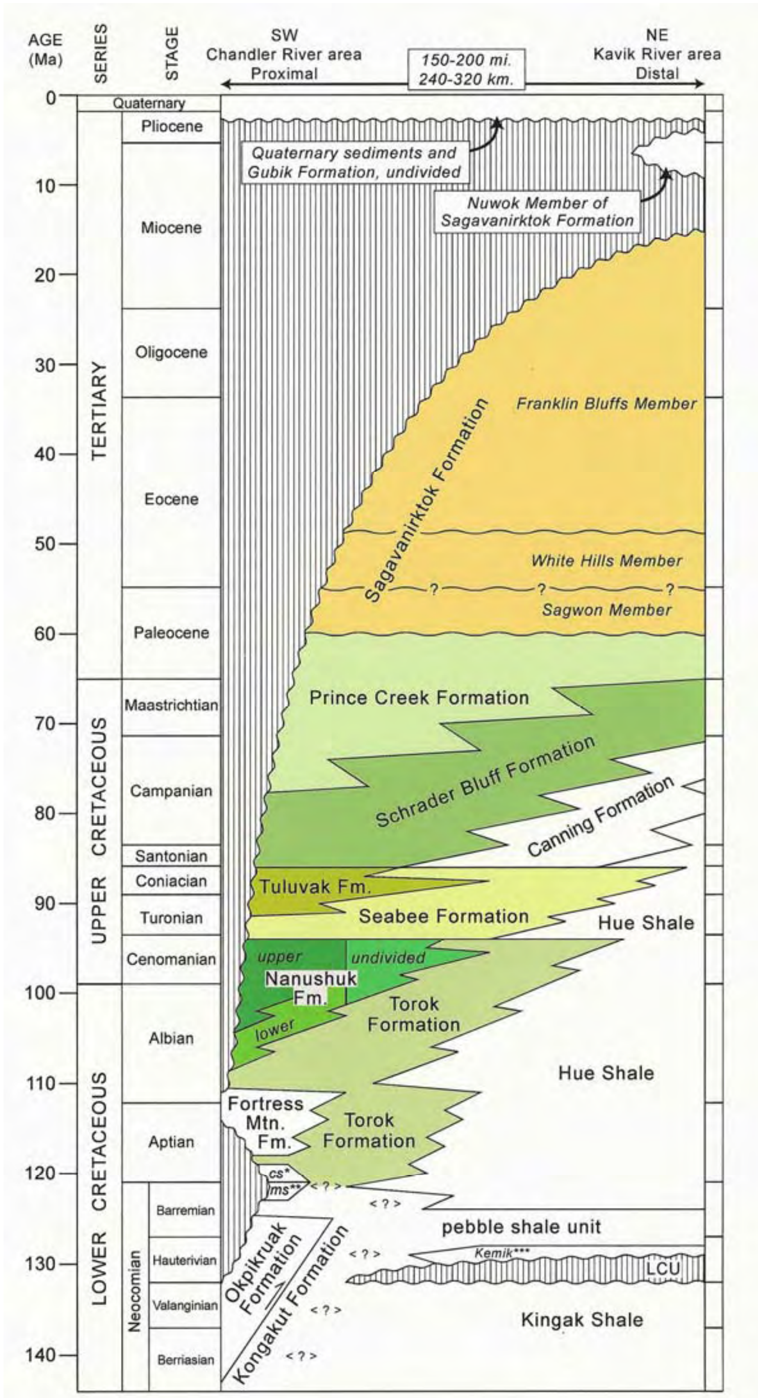

Figure 2.9. Chronostratigraphic column for the Colville basin (trough), northern Alaska, showing the revised stratigraphic nomenclature and ages of units. [abbreviations: <?> = uncertain relationships; cs* = Cobblestone Sandstone; ms* = manganiferous shale; Kemik* = Kemik Sandstone, as Revised by Molinaar, and others, 1987] (Source: Mull and others, 2003)**

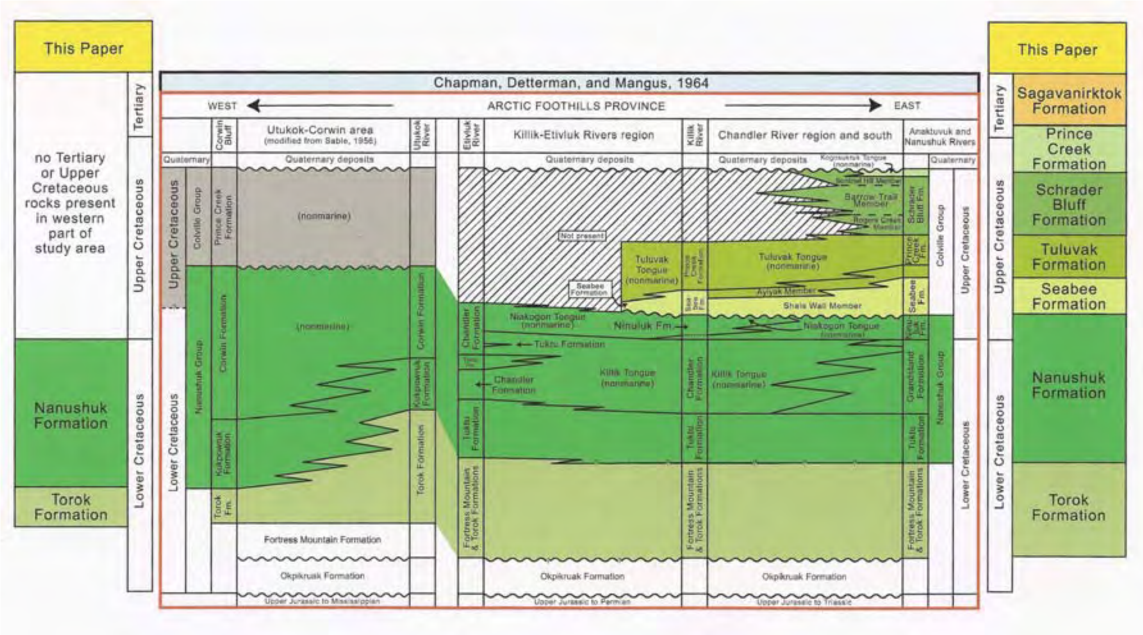

Figure 2.10. Chart illustrating relationship between former stratigraphic nomenclature and revisions as proposed by Mull, and others, 2003. Central columns show the lateral variation in previous stratigraphic nomenclature for Cretaceous stratigraphy from west to east across the western and central Brooks Range (Chapman and others, 1964). Outer columns show revisions by Mull and others (2003).

2.1.2.4.1 Okpikruak Formation

The oldest unit of the Brookian sequence is the Okpikruak Formation (Figures 2.9 and 2.10) of Early Cretaceous (Berriasian and Valanginian) age (Moore, and others, 1994). The maximum thickness of the Okpikruak is estimated to be at least 3,300 ft (1,000 m). The unit is allochtonous and is interpreted to have been originally deposited well to the south and transported northward during the thrusting associated with the Brooks Range orogeny. Lithologically, the Okpikruak is comprised of a deep-water turbidite and debris-flow assemblage with local olistostromes. The Okpikruak rests conformably to unconformably on older rocks of the Etivluk Group. The Okpikruak has a limited distribution and does not appear to exist north of the limits of the allochtonous terranes

2.1.2.4.2 Fortress Mountain Formation

The Aptain to Albian Fortress Mountain Formation (Figures 2.8, 2.9, and 2.10) is up to 10,000 ft (3,000 m) thick and is areally restricted to the southern flank of the Colville trough. The formation represents a major progradation onto the southern margin of the Colville trough in response to the emergence of the ancestral Brooks Range. As a result there is great and rapid lateral diversity in facies. The facies suite ranges from alluvial fans, with debris flows, and braided stream systems through deltaic facies to shallow marine to slope and basin deposits with turbidite and related facies. The proportion of nonmarine and shallow-marine facies, relative to deep-water facies, is higher than the conventional interpretations suggest. The Fortress Mountain was probably deposited on and seaward of a rapidly subsiding narrow shelf by short high-gradient streams draining the newly emergent highlands to the south. Coarse-grained sandstones and conglomerates are common to abundant in most facies. The undeveloped East Kurupa gas field is within the Fortress Mountain/Torok system.

Locally the Fortress Mountain is underlain by the lowermost portions of the Torok Formation and in other places it may rest conformably(?) upon a newly recognized unit, the Kfmv, a volcanic clast-bearing unit at the base of the Fortress Mountain (Wartes and Swenson, 2005 and Peapples and others, 2005) or unconformably upon deformed older strata. Laterally the Fortress Mountain grades into, and intertongues with, the shale and siltstone turbidites of the lower part of the Torok Formation (Mull, 1985). The upper contact with the Torok is also gradational.

2.1.2.4.3 Torok Formation and HRZ

The Torok Formation (Figures 2.8, 2.9, and 2.10) is the slope (foreset) to basin (bottomset) equivalent of the Fortress Mountain and Nanushuk formations and ranges in age from Aptian to Cenomanian. The Torok Formation is comprised of shale and sandstones, primarily of deep-water origin. The Torok was unaffected by the Mull and others (2003) nomenclature revisions. The formation ranges in thickness from 20,000 ft (6,000 m) near the Colville River to less than 330 ft (100 m) in its distal parts east of Prudhoe Bay (Moore, and others, 1994). The Torok Formation contains turbidite packages that exceed 100 ft (30 m) in thickness. The foreset and bottomset strata of the Torok were deposited in water depths of 1,500 to 3,300 ft (450 to 1000 m) and were deposited on and probably pass northward into the HRZ at the base of the Brookian Sequence.

The Torok Formation spans a major portion of the Early Cretaceous and the Fortress Mountain and Nanushuk may be viewed as large-scale progradations of coarse clastic facies into an otherwise shale-dominated basin. The lower portion of the Torok grades into and intertongues with the Fortress Mountain; the upper part grades into and intertongues with the Nanushuk. Mapping the distribution of the transition from the shelfal Nanushuk to the slope and basin assemblage of the Torok depicts an Early Cretaceous coastline and shelf margin that is L-shaped in plan view. Paleocurrents and facies distribution in the Nanushuk and foreset directions in the Torok reveal that the progradation was to the northeast (Bird and Andrews, 1979).

The HRZ is a distal condensed section that underlies and is probably in part equivalent to the lowermost portions of both the Torok Formation (Moore, and others, 1994) and the Hue Shale (Molenaar, and others, 1987). The unit is Aptian to Cenomanian in age and is partially equivalent to and conformably overlies the Thomson Sandstone of the Beaufortian sequence. It is conformable with the underlying Pebble Shale and with the overlying Hue Shale. The HRZ is typically 150 to 250 ft (45 to 75 m) thick, has a high organic content, and is an excellent oil source.

2.1.2.4.4 Nanushuk Formation (revised)

The Nanushuk Formation (Mull and others, 2003), formerly the Nanushuk Group (Gryc and others, 1951), is a thick nonmarine to shallow-marine delta-dominated unit of Albian to Cenomanian age (Figures 2.8, 2.9, and 2.10). The Nanushuk Formation rests conformably and gradationally upon the Torok, grades and intertongues laterally into the Torok, and is overlain conformably to disconformably by the Seabee Formation.

The Nanushuk has a maximum thickness of approximately 20,000 ft (6,000 m) in the western North Slope. The lower portion of the Nanushuk consists of a thick sequence of intertonguing shallow-marine sandstone and shelfal shale and siltstone. The upper part consists of dominantly nonmarine facies, largely associated with two recognized delta systems –the

Corwin and Umiat deltas. These deltaic systems contain facies ranging from alluvial fans through braided stream deposits to upper and lower delta plain and associated facies of the marine to nonmarine transition zone. By Cenomanian time (Moore and others, 1994) the deltas had completely filled the western portion of the Colville trough, prograded across the Barrow arch, and deposited sediment along the margin of the Canada basin.

The coarse grained facies of both the marine and nonmarine systems may act as hydrocarbon reservoirs. Discoveries, noncommercial at this time and primarily in NPRA (Kumar and others, 2002), include East Umiat, Fish Creek, Gubik, Umiat, Meade, Square Lake, Simpson, and Wolf Creek.

2.1.2.4.5 Colville Group (abandoned)

The Late Cretaceous (Cenomanian to Maastrichtian) Colville Group was comprised of three formations (Figure 2.10). In ascending order these were the Seabee Formation, Schrader Bluff Formation, and Prince Creek Formation. The Schrader Bluff and Prince Creek represent coarse progradational tongues into the outer shelf to deep marine facies of the Seabee and the even more distal Canning and Hue Formations (Figure 2.9). As previously defined the Colville Group had an approximate maximum thickness of about 6,500 ft (2,000 m). The term Colville Group was abandoned by Mull and others (2003) and its formations revised; however, it is present on a number of the figures in this report and its use is common in the existing literature.

Seabee Formation (revised): The Cenomanian to Coniacian Seabee Formation (Figures 2.9 and 2.10) is transgressive upon the nonmarine to shallow-marine Nanushuk Formation and the contact is abrupt and disconformable. It is comprised of up to 2,000 to 3,000 ft (600 to 1,200 m) of marine shelf to basin shale and sandstone with tuffs and bentonites. The Seabee was revised by Mull and others (2003) and is less inclusive than as originally defined. The Seabee grades upward into and intertongues with the overlying Tuluvak Formation as defined by Mull and others (2003). The Seabee is productive at Tarn and Milne Point. A preliminary cross section, from Umiat to Milne Point, prepared by the Division of Oil and Gas (Decker, 2006) shows the relationship of the Tarn/Bermuda interval to the Seabee Formation.

Tuluvak Formation (revised): The Turonian to Coniacian Tuluvak Formation (Mull, and others, 2003) is conformable upon and interfingers with the Seabee and is gradational and interfingers with the overlying Schrader Bluff Formation (Figures 2.9 and 2.10). The newly defined formation has a lower section comprised of shallow-marine sandstone and siltstone with interbedded shales which are overlain by nonmarine braided stream facies that in turn grade into shallow-marine sandstones, both upward and to the east. Coals and carbonaceous shales are present in the nonmarine facies. As revised the maximum thickness is probably on the order of 1,200 ft (365 m). The revised Tuluvak Formation is comprised of the Tuluvak Tongue of the Schrader Bluff and the Ayiyak Member on the Seabee as previously defined. The revised Tuluvak contains the gas accumulation at Gubik.

Schrader Bluff Formation (revised): The Santonian to Maastrichtian Schrader Bluff Formation overlies the Tuluvak Formation, is in turn overlain by the Prince Creek Formation, and is comprised of as much as 2,650 ft (800 m) of shallow-marine sandstone and shale. Marineward the Schrader Bluff grades into and intertongues with the Canning Formation. Landward, the Schrader Bluff intertongues with the non-marine Prince Creek Formation (Figures

2.9 and 2.10). The Schrader Bluff is productive at the West Sak, Schrader Bluff, and Tabasco accumulations. The relationship of the Tabasco and West Sak sandstones to the Schrader Bluff Formation is shown in the Umiat to Milne Point cross-section (Decker, 2006).

Prince Creek Formation (revised): The Campanian to Paleocene Prince Creek Formation (Figures 2.9 and 2.10) is at least 1,800 ft (550 m) thick and consists of nonmarine sandstone, conglomerate, shale and coal. The Prince Creek intertongues with the Schrader Bluff to the northeast (marineward) and is overlain conformably to unconformably by the Sagavanirktok Formation. The lower portion of the Ugnu interval at the Kuparuk field is a Prince Creek equivalent.

2.1.2.4.6 Hue Shale

In the eastern portion of the Colville trough the facies are younger than those to the west and are represented by the slope to basin facies of the Hue Shale and Canning Formation and shelf to nonmarine facies of the Sagavanirktok Formation. The oldest of these is the Barremian(?) to Maastrichtian Hue Shale (Figure 2.9), which was originally included in the Shale Wall Member of the Seabee Formation (Detterman, and others, 1975). The Hue Shale is conformable upon the HRZ and the upper contact with the Canning Formation is gradational and interfingering. Laterally it grades into facies of the Seabee Formation. The Hue Shale is 600 ft (183 m) thick at its type section and is not known to exceed 1,000 ft (305 m). The Hue is composed of interbedded black shale, bentonitic shale, bentonite, and hard indurated tuff and is interpreted to be a distal condensed facies (Molenaar, and others, 1987) deposited in slope to basin environments. Molenaar (1987) contrasts the less than 1,000 ft (305 m) of Hue Shale with the greater than 16,000 ft (5,000 m) of coeval strata south of Umiat. The high gamma-ray character and analyses of field samples indicate that the Hue has excellent source rock characteristics.

2.1.2.4.7 Canning Formation

The Santonian (Figure 2.9) to late Eocene or early Oligocene Canning Formation is strongly time transgressive. Both the lower and upper contacts are diachronous and become younger to the northeast (Figures 2.5 and 2.9). The formation is generally 4,000 to 6,000 ft (1,200 to 1,800 m) thick and is composed predominantly of shelf, slope and basin shales with local thick turbidite packages. The dominant turbidite-bearing interval is about 1,000 ft (305 m) thick with amalgamated turbidites up to 30 ft (10 m) thick (Molenaar, 1988). The Canning intertongues with the Staines tongue of the Sagavanirktok Formation. Possible reservoir sandstones are turbidites in the lower part of the formation and shelf sandstones in proximity to the Staines tongue and near the top where the Canning grades into and interfingers with the Sagavanirktok. Oil-stained Canning Formation sandstone occurs in outcroppings in the 1002 Area of ANWR and the oil accumulations at Badami and Flaxman Island are reservoired in turbidite facies of the Canning. The Mikkelsen Tongue of the Canning Formation is considered to be a good oil-prone source interval.

2.1.2.4.8 Sagavanirktok Formation (revised)

The Paleocene to Pliocene(?) Sagavanirktok Formation (Figure 2.9) is as much as 8,500 ft (2,600 m) thick. Several transgressive episodes during the Tertiary resulted in complex intertonguing of the Sagavanirktok and the Canning formations. The Sagavanirktok is composed of sandstone and bentonitic shale and lesser amounts of coal and conglomerate. These rocks were deposited is shelf and deltaic or coastal plain environments in response to repeated transgressions and regressions. Several hiatuses or unconformities were developed within the Sagavanirktok and at least one erosional episode was profound enough to have affected the Canning Formation. The continued progradation eastward eventually filled the Colville trough. Oil-stained Sagavanirktok sandstones are found east of the Sadlerochit Mountains (Bader and Bird, 1986) and the West Sak and the upper portions of the Ugnu oil accumulations are reservoired in rocks equivalent to the deltaic and shallow-marine facies of the Sagavanirktok.

2.2 Petroleum Geology

The petroleum geology of the North Slope is addressed in terms of source rocks, reservoirs, and traps as related to the regionally recognized sequences with emphasis on the components of those sequences that are critical to the generation and accumulation of the world-class reserves and potential additional resources of the area. The Ellesmerian, Beaufortian, and Brookian sequences all possess source rocks, reservoir rocks, and economic hydrocarbon accumulations. Figure 2.11 is a composite stratigraphic column constructed to display the key source rocks, reservoir intervals, and known hydrocarbons accumulations for the North Slope and the adjacent areas of the Beaufort and Chukchi seas. Three of the early discoveries on the North Slope are Ellesmerian accumulations (Prudhoe Bay, Lisburne, and Endicott). The Kuparuk, Point Thomson, and Alpine fields are examples of Beaufortian accumulations. To date the Brookian accumulations have been smaller but include fields such as Tabasco and Tarn, plus the huge but difficult to develop heavy oil accumulations of the West Sak, Schrader Bluff, and Ugnu fields.

Historically, any treatment of petroleum geology of the North Slope has been strongly focused on its oil potential with little if any discussion of the area's vast conventional gas resources and even less thought has been given to the potential associated with unconventional resources such as coalbed natural gas (CBNG) and gas hydrates. In this treatment, conventional gas is discussed but due to the timeframe under consideration there will be no discussion or evaluation of the potential impacts of CBNG or gas hydrates.

The ANS contains large quantities of coal and hence there is potential for CBNG production at some point in time. A USGS assessment of undiscovered coalbed gas was completed in 2006, and a mean estimate of undiscovered, technically recoverable resources gives a potential of about 18 TCF of coalbed gas (Roberts and others, 2006). The ANS may contain 40 TCF or more of natural gas within the hydrate deposits below existing oil and gas production facilities of the western portion of the Prudhoe Bay oil field and across the Kuparuk and Tarn oil fields. Across the entire ANS the gas hydrate in place may be as large as 590 TCF. The U.S. Department of Energy (DOE), National Energy Technology Laboratory (NETL) has a major research program underway to assess the gas hydrate potential for the nation and a major project for ANS gas hydrate reservoir characterization (U.S. Department of Energy, 2006a). These two potentially vast sources of ANS natural gas have a relatively low probability of achieving economic status within the time interval being considered in this report and are not discussed further.

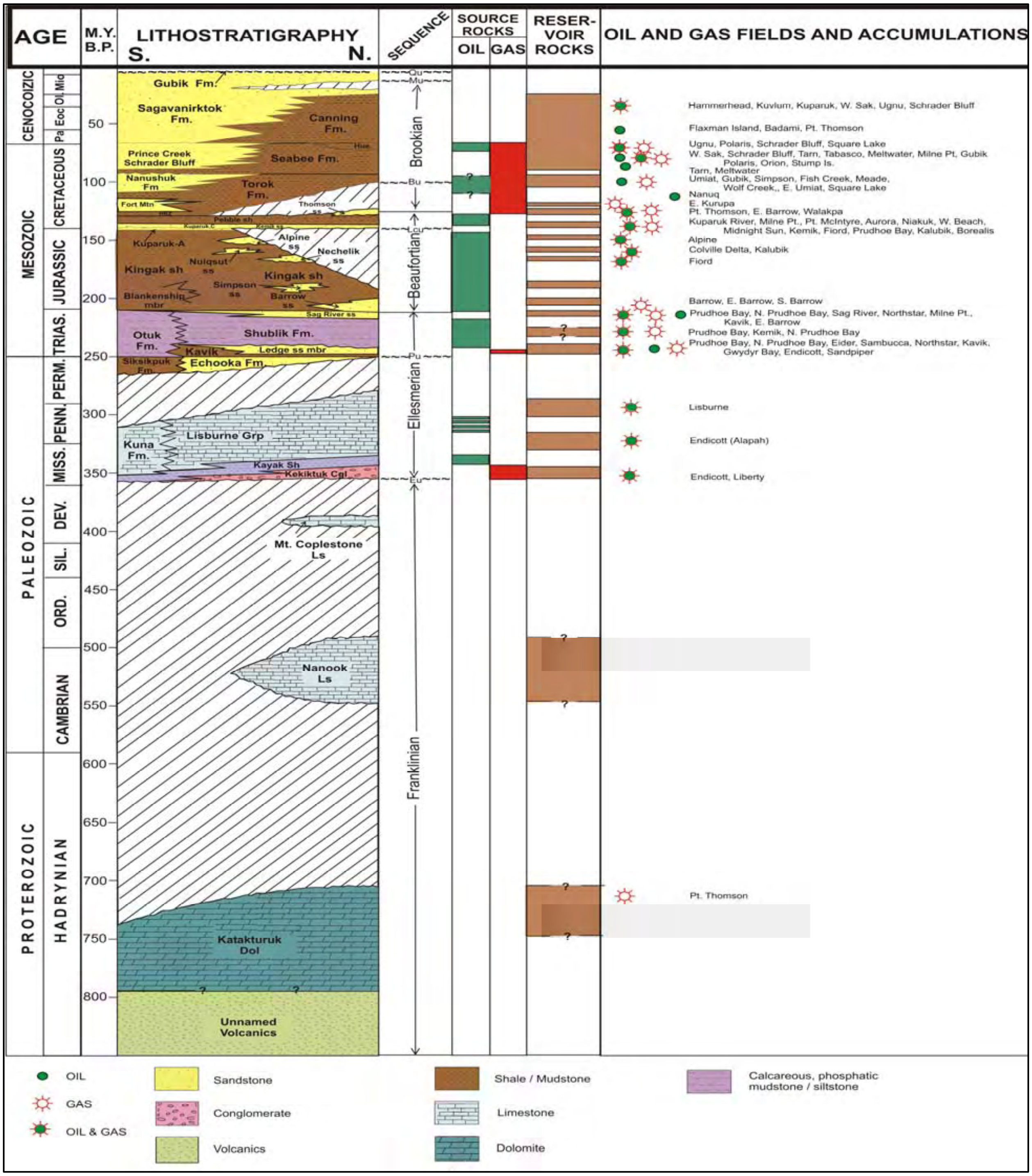

Figure 2.11. Generalized North Slope Stratagraphic Column with Source Rocks, Reservoir Horizons, and Oil and Gas Fields/Accumulations Located by Formation. (Sources: ADOG, 2003; Magoon, 1994; Lillis, 2003; Bird, 1985; Thomas, et al., 1991; and Jamison, et al., 1980)

2.2.1 Petroleum Systems

Petroleum systems have been recognized as critical to the understanding of the genesis and habitat of hydrocarbons. As defined a petroleum system is "a pod of active source rock and all related oil and gas and includes all the essential elements and processes needed for oil and gas accumulations to exist. The essential elements are the source rock, reservoir rock, seal rock, and overburden rock, and the processes include trap formation and the generation-migration-accumulation of petroleum. All essential elements must be placed in time and space such that the processes required to form a petroleum accumulation can occur. The petroleum system has a stratigraphic, geographic (Figure 2.12), and temporal extent. Its name combines the names of the source rock and the major reservoir rock and expresses a level of certainty – known, hypothetical, or speculative (Magoon and Dow, 1994).

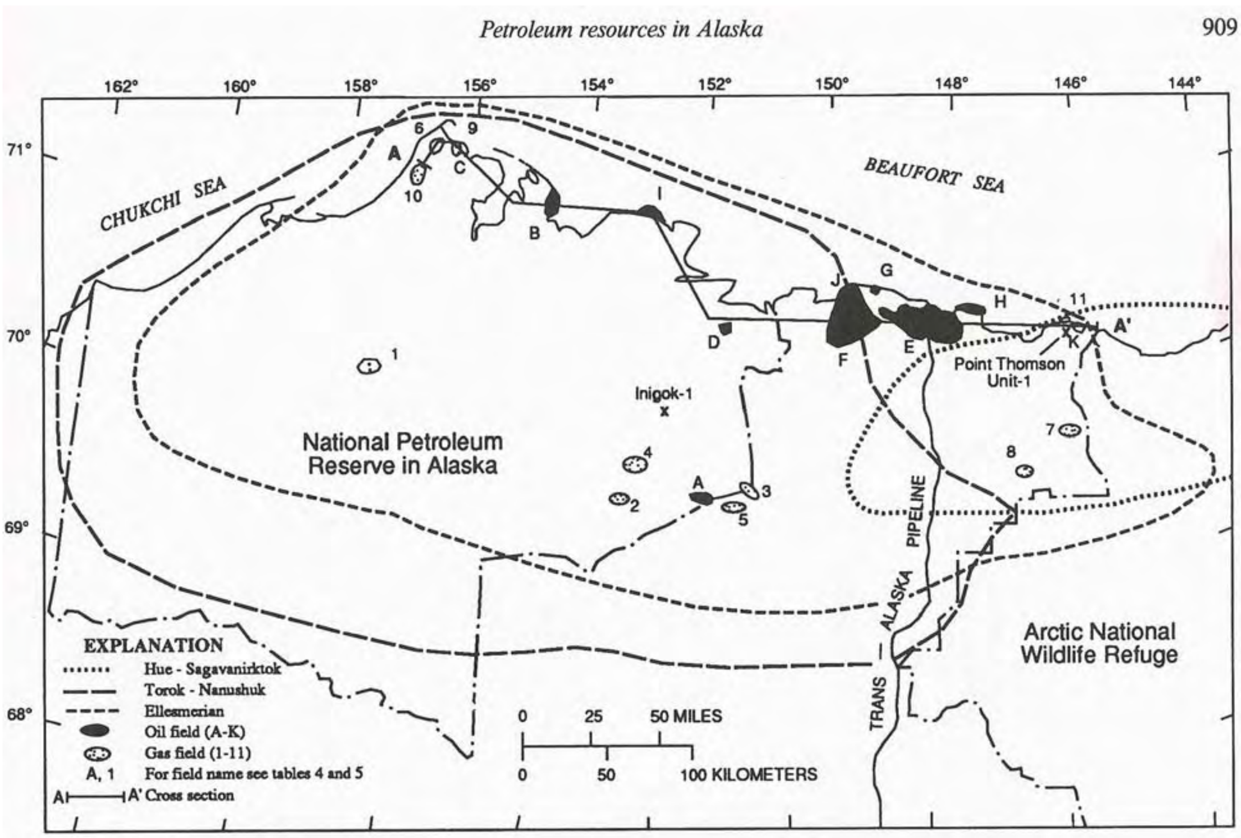

Figure 2.12. Areal distribution of three of four most significant North Slope petroleum systems. The Hue-Sagavanirktok has been renamed the Hue-Thomson petroleum system and the youngest and most easterly system, the Canning-Sagavanirktok is not shown on this map. The denoted oil and gas fields refer to those discussed in the original source of this figure. (Source: Magoon, 1994)

Magoon (1994) and Magoon and others (1999) recognized four petroleum systems on the North Slope (Figure 2.12; see also Table 2.3, page 2-57). These are the Ellesmerian, Torok-Nanushuk, Hue-Thomson, and Canning-Sagavanirktok petroleum systems. Recent publications have fine-tuned these systems to the point where there are now as many as six (Bird, 2003) or seven (Magoon and others, 2003) recognized to have been operative onshore in Arctic Alaska. Bird (2003) identified the following petroleum systems: 1) Kuna-Lisburne, 2) Shublik-Ivishak, 3) Kingak-Alpine, 4) HRZ/GRZ-Nanushuk, 5) Hue-Thomson, and 6) Canning-Sagavanirktok. The Kuna-Lisburne, Shublik-Ivishak, and Kingak-Alpine are subsets of the Ellesmerian petroleum system. Figure 2.12 shows three of the four original, more general petroleum systems including the Hue-Sagavanirktok which is now termed the Hue-Thomson. Ranked in the order of relative importance, with respect to known accumulations, they are the Ellesmerian, Torok-Nanushuk, Hue-Thomson, and Canning-Sagavanirktok petroleum systems.

2.2.1.1 Ellesmerian(!) Petroleum System

Taken in its original entirety the Ellesmerian petroleum system is the most important of the petroleum systems recognized on the North Slope. The organic-rich shales and limestones of the Ellesmerian and Beaufortian sequences are the sources for 98% of the oil endowment of northern Alaska (Bird, 1994) (Table 2.1). The Endicott, Lisburne, and Kavik appear capable of generating hydrocarbons, but have not been shown to be significant contributors to the currently known accumulations. While Magoon (1994) assigned all the Ellesmerian petroleum system source rocks to the Ellesmerian sequence, at least one source interval (Kingak Shale) of the Ellesmerian petroleum system is within the Beaufortian sequence (Figure 2.11). Bird (1994) estimates that the oil generation, migration, and entrapment components of the Ellesmerian petroleum system had a total generative potential of eight trillion barrels of oil. Only about 1% or about 80 billion barrels of oil (BBO) of the total oil generated by the Ellesmerian petroleum system is presently accounted for as in-place oil.

Table 2.1. North Slope, Alaska – Source rocks by sequence.

Sequence	Source Rock Interval	Generation Potential	Significant Contribution
Ellesmerian			
	Kekiktuk Conglomerate	Gas-prone	No
	Kayak Shale	Oil-prone	No
	Kuna Formation-Lisburne Group	Oil-prone	No.
	Kavik Shale	Gas-prone	No
	Shublik Formation-Otuk Formation	Oil-prone	Yes
Beaufortian			
	Kingak Shale	Oil-prone	Yes
	Pebble Shale Unit	Oil-prone	Yes
Brookian			
	Torok/HRZ	Oil-prone	Yes
	Hue Shale	Oil-prone	Yes
	Canning Formation, Mikkelsen Tongue	Oil/Gas-prone	Yes (?)

The Ellesmerian petroleum system extends from near the western margin of NPRA into the western portions of the 1002 Area of ANWR (144º west longitude) and from 25 to 30 miles offshore in the Beaufort Sea to nearly 69° south latitude (Figure 2.12). Bird (1994) recognized 26 accumulations as products of the Ellesmerian petroleum system. Accumulations are recognized in reservoirs ranging in age from the Early Mississippian Kekiktuk Conglomerate (Ellesmerian sequence) through the Early Cretaceous Kuparuk River Formation (Beaufortian sequence) to the Tertiary Canning and Sagavanirktok formations (Brookian sequence), and occur over an area extending from at least Barrow in the west to Point Thomson in the east and from Sandpiper in the north to Kemik in the south (see also Figure 2.20, see page 2-73). These fields contain a genetically related oil, the Barrow-Prudhoe oil type, shown in Figure 2.13 and are moderate gravity-high sulfur oils.

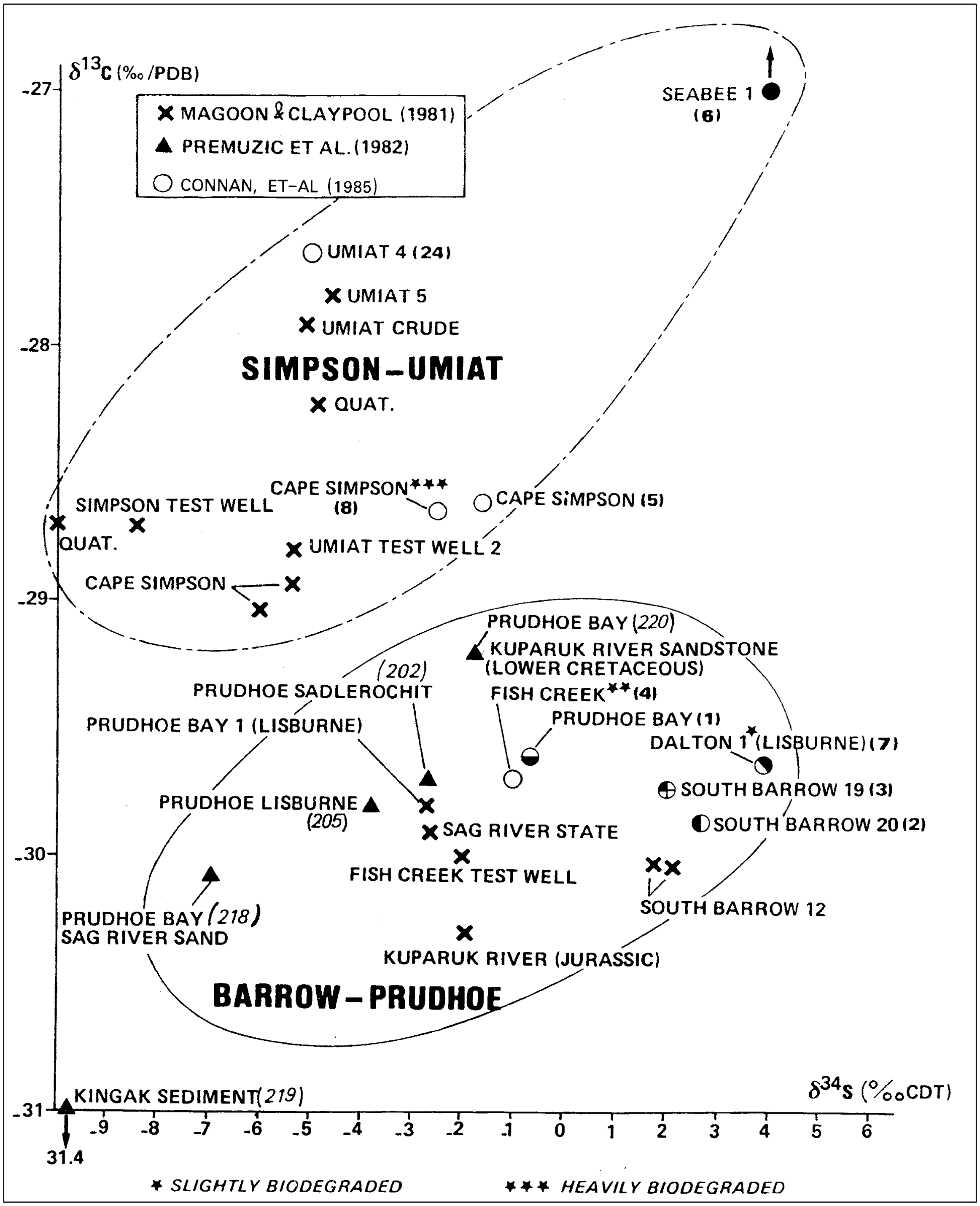

Figure 2.13. Dominant North Slope oil types. North Slope oils were originally thought of as belonging to two basic types, the Barrow-Prudhoe and Simpson-Umiat. This graph of ∂34S vs. ∂13C shows this breakdown. (Source: Magoon and Claypool, 1981, Premuzic and others, 1982, and Connan and others, 1985)

2.2.1.2 Torok-Nanushuk(.) Petroleum System

The Torok-Nanushuk petroleum system ranks second in importance. It is responsible for most of the recognized hydrocarbon accumulations not associated with the Ellesmerian system. The primary source rocks are Torok Formation including the HRZ-interval (Brookian sequence) and the Pebble Shale unit (Beaufortian sequence).

The Torok-Nanushuk petroleum system (Figure 2.12) is thought to be present and active over much of the same area as the Ellesmerian system, but it extends farther to the west and south and only as far to the east as 147° west longitude. Bird (1994) identified seven accumulations presumably associated with the Torok-Nanushuk system. Since that time the Alpine field and some of its satellites have been discovered and add to the Torok-Nanushuk system totals. Consequently, accumulations are now known to occur in reservoirs ranging from the Late Jurassic Alpine Sandstone (Beaufortian sequence) to the Late Cretaceous Schrader Bluff Formation (Brookian sequence). Analyses of samples from some of these fields are grouped on Figure 2.13 as the high gravity-low sulfur Simpson-Umiat oils.

2.2.1.3 Hue-Thomson(!) Petroleum System

The Hue-Thomson petroleum system is responsible for an unknown quantity of hydrocarbons (Magoon, 1994) in the northeastern area of the North Slope (Figure 2.12). This petroleum system was originally termed the Brookian petroleum system (Magoon and others, 1987), later revised to the Hue-Sagavanirktok/Canning(!) (Magoon, 1988), then to the Hue-Sagavanirktok(!) (Magoon, 1989).

The Hue Shale is the principal oil-source for this system. The source units of the Ellesmerian system are gas-prone in the area of Hue Shale dominance and have not contributed significantly to the oils of the area, and the Torok-Nanushuk system is not present throughout much of this area (Figure 2.12). However, the Hue-Thomson petroleum system represents essentially the same stratigraphic interval (Figure 2.5) as the Torok-Nanushuk petroleum system and produces oils of essentially identical character. Figure 2.14 shows this similarity in character. The Simpson-Umiat oils are grouped, based on carbon isotope ratios, with the oils from ANWR seeps in the Canning and Sagavanirktok formations and from the Belcher and Point Thomson wells. The oils from these two systems also have a similar range of variability in the isotope ratios.

The principal reservoir of the Hue-Thomson petroleum system is the late Beaufortian Thomson Sandstone with some contribution to the Sagavanirktok and Canning formations, but because the Hue Shale unconformably overlies Beaufortian units and older Ellesmerian and Franklinian sequence rocks, any of these units could be sourced from the Hue Shale.

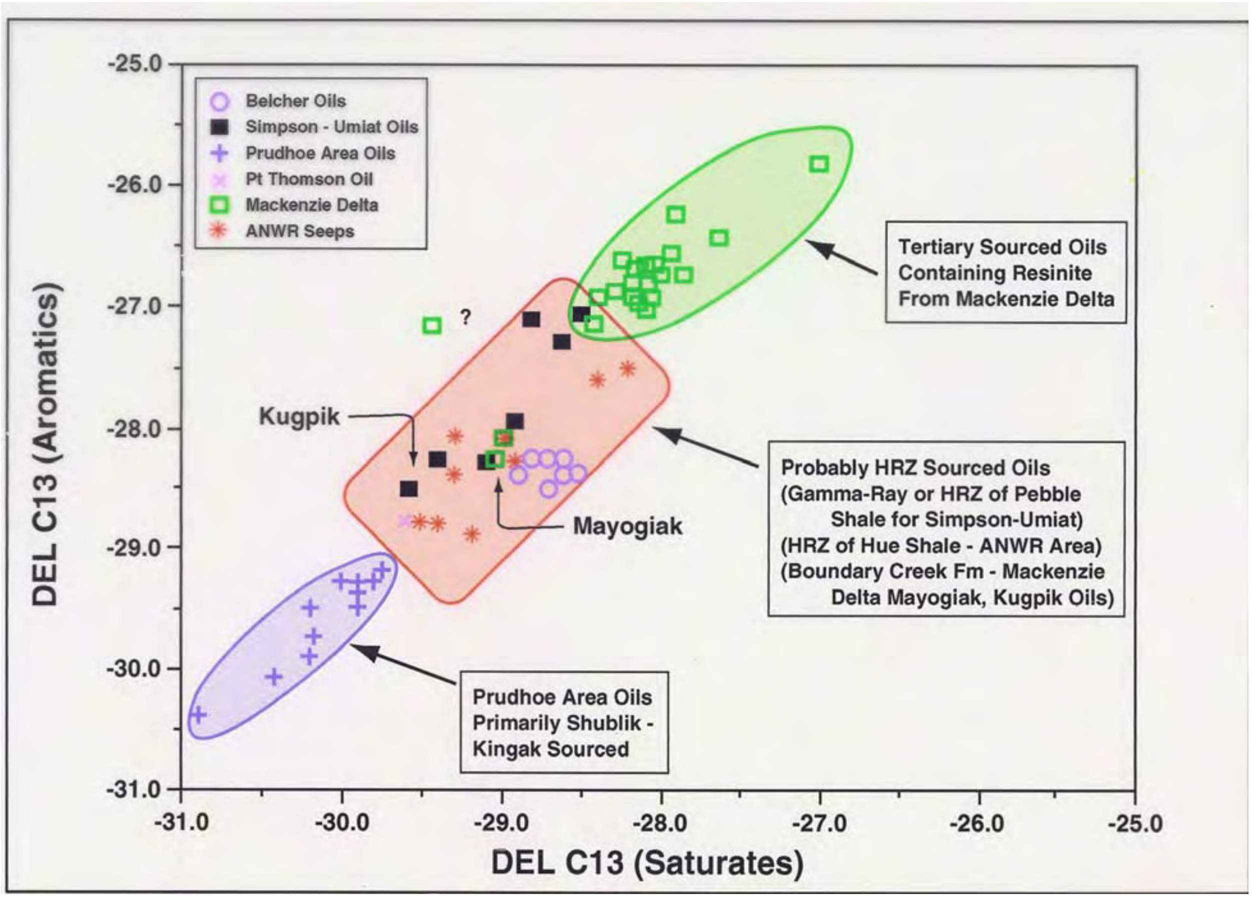

Figure 2.14. North Slope, Alaska and Mackenzie Delta, Canada oil types. Oil types are determined from carbon isotope ratios of the saturate and aromatic fractions. Samples include produced oils, oil seeps, well shows (Belcher), and extracts from oil-stained sandstones.

2.2.1.4 Canning-Sagavanirktok(.) Petroleum System

The Canning-Sagavanirktok petroleum system is based on the distinctive Manning oil type, which includes oils from the Manning Point seep, Angun Seep, Hammerhead accumulation, Belcher well(?), Kuvlum field, and the Aurora well (Magoon and others, 1999). These oils are also identical to the Mackenzie Delta Group I oils derived from age-equivalent strata of the Mackenzie delta area. The source rock is believed to be the organic-rich shale of the Mikkelsen Tongue of the Canning Formation.

The Canning-Sagavanirktok petroleum system has been mapped as occurring principally offshore and only occasionally extending onshore within the Point Thomson and Barter Island to Angun Point areas (Magoon and others, 1999 Figure PS16). The contribution to potential reserves is unknown, but if it is coextensive with the Mackenzie delta source rocks the volume must be in the billions of barrels.

2.2.2 Source Rocks

Source rocks are generally defined or evaluated based on kerogen type (Type I, II, or III), TOC content in wt.%, and the hydrogen index (HI) which is the ratio of mgHC/gTOC. Types I and II are oil-prone kerogen and Type III is gas prone. A TOC of more than 0.5 wt.% is normally required to merit consideration as a source or potential source rock. An HI of 300 or more is an indication of a good to excellent quality oil source rock. The TOC content of most North Slope rocks exceeds the threshold value of 0.5 wt.% (Bird, 1994), but the hydrogen index and kerogen type vary considerably.

Fluvial, deltaic, and prodeltaic units with low hydrogen content and Type III kerogen are generally gas-prone source rocks. Included in this category are the Endicott Group, Sadlerochit Group, Nanushuk Formation, Colville Group, and the bulk of the Canning Formation. Marine units with a high HI and bearing Type I or Type II kerogen are generally considered to be oil sources. These intervals include shale-rich facies of the Lisburne Group, the Shublik Formation, Kingak Shale, Pebble Shale unit, HRZ/Torok, Hue Shale, and the Mikkelsen Tongue of the Canning Formation.

As Table 2.1 shows there are at least five known oil-prone source rock intervals that have contributed to the known oil endowment of the North Slope and adjacent OCS areas. Additionally two or three oil-prone intervals and three gas-prone units are thought to have minor potential or have generated poorly understood volumes of oil and gas to the currently recognized reserve base.

The south to north cross section of Figure 2.4 shows the upper and lower limits of the hydrocarbon generation window and shows the generally accepted concept of oil and gas generation and migration from the deep kitchen to the south (with a probable mirror image north of the Barrow arch) and the progressively deeper burial and involvement of younger strata to the south. In the north, just to the south of the Barrow Arch in the northern portion of the coastal plain, only the Ellesmerian and Beaufortian strata have been subsided into the hydrocarbon window. To the south, in the foothills these older rocks are super mature and only the Brookian succession is within the oil and gas generation window. Local exceptions exist where early thrusting has elevated portions of the older sequences and prevented these rocks from becoming super mature for hydrocarbon generation. Such an event has locally affected the Lisburne and Otuk strata in the foothills region (Figure 2.4).

2.2.2.1 Ellesmerian Units

Figure 2.15 shows the Ellesmerian succession with three oil-prone and two gas-prone sources, six reservoir intervals, and twenty-three accumulations associated with eighteen discovered fields. The rocks of the Ellesmerian sequence possess the largest single accumulation of economically recoverable oil reserves in North America and currently account for more than 50% of the known reserves on the North Slope. Three of the five source rocks of the Ellesmerian sequence (Table 2.1) are found within the Paleozoic (Kekiktuk, Kayak, and Lisburne) but the most important, the Shublik Formation, is a lower Mesozoic unit, of Middle and Late Triassic age.

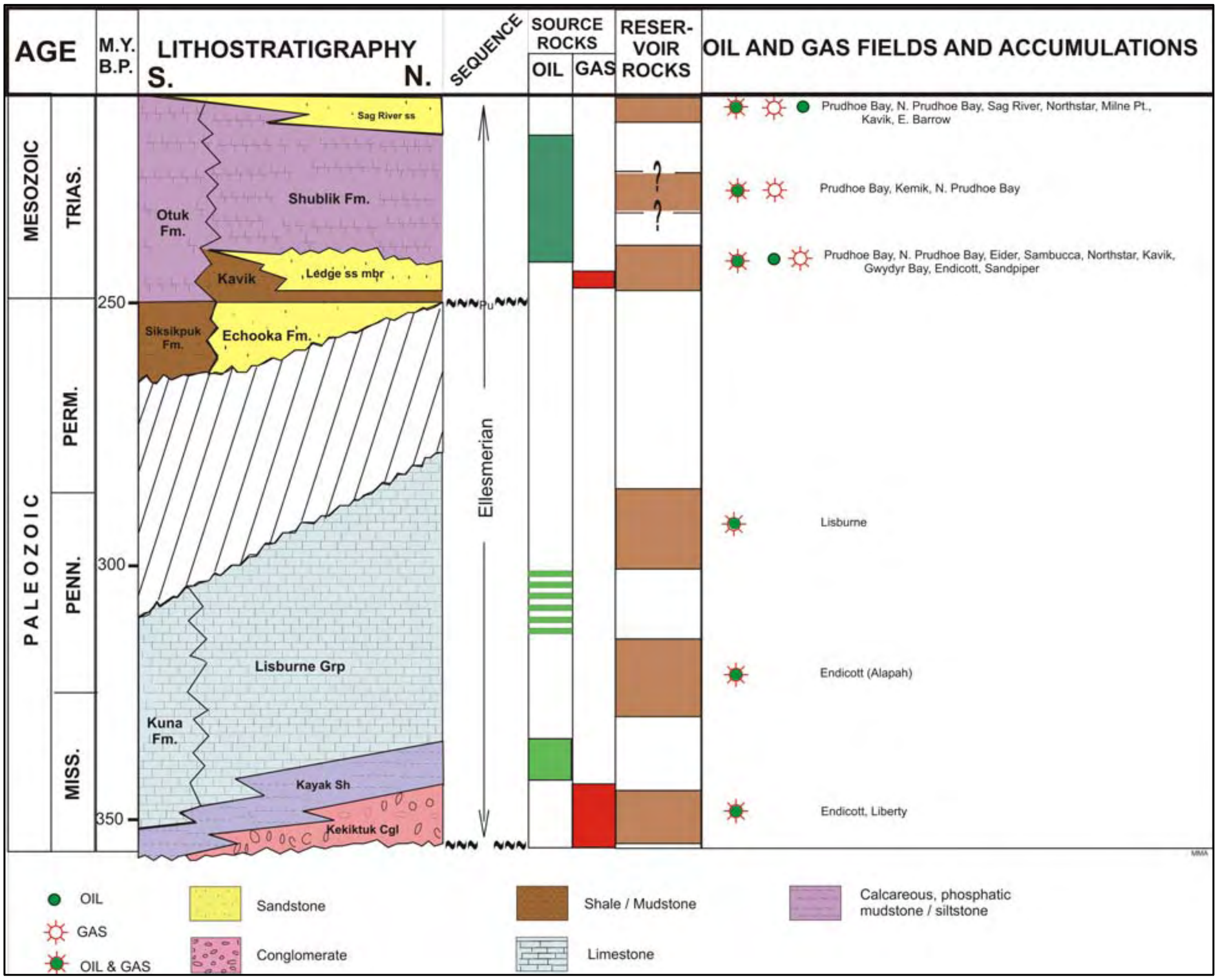

Figure 2.15. Ellesmerian Sequence – petroleum geology, source rock intervals, principal reservoirs, and accumulations of oil and gas with field names. (Sources: ADOG, 2003; Magoon, 1994; Lillis, 2003; Bird, 1985; Thomas, et al., 1991; and Jamison, et al., 1980)

2.2.2.1.1 Kekiktuk Conglomerate – Kayak Shale and Kavik Shale

Coal within the Kekiktuk Conglomerate is likely to be only a source for gas (Lillis, 2003). It and the younger gas-prone Kavik Shale have not yet been shown to have contributed significant volumes of gas to the known reserve base. Similarly, the oil-prone lithologies of the Kayak Shale are not known to have measurably contributed to the reserves at Prudhoe Bay and adjacent fields. Some consideration has been given to the thought that Kekiktuk coals may have contributed to the gas at Prudhoe Bay. Masterson (2001) considers this scenario unlikely due to the heavy isotopes of CO_2 in the gas, which would have required high maturation levels, with percent-vitrinite reflectance (Ro) greater than 2.5%.

The Kekiktuk and Kayak are probably only capable of thermogenically generating gas in appreciable volumes where the coal-bearing facies are present in the deeper portions of the basin and the thermal regime is sufficient to produce gas. The Endicott Group has an extensive distribution across the North Slope, but is limited by erosion associated with LCU to the north and northeast. It is not present north of the Barrow arch and over much of the northeastern portion of the coastal plain (Figures 2.4 and 2.7). The Kavik Shale of the Sadlerochit has a similar but more restricted distribution than the Endicott.

2.2.2.1.2 Lisburne Group – Kuna Formation

The Lisburne and its distal equivalent the Kuna Formation (Figure 2.15) possess intervals of organic rich shale (Masterson, 2001 and Magoon and Bird, 1988) that are considered to be the primary oil source facies of the Kuna-Lisburne interval (Lillis, 2003). Oil occurrences believed to be derived from the Kuna-Lisburne source rocks are few in number but widely scattered (Lillis, 2003). These occurrences include samples from the South Barrow No. 12, 17, and 19 wells; Mikkelsen Bay State No. 1; and the Kuparuk River Unit 2F-20 well. Lillis (2003) suggests that the oil from the South Barrow No. 12 well is representative of these oils (24º American Petroleum Institute (API), 1.6 wt.% sulfur (S)). The Lisburne appears to be the source of the bulk of the gas in the Lisburne field and may have contributed to the gas in both the Prudhoe Bay and Point McIntyre fields (Masterson, 2001). Seventy percent of the carbon dioxide (CO_2) at Prudhoe Bay is thought to be from the Lisburne.

The distribution of these oil and gas accumulations suggests that under the proper conditions the Kuna-Lisburne could be an oil source across those portions of the North Slope where it has been preserved and which have had a sufficient thermal history and/or good communication systems to the deeper parts of the basin. The distribution of the Lisburne is very similar to that of the Endicott, and it is also largely absent north of the Barrow arch and in the northeast (Figures 2.4 and 2.7).

2.2.2.1.3 Shublik Formation – Otuk Formation

The Shublik Formation is the principal source interval of the Ellesmerian sequence and primarily consists of Type II kerogen. The Shublik's distal equivalent is the Otuk Formation (Figure 20in the Brooks Range foothills. The chert and limestone members of the Otuk Formation are considered by Bird (1994) to be lateral time-stratigraphic equivalents of the Shublik, and are the source rock for oil found in outcrops in the central Brooks Range foothills (Lillis and others, 1999).

The Shublik Formation is the source rock for the largest volume of petroleum on the North Slope. Many of the oil fields, including the Prudhoe Bay field, contain a mixture of Shublik and other oil types (Claypool and Magoon, 1985 and Masterson, 2001). The Shublik Formation supplied approximately 60% of the oil in the main Prudhoe Bay field, Point McIntyre, and West Sak fields. Additionally, the oil in the Kuparuk Formation is predominantly derived from the Shublik Formation (Masterson, 2001). The Shublik has also supplied large quantities of gas to the fields in the Prudhoe Bay area. Masterson (2001) considers the bulk of the natural gas in the Prudhoe Bay, Kuparuk, Point McIntyre, Alpine, and Tarn fields to be sourced from the Shublik.

Bird (1994, Table 21.5) tabulated the richness of the principal Ellesmerian petroleum system source rocks. The Shublik Formation is represented by seven wells from within NPRA and the Otuk Limestone and Chert members from outcrops in the central Brooks Range foothills (Bird, 1994 Figure 21.8). Based on 38 samples, the Shublik has an average TOC content of 2.30 weight percent (wt.%) and a range of 0.49 to 6.73 wt.%. The time-equivalent Otuk is represented by 15 samples with a range of 0.20 to 10.63 wt.% and a mean of 3.30 wt.%. Additional analysis of Shublik samples, from 44 wells and 8 outcrops distributed across the

North Slope, yield TOC ranges from 0.5 to 5.6 wt.%, with an average of 1.7 wt.% (Magoon and Bird, 1987). In the area adjacent to the 1002 Area of ANWR, Keller and others (1999) analyzed samples from 4 wells and 8 outcrops. The TOC was found to range up to 10.2 wt.%. However, the Shublik is thermally over mature for oil in the 1002 Area and generally has an HI of less than 100. The Shublik is a gas-prone source in the eastern portions of the North Slope (Magoon and others, 1999).

The widespread distribution and richness of the Shublik-Otuk source rocks provide a source of oil and gas across much of the North Slope, extending as far south as the foothills of the Brooks Range. The LCU has truncated the Shublik to the north and northeast and a zero-edge trends east-southeast parallel to the Barrow arch from the Chukchi Sea to northwestern NPRA (Bird, 1994, Figure 21.8), consequently the unit was not a source north of the truncation limit. Figure 21.8 of Bird (1994) also depicts the zones of thermal immaturity, the oil window, and gas window for the Shublik and the Beaufortian Kingak Shale.

South of the truncation edge, the Shublik Formation is not uniform in thickness, and ranges from less than 100 ft thick in the Prudhoe Bay-Endicott field area it thickens to the southeast and to the west. In both of these latter areas it attains a thickness in excess of 600 ft (Bird, 1985 Figure 4). Depending upon the relative TOC content, these areas of greater thickness may be primary kitchens for oil generation, since much of the thicker portions of the Shublik occur within the zone of oil generation.

Westward into the Chukchi Sea the Shublik Formation is present over the eastern portion of the Chukchi shelf within an area limited by a line extending westward from just south of Barrow to just west of the Crackerjack well and then south to the Lisburne Peninsula (Sherwood and others, 1998, Figure 13.22). In the Klondike well the TOC ranges from 1.2 to 7.5 wt.% with an average of approximately 4.8 wt.% (Sherwood and others, 1998) and the Ro is 0.5 to 0.8 %, within the submature to early mature range for oil. The HI ranges from 400 to 650, indicative of a highly oil-prone source rock.

2.2.2.2 Beaufortian Units

The Beaufortian Sequence is depicted in Figure 2.16 with two oil-prone source rocks (Table 2.1). The Jurassic Kingak Shale, its foothills distal equivalent the Blankenship, and the Lower Cretaceous Pebble Shale unit (Figure 2.16 and Table 2.1) are the oil-prone source rocks. These source intervals are marine and contain Type II and Type III kerogen. These source rock intervals are widespread across the North Slope and have generated hydrocarbons, with oil the dominant, but not sole, product in the north, giving way to gas in the southern portions of the coastal plain and foothills.

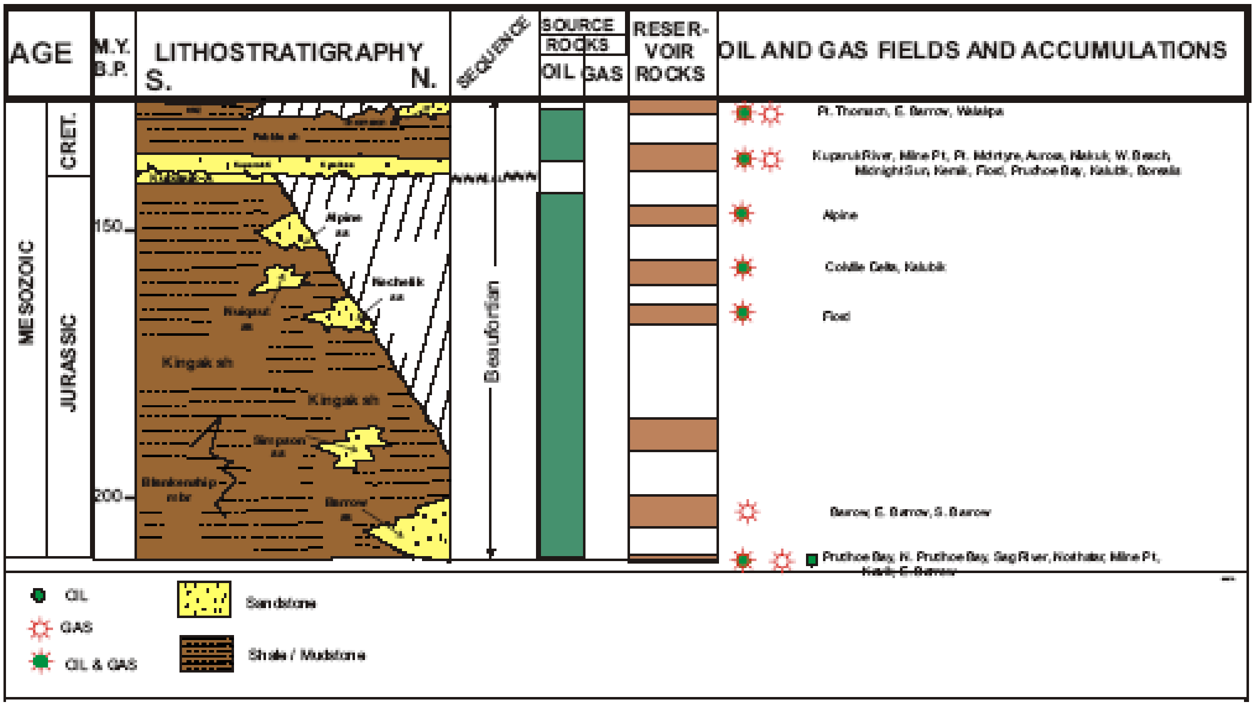

Figure 2.16. Beaufortian Sequence – petroleum geology, source rock intervals, principal reservoirs, and accumulations of oil and gas with field names. (Sources: ADOG, 2003; Magoon, 1994; Lillis, 2003; Bird, 1985; Thomas, et al., 1991; and Jamison, et al., 1980)

2.2.2.2.1 Kingak Shale – Blankenship Shale

Seifert and others (1980) sited geochemical evidence that the Kingak is the source for some of the oil in the Milne Point field and at Prudhoe Bay, and it is the second most important contributor to the Prudhoe Bay area oils. Until the discovery of the Alpine field, only a few small accumulations with pure Kingak oil had been identified (GeoMark, 1997). The Alpine field is the largest known accumulation of Kingak oil (Masterson, 2001). The gravity and sulfur content place this oil in the Umiat-Simpson family of oils (Figure 2.13).

Magoon and Bird (1987) published the results of the analysis of samples from 47 wells and 7 outcrops dispersed across the North Slope, which yielded an average TOC of 1.5 wt.% and a range of 0.5 to 3.6 wt.%, with an increase in TOC to the south. In the eastern portion of the North Slope, near ANWR, Keller and others (1999) sampled four wells and found TOC values to range up to 7.5 wt.% and average 1.4 to 2.2 wt.%. Within the 1002 Area of ANWR at the Niguanak high and in wells west of the Canning River the TOC is found to range from 0.4 to 3.4 wt.% and averages 1.5 wt.% (Magoon and others, 1999).

While the Kingak is an excellent oil source in the Prudhoe Bay area and to the west, it is a gas-prone source in the vicinity of Point Thomson and the 1002 Area of ANWR. The Kingak distribution is limited by the LCU to much the same area as the Shublik (Bird, 1994, Figure 21.8) and is gas prone in the southern and eastern portions of its distribution. Thus there is minor local potential for Kingak sourced hydrocarbons north of the Barrow arch in the Beaufort Sea, and relatively widespread potential exists for gas and possibly oil in the Chukchi Sea.

The outlier of Kingak at the Niguanak high provides some possibility for oil as well as gas within the deformed portion of the 1002 Area. While the thermal maturity of the Kingak, in the mountains to the south of the 1002 Area and in the wells to the west of the Canning River is generally well above 1.0% Ro in this part of the 1002 Area, is 0.5% based on surface samples from exposures on the Niguanak high.

The Kingak Shale is present over at least the eastern portion of the Chukchi shelf, and based on the Klondike well the TOC content ranges from 1.5 to 3.3 wt.% and averages about 2.5 wt.%. The Ro in the Klondike well is 0.6 to 0.7 % and the HI is 50 to 130, indicating a gas-prone character.

2.2.2.2.2 Pebble Shale Unit

Lower Cretaceous sources have long been recognized on the North Slope (Morgridge and Smith, 1972 and Jones and Speers, 1976). There is a close stratigraphic and depositional relationship among the Pebble Shale Unit, HRZ (GRZ), and Torok Formation. These units are all Early Cretaceous in age, marine, and organic-rich. The Pebble Shale is considered to be the uppermost unit of the south to southeastward prograding Beaufortian sequence and is discussed in this section. The HRZ and Torok Formation are the basal, distal units of the northeastward prograding Brookian sequence and are treated in that section of the report. In the older literature the HRZ is commonly included in the upper portion of the Pebble Shale unit (Magoon and Bird, 1987 and Magoon, 1994), and problems in separating these two units in the assembled data sets may lead to some misleadingly high values for the Pebble Shale unit.

The Pebble Shale unit (and HRZ) is responsible for a significant portion of the oil at Tarn and is a contributor along with the HRZ to other fields such as Umiat and Simpson (Figure 2.14).

The TOC for the Pebble Shale unit, based on 56 wells and 7 outcrops, ranges from 1.2 to 5.1 wt.% and averages 2.4 wt.% (Magoon and Bird, 1987) and in the western portion of the North Slope it increases southward from Barrow to central NPRA. There are local enriched areas in the vicinity of Teshekpuk Lake (3.2 wt.%) and in the northeastern portion of the North Slope (4.0+ wt.%).

Keller and others (1999) examined 8 wells in the area immediately west of ANWR and found the average TOC to range from 1.9 to 3.8 wt.% with a maximum sample value of 9.5 wt.%. Additional work (Magoon and others, 1999) in and adjacent to the 1002 Area, based on 7 wells and 30 outcrops, yields an average TOC of 2.4 wt.% for the well samples and 2.2 wt.% for the outcrops. Thermal maturity, as indicated by percent Ro, is marginally mature for oil in the Point Thomson area and was at peak maturity at Kavik prior to uplift. Outcrop data indicate that Ro values increase eastward from 0.8 to 3.1 % Ro in the Brooks Range south of the 1002 Area and range from 0.5 to 0.6 % Ro at the Niguanak high.

Since the Pebble Shale unit postdates the LCU, it is present across the Barrow arch and in the Canada Basin to the north. The Pebble Shale, from Barrow to Flaxman Island, is immature to marginally mature and thus has generated little if any oil (Magoon and Bird, 1987). Consequently, oils generated from the Pebble Shale must have migrated up dip, from either the Canada Basin to the north or the Colville trough to the south. The Pebble Shale is largely a gas-prone interval in and adjacent to ANWR and in the Brooks Range foothills, elsewhere across the slope it is a good oil-prone source rock.

Within the Chukchi Sea area the Pebble Shale is widespread and the TOC ranges from 2.2 to 3.1 wt.% with an average of about 2.5 wt.%. In the Klondike well the Ro is 0.5 to 0.65 % and the HI is generally in the 50 to 150 range. It is a gas-prone interval and lacks the oil-prone components seen onshore to the east of NPRA.

2.2.2.3 Brookian Units

Source rocks of the Brookian sequence, depicted in Figure 2.17, include the aforementioned HRZ and Torok Formation plus two intervals largely restricted to the northeastern portion of the coastal plain and the northern ANWR. These latter units are the Hue Shale and the Mikkelsen Tongue of the Canning Formation. Those authors that do not place the HRZ in the upper portion of the Pebble Shale generally consider it to be the basal, most distal facies of the Torok Formation (Lillis, 2003) or the Hue Shale (Magoon and others, 1999 and Keller and others, 1999). In this discussion it is considered as a distinct unit but possibly a distal facies of both the Torok Formation and Hue Shale. As a consequence the HRZ receives less discussion in the literature than it warrants, due to the tendency to include it within other source rock-bearing horizons.

2.2.2.3.1 HRZ (GRZ)

This HRZ is easily recognized on logs and has been used as a regional subsurface marker since the 1960’s. Keller and others (1999) examined eight wells in the area west of the Canning River and found that the average TOC content of these wells ranged from 1.85 to 3.93 wt.% with maxima ranging from 4.0 to 9.7 wt.%. Masterson (2001) also analyzed the HRZ and reported a range of TOC from 2.0 to 7.0 wt.% and HI of 150 to more than 400, indicating potential as a good to excellent oil source. The HRZ has been recognized as the principal source for oils in the Endicott field (Wicks and others, 1991 and Lillis and others, 1999) and a subordinate source for the other Prudhoe Bay area fields, Tarn, Point Thomson, Simpson, and Umiat. It is also a secondary source of gas for the Prudhoe Bay, Point McIntyre, and West Sak fields.

The HRZ is widely distributed across the North Slope and is capable of supplying hydrocarbons to virtually any geographic area and to most of the stratigraphic section as evidenced by the range in age of reservoirs with HRZ oils.

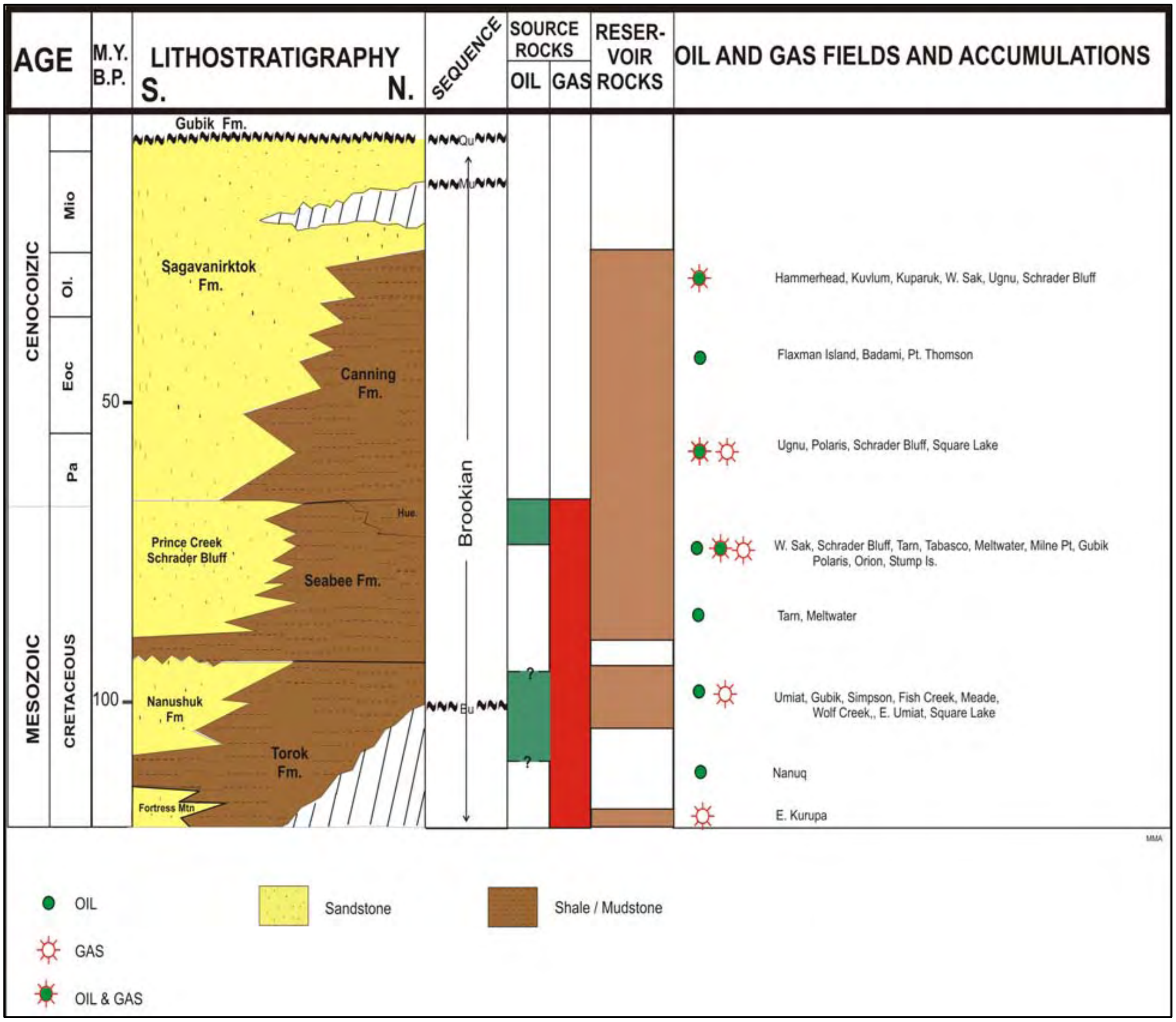

Figure 2.17. Brookian Sequence – petroleum geology, source rock intervals, principal reservoirs, and accumulations of oil and gas with field names. (Sources: ADOG, 2003; Magoon, 1994; Lillis, 2003; Bird, 1985; Thomas, et al., 1991; and Jamison, et al., 1980)

2.2.2.3.2 Torok Formation

The Torok Formation is a leaner source than most of the other recognized source rock intervals on the North Slope. The TOC content, as determined from 49 wells (Magoon and Bird, 1987), ranges from 0.6 to 1.4 wt.% with an average of 1.2 wt.%. The TOC content increases toward the base of the unit, where it may grade downward and laterally into the older portions of the HRZ. Magoon (1994) considers the Torok to have supplied oils to the Umiat, Simpson, and East Barrow oil fields. The magnitude of its contribution to gas accumulations is unknown, but it could be an important gas source in the southern portions of the coastal plain and the foothills.

The Torok occurs widely across the western and southwestern portions of the North Slope coastal plain and the Brooks Range foothills. It may attain thicknesses of 20,000 ft (6,100 m) or more in the Colville trough. It thins to the northeast and the approximate eastward depositional limit is represented on Figure 12 of Magoon and Bird (1987). The eastward depositional pinchout of the Torok is at approximately 150º west longitude, extending from the coastline southward to the latitude of Umiat, and then trending eastward to ANWR along a line of latitude at approximately 69º 10' north. At this pinchout, the Torok essentially merges with the overlying shales of the Seabee Formation and laterally with the Canning Formation (Bird, 1987). Thus, the Torok Formation's value as either an oil or gas source is largely limited to the areas south and west of the complex of oil fields in the Prudhoe Bay area.

Based on the limited well control in the Chukchi Sea, the Torok has a wide range in TOC, from 0.3 to 4.8 wt.%, with an average of 1.7 wt.%. The HI ranges from 10 to approximately 170 and the Ro in the Klondike well is 0.6 to 0.65 %. Based on the data from the Klondike well (Sherwood and others, 1998) the Torok and younger Cretaceous and Tertiary source rocks are all gas-prone sources, with low HI, generally in the 10 to 150 range.

2.2.2.3.3 Hue Shale

The Hue Shale is an organic-rich distal facies of the Seabee Formation, which lies to the south and southwest. The Hue Shale is quite restricted in terms of its geographic distribution. Figure 2.24 (page 2-122) shows that the Hue-Canning petroleum system is limited to the northeastern portion of the North Slope. As mapped, the northwestern and western limits lie to the south of the Prudhoe Bay field and extend no farther than 150º west longitude. The north and south limits are at approximately 70º and 69º north latitude respectively.

The Hue Shale has generated the oils seen in many of ANWR seeps and oil-stained out crops (Magoon and others, 1999). In addition, oil at Point Thomson field and oil shows in many of the wells in the Kavik area was sourced from the Hue Shale (Magoon and others, 1999, Figure PS13).

The Hue Shale has been sampled and analyzed in both outcrop and the subsurface. Subsurface results from the Aurora well and eight other well in the area to the west of ANWR are presented by Keller and others (1999). Both cuttings and sidewall cores from the Hue Shale in the Aurora well were examined, and the TOC content was found to range from 1.3 to 3.0 wt.% for cuttings and 2.5 to 6.0 wt.% for sidewall cores. The results of the eight-well study yielded average TOC contents ranging from 1.35 to 2.55 wt.% with a maximum of 9.9 wt.%. Outcrop studies in the Niquanak high area, along the Jago River, and at Hue Creek show that TOC content ranges from 1.4 to 12.1 wt.%..

Vitrinite reflectance values in the Hue Creek area are in the range of peak oil generation ($\approx$0.9% R_o) and under mature for oil (0.4% R_o) at the Niguanak High. These values suggest that even today there is potential for Hue Shale generated oils to be filling reservoirs in and adjacent to the 1002 Area of ANWR. The offshore potential for Hue Shale-sourced oils is unknown.

2.2.2.3.4 Canning Formation – Mikkelsen Tongue

The Mikkelsen Tongue of the Canning Formation is the youngest recognized source rock interval on the North Slope, and it is believed to be the source of the Manning oil type (Lillis and others, 1999). The Mikkelsen Tongue is equivalent to the Mackenzie Delta area Tertiary source rocks believed to be the source of the Mackenzie Delta Group I oil of McCaffrey and others (1994). In Alaska the Mikkelsen Tongue has generated oils found in the Angun and Manning seeps, as shows in the Belcher and Aurora wells, and the accumulations at Hammerhead and Kuvlum.

Sampling of the Canning Formation, quite often without specifically targeting the Mikkelsen Tongue, has occurred across the 1002 Area and within wells adjacent to it. Keller and others (1999) evaluated four wells and found TOC values ranging up to 12.3 wt.%. with a per well average range of 1.3 to 3.0 wt.%. In the Aurora well, the TOC range was 1.0 to 1.6 wt.% from cuttings and sidewall cores. However, these samples were immature for oil generation, and the regional geology suggests that the Mikkelsen kitchen lies offshore to the north of the Hammerhead and Kuvlum oil accumulations and extends eastward to the Mackenzie delta. These rocks may be responsible for large accumulations in the OCS portions of the eastern Beaufort Sea. In the Chukchi Sea this equivalent interval is a gas-prone source rock.

2.2.3 Reservoirs

Table 2.2 lists 20 reservoir horizons that have been shown to be capable of producing oil and/or gas. There are an additional five units, including three from the Franklinian sequence that are known to locally possess sufficient porosity and permeability to qualify as hydrocarbon reservoirs if encountered in appropriate trapping/accumulation settings. The Katakturuk, Fortress Mountain, and Torok have produced oil or gas during tests but have not been brought on line as economically viable reservoirs (as Prudhoe Bay and Alpine) or as sources of gas for rural communities (Barrow gas field).

2.2.3.1 Ellesmerian Intervals

Ellesmerian reservoirs are predominantly found in the siliciclastic units of the Mississippian and Triassic formations. Reservoirs have also been developed in the carbonates of the Lisburne Group. The most important sandstone reservoirs are in the Lower Triassic nonmarine to deltaic Ivishak Formation, the Upper Triassic shallow marine Sag River Sandstone, and the Lower Mississippian nonmarine Kekiktuk Conglomerate. These sandstones are comprised chiefly of quartz and chert; therefore, they are compositionally and physically mature and can withstand significant burial without compaction or chemical alteration. The Ellesmerian reservoirs were all derived from mature “continental” terrains to the north of the present-day coastline of northern Alaska. Consequently, these coarse clastic reservoir-prone facies are best developed in northern portion of the North Slope and the quality and quantity of these reservoirs decrease to the south.

Each of these units has equivalents or partial equivalents in surface exposures of the Sadlerochit-Shublik Mountains and/or the foothills of the central Brooks Range. In virtually all instances the surface sections have been highly cemented and possess little or no porosity and permeability. However, in the subsurface, these same rocks have developed or preserved good to excellent reservoir characteristics on a local to semiregional scale. The predominant cements are silica, frequently as quartz overgrowths, siderite and other carbonates, with minor associated pyrite.

Table 2.2. North Slope, Alaska–Known and potential reservoir horizons by sequence.

Sequence	Reservoir Horizon	Proven Capable of Production
ELLESMERIAN		
	Kekiktuk Conglomerate	Yes
	Alapah Limestone	Yes
	Wahoo Limestone	Yes
	Ivishak Ss./Ledge Ss. Mbr.	Yes
	Shublik Formation	Yes
	Sag River Ss/Karen Crk Ss.	Yes
BEAUFORTIAN		
	Barrow Sandstone	Yes
	Simpson Sandstone	Yes
	Nechilik Sandstone	Yes
	Nuiqsut Sandstone	Yes
	Alpine Sandstone	Yes
	Kuparuk River Fm./Kemik Ss.	Yes
	Thomson Sandstone	Yes
BROOKIAN		
	Fortress Mountain Fm.	Yes(?)
	Torok Formation	Yes(?)
	Nanushuk Formation	Yes
	Seabee Formation	Yes
	Tuluvak Formation	Yes
	Schrader Bluff Formation	Yes
	Prince Creek Formation	Yes
	Canning Formation	Yes
	Sagavanirktok Formation	Yes
FRANKLINIAN(?)		
	Katakturuk Dolomite	Yes(?)
	Nanook Limestone	No
	Mt. Coplestone Limestone	No

2.2.3.1.1 Kekiktuk Conglomerate

The basal unit of the Endicott Group, the Kekiktuk Conglomerate is the primary reservoir at the Endicott and at Liberty (Tern Island) fields (Figure 2.15 and Table 2.7 and 2.8). It is present as a regionally discontinuous unit, in the Prudhoe Bay area and across much of the northern portion of the North Slope and ANWR, south of the LCU zero truncation limits. It thins markedly to the south and is absent in the foothills. Westward in NPRA, it or the slightly older Kanayut Conglomerate is present beneath the Lisburne Group in deep fault-controlled basins. The Kekiktuk Conglomerate is locally present in the near shore portions of the Beaufort Sea in the Harrison and Smith Bay areas (Scherr and Johnson, 1995). In the Chukchi Sea it is seismically inferred to be absent to the north, but present in the central and western portions of the shelf (Sherwood and other, 1995).

Where exposed in the outcrop and when noted in wells near ANWR and south of the Prudhoe Bay area, the Kekiktuk has been shown to have little or no reservoir potential. In outcrop the Kekiktuk is tightly cemented with secondary quartz, and in wells such as the

Canning River Unit No. A-1 and the Kavik No. 1 the log calculated porosity is less than 5 % (Bird and others, 1987). In the subsurface at the Endicott field and the undeveloped Liberty field, the Kekiktuk has much improved reservoir character. Two depositional facies are represented as producing zones. The stratigraphically lower braided stream facies has an average porosity of 22% and permeability of 1146 millidarcies (md) and the upper meandering stream facies has an average porosity of 18% and permeability of 548 md (Woldneck and others, 1987).

The porosity and permeability appear to improve northward, and the better quality has been attributed to either lesser burial depth or conditions more favorable to the development of secondary porosity. The enhanced porosity does appear to be related to the subcrop of the Kekiktuk beneath the truncation zone of the LCU and may be genetically associated with weathering resulting from the Early Cretaceous erosional episode.

2.2.3.1.2 Lisburne Group

The carbonates of the Alapah and Wahoo Limestones are reservoirs at the Lisburne field. The bulk of the better porosity is in the microcrystalline dolomites and averages less than 5% in the outcrop and about 10% at the Lisburne field. Locally the porosity is a great as 20%. In the Lisburne field the matrix permeability is only 0.1 to 2.0 md (Bird and others, 1987). The effective permeability is associated with open fractures, ranging from a fraction of a millimeter to several centimeters in width (Jamison and others, 1980). The Lisburne is widespread but the better porosity, dolomitic intervals vary in thickness, amount, and stratigraphic position. There are sections exposed in the foothills, at localities like Skimo Creek and Tiglukpuk anticline, where tens to hundreds of feet of Lisburne with vuggy dolomitic porosity are observed. Some of these vugs contain dead oil.

Like the Endicott and other Ellesmerian intervals the Lisburne is absent over much of the area to the north of the Barrow arch and to the east of Prudhoe Bay as a function of erosion associated with the LCU (Figures 2.6 and 2.7). Play maps in Scherr and Johnson (1995) show its potential distribution offshore in the southern portions of the Beaufort Sea, from the east side of Smith Bay to about Mikkelsen Bay. Similar maps in Sherwood and others (1995) indicate the presence of Lisburne Group carbonates in the south-central and eastern portions of the Chukchi Sea.

2.2.3.1.3 Ivishak Formation

The equivalent of the Ledge Sandstone Member (Figure 2.15) is the principal reservoir on the North Slope. The nature of the Ivishak reservoir has been discussed by various authors (Jones and Speers, 1976, Jamison and other, 1980, and Bird and others, 1987). In the outcrop sections and in the subsurface to the south of Prudhoe Bay and near ANWR the Ledge Sandstone Member has low porosity and permeability, with thin section and core porosity averaging less than 4% and log-calculated porosity of approximately 7%. The porosity is mostly secondary, due to the dissolution of authigenic siderite (Bird and others, 1987).

At Prudhoe Bay and the other fields that produce from the Ledge Sandstone, the reservoir parameters are much improved over those seen in the outcrop exposures and the wells to the south. The reservoir parameters vary as a function of grain size or lithofacies and degree of dissolution of cements. Overall the porosity averages between 20 and 30% and the permeability ranges from 75 to 4000 md. This reservoir quality appears to have some relationship to the proximity to the LCU truncation and possible enhancement of porosity during the exposure and weathering associated with the development of the unconformity.

Exploration has led to the discovery of at least nine accumulations (both oil and gas) within the Ledge Sandstone (Figure 2.15). These are principally associated with the Barrow arch. Additional exploration along the trend of the arch to the west has encountered good reservoir quality in the Ivishak but no commercial accumulations. This includes both the offshore (Mukluk No. 1 well) and NPRA (Cape Halkett No. 1 well) areas.

The Ivishak is not extensively present to the north and east of Prudhoe Bay as a result of erosional truncation (Figures 2.6 and 2.7). To the south, the Ledge Sandstone interfingers with and ultimately grades into the Kavik Shale facies and eventually into the basal Otuk. This limits the exploration opportunities to the south. Scherr and Johnson (1995) and Sherwood and others (1995) display the limited extent of the Sadlerochit and associated Shublik and Sag River in the Beaufort Sea between Smith Bay and Prudhoe Bay and in the central and southeastern portions of the Chukchi Sea.

2.2.3.1.4 Shublik Formation

The Shublik Formation is a minor reservoir at Prudhoe Bay and North Prudhoe Bay oil fields and at the Kemik gas field (Figure 2.15). Jones and Speers (1976) state that porosity and permeability range up to 30% and 400 md. Jamison and others (1980) cite an average porosity range of 5 to 15% and refer to the permeability as “low”. The formation’s areal distribution mimics that of the Ivishak, and to the south it passes into the Otuk Formation. It is doubtful that the unit is a stand-alone reservoir objective, and if it is, the hydrocarbon would most likely be gas as it is at the Kemik discovery.

2.2.3.1.5 Sag River Sandstone/Karen Creek Sandstone

The Sag River Sandstone or Karen Creek Sandstone is a minor reservoir in at least seven fields on the North Slope (Figure 2.15). In the outcrop, the Sag River equivalent is known as the Karen Creek Sandstone and has less than 5% porosity and less than 1 md permeability (Bird and others, 1987). The porosity and permeability in wells to the south and east of Prudhoe Bay are similar to that seen in outcrop. In the Prudhoe Bay area the porosity ranges from 10 to 25% and permeability ranges up to 270 md (Jones and Speers, 1976 and Jamison and others, 1980).

The Sag River Sandstone has an irregular distribution and thickness. As with the other Ellesmerian units the Sag River Sandstone is largely absent to the north and east of Prudhoe Bay as a result of truncation by LCU (Figures 2.6 and 2.7). To the south the interval thins and if present is represented by a single sandstone bed atop the Otuk in exposures in the foothills.

2.2.3.2 Beaufortian Intervals

Beaufortian sequence reservoirs are similar to the Ellesmerian reservoirs with respect to having a northern source and a composition rich in quartz and chert. Most of the Beaufortian reservoirs were derived from the same source terranes as the Ellesmerian units or from the reworking of Ellesmerian deposits. These reservoirs are all Jurassic and Early Cretaceous in age and are predominantly shallow marine sandstone facies.

2.2.3.2.1 Sandstones of the Kingak Shale

The Kingak Shale contains at least five shallow marine sandstones that have sufficient porosity and permeability to serve as hydrocarbon reservoirs. These are the Barrow, Simpson, Nechilik, Nuiqsut, and Alpine sandstones of Figure 2.16.

These sandstones occur throughout the Kingak with the older units, the Barrow and Simpson sandstones in the western portion of NPRA and the younger sandstones such as the Nechelik, Nuiqsut, and Alpine in the vicinity of the Colville Delta. At least six accumulations are associated with these reservoirs. The porosity and permeability is relatively low, ranging from 20% and 30 to 45 md in the Barrow Sandstone to 24% and 187 md at the Walaka field, which is in a sandstone equivalent to either the Nechelik or Nuiqsut. The highly productive Alpine field produces from the Alpine Sandstone with 19% porosity and 15 md permeability. The high, 40° API, gravity of the oil is the primary reason this field is economically viable.

Currently these sandstones are only recognized within NPRA and the area of the Colville Delta. There are probably more of these sandstones across NPRA and possibly others to the east and south of NPRA. The distribution of the Kingak and Alpine-like sandstones is limited to the north and east by LCU erosion.

2.2.3.2.2 Kuparuk River Formation/Kemik Sandstone

The Kuparuk River Formation is the second most important reservoir interval on the North Slope. It is the principal or sole reservoir in at least seven fields, including the Kuparuk River, Point McIntyre, and Milne Point fields, and a secondary reservoir in three or more additional fields. In the Kuparuk River field it consists of two intervals separated by the LCU (Jamison and others, 1980, Carman and Hardwick, 1983, and Masterson and Paris, 1987). The lower or Kuparuk-A sandstone has porosity that ranges up to 30% with an average of 23% and permeability that ranges up to 500 md with an average of 100 md. The upper, Kuparuk-C sandstone has an average porosity of 21 to 23%, ranging to a high of 37% and an average permeability of about 130 md with a max of 1000 md.

In most of the other Kuparuk fields the Kuparuk-C sandstone is the principal or sole reservoir of the Kuparuk River Formation. Data from AOGCC (2004) show that averages or ranges of porosity and permeability for the other principal Kuparuk River fields are as follows: Milne Point field, 23% and 20 to 60 md; Point McIntyre, 22% and 200 md; Niakuk, 20% and 500 md; Midnight Sun, 23-30% and 3 to 1558 md; and West Beach, 19% and 107 md.

The outcrop equivalent of the Kuparuk-C member of the Kuparuk River Formation is the Kemik Sandstone of ANWR and adjacent areas. This unit is also encountered in the subsurface in wells west of the Canning River. The Kemik is a poor reservoir except where fractured. The outcrop and nearby subsurface Kemik samples have porosities that range up to 12% and average 5% as measured from cores and hand samples and 8% for log calculated values. The permeability may locally be as high as 20 md but averages about 1 md (Bird and others, 1987).

The lower or Kuparuk-A interval appears to be largely confined to the general area of the Kuparuk River field. The limited distribution is probably the result of restricted depositional extent and subsequent removal by erosion associated with the development of LCU. The Kuparuk-C sandstone and its equivalent, the Kemik Sandstone, are more widely distributed and extend discontinuously from within the NPRA on the west to the western portions of ANWR on the east. It is also present in the southern portions of the Beaufort Sea from near Point Barrow to the east of Barter Island (Scherr and Johnson, 1995). It is absent in the northern and extreme western portions of the Chukchi Sea (Sherwood and others, 1995), but is a viable target elsewhere on the Chukchi shelf, as at the Burger discovery. A probable equivalent sandstone, with oil shows, was found in the Klondike well.

West of Prudhoe Bay, the Kuparuk River formation is found at least as far south as the ARCO Itkillik No.1 well. In the vicinity of Prudhoe Bay and to the east, the only reservoir present is the Kuparuk-C interval, and it is restricted to the downthrown northern side of the north Prudhoe Bay fault. Within these areas the Kuparuk River Formation possesses good to excellent reservoir quality.

Farther east, in the vicinity of Mikkelsen Bay and beyond, equivalent strata are the Kemik Sandstone and local sandstone packages such as the Mikkelsen sandstone. In the east the Kemik is present in outcrop as far south as the point where the Shaviovik River emerges from the mountain front and in the subsurface at the Suzie and Echooka wells, near the confluence of the Sagavanirktok and Ivishak rivers. In this area, the Kemik has poor to nonexistent reservoir potential, unless fractured.

2.2.3.2.3 Thomson Sandstone

The Thomson Sandstone is known only in the Point Thomson area and has good to excellent reservoir characteristics. The reservoir interval has an average porosity of 16% and porosity ranges from 5 to 25% (Bird and others, 1987 and Gautier, 1987). The permeability ranges to a maximum of 1,000 md (Bird and others, 1987). The unit is lensoid and locally derived from the underlying Pre-Mississippian carbonates of the Franklinian sequence. The regional extent and significance of the unit are unknown. However, there is a high probability that other similar, locally sourced units are present along the trend of the Barrow arch or the uplifted rift margin.

2.2.3.3 Brookian Intervals

The Brookian sequence reservoirs of the foreland basin are sandstones deposited in a variety of environments ranging from deep-marine to nonmarine (Bird and Molenaar, 1992). There are at least nine formations with some degree of reservoir potential. At this time eight and perhaps all nine of these units have been found to contain hydrocarbon accumulations (Tables 2.7, and 2.8). These are the Schrader Bluff, Sagavanirktok, Canning, Seabee, Torok, Nanushuk, Tuluvak, Prince Creek, and possibly the Fortress Mountain formations. These units are all derived from provenance areas to the south and southwest and prograded to the northeast. Relatively little reliable and appropriate reservoir data are available for many of the formations.

2.2.3.3.1 Fortress Mountain Formation

The Fortress Mountain contains nonmarine to deep-marine sandstones. The deep-marine facies may be difficult to distinguish from the partially equivalent lower Torok. The gas accumulation at East Kurupa is within the Fortress Mountain Formation and/or the Torok (Figure 2.17). There are limited reservoir data available for the Fortress Mountain, and it is all from outcrop samples. Molenaar and others (1988) reported the results of 15 sample analyses and found that porosity averaged 7.5% with a range of 2.2 to 14.1%. Permeability determinations from the same sample set gave an average permeability of 0.07 md and a range of <0.01 to 0.4

md. Reifenstuhl and Strauch (2002) sampled the Fortress Mountain (8 samples) and found an average porosity of 3.4% with a range from 2.3 to 6.8%. The average permeability was 0.033 md with a range of 0.001 to 0.2 md.

These low permeabilities, especially in rocks with up to 14% porosity, reflect the loss of permeability resulting from the compaction and deformation of ductile grains within the sandstones the Fortress Mountain. This potential loss of permeability and reduction in porosity with depth of burial is a problem common to many of the Brookian reservoir horizons due to the high ductile grain content.

The Fortress Mountain is one of the earliest units to be deposited into the developing and growing foreland basin of the Colville trough. Consequently, it is restricted in its distribution to the southern and southwestern portions of the basin. It would probably be only a gas reservoir and would be prospective in the foothills belt in areas where it has undergone relatively shallow burial.

2.2.3.3.2 Torok Formation

The sandstone intervals of the Torok Formation are slope and basin deposits that lack wide lateral continuity. The sandstones of the lower portion of the Torok are distal equivalents or facies of the Fortress Mountain and those of the upper portion of the Torok are equivalents of the Nanushuk Formation. While the Torok Formation is widespread and spans much of the North Slope, the potential reservoir facies are more restricted and are probably best developed in those portions of the basin seaward of the major progradational lobes or primary sediment conduits of the Fortress Mountain and Nanushuk. The Torok Formation can be found as far to the east as the haul road and beyond. It is also present across major portions of both the Chukchi and Beaufort Sea OCS areas (Scherr, and Johnson, 1995 and Sherwood and others, 1995)

Generally speaking porosity and permeability are probably similar to the Fortress Mountain and Nanushuk values, and are susceptible to reduction with deep burial. Reifenstuhl and Strauch (2002) analyzed five surface samples. The porosity ranges from 6.0 to 15.5% and averages 11.7%. The average permeability is 0.16 md and the range is 0.038 to 0.301 md. The Torok Formation (Nanuq Sandstone) is the reservoir at the Nanuq field and may be the reservoir interval for the gas at East Kurupa (Figure 2.17).

2.2.3.3.3 Nanushuk Formation

As defined, the Nanushuk Formation is comprised of nonmarine, deltaic, and shallow marine deposits, all of which have reservoir potential. The sandstones of the Nanushuk are recognized to be reservoirs in at least seven currently noneconomic oil and gas accumulations (Table 2.8 and Figure 2.17). The largest is the Umiat oil field. The Nanushuk reservoir characteristics are poor to variable as determined from outcrop and subsurface control. Bartsch-Winkler and Huffman (1988) provide porosity and permeability from both outcrops and subsurface wells.

Samples from surface exposures (Bartsch-Winkler and Huffman, 1988) yield visual porosity values of 1 to 2% with and average of about 1.5%. Effective porosity averages range from 6.6 to 8.4%. The permeability of these surface samples averages between 12.2 and 14 md. Reifenstuhl and Strauch (2002) had 49 surface samples analyzed and found the average porosity to be 8.7% with a range of 2.3 to 21.3%. The permeability ranges from 0.01 to 1404 md with an average of 74.8 md. The average is strongly skewed toward the higher end because of a few samples with high permeabilities. If the five highest values (10%) are deleted from the sample set, the average permeability is reduced to 4.85 md, an order of magnitude decrease in the average. Subsurface samples tend to yield a similar set of averages. The visual porosity range is from 0 to 13% with an average of 5.5%, and the effective porosity range is 4.7 to 28.8% with a 14% average value. Permeability values range from <0.01 to 300 md.

The Nanushuk was sourced from the west and south and can be found across the entire area of NPRA, as well as south to the Tuktu escarpment and east into the subsurface. It is present in excellent exposures as far to the east as Slope Mountain along the pipeline corridor. Like the Torok, the Nanushuk or its lithologic equivalents are present over large portions of the Beaufort and Chukchi OCS areas.

The upper marine facies of the Nanushuk, in the areas along the Colville River and west of Umiat, are locally rich in quartz and chert. Here both sandstone and conglomerate intervals may provide attractive targets if present in the subsurface.

2.2.3.3.4 Seabee Formation

The Seabee Formation is the reservoir for the Tarn and Meltwater accumulations (Figure 2.17), satellites of the Kuparuk River field. Average porosity is 20% and average permeability about 10 md (Alaska Division of Oil and Gas, 2004). The relatively high porosity and low permeability are probable results of compaction and deformation of ductile grains. The Seabee has a fairly widespread distribution and is present in the subsurface from the foothills south of Umiat to the Kuparuk River field area and for some distance both to the east and west. The Seabee Formation and other former units of the Colville Group, such as the Schrader Bluff and Prince Creek Formations (Figure 2.9) are present along the outer portions of the Beaufort shelf from northwest of Barrow to north of Smith Bay and across the entire width of the shelf from Smith Bay to Camden Bay (Scherr and Johnson, 1995). In the Chukchi Sea these units are limited and appear to be present only in the northwestern portion of the area (Sherwood and others, 1995).

2.2.3.3.5 Tuluvak Formation

The Tuluvak Formation is one of the most compositionally mature elements of the Brookian sequence. It is largely comprised of nonmarine to shallow marine facies, often low in matrix content and relatively rich in terms of stable framework grains. These rocks are the reservoir for the gas accumulation at Gubik.

Porosity and permeability data derived from 60 surface samples of confirmed Tuluvak (Reifenstuhl and Strauch, 2002) provide information on porosity and permeability characteristics of these rocks. The porosity range is 5.5 to 21.1% with an average of 13.8% and the permeability range is 0.001 to 8,660 md with an average of 554 md. As with the Nanushuk Formation, the relatively small number of samples with permeabilities in the 1,806 to 8,660 md range skews the average to the high end of the range. The removal of the 6 (10%) most permeable samples from the distribution results in a decrease in the average permeability to 110.4 md. This is still an order of magnitude greater permeability than reported for any other Brookian reservoir interval in the foothills.

The Tuluvak appears to be restricted to the southern portions of the coastal plain and the northern foothills. On the Umiat to Milne Point correlation section (Decker, 2006) the Tuluvak is interpreted to depositionally pinch-out just north of the Wolfbutton well at about 70° north latitude and is believed to have limited eastern extent.

2.2.3.3.6 Schrader Bluff Formation/West Sak Sandstone

The Schrader Bluff Formation has a wide distribution across the North Slope and its distribution across the Beaufort and Chukchi areas is discussed above. The Schrader Bluff provides the reservoir for several accumulations. The most noteworthy are the Orion and Tabasco fields and as a secondary reservoir at the Milne Point and Kuparuk fields (Figure 2.17), where it is often termed the West Sak sandstone (Decker, 2006). The shallow marine succession provides opportunities for stratigraphic trapping and has sufficient reservoir quality to provide viable exploration targets, especially when in proximity to major accumulations.

Limited subsurface reservoir data (Werner, 1987) indicate a porosity range of 25 to 35% and permeability from 10 to 800 md. Surface data (Reifenstuhl and Strauch, 2002) from five samples provide some indication of the apparent deterioration of reservoir quality to the south. These surface samples have an average porosity of only 7.1% and a range of 4.8 to 8.6%. The permeability ranges from only 0.004 to 0.047 md with an average of 0.016 md. The surface samples are very fine-grained tuffaceous, silty, and calcareous sandstones, while those in the oil fields to the north are much coarser grained and cleaner. A more comprehensive sampling program may produce samples that are similar in character to those in the oil fields. There is good reason to proceed cautiously if the Schrader Bluff is an exploration target in the southern portions of the North Slope.

2.2.3.3.7 Prince Creek Formation

The Prince Creek Formation, as redefined by Mull and others (2003), occurs across much of eastern NPRA and the Colville-Canning area. There is relatively little recent data regarding the unit's reservoir parameters. In the subsurface of the Kuparuk River field area the lower portion of the heavy-oil bearing Ugnu is equivalent to portions of the Prince Creek. The Ugnu typically has porosity ranging between 30 and 35% and permeabilities in the 200 to 3,000 md range (Werner, 1987). Reifenstuhl and Strauch (2002) present a single porosity value of 21.8% and no permeability data from a Division of Geological and Geophysical Survey (DGGS) reservoir study.

The Prince Creek should be a reasonably good reservoir, especially with respect to gas, in the subsurface south of the Prudhoe Bay area. In the vicinity of NPRA, it is not known to be present in the outcrop or the subsurface south of the Awuna syncline at approximately 68.9º north latitude. But it does extend to the east as far as the Sagavanirktok and Kavik rivers, with scattered upland exposures along Fin Creek, Juniper Creek, and the Shaviovik River (Mull and others, 2003). Additionally, it has a wide distribution on the Chukchi and Beaufort shelves.

2.2.3.3.8 Canning Formation

The Canning Formation is recognized as either the principal or secondary reservoir in at least three accumulations, the Badami, Flaxman Island, Pt. Thomson and possibly Mikkelsen (Figure 2.17). These are deep water reservoirs and consequently there may be problems associated with discontinuous sandstones or compartmentalization and poor reservoir quality due to lack of sorting. Gautier (1987) reported that porosity ranged from less than 1% to 15%. The low porosities are largely due to compaction of ductile grains and the porosity could be greater in areas of abnormally high pressure. In the Point Thomson area, an area of high pressure, subsurface porosities range from 10 to 28% and average 20% (Bird and others, 1987). Nelson and Bird (1999) report porosity and permeability from the Badami No. 2 well, based on 33 sidewall cores, to average 11.2% and 5.5 md. Surface exposures have an average porosity of 5.0%.

The Canning Formation is largely restricted to the northeastern portion of the North Slope and adjacent portions of the Beaufort Sea from the Colville delta to the Canada border (Scherr and Johnson, 1995). It is present throughout much of the 1002 Area of ANWR and along with the Sagavanirktok Formation would be a primary exploration target. The Canning Formation is not recognized as such in the Chukchi Sea, but age equivalents are present in the northwestern portion of the Chukchi shelf (Sherwood and others, 1995).

2.2.3.3.9 Sagavanirktok Formation

The Sagavanirktok Formation is a reservoir in the Ugnu, Hammerhead, and Mikkelsen accumulations (Figure 2.17). In the Prudhoe Bay-Kuparuk field area where it is a productive reservoir, as the upper portion of the Ugnu sands, the Sagavanirktok has porosity in the 30 to 35% range and a permeability range of 200 to 3,000 md (Werner, 1987). In wells west of ANWR, the Sagavanirktok has an average porosity of 17% and an average permeability of 453 md (Lyle and others, 1980). Log-calculated porosities range from 20 to 30%.

The Sagavanirktok Formation has a wide distribution across the northern portion of the North Slope. It is present in the area of the Kuparuk oil field and extends well into the 1002 Area of ANWR and offshore into the Beaufort Sea, where it is present from the area north of Teshekpuk Lake to the Canada border (Scherr and Johnson, 1995). The southern and southwestern limits are controlled by erosion associated with middle to late Tertiary uplift and deformation of the Brooks Range. Like the Canning Formation the Sagavanirktok equivalents are found in only the northwest part of the Chukchi shelf (Sherwood and others, 1995).

This unit is a principal target for any exploration effort in the eastern portions of the Beaufort Sea OCS and the 1002 Area. Equivalent units of both the Sagavanirktok and Canning formations are important reservoirs in the Mackenzie Delta area of Canada.

2.2.3.4 Franklinian Intervals (?)

At present none of the units of the "Franklinian basement" are producing hydrocarbons. The most prospective intervals are the Late Proterozoic and Early Paleozoic carbonates; the Katakturuk/Dolomite, Nanook Limestone, and the Mt. Coplestone Limestone. These units are restricted to the eastern-most portion of the Colville-Canning area and the northern portions of ANWR.

2.2.3.4.1 Katakturuk Dolomite

The Katakturuk Dolomite appears to be the most widespread and prospective of the potential Pre-Mississippian carbonate reservoirs. In the Point Thomson and Flaxman Island area these rocks are believed to be the carbonates encountered in several wells, some of which were capable of producing gas and condensate. Carbonates with varying degree of reservoir quality have also been found in at least four wells (Bird and others, 1987). Bird and others (1987) considered the carbonates in the Canning River Unit A-1 well to be Katakturuk, but Nelson and Bird (1999) now assign that interval to the Nanook Limestone.

Generally, the porosity and permeability of outcrop samples are low. Forty-three samples of the Katakturuk from Katakturuk Canyon (Bird and others, 1987) have an average porosity of 2.3% and a range of 0.8 to 10.0%. The average permeability for this sample set is 0.26 md with a range of 0.1 to 1.6 md. A second set of 20 samples from the Sadlerochit and Shublik Mountains was collected by Clough (1995) and analyzed by Core Labs. These samples have an average porosity of 3.3% and range from 0.5 to 8.6%. The permeability of 15 samples averages 0.12 md and ranges from less than 0.01 to 1.19 md. Fractures, which are present in most basement complex cores, should provide greater permeability than indicated by routine analysis.

Gas and condensate have been reported from probable Katakturuk Dolomite (Figure 2.11) in the Alaska Island No. 1 and Alaska State No. F-1 wells. Daily flow rates are as high as 2.9 millios of cubic feet (MMCF) and 175 barrels of oil (BO). Other wells have flowed water at rates calculated to be as much as 4,200 barrels of water per day (BWPD).

The distribution of the Katakturuk is limited by truncation associated with at least two major regional unconformities, the Pre-Mississippian and Lower Cretaceous unconformities. It has been recognized in wells in the Point Thomson and Flaxman Island area and is present in outcrop as far north as the Sadlerochit Mountains in ANWR, immediately south of the 1002 Area. As a future exploration target it would be an objective in the extreme northeast corner of the Colville-Canning area and over a large portion on the 1002 Area.

2.2.3.4.2 Nanook Limestone

The Nanook Limestone is found in the same general area as the unconformably underlying Katakturuk Dolomite, but it appears to have a more restricted areal extent. It is locally present west of the Canning River, as in the Canning River Unit A-1 well, and locally preserved in the Sadlerochit Mountains. However, it is not known to exist north of the Sadlerochit Mountains. The knowledge of its reservoir character is somewhat limited. A set of three samples from the Shublik Mountains has an average porosity of 1.6% and an average permeability of 0.1 md. Cores from the presumed Nanook section in the Canning River Unit A-1 well yield an average porosity of 0.7% and average permeability of less than 0.1 md. Based on the limited understanding of its reservoir character and restricted distribution, it has a low chance of being an exploration target. If it does possess sufficient reservoir quality, the prospective area is probably limited to a small area west of the Canning River and south of the westward extension of the Sadlerochit Mountain front.

2.2.3.4.3 Mt. Coplestone Limestone

The Mt. Coplestone Limestone is found only in the outcrops of ANWR and appears to have a very restricted distribution. No reservoir quality information is available for this unit. It is highly unlikely that it is or will become a reservoir objective.

2.2.4 Traps

The North Slope and adjacent OCS areas of the Beaufort and Chukchi Seas are characterized by a wide array of traps, but the significance and dominance of a specific trap type tends to vary from north to south and to a lesser extent from west to east.

2.2.4.1 Continental Borderland/Rift Margin Traps

The oil and gas fields located along the Barrow arch are largely structural-stratigraphic accumulations. The majority of these traps are the result of the rifting event that formed the Canada basin and separated the North Slope from its Canadian Arctic Islands counterpart. Many of the Early Cretaceous and older traps, including those for the Prudhoe Bay and Kuparuk fields were completed when marine facies of the Pebble Shale transgressed across the older reservoir units that were exposed and truncated during the development of the LCU. Younger, post-LCU Ellesmerian petroleum system accumulations, such as West Sak and Ugnu, are believed to be associated with normal faulting (Bird, 1994).

Bird (1994) summarized the trapping styles present in known accumulations and recognized eleven structural traps, six (?) stratigraphic traps, and ten combination traps. The structural fields recognized by Bird (1994, Table 21.1 and 21.2 and Figure 21.2) occur in reservoirs that range in age from Late Triassic to Late Cretaceous and include South Barrow, Kavik, Schrader Bluff and Kuparuk accumulations at Milne Point, Gwydyr Bay, North Prudhoe, Kemik, East Barrow, Northstar, Sandpiper, and Sikulik. In this report, the Kavik and Kemik are considered to be included with the traps of the foothills-southern coastal plain area.

The stratigraphic traps occur in Jurassic to Tertiary age units and include fields such as South Barrow, West Sak (?), Ugnu (?), Flaxman Island (?), Walakpa, and Simpson, plus Badami. Exploration in the last decade has resulted in the discovery of additional stratigraphic traps in the Colville delta area, including Alpine and most of its Late Jurassic satellite fields. Also, within the western portion of the Colville-Canning area, the Tabasco, Tarn, and Meltwater fields are stratigraphic traps.

The most volumetrically important trap is the combination trap. The recognized combination traps span the Mississippian through late Early Cretaceous and include the two largest fields on the North Slope, the Prudhoe Bay Ivishak accumulation and the Kuparuk River field. In addition, the Lisburne, Point Thomson, Endicott, Niakuk, West Beach, Point McIntyre, Liberty, Sag Delta North, Sambuca, and Midnight Sun are all combination traps.

The structural component of these rift margin traps is largely extensional and the primary faulting consists of normal faults with some transtensional faults. This style dominates the northern portions of the North Slope, the Beaufort Sea OCS, and at least the northern portion of the Chukchi Sea OCS region. The combination traps typical of the Barrow arch/rift-margin setting will also be prominent features of these northern areas.

2.2.4.2 Brooks Range Foothills and Southern Coastal Plain Traps

Traps associated with known accumulations in the Brooks Range foothills and southern-most portions of the coastal plain accumulations have historically tended to be structural with some stratigraphic traps. Bird (1994, Table 21.2) identified six of these features (the Simpson is included with the rift-margin traps), and all six are structural traps. The structural traps are developed in Cretaceous rocks and include the Umiat, Meade, Wolf Creek, Gubik, Square Lake, and East Umiat accumulations.

There is excellent potential for stratigraphic trapping and a somewhat lesser probability of combination traps. These two trap types are less obvious on the seismic data and in remote areas structural targets are far easier to identify and promote. As exploration for gas proceeds, these trapping mechanisms will become increasingly common objectives.

2.2.5 Accumulations

The history of exploration and discovery is presented in the following section, Section 2.3 Exploration and Development, and the economic discoveries and undeveloped or uneconomic discoveries are presented in Tables 2.7 and 2.8.

2.2.6 Summation

The North Slope is an active and prolific hydrocarbon province with multiple source rocks and reservoirs, diverse trapping mechanisms, and an abundance of large under or unexplored acreage. Geologists and geochemists with the USGS and others (Bird, 1994, Lillis and others, 1994, Magoon and Dow, 1994, and Magoon and others, 1999) have recognized multiple petroleum systems and have summarized the components of these systems. The timing of events have been determined and tables relating the development of the source and reservoir rock, trap formation, and migration/accumulation have been developed by Magoon (1994), Bird (1994), and Magoon and others (1999). Modifications of four of these tables are presented as Tables 2.3a-d.

Tables 2.3a-d are largely self explanatory and will receive little amplification beyond a brief discussion of the timing of generation, migration, and accumulation for each of the four petroleum systems selected for this summary treatment.

Table 2.3a is the events chart for the Ellesmerian petroleum system. It and the other three charts display the source, reservoir, seal, and overburden units; the time of trap formation; and the timing of oil/gas generation, migration, and accumulation. The principal source rocks of the Shublik, Kingak, and HRZ were deposited during the Middle Triassic to Early Cretaceous and began to generate significant quantities of hydrocarbons in the Early Cretaceous. These hydrocarbons ultimately migrated and accumulated in reservoirs of Early Mississippian to Tertiary age. The major traps began to form in the Jurassic associated with the rifting of the Canada basin and the development of traps continued well into the Tertiary. Fields resulting from this series of events include Prudhoe Bay, Endicott, Lisburne, Kuparuk River, Milne Point, Point McIntyre, and Alpine.

The Torok-Nanushuk petroleum system events are depicted in Table 2.3b. The source and reservoir were both deposited in the Cretaceous and the bulk of the traps were formed in the Late Cretaceous to Early Tertiary. Oil and gas generation, migration, and accumulation were largely Paleogene events. Umiat and Gubik are examples of fields representing this series of events.

The Hue-Thompson events chart (Table 2.3c) shows the system that is probably responsible for the bulk of the oil and gas in the Point Thomson and 1002 Area. The source rock is Cretaceous in age and the reservoirs are primarily Cretaceous and Tertiary. Although not shown on the chart, older, Franklinian carbonate rocks may act as reservoirs if found in favorable position relative to the source horizon. Trap formation was restricted to the Late Cretaceous and Paleogene and oil generation, migration and accumulation were probably accomplished during the Paleocene and Eocene. The Point Thomson and Flaxman Island accumulations and oil extracts from oil-stained sandstones in the Jago River, Canning River, Katakturuk River, and in the Kavik area (Lillis and others, 1999) are products of these events.

The events of the youngest and most easterly petroleum system, the Canning-Sagavanirktok, are displayed in Table 2.3d. The presumed source rock and the potential reservoirs are Tertiary in age. Traps appear to have begun developing early in the history of the petroleum system and some are as young as Miocene. Hydrocarbon generation, migration, and accumulation appear to have been Neogene events. The oils are very similar to many in the Mackenzie delta and have been identified in the Hammerhead accumulation, from the Aurora well cores, and the Manning Point and Angun Point seeps. Because of its proximity to the Hammerhead accumulation, the oil at Kuvlum (Lillis and others, 1999) is attributed to the Canning-Sagavanirktok petroleum system.

The North Slope has an abundance of source rocks and reservoir intervals, and distinct episodes and centers of oil and gas generation and accumulation are recognized. The future exploration and development of the North Slope and the adjacent OCS areas will proceed with these facts and assumptions as one set of primary controls with regard to prioritization of exploration areas and the hydrocarbon phase anticipated. The understanding of the relative quality of the reservoir intervals; quality, quantity, and thermal history of source rocks; the time of formation and the nature of traps; and timing of trap charge will be driving forces in the quest for reserve additions.

Table 2.3. Timing of events for North Slope petroleum systems (modified from Bird, 1994, Magoon, 1994, and Magoon and others, 1999) –

a. Events Chart for the Ellesmerian Petroleum System;
b. Events Chart for the Torok-Nanushuk Petroleum System;
c. Events Chart for the Hue-Thomson Petroleum System; and
d. Events Chart for the Canning-Sagavanirktok Petroleum System.

Key to stratigraphic intervals:

1. = Pre-Mississippian Complex;
2. = Early Mississippian Unconformity;
3. = Endicott Group;
4. = Lisburne Group;
5. = Pre-Permian Unconformity;
6. = Sadlerochit Group, Shublik Formation, and Sag River Sandstone;
7. = Kingak Shale;
8. = Lower Cretaceous Unconformity;
9. = Kemik Sandstone, Pebble Shale Unit, and Hue Shale (for 2.3b it represents Fortress Mountain Formation, Torok Formation, Nanushuk Formation, Seabee Formation, and Tuluvak Formation);
10. = Lower Canning Formation (for 2.3b it represents Schrader Bluff Formation and Prince Creek Formation);
11, 12, and 13. = Canning Formation and upper Sagavanirktok Formation (for 2.3b they represent Saganvanirktok Formation); and
14. = Early Pleistocene Unconformity;
15. = Gubik Formation.

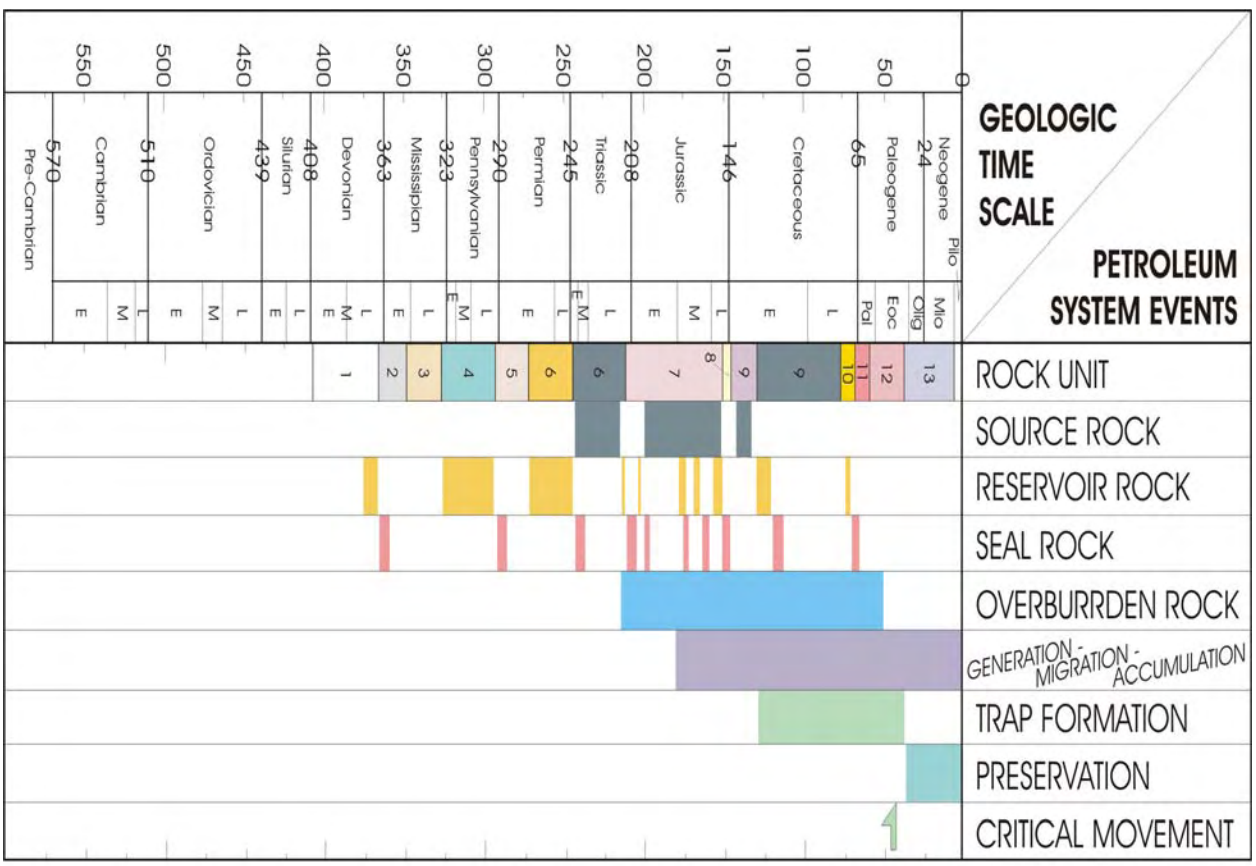

Table 2.3a, Events Chart for the Ellesmerian petroleum system.

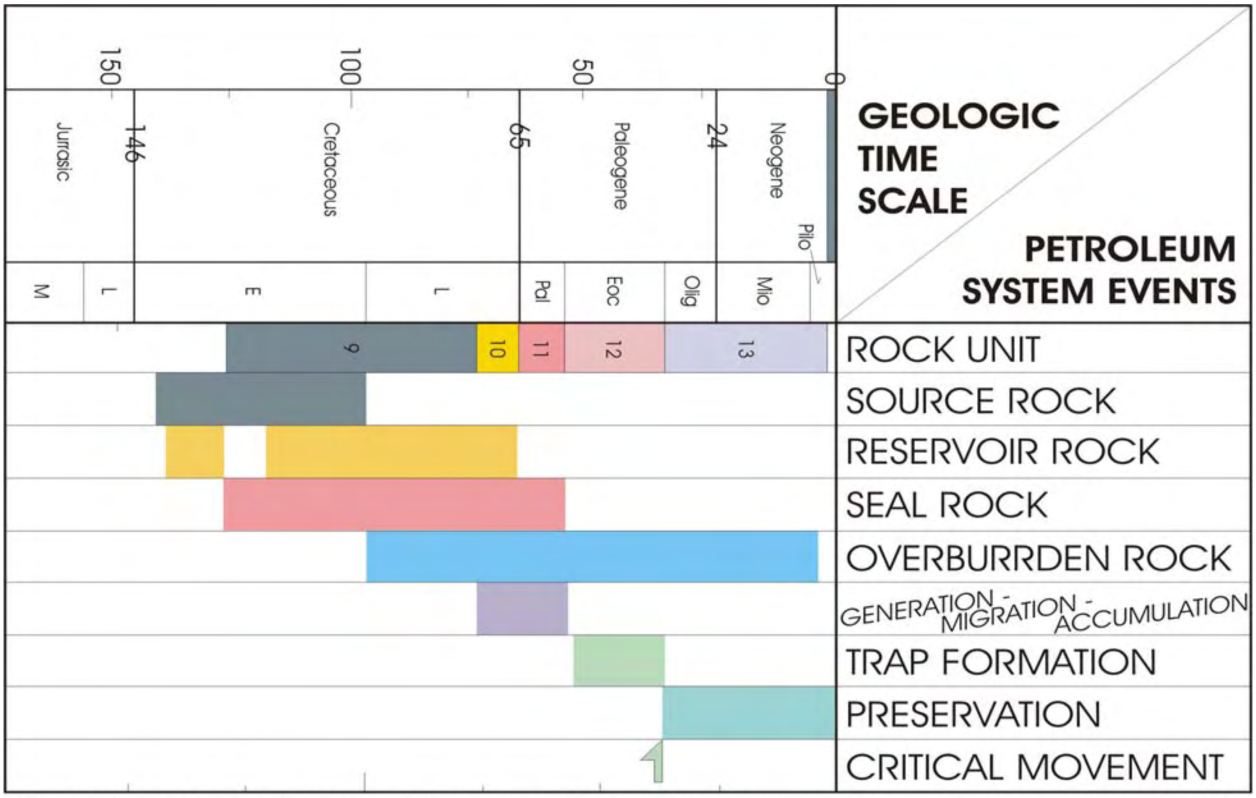

Table 2.3b, Events Chart for the Torok-Nanushuk petroleum system. Time scale: Harland et al., 1989; Berggren et al., 1995.

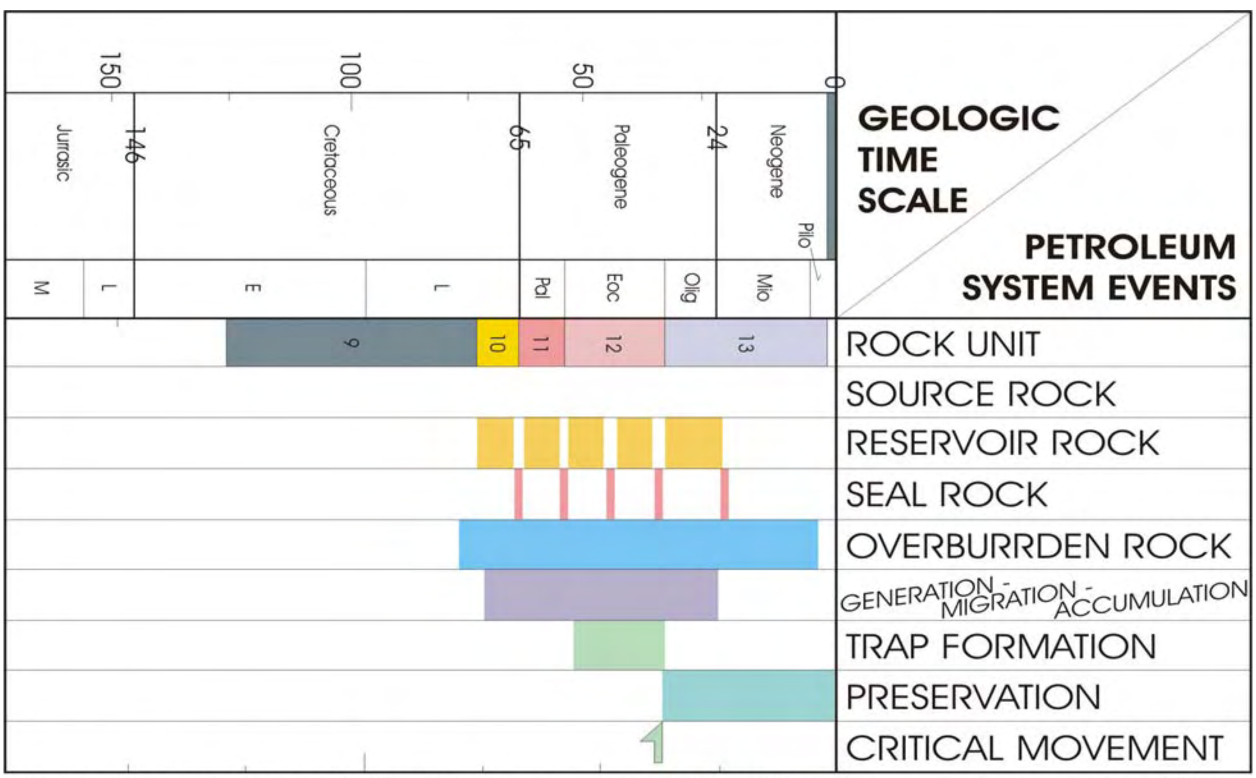

Table 2.3c, Events Chart for the Hue-Thomson petroleum system. Time scale: Harland et al., 1989; Berggren et al., 1995.

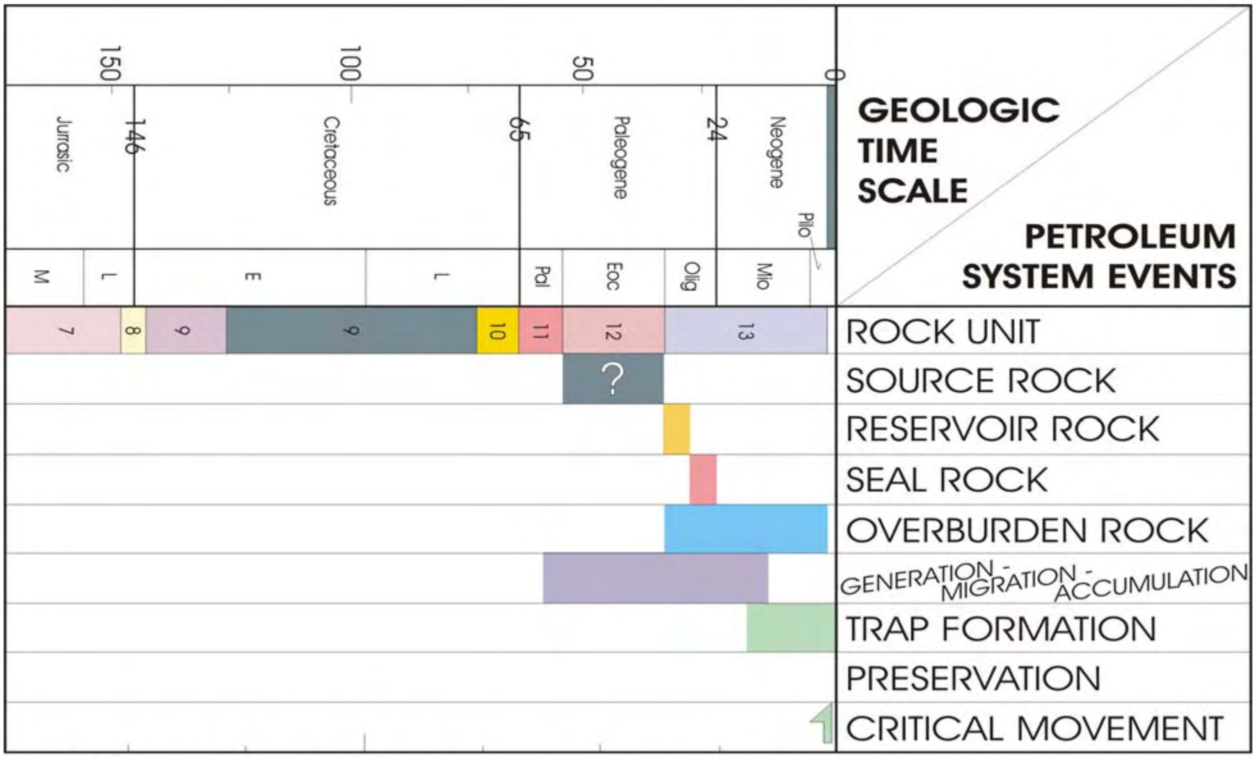

Table 2.3d, Events Chart for the Canning-Sagavanirtok petroleum system. Time scale: Harland et al., 1989; Berggren et al., 1995.

2.3 Exploration and Development

Interest in the hydrocarbon potential of the North Slope commenced when it was recognized that active oil seeps existed in the Cape Simpson area of what is now the National Petroleum Reserve Alaska (NPRA). The birth of North Slope exploration occurred with the evaluation of these seeps in 1909. This would ultimately lead to exploration activities by both the Federal Government and the petroleum industry, the investment of tens of billions of dollars, the drilling of approximately 454 exploration wells (see Figure 2.18, page 2-64), and the discovery of the largest oil and gas field in North America.

As of January 1, 2005 cumulative North Slope production totaled more than 14.989 billion barrels of oil (BBO) from 27 oil accumulations (see Table 2.7, page 2-74), with remaining reserves of 6.950 to 7.530 BBO. There are 35 trillion cubic feet (TCF), generally recognized as proven reserves, awaiting approval and construction of a gas pipeline. An additional 30-plus currently undeveloped oil and gas fields have been discovered (Tables 2.7 and 2.8).

The history of exploration and development that has led to this enormous reserve base will be presented chronologically by geographic-administrative province in the following sections. To encapsulate this process a brief chronological summary of significant events is presented in Table 2.4.

Leasing or land availability is the key component in a successful exploration effort. Without access to the land, the best geological models and economics are for naught. A brief preamble will facilitate the understanding of the leasing history as presented in the various segments.

From the original sales in the late 1950’s to the present many millions of acres have been leased. A large portion of that acreage has been evaluated, tested for one or more potential play types and either successfully developed or released back to the Federal or State agency with jurisdiction. Much of the acreage returned to the leasing agency has been reoffered and leased once again as new play concepts are developed, large “anchor” discoveries are made, or oil prices rise sharply, and the cycle is repeated.

The exploration and development history of the North Slope is presented as a series of time intervals, within which the various geographic-administrative areas are summarized individually. The initial time snapshot covers the interval preceding the discovery of the Prudhoe Bay oil field, and the concluding section summarizes the last fifteen years, from 1990 through 2004.

2.3.1 Pre-Prudhoe Bay Discovery (1900 to 1967)

The first evidence of potentially significant petroleum deposits on the North Slope of Alaska came from the oil seepages along the Arctic Coast from Skull Cliff on the Chukchi Sea to Brownlow Point on the Beaufort Sea, with exceptional seeps at Cape Simpson. The first published description of the seeps was in 1909, and in 1922 Standard Oil of California sent a geologic field party to investigate the seeps. The first claim was staked at Cape Simpson in 1914 and in 1921 individuals and industry personnel staked additional claims in areas near Cape

Simpson, Peard Bay, and along the Meade, Kukpowruk, and Kokolik Rivers (National Research Council, 2003).

Table 2.4. Chronology of significant events in the evolution of the oil and gas exploration and development of the North Slope, Alaska. **(modified from National Research Council, 2003)**

Year(s)	Exploration/Development Milestones
Before recorded history	Oil seepages used by native inhabitants of the North Slope
1882	U. S. government representatives learn of oil seeps
1909	First description of Cape Simpson oil seeps is published
1914	First oil-related claim is staked
1922	First industry-sponsored geological investigation of oil potential
1923	Naval Petroleum Reserve No. 4 (NPR-4) is established
1923-1926	First analysis of NPR-4 hydrocarbon potential
1943	Territory of Alaska Bureau of Mines sends field party to the North Slope to investigate oil and gas seepages; Land north of the drainage divide of the Brooks Range withdrawn from public entry by the Secretary of the Interior – Public Land Order 82
1944	Start of NPR-4 petroleum exploration program
1945-52	Navy-sponsored geophysical studies across NPR-4 result in exploration drilling with un-economic discoveries of oil and gas
1953	NPR-4 exploration unexpectedly recessed
1953-1968	Federal geologic field parties continue in NPR-4, Major oil companies begin exploration on the North Slope
1957	Oil discovered in Cook Inlet
1958	Public Land Order 82 rescinded, First industry-sponsored geological field programs, Alaska Statehood Act passed
1958-1966	First of 4 Federal lease sales held in 1958, the last in 1966
1959	Alaska formally admitted as a state
1960	Establishment of the Arctic National Wildlife Refuge (now ANWR) with 9,000,000 acres about half the size of ANWR today; Public Land Order 82 revoked.
1962	First industry-sponsored seismic program
1963-1967	First industry exploration drilled on the North Slope, 11 unsuccessful wells drilled, industry interest in the North Slope wanes
1964	First State of Alaska lease sale on the North Slope
1965	Area that eventually includes Prudhoe Bay oil field leased
1967	Drill rig moved from Susie to Prudhoe Bay St. No. 1 location and well spud
1968	ARCO announces the discovery of the Prudhoe Bay oil Field, the largest in North America
1969	Discovery of Kuparuk, West Sak, and Milne Point oil fields, Lease sales suspended on the North Slope for 10 years because Secretary of the Interior imposes freezes due to native land claims
1970	National Environmental Policy Act passed
1971	Alaska Native Claims Settlement Act (ANCSA) passed
1974-1982	Federally sponsored exploration along the Barrow Arch within NPRA (NPR-4)
1976	Naval Petroleum Reserve-4 is transferred to the Department of the Interior and renamed National Petroleum Reserve-Alaska (NPRA)

Year(s)	Exploration/Development Milestones
1977	Trans-Alaska Pipeline System (TAPS) become operational; Point Thomson gas and light oil field discovered
1978	Discovery of Endicott field
I979	Initial leasing of portions of the state and federal outer continental shelf (OCS) waters of the Beaufort Sea
1980	Alaska National Interest Lands Conservation Act (ANILCA) passed
1981-Present	Arctic Slope Regional Corporation (ASRC) negotiates exploration agreements with petroleum companies and converts selected acreage to leases – approximately 10 exploration wells are drilled
1981	First Beaufort Sea OCS exploration well drilled
1982	Initial leasing of portions of NPRA; Chevron drilled the Livehorse No. 1 on ASRC lands within NPRA
1983	OCS well, Mukluk No. 1, was the most expensive dry hole ever drilled in the world
1984	The fourth of four scheduled lease sales in NPRA was cancelled due to lack of industry interest, ending the first episode of NPRA leasing
1984-1985	Seismic surveys conducted in 1002 Area of the Arctic National Wildlife Refuge (ANWR)
1985	First industry well drilled on federal leases in NPRA – Brontosaurus No. 1 – was a dry hole
1986	Chevron/BP KIC well drilled on ASRC lands within the 1002 Area of ANWR: well is still in confidential status
1988	Discovery of Pt. McIntyre field in State waters of Beaufort Sea First OCS lease sale in Chukchi Sea
1989	First well drilled in Chukchi Sea – Shell Klondike No. 1; large gas discovery at Shell Burger No. 1 within Kuparuk equivalent strata
Early 1990’s	Last of the 1980’s NPRA leases were relinquished
1991-Present	Satellite field exploration and development gains prominence
1994	Discovery of the Alpine field – opens up new plays in the Jurassic
1999-Present	Renewal of leasing in the NPRA – exploration drilling at a pace of 4 to 6 wells per drilling season
2001	The Beaufort Sea, Northstar field begins production
2004	Legislation to facilitate gas pipeline construction passed

Because of anticipated shortages in oil to fuel the navy’s ships and because of the apparent potential of the region, Naval Petroleum Reserve No. 4 (NPR-4) was established by President Harding, Executive Order, No. 3797-A, in February, 1923. The boundaries of the Reserve were based on the occurrence of the known seeps and the regional traverses that had been conducted by federal personnel. The area of NPR-4 as established is about 23,000,000 acres (≈36,000 square miles).

Concurrent with the activities in NPR-4, the area to the east, from the Colville River to the Canada border was being mapped by United States Geological Survey (USGS) geologists. Geological mapping and exploration north of the Brooks Range began about 1900 when Lt. G. M. Stoney explored the upper Alatra drainage and crossed the Brooks Range to Chandler Lake (Dutro, 1987) and F. C. Schrader crossed the Brooks Range in 1901 and traversed to the Arctic Coast. His report of the traverse is the first account of the geology of the region. He named the

Lisburne Limestone and mapped other units on the north flanks of the Brooks Range. E. de K. Leffingwell, in 1919, was the first geologist to map what is now ANWR. He established the stratigraphic sequence that has been used in its general form to this date. Leffingwell reported oil seeps and oil-stained sandstone in what is now the 1002 Area of ANWR.

From 1920 through the mid 1950's, most of the exploration and evaluation effort on the North Slope was focused in and near NPR-4. From 1923 through 1926, seven USGS parties crossed the Brooks Range and NPR-4, performed reconnaissance scale geological mapping along many of the major rivers, and analyzed the hydrocarbon potential of the Reserve (National Research Council, 2003).

2.3.1.1 NPRA: Navy Exploration Phase – 1940's and 1950's

Exploration in NPRA is unique in that it is the only area in Alaska, which has been almost exclusively explored and evaluated by the Federal government. This situation was largely facilitated by the U. S. Navy and its need for fuel during World War II. The Secretary of the Interior issued Public Land Order 82 in January, 1943, which withdrew from entry, subject to pre-existing rights, for use in the prosecution of the war, all the generally recognized possible petroliferous areas of Alaska including all of Alaska north of the drainage divide of the Brooks Range. This enabled the investigations to extend and follow discoveries and favorable trends outside the boundaries of NPR-4. This order was not rescinded until 1960; more than a year after Alaska became the 49th state.

The USGS was intimately involved in the evaluations and beginning in 1944 conducted ten extensive and wide-ranging programs to support the evaluation. In keeping with Public Land Order 82 their studies were expanded to include the entire North Slope from the Chukchi Sea to the Canada border (Dutro, 1987). Geophysical studies including experimental airborne magnetometer, gravity, and seismic surveys were initiated in 1945 and by 1952 covered a large part of the Reserve. Seismic acquisition of approximately 3,750 line-miles of data covered 67,000 square miles including areas outside of NPR-4. Gravity-meter surveys covered about 26,000 square miles and airborne magnetometer surveys covered 75,000 square miles, nearly all of the coastal plain and much of the foothills of the North Slope (National Research Council, 2003).

In 1945 the exploration drilling phase of the evaluation of NPR-4 was initiated, and a depth limit of 10,000 ft was established for wells. At that time, this was thought to be the economic limit for development in the Arctic. The evaluation effort consisted of a combination of exploration (test) wells and core tests. Between 1945 and 1952 a total of 81 wells were drilled with 36 "exploration" wells and 45 core tests (Bird, 1981, Schnindler, 1988, Reed, 1958, and National Research Council, 2003, Figure 4-2). The 45 core-tests ranged in depth from 115 ft in the Simpson core-test No. 1 to 2,505 ft in the Simpson core-test No. 28. Exploration wells ranged in depth from 373 ft at the Knifeblade No. 2 to 11,872 ft in the Oumalik No.1. Only two wells were drilled deeper than the original depth limit of 10,000 ft and eight additional wells were drilled in the 5,000 to 10,000 ft depth range (Reed, 1958). Figure 2.18 indicates that 70 exploration wells were drilled during the 1940's and 1950's rather than the 81 cited above. This difference is attributed to the fact that, for this report, the delineation wells at discoveries such as Umiat are not included in the exploration well totals of Figure 2.18.

The first wells were drilled in the Cape Simpson and Umiat areas. While the first Umiat well was drilled in 1945, the Umiat oil field was not discovered until 1950. Beginning in 1945, 31 shallow core-tests were drilled in the Cape Simpson area. Oil was discovered and produced on test but in volumes insufficient to be economic. In 1948 the Barrow high was drilled and no oil was found, but gas was discovered in shallow Jurassic sandstones. The well encountered basement at 2,500 ft. The presence of this basement high followed by additional geophysical surveys delineated the Barrow arch, the northern limb of the Colville basin and a key feature in the accumulation of much of the oil and gas in the Prudhoe Bay area.

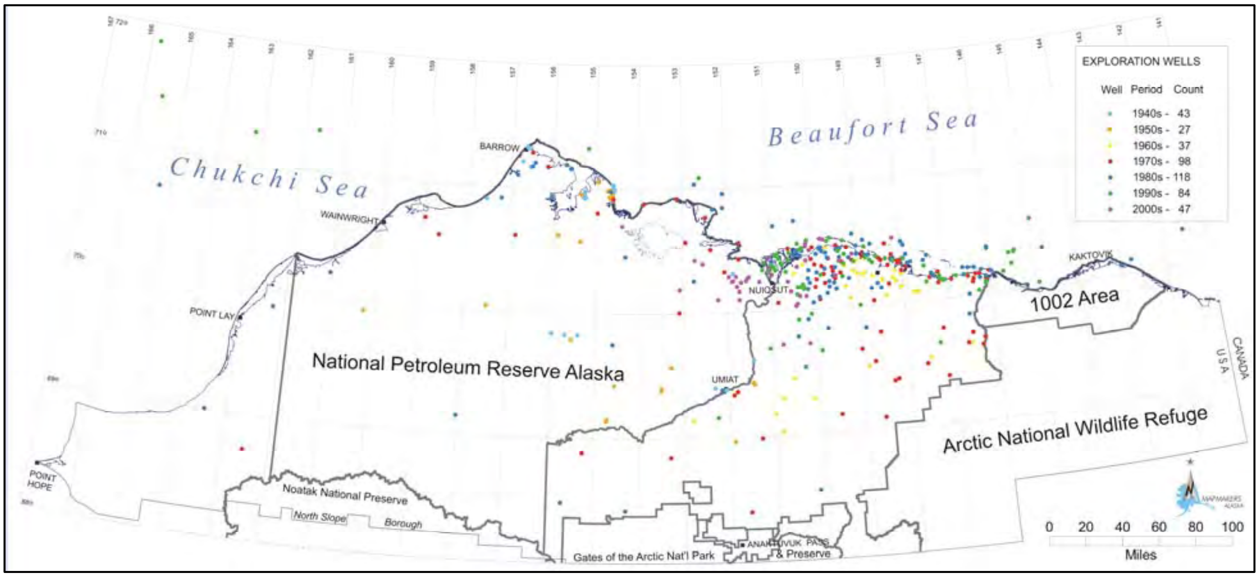

Figure 2.18. Exploration wells of the North Slope and adjacent areas, by decade drilled.

Most of the wells were drilled to evaluate middle Cretaceous objectives in the northern foothills, and ten structures were tested by 26 wells. Ellesmerian objectives were tested by seven wells on the coastal plain, with five of those wells at Barrow. Three wells in the coastal plain were drilled to test Cretaceous objectives. No pre-Cretaceous intervals were drilled in the southern foothills or northern slopes of the Brooks Range (Bird, 1981), but the Oumalik No. 1 was drilled into the upper part of the Jurassic Kingak Shale. The 36 exploration wells tested a total of 18 different prospects. Twenty-one of the 24 wells, located south of 70° north latitude, were drilled on only four structures (11 at Umiat, 3 at Wolf Creek, 3 at Knifeblade, and 2 at Gubik). The area south of 70° north constitutes approximately 65% of NPR-4 and only six features were tested during this episode of drilling. From both the regional and stratigraphic perspectives the vast majority of NPR-4 was not evaluated in the 1945 to 1952 drilling program.

This first round of drilling did result in the discovery of a number of small, sub-economic oil and gas fields (Table 2.8). Three small oil fields were discovered: Umiat, Fish Creek, and Simpson (Reed, 1958, Bird, 1981, Schindler, 1988, and Banet, 1991). Umiat is the largest with estimated recoverable resources of 70 MMBO. These are all Nanushuk Formation accumulations. Five modest to small gas fields were discovered. These are the Gubik, Barrow, Meade, Square Lake, and Wolf Creek (Tables 2.7 and 2.8). Gubik is the largest with estimated recoverable resources of approximately 600 BCF. The others range from 20 to 58 BCF and the Barrow field is being produced to supply gas to the community of Barrow. The Barrow field produces from the Jurassic Barrow Sandstone. The Meade, Square Lake, and Wolf Creek accumulations are in the Lower Cretaceous Nanushuk Formation and the Gubik accumulations are in the Upper Cretaceous Schrader Bluff and Lower Cretaceous Nanushuk formations.

The program was terminated in 1953 and the Reserve was largely ignored until the oil embargo renewed interest in developing and maintaining an additional domestic source of oil.

2.3.1.2 Colville-Canning Province; Industry efforts – 1958 through 1967

While the petroleum industry had been aware of and interested in the potential of the North Slope, the lack of land availability, remoteness, and the costs of operating in this area precluded industry participation. However, in the late 1950's and early 1960's, a number of developments provided the impetus for the industry to commence active exploration of the North Slope.

Four factors contributed to the entry of the industry into the North Slope: 1) encouraging regional geological studies, 2) the NPR-4 exploration program, 3) oil and gas discoveries in Cook Inlet, and 4) the end of the moratorium on land availability on the North Slope. The discovery of commercial quantities of oil and gas in Cook Inlet demonstrated that it was economically feasible to explore for, develop, and market hydrocarbons in and from Alaska. In 1957, Richfield Oil Corporation made the initial discovery at Swanson River on the Kenai Peninsula. This discovery contributed significantly to Alaska statehood in 1959 and provided industry with the incentive for exploration of the other sedimentary basins in the state. The North Slope was one of the areas of interest and was highlighted because of the previous work by the USGS and the Navy's exploration program. Both of these efforts supported the premise that a significant reserve potential existed on the North Slope.

The most important factor was the decision by the Federal government, through the Bureau of Land Management (BLM), to make lands available to the industry for leasing. The industry exploration of the North Slope was greatly stimulated by the knowledge that land was to be made available for leasing by the Federal government starting in 1958 under basically the same conditions that existed in the Lower 48.

NPR-4 remained a Federal Reserve and was excluded from those areas open to leasing. Soon after the Federal leasing program began and before the State held its first North Slope lease sale a second large tract of land was removed from consideration through the establishment in 1960 of the Arctic National Wildlife Range (9,000,000 acres). It was later expanded to more than 19,000,000 acres and renamed the Arctic National Wildlife Refuge (ANWR). The bulk of the onshore area available for leasing and exploration was located between the Colville and Canning rivers and generally extended from the Beaufort Sea south into the foothills. The total area of about 16,500,000 acres or 25,800 square miles also included some acreage west of NPR-4.

In the discussion of industry activities, leasing and exploration activities are summarized separately to provide a less cluttered descriptive narration. However, it should be noted that these various activities are closely related in time and are interdependent.

2.3.1.2.1 Leasing

The Federal government offered a total of 18,862,116 acres for lease in sales held in 1958, 1964, 1965, and 1966 (Jamison and others, 1980 and Thomas and others, 1991). Most of the offerings were to the east and southeast of NPR-4 and south of 70° north latitude, but the 1966 sale contained 3,022,716 acres in the area west of NPR-4. The BLM offered the leases as simultaneous filings and in blocks or tracts consisting of four contiguous sections (2,560 acres). Individual lease numbers and dates are from Table 2.5.

In 1958, the first Federal land was made available in the Gubic gas field area, and 16,000 acres were leased in a competitive lease sale (Table 2.5). The BLM offered more than 4,000,000 acres for leasing in two separate parcels in 1958. The larger of the two offerings abutted NPR-4 on the east and southeast and the smaller acreage package was south of the Prudhoe Bay/Mikkelsen Bay area. In 1964, the BLM held the second major simultaneous filing and drawing on 3,680,000 acres in the area between the Colville and Canning Rivers and essentially filling the area between the two segments offered in 1958.

Table 2.5. Summary of North Slope and adjacent OCS lease sales and simultaneous filings, 1958 through 2004. During this time interval ASRC executed exclusive exploration agreements and leased acreage to a number of companies; currently Anadarko has such an agreement with ASRC. (Sources: ADNR and MMS on-line files, Kornbrath, 1995 and BLM communication).

Date	Area	Agency	Sale Name/ Number	Acres Offered	Acres Leased
1958	Gubik area	BLM	1st North Slope sale	16,000	16,000?
1958	E/SE of NPR-4 & S of Mikkelsen	BLM	1st North Slope Offering	4,032,000	4,032,000 ?
1964	Between E & W segments of 1958 sale	BLM	2nd North Slope Offering	3,686,400	3,686,400
1964	East of Colville River delta	ADNR	State Sale No. 13	624,457	464,925
1965	E, S, & W of prior BLM offerings	BLM	Third North Slope Offering	8,171,000	1,095,680
1965	Prudhoe W to Colville R.	ADNR	State Sale No.14	754,033	403,000
1966	West of NPR-4	BLM	Fourth North Slope Offering	3,022,716	No leases issued
1967	Prudhoe Offshore/ Uplands	ADNR	State Sale No. 18	37,662	37,662
1969	Colville to Canning R. Offshore/Uplands	ADNR	State Sale No. 23	450,858	412,548
1979	Beaufort Sea, offshore Milne Pt. to Flaxman Island	ADNR	State Sale No. 30	341,140	296,308
1979	Beaufort Sea	MMS	BF	173,423	85,776
1980	Prudhoe Uplands, Kuparuk R. to Mikkelsen Bay	ADNR	State Sale No. 31	196,268	196,268
1982	Prudhoe Uplands, Sag. to Canning R.	ADNR	State Sale No. 34	1,231,517	571,954
1982	Beaufort Sea/Pt. Thomson Area	ADNR	State Sale No. 36	56,862	56,862
1982	Beaufort Sea	MMS	OCS Sale No. 71	1,825,770	662,860
1982	NPRA	BLM	No. 821	~1,500,000	675,817

Date	Area	Agency	Sale Name/ Number	Acres Offered	Acres Leased
1982	NPRA S & SE portions	BLM	No. 822	~3,500,000	252,149
1983	NPRA Northern Portions	BLM	No. 831	2,195,845	419,618
1983	Beaufort Sea, Gwydyr Bay to Harrison Bay	ADNR	State Sale No. 39	211,988	211,988
1984	Beaufort Sea, Pitt Pt. to Harrison Bay	ADNR	State Sale No. 43	298,074	281,784
1984	Colville R. Delta/Prudhoe Bay uplands	ADNR	State Sale No. 43a	76,079	76,079
1984	Beaufort Sea	MMS	OCS Sale No. 87	7,773,447	1,207,714
1985	N. S. exempt, Canning R. to Colville R.	ADNR	State Sale No. 45a	606,385	164,885
1985	Kuparuk Uplands, S. of Prudhoe Bay	ADNR	State Sale No. 47	192,569	182,560
1986	Kuparuk Uplands, S. of Kuparuk oil field	ADNR	State Sale No. 48	526,101	266,736
1986	Mikkelsen Bay Foggy Is. Bay	ADNR	State Sale No. 48a	42,503	42,503
1987	Camden Bay: Flaxman Is. To Hulahula R.	ADNR	State Sale No. 50	118,147	118,147
1987	Prudhoe Bay Uplands, Sag. to Canning R.	ADNR	State Sale No. 51	592,142	100,632
1988	Kuparuk Uplands, Colville R. Delta	ADNR	State Sale No. 54	421,809	338,687
1988	Beaufort Sea	MMS	OCS Sale No. 97	18,277,806	1,110,764
1988	Beaufort Sea, Canning R. to Canada	ADNR	State Sale No. 55	201,707	96,632
1988	Kuparuk Uplands, Canning R. to Colville R.	ADNR	State Sale No. 69a	775,555	368,490
1988	Chukchi Sea	MMS	OCS Sale No. 109	25,631,122	1,976,912
1989	Beaufort Sea, Pitt Pt. to Tangent Pt.	ADNR	State Sale No. 52	175,981	52,463
1989	Oliktok Pt., Uplands	ADNR	State Sale No. 72a	667	667
1991	Kuparuk Uplands, Canning R. to Colville R.	ADNR	State Sale No. 70a	532,153	420,568
1991	Kavik, Sag. R, to Canning R. Uplands	ADNR	State Sale No. 64	754,452	34,143
1991	Beaufort Sea, Pitt Pt. to Canning R.	ADNR	State Sale No. 65	491,091	172,865
1991	Beaufort Sea	MMS	OCS Sale No. 124	18,556,976	277,004
1991	Chukchi Sea	MMS	OCS Sale No. 126	18,987,976	159,213
1992	White Hills, Colville R. to White Hills	ADNR	State Sale No. 61	991,087	260,550
1992	Beaufort Sea, Nuluvik to	ADNR	State Sale No. 68	153,445	0

Date	Area	Agency	Sale Name/ Number	Acres Offered	Acres Leased
	Tangent Pt.				
1992	Kuparuk Uplands, NPRA to Sag. R. & ASRC lands	ADNR	State Sale No. 75[4]	217,205	124,832
1993	Nanushuk, N. S. foothills, Chandler R. to Ivishak R.	ADNR	State Sale No. 77	1,260,146	45,727
1993	Kuparuk Uplands, Canning R. to Kavik R.	ADNR	State Sale No. 70A-W	37,655	28,055
1993	Brooks Range Foothills, Sag. R. to Killik R.	ADNR	State Sale No. 57	1,033,248	0
1993	Colville R. Delta	ADNR	State Sale No. 75a	14,343	14,343
1995	Shaviovik, Sag. R. to Canning R., Kuparuk Uplands, Gwydyr Bay, Foggy Is. Bay	ADNR	State Sale No. 80	951,302	151,567
1996	Beaufort Sea	MMS	OCS Sale No. 144	7,282,795	100,025
1996	Colville R. offshore, State/ASRC on- & offshore	ADNR	State Sale No. 86a[4]	15,484	5,901
1997	Central Beaufort Sea, Harrison Bay to Flaxman Is.	ADNR	State Sale No. 86	365,054	323,835
1998	North Slope Areawide; North of Umiat Baseline	ADNR	State Sale No. 87	Areawide	518,689
1998	Beaufort Sea	MMS	OCS Sale No. 170	920,983	86,371
1999	North Slope Areawide	ADNR	NS 1999	Areawide	174,923
1999	Northeast portion of NPRA	BLM	991	3,900,000	864,204
2000	Beaufort Sea Areawide	ADNR	BS 2000	Areawide	25,840
2000	North Slope Areawide	ADNR	NS 2000	Areawide	652,355
2001	North Slope Foothills	ADNR	NSF 2001	Areawide	858,811
2001	Beaufort Sea Areawide	ADNR	BS 2001	Areawide	36,331
2001	North Slope Areawide	ADNR	NS 2001	Areawide	434,938
2002	Northeast portion of NPRA	BLM	2002	3,051,500	579,269
2002	North Slope Foothills	ADNR	NSF 2002	Areawide	213,374
2002	Beaufort Sea Areawide	ADNR	BS 2002	Areawide	19,226
2002	North Slope Areawide	ADNR	NS 2002	Areawide	32,316
2003	North Slope Foothills	ADNR	NSF 2003	Areawide	5,760
2003	Beaufort Sea	MMS	OCS Sale No. 186	9,459,743	181,810
2003	Beaufort Sea Areawide	ADNR	BS 2003	Areawide	36,995
2003	North Slope Areawide	ADNR	NS 2003	Areawide	210,006
2004	North Slope Foothills	ADNR	NSF 2004	Areawide	19,796
2004	Beaufort Sea Areawide	ADNR	BS 2004	Areawide	125,440
2004	North Slope Areawide	ADNR	NS 2004	Areawide	225,280
2004	NPRA Northwest portion	BLM	2004	5,800,000	1,403,561

[4] Pre-areawide sales with ASRC acreage included.

Under the Statehood Act, the State of Alaska selected 1,616,745 acres between the Colville and Canning Rivers, north of the Federal offerings of 1958 and 1964. The State subsequently offered these lands in three sales between 1964 and 1967 (Table 2.5).

In December of 1964, the State held its first North Slope lease sale, State Sale No. 13, offering 624,457 acres in the areas east of the Colville River (Jamison, and others, 1980), and 196 tracts, totaling 464,924 acres, were leased (Kornbrath, 1995). This area is now the site of several large oil fields, including the Kuparuk River, Milne Point, and West Sak fields.

In 1965, Federal simultaneous filings and subsequent drawings were held for approximately 8,000,000 acres in the areas to the east, south, and west of the earlier Federal offerings (Jamison, and others, 1980). These lands were largely in the Canning River drainage near the Sadlerochit and Shublik mountains and in the foothills areas.

During July of 1965, the State held competitive lease sale No. 14, the second on the North Slope, in the area that would ultimately include the Prudhoe Bay field. The sale offering was 754,033 acres, and 159 tracts totaling 403,000 acres were leased. Richfield-Humble acquired 28 tracts on what was to be the crest of the Prudhoe Bay field, and British Petroleum acquired 32 tracts on the flanks of the Prudhoe Bay structure.

In late 1966, the BLM offered 3,000,000 acres west of NPR-4 (Jamison, and others, 1980 and Thomas, and others, 1991). No leases were issued due to uncertainty arising from native land claims.

The State's third North Slope sale (No. 18) was held in January, 1967, and thirteen tracts were offered and issued. Richfield-Humble acquired seven tracts that covered the remainder of the crestal area of the Prudhoe Bay structure. This sale completed the leasing prior to the drilling of the discovery well at Prudhoe Bay. A total of 9,732,667 acres were leased prior to the Prudhoe Bay discovery. Presently only two of the leases acquired during the 1950's are still held by the original lessee or successor (Figure 2.19). Of the leases issued in the 1960's, including those issued after the discovery in 1969, 250 are still active (Figure 2.19).

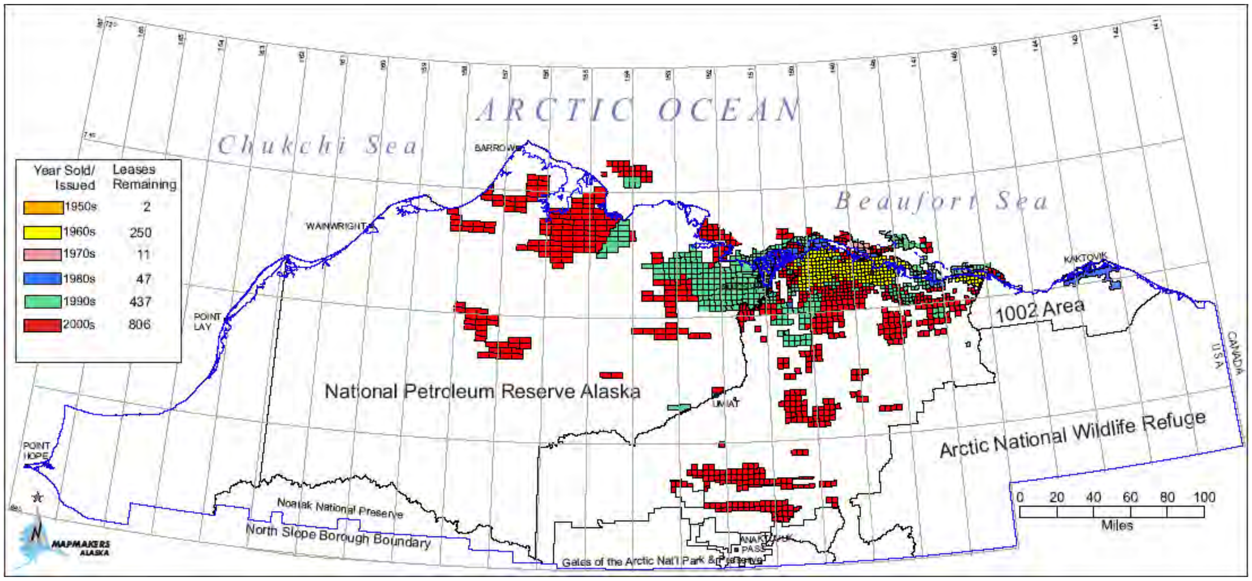

Figure 2.19. Number of currently active leases by decade of acquisition.

2.3.1.2.2 Data Acquisition

The acquisition of geological and geophysical data is either concurrent with or precedes leasing activities. With the opening of the North Slope to leasing, the industry began to acquire proprietary geological and geophysical data with twin goals of better understanding the subsurface geology and hydrocarbon potential of the region. Two fundamental data sets were acquired: geological data through summer field programs and geophysical data, primarily seismic, by winter seismic operations. Jamison and others (1980, Figure 3) provide a chart of exploration activity spanning the interval from 1958 to 1977, or the start-up of TAPS.

The first industry-sponsored geological field program was operated by Sinclair in 1958. It was a three-month program based in Umiat, in preparation for the first Federal sale in September, 1958. Sinclair was quickly followed by others, and an average of five to seven companies were in the field during the 1959 through 1961 seasons. A peak level of 30 geological crew-months was reached in 1961 and again in 1963. This level of geological field work was not again approached until the upsurge in activity immediately following the announcement of the discovery at Prudhoe Bay. The number of companies actively engaged in geological field work increased, and during 1962-1964 up to ten companies were operating geological field programs. The amount of geological field work declined rapidly over the next three years, with only two to three companies in the field during the 1965 to 1967 interval. In 1967, the year before the Prudhoe Bay discovery was announced, the geological field activity had declined to a ten-year low of two crew-months.

For the early stages of North Slope exploration there is a lack of information regarding the number of line-miles of seismic data acquired annually; therefore, the number of crew-months of seismic acquisition has been used as a gauge of activity. This number does not reveal how many permits or programs were conducted or the number of line-miles of data acquired. The number of crew months will be used as a gauge of activity through the mid-1970’s and supplemented or replaced by the number of programs permitted and the line-miles acquired for the time intervals for which such data are available.

The Alaska Division of Oil and Gas (ADOG) records of seismic acquisition in terms of seismic permits and line-miles of seismic acquisition begin in the latter half of the 1960's and were supplied by ADOG (2004), summed in five-year increments. There data do not differentiate between state onshore and state offshore areas. Similarly, the Minerals Management Service (MMS) has records of seismic permits and line-miles of 2D acquisition from 1968 to 1997 for the Beaufort Sea and from 1970 to 1991 for the Chukchi Sea. Beaufort Sea 3D data exist for the interval of 1983 to 2004 and include data acquired in nearshore state waters. These data from the ADOG and MMS are presented in Table 2.6 and Table 2.9 to provide common sources for this information. Because of the format in which some of the information on seismic data acquisition was provided to the authors, there is a one year difference in the way a decade of seismic acquisition is tabulated compared to the remainder of the information. For example, a seismic decade runs from 1991 to 2000 and the rest of the data are recorded as 1990 to 1999. This may result in some potential confusion; therefore the reader should keep in mind this distinction. Table 2.6 lists the two-dimensional (2D) data and Table 2.9 summarizes the three-dimensional (3D) data.

Sinclair and British Petroleum operated the first industry seismic program in 1962. The first seismic acquisition season consisted of 6.5 crew-months. In 1963, the total was 29.25 crew-months, and activity peaked in 1964 with 53.5 months of seismic data acquisition. There was very little seismic acquisition between 1965 and the year following the Prudhoe Bay discovery; a total of approximately 28 crew-months (Jamison and others, 1980, Figure 3). Division of Oil and Gas data (Table 2.6) indicate that 2,310 line-miles of onshore seismic data were acquired in the 1966 to 1970 time interval. Data from the MMS (Table 2.6) show that 4,151 line miles of data were acquired in the Beaufort Sea in this same time period, probably from the shallow, state-owned portions of the Beaufort Sea. The majority of these data were acquired in 1970, post-Prudhoe Bay discovery.

Table 2.6. Tabulation of North Slope and Adjacent Beaufort Sea and Chukchi Sea 2D Seismic Acquisitions – Offshore acquisitions are both Hardwater (HW) and Marine (M).

Time Period	Area				
	NPRA[1] (miles)	Colville-Canning (Includes some State Beaufort Sea (Hw))[1] (miles)	Beaufort Sea OCS (Includes some State Beaufort Sea)[2] (miles)	Chukchi. Sea OCS[2] (miles)	1002 Area of ANWR[1] (miles)
1966-1970	——	2,310	4,151	1,314	——
1971-1975	~5,200	5,223	6,788	4,703	——
1976-1980	~6,500	7,872	21,144	——	——
1981-1985	~1,416	15,625	45,163	32,776	1,450
1986-1990	——	8,006	12,961	37,270	——
1991-1995	——	4,960	1,298	——	——
1996-2000	——	1,104	649	——	——
2001-2005	——	1,017	——	——	——
TOTALS	13,116	46,117	92,154	76,063	1,450

1. Source – Alaska Division of Oil and Gas (ADOG)
2. Source – Minerals Management Service (MMS)

The marked decline in both geological and geophysical activity in the mid-1960's reflects the lack of success in the industry's exploration drilling programs through 1967.

2.3.1.2.3 Exploration Drilling

Industry-sponsored exploration drilling commenced in 1963, following five years of leasing, geological field work, and seismic data acquisition. Eleven dry holes were drilled prior to the Prudhoe Bay discovery. The first exploration well was the Colorado Oil and Gas Company Gubik No. 1, drilled in the vicinity of the Gubik gas field. The Gubik No. 1 and the seven subsequent wells were all drilled on leases acquired in the first round of Federal leasing and were located in the Brooks Range foothills within 30 miles of either the Gubik or Umiat discoveries. The initial exploration efforts were focused within or in close proximity to the areas that had shown the most promise in the Navy's exploration program. All eight wells penetrated the Cretaceous and were dry holes.

After the failure of the exploration drilling in the foothills, the industry focus shifted to the north and east. Two wells were drilled in the 1966 to 1967 interval, one each by Sinclair and Union, on acreage acquired in the first State lease sale. Both were drilled on the eastern flank of the well recognized Colville High and both were dry holes. During this same time frame the AtlanticRichfield Company (ARCO)-Humble drilled the Susie No. 1 in the northern foothills of the Brooks Range on acreage acquired in the State's second North Slope lease sale. This well was also a dry hole and presented ARCO and Humble with a critical decision: either release the rig and forego further drilling or haul the rig 60 miles to the north, during the winter, and drill in the Prudhoe Bay area. Ultimately the decision was made to move the rig and drill the Prudhoe Bay State No. 1 well.

2.3.2 Prudhoe Bay Discovery and Aftermath: (1968 to 1969)

The proposed drilling site for the Prudhoe Bay State No. 1 well was on State of Alaska leases atop the Prudhoe Bay structure. The principal objective was the carbonate sequence of the Mississippian/Pennsylvanian Lisburne Group. Secondary objectives included Cretaceous sandstones and the Permian/Triassic Sadlerochit sandstones. The Lisburne carbonates were the preferred reservoir objective because of visible porosity in outcrop and the highly indurated character of the Cretaceous and Permian/Triassic sandstones observed in surface exposures.

The drilling rig was hauled north from the Susie location during the winter of 1967 and the Prudhoe Bay No. 1 was spud in April 1967. Drilling was suspended for the summer and resumed in the fall after freeze-up. ARCO-Humble announced the discovery in January, 1968. Upon completion and testing of a confirmation well, the Sag River State No. 1, seven miles to the southeast, the recoverable economic reserve estimate of 9.6 billion barrels of oil and 26 trillion cubic feet of gas was released.

The timing of the well and its success was very opportune, as other exploration activities had virtually shut-down at the time the Prudhoe Bay State No. 1 was drilled. In 1967, there only three crew-months of geologic field work, no seismic programs were conducted by industry, and no drilling activity other than the Prudhoe Bay State No. 1.

2.3.2.1 Leasing

With the success at Prudhoe Bay, the State announced an additional sale in the Prudhoe Bay area, scheduled for the fall of 1969. Alaska State Lease Sale No. 23, often called "the billion dollar sale", drew widespread attention and was among the most financially rewarding sales the State has ever conducted. A total of 412,548 acres (Table 2.5) were leased in and around the Prudhoe Bay area. As a result of the magnitude of the discovery and to prepare for the sale, the industry greatly increased the level of exploration-related activity on the North Slope

2.3.2.2 Data Acquisition

Whereas geological and geophysical activities had declined to exceptionally low levels prior to the Prudhoe Bay discovery, they increased dramatically in 1968 and 1969. Geological crew-months increased from three in 1967 to twelve in 1968 and then to twenty in 1969. Similarly, the geophysical activity grew from zero crew months in 1967 to twenty-four in 1968 and to ninety-seven in 1969 (Jamison, and others, 1980). This activity was also reflected in the number of exploration wells drilled in this brief period.

2.3.2.3 Exploration Drilling

During the ten years of industry activity preceding the Prudhoe Bay discovery only 11 wells had been drilled. In 1968 and 1969, 33 wells were drilled and completed (Alaska Division of Oil and Gas, 2000). The locations of all wells drilled in the 1960's are indicated on Figure 2.18. The exploration wells resulted in 12 discoveries. Most of these are now productive oil fields. Field locations are shown on Figure 2.20.

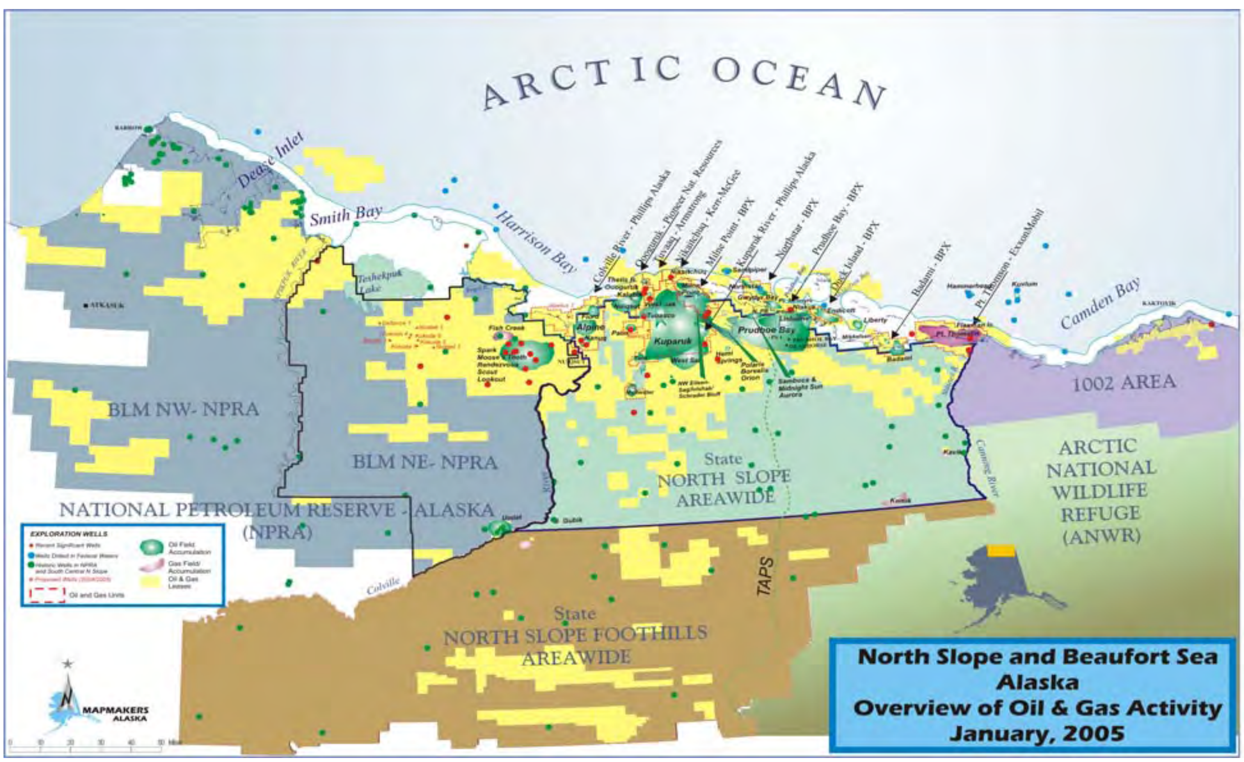

Figure 2.20. Overview of oil and gas activity – North Slope and Beaufort Sea, Alaska.

2.3.2.4 Discoveries

Table 2.7 was constructed to show, among other aspects, estimates of economical ultimate recovery (EUR), economical remaining reserves (ERR), and original oil- or gas-in-place (OOIP or OGIP) for the ANS fields discovered and producing as of December 31, 2004. Tables 2.8 shows the fields discovered but not developed as of December 31, 2004.

The twelve discoveries listed below were made in 1968 to 1969 (see Tables 2.7 and 2.8). Eleven are in the general Prudhoe Bay area, along the Barrow arch trend. The twelfth is the undeveloped Kavik gas field (Figure 2.20). The fields are listed below with cumulative production as of December 31, 2004. Total EUR for the ten fields listed below is estimated to be 16.6 BBO.

Oil/Gas Field	Cumulative Production (December 31, 2004)
Prudhoe Bay field	11,144 MMBO
Lisburne field	152 MMBO
Orion field	1.5 MMBO
Ugnu field	< 1.0 MMBO
Kuparuk River field	1,960 MMBO
West Sak field	13.6 MMBO
Milne Point field	214 MMBO
Borealis field	28 MMBO
Aurora field	10.5 MMBO
Polaris field	3.2 MMBO
Kavik gas field	Not developed
Gwydyr Bay field	Not developed

While all these fields were discovered in the 1968 to 1969 drilling seasons, the first field to be put on production, Prudhoe Bay, did not commence commercial production until 1977 and Aurora, Borealis, and Orion did not commence production until the year 2000 or later (Table 2.7).

These fields are developed principally in sandstone reservoirs; the Lisburne field is the sole carbonate reservoir. The producing horizons range in age from Mississippian to Late Cretaceous, and the reservoirs represent nonmarine fluvial, deltaic, and fan environments and shallow marine shelf, bar and shoal depositional settings.

The results of the Prudhoe Bay area discoveries and those that followed in rapid succession, plus the high level of interest in the 1969 lease sale, established the basis and direction for the next decade of exploration on the North Slope.

Table 2.7. North Slope oil and gas fields–producing as of December 31, 2004 or soon to start production. (Sources–Thomas, et al., 1991 & 1993; Bird, 1994; ADOG, 2003; ADOG, 2004a).

Field Name/ Discovery Well	Disc. Date	Reservoirs	Orig. Est. of Recovery	Prod. Start Up Date	Cum. Prod. (12/31/ 2004)	ERR (1/1/ 2005)	EUR[5]	OOIP or OGIP[6]
South Barrow/ Navy South Barrow No. 2	1949	Barrow Sandstone	26.0 BCF	1950	23.0 BCF	3.0 BCF	26.0 BCF	~37.0[6] BCF
Prudhoe Bay/ ARCO Prudhoe Bay State No. 1	1968	Ivishak, Shublik, Sag River fms.	28,500 BCF	1969 (tests)	-----	26,687 BCF	26,687 BCF	41,000 BCF
			9,590 MMBO	1977	11,144 MMBO	2,697 MMBO	13,841 MMBO	25,000[7] MMBO
Lisburne/ ARCO Prudhoe Bay State No. 1	1968	Lisburne	635 BCF	1983 (tests)	-----	347 BCF	347 BCF	~900.0 BCF
			400 MMBO	1985	154 MMB0	38 MMBO	192 MMBO	3,000 MMBO
Orion/ Kuparuk State No. 1	1968	Schrader Bluff Formation	214 – 446 MMBO	2004(?)	2.3 MMBO	212 – 444 MMBO	214 – 446 MMBO	1,200 MMBO
Ugnu/ Sinclair Ugnu No. 1	1969	Sagavan-irktok, Prince Creek fms.	350-700? MMBO		0.016 MMBO	350-700? MMBO	350-700? MMBO	7,000[8] MMBO
Kuparuk River/ Sinclair Ugnu No. 1	1969	Kuparuk Formation A and C sandstones	640 BCF	????	-----	987 BCF	987 BCF	~1,400 BCF
			600 MMBO	1981	1,975 MMBO	858 MMBO	2,833 MMBO	5,690 MMBO
West Sak/ ARCO West Sak State No. 1	1969	Sagavan-irktok, Prince Creek fms.	530 MMBO	1998	15.6 MMBO	514 MMBO	530 MMBO	8,000[9] MMBO
Milne Point/ Chevron Kavearak Pt. No. 32-25	1969	Kuparuk Formation	110 MMBO	1985	180 MMBO	238 MMBO	418 MMBO	525 MMBO
		Schrader Bluff Fm.	275 – 440 MMBO	1991	38.1 MMBO	422 MMBO	460 MMBO	4,000 MMBO
		Sag River and Ivishak formations	5.8 MMBO	1995	1.6 MMBO	0.0(?)	1.6 MMBO	62 MMBO
Borealis/Mobil West Kuparuk State no. 1	1969	Kuparuk Formation	80 – 114 MMBO	2001	30.8 MMBO	90 MMBO	121 MMBO	195–277 MMBO
Aurora/ Mobil North	1969	Kuparuk Formation	51 – 67 MMBO	2000	11.4 MMBO	28 MMBO	39 MMBO	110–146

[5] ADOG (2004) is the source for most of EUR values.
[6] OGIP volumes labeled with a ~ are back-calculated from EUR values using an average recovery of 70%.
[7] OOIP for Prudhoe Bay oil (BP Exploration and ARCO Alaska, 2001).
[8] OOIP values shown for Ugnu reflect only the “sweet spots” where production is centered and not the total OOIP for the entire accumulations. OOIP for the entire Ugnu accumulation is ~ 15-24 BBO (McGuire and others, 2005 and Smith and others,2005)
[9] OOIP for entire West Sak accumulation ~ 11-21 BBO (McGuire and others, 2005 and Bross, 2004)

Field Name/ Discovery Well	Disc. Date	Reservoirs	Orig. Est. of Recovery	Prod. Start Up Date	Cum. Prod. (12/31/ 2004)	ERR (1/1/ 2005)	EUR[5]	OOIP or OGIP[6]
Kuparuk State No. 1								MMBO
Polaris/ Mobil Kuparuk State No. 1	1969	Schrader Bluff Formation	53 – 225 MMBO	1999	3.5 MMBO	62.5 MMBO	66 MMBO	350– 750? MMBO
North Prudhoe Bay/ ARCO N. Prudhoe Bay State No. 1	1970	Ivishak Fm.	5.3 MMBO	1993	2.1 MMBO	0.0 (?) MMBO	2.1 MMBO	12 MMBO
East Barrow/ South Barrow No. 12	1974	Barrow Ss.	12.6 BCF	1981	10 BCF	9.2 BCF	19.2 BCF	~27.0 BCF
West Beach/ ARCO West Beach No. 3	1976	Kuparuk C sandstone	1.5 – 3.75 MMBO	1993	3.6 MMBO	0.0(?) MMBO	3.6 MMBO	15 – 25 MMBO
Endicott/ Sohio Sag Delta 34633 No. 4	1978	Kekiktuk Conglom-erate	731 BCF	????	-----	979 BCF	979 BCF	~1,400 BCF
			375 MMBO	1986	448 MMB0	123 MMBO	571 MMBO	1,059 MMBO
Walakpa/ Husky Walakpa No. 1.	1980	Walakpa sandstone (equiv. of Alpine or Nuiqsut ?)	32 BCF	1992	11 BCF	169 BCF	180 BCF	~250 BCF
Sag Delta North/Sohio Sag Delta No. 9	1982	Alapah Limestone	7.3 MMBO	1989	7.3 MMBO	0.0 MMBO	7.3 MMBO	3.7 MMBO
Northstar/ Shell Seal Island No. 1	1984	Ivishak Formation	210 MMBO	2001	67 MMBO	129 MMBO	196 MMBO	325 MMBO
Niakuk/ BP Niakuk No. 5	1985	Kuparuk C sandstone	55 MMBO	1994	81 MMBO	32 MMBO	113 MMBO	200 MMBO
Colville Delta/ Texaco Colville Delta No. 1A.	1985	Nuiqsut Ss.	25 MMBO	-----	-----	25 MMBO	25 MMBO	-----
Tabasco/ ARCO KRU No. 2T-02	1986	Tabasco sandstone Schrader Bluff Fm.	2 MMBO	1998	9.7 MMBO	13.6 MMBO	23.3 MMBO	48 – 131 MMBO
Pt. McIntyre/ ARCO Pt. McIntyre (P1-02) 3	1988	Kuparuk C sandstone	300 MMBO	1993	384 MMBO	207 MMBO	591 MMBO	950 MMBO
Badami/ Conoco Badami No. 1	1990	Badami Ss Canning Formation	120 MMBO	1998	4.3 MMB0	55.0? MMBO	60.0? MMBO	300? MMBO
Tarn/ ARCO Bermuda No. 3	1991	Seabee Formation	42 MMBO	1998	65 MMBO	62 MMBO	127 MMBO	255 MMBO

Field Name/ Discovery Well	**Disc. Date**	**Reservoirs**	**Orig. Est. of Recovery**	**Prod. Start Up Date**	**Cum. Prod. (12/31/ 2004)**	**ERR (1/1/ 2005)**	**EUR[5]**	**OOIP or OGIP[6]**
Kalubik/ ARCO Kalubik No. 1	1992	Kuparuk & Nuiqsut Sandstones	-----		-----	-----	OIL (? MMBO)	-----
Fiord/ ARCO Fiord No. 1	1992	Kuparuk A and Nechelik Ss	50 MMBO		-----	50 MMBO	50 MMBO	150 MMBO
Cascade/ BP Cascade No. 1	1993	Kuparuk Fm.	50 MMBO	1996	-----	50 MMBO	50 MMBO	-----
Alpine/ ARCO Bergschrund No. 1	1994	Alpine Ss.	430 MMBO	2000	138 MMBO	417 MMBO	555 MMBO	900 – 1,100 MMBO
Midnight Sun/ BP Prudhoe Bay Unit MDS No. E-100	1997	Kuparuk C sandstone	12 – 23 MMBO	1998	11.3 MMBO	12 MMBO	23 MMBO	40 – 60 MMBO
Eider/ BP Duck Island Unit MPI No. 2-56/EID	1998	Ivishak Formation	3.5 – 5.0 MMBO	1999	2.7 MMBO	3.3 MMBO	6.0 MMBO	13.2 MMBO
Meltwater/ ARCO Meltwater North No. 1	2000	Bermuda sandstone Seabee Formation	36-64 MMBO	2001	7.7 MMBO	36.3 MMBO	44 MMBO	132 MMBO
Nanuq/ ARCO Nanuk No. 2	2000	Nanuq sandstone Torok Fm.	40 MMBO	2001	-----	40 MMBO	40 MMBO	150 MMBO
Spark/ ARCO Spark No. ??	2000	Alpine Sandstone	50.0 MMBO		-----	50 MMBO	50 MMBO	150 MMBO
Palm/ ARCO Palm No. 1	2001	Kuparuk River Formation	35 MMBO	2003	????	35 MMBO	35 MMBO	70 MMBO
Alpine West/ ConocoPhillips Rendezvous No. A.	2001	Alpine Sandstone	50.0 MMBO		-----	50 MMBO	50 MMBO	150 MMBO
Lookout/Conoco-Phillips Lookout No. 1	2002	Alpine Sandstone	50.0 MMBO		-----	50 MMBO	50.0 MMBO	150 MMBO
TOTALS	**N.A.**	**N.A.**	**14,220-15,150 MMBO/ 30,575 BCF**	**N.A.**	**14,989 MMBO/ 44.00 BCF**	**6,950-7,530 MMBO/ 29,181 BCF**	**21,940-22,520 MMBO/ 29,225 BCF**	**60,200-61,040 MMBO [10]/ 45,000 BCF**

[10] The totals for OOIP do not include the entire potential for the Ugnu/West Sak/Schrader Bluff, when properly adjusted for volumes presented in footnotes 1 and 2 the OOIP range is 67.0 to 88.0 BBO

Table 2.8. North Slope, Alaska–Undeveloped oil and gas accumulations as of January 1, 2005 (after Bird, 1991 and Thomas, and others, 1991 and 1993)

Accumulation or Field/ Reservoir Formation(s)	Year of Discovery	Estimated Technically Recoverable Resources
Umiat[11]/Nanushuk Fm.	1946	70 MMBO, 50 BCF
Fish Creek[11]/Nanushuk Fm.	1949	OIL (? MMBO)
Simpson[11]/Nanushuk Fm.	1950	12 MMBO
Meade[11]/Nanushuk Fm.	1950	20 BCF
Wolf Creek[11]/Nanushuk Fm.	1951	GAS (? BCF)
Gubik[11]/TuluvakAnd Nanushuk Formations	1951	600 BCF
Square Lake[11]/Nanushuk Fm.	1952	58 BCF
E. Umiat/Nanushuk Fm.	1964	4 BCF
Kavik/Ivishak Fm.	1969	115 BCF
Gwydyr Bay[12]/Ivishak Fm.	1969	30-60 MMBO
Kemik/Shublik Fm.	1972	100 + BCF
Flaxman Island/Canning Fm.	1975	OIL (? MMBO)
East Kurupa/Torok-Fortress Mtn. Formations	1976	GAS (? BCF)
Pt. Thomson/Thomson Sandstone and Canning Fm.	1977	300 MMBO, 5000 BCF
Mikkelson/Canning Fm.	1978	OIL (? MMBO)
Tern Is. (Liberty)/Kekiktuk Conglomerate	1982	150 MMBO
Hemi Springs/Kuparuk Fm.	1984	OIL (?MMBO)
Hammerhead/Sagavanirktok Fm.	1985	~200 MMBO
Sandpiper/Ivishak Fm.	1986	150 MMBO/GAS (? BCF)
Sikulik/Barrow Sandstone	1988	16 BCF
Stinson[13]/????	1990	OIL (? MMBO)
Burger/Kuparuk Equivalent	1990	14,000 BCF, 724 MMBO
Kuvlum[13]/????	1993	400 MMBO
Thetis Island[13]/Nuiqsuit	1993	OIL (? MMBO)
Sourdough[13]/?????	1994	~100 MMBO
Pete's Wicked[13,14]/Sagavanirktok and Ivishak Fms.	1997	OIL (? MMBO)
Sambucca[13]/Ivishak Fm.	1997	19 MMBO(?)
Oooguruk[13]/Nuiqsut Sandstone(?)	2003	70 MMBO(?)
Nikaitchuq[13]/Nuiqsut and Sag River Sandstones(?)	2004	70 MMBO(?)
Tuvaaq/Schrader Bluff Fm.	2005	OIL (?MMB0)
Total		**2,300 + MMBO/ 20,000 + BCF**

[11] Navy and other federally-operated wells.
[12] Pioneer Natural Resources has applied to develop several small accumulations in this area, probably by 2006.
[13] Discoveries that post-date the data of the Bird and Thomas and others reports.
[14] Pete's Wicked accumulation will be included as part of the Gwydyr Bay development program

2.3.3 Post-Prudhoe Bay Discovery: (1970 through 1989)

The focus of industry activity after 1969 was largely determined by the exploration success along the Barrow arch trend and land availability. There were no lease sales held on the North Slope or in the adjacent waters of the Beaufort Sea for a ten-year period, 1969 to 1979. This hiatus was due to the uncertainty regarding land status while the Alaska National Interest Lands Conservation Act (ANILCA) was debated and finalized. For that ten-year interval, drilling activity was confined to the areas previously leased. Commencing in 1979, the shallow State waters and the Federal OCS areas of the Beaufort Sea were made available through a series of State and Federal lease sales and additional onshore sales were conducted for lands in the Colville-Canning area.

In the 1980's, the Federal government, through the BLM, opened most of NPRA to leasing. Although the 1002 Area of the ANWR had not been made available for leasing, there are Native Corporation in-holdings within the 1002 Area and in other parks and monuments. In the mid-1980's, a land trade between the Federal government and several Native corporations was strongly considered as a means to reduce these inholdings in the parks. At various times the Arctic Slope Regional Corporation (ASRC) has made all or portions of their land-holdings available to companies through exclusive exploration/leasing agreements.

The discussion of the post-Prudhoe Bay activity will be parsed into five geographic areas that have different degrees of accessibility, administrative frameworks, and economic parameters. These include 1) the Colville-Canning area/State Beaufort Sea waters (ADNR and ASRC), 2) National Petroleum Reserve-Alaska (BLM and ASRC), 3) Beaufort Sea OCS area (MMS), 4) the 1002 Area of the Arctic National Wildlife Refuge (ASRC and the United States Fish and Wildlife Service (FWS)), and 5) Chukchi Sea OCS area (MMS). Any discussions regarding the administration and conduct of exploration regarding ASRC holdings will be brief due to the confidentiality of the process.

2.3.3.1 Colville-Canning Province: State and Native Lands and State Waters of the Beaufort Sea

Through the 1970's, the area between the Colville and Canning rivers, from the Beaufort Sea south to the Brooks Range, was the only portion of the North Slope open to exploration. The bulk of the exploration activity was concentrated in the northern portion of the area, near Prudhoe Bay and to the east and west paralleling the coastline, following the structural trend of the Barrow arch.

In 1979, the State of Alaska began a leasing program in the State waters of the Beaufort Sea. This acreage is generally confined to a coastal strip three miles wide and seaward of the shoreline from Point Barrow on the west to the Canada-United States border on the east. The Stated owned and administered nearshore zone is wider in the vicinity of barrier islands and major inlets.

2.3.3.1.1 Leasing

The ten year leasing hiatus, imposed to resolve the land claims issue, concluded and sales were resumed in 1979. The first sale was a joint State/Federal Beaufort Sea sale (Table 2.5). Alaska state sale No. 30 consisted of 341,140 acres within the three-mile limit and 296,308 acres were leased. This sale marked the first major venture into offshore leasing in the Arctic by either the State or Federal government and signaled the opening of a new but highly environmentally sensitive and expensive exploration province in northern Alaska. From 1979 through 1989, the State conducted a total of eighteen lease sales with seven offshore (Table 2.5).

Lease sale frequency and size of the offerings have varied greatly over this period of time. There were no sales for ten years, but three sales were held in 1988. The size of the offerings ranged from a low of 667 acres (State Sale No. 72a) to as much as 1,231,517 acres in State Sale No. 34. In the 18 sales, 6,065,494 acres were offered and 3,423,645 acres were leased. Approximately 32.5% or 1,114,184 acres were acquired in the seven offshore leases. The remaining 67.5% or 2,309,461 acres were leased in the eleven onshore sales. A significant portion of the reported total leased acres, in these sales and other sales held between 1990 and 2005, includes acreage acquired in earlier sales, surrendered back to the State or appropriate Federal agency, and subsequently reoffered and leased again. The percentage of leases that are being recycled to the industry has not been calculated. It is entirely possible that advances in technology, changing exploration concepts, and oil prices have resulted in some tracts being leased three or more times.

Table 2.5 was not designed to provide information regarding the degree of competition for individual tracts or to reflect the number of companies or groups of companies participating in the sales. However, it is appropriate to generalize and state that the level of competition and number of participants have tended to decrease in a given geographic area over time. This may in part be reflected by the decrease in the percent leased from the early Beaufort Sea sales (nearly 100%) to the Beaufort Sea sales in the late 1980's (~40%). Alternatively, poor exploration results and/or reduced quality of remaining acreage may be the cause of declining interest.

Native lands were not available to the industry through a competitive bidding process. The rights to explore, lease, and drill were negotiated as exclusive agreements. ASRC owns the subsurface rights to all native lands on the North Slope – for both regional and village corporation holdings.

ASRC assigned the exploration rights to several companies, at various times during the 1970's and 1980's. As a result of these agreements a total of nine wells were drilled on native lands between 1977 and 1986. This total includes the wells on native lands in NPRA, ANWR, and west of NPRA as well as those in the Colville-Canning area. The wells with the operator, year drilled, and measured depth (MD) are listed below.

1. Texaco, Tulugak No. 1 – 1977: MD = 16,457 ft
2. Chevron, Eagle Creek No. 1 – 1978 (west of NPRA): MD = 12,049 ft
3. Chevron, Tiglukpuk No. 1 – 1978: MD = 15,797 ft
4. Chevron, Akuluk No. 1 – 1981 (west of NPRA): MD = 17,038 ft
5. Chevron, Killik No. 1 – 1981: MD = 12,492 ft
6. Chevron, Cobblestone No. 1 – 1982: MD =11,512 ft
7. Chevron, Livehorse No. 1 – 1982 (NPRA): MD = 12,312 ft
8. Unocal, Tungak Creek No. 1 – 1982 (west of NPRA): MD = 8,212 ft

9. Chevron/BP KIC No. 1 – 1986 (1002 Area, ANWR): MD = 15,193 ft

2.3.3.1.2 Data Acquisition

There was a change in the level and mode of data acquisition after the major discoveries in the Prudhoe Bay to Colville Delta area. A major change was the introduction of 3D seismic acquisition and processing technologies to the North Slope in the early 1980's. Table 2.9 was constructed to document the level of 3D seismic acquisition on the North Slope and the adjacent Beaufort and Chukchi seas.

Following the high level of activity generated by the 1968 to 1969 discoveries, geological and geophysical crew activity decreased sharply in the early 1970's and then increased and stabilized by the late 1970's (Jamison, and others, 1980). Seismic acquisition was at a post-Prudhoe high in 1970 with 96 crew-months. The acquisition level decreased to eight crew-months in 1972 and spiked again at 85 crew-months in 1975 before dropping back somewhat in the late 1970's. The ADOG data (Table 2.6) suggests that the level of activity post-1970 attained relatively high levels in the early 1970's and continued to increase until the early or middle 1980's. The data of Table 2.6 reflect this activity level but include some shallow Beaufort Sea acquisition and the Jamison and others (1980) crew-months represent only onshore acquisition. From 1970 to 1990 more than 37,500 line-miles of 2D seismic were acquired in the shallow Beaufort Sea and within the confines of the Colville-Canning province. Much of this acquisition in the late 1970's and early 1980's was offshore and in preparation for and follow-up on acreage acquired in the joint State/Federal lease sale of 1979.

Table 2.9. Acquisition of 3D seismic data – North Slope and adjacent Beaufort Sea. Sources are shown in parentheses.[a]

	Area		
Time Period	**North Slope Onshore[b] (ADOG)**	**State Waters of Beaufort Sea (MMS)**	**Beaufort Sea OCS (MMS)**
1981-1985	1,475 miles	——	1 program (HW)
1986-1990	629 miles	——	1 program (HW)
1991-1995	1,160 miles	——	1 program (HW)
1996-2000	5,186 miles	——	11 programs 6(M)/5(HW)
2001-2005	2,286 miles	4 programs 1(M)/3(HW)	——

a. Note that the onshore data from the ADOG does not differentiate between Colville-Canning and the NPRA or shallow Beaufort Sea hardwater acquisitions; also the information provided by the MMS does not include mileage for the 3D program.
b. May include both NPRA and State Beaufort Sea.

Throughout the 1980's the activity level varied but probably averaged about 20 crew-months per year. One of the major reasons for such a decrease has been the departure of several companies from the North Slope and the merger of former competitors in the late 1980's.

Three-dimensional (3D) seismic acquisition was first used on the North Slope in the early 1980's and by 1990 approximately 2,100 miles of 3D data had been acquired (Table 2.9). The locations of these early data acquisitions are not known and they were possibly acquired over existing fields to better guide development and not for exploration purposes.

Geological field programs exhibit a similar profile. In the early 1970's, geological field programs averaged about 20 crew-months per year. By 1974, this had decreased to six crew-months and the activity level for the remainder of the 1970's the average was 5 to 6 crew-months per year. In the 1980's, the amount of field work varied considerably but did not reach the levels seen earlier, not even those levels of the early 1970's. Much of this was related to the emphasis on exploration and development of existing acreage positions both on- and offshore.

One important aspect of geological field work is that, unlike seismic acquisition and exploration drilling, it usually takes place external to the principal area of exploration interest, where the objective intervals are exposed at the surface. Much of the geological field work has been carried out in the Brooks Range to the south and in the Sadlerochit and Shublik Mountains to the southeast in ANWR. Geologic field work was severely curtailed in ANWR by the emplacement of Federal regulations in the late 1970's and 1980's.

2.3.3.1.3 Exploration Drilling

A total of 216 exploration wells were drilled during the 1970's and 1980's (Figure 2.18). This includes wells drilled in NPRA, the Colville-Canning area, in State and Federal waters of the Beaufort and Chukchi Seas, and on native lands, including one within the 1002 Area of ANWR. Following the initial surge of drilling activity associated with the Prudhoe Bay discovery, the level of exploration drilling decreased substantially. The future of the pipeline was uncertain and no lease sales, offering additional drilling opportunities, were held between 1969 and 1979.

In the Colville-Canning area and State waters of the Beaufort Sea, 34 exploration wells were drilled in the five years following the 1969 lease sale. This is only one more than the 33 drilled in 1968 to 1969. An additional 33 wells were drilled during the 1975 to 1977 interval, prior to the start-up of TAPS in June, 1977 (Jamison, and others, 1980). Twelve of these wells were drilled directionally from onshore pads into the shallowest portions of the Beaufort Sea. Between the opening of the pipeline in 1977 and the end of the 1980's, exploration became more wide spread and 81 wells were drilled in the shallow Beaufort Sea and across the Colville-Canning Province.

Offshore drilling from ice or gravel islands and large ice-resistant drilling vessels in State waters did not commence until after the 1979 lease sale. Between 1980 and the end of 1989 there were a total of 29 wells drilled in the State waters of the Beaufort Sea.

2.3.3.1.4 Discoveries

From 1970 through 1989 there were 17 discoveries in the Colville-Canning area and the State Beaufort Sea waters. Ten were onshore and six were either entirely or partially in State waters of the Beaufort Sea. The seventeenth discovery, at Seal Island No. 1 (now Northstar), was on joint State-Federal acreage. Nine of these discoveries have produced or are currently producing economic quantities of oil and two will be developed in the near future (Point Thomson and Colville Delta). The discoveries are summarized on Tables 2.7 and 2.8 and listed below with cumulative production as of December 31, 2004.

Oil/Gas Field	Cumulative Production (December 31, 2004)
North Prudhoe Bay	2.0 MMBO
Kemik Gas Field	not developed
Flaxman Island	not developed
West Beach	3.6 MMBO
East Kurupa Gas Field	not developed
Point Thomson Gas/condensate (light oil)	not developed
Endicott	446.1 MMBO
Mikkelsen	not developed
Sag Delta North	7.9 MMBO
Northstar	58.1 MMBO
Hemi Springs	not developed
Niakuk	80.2 MMBO
Colville Delta	not developed
Tabasco	9.1 MMBO
Point McIntyre	379.6 MMBO
Badami	4.4 MMBO
Stinson (?)	not developed

The nine producing fields have EUR of 1.53 BBO. Endicott and Point McIntyre are both expected to produce more than 500 MMBO.

Pt. Thomson is a large field with an estimated 5 TCF and 360 MMBO and has been the subject of at least 20 "plans of development". It is doubtful the field will be developed before a gas pipeline is approved and well-along in the construction phase. The potential for satellite development in the area and addition post-1980's discoveries should provide the necessary incentive to proceed.

2.3.3.2 National Petroleum Reserve-Alaska (NPRA)

The decades of the 1970's and 1980's were highlighted by a variety of programs and activities in NPRA. The Federal government undertook a second episode of exploration, NPRA was opened-up to industry exploration and leasing for the first time, and ASRC made some of its inholdings available to industry for exploration.

Prior to the start-up of this new exploration program and during the relative lull in activity between formal exploration efforts, the U. S. Navy drilled eight development wells in the Barrow gas field for local use. Additionally a shallow exploration well was drilled at Iko Bay. This work was not considered part of the expanded exploration program (Schindler, 1988).

A small gas accumulation was discovered at East Umiat in 1963. The production is from sandstones in the Nanushuk Group at 1,800 to 3,000 feet depth. There has been no estimate of recoverable reserves and the trapping is structural in nature (Bird, 1981). As a result of the Navy's drilling efforts in the Barrow area, the East Barrow gas field was discovered in 1974. It produces from the Jurassic Barrow sandstone at 1,900 to 2,100 feet depth. The estimated recoverable reserves are 19.2 billion cubic feet (BCF), and the trap is also structural in origin (Bird, 1981).

2.3.3.2.1 USGS/Husky Exploration Program – 1974 through 1982

The Organization of Petroleum Exporting Countries (OPEC) oil embargo caused the U. S. Congress to allocate funding to develop Elk Hills Petroleum Reserve and explore NPRA, due to concern that a long-term shortage of oil might develop. This initial funding level of $7.5 million for NPRA (Schindler, 1988) later grew to many times that modest amount and a seven-year program evolved.

The second phase of NPRA exploration commenced with the Cape Halkett No. 1 well in 1975 and ended six years later with the Koluktak No. 1 well in 1981. During this interval twenty-eight wells were drilled (Weimer, 1987 and Schindler, 1988). These wells represent a total of 283,869 feet of exploration drilling.

To support this drilling an extensive multi-year seismic acquisition program was initiated and completed. The result was a large grid that provided government geologists with a better framework within which they could more scientifically locate the exploration wells. Based on the existing literature the precise number of seismic line-miles acquired is uncertain. The number of line-miles reported ranges from 12,300 (Banet, 1991) to 13,179 (Schindler, 1988), and 14,770 (Weimer, 1987). Schindler (1988) lists seismic acquisition by year and the others simply provide a total figure. Thus, Schindler's figures are believed to be more accurate. They are also in close agreement with the 13,116 line-miles acquired between 1972 and 1982, as cited by ADOG and included in Table 2.6.

The twenty-eight wells were principally situated along the Barrow arch with a strong emphasis on play types recognized in the productive Prudhoe-Kuparuk area to the east. The twenty-eight wells tested twenty-six different objectives. The two exceptions were the Walakpa No. 2 and East Simpson No. 2 wells which were drilled on the same features as the Walakpa No. 1 and East Simpson No. 1 wells respectively. Only four of the twenty-eight wells were drilled south of 70° north latitude; therefore, the bulk of NPRA was not evaluated by the drill during this exploration phase.

Weimer (1987) summarizes the wells in a tabular format and Schindler does a similar treatment in narrative text. While Schindler provides more detail, the Weimer treatment is easier to use. Well depths range from 3,666 feet (Walakpa No. 1) to 20,335 feet (Tunalik No. 1). Two wells (Tunalik No. 1 and Inigok No. 1) exceed 20,000 feet and eleven wells have a total depth between 10,000 and 20,000 feet. Eleven wells fall into the 5,000 to 10,000 foot depth range and two wells are shallower than 5,000 feet. For a convenient reference the wells are grouped below, by primary drilling objective(s). In the listing below, the wells are generally arranged in stratigraphic succession from older to younger exploration horizons:

Target Horizon(s)–Well Name

- Lisburne/Kekiktuk–Ikpikpuk No. 1
- Lisburne–Lisburne No. 1
- Ivishak/Lisburne–W. T. Foran No. 1, Drew Point No. 1, Kugrua No. 1, Inigok No. 1, Tunalik No. 1, and J. W. Dalton No. 1

- Ivishak–Cape Halkett No. 1, East Teshekpuk No. 1, South Harrison Bay No. 1, East Simpson No. 1, East Simpson No. 2, and South Meade No. 1
- Sag River Sandstone–West Dease No. 1
- Kingak sandstones/Ivishak–South Simpson No. 1
- Simpson sandstone (Jurassic)–Walakpa No. 1, Kuyanak No. 1
- Jurassic "bar sandstone"–North Inigok No. 1
- Walakpa Ss/Simpson Ss/Barrow Ss/Sag River Ss–Tulageak No. 1
- Walakpa Ss/Simpson Ss–Walakpa No. 2
- Neocomian Ss/Jurassic Ss/Lisburne–Peard No. 1
- Kuparuk/Ivishak–Atigaru Point No. 1, West Fish Creek No. 1
- Kuparuk–North Kalikpik No. 1
- Torok Ss/Fortress Mountain–Seabee No. 1, Awuna No. 1
- Nanushuk sandstone–Koluktuk No. 1

From this list of drilling targets it is obvious that the Prudhoe-Kuparuk play types dominated the drilling program. Twenty-one of the twenty-eight wells targeted Prudhoe-Kuparuk area reservoirs. No oil discoveries resulted from the 28-well program, but favorable oil shows (Lisburne No. 1 well), ubiquitous gas shows, and a gas discovery at Walakpa (180 BCF) indicate that hydrocarbons are present throughout he area. A very robust gas show at the North Inigok No. well (30 million cubic feet per day (MMCFPD) on a drill stem test) with 27% ethane through pentane plus, suggests the existence of a down-dip oil accumulation.

The drilling program ended when the Koluktuk No. 1 was plugged and abandoned in April 1981. The drilling resulted in the discovery of two gas fields (Table 2.7) and evidence of oil potential as far south as the location of the Lisburne No. 1 well, in T11S and R16W, near the southern boundary of NPRA. With a reestablishment of the NPRA boundary, the Lisburne No. 1 well now lies outside NPRA (Figure 2.18).

2.3.3.2.2 Industry Activity, Early-Middle 1980's

After the completion of the second round of federally-sponsored exploration in NPRA, the government elected to open the Reserve to leasing and encouraged industry exploration. The second phase of Federal exploration did not yield any significant discoveries but did provide a wealth of information for future operations.

Leasing: The Federal leasing program in NPRA was administered by the BLM and commenced in 1982 with two lease sales (Nos. 821 and 822) in January and May (Table 2.5). A total of 271 tracts with 5,035,722 acres were offered in the two sales. Most of the acreage was located in the southern and southeastern portions of the Reserve. Between the two sales, 38 tracts with a total of 927,966 acres were leased. In both sales, the leasing tended to be focused in three areas; 1) west of Nuiqsut, 2) west of Umiat, and 3) west of the Lisburne No. 1 well. This leasing activity was probably directed at Umiat style plays or at least Cretaceous, perhaps Kuparuk, objectives.

The third sale (No. 831) was held in July, 1983 with an offering of 84 tracts totaling 2,195,845 acres scattered across the northern portion of NPRA. Twenty tracts, with a total of 419,618 acres (Table 2.5), were leased and appear to have been selected to evaluate Prudhoe Bay area play-types. The leases were largely concentrated in the area between Admiralty Bay and the Chukchi Sea. A Fourth sale was scheduled for July 1984 (No. 841), but when no bids were submitted the sale and future lease sales were cancelled. This brought leasing to a close until late in the 1990's.

Data Acquisition: Prior to the sales, the industry conducted no new geological or geophysical data acquisition programs. The industry relied almost exclusively on the existing geological surface work, their proprietary geological field programs, and the publicly available USGS reports. Similarly, the existing federally acquired seismic data base was reprocessed and reinterpreted in lieu of conducting proprietary industry seismic acquisition programs.

Exploration Drilling: One well was drilled within NPRA as a result of this short-lived leasing program. The ARCO Brontosaurus No. 1 was drilled to a depth of 6,660 feet in 1985. The target was the updip, onlap wedgeout of the Ivishak Sandstone onto the Barrow arch. The well was plugged and abandoned (Weimer, 1987). A second well was drilled by industry inside the boundaries of NPRA on native corporation inholdings. The Chevron Livehorse No. 1 was drilled in 1982 to a total depth of 12,312 feet. It too targeted the Ivishak Sandstone and was a dry hole (Weimer, 1987).

Discoveries: The brief exploration drilling effort did not result in a discovery and the area was abandoned by the industry and remained dormant until the late 1990's, when the industry's interest was rekindled by the Alpine discovery, just to the east of NPRA in the Colville Delta area.

2.3.3.3 Beaufort Sea – Federal OCS

The OCS area of the Beaufort Sea was unavailable to the petroleum industry until the joint State/Federal lease sale of 1979. This and subsequent sales provided access to waters beyond the three-mile limit, extending from Point Barrow on the west to the United States-Canada border on the east. The original assessment area included deep water regions and totaled 34,430 square miles (Sherwood and others, 1995). As treated in this report, the prospective area consists of the OCS portion of the Beaufort Sea shelf and encompasses approximately 12,160,000 acres or 19,000 square miles (Sherwood, 2005).

2.3.3.3.1 Leasing

Four lease sales were held in the OCS portion of the Beaufort Sea between 1979 and 1990 (Table 2.5). A total of 28,050,266 acres were offered in these sales, ranging from a low of 173,423 acres in 1979 (Sale BF) to a high of 18,277,806 acres in 1988 (OCS Sale 97). That total includes previously unoffered acreage, reoffering of surrendered leases, and reoffering of previously offered but unleased acreage. The leased acreage totaled 3,067,114 acres with more than 75% of that leased in OCS sales 87 and 97 (Table 2.5). However, leased acreage as a percent of offered acreage was much higher in the earlier sales where nearly 49% of the acreage offered in Sale BF was leased, and in OCS Sale 97 only 6% was leased. This latter sale was an areawide sale, and this leasing approach now appears to be the standard practice for OCS sales in Alaskan waters.

OCS Sale No. 71 included the leasing of the acreage that comprised the basis for the Mukluk prospect. The structure is located in Harrison Bay, is approximately 170,000 acres in size, and was leased for total high bids exceeding $1.5 billion, with the highest single bid of $227 million for one 5,700 acre tract on the crest of the structure. This feature and the money invested in it eventually proved to be the biggest financial disappointment in the history of exploration on the North Slope and the adjacent waters of the Beaufort Sea.

2.3.3.3.2 Data Acquisition

The data acquisition process is different in the OCS regions. There is generally little, or more commonly, no geological field work conducted exclusively for the purpose of better understanding the subsurface geology of the offshore region. Rather, the subsurface well control resulting from the onshore drilling activity and, secondarily, outcrop geology is tied into the seismic grids to extend the existing geologic framework into the offshore areas and assist in the definition of potential prospects.

Seismic acquisition in the Beaufort OCS commenced in 1970 and continued through out the region until 1997, but only 1,947 miles of the total of 91,915 miles of 2D seismic data were acquired post-1990 (Table 2.6). Some portion, of the approximately 90,000 miles of seismic data, was acquired within state waters. The portion that occurred within state waters was not made available to the authors of this report, at least in part because of confidentiality regarding proprietary acquisition by the various lease/data owners.

Seismic acquisition has involved both summer marine and winter hardwater (on ice) programs. A total of 194 2D permits were issued from 1970 through 1989 with 123 for marine and 71 for hardwater programs. The area of acquisition extends from near Point Barrow on the west to the United States-Canada border on the east.

The acquisition of 3D seismic data began in 1983 and only one permit was granted and completed by the end of 1989 (Table 2.9). This was a hardwater program and was probably acquired in the vicinity of existing production to enhance development of known reserves.

2.3.3.3.3 Exploration Drilling

Drilling in the Beaufort Sea OCS commenced in 1981 with the Beachy Point No. 1, and through 1989 a total of 20 wells had been drilled in the OCS portion of the Beaufort Sea. The 20 exploration wells tested 14 individual prospects. Five of the 14 prospects (nine wells) were determined, by the MMS, to be capable of producing hydrocarbons. The drilling peak was in 1985 to 1986 when 11 of the 20 wells were drilled. Drilling quickly decreased after this peak, and only one well a year was drilled from 1987 to 1989.

Among the dry holes was the Mukluk No. 1 well. Prior to drilling, the Mukluk structure was thought to have recoverable reserves in the range of 1.5 to 10.0 BBO. The well was drilled in 1983 from a man-made island 350 ft in diameter erected in 48 ft of water. At a cost of $120 million, the Mukluk well retains to this day the dubious distinction of being the most expensive dry well ever drilled.

Depending on water depth, the OCS exploration wells are either drilled from an artificial island or large, heavy, usually bottom-anchored drilling structures. Through 1990 ten wells were drilled from gravel islands, one from an ice island, and nine from drilling rigs such as the Glomar Beaufort Sea CIDS or the Canmar Explorer II. If a commercial discovery is made and the field developed, a larger more permanent structure is built to provide the base for long-term operations.

2.3.3.3.4 Discoveries

Four of the five prospects deemed capable of production (MMS, 2001) have been termed significant discoveries by both the MMS (2001) and ADOG (2000). Three of these are completely in OCS waters and are the Hammerhead, Sandpiper, and Tern/Liberty (Table 2.8). The fourth discovery is the Northstar field (Seal wells) that underlies both state and federal acreage (Table 2.7). The first OCS discovery was Tern (Liberty) in 1983, followed by Seal/Northstar in 1984, Hammerhead in 1985, and Sandpiper in 1986.

Water depths range from as little as 21 ft at Liberty to as much as 103 ft at Hammerhead. These depth variations dictate both the type of basic exploration drilling structure to be utilized and the type of production facility that would need to be built. The costs escalate significantly with incremental increases in water depth. Three of these discoveries Liberty, Sandpiper, and Northstar lie offshore from the well-established Kuparuk and Prudhoe Bay oil fields and their infrastructure. The Hammerhead discovery lies 50 to 60 miles east of Prudhoe Bay field and 15 - 20 miles north of Pt. Thomson in relatively deep water.

The Northstar field has been developed and production began in late 2001 (Table 2.7). After BP Alaska suspended plans to develop the Liberty field in 2002, it has determined to proceed with a Memorandum of Understanding (MOU) with the MMS that could lead to final approval of the plan of development and depletion in late 2007 (PN, 2004a). Development of the Sandpiper discovery will probably occur when and if the recent discoveries in the Gwydyr Bay and offshore Kuparuk areas are developed. Development of the Hammerhead discovery has been thought to be largely dependent upon establishment of commercial oil production in the PointThomson-Flaxman-Sourdough area, but the recent acquisition of this acreage by Shell and their plans to purchase two vessels capable of drilling on the Hammerhead structure (PN, 2006a) may significantly alter that perception.

2.3.3.4 1002 Area of Arctic National Wildlife Refuge (ANWR)

The Arctic National Wildlife Range, now the Arctic National Wildlife Refuge, was established in 1960 and originally contained 9,000,000 acres. The ANILCA legislation of 1980 more than doubled the Refuge to approximately 19,000,000 acres and designated 9,000,000 acres as wilderness (not the 1002 Area). Approximately eight-percent of the Refuge or 1,500,000 acres were set aside, as the “1002 Area”, for special study of the regions fish and wildlife values, as well as it hydrocarbon potential. The authors of that study ultimately concluded that the area had enormous hydrocarbon potential and recommended that the area be opened to exploration and leased by competitive bid, subject to prudent environmental safeguards and controls. The area has not been opened for exploration since that time and can only be opened through an act of congress and with the president’s concurrence.

The 1002 Area of ANWR extends from the Canning River on the west to the Aichilik River on the east and from the approximate 1,000 ft contour on the south to the Beaufort Sea/Kaktovik Inupiat Corporation lands on the north. The Kaktovik Inupiat Corporation selected lands within the Arctic National Wildlife Range following the 1971 passage of Alaska Native

Claims Settlement Act (ANCSA). This inholding is located along the Beaufort Sea coast in the vicinity of Barter Island and is comprised of 92,160 acres.

The 1002 Area of ANWR has long attracted the interest of the petroleum industry. There are active oil seeps, exposures of oil-stained sandstone, large attractive structures. Oil-prone source rocks are present both in outcrop and in the subsurface – as confirmed by wells along the refuge boundary, and hydrocarbon accumulations occur to the west (Pt. Thomson), north (offshore at Kuvlum), and east (Canadian Beaufort /Mackenzie delta).

2.3.3.4.1 Federal Lands

The approximately 1,500,000 acres of Federal land within the 1002 Area are administered by the FWS. Since the passage of ANILCA, the area has been the subject of two hydrocarbon resource evaluations by the USGS, experienced a two-season long seismic acquisition program, flanked by exploration drilling on the west, north, and east, and seen an unsuccessful attempt to complete a land-trade with several native corporations.

Leasing: There has been no leasing within the 1002 Area. However, there was an attempt to execute a land-trade with several native corporations that had significant inholding within national parks or other wilderness areas. In the mid-1980's, it was proposed that these corporations would trade these inholdings for lands of "equal" value within the 1002 Area. Six corporations were found qualified to participate and each formed a partnership with one or more major oil companies. The industry partners were to supply the technical expertise and in return have the exclusive right to explore any lands acquired by the native corporation partner.

The Federal government proposed and developed a tract selection/land-trade process, and the native corporations and industry partners proceeded to bid on 71 complete or partial tracts. These tracts were four square mile parcels (2,560 acres) and the bidding indicated interest in eight to ten prospects. As a point of interest, virtually all the tracts that received bids were either along the trend of the Marsh Creek anticline or to the east of it. All areas of interest were within the deformed portion of the 1002 Area. This largely conforms to the findings of the 1987 USGS evaluation but is in sharp contrast to the conclusions reached by the USGS in their 1998 assessment. This proposed land trade was never carried through to the point of completion and the lands were never transferred.

Data Acquisition: The ANWR has a long history of geological study and mapping. The first geologic mapping was by Leffingwell in 1919. He reported oil seeps and oil-stained rocks within what is now ANWR and established the general stratigraphic sequence as it is known today. Industry-sponsored field work was sparse until after the discovery of Prudhoe Bay. In 1969, at least eight companies participated in field programs of varying duration and completeness. A minimum of 20 to 25 crew months of geologic mapping and evaluation were logged in 1969. Subsequently geological programs varied from less than a crew month to five to six crew months throughout the 1970's and 1980's.

Geophysical activity within the 1002 Area has historically consisted of the less invasive, but limited value, gravity and magnetic surveys. The only seismic acquisition within the Refuge occurred during two successive field seasons in 1984 and 1985 under Federal oversight. A 22-company consortium shared the costs of acquisition and processing. These two seasons produced approximately 1,450 line-miles of data (Table 2.6). The data were of mostly poor to moderately good quality.

Exploration Drilling: There has been no exploration drilling on Federal lands within the 1002 Area or any other federally controlled portion of ANWR. However, the area is surrounded on all sides, except to the south, by exploration wells drilled on state, Native Corporation, Federal OCS, and Canadian OCS acreage. At least 40 wells have been drilled within 20 miles of the 1002 Area. These wells have found at least six oil and (or) gas accumulations.

Discoveries: With no exploration drilling there have been no discoveries. However, both the Pt. Thomson and Flaxman Island accumulations are in extremely close proximity to the 1002 boundary and there is a remote chance that one or both may extend beneath the 1002 Area. An additional discovery, Sourdough, was made in the 1990's and almost certainly extends into the 1002 Area.

2.3.3.4.2 Native Corporation Lands

The Kaktovik Inupiat Corporation (KIC) acreage has offered opportunity for exploration within the boundaries of ANWR. While KIC owns the surface rights, the subsurface domain is owned by the ASRC. ASRC entered into an exploration agreement with Chevron and British Petroleum that granted them exclusive exploration rights to these lands. Consequently, Chevron and BP drilled the KIC No. 1 well in 1986. The results of that well have been held confidential to this time and nothing is known about the stratigraphy or hydrocarbon potential of the section encountered in the well. In an attempt to replicate the stratigraphy that may have been observed in the KIC well, an industry consortium drilled the Tenneco Aurora well in 1988 on an OCS lease. The Aurora well is located about six miles east-northeast of the KIC well. The results were mixed and did not provide the consortium with reliable answers to the questions regarding the stratigraphy and hydrocarbon potential of the KIC well.

2.3.3.5 Chukchi Sea – Federal OCS

The Chukchi Sea is situated north of the Bering Straits, between the western North Slope and eastern Siberia. This area was long ignored because of the extreme remoteness, high cost of operation, and extensive ice cover. There is no infrastructure, no major population centers, and no year around, reliable transportation network/system. Given these negatives any potential hydrocarbon accumulation would have to be very large and oil (gas) prices would have to be high and sustainable.

In the early to middle 1980's factors appeared to favor the possibility that the Chukchi Sea had large resource potential and long term pricing would support exploration in this hostile environment. Consequently, the MMS began to evaluate the level of industry interest and ultimately determined that there was sufficient interest to proceed with a leasing program in the Chukchi Sea. A good summary of the Chukchi Sea OCS is presented in Sherwood, and others (1998b). The 1995 assessment area covered 44,580 square miles or more than 28,500,000 acres (Sherwood and others, 1995). The Chukchi Sea assessment area has since been reconfigured, and the shelf portion of the area is now 41,280,000 acres or approximately 64,500 sq. miles (Sherwood, 2005).

2.3.3.5.1 Leasing

Two areawide lease sales have been held in the Chukchi Sea. The first sale, OCS Sale 109, was held in 1988. The MMS offered more than 2,500,000 acres in the only sale held during the 1970's and 1980's, and tracts totaling 1,976,912 acres were leased (Table 2.5).

2.3.3.5.2 Data Acquisition

Once again, because of the offshore nature of the offerings there were no geological programs conducted to provide information for the sales. Rather, the seismic programs were designed to provide ties from the geology of the few relatively proximal onshore wells and previously studied exposures in NPRA and the areas west of NPRA, to the offshore seismic grids.

A modest amount of seismic data had been acquired in the Chukchi Sea prior to 1970. Nearly 5,000 line-miles of 2D seismic data were acquired in the early 1970's (Table 2.6). However, the pace of seismic acquisition increased greatly with the knowledge of pending lease sales, and 69,185 line-miles of data were acquired during the 1980's (Table 2.6). With the exception of a single hardwater program in 1986 all the data were acquired in open water conditions during the summer.

2.3.3.5.3 Exploration Drilling

During 1989, The Klondike No. 1 well was drilled in the Chukchi Sea by Shell on leases acquired in OCS Sale 109. The well was drilled with the drillship Explorer III in a water depth of 141 ft. The Klondike well had oil shows in the Shublik/Fire Creek (uppermost Sadlerochit), Kuparuk, and Brookian turbidites near the base of the Torok. While this was the only well to be spud and completed in the 1980's, four additional wells were drilled in the 1990's.

2.3.3.5.4 Discoveries

The Klondike No. 1 well did not yield a discovery, but it did have good shows in three highly prospective intervals, all of which are productive in the Colville-Canning area.

2.3.4 Recent Activity: (1990 through 2004)

The interval from 1990 to the present has provided a new chapter in exploration in northern Alaska that includes additional offshore discoveries and development, Jurassic, Alpine-style discoveries near and within NPRA, new emphasis on smaller satellite fields, development of the heavy oil deposits of West Sak and Schrader Bluff, gas as a viable exploration objective, and the growing role of intermediate to small companies as active bidders and explorers on the North Slope.

The decline of the older large fields of the Prudhoe Bay area has resulted in an increased emphasis on enhanced recovery techniques, extended-reach horizontal drilling technology, and 3D seismic data to maximize the recovery from these fields. The presence of the established infrastructure and the spare capacity at the major fields has also contributed to an emphasis on exploration for and development of satellite fields. Small fields with only a few tens of MMBO are now being developed, if they are easily accessible from existing infrastructure. Tabasco and Midnight Sun (Table 2.7) are prime examples. Older, previously ignored, accumulations such as North Prudhoe Bay and West Beach that were discovered in the early to mid-1970's have been developed and brought to production in the late 20th Century and early 21st Century (Table 2.7).

The potential associated with the construction of a gas pipeline from the North Slope to either the Midwest through Canada or to an ice free port at Valdez or in the greater Anchorage/Kenai area has created a great deal of interest in natural gas exploration. This gas emphasis has largely been reflected in State of Alaska's Foothills areawide lease sales and the renewal of industry exploration agreements with ASRC.

2.3.4.1 Colville-Canning Province: State and Native Lands and State Waters of the Beaufort Sea

During the last decade of the 20th Century the first few years of the 21st the bulk of exploration and development has continued to take place within the Colville-Canning area and the adjacent shallow waters of the Beaufort Sea. However, the type of play and the players were undergoing significant change during this period. The major producers, ConocoPhillips, BP Alaska, and ExxonMobil played a reduced role in terms of areawide exploration and leasing. By 2003 BP Alaska had virtually ceased to participate in lease sales, was conducting exploration solely in and around the existing producing areas, and was concentrating on increasing production from existing fields. ExxonMobil had completely abandoned exploration drilling by 2000 and had ceased to participate in lease sales. Only ARCO Alaska/Phillips Alaska/ConocoPhillips continued to participate broadly in lease sales and wildcat exploration drilling, but at a reduced level.

Companies, previously uninvolved in North Slope exploration and production have picked up the slack and have been the most active participants in the areawide lease sales both on- and offshore. They have also been increasingly active drillers and have discovered a number of small- to moderate-sized oil accumulations in the last three or four years.

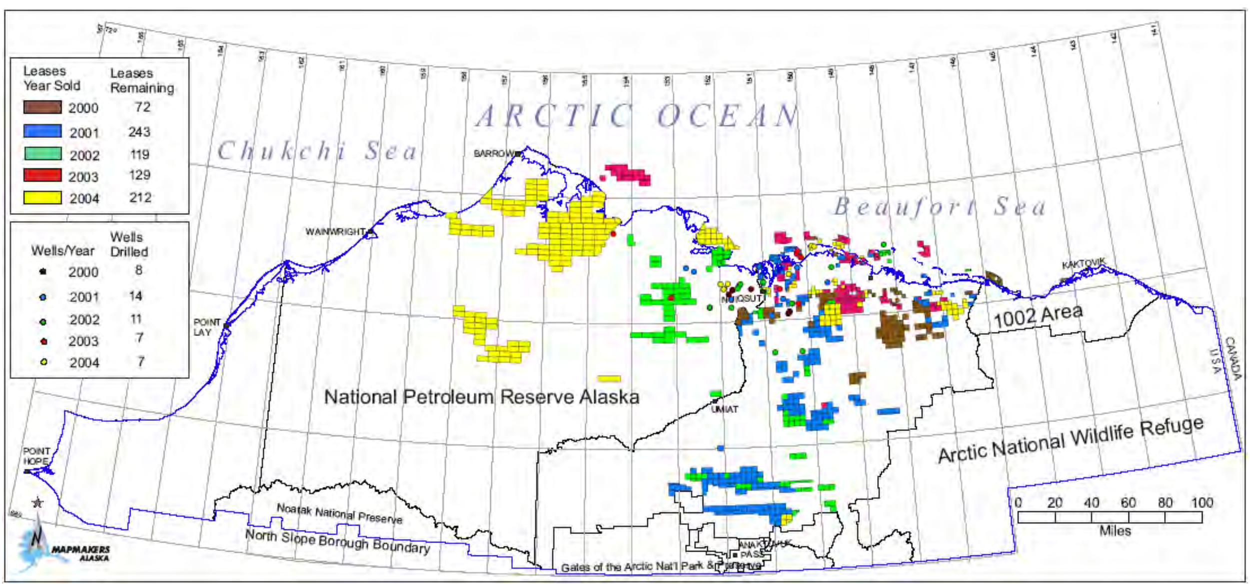

Figure 2.21. Leases and Exploration Wells 2000 to 2004.

2.3.4.1.1 Leasing

Between January 1, 1990 and December 31, 2004 the State conducted a total of 29 lease sales on the North Slope and the adjacent State waters of the Beaufort Sea (Table 2.5). The level of leasing activity and the size of lease offerings has varied greatly over this period, from years with no lease sales to years with three areawide lease sales. The annual offering has ranged from a low of zero acres in 1994 to over 10,000,000 acres per year from 2001 to the present.

The State commenced offering areawide sales in 1998 with State Sale No. 87. Since 2001 there have been three areawide sales per year (Table 2.5). These are the North Slope areawide sale, the North Slope Foothills areawide sale, and the Beaufort Sea areawide sale. Prior to the establishment of the areawide sales, two to three localized sales were held per year with an average offering of approximately 1,000,000 per year. Over that seven-year span the State leased 1,582,689 acres or an average of 226,098 acres per year. The areawide sales have resulted in an average of 521,440 acres leased per year or more than double the previous annual average.

The ASRC has continued to make its extensive landholdings, especially those in the foothills, available for exclusive exploration agreements. From the late 1990's to the present Anadarko Petroleum Corporation, and a varying group of partners, have had such an agreement with ASRC. The foothills land position is ideally situated to provide excellent opportunities for a major gas exploration effort. ASRC has also leased acreage through the competitive bidding process. Prior to the onset of the State of Alaska areawide lease sales in 1999, ASRC participated by offering selective tracts in State sales No. 75 and 86a (Table 2.5). From 1999 to the present, ASRC land has been offered with State lands in the areawide sales.

Many of the leases acquired at these and earlier lease sales have been relinquished back to the State by the winning bidder and only a fraction of the total acreage leased is still retained by the lessees (Figure 2.19). One of the most significant relinquishments was by Burlington Resources. They relinquished 32 tracts with a total of approximately 185,000 acres that had been acquired in the North Slope Foothills 2001 sale.

The impacts of the areawide sales, the interest in gas as a commercially viable resource, and the emerging significance of NPRA are all reflected in Figure 2.19. This is even more dramatically demonstrated when only the last five years are considered (Figure 2.21). Within the Colville-Canning area, as recently as 2000, the bulk of the leasing was concentrated in the area south and southeast of Prudhoe Bay. In 2001 and 2002 much of the leasing activity shifted south to the foothills belt (Figure 2.21), with some leasing by smaller companies in the shallow State waters of the Beaufort Sea. This transfer of interest was driven by the prospects of a gas pipeline and the well-recognized gas potential of the large foothills-belt structures.

Once the majority of the obvious foothills features had been leased and the pipeline was not moving forward, leasing activity shifted back to the north and blocks south of the producing fields and offshore tracts dominated. Both of these areas provide the opportunity to pursue and develop smaller oil prospects that would be developed as satellites to the major producing fields and depend upon the existing infrastructure to be economically viable.

2.3.4.1.2 Data Acquisition

The trend of major companies to leave the North Slope or to decrease competition by mergers reached a zenith in the late 1990's and early 2000's. This has been only partially offset by the arrival of small to intermediate sized companies that have more limited budgets and thus acquire less seismic data and focus on small select areas. Additionally these smaller companies tend to not sponsor geological field programs.

There was very little in the way of industry-sponsored geological field work in the 1990's with an average of one to two geological field crews (1 to 1.5 crew-months) per year. In the early part of the 2000's this increased modestly to two to four field crews (1.5 to 3 crew-months) per year. There were more companies involved than the number of crews may suggest, since some of the field programs were jointly-sponsored by two or three companies.

The 2D seismic acquisition totals 7,081 line-miles (Table 2.6) with some portions of this acquired in NPRA and the shallow Beaufort Sea. Based on Kornbrath and others (1997) at least 2,615 miles were acquired in NPRA between 1992 and 1997, with additional acquisition since that time. Thus, it is probable that only 3,000 to 4,000 line-miles of 2D seismic data were acquired within the Colville-Canning province.

Compared to prior years, the acquisition of 3D seismic data increased dramatically in the 1990's with a total acquisition of 8,632 miles between January 1, 1991 and December 31, 2004 (Table 2.9). Once again some percent of these data were acquired in NPRA and the shallow Beaufort Sea. Kornbrath, and others (1997) reported a 3D program in 1996 that acquired 152 square miles and there have been numerous programs since that date. Several of the companies that leased large blocks in the foothills have acquired 3D seismic programs. A conservative estimate of Colville-Canning 3D acquisition during the period in question is 5,000 miles. There were four 3D programs in the State waters of the Beaufort Sea in the early 2000's, one marine and three hardwater (Table 2.9). Anadarko has acquired both 2D and 3D seismic programs across prospective features underlying portions of the ASRC acreage for which they and their partners currently have exclusive exploration rights.

Costs of seismic acquisition and processing may constitute a significant portion of a company's exploration budget. In the Alaskan arctic, costs for acquisition of a 2D seismic program average about $15,000 per line-mile for onshore and hardwater surveys (Hastings, J., 2005). Processing costs add an additional $700 per line-mile. There has been no marine seismic acquisition for more than a decade. Estimated costs for a marine 2D program are about $15,000 to $20,000 per line-mile, if the seismic vessel is steaming at four knots/hour, 24 hours a day.

As one would anticipate, costs for 3D acquisition and processing are higher and reconnaissance onshore and hardwater 3D programs average about $35,000 per square mile. In-field 3D programs are much more expensive and average about $60,000 per square mile. These estimates do not include fuel and transportation costs, which are paid by the client. The cost of a 3D program increases as spacing decreases. The last marine 3D seismic program was acquired in 1997 and estimated average costs for acquisition and processing of a marine 3D survey are approximately $120,000 per square mile (Hastings, J., 2005).

These costs will probably continue to be representative for the foreseeable future, in the areas currently being explored and exploited. For more remote areas and the Chukchi Sea, the costs should be expected to be higher because of the distance from infrastructure and length of supply routes.

2.3.4.1.3 Exploration Drilling

Exploration drilling during the 1990's was widely dispersed and 84 exploration wells were drilled across the North Slope and in the Beaufort and Chukchi seas (Figure 2.18). There is some discrepancy in the numbers, based on how various agencies classify exploration wells. Approximately 70 of the 84 exploration wells were drilled within the Colville-Canning area/shallow Beaufort Sea area.

The majority of these wells were drilled along the Barrow arch trend both on and offshore in State waters. Much of this activity was concentrated in the vicinity of the Colville delta, where the Alpine discovery was made. These wells included the ARCO Nuiqsut No. 1, which is on ASRC lands. Only six exploration wells were drilled south of 70° north latitude. The ARCO Big Bend No. 1 drilled on ASRC acreage was one of these.

Drilling activity varied over the decade and two peaks of activity occurred during the 1992 to 1993 and 1996 to 1998 drilling seasons. In 1992 and 1993 a total of 22 exploration wells were drilled and in 1996 through 1998 when 26 wells were drilled.

The 2000 through 2004 exploration drilling resulted in a total of 47 exploration wells (Figure 2.18) with 28 of them being in the Colville-Canning area. Approximately 75% of these wells were drilled in the vicinity of the Colville delta and the adjacent area, just to the north and northwest of the Kuparuk Field. The ConocoPhillips Lookout No. 2 was drilled on ASRC leases in the Colville Delta area.

Currently, exploration wells are often drilled far from the existing road network and require the construction of ice roads or the use of tundra-sensitive vehicles such as Rolligons. All exploration wells are drilled during the winter and most are accessed and supplied by ice roads. Several factors impact the cost and feasibility of ice road construction. Chief among these are, nature of the terrain including the number and length of river crossings, the availability of lakes for water/ice, and road maintenance. An ice road six inches thick and 30 to 35 feet wide would require 1 million to 1.5 million gallons of water per mile. The cost of such an ice road may range from $50,000 to $100,000 per mile.

Due to the lack of permanent roads and the costs and environmental consequences associated with building gravel drilling pads for exploration wells, the current practice is to built ice pads for exploration wells and simply allow them to melt away after the drilling season. In rare instances these pads have been insulated and used for two seasons to drill an exceptionally deep well or for a multi-well program. A six-acre drilling pad, 12 inches thick, would require approximately 2,000,000 to 3,600,000 gallons of water and cost $300,000 to $500,000 to construct. Recently, at least one operator has been experimenting with an elevated drilling platform constructed from portable lightweight modules. This approach may have application in areas where there is no access to an adequate water supply for ice pad construction. Offshore exploration drilling is accomplished by extended-reach horizontal drilling from onshore sites, from offshore barrier islands, from man-made ice- or gravel islands, or via ice-resistant drilling vessels.

2.3.4.1.4 Discoveries

In the Colville-Canning area and the State of Alaska waters of the Beaufort Sea, twelve discoveries were made in the 1990's and five in the 2000 through 2004 time frame (Tables 2.7 and 2.8). The discoveries are shown on Figure 2.20. Eleven of these 17 fields are either currently producing or will be in the near future (Table 2.7). The other six (Table 2.8): 1) contain insufficient reserves to be developed, 2) are too remote at this time, or 3) have been discovered in the last year or two and are being evaluated for development. The discoveries are listed below with cumulative production through December 31, 2004.

Oil/Gas Field	Cumulative Production (December 31, 2004)
Badami Field	4.35 MMBO
Tarn Field	61.35 MMBO
Kalubik Field	soon to be developed
Fiord Field	soon to be a satellite for Alpine (CD-3)
Cascade Field	????? MMBO[15]
Thetis Island Field	not developed
Alpine Field	123.8 MMBO
Sourdough Field	not developed
Gwydyr Bay Field	soon to be developed[16]
Midnight Sun Field	10.8 MMBO
Sambucca Field	not developed
Eider Field	2.7 MMBO
Meltwater Field	6.7 MMBO
Palm Field	???? MMBO[17]
Nunaq Field	soon to be a satellite for Alpine (CD-4)
Oooguruk Field	soon to be developed
Nikaitchuq Field	soon to be developed

The seven producing fields have an estimated ultimate recovery of 760 MMBO. The Fiord and Nanuq fields are currently in the planning stages for development and they will be satellites for Alpine (PN, 2004b). The estimated recoverable reserves are 50.0 MMBO for Fiord and 40.0 MMBO for Nanuq (PN, 2004c). The Kalubik and Gwydyr Bay fields are clustered in the vicinity of the Oooguruk, Nikaitchuq, and other existing fields and will probably be developed within one to three years.

The Badami field was shut-in by BP Alaska due to production problems and reservoir continuity issues. BP is testing three techniques to redevelop the field and put it back on production in the latter half of 2005.

[15] Now producing as a part of the Milne Point Kuparuk pool.
[16] May be the focal point for the development of several small accumulations in the general area (PN, 2004b).
[17] Now producing as part of the Kuparuk field.

2.3.4.2 Beaufort Sea – Federal OCS

The Beaufort Sea OCS area has continued to see exploration activity but at reduced levels. The failure of the Mukluk well in 1983 and the inability of the discoveries that were made during the 1980's to yield economic quantities of oil significantly reduced the level of activity during the 1990 to 2005 time interval. Despite the poor results leasing, exploration drilling, and discoveries continue to occur in the Beaufort Sea OCS.

2.3.4.2.1 Leasing

The MMS held four OCS sales in the Beaufort Sea between 1991 and 2003; OCS sales No. 124, No. 144, No. 170, and No. 186 (Table 2.5). In these four sales, a total of 36,220,497 acres were offered and the sale size ranged from 18,556,976 (No. 124) to 920,983 (No. 170) acres. Sale No. 124 was an areawide sale and subsequent offerings have consisted of only portions of the total available area. These sales resulted in 645,400 acres being leased. Currently the only active OCS leases are leases acquired in the 1990's and sales in the 2000's (Figure 2.19). The 2000 through 2004 leasing activity is presented by year in Figure 2.21. The emphasis in the OCS sale No. 186 was on tracts north of Smith Bay, northeast of the Colville Delta and north of Badami.

2.3.4.2.2 Data Acquisition

Acquisition of seismic data included both 2D and 3D acquisition technology. A total of 5,316 line-miles of 2D data were acquired between 1991 and 1997 (Table 2.6). No 2D seismic data have been acquired in the Beaufort OCS since 1997. The acquisition of 3D seismic data in the Beaufort Sea OCS totals 12 programs during the 1990's and early 2000's (Table 2.9). These programs were equally divided between hardwater and marine acquisitions.

2.3.4.2.3 Exploration Drilling

Drilling activity in the Beaufort OCS was significantly reduced relative to the levels seen in the 1980's. Eleven exploration wells were drilled in the Beaufort OCS region between January, 1990 and December, 2004 (Figure 2.18). The McCovey No. 1 well is the only well drilled in the OCS since the beginning of the 21st Century (Figure 2.21) and is in fact the only well drilled in the Beaufort OCS since 1997. This low level of activity is largely driven by three factors: 1) failure to find large accumulations (1.0 + BBO), 2) environmental concerns, and 3) high cost of drilling in water depths greater than 40 to 50 feet. Exploration drilling in the OCS is expected to remain at low levels until at least 2010, when declining production in existing fields will put increased pressure on industry to find new sources of production and keep the pipeline open and flowing. However, the recent acquisition of leases in area of the Hammerhead, Kuvlum, and Wild Weasel structures by Shell E and P (during a 2005 OCS sale, which postdates the tabulation in Table 2.5) and efforts by Shell to acquire rigs to drill in the Beaufort Sea suggests activity may resume on some or all of these features within the next two years.

2.3.4.2.4 Discoveries

Two of the ten exploration wells encountered hydrocarbons (Table 2.8), the Kuvlum No. 1, drilled in 110 ft of water, offshore from the western end of the 1002 Area (Figure 2.21), and the Liberty No. 1, drilled in 21 ft of water, on the previously discovered Tern accumulation (Figure 2.21). The Kuvlum discovery is estimated to have recoverable reserves of approximately 400 MMBO but because of its remote location and water depth it has not been developed. Development of the Point Thomson Field may positively impact the Kuvlum accumulation as well as the Hammerhead accumulation. The Liberty Field, with about 150 MMBO, is in much shallower water and is less than 10 miles from the Endicott facilities and 20 miles from the

Badami facilities. BP Exploration (Alaska) is reviving the Liberty development plan and it may be contributing to North Slope production within the next two to four years.

2.3.4.3 Chukchi Sea – Federal OCS

The activity in the Chukchi Sea OCS during the 1990's was primarily a continuation of the leasing and follow-up exploration of the late 1980's. The activity was confined to 1990 and 1991. There have been no lease sales or exploration drilling since 1991.

2.3.4.3.1 Leasing

There was only one lease sale in the Chukchi Sea during the 1990 to 2005 time period. The single sale was OCS sale No. 126, which was held in 1991 A total of 18,987,976 acres were offered and 159,213 acres were leased.

2.3.4.3.2 Data Acquisition

Like the leasing activity, seismic acquisition was limited and completed by the end of 1991. A total of 861 line-miles of 2D seismic data were acquired during the 1990 and 1991 seasons (Table 2.6). There were no 3D seismic programs acquired during this time period.

2.3.4.3.3 Exploration Drilling

Four exploration wells were drilled in 1990 and 1991, in water depths ranging from 137 to 152 ft (Figure 2.18). These were the Burger, Popcorn, and Crackerjack wells all drilled by Shell and the Diamond well drilled by Chevron. There are good to excellent oil and gas shows in all three of the Shell wells (Sherwood, and others, 1998b). The Burger well has two zones of gas pay, in a 110-foot thick Kuparuk-C sandstone equivalent and a 36-foot thick deltaic Nanushuk sandstone. The Popcorn No. 1 has gas and condensate in a 20-foot thick Kuparuk(?) equivalent sandstone atop the Jurassic unconformity, oil shows in Torok turbidites, and Permian and Pennsylvanian carbonates of the Lisburne Group. The Crackerjack No. 1 well has oil shows in Early Cretaceous turbidites of the Torok and in sandstones of the Nanushuk Formation. A zone of gas pay was identified in the Echooka Formation. The Diamond No. 1 well has trace oil shows in sandstones of the Torok Formation, Ivishak Formation, Echooka Formation, and the carbonates of the Lisburne Group (Sherwood, and others, 1998b).

2.3.4.3.4 Discoveries

At least one discovery can be attributed to this brief round of drilling. The Burger No. 1 well is a gas discovery (Table 2.8), "possibly with multi-TCF reserves" (Sherwood, and others, 1998b). The primary gas zone is the Kuparuk-C equivalent. Preliminary estimates placed the range of estimated recoverable gas resources at 2 to 10 TCF with a mean of 5.0 TCF. Recent reevaluation of the Burger gas discovery has estimated the mean gas resources for the most likely case at 14.0 TCF and condensate at 724 MMB (Craig and Sherwood, 2005). Craig and Sherwood (2005) state that: "Burger could represent the largest hydrocarbon discovery to-date on the Alaska OCS. However, volumetric estimates for the Burger pool are highly speculative because only one well was drilled on a very large structure."

2.3.4.4 National Petroleum Reserve-Alaska (NPRA)

Exploration interest and activity were renewed following the discovery of the Alpine field, just to the east of the Reserve in 1994. This discovery and the additional exploration drilling it spawned led to the decision to reopen NPRA to leasing and exploration. Thus the Federal government, through the BLM, began to lease acreage in 1999. These sales led in turn to exploration drilling and to several small discoveries.

2.3.4.4.1 Leasing

The BLM has held three lease sales within NPRA since the renewal of leasing in 1999 (Table 2.5). Two sales were held in the northeastern planning area, in 1999 (Sale No. 991) and 2002 (Sale No. 2002). The acreage offered in Sale No. 991 was 3,900,000 acres and approximately 22% or 864,204 acres were leased. Sale No. 2002 offered 3,051,500 acres, essentially the acreage not leased in the 1999 sale. An additional 579,269 acres were leased in the 2002 sale. A single sale was held in the northwestern planning area. This sale (Sale No. 2004) presented a total of 5,800,000 acres and 1,403,561 acres were leased (Table 2.5). As a consequence of the success of these sales the BLM is proceeding with periodic sales in NPRA and with continued success these should be held every two to three years for the foreseeable future.

2.3.4.4.2 Data Acquisition

Data acquisition has been largely limited to 2D and 3D seismic acquisitions. A modest amount of geological field work was done and continues to be planned. The geological programs focus on the Cretaceous exposures in southern NPRA and to the south of NPRA. Geological field work has averaged about three to four crew weeks per year for the last decade.

Seismic program information, as supplied by the ADOG and the MMS, does not distinguish between data acquired within NPRA and on State of Alaska lands. The best estimate available is that approximately 3,000 to 3,500 line-miles of 2D data have been acquired within NPRA (Table 2.6). This represents the 2,617 line-miles reported by Kornbrath (1997) plus post-1997 acquisitions of 500 to 1000 miles.

The magnitude of 3D seismic acquisition is not known with certainty but is probably on the order of 3,000 to 3,500 square miles (Table 2.9). This may be on the optimistic end of the spectrum, but the use of 3D for both exploration and development in the pursuit of stratigraphic traps has increased in recent years and this range of acquisition seems in line with those activities.

2.3.4.4.3 Exploration Drilling

The first well to be drilled following the 1999 lease sale was the ConocoPhillips Spark No. 1. It was completed as a dry hole in April, 2000. Since that date an additional 17 exploration wells have been drilled within NPRA (Figure 2.18). To date all 18 exploration wells have been drilled within the northeastern planning area (Figure 2.20). The most westerly well is the ConocoPhillips Puviaq No. 1, located to the west of Teshekpuk Lake (Figure 2.20).

The annual exploration drilling activity for the 2000 through 2004 interval is summarized in Figure 2.21. The bulk of the exploration within NPRA has been focused southwest of Alpine (Figures 2.20 and 2.21) with 11 of the 18 wells drilled in this area.

2.3.4.4.4 Discoveries

The NPRA exploration is on the verge of yielding production. To date at least three discoveries have been made in the area to the southwest of Alpine. These are the Spark, Lookout, and Alpine West fields. They will all be developed as satellites to the Alpine field. Estimated EUR is about 50.0 MMBO per field (Table 2.7). DST results from four wells have been released (BLM, 2005). These wells are the Lookout No. 2, Rendezvous No. 1, Spark 1A, and Carbon No. 1 (Figure 2.20). The test results give rates of 320 to 4000 BOPD of high gravity oil and 5.0 to 26.0 MCFGPD.

A number of wells remain confidential and the results are unknown. The most intriguing of these is the Puviaq No. 1. Due to its location in the extreme northwest corner of the northeastern planning area, it is a potential key to the prospectivity of the Teshekpuk Lake area and the northern portion of the northwestern planning area.

2.3.4.5 1002 Area of the Arctic National Wildlife Refuge (ANWR)

There was no exploration or development activity within the 1002 Area during the 1990's and early part of the 2000's. The area remains off-limits to the petroleum industry despite repeated efforts in congress to approve exploration and development of this portion of the Refuge. The USGS reevaluated the 1002 Area's hydrocarbon potential (Bird and Houseknecht, 1998) and concluded that the mean technically recoverable reserves within the 1002 Area are 7,668 MMBO and within the entire study area (1002 Area, Native lands, and adjacent State waters within the 3-mile limit) 10,322 MMBO. These numbers are appreciably higher than the earlier USGS estimates and provide further incentive for exploration.

2.3.5 Summation of Activities to December 31, 2004

With varying degrees of intensity and success the North Slope and adjacent OCS areas of the Beaufort and Chukchi Seas have been the foci of oil exploration since the mid-1940's. The emphasis is correctly placed on "oil exploration" since there has not been and still is no market for gas. The gas discoveries have been incidental to the search for oil.

The two phases of federally sponsored exploration, of what is now NPRA, found several small subeconomic accumulations of oil and gas and provided a wealth of geological, geophysical, and well data as the basis for future evaluation of the hydrocarbon resources of the North Slope and adjacent OCS areas. The first phase, in the 1940's and 1950's, focused on the Late Mesozoic, primarily the Cretaceous section. This drilling program discovered several small gas fields and a number of these now provide gas to the village of Barrow. The second exploration phase in the late 1970's and early 1980's was directed toward the evaluation of the Prudhoe Bay area plays, largely centered along the Barrow arch. These efforts proved to be unsuccessful.

Commencing in 1958, the area to the east of NPRA and west of the Canning River was made available to the petroleum industry for exploration. After nearly 10 years of seismic acquisition, geological field work, and 11 dry holes, the first major discovery was made at Prudhoe Bay. This discovery was the stimulus for a major reallocation of industry resources to the North Slope and resulted in leasing and exploration programs that have led to the discovery of additional major oil fields and a combined EUR of more than 21.0 BBO. As of January 1, 2005 more than 14.7 BBO have been produced or about 70% of the EUR. Known gas reserves, largely associated with these oil discoveries, total 35 TCF.

The exploration success of the Colville-Canning area led to leasing and industry-sponsored exploration in the Beaufort and Chukchi seas and within NPRA. The exploration success is the result of widespread and predictable leasing programs, extensive geological and geophysical data acquisition programs, and exploration drilling programs with diverse objectives. Through 2004 there have been a total of 72 lease sales (Table 2.5) since the onset of leasing in 1958 and more than 26.5 million acres have been leased. Some acreage has been leased more than once.

As of January 1, 2005, there were a combined total of 1,553 active leases in the Beaufort Sea, NPRA, and the Colville-Canning area with the majority of the leases (1,243 or 80%) issued in the last 15 years. These newer leases are concentrated in NPRA and in the Brooks Range foothills (Figure 2.19). The 2000 to 2004 leasing activity is shown on (Figure 2.21). It emphasizes: 1) activity by independents and smaller companies in the Colville Delta-Gwydyr Bay area, 2) expectations for a gas pipeline and market with the foothills acreage, 3) westward extension of exploration into NPRA based on the discovery at Alpine, and 4) continued emphasis by the major producers on close-in satellite development.

Nearly 230,000 line-miles of 2D seismic data had been acquired by the end of 2004, with approximately 61,000 miles of land and hard water data and more than 168,000 miles of marine data (Table 2.6). The land 3D seismic acquisitions total more the 10,700 square miles. The amount of OCS 3D is not available but at least 18 programs have been completed, with 11 hard water and 7 marine acquisitions (Table 2.9).

Exploration drilling has been widespread but not intensive. On the North Slope and in the adjacent Beaufort and Chukchi Seas, a total of 454 wells have been classified as exploration wells (Figure 2.18). When the size of the area is considered, this is a very low exploration drilling density. The Colville-Canning area and the adjacent State waters of the Beaufort Sea are the most extensively explored areas with approximately 301 exploration wells. The total for State and Native lands is approximately 23,000 square miles (Bird and others, 2005) and yields a well density of one well per 76 square miles. Within NPRA a total of 118 “exploration” wells have been drilled. Of this number 45 were core tests. If the core tests are discounted, the federal exploration efforts and industry exploration drilling has totaled 73 exploration wells. With an area of approximately 36,000 square miles this yields a drilling density of one well per 495 square miles. The Beaufort Sea OCS shelf has an area of approximately 19,000 square miles with 30 exploration wells. The exploration well density is one well per 630 square miles. The Chukchi Sea planning area covers 64,500 square miles (Thurston and Theiss, 1987) with only five exploration wells, for a drilling density of one well per 12,900 square miles.

From an exploration perspective, the North Slope and adjacent areas are far from resembling a mature petroleum province. The majority of the wells in both the State onshore and near-shore Beaufort Sea are clustered along the Barrow arch trend with only forty-five of the 301 exploration wells located south of 70º north latitude Figure 2.18). The area south of 70º north latitude constitutes nearly 75% of the State acreage. This southern portion of the State land holdings has a well density of one well per 383 square miles. Thus only the area along the Colville-Canning portion of the Barrow arch and the adjacent portion of the Beaufort Sea has experienced moderate to high exploration drilling activity. Here, the drilling density is approximately one exploration well per 22 square miles.

Figure 2.21 shows both the recent exploration wells and their distribution and also the permitted wells for the 2005 drilling season. This planned activity foreshadows the near-term exploration trends and continues the pattern of activity represented by the last four to five years of exploration drilling. The areas of concentration continue to be in or near currently established production and infrastructure and westward into NPRA. The latter activity is a continuation of the evaluation of the productive trend at Alpine and its satellites and the search for Brookian turbidite and additional Kuparuk production.

Large volumes of gas have been discovered in the exploration process and vast areas of high gas potential remain under- or un-explored. With the currently published estimates of gas at Point Thomson, Prudhoe Bay and adjacent fields, and the recently revised volumes for Burger, the known resource base is approximately 50 TCF. This resource and other potential gas resources await a decision to build a gas pipeline.

The role of gas in the future of the ANS eloporation and development is described in Section 2.4 – Section 2.4.2 Long Term (2015 to 2050).

2.4 Future Exploration Potential and Activity

"Even if prices and political stability were to continue to favor exploration and extraction of North Slope oil and gas, many variables bear on the amount of activity and the success of future exploration and development: land availability, the regulatory environment, pricing, technology, exploration concepts, competition, and the infrastructure" (National Research Council, 2003). The magnitude and success of future exploration and development will be largely dependent on the degree to which the following assumptions are satisfied:

A. Oil (and gas) prices remain high enough to support continued exploration and development.
B. Climate change will not be so great, during the next 50 years, to render current exploration methods obsolete or foreclose modifications, such as the use of Rolligons and new drilling platforms.
C. All new exploration and development activities will use technologies at least as good as those at Alpine.
D. Onshore exploration (and probable extraction) will continue to expand both southward into the foothills of the Brooks Range and westward across the NPRA.
E. Offshore exploration (and probable extraction) will continue, but at a cautious pace, along the Beaufort Sea coast/shelf from Point Barrow to Flaxman Island and possibly eastward to the Canadian border. The exploitation of the Chukchi Sea OCS will depend on anticipated success in adjacent portions of NPRA and the construction of a gas pipeline.
F. Facility sharing agreements will be in place, which permit reasonable and affordable access for those companies not currently producing and transporting hydrocarbons.
G. A gas pipeline will be built and, over time, gas will become a significant if not the dominant component of many exploration and development programs and new explorers will have access to the gas pipeline.

H. The number of exploration companies, especially those with gas interests, will expand, competition will increase, and a greater variety of play types will be evaluated and drilled.

Beyond the issues presented above, the fundamental control on oil and gas occurrence and distribution is the petroleum geology of the North Slope and variations in character of the source and reservoir intervals or their absence within and across the prospective areas. In the petroleum geology section, the distribution and character of these units were presented to provide a basis for the findings of this portion of the report.

Exploration and evaluation of the hydrocarbon potential of much of the North Slope and adjacent offshore areas is still in its infancy. Despite the success in the Prudhoe Bay area, little exploration drilling has occurred across much of the region, and stratigraphic exploration has only recently become a meaningful component of most exploration programs. As discussed in the previous section, exploration drilling has been heavily concentrated along the Barrow arch trend, and most of that activity has been restricted to the Colville-Canning area. Oil has been and currently is the exploration objective of all ongoing exploration programs. It will continue to be the primary focus of near term exploration programs until such time as a gas pipeline has been approved and facility sharing and facility/pipeline access issues have been addressed.

The basic assumptions for this projection of future activity are that there will be significant new discoveries and development of both oil and gas and a continued gradual decline in production from older fields. This decline of production from the older fields will likely influence the rate and timing of satellite development.

The future projections discuss activity in three major operating provinces based on administrative agency and physical environment. These are the State lands both onshore and offshore, the OCS areas of the Beaufort and Chukchi seas, and NPRA. For completeness, a fourth province, the 1002 Area of ANWR is included in the forecast. Much like the treatment in the prior sections these areas generally have similar restrictions, lease terms, and other regulatory aspects in common and thus have some degree of predictability regarding operational style and infrastructure.

For the purposes of this discussion, it is assumed that a gas pipeline will be approved within six to twelve months (late 2006) and gas production and shipping will commence in approximately ten years, or about 2015 to 2016. Thus, the future of exploration and development on the North Slope and adjacent areas is addressed as having two components; an oil-dominated near term (2005 to 2015) phase, building on current exploration trends and philosophies and an increasingly gas-dominated long term (2015 to 2050) phase, relying on the development of a gas pipeline and open access to it and associated infrastructure.

Publicly available federal resource estimates and other citations are utilized to frame or represent the magnitude of oil and gas that may be available or potentially discovered through comprehensive exploration programs. These numbers are not to be considered as absolutes but can be thought of as approximations of the order of magnitude of generated, migrated, and accumulated oil and gas.

Over time the estimates of undiscovered resources have been reported in a variety of formats. These include OOIP/OGIP, technically recoverable resources or reserves, and economically recoverable resources or reserves. The OOIP/OGIP is the estimate of the total volume of oil or gas in a reservoir or reservoirs prior to the onset of production. It does not represent the quantity of the resource that may be produced from the field. The OOIP at Prudhoe Bay was approximately 23 BBO. Technically recoverable resources (reserves) are the volume of oil and/or gas that may be technically and physically recovered independent of price. Economically recoverable resources (reserves) are that portion of the technically recoverable resources that may be economically recovered and are sensitive to both price and technology. The current estimate of economically recoverable reserves at Prudhoe Bay is 13.8 BBO or nearly 60% of the OOIP and more than 40% greater than the original EUR estimate of 9.6 BBO). This may be considered to represent reserves growth totaling 4.2 BBO for the Prudhoe Bay field.

Table 2.10 is presented to provide a comparison of oil production and EUR for the ANS. The OCS areas are treated separately and have been excluded from this table.

The data in Tables 2.10 through 2.16 are variously presented as unrisked undiscovered original oil/gas in place, unrisked undiscovered technically recoverable oil/gas, risked undiscovered technically recoverable oil/gas, risked undiscovered economically recoverable oil/gas, conditional undiscovered technically recoverable oil/gas, and conditional undiscovered economically recoverable oil/gas. Occasionally where only a single well has encountered an accumulation estimates are considered conditional (risked or unrisked) discovered oil/gas (Craig and Sherwood, 2005). In the discussion, clear distinctions are made among oil/gas-in-place, technically recoverable resources, and economically recoverable reserves. Where estimates of oil and gas volumes have been calculated in more than one format the various formats will be presented to permit the greatest possible opportunity to compare between or among areas treated differently by the assessment teams or agencies.

Table 2.10. Comparison of ANS oil production, reserves, identified resources and estimated resources at three points in time: 12/31/89 (Thomas and others, 1991), 12/31/00 (Energy Information Administration, 2001), and 06/30/05 (Bird and others, 2005 and Alaska Oil and Gas Conservation Commission, 2005).

Date of Source Report	Area	Oil Produced at Time of Report	Remaining Discovered Oil		Undiscovered Oil Resources	Total
			Producing Fields	Identified Developing Fields		
12/31/89	North Slope	7.36 BBO	6.33 BB0	1.96 BBO	12.43 BBO	28.08 BBO
	Colv.-Cann. and State Beaufort Sea				7.10BBO	
	NPRA				2.10 BBO	
	1002 Area				3.23 BBO	
12/31/00	North Slope	13.31 BBO	4.53 BBO	1.31 BBO	13.32 BBO	32.47 BBO
	Colv.-Cann.				1.541 BBO	
	NPRA				1.480 BB0	
	1002 Area				10.3 BBO	

Date of Source Report	Area	Oil Produced at Time of Report	Remaining Discovered Oil		Undiscovered Oil Resources	Total
			Producing Fields	Identified Developing Fields		
06/30/05	North Slope	14.30 BBO	4.93 BBO	1.83 BBO	25.0 BBO	46.06 BBO
	Colv.-Cann.				4.0 BBO	
	NPRA Entire Area				10.40 BBO	
	1002 Area Entire Area				10.60 BBO	

The determination of "economically" recoverable reserves is to a great extent a function of the assumed oil or gas price used by the assessors. As recently as 2002 (Bird and Houseknecht, 2002) the oil price range used to provide an estimate of economically recoverable reserves was approximately $22.00 to $30.00 per barrel. The real world price for the better portion of the last year (late 2004 through 2005) has been in the $45.00 to $65.00 per barrel range. The probability that the price will stay in that range is unknown, but it is probably reasonable to assume that a price well above $30.00 per barrel will hold for the foreseeable future. This leads to the conclusion that most if not all estimates of economically recoverable volumes of oil and gas are conservative and in certain areas the economically recoverable volumes may be approaching the technically recoverable values. The impacts of different oil price assumptions on estimates of economically remaining reserves (ERR) are described in Section 3, Engineering and Economic Evaluation.

One of the primary objectives of this segment of the report is to present a possible scenario for future exploration activity and discovery of economic quantities of hydrocarbons. The timing of these activities is an important aspect of this approach and the attempts to forecast when or where these may occur are fraught with uncertainty and must be recognized for what they are **– one perception of the best estimates of future events**. The information derived from published assessments of resources and the recent trends in leasing, exploration drilling, and discoveries are used to develop these forecasts.

In the near-term (2005 to 2015), it has been assumed that in the individual areas of interest, drilling activity will continue at a pace at least equivalent to that of the last decade. Discovery frequency and size will similarly be of the same order of magnitude as the recent or known discoveries in the area. These assumptions may be conservative in the respect that they do not account for the discovery of fields in the upper range of resources ascribed to the various play types.

For the long-term (2015 to 2050), the basic assumption is that by 2040 at least 50 and possibly 75% of the assessment volumes of technically recoverable oil and gas will have been discovered and economically developed. A recent evaluation of the sensitivity of oil price to volumes of economically recoverable oil indicates that at prices of $51.00/barrel (below the current range of oil prices), more than 90% of the estimated technically recoverable resources of the 1002 Area are economically recoverable (Attanasi, 2005). This tends to suggest that the 50 to 75% guidelines used here are quite conservative in the current pricing environment.

Beyond 2040, the picture becomes so obscure that any attempt to put timing and location constraints on activities is probably meaningless. The timing and location of development are considered to be a function of proximity to the existing infrastructure, specifically TAPS and a future gas pipeline, which is assumed to be built along basically the same corridor as the oil pipeline, at least while traversing the North Slope and Brooks Range. Secondary and satellite fields require the development of infrastructure associated with large stand-alone fields like Prudhoe Bay, Kuparuk, and Alpine to minimize the cost of development.

Additional elements that may facilitate exploration and development are year-round gravel roads proposed by the State of Alaska. The proposal consists of four roads: 1) to NPRA from the end of the existing spine road, 2) a road to Point Thomson, and 3) and 4) roads east and west from the Dalton Highway into the foothills (PN, 2004d). The road to NPRA would be 20 miles long and a 3,300 ft bridge would span the Colville River, providing access to NPRA development areas and Nuiqsut. At the time of publication, construction was expected to occur in the fall and winter of 2006.

The coastal road to Point Thomson would be 55 miles long and built on State lands. This road will provide access to potential exploration and development sites within the northern portion of the Colville-Canning area and to the 1002 Area of ANWR if it is opened to exploration.

The foothills roads are intended to provide all-season access to oil and gas leases on State land in the Brooks Range. The western road is planned to extend to the upper Kuparuk River. This would greatly simplify the transportation issues since ice roads are often impractical because of slope and terrain breaks. The eastern road would provide the same function for access to leases east of the Dalton Highway. Both of these road proposals are awaiting a gas pipeline project approval.

2.4.1 Near Term (2005 to 2015) – Primarily Oil

The most immediate of the near-term exploration and development trends are obvious to even the most casual observer of the oil and gas industry in Alaska. The proposed 2005 exploration drilling shown on Figure 2.21 demonstrates these trends, which are reinforced by the current lease status as reflected by the leasing and retention of leases for the last five years. These comprise the exploration activity of eastern NPRA, where the Alpine- and Tarn-like play trends are primary targets, the Kokoda and Iapetus wells of Figure 2.21, with the Kuparuk as a secondary objective; the exploration drilling east of the Colville Delta to Gwydyr Bay, the Tuvaaq and Ataruq wells of Figure 2.21, where reservoirs equivalent to those at Alpine and the Kuparuk/Milne Point fields are targets; and the satellite exploration in and around Prudhoe Bay and the Kuparuk fields by the major operators.

The recent leasing activity, as shown by the active leases of Figure 2.21, support these exploration trends or philosophies and in addition highlight the gas-driven exploration interest in the Brooks Range foothills. Exploration drilling in the latter area is in abeyance, awaiting a decision on the gas pipeline and resolution of issues regarding access to it.

2.4.1.1 State and MMS Administered Lands

The State of Alaska and MMS administered lands include the onshore area between the Colville and Canning rivers and the State and OCS waters of the Beaufort and Chukchi seas (Figure 2.20). Most of this region, with the notable exception of the Chukchi Sea, has been available for leasing for at least 25 years (Table 2.5) and has experienced multiple sales, several episodes of exploration drilling, and generally well established procedures and regulations. The Chukchi Sea was not opened to leasing until 1988 (Table 2.5) and has seen only one episode of drilling, but otherwise it can be viewed as being somewhat similar to the Beaufort Sea in regard to operating conditions, leasing stipulations, lead-time from discovery to production, and infrastructure requirements.

2.4.1.1.1 Colville-Canning Province and State Waters of the Beaufort Sea

The Colville-Canning province and the adjacent State waters of the Beaufort Sea remain the most active exploration area of the North Slope. The bulk of the area is under State ownership, but ASRC controls approximately 3,000,000 acres in the Brooks Range foothills. The exploration and development history has been discussed in an earlier section. This area accounts for virtually all current oil production and more than 95% of the known gas resources of the North Slope. The major oil fields include the Prudhoe Bay, Kuparuk, Endicott, Pt. McIntyre, Milne Point, and Alpine fields. Prudhoe Bay and Point Thomson fields contain the largest gas accumulations. All of these fields are in the northern area, on or near the Barrow arch and between the Colville and Canning rivers.

Currently, exploration and development activities are divided between this area and the eastern portions of NPRA, with the bulk of development activity focused on satellite and other small, near-infrastructure oil accumulations. Within the general Colville-Canning area and adjacent State waters of the Beaufort Sea, the future of near-term exploration, beyond the proposed 2005 drilling (Figure 2.21), is dependent to a great extent on decisions regarding ease of access to infrastructure for new operators and the construction of a gas pipeline.

An update on planned and completed wells was supplied by Alaska Oil and Gas Conservation Commission (AOGCC) (2006) and there were 11 wells permitted for the Colville-Canning area for the 2005 drilling season. As of August 7, 2005, six of these wells had been reported to the AOGCC as completed. These wells include the Franklin Bluffs No. 1, Atarug No. 2, Atarug No. 2A, Kigun No. 1, Nikaitchuq No. 3, and Nikaitchuq No. 4. Five wells were permitted for the 2006 drilling season (AOGCC, 2006) and include the Mt. Elbert No. 1, Antigua No. 1, Cronus No. 1, Kuparuk River Unit W. Sak 1H-South, and Kuparuk River Unit W. Sak 1R-East. None were completed as of this writing.

The approach to future exploration will be largely controlled by the proximity to infrastructure and the regional understanding of the petroleum geology of the area and sequential discovery of hub or anchor fields and the smaller satellites that depend upon them for economic viability. Source rock distribution and character as well as nature of reservoir and adequacy of traps/seals will be the primary geological drivers for the continued exploitation of the regions hydrocarbon resources. The type of hydrocarbon will be largely determined by the nature and thermal maturity of the source rocks; therefore, considerable emphasis is placed on the source rock character and geographic distribution.

The primary source rocks of the Shublik and Kingak are absent east of Prudhoe Bay in the northeastern portion of the area, but the HRZ is present across the entire area. From the Colville delta to the eastern limits of the Prudhoe Bay field and the source rock intervals are thermally immature with respect to generation of oil or gas (Bird, 1994, Figure 21.8). Here the R_o values are less than 0.6%. Figure 2.22 displays the zones of thermogenic petroleum generation and destruction, with the oil generation window occurring between 0.6 and approximately 1.3% Ro. The oil floor is at a Ro value of 1.35%.

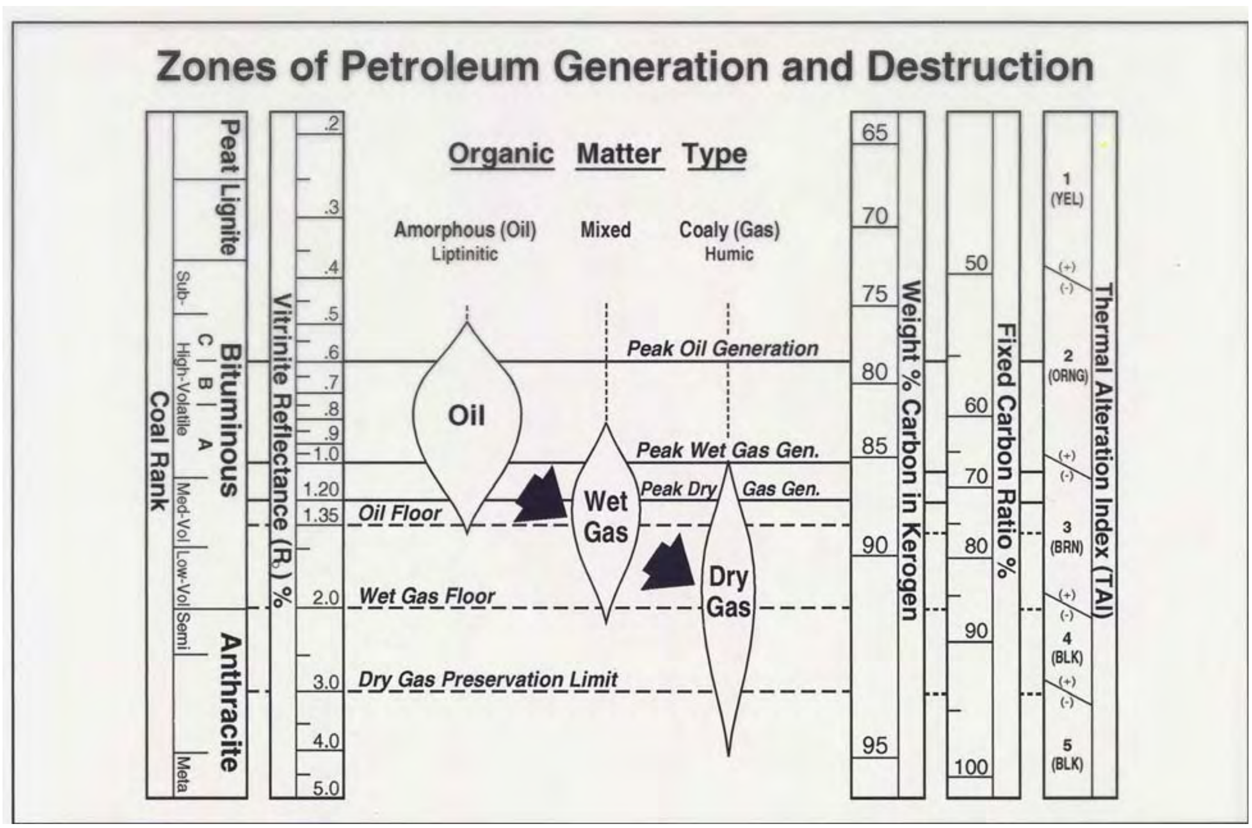

Figure 2.22. Correlation of coal rank scale with several petroleum maturation scales, showing zones of hydrocarbon generation and destruction. The vitrinite reflectance (Ro) scale is most commonly used. (Source: Dow, 1977)

In the southern Colville-Canning area, the Shublik and Kingak are deeply buried and no longer are capable of generating oil, and the southern portion of the region tends to be a gas-prone province. The southern limit of oil generation for the Kingak and Shublik occurs at the 1.3% R_o contour on Figure 21.8 of Bird (1994). This contour trends diagonally southeastward across the area from about 69º 20’ north latitude to approximately 69º north latitude.

The Pebble Shale, HRZ, and Torok are present across much of the northern Colville-Canning area, but they are thermally immature for both oil and gas over much of the northern portion. Magoon and Bird (1985) and Magoon and Bird (1987) provide maps depicting contours of vitrinite reflectance values for the base of the Pebble Shale unit and the top of the Torok Formation. These maps bracket this package of Lower Cretaceous source rocks and demonstrate that currently the bulk of the sedimentary package is thermally immature for oil or gas generation north of about 70º north latitude. The top of the oil generation window shifts southward in the younger units and the 0.6% Ro value at the top of the Torok generally occurs south of 69º 30' north latitude and in places as far south as 69º. Thus, in much of the area the in-situ Lower Cretaceous source rocks did not make a significant contribution to known and unknown resources. Pebble Shale, HRZ, and Torok oils in the northern area probably migrated from the deeper portions of the Colville trough to the south.

Prior to examining the possible reserve additions and the activity necessary to discover them it is important to review estimates of the magnitude of the potential undiscovered resources. Table 2.11 summarizes the estimates of the hydrocarbon potential of the area in question. The Colville-Canning and State Beaufort Sea areas have not historically been evaluated as a discrete entity as have ANWR and NPRA. The estimated resources/reserves for these State areas were grouped with the Federal lands to yield an estimate for the entire North Slope. The starred (*) estimates in the first row of Table 2.11 represent the 1990 USGS slope-wide estimates minus the 1987 ANWR and 1980 NPRA estimates. There were no economically recoverable estimates by the USGS for ANWR and NPRA at that time, and consequently no "adjusted" Colville-Canning and adjacent Beaufort Sea economically recoverable values are presented.

Table 2.11. Estimates of hydrocarbon volumes -- State of Alaska lands North Slope, Alaska. Estimates originally presented included NPRA and ANWR assessments.

Source of Estimate	Estimate Format	Oil (BBO)			Gas (Nonassoc.) (TCF)		
		95%[a]	Mean	5%[a]	95%	Mean	5%
USGS 1990 revisions	Risked undiscovered technically recoverable	2.2 1.3*[b]	12.6 7.1*	35.4 20.8*	8.6 ???*	54.1 ???*	157.4 ???*
USGS 1995	Risked undiscovered economically recoverable	0.00 ???*	7.7 ???*	26.7 ???*	23.3 ???*	63.5 ???*	124.3 ???*
USGS 2005[c]	Risked undiscovered technically recoverable	2.6	4.0	5.9	23.9	33.3/ (4.2[d])	44.9

a. 95% probability level means that statistically there are 19 in 20 chances that the resources are as great as or greater than the volume indicated, and the 5% probability level refers to a 1 in 20 chance that the resources are as great or greater than the estimated volume.
b. The numbers with an * reflect the non-Federal lands estimates determined by extracting the appropriate estimates for NPRA and ANWR.
c. USGS 2005 numbers are for the Central North Slope State and Native lands and the State shallow Beaufort Sea.
d. Associated gas.

Figure 2.23 presents stratigraphy, petroleum systems, petroleum plays and a summary of the ages, names, and rock types present in the Central North Slope assessment area.

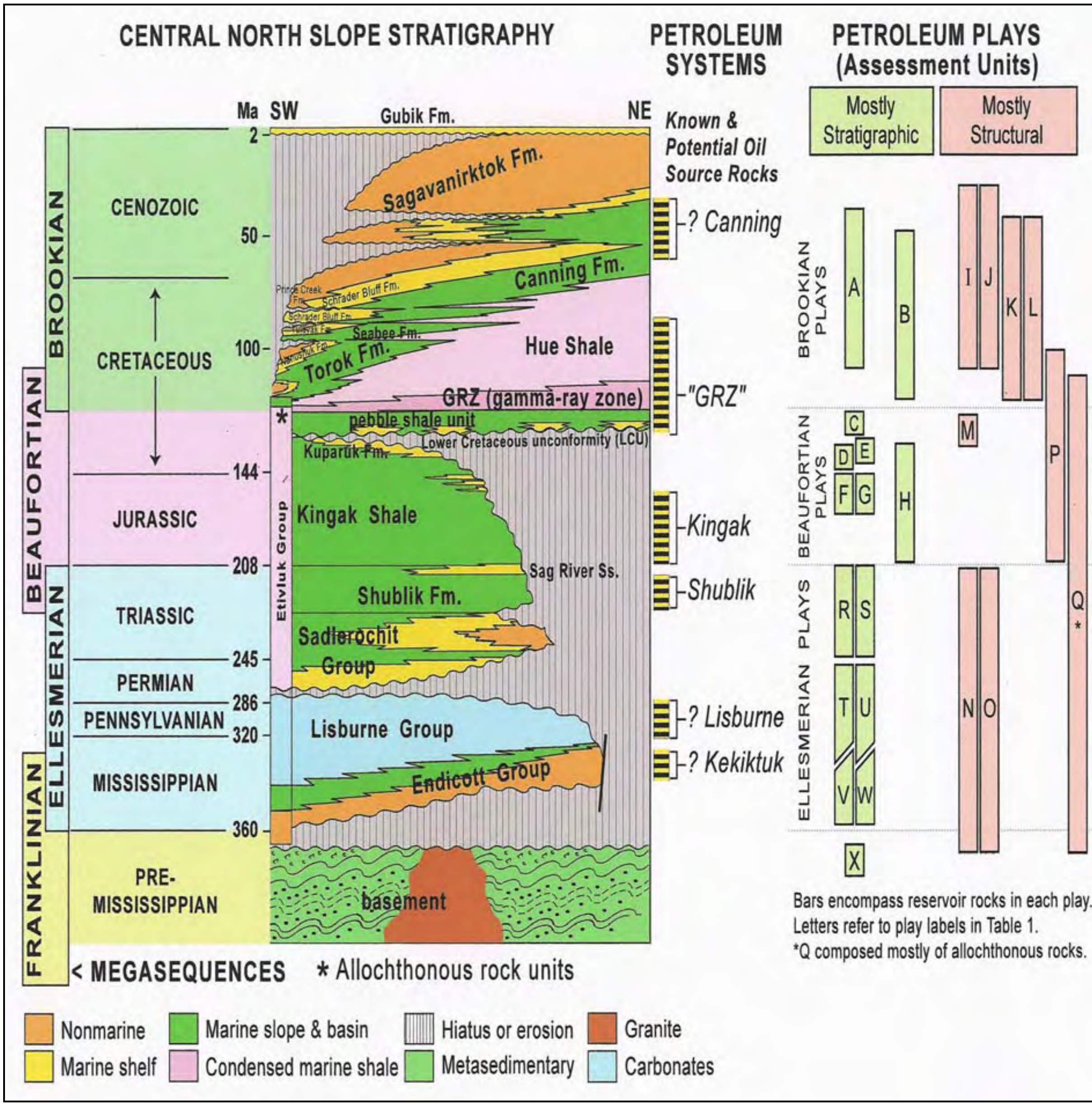

Figure 2.23. Summary of ages, names, and rock types present in the central North Slope assessment area. Colored bars at right show the stratigraphic position of the 24 petroleum plays evaluated in the 2005 assessment. Letters on the colored bars refer to the plays of Garrity and others, 2005, Table 1. The following listing identifies the plays:

A.	Brookian Topset	M.	Beaufortian Structural
B.	Brookian Clinoform	N.	Ellesmerian Structural
C.	Kemik-Thomson	O.	Basement Involved Structural
D.	Beaufortian Kuparuk Topset	P.	Thrust Belt Triangle Zone
E.	Beaufortian Cretaceous Shelf Margin	Q.	Thrust Belt Lisburne
F.	Beaufortian Upper Jurassic Topset East	R.	Triassic Barrow Arch
G.	Beaufortian Upper Jurassic Topset West	S.	Ivishak Barrow Flank
H.	Beaufortian Clinoform	T.	Lisburne Barrow Flank
I.	Brookian Topset Structural North	U.	Lisburne Barrow Flank
J.	Beaufortian Topset Structural South	V.	Endicott Truncation
K.	Brookian Clinoform Structural North	W.	Endicott
L.	Brookian Clinoform Structural South	X.	Franklinian

The most recent assessment of North Slope oil and gas resources was released in mid-2005 (Bird and others, 2005). This assessment pertains to the Central North Slope, Alaska (Colville-Canning province) and the adjacent offshore area. These are non-Federal, State of Alaska and Native corporation lands. The 2005 assessment (Bird and others, 2005) considers oil, associated gas, nonassociated gas, and natural gas liquids (NGLs). These estimates are presented as risked undiscovered technically recoverable resources and are shown in part on Table 2.11. The oil resources are estimated to range from 2.6 to 5.9 BBO and have a risked mean of 4.0 BBO. Nonassociated gas resource estimates range from 23.9 to 44.9 TCF and have a risked mean of 33.3 TCF. The mean associated gas estimate is 4.2 TCF. The risked mean for the NGLs is 478 MMBO.

There are two other areas of State lands within the "three-mile" limit of the Beaufort Sea. The area west of the Colville River was assessed as a portion of the 2002 NPRA (Bird and Houseknecht, 2002) assessment. These values are incorporated within the estimate for the ENTIRE AREA of Table 2.13 on page 2-126 (Bird and Houseknecht, 2002). Similarly the State offshore areas east of the Canning River are included in the estimate for the ENTIRE AREA portion of the 1998 assessment of ANWR (Table 2.14, page 2-127) (Bird and Houseknecht, 1998). These areas are included in the discussions below even though the potential magnitude of resources is included in other assessments (Bird and Houseknecht, 1998 and 2002).

The 2005 assessment (Bird and others, 2005) involved the recognition and analysis of 24 plays (Figure 2.23). Approximately two-thirds of the oil or 2.5 BBO are expected to be found in three plays in the northern portion of the assessment area. The most prospective appear to be the Brookian Clinoform, Brookian Topset, and Triassic Barrow Arch plays (plays B, A, and R of Figure 2.23) with means of 1.6 BBO, 0.44 BBO, and 0.4 BBO respectively. The mean resources of the Early Cretaceous sandstones of the Kuparuk River Formation (play D), Kemik Sandstone (play C), and the Point Thomson Sandstone (play C) and the Brookian Topset Structural North (play I) provide an additional 690 MMBO; thus, these seven plays total approximately 3.19 BBO or 76% of the estimate for the Central North Slope assessment (Bird and others, 2005).

As anticipated, results of the 2005 assessment placed the bulk of the gas resources in the southern portion of the Colville-Canning province. Four plays (B, P, Q, and O of Figure 2.23) are believed to contain 50% of the nonassociated gas. In the order of plays presented above, the primary plays and the risked mean recoverable gas resources are Brookian Clinoform (6.44 TCF), Thrust Belt Triangle Zone (3.84 TCF), Thrust Belt Lisburne (3.59 TCF), and Basement Involved Structure (3.02 TCF). These plays have an aggregated mean of 16.9 TCF. Four additional plays, Kemik-Thomson (play C), Brookian Topset Structural South (play J), Brookian Clinoform Structural South play K), and Beaufortian Structural (play M), have estimated means between 2.0 and 2.5 TCF and total 9.4 TCF. The aggregated means of these eight plays comprise 80% of the assessment area's mean recoverable gas.

The northern plays are primarily oil with associated gas. Prudhoe Bay is a prime example and Point Thomson may be looked upon as an extreme case of this association. The southern or foothills plays are largely nonassociated gas plays with some possibility of oil. East Umiat and Gubic are examples of these gas accumulations.

Northern Colville-Canning and State Beaufort Sea: For the purposes of this report the northern portion of the Colville-Canning area extends from the coast south to approximately 69º 25' north latitude or to the southern limits of the State of Alaska North Slope areawide sales region. Under virtually any likely scenario, the northern portion of the Colville-Canning area and the shallow Beaufort Sea will continue to be a focus of exploration and development activity for the next decade. It is anticipated that the major producers will continue to add production through the discovery and development of smallish satellite oil fields and new medium-size accumulations. Recently active small to intermediate size companies are expected to continue to explore acreage that is proximal to infrastructure and develop new fields, such as the recent finds at Oooguruk and Nikaitchuq (Figure 2.20). These opportunities are present both onshore and in the shallow nearshore State waters of the Beaufort Sea.

The Ellesmerian reservoirs of the Mississippian Endicott and Lisburne Groups (Figure 2.15) and the Triassic Ivishak Formation will continue to be exploration objectives but much of the emphasis will shift to the younger Beaufortian and Brookian sections. The Beaufortian Upper Jurassic Alpine and related sandstones and Early Cretaceous Kuparuk Formation, Kemik Sandstone, and Point Thomson Sandstone equivalents (Figure 2.16) and the Brookian Late Cretaceous and Tertiary Schrader Bluff, Prince Creek, Sagavanirktok and Canning formations (Figure 2.17) will tend to be the focus of future exploration efforts for oil.

As summarized above, Bird and Houseknecht (2005) identified the primary oil plays as the Brookian Clinoform (Torok/Seabee/Canning formations), Brookian Topset (Nanushuk/Tuluvak/Schrader Bluff/Prince Creek/Sagavanirktok formations and "equivalents"), and the Triassic Barrow Arch (Ivishak/Shublik/Sag River formations). The Early Cretaceous topset units of the Kuparuk River Formation, Kemik Sandstone and Point Thomson Sandstone have a combined mean of 427 MMBO and are attractive secondary targets.

The major Ellesmerian and Beaufortian reservoirs in the Prudhoe-Kuparuk area are present throughout the north-central and northwestern portions of the region but are absent in the northeast due to erosion associated with the LCU. The reservoir quality and thickness of the Ellesmerian and Beaufortian reservoirs decrease to the south and some units, notably the Beaufortian reservoirs, were deposited and preserved nonuniformly across the prospective area. The Brookian reservoirs are widespread across both the Colville-Canning area and the shallow Beaufort Sea and provide numerous stratigraphic targets.

Based on the distribution and character of the various reservoir and source rock intervals, the hydrocarbon potential of the northern Colville-Canning area and the State shallow Beaufort Sea area varies considerably in the level of prospectivity. Of the 24 plays recognized in the USGS 2005 assessment (Bird and others, 2005) 16 plays are present either wholly or partially in the oil-prone northern Colville-Canning area and adjacent shallow Beaufort Sea. Only one play, the Brookian Clinoform, is estimated to have more than 500 million barrels (MMB) of technically recoverable oil. Two plays, the Brookian Topset and the Triassic Barrow Arch, have between 250 and 500 MMBO. However, there is considerable areal overlap and potential vertical stacking of reservoir horizons, which provides the opportunity for multiple targets. Thus, a number of the less prospective plays may be evaluated and contribute to the reserve base as secondary or tertiary objectives.

In this area the pending level of exploration activity is relatively easy to assess. The major operators are not pursuing aggressive exploration programs. They have developed a low-risk, reserve-addition philosophy that entails exploration or extension drilling within a few miles of the existing production and transportation infrastructure. The emphasis is frequently on exploiting small accumulations that can be developed from existing pads and infrastructure through the application of extended reach horizontal drilling and multilateral completion technologies.

The initial drilling season (2005) of the near-term interval saw ConocoPhillips drill a single exploration well from an onshore site to an offshore location west of Fiord and add an exploration tail to an Alpine development well – possibly testing deeper Jurassic sandstones or the Sag River Sandstone. The activities of the major producers should result in reserve additions reflecting the addition of production from Fiord, Nanuq, Sambucca, and the expansion of the heavy oil operations. These activities may be expected to bring proven, economically recoverable resources of more than 250 MMBO on line by 2010. Fiord and Nanuq are expected to commence production in late 2006 and reach a peak of 35,000 barrels of oil per day (BOPD) in 2008 (PN, 2005a). BP Exploration (Alaska) is restarting the Badami oil field for a three-year period to test new recovery techniques (PN, 2005b). Production was suspended in early 2003 and the field has been in warm shutdown since then. The EUR for this field is uncertain but certainly less than the original estimate of 120 MMBO. An estimated revised EUR is 60 MMBO (Table 2.7). This value is based on the assumption that the operators must see an economic benefit to producing the field and that reserves of this magnitude would be required to justify the continued effort to develop and produce the oil. Production rates for Badami were approximately 1,500 BOPD in December 2005.

The major operators will continue exploring around the fringes of the known large accumulations, and further satellite drilling and development may be expected to add an additional 100 to 150 MMB of economically recoverable oil by 2015. Additional prospects in the Brookian Clinoform and the Upper Jurassic Topset East will be targeted and at least one success in range of 150 MMBO is anticipated.

The more recent arrivals to the North Slope are also leasing and drilling features in close proximity to the infrastructure. Kerr-McGee completed two offshore exploration wells in the State waters of the Beaufort Sea. These wells reflect a continuation of recent drilling focus within the Colville-Canning area. The existing discoveries attributed to Kerr-McGee, Pioneer, and Armstrong at Oooguruk, Nikaitchuq, Tuvaaq, and in the Gwydyr Bay area are expected to be developed in the next two to four years and will add more than 200 MMB of economically recoverable oil.

Exploration by these companies over the next five years will probably result in two small discoveries with a total of 50 to 75 MMB of economically recoverable oil. These discoveries are anticipated to be within 20 miles of existing infrastructure and to occur in Alpine, Kuparuk, and Schrader Bluff reservoirs as either single or multiple horizon fields. Development and production of their existing resource base is probably a precondition for any effort to venture into more frontier or higher risk areas. It is anticipated that this will occur in the latter half of the coming decade or after 2010.

Other leased acreage in the area south of the Barrow arch trend is prospective. The smaller companies and other "new to the North Slope" operators will drill attractive prospects in these areas during the 2005 to 2015 timeframe. Targets include horizons ranging from the Mississippian Endicott Group to the Lower Tertiary Canning and Sagavanirktok formations. Two economic discoveries, each in the 100 to 150 MMBO range, are expected to be found within 10 to 25 miles of infrastructure.

In summation, cumulative additions to production from known but as yet undeveloped or under-developed fields are anticipated to total 450 MMBO. As yet undiscovered "reserves" that should be discovered and developed by 2015 are expected to total 650 MMBO; thus, providing a total addition of approximately 1.1 BB of economically recoverable oil.

There is no expectation for an exploration program directed exclusively for gas in the northern portion of the Colville-Canning province or the adjacent State waters in the Near-Term period.

Southern Colville-Canning Area/Brooks Range Foothills: The State and ASRC owned lands south of 69º 25' north latitude comprise the southern portion of the Canning-Colville area (the State Foothills areawide lease sale area). Based on the character and history of the source rock sequences, this area is viewed as gas-prone. With respect to the Shublik and Kingak, the area south of the 1.3% Ro contour is a zone of predominantly wet gas, and farther to the south a realm of dry gas. There are a number of outliers of Kingak and Shublik, south of this gas-generation line, which have anomalously low Ro values and suggest that there is at least local potential for oil generation and accumulation in this otherwise gas-dominated area.

In a typical transect from north to south, increasingly greater portions of the Lower Cretaceous interval are within the oil generation window and enhance the probability that oil may have been generated in these younger rocks and accumulated in reservoirs of the Lower Cretaceous and overlying portions of the section. In fact, oil stained sandstones are not uncommon in the Torok and Nanushuk exposures within the foothills belt. However, the limit of oil preservation for the Pebble Shale Unit, the 2.0% Ro contour of Magoon and Bird, (1987, Figure 8) trends east-southeast across the area from 69º north latitude to about 68º 20'. Thus gas is the predominant hydrocarbon phase south of the 1.3% Ro contour and should be the sole phase south of the 2.0% Ro contour.

In support of the USGS assessment (Bird and others, 2005), Anadarko Petroleum Corporation has estimated that there are technically recoverable resources of 0.5 to 2.5 BBO and 20 to 40 TCF (Nelson, 2002) in the Brooks Range foothills belt of the Colville-Canning area.

Bird and Houseknecht (2005) have identified fifteen plays with mean recoverable gas resources in the range of 0.5 to 6.5 TCF. Thirteen of the fifteen plays occur predominantly in the southern portion of the assessment area. The four most important gas plays occur in the southern portion of the Colville-Canning area. One play is estimated to have mean recoverable resources of more than 6.0 TCF (Brookian Clinoform) and three have more than 3.0 TCF (Thrust Belt Triangle Zone, Thrust Belt Lisburne, and Basement Involved Structural) (Figure 2.23). While some gas opportunities exist in the north they are probably not of sufficient size to motivate exploration by companies seeking to establish proven reserves prior to the completion of the gas pipeline, assumed to be in 2015.

The southern portion of the Beaufortian Clinoform play is present over nearly the entire portion of the assessment area south of 69.5º north latitude and includes reservoir horizons ranging from the Fortress Mountain/Torok package through the Canning Formation. The Thrust Belt Triangle Zone play occupies a gently concave northward arc largely south of 69º north latitude and north of 68.5º north latitude. The reservoirs are principally Brookian and include Kingak through the Nanushuk/Torok horizons. The Thrust Belt Lisburne play is situated south of the Triangle Zone play and includes potential reservoirs ranging from the Endicott equivalents through the Nanushuk/Torok package. The Basement Involved Structural play occupies the southeastern to eastern portion of the assessment area and trends northeastward parallel to ANWR boundary as far north as the truncation limits of the Ellesmerian sequence. The prospective reservoirs are all Ellesmerian and range from the Endicott to the Ivishak.

Bird and Houseknecht (2005) predict that 96% of the undiscovered nonassociated gas resources occur in accumulations smaller than 3.0 TCF. The estimated accumulation size is believed to be conservative and the authors anticipate a greater total resource and generally somewhat larger accumulations. Gas exploration is predicted to commence about 2009 and to be focused in the foothills area.

Two major discoveries are expected prior to 2012 with economically recoverable gas estimated to be 2.5 TCF (Lisburne or Torok/Nanushuk) and 5.0 TCF (Torok/Nanushuk). These accumulations are expected to be between 30 and 60 miles west of the pipeline corridor. The most appropriate reservoir analogs would be the Lisburne field at Prudhoe Bay and the Gubik or Umiat fields. Two to three smaller (0.5 to 1.5 TCF) fields totaling 2.5 TCF may be found by 2015, probably from the same or similar reservoirs.

The forecast is for economically recoverable gas totaling 10.0 TCF to be discovered but not produced by 2015. Gas production could commence within one year of the projected start-up of the gas pipeline or in 2016.

2.4.1.1.2 Beaufort and Chukchi OCS Areas

The Federal OCS areas of the Beaufort and Chukchi seas are administered by the MMS and hence have similar administrative, leasing, and environmental policies and regulatory structure. However, they have, at least locally, rather dissimilar stratigraphy and hydrocarbon prospects. The most recent update of the evaluations of these areas was performed in 2000 (MMS, 2000) but the key documents are Scherr and Johnson (1998) and Sherwood and others (1998).

Estimates of resource volumes, for variously ranked pools (Scherr and Johnson, 1998 and Sherwood and others, 1998) in both the Beaufort and Chukchi seas, were presented as a combination of oil and gas charge within each pool. There are three possible distributions of these resources. The traps are either: 1) filled with oil, 2) filled with gas, or 3) contain one of a nearly infinite number of possible gas-to-oil ratios. The MMS is now abandoning this approach and in the future will represent these data with some form of billions of barrels of oil equivalent

(BBOE) presentation. For the purposes of this report, plays will be represented by pool (field) sizes expressed as either 100% oil or 100% gas.

Beaufort Sea OCS area: Exploration of the Beaufort OCS will most probably continue to be centered in those areas offshore from currently developed infrastructure and target conventional (structurally defined) oil plays and/or the areas near existing but as yet undeveloped discoveries (Hammerhead and Kuvlum).

The Beaufort Sea OCS Sale 195, held in March 2005 provided the first indications of the directions in which activity may be initially focused during the 2005 to 2015 timeframe. Sale 195 offered approximately 9.4 million acres in 1,800 blocks. The sale resulted in 121 tracts totaling 250,400 acres being awarded to the high bidders.

This new leasing suggests that operators retain a substantial interest in both the area and the variety of plays known to have oil potential. Twenty-three plays were identified by the MMS (Scherr and Johnson, 1998), with aggregated mean undiscovered recoverable resources of 8.84 BBO and 43.50 TCF (Table 2.12). The revisions that occurred subsequent to this assessment placed a portion of the western Beaufort Sea assessment area in the Chukchi shelf assessment province and resulted in the revised estimates of the National Assessment Update (MMS, 2000) (Table 2.12), with mean risked undiscovered technically recoverable resources of 6.9 BBO and 32.1 TCF.

Table 2.12. Estimates of hydrocarbon volumes: Beaufort Sea and Chukchi Sea OCS areas.

Year of Estimate	Source of Estimate	Assessment Area	Estimate Format	Oil (BBO)			Gas (TCF)		
				95%	Mean	5%	95%	Mean	5%
1987	Mast et al. (1989, tbl. A2)	Beaufort Sea	Risked, Conventionally Recoverable	0.49	1.27	3.74	2.14	8.26	12.81
1987	Mast et al. (1989, tbl. A4)	Beaufort Sea	Risked, Economically Recoverable at $18/bbl	0	0.21	1.74	0	0	0
1987	Cooke (1991, tbl. 4)	Beaufort Sea	Risked, Economically Recoverable at $30/bbl	0	0.38	1.84	0	2.38	11.48
1990	Cooke (1991)	Beaufort Sea	Risked, Conventionally Recoverable	Conventionally Recoverable Resources Not Re-Calculated in 1990 Update-See 1987 Estimates					
1990	Cooke (1991, tbl. 1)	Beaufort Sea	Risked, Economically Recoverable at $18/bbl	0	0.38	2.63	0	0	0

Year of Estimate	Source of Estimate	Assessment Area	Estimate Format	Oil (BBO)			Gas (TCF)		
				95%	Mean	5%	95%	Mean	5%
1990	Cooke (1991, tbl. 3)	Beaufort Sea	Risked, Economically Recoverable at $30/bbl	0	0.67	3.33	0	2.45	10.17
1995	Scherr and Johnson (1998, tbl. 14.1)	Beaufort Sea	Risked, Conventionally Recoverable	6.278	8.835	11.965	20.101	43.502	79.148
1995	Craig (1998, tbl. 27.11)	Beaufort Sea	Risked, Economically Recoverable at $18/bbl	0.72	2.27	4.44	0	0	0
1995	Craig (1998, tbl. 27.12)	Beaufort Sea	Risked, Economically Recoverable at $30/bbl	Not Reported	3.223	Not Reported	Not Reported	0	Not Reported
2000	MMS (2000, tbl. 1)	Beaufort Sea	Risked, Conventionally Recoverable	3.56	6.94	11.84	12.86	32.07	63.27
2000	MMS (2000, tbl. 2)	Beaufort Sea	Risked, Economically Recoverable at $18/bbl	0	1.78	6.64	0	2.93	9.68
2000	MMS (2000, tbl. 3)	Beaufort Sea	Risked, Economically Recoverable at $30/bbl	1	3.24	7.76	0.64	4.2	10.67
1987	Mast et al. (1989, tbl. A2)	Chukchi Sea	Risked, Conventionally Recoverable	0	2.22	7.19	0	6.33	16.87
1987	Mast et al. (1989, tbl. A4)	Chukchi Sea	Risked, Economically Recoverable at $18/bbl	0	0.59	3.59	0	0	0
1987	Cooke (1991, tbl. 4)	Chukchi Sea	Risked, Economically Recoverable at $30/bbl	0	1.03	5.79	0	2.52	13.92
1990	Cooke (1991)	Chukchi Sea	Risked, Conventionally Recoverable	Conventionally Recoverable Resources Not Re-Calculated in 1990 Update-See 1987 Estimates					
1990	Cooke (1991, tbl. 1)	Chukchi Sea	Risked, Economically Recoverable at $18/bbl	0	1.36	8.76	0	0	0

Year of Estimate	Source of Estimate	Assessment Area	Estimate Format	Oil (BBO)			Gas (TCF)		
				95%	Mean	5%	95%	Mean	5%
1990	Cooke (1991, tbl. 3)	Chukchi Sea	Risked, Economically Recoverable at $30/bbl	0	1.69	10.65	0	4.46	27.55
1995	Sherwood et al. (1998, tbl. 13.14)	Chukchi Sea	Risked, Conventionally Recoverable	6.801	13.015	21.943	9.808	51.84	141.754
1995	Craig (1998, tbl. 27.11)	Chukchi Sea	Risked, Economically Recoverable at $18/bbl	0	1.14	4.48	0	0	0
1995	Craig (1998, tbl. 27.12)	Chukchi Sea	Risked, Economically Recoverable at $30/bbl	Not Reported	2.845	Not Reported	Not Reported	0	Not Reported
2000	MMS (2000, tbl. 1)	Chukchi Sea	Risked, Conventionally Recoverable	8.6	15.46	25.03	13.56	60.11	154.31
2000	MMS (2000, tbl. 2)	Chukchi Sea	Risked, Economically Recoverable at $18/bbl	0	0.97	7.2	0	0	0
2000	MMS (2000, tbl. 3)	Chukchi Sea	Risked, Economically Recoverable at $30/bbl	1.42	6.11	10.96	0	0	0

The plays in the Beaufort Sea are associated with the same general stratigraphy that is present onshore, but the pre-LCU units of the Ellesmerian and Beaufortian are restricted to the southern and generally central portions of the shelf. Thus the reservoirs and source rocks, most responsible for the reserves and production in the Prudhoe Bay – Kuparuk area, are limited in distribution to the south-central portion of the shelf. The younger (post-LCU) reservoirs and source rocks generally have shelf-wide distribution. These latter units include the upper Kuparuk River Formation or Kuparuk C sandstone which postdates LCU and is the reservoir in the Point McIntyre, Niakuk, West Beach, and Midnight Sun fields (Figure 2.20).

The revised Beaufort shelf assessment province has approximately fifteen plays ranging from Pre-Mississippian "basement" objectives to Tertiary targets. Four of these plays have estimated mean recoverable oil of approximately one billion barrels or more (Scherr and Johnson, 1998). These are the Beaufortian Rift play – 0.91 BBO (Kuparuk River Formation and Jurassic Kingak Shale sandstones – fields include the Kuparuk and Alpine), the Brookian Faulted Eastern Topset play – 1.05 BBO (Sagavanirktok – shows in the Galahad well), the Brookian Unstructured Eastern Topset play – 1.65 BBO (Sagavanirktok – fields include the West Sak and

Ugnu onshore and Hammerhead and Kuvlum offshore), and the Brookian Foldbelt play – 2.04 BBO (Sagavanirktok and Canning Formations – tested by the Corona, Belcher, and Aurora wells, located north of the 1002 Area).

The Beaufortian Rift, Brookian Faulted Eastern Topset, and Brookian Unstructured Eastern Topset plays are the most easily accessible and attractive of the Beaufort Sea OCS plays. The Beaufortian Rift play formations have proved to be highly productive at Kuparuk, Milne Point, Point McIntyre and other smaller fields and are among the active exploration targets in eastern NPRA and the State onshore and offshore lands. These plays are located offshore from the Colville-Canning area and have the potential for "relatively" easy access to the onshore infrastructure. The Brookian Unstructured Eastern Topset play overlies the Rift play and also contains large volumes of oil in the West Sak and Ugnu fields onshore. The Faulted Eastern Topset play prospects are also relatively proximal to existing infrastructure. The Brookian Faulted Eastern Topset play exists seaward of the unstructured topset play in deeper waters. While the target intervals are the same as in the unstructured topset play only one well, the Galahad located northwest of Kuvlum (Figure 2.20), has tested this play concept.

The fourth play, the Brookian Foldbelt play, is located offshore from ANWR and would be extremely difficult to explore and develop without access to onshore facilities within ANWR and thus is probably not a likely target in the near term.

Of the other eleven plays, only the Upper Ellesmerian or Sadlerochit play has an estimated mean of more than 0.5 BBO; however, in the 5% case it is estimated to have greater potential than the Rift or Faulted Brookian plays (Scherr and Johnson, 1998). Since it underlies both the Beaufortian Rift play and the Eastern Brookian Unstructured plays, it is likely that this play would be tested in any well drilled to evaluate those shallower objectives.

Prospects on the outer shelf portions of Beaufort OCS will not be primary targets until shallow water, near shore prospects have been proven to be economically developable or in the rare instance where the possibility of a very large discovery is compelling enough to support the risk. The Beaufort OCS offshore from the western portions of NPRA and ANWR will not be exploration targets during the next decade unless significant onshore discoveries have been made in adjacent portions of NPRA, or ANWR has been opened to exploration and development.

For the near term, exploration in the Beaufort OCS will most likely be confined to the relatively shallow portions of the Beaufort shelf and restricted largely to that portion of the shelf between Harrison Bay and the mouth of the Canning River (see Figure 2.20). Exploration wells will be drilled with multiple objectives and test Brookian through upper Ellesmerian target horizons. The 1995 assessment, as presented by Scherr and Johnson (1995 and 1998), provides estimates for the three plays (Upper Ellesmerian, Beaufortian Rift, and Brookian Unstructured Topset) ranging from 1.61 to 7.27 BBO with a mean of 3.32 BBO. The assessment of these three plays (Scherr and Johnson, 1995 and 1998) includes a range of 2.1 to 14.8 TCF with a mean of 5.2 TCF. While adding gas reserves will not be an objective during the next decade, it is highly probable that the discovery of oil will carry with it some quantity of gas.

OCS lease sale 195 largely confirmed the continuation of the recent leasing and drilling patterns. The sale drew single bids on 121 tracts for a total of 618,751 acres (Minerals Management Service, 2005). The great bulk of the leases (85%) are located between Harrison Bay and Barter Island. Most of the leased tracts are just seaward of the 3-mile limit and lay between the Colville Delta and Prudhoe Bay. Nine tracts were leased north of Smith Bay, about 40 miles east of Barrow and nine east of the Kaktovik Deferral area, approximately 20 miles west of the Canada border. Leases containing the Hammerhead and Kuvlum oil accumulations were acquired by Shell in that sale. Approximately half of the leases are contiguous with existing leased tracts and in part expand the holdings of the lessees.

The MMS is quoted as interpreting the sale results to indicate that the plays targeted in the sale were Brookian plays and chiefly the Brookian Unstructured Eastern topset and Brookian Foldbelt plays (PN, 2005c), which are two of the four most attractive plays in the area.

If the next decade replicates the drilling activity (three exploration wells) of the previous 10 years, drilling in the Beaufort OCS will be minimal and two to four wells may be expected. At this juncture the only indication that activity will increase is renewed interest in the area on the part of Shell and reports that Shell is purchasing rigs to drill in the Beaufort OCS (PN, 2006a). The major operators have not shown much interest in the OCS recently and are concentrating on satellite development and their limited exploration activity is focused on eastern NPRA. The smaller newly active companies, operating in the Colville Delta to Prudhoe Bay area, are exploring for small to moderate size accumulations in close proximity to infrastructure and have rarely ventured into the OCS. The sole exception is Armstrong, which acquired seven leases in OCS Sale No. 186 adjacent to their existing State leases and acquired 20 adjacent leases in OCS Sale No. 195. Higher levels of activity are possible if more companies become involved in exploration on the North Slope and adjacent waters. The presence of more competitors tends to lead to greater diversity in play concepts and risk taking.

The anticipated near term exploration results are the discovery of one small to moderate size accumulation (100 to 500 MMBO) with one or two productive intervals, presumably the Kuparuk River Formation and the Sadlerochit or Endicott. To be a commercial success, depending on location, the field would probably need to have 300 to 500 MMBO of economically recoverable oil. Five hundred billion to a trillion cubic feet of gas could be expected to be associated with such a discovery. Additionally, two to four small satellite-like fields from the same group of reservoir horizons are to be expected with potential economically recoverable resources of 50 to 100 MMBO each. These discoveries are expected to occur within five to twenty miles of the shoreline.

The results of these efforts are expected to be 650 MMBO (a total of four discoveries) and approximately 1.0 TCF of economically recoverable resources.

With Shell’s acquisition of leases that include the Hammerhead (renamed Kaktovik) and Kuvlum discoveries, it is probable that by as early as 2007 these fields and Wild Weasel may be targeted for additional drilling and possible development. If additional reserves are found and developed these fields could account for at least 500 to 600 MMBO. It is doubtful that production would commence prior to 2015.

Chukchi Sea OCS area: The MMS has recognized twenty-two plays in the Chukchi Shelf Assessment Province (Sherwood and others, 1998) with aggregated unrisked undiscovered technically recoverable means of 13 BBO and 51.8 TCF (Table 2.12). Revisions completed in 2000 (MMS, 2000) increased these estimates to 15.5 BBO and 60.1 TCF. These revised estimates largely reflect the redefined boundaries of the Chukchi and Beaufort shelf assessment provinces. The redefinition of these provinces transferred the area west of Point Barrow from the Beaufort shelf to the Chukchi shelf assessment province.

Seismic data and the limited exploration drilling in the Chukchi Sea have documented the presence of virtually all the reservoir intervals found in the Prudhoe Bay area, plus potential reservoirs of the pre-Mississippian Franklinian sequence. The presence of the major source rock intervals of the Shublik Formation, Kingak Shale, and Pebble Shale have been documented by drilling.

The next Chukchi Sea lease sale (OCS Sale No. 203) is scheduled for 2007. A sale was previously scheduled for 2003, but cancelled due to lack of interest. The MMS is continuing to prepare for the 2007 sale and is canvassing the industry to gauge the current level of interest. Recently, the MMS released a re-evaluation of the Burger gas discovery (Craig and Sherwood, 2005) and the unrisked mean resources in the most likely case are 14.04 TCF and 724 MMB NGLs. The risked mean values are 9.48 TCF and 489 MMB NGLs.

The magnitude of these estimates provides encouragement for the future of exploration in the Chukchi Sea, but until exploration and development within NPRA reach the western portions of NPRA and the gas pipeline is built there is no market or economic incentive to explore for and develop the resources of the Chukchi Sea. Consequently, it is expected that no significant exploration and development will occur in the Chukchi Sea area until after 2015. The plays and their character will be presented in the long term potential portion of the discussion.

2.4.1.2 Other Federal lands

NPRA and the 1002 Area of ANWR are administered by different Federal agencies, have experienced very different levels of evaluation and exploration, and are potentially prime areas of future exploration activity and development. However, the near term prospects for the two areas are markedly different. As has been shown, the NPRA is experiencing a successful leasing and expanding exploration drilling phase, with an encouraging level of success in the area west of the Alpine field. ANWR is currently closed to exploration, but at the time of this report, the matter of opening the 1002 Area was once again being considered and may be included in the forthcoming budget proposal.

2.4.1.2.1 National Petroleum Reserve Alaska (NPRA)

The NPRA is currently the second most active of the exploration domains in Arctic Alaska. The recent exploration and leasing activity in this area is reflected by the current lease holdings and last five years of exploration drilling shown on Figure 2.21. This figure also shows the proposed activity for 2005. Prior to the beginning of the 2005 drilling season six wells were permitted, but only three were reported as drilled and completed. The three wells are the Kokoda No. 1, Kokoda No. 5, and Iapetus No. 2. The Kokoda wells targeted Brookian turbidites. No wells were permitted in 2006, but at least one well, which was permitted in 2005, is being drilled as this report does to press.

The BLM administers the NPRA, and the hydrocarbon resource assessments have been performed under the auspices of the USGS. The USGS 2002 assessment of the NPRA identified 24 plays. Bird and Houseknecht (2002) constructed a figure relating the stratigraphic section and the plays. It is reproduced here as Figure 2.24.

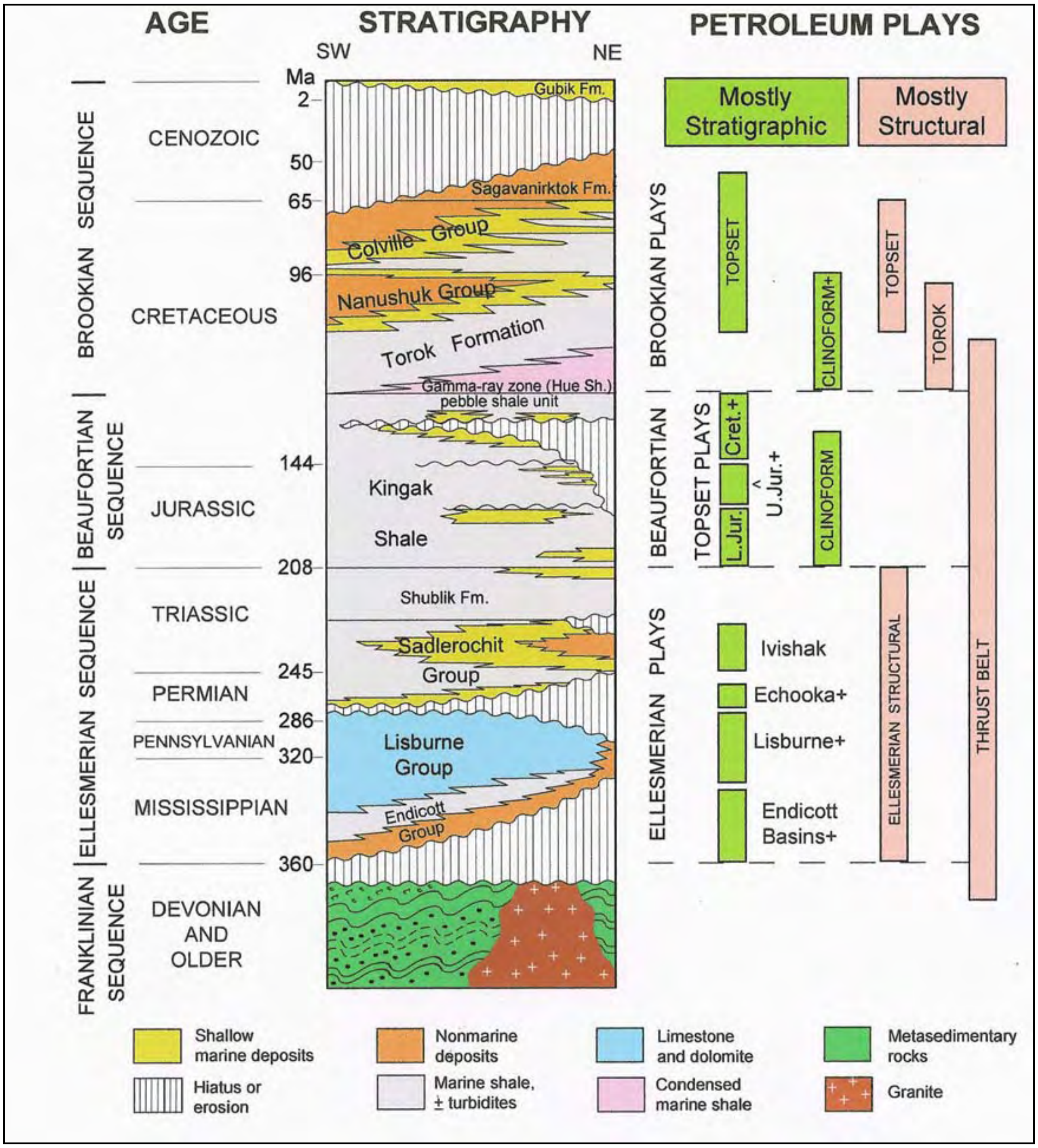

Figure 2.24. Summary of ages, names, and rock types present in NPRA. Colored bars at right show the stratigraphic position of the 24 petroleum plays evaluated in the 2002 assessment. Note that the bars with a "+" symbol indicate multiple plays in different areas. Plays indicated by bold outlines include those with the greatest oil and (or) gas potential. (Source: Bird and Houseknecht, 2002)

The reservoir horizons are similar to those of the Colville-Canning area, but the main reservoirs in the Prudhoe Bay and Kuparuk field area tend to be less well developed and are generally poorer quality. As in the Prudhoe Bay area, the Shublik, Kingak, and HRZ are the primary source rocks in NPRA (Houseknecht, 2003a and 2003b). The distribution of the Shublik and Kingak is less strongly controlled by the LCU and they are recognized to be present across the entirety of NPRA with the exception of the extreme northern portion, at Point Barrow (Bird, 1994, Figure 21.8). Flanking the small truncation area at Point Barrow is a narrow band of thermally immature Shublik/Kingak. For the Shublik and Kingak source intervals, the southern limit of oil generation trends southeast from 70º 15' north latitude along the Chukchi coast to about 69º 20' north latitude, north of Umiat. South and southwest of this limit, the area is predominantly a gas province.

The HRZ, the associated Torok Formation and the Pebble Shale unit blanket the entire NPRA with source rocks of varying quality. Generally the HRZ is an excellent oil-prone source while the Torok and Pebble Shale are of somewhat lesser quality and locally are more prone to generate gas. The entire sedimentary package becomes more deeply buried and thermally mature to the south. Consequently, greater portions of the section have passed through the oil-generation window and into the gas-generation realm. The southern limits of oil generation is at approximately 69º north latitude and the interval is thermally immature for oil-generation north of a line trending southeast, subparallel to the Beaufort Sea coast, from 71º north latitude in the Point Barrow vicinity to 70º north latitude at the Colville River.

Most of the stratigraphic section, from the Lower Mississippian to the Lower Tertiary, is represented by one or more play types. Twenty of the twenty-four plays are stratigraphic. The seven Ellesmerian stratigraphic plays (Figure 2.24) include the Mississippian Endicott and Lisburne Groups, the Permian Echooka Formation and the Triassic Ivishak Formation. The Echooka Formation has not been an exploration target in the Colville-Canning area. There are eight Beaufortian stratigraphic plays (Figure 2.24) consisting of a cliniform or turbidite play, Jurassic Kingak topset plays, and Cretaceous Kuparuk topset plays. The five Brookian stratigraphic plays (Figure 2.24) are primarily clinoform or turbidite plays in the Cretaceous Torok and topset plays in the Cretaceous Nanushuk through Tertiary Sagavanirktok interval. Several of the stratigraphic plays exist as “multiples” in different geographic areas (Bird and Houseknecht, 2002).

The structural plays (Figure 2.24) include a thrust belt play that incorporates Mississippian through Early Cretaceous units, an Ellesmerian structural play that involves Mississippian through Triassic strata, an Early Cretaceous Torok play, and an Early to Late Cretaceous topset play.

The USGS has periodically performed assessments of the oil and gas potential of NPRA for over a quarter of a century. The estimated mean technically recoverable volumes have increased with each assessment (Table 2.13) as more and better data, backed by discoveries in the Colville-Canning area, have revealed the generative potential of the source rocks and the presence and character of prospects in an ever increasing variety of stratigraphic intervals and trapping situations.

Table 2.13. Comparison of USGS assessments, from 1976 to 2002, of the hydrocarbon resources of the NPRA (ENTIRE AREA includes Federal and Native land and the State offshore areas).

Agency/Year	Estimated Technically Recoverable Hydrocarbon Resources					
	Oil (BBO)			Gas (TCF)		
	95 %	Mean	5%	95 %	Mean	5%
U.S. Geol. Survey/1976	1.0	1.9	3.0	3.2	6.3	10.6
U.S. Geol. Survey/ 1980	0.3	2.1	5.4	1.8	8.5	20.4
Bird and Houseknecht, 2002 (NPRA ONLY)	5.9	9.3	13.2	39.1	59.7	83.2
Bird and Houseknecht, 2002 (ENTIRE AREA)	6.7	10.6	15.0	40.4	61.4	85.3

The most recent assessment resulted in an aggregated mean for technically recoverable oil of 10.565 BBO with a range of 6.7 to 15.0 BBO and for gas 61.35 TCF with a range of 40.4 to 85.3 TCF. Bird and Houseknecht (2002, Table 1) provide estimates of technically recoverable oil and nonassociated gas for each of the 24 NPRA plays evaluated in the 2002 assessment.

Of the twenty-four plays, only four are deemed to have mean technically recoverable oil resources of approximately 1.0 BBO or greater. These are the Beaufortian Upper Jurassic topset plays (Alpine-like) in the northwest (1.86 BBO) and northeast (5.18 BBO) planning areas and the Brookian Lower Cretaceous clinoform/turbidite (Tarn-like) plays of the north (1.31 BBO) and central (0.98 BBO) portions of the NPRA (Figure 2.24). The Upper Jurassic northwest and northeast topset plays occur in a 60-mile wide belt that trends southeast across NPRA subparallel to the Beaufort Sea coastline and south of Smith Bay. The Brookian clinoform plays trend nearly east-west across NPRA and are present over the northern half on NPRA.

The Upper Jurassic topset plays of the northeastern area are estimated to have mean technically recoverable reserves of 5.2 BBO or approximately half of the recoverable oil assigned to NPRA in the 2002 assessment (Table 2.13). The same play type in the northwestern area is given a mean of 1.9 BBO. These two Alpine-Nuiqsut-Nechelik play trends account for a total of 66.7% of the estimated aggregated mean technically recoverable oil for the assessment area. The means for the Brookian clinoform/turbidite plays total 2.28 BBO with 1.3 BBO for the north set of plays and 0.98 BBO for the central trend for an additional 21.6% of total estimated technically recoverable oil.

In summation these four plays are considered to represent more than 88% of the technically recoverable oil in NPRA. If these numbers represent a reasonably sound proportional distribution of expected volumes, the primary reservoir formations of the Prudhoe Bay-Kuparuk area are not stand-alone objectives and have little potential to contribute to the resource-base in NPRA. Similarly, the structural plays would seem to have little oil potential with an aggregated mean of only 0.18 BB0. Eight of the plays are considered to have no technically recoverable oil in the mean case (Bird and Houseknecht, 2002, Table 1).

Six plays have mean technically recoverable gas resources of 3.0 TCF or greater (Bird and Houseknecht, 2002). Four are stratigraphic plays, the Beaufortian Upper Jurassic topset in both the southwest and southeast and Brookian clinoform/turbidite plays in the central region and the deep portions of the southern area. These plays are generally located just south of the oil-bearing belt of plays. The mean technically recoverable estimates for the Upper Jurassic topset southwest and southeast plays are 5.22 and 5.14 TCF, respectively. The Brookian clinoform south-deep has an estimated mean of 3.79 TCF and the clinoform central play has an estimated mean of 5.41 TCF. The total mean resources for these plays are 19.56 TCF or approximately 32% of the aggregated mean recoverable gas.

Structural plays represent a major portion of the gas potential in NPRA. The Torok and Brookian topset structural plays have mean recoverable gas volumes of 17.91 and 10.61 TCF, respectively. Summed, these two structural plays have 28.52 TCF or 46.5% of the aggregated mean gas resources for NPRA. The six plays listed here represent more than 60% of the estimated mean gas potential of the NPRA.

The estimates for associated gas presented in the USGS 2002 assessment (Bird and Houseknecht, 2002) may require an upward revision for at least one and possibly two plays. Drill stem tests in the northeast area have yielded daily flow rates of 6.6 to 26.5 MMCF from recent wells evaluating Beaufortian Upper Jurassic topset northeast plays (PN, 2004e). These same wells tested high gravity oil at rates of 320 to 4,000 BOPD. The 2002 assessment did not identify any gas resource potential in either the Upper Jurassic northeast or northwest topset plays.

Based on these estimates and knowledge of the geology of the area, it is most probable that exploration efforts over the next decade will continue to be focused on the Upper Jurassic sandstones (Alpine, Nuiqsut, and Nechelik) of the Kingak Formation and Brookian clinoform/turbidite plays (Tarn and Tabasco). The Kokoda No. 1 and Kokoda No. 5 wells (Figure 2.21) were drilled during the 2005 drilling season to evaluate Brookian turbidite plays.

Currently, only one group is actively exploring within the NPRA, but their efforts have been at least moderately successful. Thus, it can be expected that exploration drilling will continue to pursue Beaufortian topset and Brookian turbidite plays to the west and southwest, in an ever-widening search. If the exploration drilling activity remains at current levels, it would be reasonable to have 25 to 30 additional exploration wells drilled by the end of 2015. Given that activity level, the discovery of two moderately sized oil fields may be expected, with economically recoverable oil in the 250 to 500 MMB range. An additional four to six 50 to 100 MMBO small or satellite fields should be anticipated. These discoveries can be expected to be made within 25 to 75 miles of the existing infrastructure at Alpine. These fields could provide a total of 0.7 to 1.5 billion barrels of additional recoverable oil added to the reserve base by the year 2015. An “average” would be approximately 1.1 BBO. Production should begin within three to five years of discovery and successful delineation.

Significant volumes of associated gas would be a by-product of oil exploration during this time frame but obviously no commercial production would occur. The quantity of gas that might be discovered while pursuing the currently favored oil plays is uncertain. The MMS assigns very little probability of gas to the Beaufortian plays in the northeast and northwest planning areas (Bird and Houseknecht, 2002), but gas flow-rates from recent wells have been as high as 25.0 MMCF/D. Therefore, it is reasonable to expect continued exploration of these trends to involve the discovery of some large volumes of gas. Resource additions of 1.0 trillion cubic feet or more of associated gas are possible. Current thinking assigns the bulk of the NPRA nonassociated gas resources to the southern portions of NPRA, and these areas are unlikely sites for exploration until a gas pipeline is approved and the builders are committed to or proceeding with the construction of the line.

2.4.1.2.2 1002 Area of Arctic National Wildlife Refuge (ANWR)

The 1002 Area of ANWR has long been considered to be one of the most prospective portions of Arctic Alaska. However, due to its current status as a portion of ANWR it is not open to exploration and development. The only oil and gas directed activities have been the two seismic acquisitions seasons in 1984 and 1985 and the single well drilled on ASRC inholdings in 1986.

The FWS administers the Refuge but the hydrocarbon resource assessment has been performed by the USGS. Table 2.14 displays the historical evolution of resource assessments for the 1002 Area. The key point to recognize is that as more information has become available the understanding of the resource potential of the area has evolved and the assessment of the volume of technically recoverable oil has increased from a mean of 2.53 BBO in 1986 (Hanson and Kornbrath, 1986) to a mean of 7.67 BBO in 1998 (Bird and Houseknecht, 1998). The entire assessment area, which includes State and native corporation land, has a mean technical ultimate recovery (TUR) of 10.3 BBO (Table 2.14), and the mean OOIP is 27.778 BBO. The mean nonassociated OGIP volume is estimated to be 5.12 TCF and the mean technically recoverable volume is 3.841 TCF. The mean OGIP for associated gas is estimated to be 13.4 TCF and mean technically recoverable associated gas is 4.75 TCF. The sum of OGIP is 18.5 TCF and mean recoverable gas is 8.59 TCF.

Table 2.14. Historical estimates of hydrocarbon resources in the 1002 Area of ANWR. (ENTIRE AREA includes Federal and Native lands and State offshore areas)

Source	Oil-in-Place (BBO)			TUR (BBO)
	95 %	Mean	5%	Mean
Mast, and others, 1980	0.2	4.9	17.0	????
Hanson and Kornbrath, 1986	0.08	7.3	26.5	2.53
Dolton, and others, 1987	4.8	13.8	29.4	3.23
Bureau of Land Mgmt. 1991	????	????	????	3.57
Gunn, 1992	????	23.3	49.5	6.97
Bird and Houseknecht, 1998 (1002 AREA of ANWR)	11.6	20.7	31.5	7.67
Bird and Houseknecht. 1998 (ENTIRE AREA)	15.6	27.8	42.3	10.3

Figure 2.25 was constructed (Bird and Houseknecht, 1998) to relate the ten identified plays of the USGS's 1998 assessment to the stratigraphic section. While the subheading atop the lithologic column suggests the section represents a southwest to northeast transect through the 1002 Area, it actually is more representative of a section from the eastern plunge of the Sadlerochit Mountains northeast to the vicinity of the Niguanak high.

The variety of reservoir and source rocks of the 1002 Area are both similar and dissimilar to what in found to the west in the Colville-Canning province. Erosion associated with LCU has removed the entire Ellesmerian sequence and most of the lower Beaufortian sequence from the western portion of the 1002 Area, and the upper-most Ellesmerian and the entire Beaufortian are absent due to erosion in much of the eastern part of the area. As a consequence the Kingak Shale plays a minor role as a source rock, but the Hue Shale, Mikkelsen Tongue of the Canning Formation, and probably the Shublik are viable source rocks for the area (Figure 2.25).

The reservoir rocks of the Ellesmerian and lower Beaufortian sequences are absent in the west. In the eastern portion of the 1002 Area the lower Beaufortian reservoirs are missing. Latest Beaufortian and Brookian reservoirs are present across the 1002 Area and the Ellesmerian reservoirs occur only in the extreme south and southeast portions of the 1002 Area (Figure 2.25). Potential Franklinian sequence reservoirs are expected to exist throughout the area but are of unknown quality and presumed to be primarily carbonates of the Katakturuk Dolomite and Nanook Limestone (Figure 2.25).

There is still a great deal of uncertainty regarding the ultimate political outcome and when or if exploration and development may occur within the 1002 Area. Consequently, there are a number of scenarios that may be put forth regarding the future of oil and gas exploration and production. For the purposes of this report only two will be considered.

Scenario I, the efforts to open the ANWR 1002 area to exploration and development will fail and the 1002 Area of ANWR will become permanently closed to industry. As a consequence of this scenario there would be no further need to address the area in this or the following long term section.

Scenario II is based on the assumption that the 1002 Area will be opened to exploration within the next 5 to 10 years. There many possible options for this scenario but the timeline proposed here for illustration is based on a 2010 approval. A later approval, up to a certain point in the future, simply moves the dates to accommodate the length of the delay in opening.

The Energy Information Administration (EIA) (2002 and 2004) utilized the 1998 USGS assessment (Bird and Houseknecht, 1998) to establish a time line from approval date to exploration and development of 7 to 12 years. If it is assumed that approval is granted in 2010 that would mean development and accompanying production would most likely occur between 2017 and 2022. For this illustration, it is assumed that a minimum of 10 years are required to complete development. This scenario is envisioned to occur as follows:

- 2010–exploration and development in the 1002 Area approved
- Winter 2011/2012–acquisition of a high quality 2D program to compliment, enhance the utility of, and perhaps infill existing seismic control and delineate structural plays
- Winter 2012/2013–acquisition of 3D seismic programs to better delineate structures and to identify and delineate potential stratigraphic plays
- 2014–first lease sale in 1002 Area
- 2015 or 2016–first exploration drilling, along eastern side of Canning River and/or along the northern flank of the Marsh Creek anticline

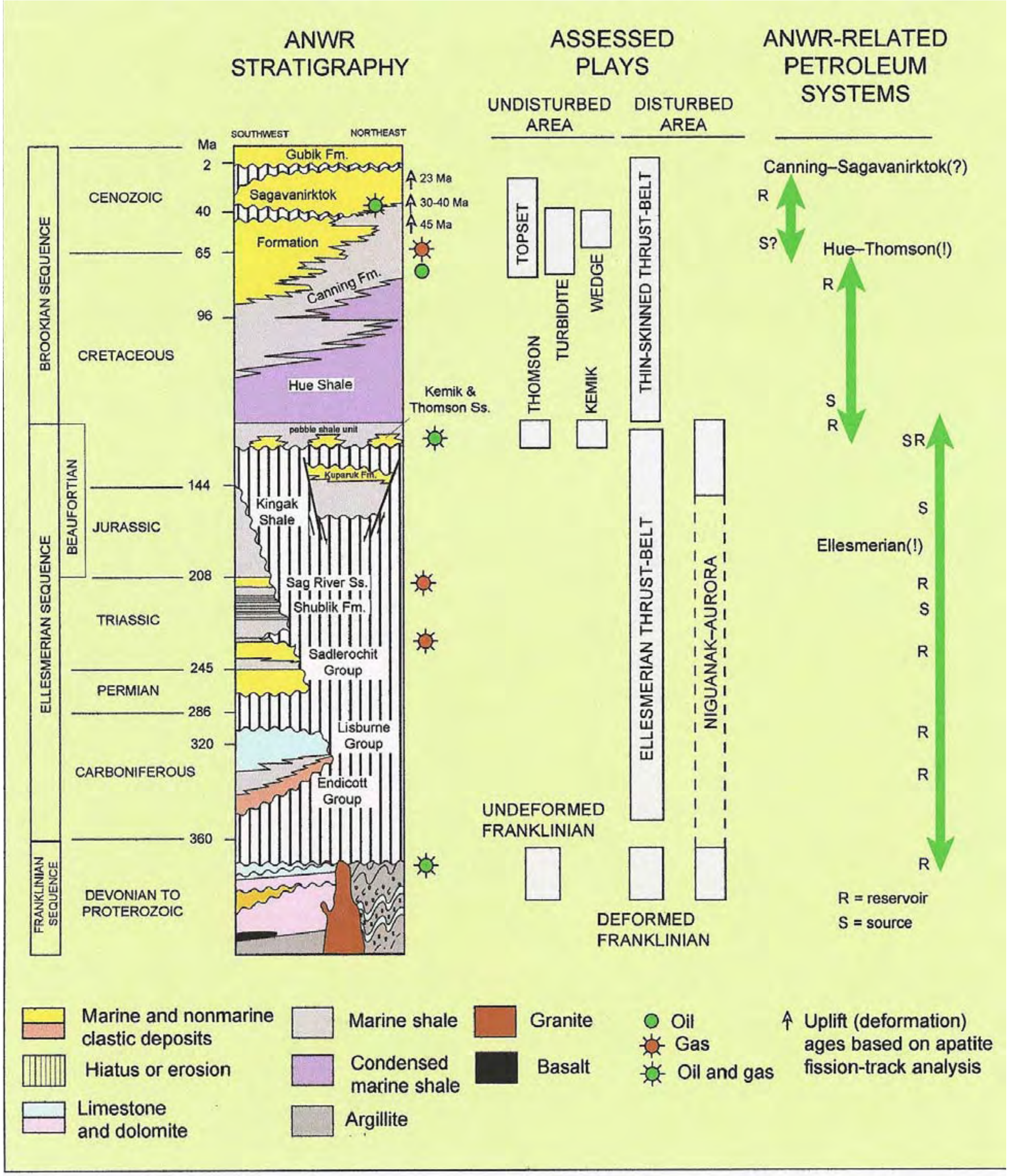

Figure 2.25. Summary of ages, names, and rock types present in the 1002 Area of ANWR. The occurrence of recoverable petroleum in these rock formations outside the 1002 Area is indicated by green and red circles. Gray bars at right indicate the 10 petroleum plays assessed in the 1002 study and their corresponding rock formations (to the left). Note the grouping of plays according to deformed and undeformed areas. (Source: Bird and Houseknecht, 1998)

- 2016 or 2017–first “economic” discovery
- 2017 or 2018–evaluation of first “economic” discovery
- 2019–field development commences
- 2022–first production from 1002 Area into TAPS

These sequential steps assume no inordinate delays due to litigation and that the time from discovery to the onset of production mimics Alpine, which required six years (1994 to 2000). Thus, the estimates of this report and that of the EIA of 7 to 12 years from approval to production are possibly on the conservative side. Since this time line places the first feasible production in the long term category the discussion of plays and possible 1002 Area exploration will be addressed more expansively in that section.

2.4.2 Long Term (2015 to 2050)–Dual Oil and Gas Activity

The character of this phase of activity is largely dependent on the development of a gas pipeline that is capable of receiving and transporting large quantities of natural gas. The proposed capacity ranges between 4.5 and 6.0 BCFD. With such a pipeline and the necessary supporting infrastructure in place or well into the construction phase, much of the effort will be directed to bringing known gas resources to production and exploring in frontier regions for additional gas resources. This is not meant to imply that oil exploration will cease, but that gas may assume an equal or primary role with respect to exploration drilling and expenditures in much of Arctic Alaska.

By 2015 the areas most proximal to the current (2006) developments and their infrastructure will be largely explored and the more obvious features evaluated and developed. Exploration over the longer term will continue to expand outward from these core areas to take maximum advantage of and add to the in-place facilities and transportation systems. Sequentially, exploration activities can be expected to continue in the Colville-Canning province and adjacent State waters and eastern NPRA, with a well-defined shift from north to south as gas exploration increases. Secondly, given that exploration is approved in the 1002 Area of ANWR, exploration will expand as rapidly as possible into the coastal plain of ANWR. Thirdly, exploration within NPRA will move westward and southward, concurrent with an increase in the breadth of exploration in Beaufort Sea. Fourthly, exploration activity will be resumed in the Chukchi Sea as a result of the westward expansion of the production and transportation infrastructure resulting from success within NPRA and the potential indicated by the Burger discovery.

2.4.2.1 State and MMS Administered Lands

These lands will continue to be explored for oil and now gas, because they are proximal to the existing oil and developing gas infrastructure. The active exploration halo will expand outward from the vicinity of the older fields and move southward into the gas prone regions of the southern coastal plain and the Brooks Range foothills. Offshore, the areas of interest are expected to continue the trends followed during the 2005 to 2015 episode, and to expand to both the east and west in the Beaufort Sea as well as farther offshore into the middle and outer portions of the shelf. In the Chukchi Sea the entire eastern two-thirds of the shelf is considered to be an active exploration province given a nearby infrastructure and attractive price situation.

2.4.2.1.1 Colville-Canning Province and State Waters of the Beaufort Sea

For the purposes of estimating the long term prospectivity and success, approximately 50 to 75% of the USGS estimates of 2005 assessment, less the proposed success for the 2005 to 2015 interval, are assumed to be found during the fifteen years from 2015 to 2030 and the remainder over the next twenty years. The greater degree of success is expected in the areas closest to existing infrastructure, with only about 50% of estimated resources found in the more remote and poorly explored portions of the area. Once again it should be remembered that the 2005 reevaluation of the 1002 Area of ANWR, using an oil price similar to that existing today, indicated that 90% of the technically recoverable oil would be economic (Attanasi, 2005). This general approach will also be utilized in the other areas of northern Alaska.

Northern Colville-Canning and State Beaufort Sea: Even 25 to 40 years into the future the plays of interest will be basically unchanged from those that have been the historical targets in this area. The most noteworthy exception would be the Brookian Foldbelt play to the east, offshore from the 1002 Area. This play is virtually undevelopable unless the adjacent portions of the 1002 Area have been opened to exploration and development.

Once again the primary oil exploration targets are Brookian Clinoform and Topset plays, plus the Triassic Barrow Arch play. The principal area for oil prospects in all of these plays is north of 70º north latitude. The eastern limit of the Triassic Barrow Arch play is at about 147º west longitude and the Brookian plays extend entirely across the area (Garrity, and others, 2005). Over the 35 years, from 2015 to 2050, exploration of the northern portion of the Colville-Canning area should test virtually all identifiable prospects with economic potential. The bulk of the discoveries are expected to occur prior to 2030.

The Brookian Clinoform prospects are anticipated to yield two fields of approximately 250 MMBO each and two others in the 100 to 150 MMBO range. These will be within 20 to 30 miles of existing infrastructure. At least three to five satellites are expected within the clinoform play with an average size of 50 MMBO. Both the Brookian Topset and Triassic Barrow Arch plays may be expected to yield a 150 MMBO field and two to three 50 MMBO satellites. In all three plays, the larger fields will probably be developed first with the satellites following later in the sequence of development. The economically recoverable volumes associated with these three plays are anticipated to total 1.5 BBO.

The Brookian Topset Structural North and Thomson plays are each expected to yield discoveries of commercial size. Each play should have a discovery of about 100 MMBO and a smaller field of 50 MMBO. The Beaufortian Kuparuk Topset, Beaufortian Upper Jurassic Topset West, Brookian Clinoform Structural North, and perhaps the Lisburne Barrow Arch plays will provide additional upside opportunities as secondary and tertiary objectives and each can be expected to provide one to three accumulations in the 25 to 50 MMBO range. These smaller plays are expected to generate about 550 MMBO.

This level of success will result in an addition of approximately 2.05 BBO. These fields are expected to begin production as early as 2020 and be fully developed by 2035. The continued efforts to improve recovery from the viscous oil accumulations of the Ugnu and West Sak (Schrader Bluff) may add equal if not greater volumes of oil reserves, but this aspect may more properly be addressed under the subject of reserve growth in a later section of the report.

Gas exploration and development in the northern portion of the Colville-Canning area will be limited. Most if not all gas discoveries will be associated gas and will be found as a by-product of oil oriented exploration activities. Bird and others (2005) estimated mean undiscovered recoverable associated gas to be 4.2 TCF and to be principally associated with the Brookian Clinoform, Brookian Topset, Kemik-Thomson, and Triassic Barrow Arch plays. These plays are estimated to have 3.1 TCF or nearly 75 recent of the associated gas. The gas will be found as the oil exploration proceeds and may be produced late in the history of the individual fields. The largest associated gas accumulation is expected to be 0.5 TCF and found with the largest Brookian Clinoform oil accumulation. Once again 75% of the recoverable gas volume is expected to be economically recoverable; thus, for these four plays economically recoverable gas is estimated to total 2.3 TCF.

Southern Colville-Canning Area/Brooks Range Foothills: As stated earlier the southern Colville-Canning area is largely a gas province. The 2005 USGS assessment (Bird and others, 2005) suggests that the aggregated mean undiscovered technically recoverable oil is less than 500 MMBO. From a review of the limited play and prospect data available at the time of this report, it appears that no oil prospect/accumulation is expected to have more than 64 to 128 MMBO (the approximate size of the Umiat accumulation). This estimate is at or below the low end of the 500 to 2,500 MMBO potential proposed by Anadarko (Nelson, 2002). The 5% probability sum for the technically recoverable oil in the predominantly gas plays is 900 to 1,000 MMB and provides an upside for oil that one or more companies may find attractive enough to pursue.

Based solely on the USGS assessment, it is difficult to present a case in which oil is the primary exploration target. However, the Umiat field in or near the gas-prone region and the presence of the exhumed Torok “oil field” south of the Tuktu escarpment are proof that oil was generated and accumulated in this portion of the Colville-Canning province. Dead oil in exposures of the Lisburne at Tiglukpuk anticline and in the Skimo Creek area along the front of the Brooks Range are further evidence that oil was generated and at one time migrated into or through reservoirs in this area.

The possibility of an accumulation in excess of 150 MMBO exists in at least two plays the Thrust Belt Triangle Zone (5% case = 217 MMB) and the Thrust Belt Lisburne (5% case = 250 MMB) (Figure 2.23, plays P and Q) predicated on the magnitude of the upper end of the potential resource distribution.

The primary gas plays and the mean recoverable resources in this area are the Brookian Clinoform (6.44 TCF), Thrust Belt Triangle Zone (3.84 TCF), Thrust Belt Lisburne (3.59 TCF), and Basement Involved Structural (3.02 TCF) plays. These four plays were assessed (Bird and others, 2005) to have slightly more than 50% of the aggregated mean for nonassociated recoverable gas (33.32 TCF). The probable reservoir horizons for each of these plays are indicated on Figure 2.23; plays B, P, Q, and O respectively.

The near-term (2005 to 2015) exploration was estimated to have found 10.0 TCF of economically recoverable gas, primarily from the Brookian Clinoform and Thrust Belt

Lisburne/Thrust Belt Triangle Zone plays. The remaining potential is assumed to be 20 to 25 TCF.

The USGS assessment (Bird and others, 2005) recognizes only one gas accumulation (Brookian Clinoform) with technically recoverable reserves in excess of 3.0 TCF and that accumulation was previously projected to be found during the near-term phase of exploration. Thus the remaining accumulations are expected to be equal to or less than 3.0 TCF.

The forecast is for an additional three accumulations averaging 2.5 TCF of economically recoverable gas with one each from the Lisburne Group, Torok/Nanushuk, and Sagavanirktok/Canning. These discoveries are considered to be discovered over a 10- to 15-year interval with the last one in 2030. They will be within 50 to 150 miles of the gas pipeline, and for the purposes of modeling are spaced equidistantly at 50, 100, and 150 miles. Five smaller fields, averaging 1.5 TCF, are expected to be found during this same time span and at similar distances from the pipeline. Similar reservoirs will be targeted. These larger fields are expected to contribute 15.0 TCF to the reserve base.

The smallest series of discoveries are anticipated to range from 0.5 to 1.5 TCF and average about 0.75 TCF. These will be targeted in the latter phase of exploration and only after the larger more economic accumulations have been discovered and developed. Thus, they will need to be in reasonable proximity to the infrastructure. These fields are assumed to be distributed among several reservoirs and to be associated with some of the lesser play types, principally the Brookian Topset Structural South (Nanushuk, Prince Creek, Tuluvak, and Sagavanirktok formations), Brookian Clinoform Structural South (Torok, Seabee, and Canning formations), Beaufortian Structural (Kuparuk/Kemik), and Ellesmerian Structural (Endicott, Lisburne, Sadlerochit groups). Approximately eight fields of this size are expected, with the first being discovered in 2016 and the last by 2040. These accumulations will be found within 10 to 20 miles of developed gas fields and total about 6.0 TCF.

The total gas additions of economically recoverable gas resulting from the long-term exploration effort in the southern portions of the Colville-Canning area are estimated to be approximately 21 TCF.

Additions to the oil reserve base are very uncertain. There is a possibility that a single economic accumulation could be found in close proximity to the existing oil pipeline. This would be a 125 to 250 MMB accumulation with some additional possibility of satellite development.

Summary: Economically recoverable oil resulting from the long-term exploration and development of new fields may be expected to add an additional 2.05 BBO to the ultimately recoverable reserves of the area. The development and implementation of new more efficient technologies for improving recovery from the heavy oil accumulations at West Sak and Ugnu may double or triple that expectation. Additionally, long-term exploration has the potential to add 21 TCF of nonassociated gas and 2.3 TCF of associated gas to the 35 TCF of proven reserves as of January 1, 2005 and the 10.0 TCF forecast to have been discovered between 2005 and 2015. The estimate of ultimate production from existing discoveries, reserve growth, and both near-term and long-term exploration success is tabulated in Tabel 2.15 for the Colville-Canning area and the State Beaufort Sea waters. Reserves growth potential is discussed in Section 2.5.2 and included in this table for completeness. No reserves growth is indicated for gas, but with reserves growth in the major medium to light oil fields there will be a concurrent increase in the available gas (associated solution gas).

Table 2.15. Estimate of ultimate cumulative production of oil and gas from Colville-Canning Area and State Beaufort Sea Lands.

Resource Component	Oil (BBO)	Gas (TCF)
Production as of 12/31/04	14.90	0.00*
ERR as of 12/31/04	6.95-7.35	35.00
Reserves growth in producing fields (12/31/04)	5.0-6.0	0.0
Near-term exploration success (2005 to 2015)	1.10	10.0
Long-term exploration success (2015 to 2050)	2.05	23.3
TOTALS	**30.00-31.40**	**68.30**
* 5.188 TCF has been used for lease operations and local sales to ANS North Slope utilities and pipelines, the balance of the total production of 55.418 TCF has been injected (ADNR,		

Beaufort Sea OCS Area: The Beaufort Sea OCS area has the potential to provide significant additional reserves (Table 2.12), if there has been timely and appropriate infrastructure development to accommodate more widespread onshore and shallow Beaufort Sea discoveries. Based on the discoveries to date and the assessments by the MMS, the Beaufort Sea OCS has the potential to add approximately 4.3 BBO and 20.0 TCF (approximately 60% of the revised assessments) between 2015 and 2050, with the bulk of the oil expected to be discovered prior to 2030. Gas will not be a priority during the early phases of this longer term exploration effort but some quantity will be discovered as a by-product of the oil-oriented exploration. By 2025, gas exploration will probably have achieved a stand-alone exploration status.

Most of the additions to the oil side of the ledger are expected be from the four plays discussed in the near term section (Rift, Brookian Faulted Eastern Topset, Brookian Unstructured Eastern Topset, and Brookian Foldbelt) and the Upper Ellesmerian play, with lesser contributions from the Lisburne and various other Brookian plays (Scherr and Johnson, 1998).

Oil discoveries have been made in the Brookian Unstructured Eastern Topset (Kuvlum) and the Upper Ellesmerian (Northstar), demonstrating the viability of these plays. From a discovery timing perspective, the 2015 to 2050 discoveries and associated development will probably occur first in the Upper Ellesmerian, Rift, and Brookian Unstructured Eastern Topset plays. The timing of discoveries and specially development in the Brookian Faulted Eastern Topset and Brookian Foldbelt plays will lag behind the others because of their relative remoteness and political considerations.

Based on the MMS estimates of pool sizes (Scherr and Johnson, 1998) the larger "primary" fields should range from 350 to 1,450 millions of barrels of oil equivalent (MMBOE) and average about 700 MMBOE. Four fields of this magnitude (2.8 BBO total reserves) are assumed to be discovered. These discoveries are expected to be primarily from Rift and Brookian Eastern Faulted Topset plays. Approximately five to six secondary fields (1.1 BBO) with reserves ranging from 100 to 300 MMBO can be expected to be economic once the primary fields are developed. These secondary fields and an equal number of smaller satellites (50 to 100 MMBO) are assumed to be found in approximately equal proportions from the five main play types. These smaller fields (0.4 BBO), in close proximity to either the primary or secondary fields, will be discovered and developed in much the same fashion as the Prudhoe Bay and Kuparuk satellites are today.

In most instances, the primary and secondary plays should be within 25 miles of the coast line and from there accessible to the onshore transportation and processing infrastructure. The notable exceptions are Brookian Faulted Eastern Topset and Brookian Foldbelt plays. The Brookian Faulted Eastern Topset play is almost everywhere more than 25 miles offshore, and the Brookian Foldbelt play has the dual obstacles of lying offshore from the 1002 Area and about 50% of the play area is more than 25 miles from shore.

Due to the lack of applicable data or history, the major discoveries are assumed to occur once every two to four years with smaller fields occurring with about twice that frequency. The Rift and Upper Ellesmerian plays should be discovered first followed by the Brookian Eastern Topset and then the remaining plays. The lead time from discovery to first production is estimated to be 7 to 8 years in the Beaufort OCS. The additions of economically recoverable oil are expected to total approximately 4.3 BBO.

Due to economic considerations and the need to maintain the oil pipeline capacity, gas exploration, while potentially significant, will probably lag behind the continued search for oil, especially in areas relatively near the present oil handling infrastructure.

The major gas plays are generally the same as the oil plays with the addition of the Brookian Faulted Eastern Turbidite play. Scherr and Johnson (1998) estimate the Brookian Faulted Eastern topset play to have a mean value for risked undiscovered conventionally recoverable gas of 16.07 TCF. The Rift, Brookian Faulted Eastern Turbidite, and the Brookian Foldbelt plays have mean values that range from 2.5 to more than 3.5 TCF. The mean sizes of the larger gas prospects range from 5.0 to 8.5 TCF. The secondary accumulations range from 2.0 to 5.0 TCF, when traps are 100% filled with gas.

Discoveries in the first half of the 2015 to 2050 time period are anticipated to be in the 0.5 to 2.0 TCF range in Rift (Kuparuk River) and Upper Ellesmerian (Sadlerochit) plays. The bulk of the gas will be discovered post-2030 as exploration moves offshore into the area of the Brookian Faulted Eastern Topset play and eastward into the area of the Brookian Foldbelt play, which lies offshore from the 1002 Area of ANWR. Three fields with mean gas resources between 2.0 and 7.0 TCF are expected to be discovered in the 15 to 20 years prior to 2040. These fields will most probably be found in the Brookian Faulted Eastern Topset and Brookian Foldbelt plays. The reservoirs are probably the Sagavanirktok and to a lesser extent the Canning Formations. An additional five, smaller 0.5 to 2.0 TCF, fields should complete the probable economically developable discoveries. The total estimated economically recoverable gas from these discoveries would be approximately 20 TCF.

Table 2.16 is presented to show the impacts of exploration on the reserve potential of the Beaufort OCS. Currently the only production in the Beaufort OCS is from the Northstar field and those volumes are included in Table 2.15.

These presumed discoveries, oil or gas, will require between 7 to 10 years to develop. The variation is a function of many factors including proximity to onshore infrastructure, water depth and seasonal operating restrictions.

Table 2.16. Estimate of ultimate production of oil and gas from the Beaufort Sea OCS area.

Resource Component	Oil (BBO)	Gas (TCF)
Production as of 12/31/04	0.00	0.00
ERR as of 12/31/04	0.00	0.00
Reserve growth in producing fields (12/31/04)	0.00	0.00
Near-term exploration success (2005 to 2015)	0.65	1.00
Long-term exploration success (2015 to 2050)	4.30	20.00
TOTALS	**4.95**	**21.00**

Chukchi Sea OCS Area: The Chukchi Sea OCS is an attractive exploration area and it will become an active and rewarding exploration province if key conditions are met. These include the development of an infrastructure within NPRA, the existence of both an oil and gas pipeline and continued high prices for both commodities. It is possible that the lure of the gas resources, believed to be associated with the Burger feature (Craig, and Sherwood, 2005), will accelerate this pace somewhat. However, this is dependent upon the MMS holding a lease sale in 2007 and a contractual obligation to build the gas pipeline from the North Slope to southern markets. However, it is more likely that any active exploration in the Chukchi Sea will depend on the measured westward expansion of infrastructure to western NPRA.

Of the twenty-two plays identified by the MMS (Sherwood and others, 1998) four have the bulk of the aggregated mean risked undiscovered technically recoverable reserves (Sherwood and others, 1998). These plays and their mean risked undiscovered recoverable resources are the Endicott-Chukchi Platform (3.00 BBO and 9.76 TCF), Rift-Active Margin (4.14 BBO and 8.55 TCF), Rift-Stable Shelf (2.25 BBO and 7.19 TCF), and North Chukchi High/Sand Apron (1.47 BBO and 17.98 TCF). These total nearly 10.86 BBO or 70.0% of the 15.5 BBO of 2000 MMS revised assessment (Minerals Management Service, 2000) and 43.48 TCF or 72.2% of the 60.1 TCF estimated in the 2000 MMS revisions.

The Endicott-Chukchi Platform play is comprised of Late Devonian(?) to Mississippian sandstones deposited in marginal marine to fluvial environments in the Hanna trough during an early rift- or fault-driven phase of subsidence (Sherwood and others, 1998). The play area ranges from 75 to over 150 miles offshore in the central and western portions of the Chukchi Sea. The equivalent rocks are productive at the Endicott Field in the Colville-Canning area. This play was not tested by any of the five wells drilled in the Chukchi Sea.

The Rift-Active Margin play consists of Late Jurassic to Early Cretaceous sandstones that were deposited in a zone of active faulting and flexural subsidence near an active rift margin

(Sherwood and others, 1998). The faulting resulted in locally thickened intervals reminiscent of the Point McIntyre field. The strata are age equivalent to the Late Jurassic Alpine, Nuiqsut, and Nechelik sandstones and the Early Cretaceous Kuparuk River Formation. The area of prospectivity lies between 75 and 175 miles offshore in the northwest-central portion of the Chukchi Sea. In the Colville-Canning area these units produce in the Alpine, Kuparuk, and Point McIntyre fields among others. Three wells (Burger, Crackerjack, and Popcorn) penetrated this play. The Burger and Popcorn wells encountered gas with condensate. The Burger structure has been estimated to contain risked mean resources of 9.48 TCF and 489 MMBO NGLs (Craig and Sherwood, 2005).

The Rift-Stable Shelf play consists of strata equivalent to those of the Rift-Active Margin play but deposited to the south of the rift zone on a tectonically stable shelf and slope. The anticipated lithologies consist of fine-grained marine shelf sandstones with less lateral continuity than those of the Rift-Active Margin play (Sherwood and others, 1998). This facies resembles that of the Kuparuk-A sandstone of the Kuparuk River field. The play trend extends from the eastern margin of the Chukchi Sea (from Icy Cape to Barrow) southwestward across the shelf to the Russian-United States boundary, which lies up to 150 miles offshore and west of Point Lay. The Klondike and the Diamond wells penetrated the stratigraphic interval. The Klondike encountered 80 feet of oil-bearing sandstone and the Diamond found only the Pebble Shale unit with no sandstone interval.

The North Chukchi High/Sand Apron play is inferred to consist of shallow marine to fluvial sandstones of Early Cretaceous to Tertiary age and includes both Lower and Upper Brookian successions (Sherwood and others, 1998). There have been no discoveries in these rocks but time equivalent units in the Colville-Canning area include portions of the Sagavanirktok and Nanushuk formations. This play area is in the central northern Chukchi shelf, between 90 and 170 miles northwest of Point Franklin. None of the five Chukchi Sea wells encountered this play.

Secondary plays, with mean risked recoverable resources between 0.5 and 1.0 BBO and 2.5 to 5.0 TCF are the Sadlerochit-Chukchi Platform (0.54 BBO and 2.99 TCF), Sadlerochit-Arctic Platform (1.16 BBO and 3.33 TCF), Lower Brookian Foldbelt (4.49 TCF), and Upper Brookian Paleovalleys (0.89 BBO). These plays total 2.59 BBO, 16.7% of the assessment area mean and 10.81 TCF, 18% of the aggregated mean.

The two Sadlerochit plays are targeting the same sequence of strata that are the primary reservoirs at the Prudhoe Bay and Northstar oil fields. The Sadlerochit of the Chukchi Platform consists of shallow marine fine-grained sandstones which were encountered by the Crackerjack and Klondike wells. Both of these wells established the presence of pooled hydrocarbons in the play sequence (Sherwood and others, 1998). The Sadlerochit-Chukchi Platform play area is 70 to 140 miles west to northwest of Icy Cape.

The Arctic Platform Sadlerochit sequence is thought to consist of marginal to shallow marine facies. The Diamond well penetrated this interval and found no hydrocarbons. However, the well encountered 310 ft of Ivishak sandstone and 575 ft of Echooka sandstone (the thickest observed anywhere). The play area extends from just offshore NPRA to about 140 miles northwest of Wainwright.

The Upper Brookian-Paleovalley play is inferred to be comprised of fluvial sandstones of Early Tertiary age. These rocks are thought to be time-equivalents of the Ugnu and portions of the Sagavanirktok Formation which produces at West Sak. The paleovalleys are located in the central portion of the western half of the Chukchi shelf and lie between 65 and 165 miles northwest of Icy Cape. Three wells, the Popcorn, Crackerjack, and Klondike, tested this interval and found thick sections of highly porous sandstone but no pooled hydrocarbons.

The Lower Brookian Foldbelt play is comprised of folded and faulted anticlines developed in the largely deltaic sandstone of the Nanushuk Formation. The foldbelt is located in the southern portion of the Chukchi Sea and just north of the Herald Arch. It extends from the coast line to nearly the Russian portion of the basin. This play was not tested by any of the Chukchi Sea exploration drilling. Onshore exploration drilling, primarily within NPRA, has resulted in the discovery of six gas fields (Tungak Creek(?), Wolf Creek, Gubik, Meade, Square Lake, and East Umiat).

The aggregated mean of the seven most prospective oil plays is 13.45 BBO or 86.6% of the estimated aggregated mean for the basin. Based on this assessment, virtually all future oil exploration will be focused on these intervals. Similarly the seven gas plays with the greatest resource potential are estimated to have 54.29 TCF or 90.2% of the aggregated mean for the Chukchi shelf assessment area.

The second round of exploration in the Chukchi Sea may commence as early as 2010 if a sale is held in 2007, but production prior to 2015 or 2020 is improbable. The area is attractive and possesses all the necessary components for a prolific petroleum province. However, the remoteness and the dependency on the westward spread of exploration and development of the required infrastructure largely control the timing of future activities.

Based on the assumption that the gas pipeline would have been completed prior to the development of any Chukchi Sea discoveries, oil and gas exploration will probably proceed jointly. For this discussion approximately 60% of the aggregated mean oil and 75% of the aggregated mean gas assessments are assumed to be discovered by 2050 or about 9.5 BBO and 45 TCF. The higher proportion of the gas resource assumed to be discovered is based on the evaluation of the gas resource at the Burger prospect, where the MMS has calculated a risked mean resource of 9.48 TCF. The Burger prospect gas is reservoired within the Kuparuk River Formation equivalents of the Rift-Active Margin play. For the most likely case, the risked mean gas resource at Burger (9.48 TCF) is greater than the 1995 risked mean gas endowment (8.55 TCF) for the play that contains the Burger pool. Indeed the risked mean gas resource at Burger represents 15.8% of the year 2000 Chukchi-wide risked mean gas endowment of 60.11 TCF (Table 2.12). The risked mean condensate resource at Burger (489 MMB) represents over 11% of the 1995 risked mean oil endowment for the Burger-type plays basinwide.

In structures with 100% oil, in the most likely case the upper limit of mean pool size may range above 1.0 BBO (Sherwood and others, 1998) and probably to as much as 1.5 BBO. The mean pools sizes in the most likely case for gas-only features were estimated by Sherwood and others (1998) to range to nearly 9.5 TCF and may exceed 11.5 TCF. Primary oil prospects are considered to range between 0.5 and 1.5 BBO and secondary features to have between 0.25 and 0.5 BBO. The primary gas prospects are given a range of 5.0 to 10.0+ TCF and the secondary targets range from 2.5 to 5.0 TCF. There are thought to be eight to twelve primary oil prospects and four to six primary gas prospects. The number of secondary oil and gas prospects are estimated to total about 20 and 12, respectively.

Considering that Burger is assessed to have nearly 9.5 TCF and nearly 0.5 BBO the remaining risked undiscovered economically recoverable resources expected to be found by 2050 are 36.5 TCF and 9.0 BBO. Oil exploration is expected to result in five to seven large fields that range between 0.5 and 1.5 BBO and average approximately 1.0 BBO and yield 6.0 BBO. The discovery of approximately the same number of secondary prospects with an average of 350 MMBO would add an additional 2.1 BBO. The largest accumulations are expected to be found in the two Rift plays (Kuparuk equivalents), the Endicott plays of the Chukchi Platform, and Sadlerochit plays. Eight to ten smaller satellite plays with 50 to 150 BBO may be expected to contribute an additional 0.9 BBO. Including the NGLs at Burger, the total long term additions of economically recoverable oil are approximately 9.5 BBO.

The gas potential may be higher than expected, if the revised estimate for Burger (Craig and Sherwood, 2005) is of the right order of magnitude. The most prospective gas plays are the Rift plays, the Brookian Sand Apron, and the Endicott-Chukchi Platform. With the Rift-Active Margin play having contributed a possible 9.5 TCF at Burger, it is probable that other large accumulations are present. Sherwood and others (1998) suggest that the Sand Apron play has the greatest gas potential and may yield a 10.0+ TCF accumulation. The operating assumption is that an additional three fields in the 5.0 to 10.0+ TCF range will be found and average about 6.5 TCF. Five to six secondary gas accumulations are estimated to average 3.0 TCF. The total of primary and secondary discoveries, including Burger, is projected to be approximately 46 TCF. Smaller gas accumulations in the 1.0 to 2.0 TCF range may add an additional 4.0 TCF. The total long term gas additions, including Burger, are expected to be in the area of 50.0 TCF.

Table 2.17 is a brief summary of the estimates of economically recoverable oil and gas expected to be discovered between 2005 and 2050. These numbers include the MMS (Craig and Sherwood, 2005) estimates for the Burger discovery.

Table 2.17. Estimate of the ultimate production of oil and gas from the Chukchi Sea area.

Resource Component	Oil (BBO)	Gas (TCF)
Production as of 12/31/04	0.00	0.00
ERR as of 12/31/04	0.00	0.00
Reserve growth in producing fields (12/31/04)	0.00	0.00
Near-term exploration success (2005 to 2015)	0.00	0.00
Long-term exploration success (2015 to 2050)	9.50	50.00
TOTAL	**9.50**	**50.00**

Because of the remoteness of the Chukchi Sea plays from the existing infrastructure and any future gas pipeline from the North Slope to a southern terminus, there will be a long lead time from the establishment of commercial quantity of reserves to first production and transportation of oil or gas. It is estimated that 10 to 12 years may be required. This timeline may be abbreviated by two to four years if a portion of or all the necessary infrastructure has been extended to western NPRA prior to the development of the Chukchi Sea resources.

2.4.2.2 Other Federal lands

By 2015, both exploration and development in the NPRA should be well established with activity proceeding westward and southward with the dual objectives of oil and gas. To the east, in the 1002 Area of ANWR either the area remains closed to drilling or exploration has begun, and, with early success, production of the first oil (gas?) will occur approximately two to three years into the future (in 2017 or 2018).

2.4.2.2.1 National Petroleum Reserve Alaska (NPRA)

The potential for medium-sized (by North Slope standards) oil and gas fields is good to excellent in NPRA. The northern portion of the area has numerous opportunities for Beaufortian topset and to a lesser extent Brookian clinoform oil accumulations. To the south the area is dominantly gas-prone with the best opportunities in the structural plays involving Brookian topset and clinoform units. Smaller accumulations are believed to be present in the Beaufortian topset plays. Over the long term, the oil exploration program will gradually expand westward, following the Alpine-Nuiqsut-Nechelik trends. Some exploration programs may de designed to look for oil to the south, lured by the known accumulation in the Brookian topset sequences at Umiat and the Brookian Clinoform potential.

The most promising oil play is the Upper Jurassic topset play of the northeastern portion of NPRA, followed by the similar play in the northwest portion of NPRA and the Brookian Clinoform plays of the northern and central areas (Bird and Houseknecht, 2002). USGS reports (Houseknecht, 2003a and 2003b) indicate that there is the potential for one field with 0.5 to 1.0 BBO and an additional eight to nine fields with 0.25 to 0.5 BBO. Twenty to thirty fields with 50 to 250 MMBO are possible. An estimated 65 to 70% of these prospects lie within 25 to 100 miles of the Alpine field and its existing infrastructure and 75 to 80% of the oil is thought to be in Alpine-like plays.

Approximately two-thirds of the technically recoverable oil (6.5 BBO) is assumed to be found during the near and long term exploration process and ultimately produced economically. For the long term success, the maximum field size is assumed to be 0.75 BBO with six fields in the 250 to 500 MMBO range and averaging 400 MMBO. An additional fifteen fields in the 50 to 250 MMBO range and averaging 150 MMBO are considered to be economic because of proximity to the larger fields and the existing infrastructure. Five of the seven largest fields are expected to be within 100 miles of the Alpine field, as well as the majority of the smaller fields. The more remote discoveries may be as much as 200 miles west of Alpine and would most probably require a string of successes across the NPRA or a very large discovery in the Chukchi Sea to be viable.

The total quantity of economically recoverable oil expected to be discovered in this phase of exploration and development in the NPRA is estimated to be 5.4 BBO.

The prospects for gas are considered to be the best in the southern portion of the NPRA (Bird, and Houseknecht, 2002). The assessments by the USGS (Houseknecht, 2003a, 2003b, and Potter and Moore, 2003) suggest that there are numerous prospects with reserves in the 1.0 to 6.0 TCF range. The most prospective structural plays involve the Torok and the topsets of the Brookian. These two plays are assessed to have aggregated mean technically recoverable undiscovered resources of 28.5 TCF. The Upper Jurassic topset and the Brookian clinoform plays are thought to be attractive secondary gas targets. The four stratigraphic plays have an aggregated mean of 19.5 TCF. Based on recent drilling activity in Upper Jurassic topset prospects of the northeastern portion of the NPRA, these rocks may also have considerable gas potential. Providing that the gas pipeline is approved and built in the timeframe suggested in this report, gas exploration will be a major component of exploration in NPRA by 2015.

The Torok and Brookian Topset structural plays are stacked plays, with the Brookian Topset plays (Nanushuk) atop the Torok Clinoform/Turbidite plays, and trend east-west across NPRA in a zone that is bracketed between 69º and 70º north latitude (Bird and Houseknecht, 2002, figures 9 and 10). The Brookian Topset Structural plays are represented by the Umiat oil field and the Gubic Gas field. The East Kurupa gas field is an example of a Torok structural play.

These structural plays will probably be the first pure gas-oriented exploration targets, and it is assumed that as much as 75% of the 28.5 TCF will be discovered and proven to be economic. Estimates by the USGS suggest that 75 to nearly 85% of the technically recoverable resources may be economic, for gas cases in which gas prices range from $6.00 to $10.00/MCF (PN, 2006b). The first discovery is anticipated to occur between 2010 and 2012 with lead time to production of about seven years. The majority of the large structural plays will be discovered over a 15- to 20-year period. For modeling purposes the larger discoveries are considered to range from 1.5 to 6.0 TCF with one at 6.0 TCF and three ranging from 1.5 to 3.0 TCF and averaging 2.25 TCF. Six smaller discoveries ranging between 0.75 and 1.5 TCF and averaging 1.25 TCF are considered to be satellites to the large fields and will largely be discovered and/or developed post-2030. The anticipated additions of economically recoverable gas, from the structural plays, are approximately 20.25 TCF. These prospects are from 50 to 200 miles west and southwest from Alpine.

The stratigraphic plays are expected to have fewer resources and to be smaller individual accumulations. They will tend to be targets once the larger structural plays have been discovered and developed. Because the individual accumulations are thought to be relatively small, generally less than 1.5 to 2.0 TCF, the presumption is that not as many will be found and only those relatively close to the infrastructure will be developed. Thus, only about 50% of the technically recoverable resources attributed to these plays are projected to be developed. This value is expected to include associated gas from the Beaufortian Topset plays in the northeast and northwest which appear to have been considered to be gas deficient. The prospects with the best chance to be commercial have potential reserves in the 0.75 to 1.7 TCF range and average 1.25 TCF. Seven or eight such accumulations are estimated to be found. Possible reserve additions range from approximately 9.0 to 10.0 TCF. Much like the structural plays, most of these prospects are between 69º and 70º to 70.5º north latitude and are from 25 to 200 miles from Alpine.

With this level of success, the long term exploration and development activities in NPRA will result in the addition of 30.0 TCF of economically recoverable gas. The summary of expected economically recoverable oil and gas, related to exploration activities is presented in Table 2.18.

Table 2.18. Estimate of ultimate production of oil and gas from the National Petroleum Reserve Alaska (NPRA).

Resource Component	Oil (BBO)	Gas (TCF)
Production as of 12/31/04	0.00	0.00
ERR as of 12/31/04	0.00	0.00
Reserves growth in producing fields (12/31/04)	0.00	0.00
Near-term exploration success (2005-15)	1.10	1.00
Long-term exploration success (2015-50)	5.40	30.00
TOTAL	**6.50**	**31.00**

2.4.2.2.2 1002 Area of Arctic National Wildlife Refuge (ANWR)

The possibility that the 1002 Area of ANWR will not be opened to exploration and development is a real possibility, but it is necessary to present a development scenario for the area that allows all contingencies to be considered and evaluated. In the near-term section (Section 2.4.1), the timing assumed for the exploration and development was such that the earliest discovery occurred in 2015/2016 and production did not commence until 2022. Thus no production was attributed to any exploration success that may have taken place between 2005 and 2015 and most of the 1002 Area exploration and development and all production are anticipated to take place between 2015 and 2050.

A summary of the results of the 1998 assessment (Bird and Houseknecht, 1998) is presented in Table 2.19. As seen earlier (Tables 2.14) these estimates are considerably larger than those of previous assessments, and the areal and play distribution of the technically recoverable resources, of the 1998 assessment (Bird and Houseknecht, 1998) are markedly different from those of the 1987 USGS assessment (Dolton and others, 1987). The range and mean of technically recoverable oil and nonassociated gas resources for the entire study area (Table 2.19) are 5.72 to 15.96 BBO with a mean of 10.32 BBO and 0.0 to 10.85 TCF with a mean of 3.84 TCF. The range and means for the 1002 Area, excluding the State shallow water and ASRC lands, are 4.25 to 11.8 BBO and 7.67 BBO. The potential distribution of gas resources, by owner, was not included. For this scenario the entire area is treated as a unit, since it is highly unlikely that the majority of the ASRC or State lands can be developed without the 1002 Area being open for exploration.

Table 2.19. Technically recoverable oil and nonassociated gas for 1002 Area of the Arctic National Wildlife Refuge (source, Bird and Houseknecht, 1998)

Segment Assessed in 1998	Oil (BBO)			Nonassociated Gas (TCF)		
	95 %	Mean	5%	95 %	Mean	5%
Entire assessment area	5.72	10.32	15.96	0.0	3.84	10.85
ANWR 1002 Area (Federal) Total	4.25	7.67	11.8	0.0	????	????
Undeformed part of Federal lands	3.40	6.42	10.22	0.0	0.47	????
Deformed part of Federal lands	0.0	1.25	3.19	0.0	3.37	????

The 1998 assessment (ANWR Assessment Team, 1999) identified ten plays. These can be considered to consist of two areally distinct groupings with little if any overlap. The first group of six plays is largely stratigraphic in nature with some large but relatively rare structural traps. These plays are present northwest of the Marsh Creek Anticline trend in the "undeformed" portion of the 1002 Area. The remaining four plays lie in the deformed portion of the 1002 Area, east and southeast of the Marsh Creek Anticline. These plays are mainly structural in character and require four-way dip closure or up-dip sealing faults.

The six plays of the undeformed area are: 1) Brookian Topset of the Paleocene to Miocene Sagavanirktok Formation, 2) Brookian Turbidite in the Paleocene to Oligocene Canning Formation, 3) Brookian Wedge of the Eocene Sagavanirktok/Canning formations, 4 and 5) Beaufortian Topset in the Early Cretaceous Thomson and Kemik Sandstones, and 6) undeformed Franklinian of the pre-Mississippian carbonates and clastics.

The four plays of the deformed area are: 1) Deformed Franklinian in pre-Mississippian carbonates overlain by Brookian rocks, 2) Thin-Skinned Thrust-belt within the Brookian Sagavanirktok and Canning formations, 3) Ellesmerian Thrust-Belt within Mississipian through Early Cretaceous strata, and 4) Niguanak-Aurora principally consisting of Franklinian strata with lesser contributions from overlying Beaufortian and Ellesmerian units.

Based on the 1998 assessment (Schuenemeyer, 1999), only three of these plays have mean technically recoverable resources in excess of 1.0 BBO and 1.0 TCF. These are the Brookian Topset (6.2 BBO and 1.7 TCF) and Brookian Turbidite (1.6 BBO and 1.6 TCF) plays of the undeformed area and the Thin-skinned Thrust-belt (1.15 BBO and 1.8 TCF) play of the deformed portion of the 1002 Area. The aggregated means for these three plays are 8.95 BBO and 5.1 TCF.

While these three plays would be the most obvious exploration objectives, based on the distribution of resources presented in the 1998 assessment, most of the less prospective plays could be secondary exploration targets due to the superposition of the various plays. The widespread distribution of the topset and turbidite plays are such that they overlay most if not all of the areas occupied by the four less prospective plays. Similarly, the Thin-Skinned Thrust-Belt play is locally underlain by the deformed Franklinian and Niguanak-Aurora plays, with the Deformed Franklinian play in the western and central portions of the Thin-Skinned Thrust-Belt play and the Niguanak-Aurora play in the eastern portion. The Ellesmerian Thrust-Belt play barely overlaps these plays in the southern portions of their distributions and would probably not be a stand-alone objective.

At the most probable time for development, the nearest infrastructure would be the facilities at Point Thomson and these would serve as the primary gathering center for oil and/or gas produced within the 1002 Area, adjacent State waters, and ASRC inholdings. Thus, more than 50% of the potential reserves, as distributed in the 1998 assessment, would be within 35 miles of the Point Thomson production and transportation facilities. The most remote topset and turbidite accumulations would be approximately 60 miles from Point Thomson. The most distant Thin-Skinned Thrust-Belt prospects could be up to 90 miles east of Point Thomson.

With the assumption that 70% of these resources (8.95 BBO) are converted to economically recoverable reserves, the reserve additions would total 6.25 BBO and 3.5 TCF. With $51.00/barrel oil prices the USGS estimates 90% of the technically recoverable oil would be economic (Attanasi, 2005).

The author believes that the volumes for the deformed area are conservative and that greater potential for both oil and nonassociated gas exists in the deformed portion of the 1002 Area than the 1998 USGS assessment indicates. The Angun Point and Manning Point oil seeps are well within the limits of the deformed zone and support the migration of oil into the area and the possible accumulation of Canning Formation (Mikkelsen Tongue) oils in reservoirs of this portion of the 1002 Area. Similarly, the large Niguanak and Aurora structures are ideally situated to act as reservoirs for gas generated in the deeply buried Ellesmerian and Beaufortian source rocks of the southern portions of the 1002 Area.

The first exploration wells would probably have multiple targets and evaluate those intervals most easily identified and confirmed by seismic data. Thus, the topset structural plays and the thin-skinned thrust-belt prospects plus the more obvious stratigraphic turbidite plays would be likely early targets within the areas of overlap. The overlap zone of two plays within 30 to 40 miles of Point Thomson will probably see the first exploration drilling. With time, exploration drilling will proceed to the east and focus on the topset, turbidite, and thin-skinned thrust-belt play prospects with the other plays being secondary objectives.

The topset play has a variety of trapping styles including anticlines, growth anticlines, growth faults, up-dip shelf-edge pinch-outs, and stratigraphic lenses (Houseknecht and Schenk, 1999a). The topset play, and to a slightly lesser extent the turbidite play, occupies the entire area of the undeformed portion of the 1002 Area and extends south-southeast from the Barter Island area into the central portion of the 1002 Area. The Turbidite play lacks this southward extension. Both plays generally trend parallel to the Beaufort Sea coastline in a belt that ranges from 10 to 20 miles wide (Houseknecht and Schenk, 1999a and 1999b).

Under the preferred scenario, the first economic discovery will be made in 2012/2013 and probably in Sagavanirktok Formation reservoirs (topset play), which have a mean technically recoverable resource estimated to be 6.3 BBO (Schuenemeyer, 1999). The first discovery is expected to be in the 0.5 to 1.0 BBO range (750 MMBO) and to be within 40 miles of Point Thomson. Reservoir properties will resemble those of the Kuvlum and Hammerhead fields for a potential Sagavanirktok reservoir. Additional topset discoveries are expected to be found, including another field of similar size, a field in the 1.0 to 1.5 BBO range (1.25 BBO) and three accumulations in the 0.25 to 0.5 BBO range (average of 0.35 BBO). Four fields in the 0.125 to 0.25 BBO (average 0.15 BBO) are anticipated to be discovered within 20 to 60 miles of Point Thomson. An unknown number of satellites (probably 6 to 10) are to be expected, with per field reserves in the 30 to 75 MMBO range, with an average of 50 MMBO). This level of success would yield 4.80 BBO from Brookian topset prospects.

The near exact concordance of the turbidite and top set play areas would greatly facilitate the exploration of the Canning Formation turbidite play. The turbidite prospects may require 3D seismic data to be adequately defined. The most obvious features are mounds and channels (Houseknecht and Schenk, 1999b). Existing accumulations attributed to this play-type include the Badami, Flaxman Island accumulation, and possibly Sourdough.

Schuenemeyer (1999) estimated that the mean technically recoverable resources for this play are 1.6 BBO, with the largest accumulation in the 0.25 to 0.50 BBO range. Exploration success is anticipated to yield one field with 350 MMB of economically recoverable oil. This field is expected to be found in the 2013 to 2020 timeframe and to be within 50 miles of Point Thomson. Additional discoveries, between 2015 and 2035, are estimated to include three accumulations in the 125 to 250 MMBO range, probably averaging 175 MMBO and three to five smaller, satellites in the 50 to 100 MMBO range. The smaller fields must, out of economic necessity, be discovered in close proximity to larger, stand-alone fields of this or other plays in order to be developed. Aggregated additions from the turbidite play are approximately 1.2 BBO.

Perry and others (1999) recognize the thin-skinned thrust-belt play as consisting of northeast-trending folds and thrust-bounded structures which formed in the Brookian succession above a detachment lying above and close to the pre-Mississippian basement. The play extends east-northeastward across the 1002 Area from the extreme southwest corner where it is only about 10 miles wide and widens to approximately 30 miles, encompassing the entire coastline from Barter Island to Aichilik River (Potter and others, 1999). This play is considered to have analogs at Umiat, East Umiat, and Gubic fields, in and near NPRA, and in the Beaufort Sea and Mackenzie Delta areas to the east in Canada.

The thin-skinned thrust-belt play is estimated to have mean recoverable resources of 1.15 BBO (Schuenemeyer, 1999). The potential for stand-alone economically successful accumulations for this play are limited. Schuenemeyer (1999) estimates that the largest field is in the play is in the 250 to 500 MMBO range with only one additional play in both the 125 to 250 MMBO and 62.5 to 125 MMBO ranges. Most of the accumulations are expected to be small and would probably contain less than 50 MMBO (Schuenemeyer, 1999). Presuming that one field is discovered in each of the class sizes and the smaller fields can take economic advantage of proximity to larger accumulations the economically recoverable oil attributable to this play would aggregate to 750 MMBO. It is likely that these discoveries would occur between 2015 and 2025. The assumption is that the larger fields would be discovered first and would tend to be associated with the Marsh Creek anticline and the southern margin of the Aichilik high.

Using the USGS 1998 estimate for mean technically recoverable resources attributable to the entire study area (Table 2.19) and, assuming 70% of the technically recoverable resources in the three most prospective plays, are converted to economically recoverable resources as discussed above, the 1002 Area would yield approximately 6.35 BBO, in good agreement the earlier estimate of 6.25 BBO.

The gas resource was not treated as an exploration objective in the 1998 study. The aggregated OGIP for all ten plays is 18.5 TCF and the aggregated technically recoverable gas is 8.59 TCF with 3.84 TCF (47%) as nonassociated gas and the remaining 4.75 TCF as associated gas.

The technically recoverable associated gas is anticipated to be discovered as a by-product of oil exploration and is expected to be found in three plays, the Topset (1.7 TCF), Turbidite (1.4 TCF), and Thomson (0.46 TCF) plays. This comprises 75% of the associated gas. Two of these plays are the most prospective for oil and the gas and would be found early in the exploration process. The Thomson play would be a probable secondary objective in any exploration due to the reserves at Point Thomson. A total of approximately 2.0 TCF may be expected in association with the oil discoveries.

The most prospective nonassociated gas opportunities are within the deformed portion of the 1002 Area and are the Deformed Franklinian (0.82 TCF), Thin-Skinned Thrust-Belt (1.47 TCF), and Ellesmerian Thrust-Belt (0.88 TCF) plays. The data presented by the USGS (Bird and Houseknecht, 1998) does not support an extensive gas exploration effort in the 1002 Area. Thus, if the assessment data are utilized for purposes of forecasting gas reserve additions, the contribution from the 1002 Area will be minimal and not worth considering as a major factor in future production.

While the 1998 USGS assessment allocated the greatest reserves to the plays of the undeformed area, other investigators have attributed a greater proportion of the area's oil resources to the plays in the deformed portion of the 1002 Area. This was also true of the 1987 USGS assessment. Without going into detail regarding the decision to reallocate the majority of the area's resources to the undeformed portion of the 1002 Area, it remains possible that there may be a greater potential for oil and gas in the southeastern two-thirds of the 1002 Area than is reflected by the 1998 assessment. The major obstacle would appear to be charging the large Niguanak and Aurora features with oil and/or gas.

Grow and others (1999) have approached these features with two scenarios – as a play with two large individual and unique prospects and as a play with many individual prospects. In the two-prospect case, the prospect closure is thought to range from 120,000 to 250,000 acres with a median of 180,000 acres. The range of trap depths is from 9,000 to 15,000 feet with a median depth of 12,000 feet. In the many-prospect scenario, the closures are considered to range from 5,000 to 120,000 acres with a median of 20,000 acres. With features of this size and the possibility of sourcing from the Hue Shale and Mikkelsen Tongue of the Canning Formation, it is difficult to believe that these features will not be high on a prospective lessee's drilling agenda. Whether the hydrocarbon charge is oil or gas, the potential for a very large accumulation exists. The proposed median trap fill for the many-prospect case is 45% and 20%

for the two-prospect scenario. The 20% fill reflects the extreme size of the features and the low probability that the features could be filled or that a seal would be sufficient to retain the size of the hydrocarbon column required to fill the structures.

Table 2.20 has been constructed in the same manner as Tables 2.15 to 2.18 and summarizes the expected economically recoverable oil and gas associated with exploration in the 1002 Area of ANWR, if the area is opened to oil and gas exploration and development.

Table 2.20. Estimate of ultimate production of oil and gas; 1002 Area of ANWR.

Resource Component	Oil (BBO)	Gas (TCF)
Production as of 12/31/04	0.00	0.00
ERR as of 12/31/04	0.00	0.00
Reserves growth in producing fields (12/31/04)	0.00	0.00
Near-term exploration success (2005 to 15)	0.00	0.00
Long-term exploration Success (2015 to 50)	6.25	2.00+
TOTAL	**6.25**	**2.00+**

The volumes associated with a more optimistic oil or gas case have not been calculated for this play, but if there was sufficient charge available, these features could have oil-in-place or gas-in-place volumes is the billions of barrels and trillions of cubic feet. With recovery factors of 25 to 30% or more, the ultimate recoverable oil resources from the 1002 Area could be increased by 50 to 100% and gas resources could be in the trillions of cubic feet.

2.4.3 Summary of Exploration Results

The undeveloped and, in many instances, unexplored prospective areas of the North Slope and adjacent Beaufort Sea and Chukchi Sea shelves have the potential to add billions of barrels of oil and trillions of cubic feet of gas to the shrinking volume of estimated remaining oil reserves and 35 TCF of known gas. These resources have the potential to support active exploration, development and production well into the middle of the 21st century. The estimated volumes of economically recoverable oil and gas presented in the preceding sections are predicated on the concept that the assessments by the MMS (OCS areas) and the USGS (onshore areas) are reasonable order-of-magnitude estimates. The timing, location, and play types associated with the postulated discoveries and the consequent development and production of these new fields are based on the assessed potential associated with the most attractive appearing prospects and their proximity to existing infrastructure.

Table 2.21 summarizes the discoveries by area and exploration phase. For the near term, all economically recoverable oil and gas additions are expected to be discovered or developed in the areas with active exploration operations at the time of this report (Colville-Canning, NPRA, and the shallow portions State and Federal portions of the Beaufort Sea shelf). The major emphasis for the near term will continue to be on oil exploration with the sole exception of gas-directed exploration in the Brooks Range foothills during the latter portion of the 2005 to 2015 timeframe. Near-term results are expected to be 2.85 BBO (perhaps an additional 0.5 to 0.8 BBO if Kuvlum and Hammerhead are more fully evaluated and developed) and 12.0 TCF (Table 2.21). There will be no commercial gas production until 2015 or later.

The long-term discoveries largely reflect the expansion of exploration into those areas that have historically been excluded from exploration activities, are remote from existing infrastructure, and/or are gas-prone. The greater OCS areas of the Beaufort and Chukchi seas, the bulk of NPRA, and the entire 1002 Area of ANWR are representative of the first two areas of expanded exploration and the southern portions of both the Colville-Canning province and NPRA are typical of the gas-prone areas.

Additions of economically recoverable oil, as a result of long-term exploration success, are estimated to be more than 1.3 times the current EUR of producing and identified North Slope fields production of 21.06 BBO (Table 2.10) or about 27.5 BBO (Table 2.21). The Chukchi Sea, 1002 Area of ANWR, and the northern portion of NPRA are expected to contribute the greatest volumes of oil. These three areas alone are estimated to produce 21.15 BBO or a volume equivalent to the current EUR from known fields in the developed area of the Colville-Canning province and adjacent shallow waters of the Beaufort Sea (Table 2.10).

Table 2.21. Summary of forecast ANS economically recoverable oil and gas additions.

EXPLORATION PROVINCE	Near Term 2005 to 2015		Long Term 2015 to 2050		Total 2005 to 2050	
	Oil	Gas	Oil	Gas	Oil	Gas
Colville-Canning & State Beaufort Sea	1.1 BBO	10.0 TCF	2.05 BBO	23.3 TCF	3.15 BBO	33.3 TCF
Beaufort Sea OCS	0.65 BBO (plus Hammerhead and/or Kuvlum?)	1.0 TCF	4.3 BBO	20.0 TCF	4.95 BBO	21.0 TCF
Chukchi Sea OCS	N.A.	N.A.	9.5 BBO	50.0 TCF	9.5 BBO	50.0 TCF
NPRA	1.1 BBO	1.0 TCF (assoc. gas)	5.4 BBO	30.0 TCF	6.5 BBO	31.0 TCF
1002 ANWR	N.A.	N.A.	6.25 BBO	2.0+ TCF	6.25 BBO	??? (0 to several TCF)
TOTAL ARCTIC ALASKA	**2.85 BBO**	**12.0 TCF**	**27.50 BB0**	**125.3 TCF**	**30.35 BBO**	**137.3 TCF**

The majority of the economically recoverable gas additions are expected to be found and developed during the 2015 to 2050 exploration phase (Table 2.21). Gas additions during this time interval are estimated to be in excess of 125 TCF with 100 TCF from the OCS and southern NPRA. The cumulative gas additions are 3.5 times the known proven reserves as of January 1, 2006.

These estimated additional volumes of oil and gas for the time interval from 2005 to 2050 are depicted by area in Figure 2.26.

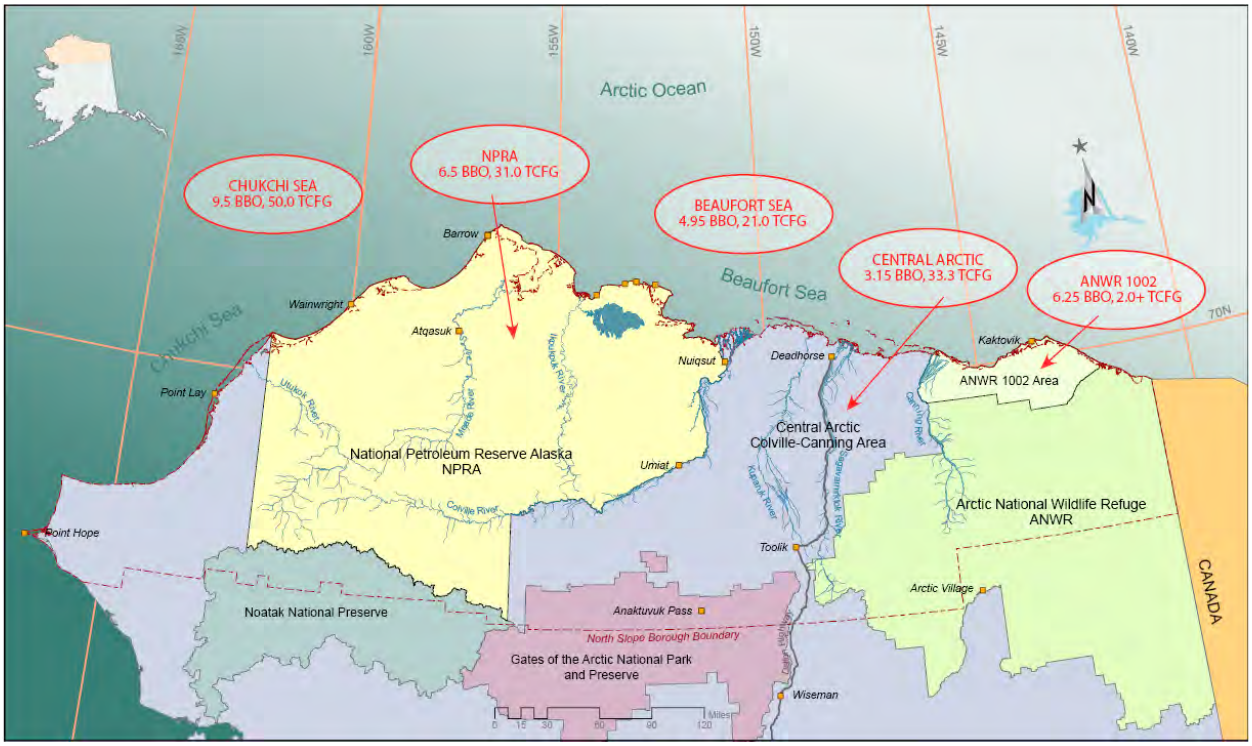

Figure 2.26. Estimated additions to Northern Alaska economically recoverable oil and gas resources from exploration during 2005 to 2050 interval. (Current cumulative production, ERR, and reserves growth volumes are not included.)

Looking ahead to 2050, the additions to reserves through exploration are estimated to be approximately 30 BBO, or two times the current cumulative production, and 135 TCF, or about four times the current known gas reserves. This represents about 60% of the USGS mean estimate of undiscovered conventional gas resources for the North Slope, and adjacent OCS areas (PN, 2006b). These volumes do not take into account reserves growth within the existing fields nor the unconventional gas potential of coal bed natural gas or gas hydrates.

2.5 Summation of Reserves and Economically Recoverable Additions

The ultimate magnitude of economically recoverable conventional oil and gas resources in Arctic Alaska includes the sum of the produced oil (and gas), the unproduced known reserves in the developed fields (Prudhoe Bay, Kuparuk, etc.), the known but undeveloped reserves (Point Thomson, Liberty and others), volumes attributable to future reserve growth in producing fields (West Sak, Ugnu and others), and the economically recoverable oil and gas anticipated to be added through future exploration and development. Most of these components of the ultimate potential for conventional oil and gas have been addressed elsewhere in this report and will be summarized again here and the component attributable to reserve growth will be reviewed and discussed.

2.5.1 Original Estimates of Ultimately Recoverable Reserves

Not all the discovered fields have published estimates of “reserves”. The smaller oil fields, especially those within NPRA and gas fields, lack estimates of technically recoverable resources not to mention “economically recoverable reserves”. Recently, there have been some efforts to provide these volumes. A notable example is the work of Verma and others (2005) in which the authors assessed the Kavik gas field to have 165 BCF of in-place gas and technically recoverable resources of 115 BCF. The attempt to define EUR is limited by the values associated with the known producing fields. Any estimate of ultimate recovery for the other fields awaits commercial development, and consequently a total EUR for northern Alaska is a conservative number, even with respect to the known accumulations.

2.5.1.1 Producing Fields (as of December 31, 2004)

The original estimates of recoverable reserves for the producing fields are presented in Table 2.7 (p. 2-75). These estimates total between 14.275 and 15.2 BBO and 30.575 TCF. The range in estimated recoverable oil reserves is largely related to the uncertainty regarding recovery rates for the viscous oil fields in the Ugnu, West Sak, and Schrader Bluff accumulations. The recovery anticipated for these heavy oil accumulations is conservative and historically has been based on the use of older technologies. Recent technological advances have improved the rate and total recovery potential. The potential for reserve growth in these fields is very good and will be discussed later.

Several of the gas fields, included in the Table 2.7 tabulation, are being produced to supplement energy requirements for local villages. These fields would not normally be considered economic and would not have been developed except for the local needs. South Barrow, East Barrow, and Walakpa gas fields are in this category and had original reserve estimates totaling approximately 70 BCF, an insignificant portion of the gas reserve picture.

2.5.1.2 Discovered but Undeveloped Accumulations

Most of the discovered but undeveloped accumulations are presented in Table 2.8 as estimated technically recoverable resources and at this time are either uneconomic because of small size and/or remoteness (Umiat, Kavik, and Burger) or are awaiting the development of an appropriate infrastructure (Point Thomson). Some of the undeveloped fields that are expected to be developed within two to three years are included in Table 2.7. The total estimated technically recoverable resources from the fields of Table 2.8 are 2.3+ BBO and 20.0+ TCF. Many of these fields will be reevaluated based on current economics and technology and this may lead to eventual development over the next 5 to 20 years. If it is assumed that approximately 75% of the technically recoverable resources will be converted to economically recoverable reserves, these fields will add 1.7 BBO and 15.0 TCF to the reserve base. The most probable conversions are Point Thomson, Kuvlum, Hammerhead, Liberty, Sourdough, and the Pete’s Wicked, Oooguruk/Nikaitchuq/Tuvaaq grouping of fields. Gubic and Umiat may fit into this category as exploitation moves southward and the gas line is developed. Burger, in the Chukchi Sea, is at least 20 years from being commercialized.

2.5.2 Reserves Growth

Reserves growth may add significant quantities of oil or gas without any additional exploration. These reserves are usually “discovered” through better understanding of the reservoir geometry, redefinition of the reservoir, enhanced recovery technology, and improved economic conditions. The subject will be addressed in three sections; historic growth in existing fields, future growth in producing fields, and reserve growth anticipated during the producing life of yet undiscovered oil and gas fields. Potential volumes of reserves associated with the third category are very nebulous and must be considered as speculative at best.

2.5.2.1 Discovery to Present (January 1, 2005)

Reserve growth has been demonstrated in most of the North Slope's major oil fields. Table2.22 demonstrates the documented change in booked reserves on a field-by-field basis over the productive life of ten of the fields in the Colville-Canning area. Note that the Lisburne and Badami fields are expected to produce significantly less oil than originally estimated. These fields differ in significant ways from the other oil fields presented in Table 2.22.

Table 2.22. Change in economically recoverable reserves (reserve growth) from discovery or onset of production to December 31, 2004 (EUR)

Producing Field	Original Reserve Estimate	Estimated Ultimate Recovery	Difference
Prudhoe Bay	9,590 MMBO	13,841 MMBO	+4,251 MMBO (+44.3%)
Lisburne	400 MMBO	192 MMBO	-208 MMBO (-52.0%)
Kuparuk River	600 MMBO	2,833 MMBO	+2,233 MMBO (+272.2%)
Milne Point-Kuparuk	110 MMBO	418 MMBO	+308 MMBO (+280.0%)
Endicott	375 MMBO	571 MMBO	+196 MMB0 (+52.3%)
Point Mcintyre	300 MMBO	591 MMBO	+291 MMBO (+97.0%)
Northstar	210 MMBO	196 MMBO	-14 MMBO (-6.7%)
Badami	120 MMBO	60(?) MMBO	-60(?) MMBO (-50.0%)
Tarn	42 MMBO	127 MMBO	+85 MMBO (+202.4%)
Alpine	430 MMBO	555 MMBO	+125 MMBO (+29.0%)
TOTAL	**12,177 MMBO**	**19,384 MMBO**	**+7,207 MMBO (+59.2%)**

The Lisburne oil field is the only producing carbonate reservoir on the North Slope. Despite porosity that may reach 20%, the reservoir has limited matrix permeability, about 0.1 to 0.2 md (Bird and others, 1987), and the production is largely controlled by fractures, which initially deliver oil to the borehole at high rates. However, the production has been shown to decline rapidly as the fractures are produced. The rate of delivery of oil to the fractures from the matrix porosity was historically so low that the well rates decreased by as much as 90% in a month. Recent implementation of extended reach horizontal wells and multilateral completions has markedly increased production and some of the apparent decrease in EUR may be regained. Current expectations are that the Lisburne field will produce only 48% of the original EUR.

In a somewhat similar situation the Badami field was the first of several turbidite reservoirs to be developed, and the degree and extent of compartmentalization was not fully recognized at the time the field was developed. The efforts to restart the field involve the use of multilateral wells and recognition of the complex reservoir geology. There appears to be a good possibility of regaining some of the reserves thought to be lost due to the inability to meet reservoir performance standards. The shortfall is estimated to be 50% of the original EUR, but the potential for fewer reserves is great and the ultimate recovery may be considerably less than the estimated 60 MMBO.

The Northstar field is currently expected to have a EUR of about 6.7% less than originally estimated. The field is young, having only been producing since 2001 and it is anticipated that this field will also see an increase in the EUR over time.

The majority of the fields have demonstrated significant reserve growth over their producing life (Table 2.22). For these fields the reserves growth ranges from 29.0% at the Alpine field to 372.2% at the Kuparuk River field. The ten fields, including the Lisburne and Badami fields, are expected to produce an additional 7,207 MMBO or 59.2% more oil than originally anticipated. Thus, as many have said, “the best place to find oil is in an oil field”.

2.5.2.2 Estimated Post-2004 Reserves Growth in Existing Fields

It is highly improbable that the EUR figures of Table 2.22 are the field abandonment values for production. While there is no expectation that fields such as Prudhoe Bay and Kuparuk River will continue to experience increases in reserves at the prior rates, they and other newer fields will be treated with more efficient tertiary recovery methods, such as CO_2 floods, and increase their yields beyond the currently forecast levels. In fact, new fields are now being brought on line with enhanced recovery technologies incorporated into the original development scheme. The availability of CO_2 in sufficient volumes may be attainable from the gas cap at Prudhoe Bay and from Point Thomson. There are an estimated 5.0 TCF of CO_2 in the Prudhoe Bay gas cap and oil column (Masterson, 2001), which is located in close proximity to the fields most able to benefit from such a program. Miscible CO_2 floods would be applicable to the majority of the producing fields and have the potential to increase recovery by 8 to 11% of the OOIP (Nelms and Burke, 2004).

The largest potential reserves growth will probably occur in the viscous, heavy oil fields. The current estimate of economically recoverable reserves is between 1.155 and 1.630 BBO (Table 2.7). The ultimate reserve numbers may be much larger and estimates cited by Rosen (2005) indicate that one-fifth of the ANS in-place viscous oil could be produced. Since the estimates for in-place viscous oil range from 26.0 to 45.0 BBO, the total recoverable reserves could be 5.0 to 9.0 BBO. The USGS (Anchorage Daily News, 2003) is quoted as estimating that the ANS has 7.0 billion barrels of recoverable heavy oil. New Technology Magazine (2005) and IHS Energy (2005), referencing the DOE, state that advanced enhanced recovery technology has the potential to extract “several billion barrels of oil”.

The potential for reserves growth in the heavy oil fields is in the order of 3.0 to 4.0 BBO, and this oil can be expected to be produced between 2015 and 2050. The timing for the development and production of these volumes of heavy oil is dependent upon a continued high price structure, availability of technology, and a ready supply of reactant, perhaps CO_2 extracted from the gas as it is conditioned for the pipeline. If the full development of the heavy oil potential awaits a large and reliable supply of CO_2, it may be post-2015 before most of this potential is realized. The low gravity of these oils, generally between 14 and 21° API would dictate that only an immiscible CO_2 flood would be effective (Taber and others, 1996). Immiscible CO_2 floods are only about half as effective as miscible floods.

Fields currently on production may be expected to add reserves at rates dependent upon their age (prior growth), oil properties, and recovery technologies utilized. Fields such as

Prudhoe Bay and Kuparuk River will see modest incremental growth and Alpine and Northstar more vigorous growth. Based on the performance of these reservoirs it may be possible to use them as analogs and estimate how newer fields such as Northstar may perform in terms of increased recovery rates and addition of reserves. An aggregated estimate of reserves growth for these ten fields is 2.00 BBO with approximately two-thirds coming from Prudhoe Bay and Kuparuk River fields and the remainder from the smaller fields.

In summary the potential for additional reserves growth from currently producing fields is 5.0 to 6.0 BBO (3.0 to 4.0 BBO from the viscous, heavy oil fields and 2.0 BBO from the conventional oil fields) with the great bulk of this production post-2015.

2.5.3 Potential Reserve Additions through Exploration

If exploration were to remain confined to the areas of current exploration and development activity (northern portion of Colville-Canning province and adjacent State waters, and eastern NPRA–see Figure 2.20), the magnitude of reserve additions would be significantly reduced from the projections made in the foregoing sections. A review of the contrast between the magnitude of potentially recoverable resources is provided by comparing the EUR of oil and gas if future activities were confined to the currently active areas and the EUR if all the provinces were systematically and thoroughly explored and subsequent economic discoveries were developed as proposed and outlined in the preceding sections (Table 2.23).

2.5.3.1 2004 Core Producing Area

Under the unlikely circumstances that the areas of current exploration and development (core producing area) were to define the geographical limits of future activity in Arctic Alaska, the volume of additional oil and gas would consist of reserves growth in the existing fields and reserves associated with any new discoveries within this limited area. These are tabulated in the first row of Table 2.23 and indicate a total of 9.9 to 10.9 BBO and 12.0 TCF would be added by 2050.

Restriction of activity to this core area is highly unlikely. Exploration and development is even now moving westward within NPRA and this scenario does not include the possible delineation and potential development of the Hammerhead and Kuvlum oil fields.

Table 2.23. Additions of economically recoverable oil and gas for differing exploration scenarios (including near and long term).

Area Under Development	Oil (BBO)			Gas (TCF)
	Growth	Exploration	Total	Exploration
Current Activity[a]	5.0-6.0	4.9	9.9-10.9	12.0
Current Plus NPRA & Southern Central Arctic	5.0-6.0	10.3	15.3-16.3	65.3
Current, NPRA, Southern Central Arctic, Plus Beaufort Sea	5.0-6.0	14.6	19.6-20.6	85.3
Current, NPRA, Southern Central Arctic, Beaufort Sea, Plus Chukchi Sea	5.0-6.0	24.1	29.1-30.1	135.3

Current, NPRA, Southern Central Arctic, Beaufort Sea, Chukchi Sea, Plus 1002 Area	5.0-6.0	30.35	35.35-36.35	137.3
a. Current Activity area – Northern portion of Colville-Canning province and adjacent State waters, and eastern NPRA – see Figure 2.20.				

2.5.3.2 Frontier Exploration

The addition of the four subprovinces and the southern portions of the Colville-Canning area provide the reserve increases recorded in the second through fifth rows of Table 2.23. Economically recoverable oil, due to exploration, is estimated to increase from 4.9 BBO to 30.35 BBO as the frontier exploration provinces are explored and developed. The exploration derived additions to the economically recoverable gas base are even more dramatic, increasing from 12 TCF to 137.3 TCF. It is obvious from numbers such as these that for production to continue well into the middle of the 21st century and for the pipeline(s) to remain economically viable enterprises, there must be ongoing and widespread exploration and development of the regions conventional hydrocarbon resources.

While the probability is low that events will unfold as sequenced in the exploration and development scenario used for this evaluation, the general conceptual approach to exploration and the premise that larger fields will be developed and spur further drilling and subsequent development of accumulations otherwise uneconomic is sound. The projected number and size of discoveries are virtually all within the ranges proposed by the USGS and MMS assessment teams. The test of whether the primary fields will be sufficiently large to prove economic will be largely dependent on price and proximity to, or availability of, infrastructure (see Section 3.8 for economic analysis of minimum economic field size). The hydrocarbon generation potential for this large area, comprised of entire North Slope and the Beaufort and Chukchi sea shelves, is at least 10.0 to 20.0 trillion barrels of oil and thousands of TCF of natural gas. Bird (1994) estimates that the Ellesmerian Petroleum System of the North Slope, generated 8.0 trillion barrels of oil. The additional generative potential of the Ellesmerian and other petroleum systems, not only on the North Slope but also beneath the offshore areas of the Beaufort and Chukchi seas, should be sufficient to have generated hydrocarbon volumes of the magnitude suggested. Therefore, the additional economically recoverable resources attributed to future exploration success are a trivial fraction of the volumes generated.

2.5.4 Summary

The geological considerations discussed in this report support the conclusion that Arctic Alaska can have a long and fruitful future with respect to the development and marketing of the region’s oil and gas resources provided: (1) high oil and gas prices continue, (2) stable fiscal policies remain in place, and (3) all areas are open for exploration and development. The productive life of the Alaska North Slope would be extended well beyond 2050 and could potentially result in the need to refurbish or restructure TAPS and add capacity to the gas pipeline. **However, the future expectation for Arctic Alaska becomes increasingly pessimistic if the assumptions are not met as illustrated by the following scenarios**:

- Scenario 1: If the ANWR 1002 Area is removed from consideration, the estimated economically recoverable oil is 29 to 30 billion barrels of oil and 135 trillion cubic feet of gas.
- Scenario 2: Scenario 1 plus removal of the Chukchi Sea OCS results in a further reduction to 19 to 20 billion barrels of oil and 85 trillion cubic feet of gas.
- Scenario 3: Scenario 2 plus removal of the Beaufort Sea OCS results in a reduction to 15 to 16 billion barrels of oil and 65 trillion cubic feet of gas.
- Scenario 4: Scenario 3 plus no gas pipeline reduces the estimate to 9 to 10 billion barrels of oil (any gas discovered will likely remain stranded).

The most likely scenario is some combination of these hypothetical scenarios. Opening of the 1002 Area of ANWR is highly problematic and the likely restrictions on seismic and drilling activity in the Chukchi OCS and Beaufort OCS areas and possible restrictions to available development areas in NPRA support the lower estimates.

3. Engineering and Economic Evaluation

This section presents an engineering and economic evaluation of the Alaska North Slope (ANS) petroleum producing complex. The goal is to combine the geologic and engineering findings to evaluate future economical oil and gas production for the ANS and estimate the resulting revenue generated for industry, the state of Alaska, and the federal government. Specific objectives of the analyses are to:

- Estimate future ANS economical oil and gas production from: (1) currently developed fields, (2) pools with announced and pending development plans, and (3) pools with recognized potential for development.
- Determine the minimum economic field sizes (MEFS) for exploration and production (E&P) projects at differing distances from the existing petroleum production infrastructure and exploration areas (Central Arctic including Foothills gas, NPRA, 1002 Area of ANWR, and the Beaufort and Chukchi Sea OCS areas).
- Examine the role of natural gas off-take and sales through an Alaska Gas Pipeline, assumed to be operational in 2015, on the future economic viability of ANS oil and gas development and production.
- Identify future facility constraints for oil, water, and gas handling and analyze impact of facility sharing on the economics of future development.

A brief description of each pool and field is provided and production forecasts of estimated remaining technically and economically recoverable oil and gas reserves and ultimate recovery are presented for individual pools from production history, field performance observations, and analog reservoirs. These estimates are presented as technical remaining recoverable (TRR) resources and technical ultimate recoverable (TUR) resources. The economic analysis provides estimated remaining reserves (ERR), and estimated ultimate reserves (EUR) for four oil and gas price scenarios.[18] Production forecasts are developed for each producing pool. These forecasts are used to generate the TUR estimates used in the economic analysis for each pool to determine EUR's. Generic production forecasts are developed for pools that may be discovered through future exploration based on anticipated formation types and analogous producing field characteristics. Forecasts of this type are used to estimate MEFS for various locations across the ANS basins described in Section 2.

These results are combined into composite forecasts of future ANS oil and gas production using specific investment, operating costs, and pricing assumptions. The implications of future development scenarios on the long-term viability of ANS oil and gas production are identified and summarized.

[18] Petroleum reserves can have several different meanings depending on source and application for the reserves information. A general definition of petroleum reserves is the volume of hydrocarbons reasonably expected to be produced in some future time period under current or planned operations. See Section 3.1.3.

A major issue facing Alaska and the industry is how long ANS production can be stabilized before entering another period of sustained decline? This depends on the potential for new discoveries, continued development of smaller satellite pools, development of the heavy viscous oil resources, increasing recovery from existing reservoirs, and the effect of major gas sales on the economic life of ANS oil and gas production.

A major limiting factor in the economic life of ANS oil production is the lower throughput limit for operation of Trans Alaska Pipeline System (TAPS). The recently completed TAPS Pipeline Reconfiguration by Alyeska Pipeline Service Company (Alyeska, 2004) has resulted in a reduction from the original ten pumping stations (PS) with pumping capability to four stations (PS 1, 3, 4, and 9) that must be on line for any flow rate because of the mountain ranges and the associated elevation changes between PS 1 and Valdez. Reconfiguration involved replacing natural gas pump drivers with electric motors and modern centrifugal pumps. Three driver packages are currently installed at PS 1, 3, 4, and 9 that support throughput up to 1.14 MMBOPD (Alyeska, 2004). Placing additional pump skids at these pump stations and at PS 7 and 12 would provide capacity of 1.5 MMBOPD. Taking pumping units off-line down to one unit at each of the four required stations is expected to result in a lower continuous operating limit of between 300,000 to 450,000 BOPD.[19] The crude oil mix determined by current and future crude oil characteristics from known and undiscovered ANS pools and temperature profiles achievable at the lower rates will impact the lower limit that can be maintained. TAPS tariffs will increase as the throughput decreases because of fixed costs (e.g., operating and maintenance) related to pipeline costs being allocated to fewer barrels of oil.

The timing and amount of economically recoverable oil from the ANS that would be lost because of the total production rate reaching the TAPS lower limit will be shown for the scenarios analyzed in this section.

3.1 Engineering Analysis

This section presents a brief overview discussion of North Slope development history and the approach and data used to develop forecasts of oil and gas TRR.

3.1.1 Development History

The discovery of the Prudhoe Bay field in January 1968 is significant not only for the size of the discovery, but also because it is the largest oil accumulation in North America. This discovery was of sufficient value to support the grass roots development of a petroleum infrastructure on the ANS. The total ANS still produces about 16% of the U.S. domestic oil production almost 30 years after startup of production in 1977. The continued application of advanced technology combined with the relentless effort to reduce costs has allowed this major oil production province to sustain a major role in the nation’s energy supplies. Advanced technology has allowed technical and economic access to an increasing fraction of the total petroleum endowment with decreasing physical impact.

The development of the Prudhoe Bay Unit (PBU) required the installation of a complete

[19] Personal communication, Alyeska Pipeline Service Company, June 2006.

petroleum infrastructure prior to the delivery of oil to domestic markets, which occurred 10 years after discovery (Thomas et al., 1991). The construction of TAPS, the delivery of production facilities by sealift, drilling supplies, and crew quarters was a huge logistical undertaking. PBU production increased from 316 thousand barrels of oil per day (MBOPD) in 1977 to over 1,500 MBOPD by 1980. This rate was sustained though 1989. Peak production coincided with a higher oil price regime through 1985, providing large revenues to the stakeholders (industry; state, local, and federal governments). Industry reinvested a portion of these revenues to support the development of the Kuparuk River field and for continued exploration. First production from the Kuparuk River Unit (KRU) was in 1981 and production increased to a plateau of over 300 MBOPD by 1988 before starting on decline in 1992. KRU development was scheduled to allow full utilization of TAPS capacity consistent with the oil markets and the investment climate.

ANS oil production increased to over 2,000 MBOPD in 1988 including production from the Lisburne and Endicott fields before starting to decline in 1989. This decline continued until 2000 when oil production was stabilized at about 1,000 MBOPD from 2000 through 2003 before declining to below 900 MBOPD. Lower 48 oil production has continued to decline (Figure 3.1).

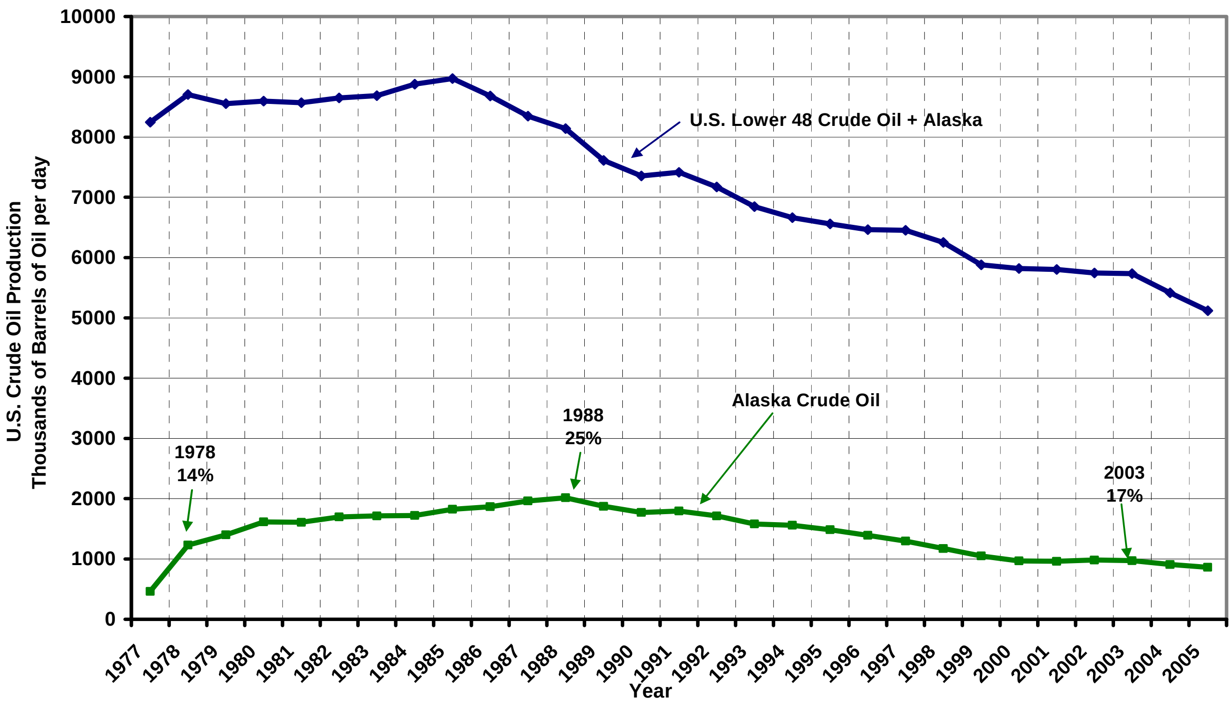

Figure 3.1. Comparison of Lower 48 and Alaska oil production history.

The discovery of new pools and the development of satellite accumulations as well as application of advanced technology have allowed ANS production decline to be minimized in the short term as shown in Figure 3.2.

3.1.2 Source Data

The TRR forecasts rely on publicly available information including plans of development filed with the Alaska Department of Natural Resources (ADNR), conservation orders filed with the Alaska Oil and Gas Conservation Commission (AOGCC), open file information from both

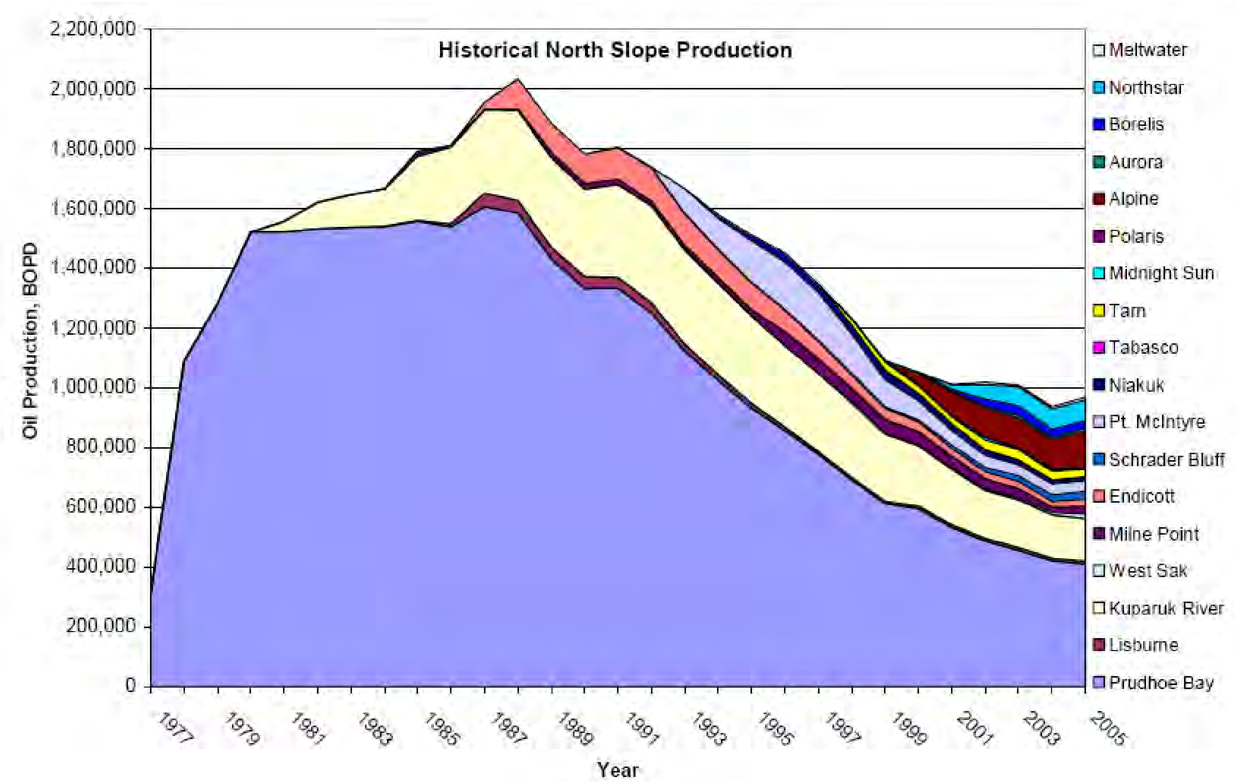

Figure 3.2 Historical Alaska oil production history by pool (ADNR, 2004).

ADNR and AOGCC, and various trade publications. This information was also used in the preparation of production forecasts and development drilling scenarios.

The AOGCC maintains a publicly available database of all production data from all producing pools in Alaska. This database consists of the production data for each pool; well name, date, oil, water, gas production, production days, water injection, gas injection, and water and gas injection days. The pool numbers assigned by AOGCC provide a unique identifier for each pool and are helpful as different accumulations are developed in the same formation and proximal to other pools in the same formation, unit, or both. The list of ANS pools and pool numbers assigned by the AOGCC, and estimated original-oil-in-place (OOIP) volumes are given in Table 3.1. Prudhoe Bay OOIP is about 56% of the total oil discovered on the North Slope to date. However, as shown in Table 2.7 (page 2-75), the Ugnu accumulation, which is estimated to contain from 15 to 24 billion barrels (BBO), is excluded from this evaluation as economically and technically infeasible for development at the present time. However, the Milne Point Unit Schrader Bluff pool as defined the AOGCC contains productive zones in the Lower Ungu (Thomas et al., 1993, p B-4).

Table 3.1. AOGCC pool names and estimated of original-oil-in-place (OOIP).

POOL NAME	AOGCC Pool Number	OOIP (MBO)
Colville River, Alpine Oil	120100	900,000
Badami, Badami Oil	60100	300,000
Endicott[a], Endicott Oil	220100	1,059,000
Endicott, Ivishak Oil	220150	16,000
Endicott, Eider Oil	220165	13,000
Kuparuk River, Kuparuk River Oil	490100	5,690,000
Kuparuk River[b], West Sak Oil	490150	2,000,000
Kuparuk River, Meltwater Oil	490140	132,000
Kuparuk River, Tabasco Oil	490160	99,500
Kuparuk River, Tarn Oil	490165	255,000
Milne Point, Kuparuk River Oil	525100	525,000
Milne Point[b], Schrader Bluff Oil	525140	2,000,000
Milne Point, Sag River Oil	525150	62,000
Milne Point, Ugnu Undefined Oil	525160	Not included
Northstar, Northstar Oil	590100	284,700
Prudhoe Bay, Aurora Oil	640120	100,000
Prudhoe Bay, Borealis Oil	640130	263,000
Prudhoe Bay, Lisburne Oil	640144	3,000,000
Prudhoe Bay, Niakuk Oil	640148	200,000
Prudhoe Bay, Prudhoe Oil	640150	25,000,000
Prudhoe Bay, Polaris	640160	750,000
Prudhoe Bay, Orion Schrader Bluff Oil	640135	1,070,000
Prudhoe Bay, Midnight Sun Oil	640158	60,000
Prudhoe Bay, Point McIntyre Oil	640180	800,000
Total		**44,517,200**

a. Endicott is known as the Duck Island Unit.
b. The total OOIP for the West Sak and Schrader Bluff is described in Table 2.7.

3.1.3 Discussion of petroleum reserves

The concept of petroleum reserves can have several different meanings depending on the purposes and application for the reserves information. A general definition of petroleum reserves is the volume of hydrocarbons reasonably expected to be produced in some future time period under current or planned operations. The U.S. Security and Exchange Commission (SEC) definition of reserves requires a more rigorous analysis to determine the fraction of technically recoverable hydrocarbons that may be produced economically under current economic and operating conditions.

The SEC has prepared detailed guidelines and approved methodologies to estimate reserves for financial reporting purposes to assure comparability of reserve estimates among U.S. publicly traded petroleum companies. The SEC requires the reporting of proved reserves, defined as:

> "Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based on future conditions." (SEC, 1975)

The SEC recognizes only proved developed and proved undeveloped as reserve categories.

The Society of Petroleum Engineers (SPE, 2001) further divides reserves into three general categories with increasing uncertainty: proved, probable, and possible, with additional proved sub-categories for proved developed and proved undeveloped. The SPE methodology provides a formal mechanism for reserve recognition and category upgrades based on continued field development and the implementation of improved hydrocarbon recovery technologies.

3.1.4 Oil reserves forecasts

A pool's TRR may be estimated from technical aspects considering alternative pool development, operational, and recovery technologies employed without specific consideration of price expectations and development costs. One method used is an empirical production decline curve analysis where a production rate versus time plot is used to extrapolate a historic production trend into the future including the impact of known or expected modifications to recovery processes. In some instances where historical production data are not available, or not adequate for decline curve analysis, reserves are geologically based, relying on volumetric quantities of oil- and gas-in-place and expected recovery factors from analogous reservoirs and fields. Hypothetical project developments use a standard production build up period, peak production plateau, and a decline production schedule, with the length of the plateau determined by the TRR.

Future water and gas production forecasts are determined using an empirical dimensionless-variable approach described in Section 3.2.1.8. These forecasts are used in calculations of operating costs.

3.2 Economic Evaluation

This section presents the approach, sources of data, the economic model, and economic parameters used. Results of the economic evaluation of the ANS oil and gas producing pools are presented for each pool in Sections 3.3 to 3.9. The TRR and associated production forecasts are used as primary inputs to the economic evaluation. The results derived include ERR; gross revenue; investments; operating costs; state, federal, and local government taxes and royalties; and net income to the operators. Two major operational scenarios are considered; oil production from the existing fields and new developments with no major gas sales and oil production after the start of major gas sales from the ANS. This second scenario is predicated on the construction of a 52-inch pipeline and the transport of 4.5 billion cubic feet per day (BCFPD) of gas to the Lower 48 states.

Specific goals of the economic evaluations are to estimate likely economic oil and gas production from existing fields and satellite developments, discovered but undeveloped accumulations with announced plans for development, and other known accumulations. Additional goals are to estimate the minimum economic field size (MEFS) at various locations on the ANS. These goals are investigated under a range of oil price scenarios. The effect of potential facility sharing arrangements is evaluated.

The focus is on individual resources at the pool level. The review relies on historical pool performance to forecast oil, water, and gas production. The ability to forecast all three phases from each field allows a comparison of oil, water, and gas production and the identification of potential fluid processing constraints for existing and shared facilities.

3.2.1 Model

The economic model used is based on earlier economic studies of Alaska's hydrocarbon resources (Thomas, et al. 1991, 1993, 1996, 2004), which was vetted by the U.S. General Accounting Office (GAO, 1993). These studies used commercially available software[20] to create a customized program to model in detail a deterministic discounted cash flow of oil and gas development under state of Alaska, federal, and local government tax and royalty rules and environmental regulations. The model provides a detailed treatment of Alaska petroleum tax law and has been refined from these previous studies.[21] The financial analyses use a series of data files describing each project, the oil and gas price tracks, TAPS and ANS field pipeline tariffs, marine transport rates, and other inputs that are needed to evaluate the economics of projects. Economic model outputs include a pro forma statement and a detailed report on per barrel metrics. This approach standardizes the analyses allowing better comparability of the results.

No attempt is made to model the economic performance of an individual working interest owner; instead the focus is on the economic performance of each pool at 100% ownership. The discounted cash flow models are constructed to use a high level of financial detail and to provide

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[20] Interactive Financial Planning System (IFPS), Comshare (U.S.), Inc. Ann Arbor, MI.

[21] The Petroleum Profits Tax (PPT) passed by the state of Alaska Legislature on August 11, 2006 is not analyzed in this report. The details for implementation of the new law have not been defined and clarified by the state to a sufficient degree to allow a definitive evaluation at this time.

detailed results for the estimation of industry, state of Alaska, and federal government revenues and taxes; MEFS; and per barrel metrics. The models are used to evaluate various scenarios for the currently developed and producing pools, fields with development plans, known undeveloped fields, and to estimate MEFS, for a specified financial return or hurdle rate. The economic analyses presented are unrisked because insufficient geoscience and business information is available for a risking exercise.

A discount rate of 10% is used to calculate a cumulative present worth (PW). A cumulative PW of zero indicates that the project will provide a 10% rate of return for the assumed or estimated costs and price scenario at the end of production. The economic analyses presented are un-risked because insufficient geoscience and business data are publicly available for a risking exercise. An un-risked approach may not reflect actual project investment hurdles required by ANS operators and investors nor is a 10% discount rate the rate that industry might use for internal business decisions. Sensitivities to the discount rate are examined and presented in Section 3.6.1.

Geophysical, geologic, and exploration (GG&E) costs are project specific, including lease acquisition and lease bonus, lease rentals, geophysical surveys and interpretation, staff time and resources, the cost to prepare a location and drill an exploration well. These costs may be amortized and capitalized under successful-efforts accounting structure (Thompson and Wright, 1985; Stermole and Stermole, 1993). However, these costs are difficult to obtain without access to proprietary company financial and lease data. Therefore, in this analysis, historical GG&E and lease acquisition costs for currently producing pools are sunk costs and are excluded from economic modeling and amortization. However, GG&E costs are estimated for the MEFS analysis presented in Section 3.8.

Currently producing pools may have some carryover tax effects and these are modeled over the historical development time period to quantify the year-end 2004 property tax basis, unamortized intangible drilling costs, and state and federal tangible property book value for depreciation purposes. Project capital financing is assumed to be 100% equity with no debt financing or financial leverage.

The economic study uses the production forecasts developed in Section 3.3 to 3.9 for currently producing pools, pools under development or development planning, and for hypothetical exploration and development scenarios in the NPRA, ANWR 1002 area, Foothills, Beaufort Sea, and Chukchi Sea. Project development activities take place prior to the start of production. This results in a period of time in which project capital is being invested before a project's cash flow starts. This lead time varies with the project under evaluation and the relative distance from available infrastructure, production facility access, size of the discovered pool, and other factors.

The economic model uses a discounted after-tax cash flow analysis to conduct the analysis and reporting including a pro forma statement of the operating and tax structure of the study pools. A project cash flow statement for producing petroleum assets contains many separate line items, comprising three general categories; revenue and operating expenses, state taxes and credits, and federal taxes and credits, as shown:

Gross Revenue = Production Rate * Wellhead Price

Net Revenue = Gross Revenue – Royalty

Net Operating Revenue = Net Revenue – Operating Costs

State Taxable Income = Net Operating Revenue – Allocated Overhead – Interest Expense – Dry Hole Expense – Production Taxes (severance and ad valorem) –State Depreciation – Expensed Intangible Drilling Costs – Amortization

Income after State Taxes = Income before State Taxes – State Income Taxes + Exploration Tax Credits

Federal Taxable Income = Income after State Taxes + State Depreciation – Federal Depreciation

Net Income after taxes (Profit) = Income before Federal Taxes – Federal Income Taxes

Net After-Tax Cash Flow = Net Income after taxes (Profit) – Investment + Non-Cash Deductions (i.e., Depreciation, Expensed Intangible Drilling Costs, Amortization, and Depletion)

Two cash flows are important for financial analysis and optimization: (a) net income after taxes (or profit), which is a direct measure of the revenue generated from the investment, and (b) net after-tax cash flow, which is a measure of the residual cash flow available to the investor. In this analysis, the determination of ERR and revenues are based on the year when net operating revenue becomes negative.

Two reports are created by the economic model for each pool, a pro forma cash flow statement, and a statement of the oil, gas, and water production and economic results on a per-barrel-of-oil basis. These reports are used to check values, examine the income and investments, and to generate economic metrics on a per barrel basis. Descriptions and examples of pro-forma and per-barrel statistics statements are in Appendix A.

3.2.1.1 Pool Data

Historical pool production is from the AOGCC electronic production database. The database contains individual well records for monthly oil, gas and water production from April 1969. These production data are used for calculating derivative data such as active well counts, daily production, gas-oil ratio (GOR), and water cut trends. Production data for producing pools are presented in Section 3.3.

In instances where historical production data are not available or not adequate for decline curve analysis, reserves are geologically based (or based on published estimates if those are available), relying on volumetric quantities of OOIP and original-gas-in-place (OGIP) and expected recovery factors from analogous reservoirs and fields. Hypothetical project developments use a standard production build up period, peak production plateau, and a decline production schedule, with the length of the plateau determined by the TRR. These forecasts are described when used in Section 3 of the report.

3.2.1.2 Model resource parameters

Primary resource parameters are the OOIP, OGIP, oil gravity, and the estimated total recovery [primary, secondary, and enhanced oil recovery (EOR)]. The recovery factor varies by field depending the well spacing, improved oil recovery implemented, well configuration (vertical, horizontal, multi-lateral), and intrinsic reservoir and fluid properties. The individual pool forecast of TRR liquid volumes developed in Section 3.3 are used in the economic model.

3.2.1.3 Oil Prices

The current high oil prices and price volatility increases the uncertainty in forecasting future oil prices. However, an oil price forecast is necessary to estimate future project cash flows and provide a common basis to compare the relative economic merit of competing investment opportunities under comparable conditions.

Figure 3.3 compares historical ANS West Coast and WTI prices over the time period from January 1988 to December 2004. The differential between the price of benchmark West Texas Intermediate (WTI) and the ANS spot price has averaged $2.32/barrel from 1988 through 2006. From 2004 through 2006 the WTI-ANS differential has averaged $2.68/barrel. Price volatility has clearly been increasing since 1996. Figure S.11 also includes the DOE Energy Information Administration (EIA) Annual Energy Outlook 2006 forecast (reference case) and the Alaska Department of Revenue (ADOR) fall 2006 forecast.

Four flat price decks (nominal dollars) of $25/barrel, $35/barrel, $50/barrel, and $60/barrel for ANS West Coast prices are expected to bracket the oil price range applicable to North Slope crude as illustrated in Figure S.11. Prices are escalated by the general inflation factor of 2.4% and there is no real oil price appreciation. This range roughly brackets the range of oil prices and the impact on future reserves and on state, federal government, and unit owner’s revenue streams.

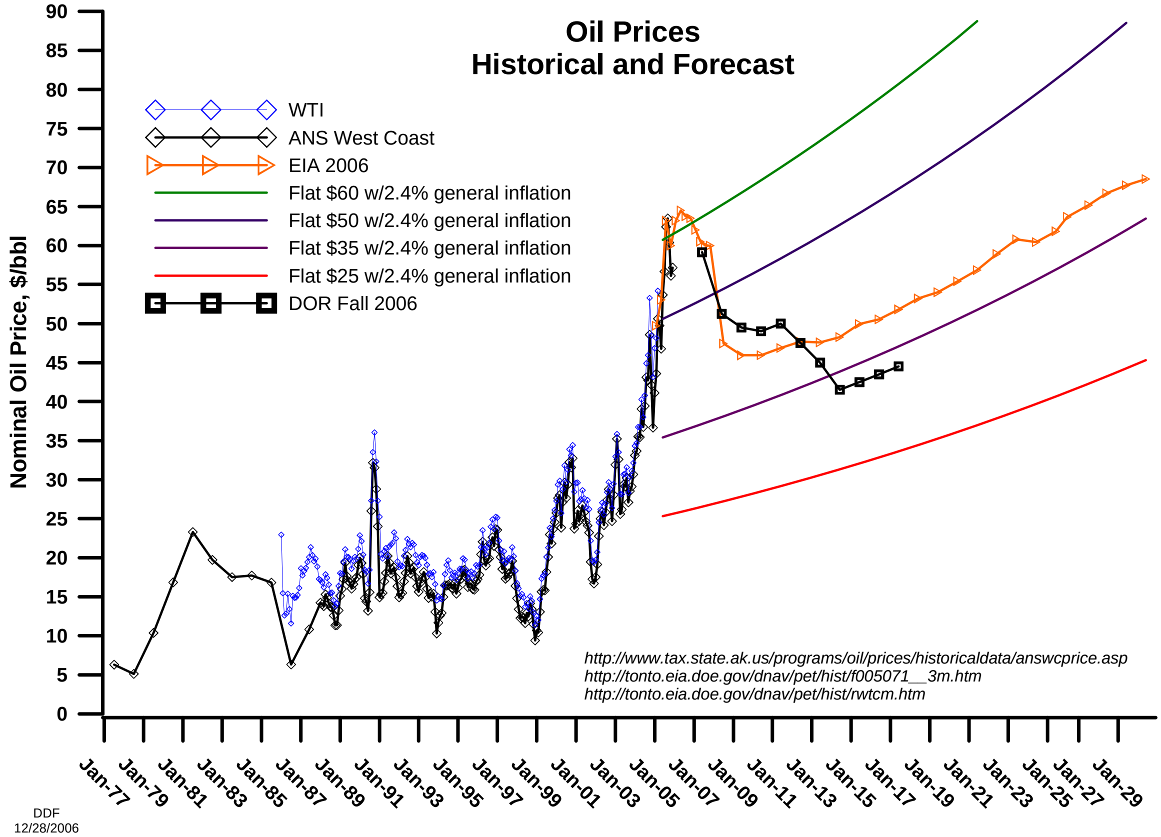

Figure 3.3 Comparison of historical oil prices and oil price forecasts (AEO, 2006; ADOR, 2006).

3.2.1.4 Gas Prices

Prior to the start of major gas sales, natural gas sold between Units on ANS, including miscible injectant (MI), is priced using a settlement agreement between the state of Alaska and field operators. The agreement established a Local Gas Formula (LGF) for setting ANS gas prevailing value prior to the start of major gas sales. Natural gas delivered off lease or sold to other Units is subject to payment of royalty and production taxes. The gas prevailing value in dollars per thousand cubic feet ($/MCF) is;

$$LGF = 0.75\left[\frac{ANS\ West\ Coast\ Spot}{16.16}\right]$$

The prevailing value for natural gas sold and used off Unit is directly related to the oil price received at a West Coast terminus, greatly simplifying natural gas valuation. This ANS gas valuation is not tied to Lower 48 or world markets and does not provide an appropriate pricing mechanism for gas that will be exported off the ANS. Hence, a different gas pricing method is used in this assessment.

Historical average U.S. wellhead, Henry Hub spot, Cook Inlet prevailing natural gas prices, and WTI oil spot prices (converted at 8 MCF/bbl or 8,000 MBTU/bbl) are shown in Figure 3.4.

The recent history indicates that oil and natural gas prices are not at direct BTU parity over the last few years and a review of the last 20 years indicates an 8:1 BTU price relationship. Hence, for this assessment, the four natural gas price forecasts used are the BTU equivalent of the four ANS West Coast oil price forecasts at eight-to-one. The recent history indicates that oil and natural gas prices are not at parity on a BTU basis for the last few years. Hence, the four natural gas price forecasts used are the BTU equivalent of the four ANS West Coast oil price forecasts as discussed in Section 3.2.1.3.

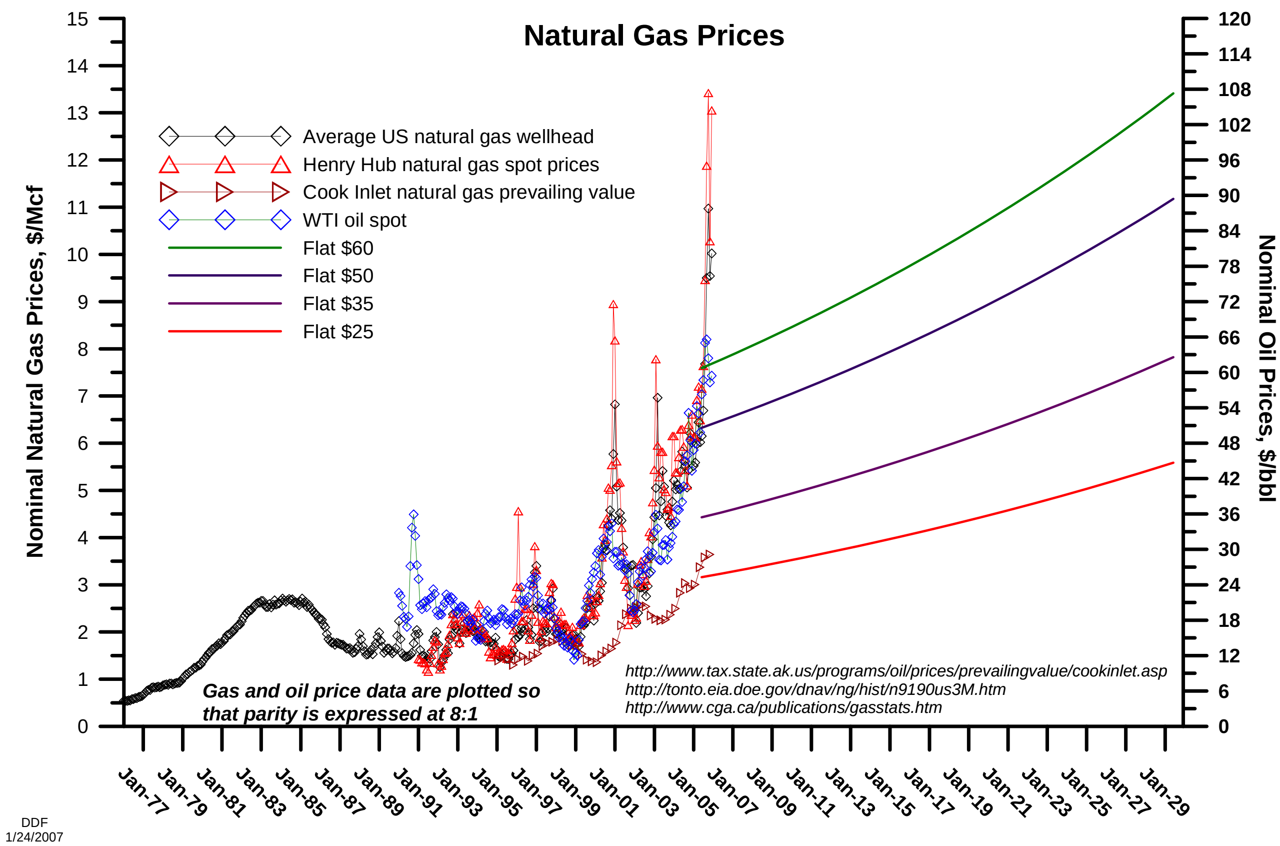

Figure 3.4. Comparison of historical natural gas prices and price forecasts.

To determine wellhead gas prices, a yearly gas pipeline tariff schedule is developed and used to net back natural gas prices to the wellhead.[22] The tariff is calculated using an economic model for a gas pipeline project to Chicago (see Section 3.2.1.6) (DOE, 2006).

3.2.1.5 Oil Transport Costs and Quality Adjustment

The cost to transport ANS oil to the West Coast market consists of marine transport and TAPS and field pipeline tariffs.

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[22] The Alaska Gas Pipeline (AGP) is expected to be a high pressure dense phase line and transport enriched natural gas that contains significant quantities of ethane, propane, butanes, and pentane in addition to methane and have a BTU content of 1,200 to 1,500 BTU/standard cubic foot (scf) (ANGDA, 2005). At this stage of planning, the quantity and value of these non-methane hydrocarbons are uncertain and are not explicitly included in the economic evaluations.

The state of Alaska publishes the Alaska Location Differential (formerly called the Marine Transportation Deduction) that netbacks the West Coast oil prevailing value to the Valdez tanker port (shown in Table 3.2). Marine transportation cost is escalated at the general inflation rate for the out years.

Table 3.2. Historical and forecast marine transport costs (nominal dollars) (ADOR, 2005).

Year	$/barrel	Year	$/barrel
2000	1.32	2009	1.93
2001	1.29	2010	1.98
2002	1.39	2011	2.03
2003	1.79	2012	2.08
2004	1.66	2013	2.13
2005	1.52	2014	2.18
2006	1.78	2015	2.23
2007	1.83	2016	2.28
2008	1.88		

TAPS is a 48-inch common carrier crude oil pipeline owned and operated by five companies, known as the TAPS Carriers: BP Pipelines (Alaska) Inc.; ExxonMobil Pipeline Company; ConocoPhillips Transportation Alaska, Inc.; Koch Alaska Pipeline Co., LLC; and Unocal (Chevron) Pipeline Company. TAPS tariffs are filed on a calendar year basis, with new tariffs taking effect January 1 each year. The 2005 TAPS tariff is $3.25/BO (FERC, 2004) and the TAPS tariff forecast used by ADOR (2005) is presented in Table 3.3. TAPS tariff is escalated at the general inflation rate for the out years.

Table 3.3. Forecast TAPS tariff. (Source: ADOR, 2005)

Year	TAPS Tariff ($/barrel)	Year	TAPS Tariff ($/barrel)
2006	3.66[23]	2012	3.51
2007	3.75	2013	3.66
2008	3.64	2014	3.83
2009	3.59	2015	3.89
2010	3.56	2016	3.99
2011	3.58		

Field pipeline tariffs are posted by the operators. Oil that traverses several field pipelines is assessed a field tariff for each pipeline segment. Field pipeline tariffs are presented in Table 3.4.

[23] For comparison purposes, Alaska Department of Revenue 2006 Fall Forecast tariffs are $4.06/bbl for 2006, $4.38/bbl for 2007, $4.11/bbl for 2008 with 2009 through 2017 lower by about $1.00/bbl than the tariffs contained in the 2005 Forecast. These forecasts were not available for use in this analysis

Table 3.4. Field pipeline tariffs, $/barrel.

Field	Tariff ($/barrel)	Notes
Alpine	0.66	To Kuparuk pipeline
Badami	0.24	To TAPS Pump Station #1, (RCA P-04-2)
Endicott	0.68	To TAPS Pump Station #1
Kuparuk	0.19	To TAPS Pump Station #1
Milne Point	0.24	To intersection with Kuparuk pipeline (RCA P-04-3)
Northstar	1.31	To TAPS Pump Station #1

The oil quality of the different fields varies from heavy to light oil and is reflected in the American Petroleum Institute (API) gravity value. Historically, a quality bank has been used by TAPS to adjust the value of the different oils and compensate for differentials in the value of shippers' oil commingled in the pipeline. Variation from the specified API gravity results in a positive price adjustment for crude oils with a higher API gravity and a negative price adjustment for crude oils with lower API gravity. The quality bank adjustment used is $0.0364 per 0.1°API referenced to a gravity of 28°API (ConocoPhillips Alaska, 2006). This approach is a simplification of the current methodology, which is based on a distillation methodology.[24]

3.2.1.6 Gas Tariffs

For the economic evaluation of major gas sales with delivery of ANS gas to Chicago, an estimation of the natural gas tariff is required. The tariff calculation uses a full life cycle cost basis that includes the capital cost of; the pipeline, gas conditioning plant on the North Slope for the removal of CO_2 and other contaminates, compressors, and estimated decommissioning costs after the useful life of the pipeline. Capital costs for a 52-inch pipeline project were estimated at $21 per diameter-inch foot, $1.6 billion for compressors, and $2.4 billion for a gas conditioning plant at the pipeline inlet (2005$). The annual cost of service is the sum of the annual operating costs, depreciation, the regulatory return on the installed capital, decommissioning costs (as a sinking fund), ad valorem, and income taxes. The annual tariff is the cost of service divided by the annual pipeline volume. This tariff calculation is described in Appendix B.

Tariffs as a function of flow rate for the 52-inch pipeline are presented in Figure 3.5 and in Table 3.5a and Table 3.5b. The tariffs in Table 3.5a are the 12-yr average from 2015 to 2026 in 2005$. Table 3.5b contains the yearly tariffs for a 4.5 BCFPD rate. For the out-years beyond 2026 the gas tariffs are escalated by 2.4%. Yearly tariffs vary as a result of depreciation schedules, property taxes, and income taxes. The yearly gas pipeline tariff schedule is used to net back natural gas prices to the wellhead.

[24] The quality bank methodology has been the topic for litigation and FERC hearings over a number of years. A decision was made by FERC October 20, 2005 affirming an administrative law judge's initial decision compensating shippers according to the quality of the crude oil delivered to TAPS. The valuation method uses a distillation method for valuing the various components of the crude oil and is separated into components such as butane, propane, naphtha and residual. Market values are assigned to each cut and the value of a crude oil stream is determined by the relative weighting of the cuts.

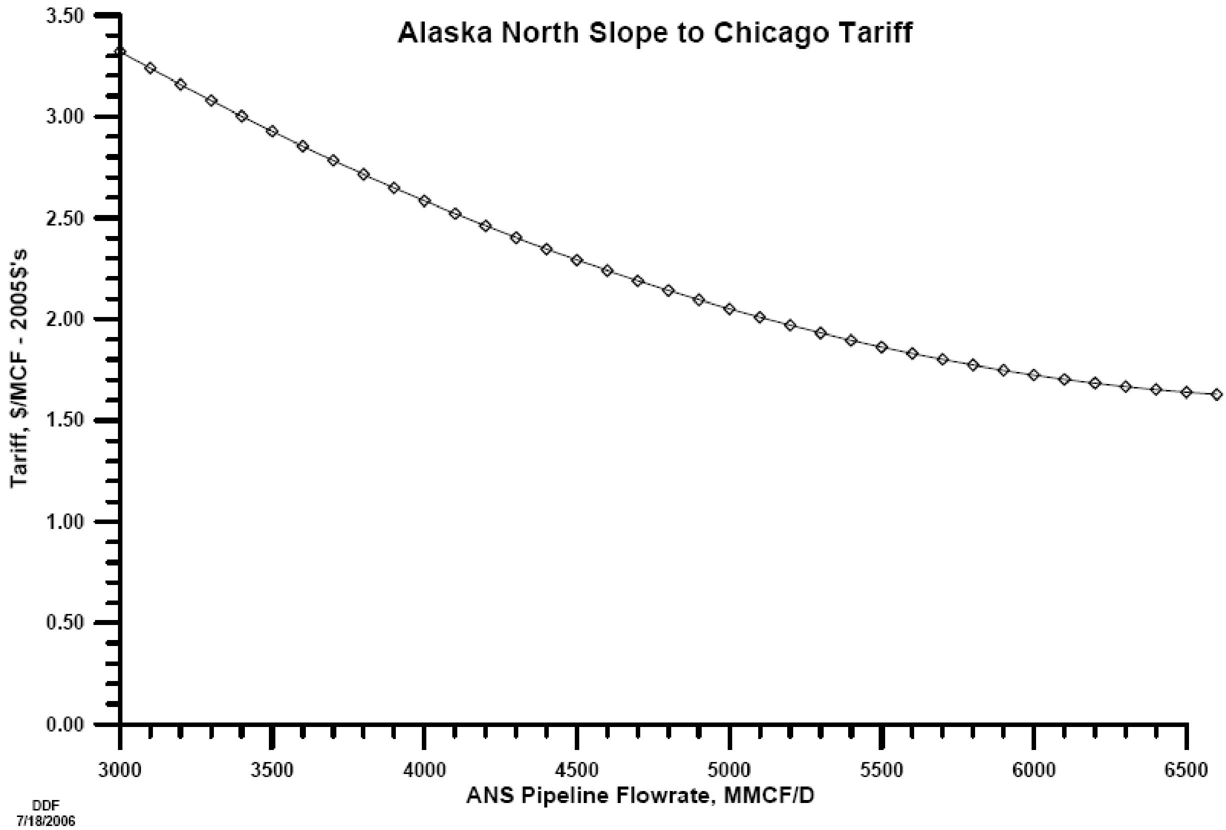

Figure 3.5. ANS 52-inch pipeline tariff (12-yr average, 2005$).

Table 3.5a. ANS tariff to Chicago (12-yr average, 2005$).

Flow Rate MMCFPD	$/MCF	Flow Rate MMCFPD	$/MCF	Flow Rate, MMCFPD	$/MCF
3000	3.322	4200	2.461	5400	1.896
3100	3.239	4300	2.402	5500	1.862
3200	3.158	4400	2.346	5600	1.831
3300	3.079	4500	2.292	5700	1.801
3400	3.002	4600	2.239	5800	1.774
3500	2.927	4700	2.189	5900	1.748
3600	2.854	4800	2.141	6000	1.725
3700	2.784	4900	2.095	6100	1.704
3800	2.715	5000	2.051	6200	1.684
3900	2.648	5100	2.009	6300	1.667
4000	2.584	5200	1.969	6400	1.652
4100	2.521	5300	1.932	6500	1.639

Table 3.5b. ANS tariff by year for a 4.5 BCFPD pipeline (2005$'s).

Year	2005$
2015	2.599
2016	2.931
2017	2.784
2018	2.647
2019	2.517
2020	2.394
2021	2.278
2022	2.169
2023	2.065
2024	1.968
2025	1.876
2026	1.788

3.2.1.7 Royalty

Royalty is a fraction of the gross wellhead value that is paid by the lessee to the lessor for production from a lease and can be taken in kind. The customary royalty for ANS production is 12.5 per cent (1/8). There are some leases that may have a 16.67% royalty and a few have net profits interest royalty.

3.2.1.8 Estimating Water and Gas Production

Gas and water production forecasts are needed for operating cost determination and to examine facility constraints. One of the difficulties of forecasting future oil, water, and gas production for ANS fields is the wide variation of reservoir properties, fluid properties, well design, improved oil recovery processes, and other engineering and operational considerations. A complete analysis would require access to reservoir engineering data (well tests, well completions, recovery technologies, etc.) and detailed reservoir simulation for each pool and is not feasible for this study. Hence, a method to reduce the complexity of the analysis involving transforming the pool-specific production data to dimensionless variables was developed (see Appendix C).

The production data are transformed for each field using the water cut (WC) and GOR_D, as defined below:

$$WC = \frac{q_w}{q_w + q_o},$$

where q_w is the monthly water production and q_o the monthly oil production. The dimensionless gas-oil ratio (GOR_D) is defined as:

$$GOR_D = \frac{GOR_t}{GOR_{initial}},$$

where GOR_t is the current *GOR* and $GOR_{initial}$ is the ratio at discovery reflecting initial conditions of pressure and saturation. The WC and GOR_D are plotted versus the recovery factor (RF), defined as follows:

$$RF = \frac{N_p}{TUR},$$

where N_p is the cumulative oil produced.

This methodology is illustrated in Figure 3.6 for the Kuparuk River pool. Using an estimated TUR for the pool or field, the cumulative oil recovery (N_p), is reduced to a scalar quantity, RF, which allows for direct comparison of the various fields. Presenting WC and GOR in this fashion allows direct comparison of the increase in WC and GOR between different pools and a calculation of future water and gas production based on the historical production.

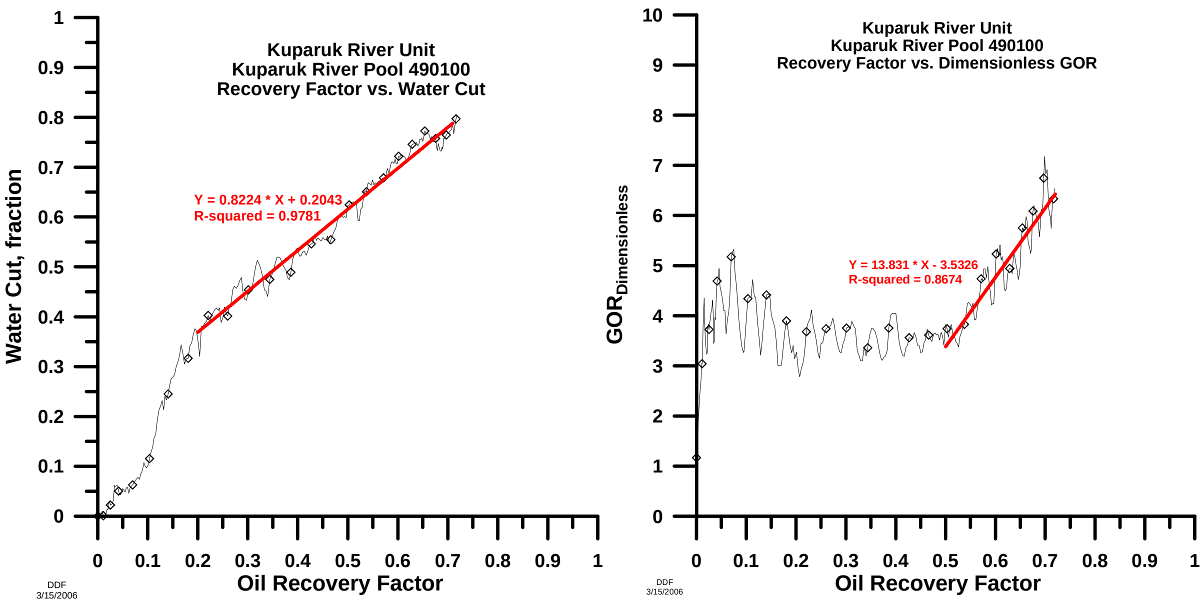

Figure 3.6. Kuparuk River pool water cut and dimensionless GOR versus recovery factor.

Pools with similar formations, reservoir fluids, and displacement mechanisms are observed to have similar production responses when using this dimensionless approach. When sufficient pool data are not available, forecasts are made using information for a similar reservoir.

3.2.1.9 Well Counts

The number of active production and injection wells at year-end 2004 is taken from state production records. New wells are added to the number of active wells based on the specified fraction of injection and production wells. The average well production rate is calculated by the yearly production divided by the number of active production wells and is used for the economic limit factor (ELF) in the determination of severance taxes, and variable operating costs. Well attrition is assumed to vary with time between 2.5% and 5% of the total current active production and injection wells. This method is used to model well abandonment or mechanical failure during the life of the field. Thus, even if there is new drilling, the operating well count will eventually decline, mimicking field operations.

3.2.1.10 Operating Costs

Operating costs consist of both fixed and variable components. The average North Slope fixed cost is assumed to be $1,000,000 per well per year (2005$). The fixed cost is based on a recent study that estimated Alaska operating costs (fixed plus variable) at $1.761 million per well (2000$s) (NPC, 2003). This costs was escalated to 2005$s at 3.54%/year yielding $2.096 million per well per year total operating costs using the Bureau of Labor statistics Producer Price Indices (PPI), oil and gas services component. As discussed in the section on inflation, the extreme volatility in the PPI oil and gas components makes estimating the total operating cost per well uncertain. There is a dearth of data to refine the total operating cost assumptions. These costs are reduced near the end of a field's economic life as a function of the recovery factor to approximate the actions a prudent operator would undertake to reduce costs as a pool's production declines to extend the economic limit. Variable costs are those component that are a linear function of the production rate, such as lifting costs on a per-barrel-fluid-lifted basis (crude oil and water production) or a facility-sharing fee on produced fluids. The average lifting cost for North Slope production is assumed to be $0.50 per barrel of fluid for conventional oil pools and $0.75 per barrel of fluid for viscous oil pools because associated solids production increases costs.

There are several ways to estimate the economic limit. This study assumes the economic limit occurs when total operating costs exceed net revenues. The total operating costs include the lifting costs, facility cost-sharing fees, well workover costs, and fixed operating costs.

3.2.1.11 Capital Expenditures

Capital expenditures include a broad range of costs for exploration activities, delineation and development wells, offshore platforms, production facilities, field pipelines, other infrastructure related investments, and regulatory costs. Capital costs are either tangible or intangible and are treated differently for tax purposes. Project development costs are scheduled on a pool-by-pool basis. A review of the trade literature related to North Slope development was made to identify general cost ranges for development wells, production facilities, and pipelines.

The investment schedules for all pools are shown in Appendix D. Investment costs are year-end 2004 and inflated to then-current-year dollars using the capital inflation rate of 2.4% (see Section 3.2.2). Costs for platforms, production facilities, and pipelines are 100% tangible, development wells are 30% tangible costs, and exploration well costs are all intangible.

Facility costs: Production facility costs are estimated for recent developments based on a dollar per bbl/day peak production capacity basis. An analysis of the property tax base of the North Slope Borough assessment for 2004 suggests facility costs for grass roots projects are about $10,000/BOPD-peak-production-rate and is used in all new development projects. Pipeline costs per foot are estimated to be $20/diameter-inch for onshore projects and $40/diameter-inch for offshore. An algorithm is used to size pipelines and estimate the associated capital costs for new developments or satellite accumulations (See Appendix 3-E).

Well Costs: The wide range of development wells used (vertical, horizontal, multilateral, coiled tubing drilling) makes it difficult to estimate the cost for a "standard" development well or even what constitutes a "standard" well. Development information from recent fields suggests the standard well in the future will be either horizontal or multilateral completions with a development well cost of at least $8.5 million. The drilling investment schedule is developed from the number of future development wells provided in Section 3.3, anticipated well productivity, and development well cost. The development drilling costs reflect the differences in the characteristics and location of each pool and the development well design used. ANS well cost estimates by pool used in the economic evaluations are listed in Table 3.6.

Table 3.6. Well cost estimates for ANS pools.

Pool	Estimated Well Cost, 2005$ thousands	Note
Alpine	8,500	Onshore
Alpine West	8,500	Onshore
Ataruq	5,000	Onshore
Aurora	7,500	Onshore
Borealis	7,500	Onshore
Endicott	2,500	Offshore
Fiord	11,000	Onshore
Gwydyr Bay	8,500	Onshore/Offshore
Kuparuk River	1,600	Onshore
Liberty	12,000	Offshore
Lisburne	2,500	Onshore
Lookout	11,000	Onshore
Meltwater	7,500	Onshore
Midnight Sun	8,500	Onshore
MPU Kuparuk	2,500	Onshore
MPU Schrader Bluff	11,000	Onshore
Nanuq	11,000	Onshore
Niakuk	2,500	Onshore/offshore
Nikaitchug	7,000	Offshore
Northstar	10,000	Offshore
Oooguruk	10,000	Offshore
Orion	10,000	Onshore
Placer	6,000	Onshore
Point Thomson	6,000	Offshore
Polaris	15,000	Onshore
Pt. McIntyre	7,500	Onshore
Sambuca	2,500	Onshore
Sandpiper	6,000	Offshore
Sourdough	10,000	Onshore
Spark	10,000	Onshore
Tabasco	11,000	Onshore
Tarn	6,000	Onshore
Tuvaaq	7,500	Offshore
West Sak	10,000	Onshore

Intangible costs are 70% for development and delineation wells and 90% for exploration wells with the balance tangible costs. Tangible and intangible drilling costs have different tax treatment and are either expensed or amortized.

3.2.1.12 Alaska Petroleum Taxation

The parameters used in determining Alaska taxes are described below.

Depreciation: Depreciation is a deduction for capital recovery and is calculated using a units-of-production basis (consistent with successful efforts accounting) on the total investment (tangible and intangible) once an asset has been placed in service. The units-of-production factor is the yearly production divided by the year-end remaining reserves. The depreciable basis is the total investment less cumulative depreciation. This is a deduction for the determination of state income tax liability and is a non-cash expense.

Property Tax: The property tax base is the cumulative tangible investment, less the prior year's property tax base divided by the remaining project life. This balance is adjusted for the current year inflation plus the prior year's tangible investment. The property tax (ad valorem) is 2% of the current year property tax base. The 2004 North Slope Borough property assessment roll was used to identify real property by Unit or project and was used in the historical carryover values for the economics model. The total assessed property value for ANS is $10.537 billion of which PBU comprises 44 % of the total.

Oil Severance Tax: Production taxes are a function of the average well rate and the field rate using the state Economic Limit Factor (ELF) as an adjustment to the severance tax. The model tracks the number of active production wells using the historic number of production wells plus any new wells drilled. The number of active production wells is reduced by 2.5% a year due to well attrition.

The state oil severance tax is calculated on the wellhead value less royalty payment. The statutory production tax rate on oil is 12.25% of its value at the point of production for the first five years of field production and 15% thereafter. There is a minimum tax of $0.80/BO. The severance tax is then multiplied by the oil ELF;

$$ELF = \left[1 - \left(\frac{300 * number of\ production\ wells}{Total\ Field\ Volume}\right)\right]^{\left[\frac{150,000}{Total\ Field Volume}\right]^{1.53333}},$$

where Total Field Volume is in BOPD.

Gas Severance Tax: The state gas severance tax is calculated on the wellhead value less royalty payment. The severance tax paid is the greater of either $0.064/MCF or an alternative calculation at 10% of the net wellhead value. The appropriate value is multiplied by a gas economic limit factor (GELF). The GELF is calculated by:

$$GELF = \left[1 - \left(\frac{3000}{Average\ Well\ Rate}\right)\right],$$

where the Average Well Rate is in MCFPD.

Income Tax: Alaska uses a form of unitary taxation for state income taxes based on weighted fraction of a company's Alaskan portion of worldwide sales, production, and assets. The statutory tax rate for petroleum production operations is:

$$Income = 0.094\left[\tfrac{1}{3}\left(\frac{Alaska\ sales}{Worldwide\ sales} + \frac{Alaska\ production}{Worldwide\ production} + \frac{Alaska\ assets}{Worldwide\ assets}\right)\right].$$

It is difficult to independently determine a company's Alaska segment and worldwide operations; therefore a nominal effective tax rate of 3% is used. State income tax is calculated before federal tax. Operating cost, severance and property tax, and state depreciation are deductions from net revenue for state income tax determination.

Exploration Tax Credit: Alaska provides for a tax credit for qualifying exploration costs that lead to a discovery[25] for the time period after July 1, 2003, and before July 1, 2007. A 20% credit is available for wells drilled not less than three miles from a preexisting suspended, completed, or abandoned oil or gas well. A 40% credit is available for an exploration well that is located not less than 25 miles outside of the outer boundary, as delineated on July 1, 2003, of any unit that is under a plan of development.

3.2.3.13 Federal Petroleum Taxation

Depreciation, Depletion and Amortization: State depreciation is added back to the net income after state income tax before the calculation of federal taxable income. Federal depreciation is calculated using a 10-year, 150% declining balance of tangible assets with no switch-over. Intangible drilling costs (IDC) are 70% expensed in the current year and the balance amortized over 60 months. Intangible portions of exploration and development wells are 90% and 70%, respectively. No depletion deductions are used.

Federal Income Tax: The federal income tax rate is 34% of the federal taxable income. Federal tax loss-carry-forward is used and no federal taxes are paid until the loss-carry-forward balance is recovered.

3.2.2 Discounted Cash Flow Analysis

Discounted cash flow analysis is used as the primary economic evaluation tool and is a commonly used mineral and petroleum industry method. The economic model requires a number of inputs to describe in detail the ANS oil and gas pools. In this model, approximately 390 variables are used to describe and calculate production and economic metrics.

The decision making process typically used by industry is described in Thomas et al., (1993, Section 1.2). The present worth (PW) of a project is cumulative net cash flow generated from the project's time sequenced revenues using a company's internally determined price forecast and expenses discounted to current year dollars; i.e., 2005$ in this assessment. For example, a project that produces exactly a 10% return is defined as $PW_{10} = 0$, indicating that the cumulative present worth at the end of the project is 0, so that the investment earns a 10% return,

[25] Alaska State Statues, Sec. 43.55.025, Oil and Gas Exploration Tax Credit.

after tax, measured in current year dollars. Industry decision making will likely involve other criteria and possible risking based on internal assessments of financial, political, and technical risk.

A 10% discount rate is used and is assumed to be representative of the current investment climate. The discount factor is calculated using a yearly discrete formulation and midyear timing. This discount rate is unrisked and may not reflect actual project investment hurdle metrics used by North Slope operators. Analyses to test the sensitivity of projects economic viability to the discount rate are performed to illustrate which projects may not pass this economic hurdle at the discount rate is increased from 10% to 15% to 20%. Fundamental components in any investment decision analysis are the commodity price forecast used and the anticipated inflation rates.

Inflation: A forecast inflation rate of 2.4% per annum is used for general costs, transportation costs, and oil prices; a 3.5% per annum is used for drilling and operating costs. The general inflation rate is consistent with the average Gross Domestic Product (GDP) deflator for the last five years. The drilling and operating cost inflation is based on the PPI, "support activities for oil & gas operations" index, which has averaged 3.54% per annum over the last 20 years with extreme volatility. All costs are inflated to then-current (nominal) dollars from a year-end 2004 base using mid-year escalation. The increasing volatility of the two indices over the last five years suggests the 3.5% per annum inflation rate may understate the sector inflation rate, as shown in Figure 3.7. This figure presents the six-month moving-average monthly change in the PPI indices. The WTI oil price is presented for comparison with the cost indices.

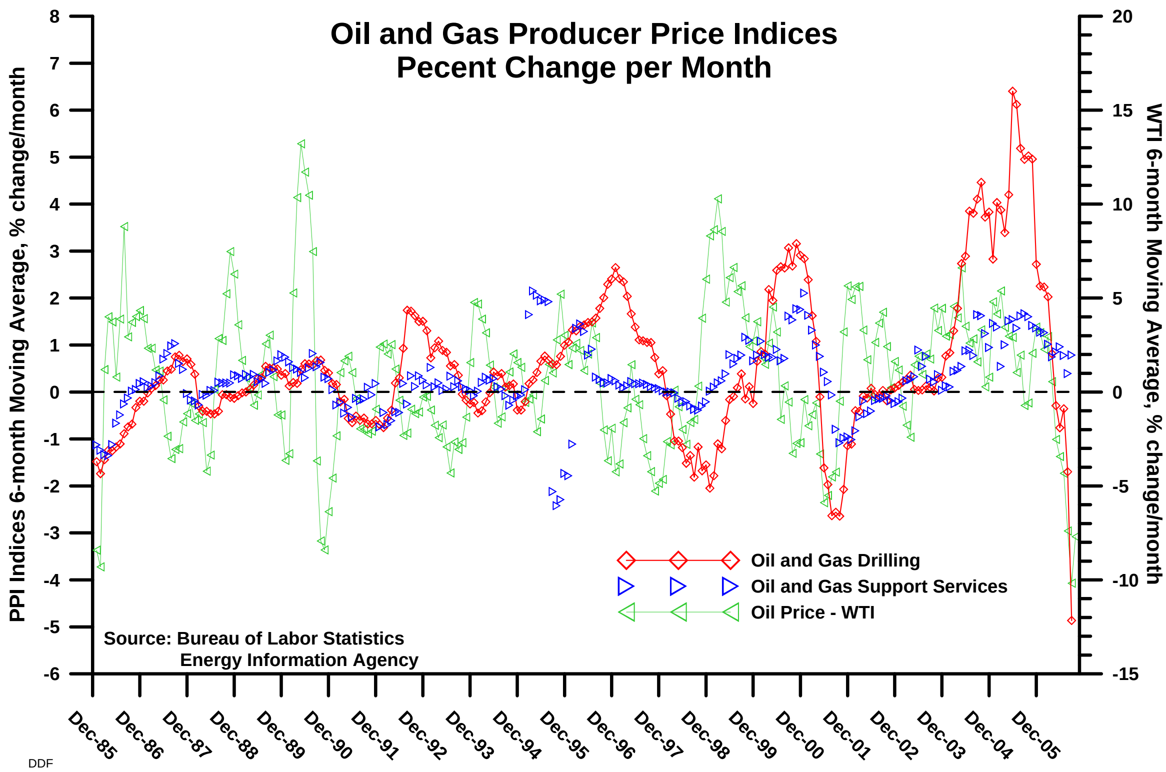

Figure 3.7 Monthly change in Oil and Gas Producer Price Indices compared to WTI.

3.3 Producing Pools without Major Gas Sales

This section presents a description of the engineering and economic evaluations for the currently producing pools and projects listed in Table 3.1. Production forecasts of estimated technical recoverable oil and NGLs are shown graphically for each pool. The forecasts are tablulated in Appendix E.

The section is organized as follows:

Prudhoe Bay Field
- Prudhoe Bay Unit –
  - Initial Participating Area (IPA)
  - Aurora Pool Participating Area (PA)
  - Borealis Pool PA
  - Midnight Sun PA
  - Orion PA
  - Polaris PA
  - Lisburne PA
  - Niakuk PA
  - North Prudhoe Bay PA
  - West Beach PA
  - Point McIntyre PA

Duck Island Field
- Duck Island Unit
  - Endicott PA
  - Eider PA
  - Sag Delta North PA

Northstar Field
- Northstar Unit IPA

Badami Field
- Badami Unit IPA

Kuparuk River Field
- Kuparuk River Unit
  - Kuparuk River IPA
  - Meltwater PA
  - Tabasco PA
  - Tarn PA
  - West Sak PA

Milne Point Field
- Milne Point Unit
  - Kuparuk River IPA
  - Sag River PA
  - Schrader Bluff PA

Alpine Field
- Colville River Unit
  - Alpine IPA

3.3.1 Prudhoe Bay Unit IPA

The Prudhoe Bay pool was discovered in 1968 and produces 27.4ºAPI crude oil from the Ivishak formation (Table 2.7). The Ivishak formation was unitized as the PBU and put into commercial production in June 1977. Engineering and economic analysis to determine TRR and ERR based on the assumed price scenarios and the associated revenue to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.1.1 PBU Pool Engineering and Economics

The Prudhoe Bay pool has an estimated OOIP of 25 BBO and OGIP of 46 TCF[26] (Thomas et al., 1993 and 1996; ConocoPhillips, 2006). Oil and condensate recovery from all technologies employed will be about 58% of OOIP. The development of PBU involved the installation of a modern petroleum infrastructure in an Arctic wilderness and required significant

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[26] The OGIP is about 46 TCF, which includes 12% CO_2 resulting in an OGIP for hydrocarbon gas of about 41 TCF.

resources of time, people, engineering, and money to develop. The installation of TAPS required federal legislation to proceed. PBU was initially separated into initial Oil Rim and Gas Cap participating areas (IPAs) with different ownerships and the Oil Rim IPA was separated into two different operating areas. BP Exploration (Alaska), Inc. (BPA) operated the western half of the Oil Rim IPA and ARCO Alaska operated the eastern half of the Oil Rim IPA and the Gas Cap IPA. In 2002 the two IPA's were combined and BPA became operator of the entire unit.

The developed area of PBU includes over 200 square miles. The IPA has six separate liquid and gas processing facilities. On the eastern side of the field they are called Flow Stations (FS1, FS2, and FS3) and on the western side of the field they are called Gathering Centers (GC1, GC2, and GC3). These facilities, field pipelines, and roads are shown in Figure 3.8 along with facilities at other North Slope Units.[27] Although PBU has excess oil processing capacity, the facilities are currently at water and gas handling capacity.

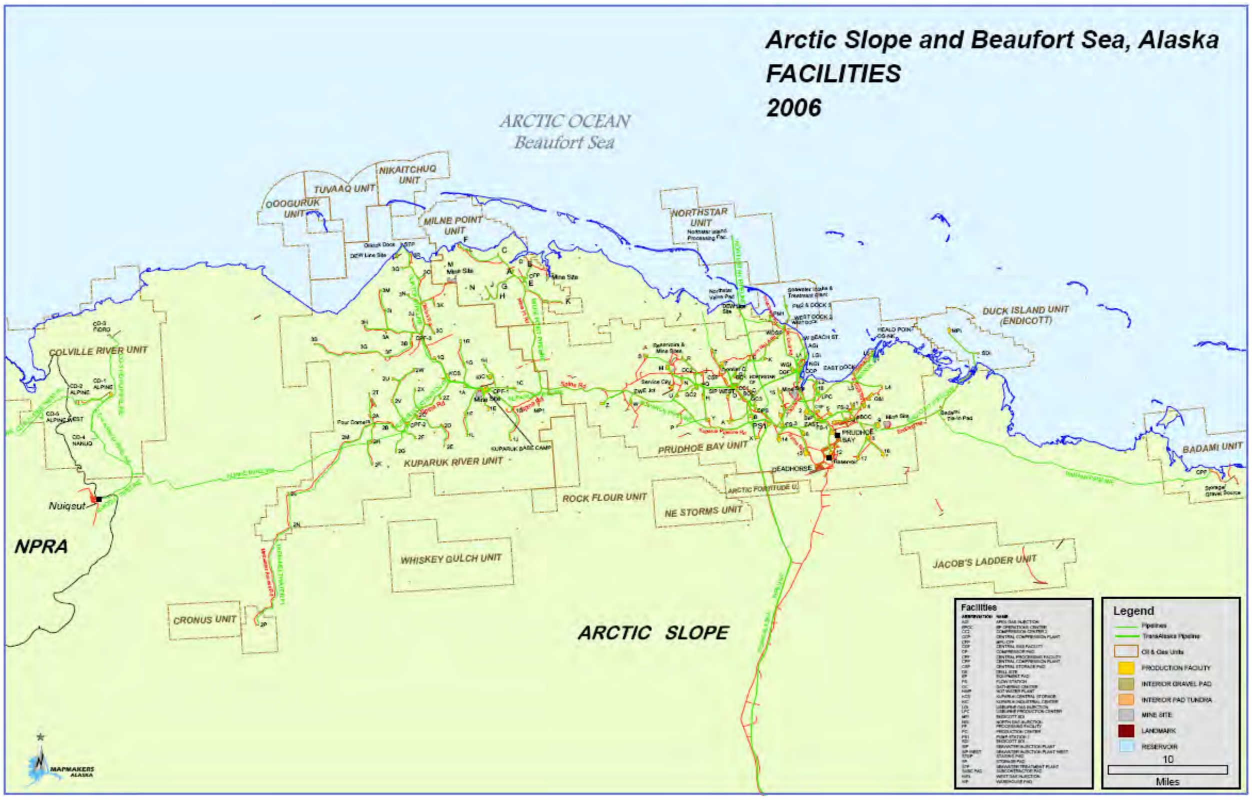


Figure 3.8. ANS Units, oil and gas processing facilities and pipelines.

By year-end 2004, about 2,600 wells had been drilled in PBU. From an initial rate of 137 MBOPD in June 1977, production quickly increased to over 1,000 MBOPD by March 1978. Production reached a maximum of 1,574 MBOPD in March 1980. The offtake rate for crude oil was limited by the state of Alaska to 1,500 MBOPD for conservation purposes. The PBU production volumes over 1,500 MBOPD were condensate and natural gas liquids (NGLs). Production averaged over 1,530 MBOPD for 106 months before the field started to decline in

[27] This figure is included in the Maps and Figure Appendix in PDF format for viewing of the details.

1989.

The gas processing capacity was increased to 8.5 BCFPD in the early 1990's and led to a major expansion of miscible flooding for enhanced oil recovery (EOR). In addition, improved reservoir management, the application of multilateral wells from existing vertical wells, and other advanced production technologies have contributed to increasing the recovery factor to approximately 58% of the OOIP (25 BBO). It is assumed that these and other emerging technologies will continue to be applied in the future.

The historical and future technically recoverable oil [crude oil, condensate, plus NGLs], gas, and water productions versus time are shown in Figure 3.9. The historical oil plus condensate production is used to estimate a future oil production decline rate. The established historical decline rate of 6.25% per year is assumed to continue unless there are major changes in oil production resulting from future operational practices. Reserves are estimated from the current production rate of 350 MBOPD to an abandonment rate of 20.0 MBOPD for an estimated TRR of 1,866,327 MBO and a TUR or 12,564,846 MBO.

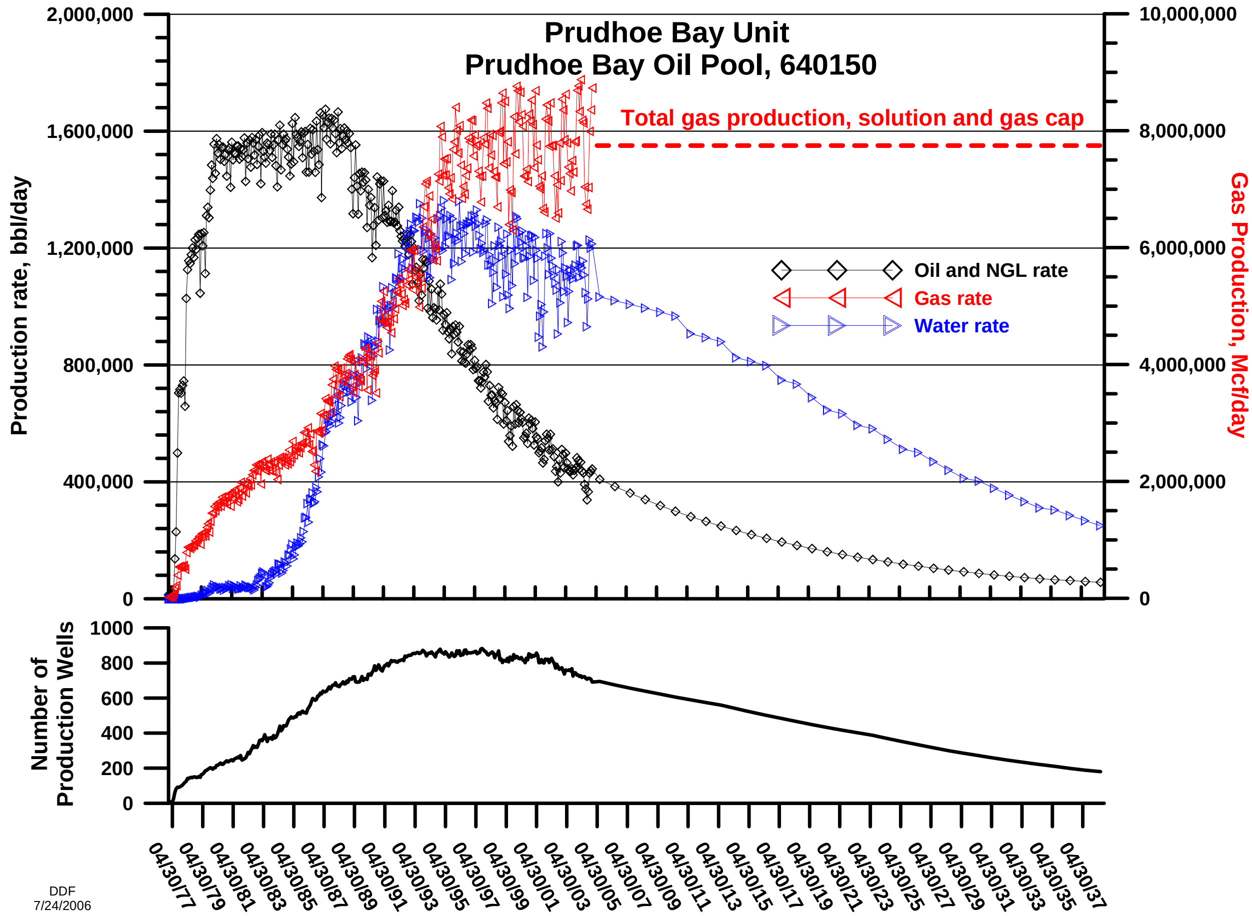


Figure 3.9. Prudhoe Bay Unit–Prudhoe Bay pool production history and forecasts.

NGLs are currently recovered from produced gas, both solution gas and gas cap gas. The production of NGLs is assumed to continue at the established decline of 5% per year. NGL reserves are estimated from the current 70.0 MBPD to a final rate of 5.0 MBPD for a TRR for

NGLs of 473,210 MB and a TUR of 918,406 MB. The current gas production is controlled by the gas handling capacity of the PBU IPA facilities. The gas forecast is 7.8 BCFD with processed gas used for miscible rich gas injection (MI) and lease operations. Excess gas, or about 92.5%, of the produced gas is currently reinjected into the gas cap and will continue until a gas pipeline is available to export natural gas from the ANS. Total TUR of oil, condensate, and NGLS is 13,483,252 MB.

Historical oil recovery versus GOR_D discussed in Section 3.2.1.8 is not applicable and not required for PBU because the large volumes of gas injected into the gas cap include recycled gas from both the oil rim and the gas cap. Gas production through 12/31/2004 totals about 48 TCF, which exceed current estimates of OGIP for the gas cap and oil rim. Future gas volumes are forecasted at the capacity of the processing facilities. Reinjected gas volumes are estimated using the last ten-year average of 7.5% for lease uses, which include fuel, shrinkage, MI production, minor gas sales, and flare losses.

Historical oil recovery versus water cut is used to estimate future water production with the response terminated at 0.9 water cut at depletion as shown in Figure 3.10 (see Appendix C for detailed description of the methodology). The historic relationship shows very good linearity and is used for water production forecasts.

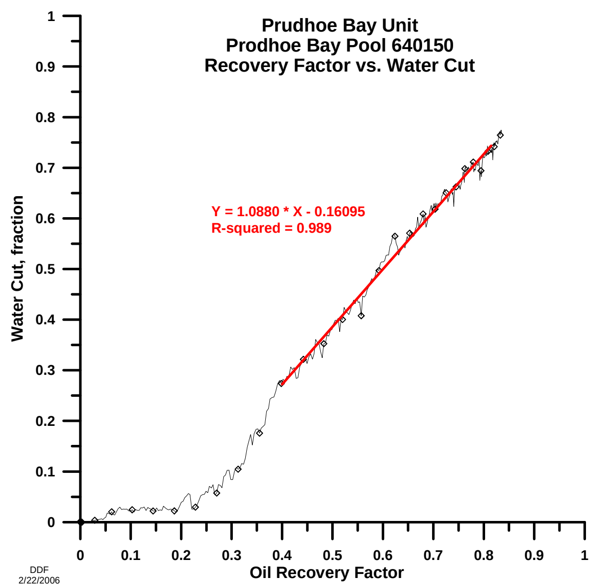


Figure 3.10. Prudhoe Bay Unit–Prudhoe Bay pool recovery factor versus water cut.

Prudhoe Bay pool historical oil, gas, and water cumulative production is presented in Table 3.7.

Table 3.7. Prudhoe Bay pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	10,698,519 MBO
Cumulative NGL recovery	445,196 MB
Cumulative oil and NGL recovery	11,143,715 MB

VARIABLE	VOLUME
Cumulative gas production	48,187,300 MMCF
Cumulative Reinjected gas	44,106,462 MMCF
Cumulative water recovery	7,314,494 MB

Forecasts of Prudhoe Bay pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.8.

Table 3.8. Prudhoe Bay pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2031	2040	2040	2040
Oil and NGLs ERR (MB)	1,985,268	2,213,277	2,213,277	2,213,277
Future Gas forecast (MMCF)	51,875,240	59,369,100	59,369,100	59,369,100
Future water forecast (MB)	9,113,518	10,578,211	10,578,211	10,578,211
Oil and NGLs EUR (MB)	13,128,983	13,356,992	13,356,992	13,356,992
Ultimate gas production (MMCF)	100,062,540	107,556,400	107,556,400	107,556,400
Total gas reinjected (Est.) (MMCF)	91,588,543	99,489,670	99,489,670	99,489,670
Ultimate water production (MB)	16,428,012	17,892,705	17,892,705	17,892,705

The revenue to the state and federal governments and net income, investment, and operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.9.

Table 3.9. Prudhoe Bay pool – Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$1,163,293	$1,163,293	$1,163,293	$1,163,293
Total operating costs	$27,911,818	$35,875,420	$35,875,420	$35,875,420
State royalty	$5,670,095	$10,360,322	$15,991,085	$19,744,928
State taxes – Severance	$2,997,814	$4,881,271	$7,412,960	$9,100,748
State taxes – Income	$199,625	$863,984	$1,970,493	$2,708,166
State taxes – Other	$1,496,806	$1,507,579	$1,507,579	$1,507,579
State Total (Royalty and Taxes)	**$10,364,340**	**$17,613,156**	**$26,882,117**	**$33,061,421**
Federal taxes	**$2,790,771**	**$10,418,669**	**$22,582,907**	**$30,692,394**
Industry net income	**$5,355,845**	**$20,224,475**	**$43,837,400**	**$59,579,356**

3.3.2 PBU – Aurora PA

The Aurora pool was discovered in 1969 and production from the Kuparuk formation was started in December 2000 (Table 2.7). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government is described in this section.

3.3.2.1 Aurora PA Engineering and Economics

The Aurora pool is a recent satellite development targeting an accumulation of from 110 to 146 MMB OOIP of 29.6°API oil. The operator estimates primary recovery to be 12% of the OOIP and secondary recovery another 34%, for a TUR of 46% of the OOIP (AOGCC, 2001). Until the production response indicates differently, it is assumed the TUR is 37.5% of OOIP.

Oil production from the Aurora pool is being processed by the PBU IPA facility at the maximum rate possible under gas and water handling constraints. The pool started production November 2000, and by March 2003 achieved a production peak of about 10 MBOPD. Production was maintained above 10 MBOPD for 17 months before entering a decline. Historical and forecast oil, water, and gas production versus time is presented in Figure 3.11. The historical oil production versus time plot was used to estimate a future oil production decline of 15%/yr.

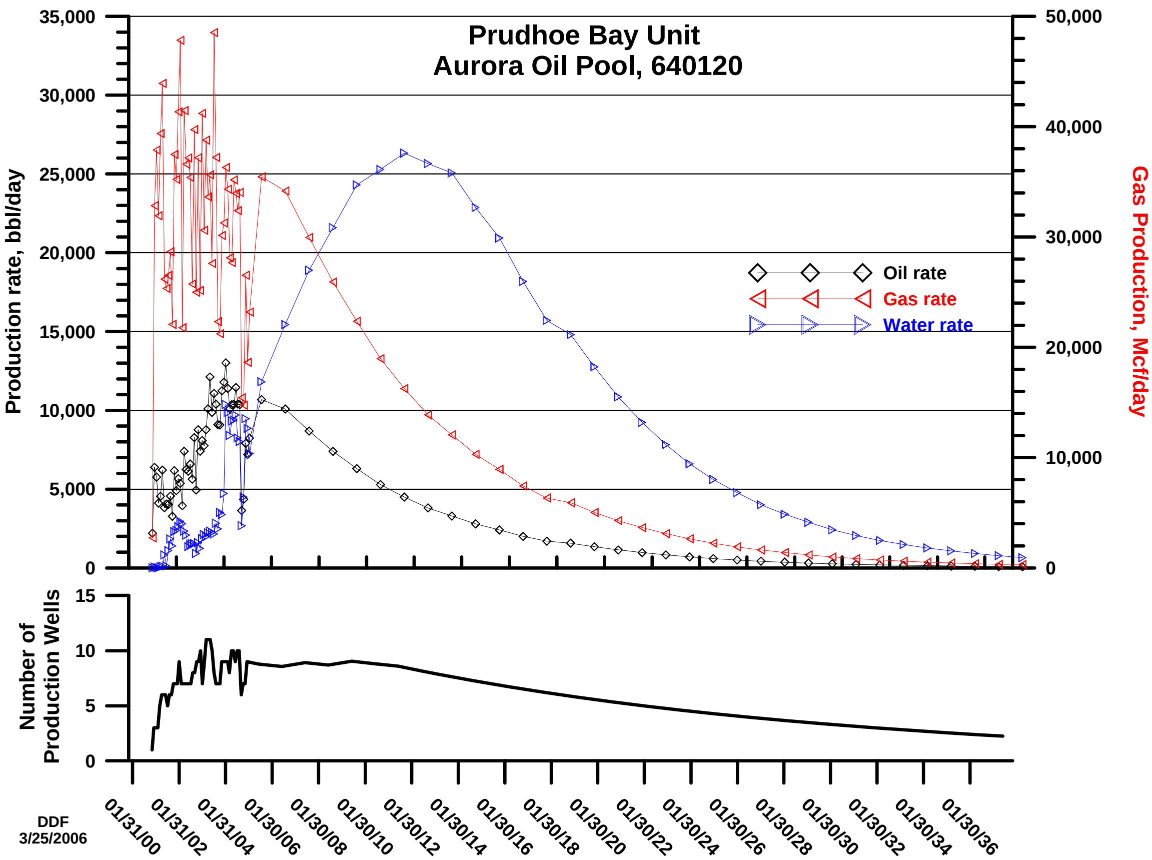


Figure 3.11. Prudhoe Bay Unit–Aurora pool production history and forecasts.

The waterflood was started in December 2001 and the miscible injection process in December 2003. It is too soon for a production response to be evident from the MI project. It is assumed the combination of waterflood and MI project will increase oil production to approximately 10 MBOPD, which will be maintained into 2006 before starting to decline. Some reports suggest the production rates could reach between 14 and 17 MBOPD. Since production response has not been confirmed a higher rate, the lower rate is used.

The production forecast assumed 14 months of level production after December 2004 before entering a 15%/yr decline. The production forecast for the indicated reserves assumed a technical economic limit of 0.25 MBOPD. This gives a TRR of 34,400 MBO, and a TUR of 45,797 MBO.

The historical oil recovery versus GOR_D was used to forecast gas production, Figure 3.12. Historical oil recovery versus water cut was used to estimate future water production with the response terminated at a 0.90 water cut at depletion, Figure 3.11. Gas production in excess of lease operations is used in the MI project.

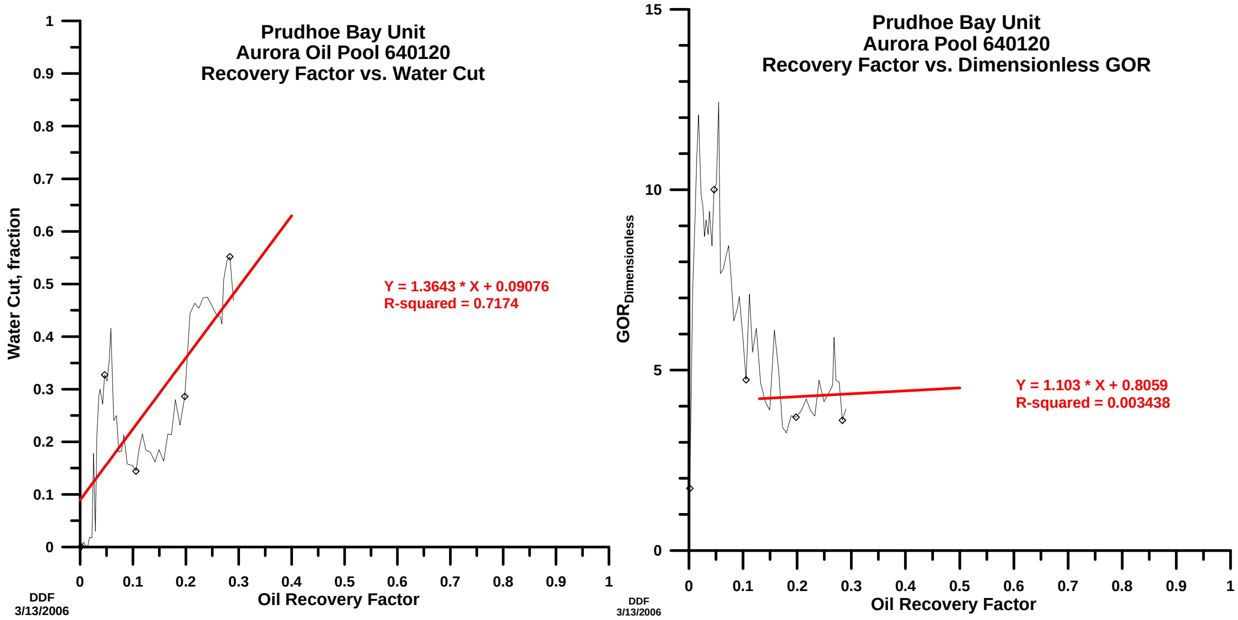


Figure 3.12. Prudhoe Bay Unit–Aurora pool recovery factor versus water cut and GOR.

Aurora historical oil, gas, and water cumulative production is presented in Table 3.10.

Table 3.10. Aurora pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	11,397 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	11,397 MBO
Cumulative gas production	47,583 MMCF
Reinjected gas	5,752 MMCF
Cumulative water recovery	5,152 MB

Forecasts of Aurora pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.11.

Table 3.11. Aurora pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2016	2022	2026	2028

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Oil and NGLs ERR (MB)	26,870	30,582	31,709	32,051
Future Gas forecast (MMCF)	88,368	101,264	105,212	106,412
Future water forecast (MB)	84,026	118,309	128,957	132,133
Oil and NGLs EUR (MB)	38,267	41,979	43,106	43,448
Ultimate gas production (MMCF)	135,951	148,847	152,795	153,995
Total gas reinjected (Est.) (MMCF)	16,434	17,993	18,470	18,615
Ultimate water production (MB)	89,178	123,461	134,109	137,285

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.12.

Table 3.12. Aurora pool–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$18,419	$18,419	$18,419	$18,419
Total operating costs	$264,240	$377,812	$436,778	$462,936
State royalty	$68,532	$123,473	$198,135	$247,642
State taxes – Severance	$57,031	$90,099	$138,020	$169,898
State taxes – Income	$3,709	$10,354	$22,657	$31,277
State taxes – Other	$6,496	$8,850	$9,828	$10,114
State Total (Royalty and Taxes)	**$135,768**	**$232,776**	**$368,640**	**$458,931**
Federal taxes	**$49,580**	**$127,897**	**$264,582**	**$359,713**
Industry net income	**$93,820**	**$247,554**	**$513,601**	**$698,265**

3.3.3 PBU – Borealis PA

The Borealis pool was discovered in 1969 and production from the Kuparuk formation was started in November 2001 (Table 2.7). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government is described in this section.

3.3.3.1 Borealis PA Engineering

The Borealis pool is a recent satellite development targeting an accumulation of between 195 and 277 MMBO OOIP of 24.1°API oil. The operator estimates primary recovery to be 13% of the OOIP, secondary recovery another 23%, and 5% for EOR using MI, for a technical recovery of 41% of the OOIP (AOGCC, 2002).

Oil production is processed by the PBU IPA facilities at the maximum rate possible under gas and water handling constraints. The pool started production November 2001 at an initial rate of 19.0 MBOPD and reached a production plateau of over 30 MBOPD by February 2003. The rate was maintained above 30 MBOPD for 17 months before starting on decline. Water flooding started June 2002 and limited gas injection using MI in June 2004. MI may be used in a possible expansion to the south and southeast and, if proven economical, five additional wells could be drilled (ADNR, 2003); however no reserves were given to this possible expansion. The oil, water, and gas production history and forecasts are presented in Figure 3.13.

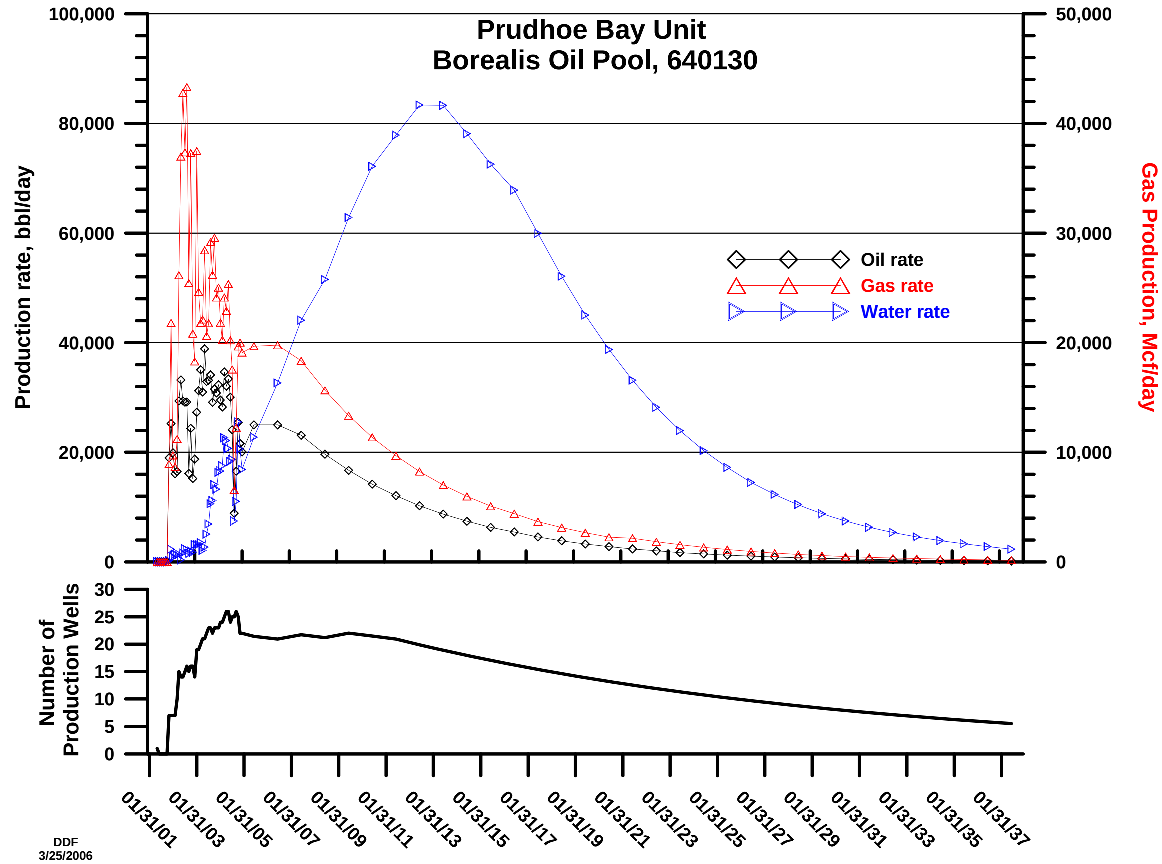


Figure 3.13. Prudhoe Bay Unit–Borealis pool production history and forecasts.

Historical oil production was used to estimate a future oil production rate with a decline rate of about 15%/yr. The last six months of 2004 had a sharp reduction in oil production and a corresponding increase in the water cut. No data were found to indicate this lower rate will not continue. The average water cut for the last six months of 2004 was 0.462. Performance analogue to the Kuparuk River formation in the KRU indicates a recovery of about 30% occurred at a water cut between 0.45 and 0.50. This would suggest a TUR of about 103 MMBO. It is assumed the an average production of 25 MBOPD will be regained in 2005 and continued through January 2007 at which time production will start a 15%/yr decline. The forecast uses an assumed field abandonment limit of 0.025 MBOPD, and gives a TRR of 74,340 MBO. The TUR is 105,189 MBO.

Historical recovery versus GOR_D is used to forecast gas production and historic recovery versus water cut is used to estimate future water production with the response terminated at a 0.90 water cut at depletion, Figure 3.14. It is assumed that produced gas is used in lease operations with excess gas being used for the MI project.

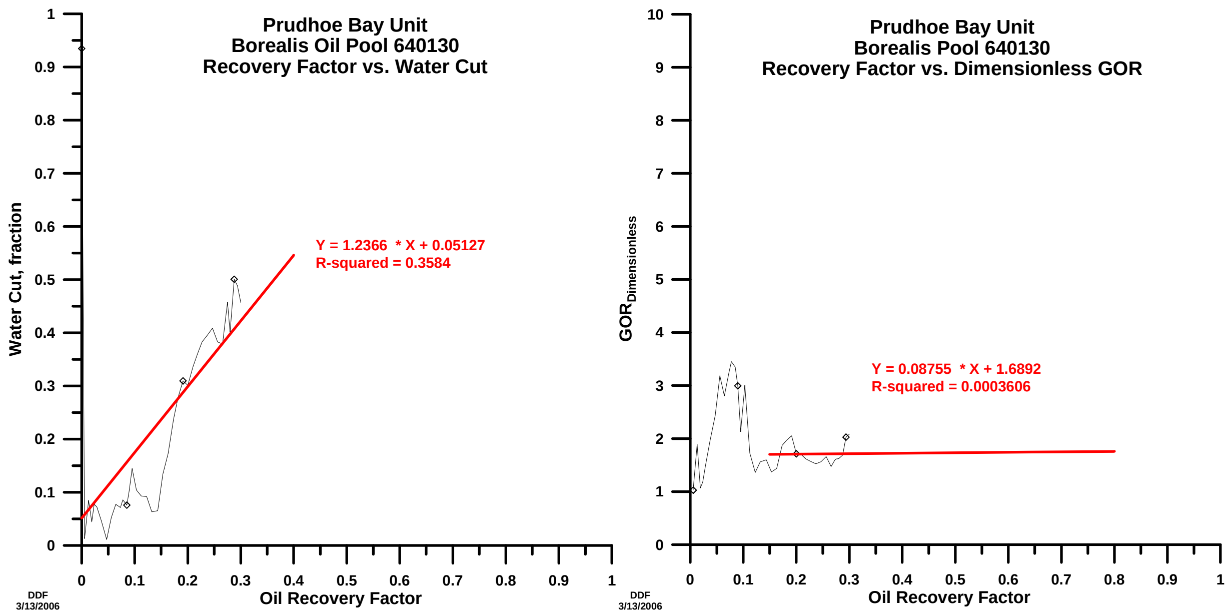


Figure 3.14. Prudhoe Bay Unit–Borealis pool recovery factor versus water cut and GOR.

Borealis pool historical oil, gas, and water cumulative production is shown in Table 3.13.

Table 3.13. Borealis pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	30,849 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	30,849 MBO
Cumulative gas production	27,080 MMCF
Cumulative Reinjected gas	622 MMCF
Cumulative water	10,143 MB

Forecasts of Borealis pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.14.

Table 3.14. Borealis pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2015	2020	2025	2027
Oil and NGLs ERR (MB)	59,185	67,755	71,537	72,375
Future Gas forecast (MMCF)	47,128	54,055	57,406	58,171
Future water forecast (MB)	227,381	338,221	390,944	402,461
Oil and NGLs EUR (MB)	90,034	98,604	102,386	103,224
Ultimate gas production (MMCF)	74,208	81,135	84,486	85,251
Total gas reinjected (Est.) (MMCF)	1,704	1,864	1,941	1,958
Ultimate water production (MB)	237,524	348,364	401,087	412,604

Borealis pool revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.15.

Table 3.15. Borealis pool–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$36,837	$36,837	$36,837	$36,837
Total operating costs	$584,859	$837,244	$1,026,052	$1,090,117
State royalty	$145,959	$266,507	$439,818	$551,430
State taxes – Severance	$125,803	$200,504	$310,795	$383,485
State taxes – Income	$5,517	$18,932	$45,703	$64,885
State taxes – Other	$19,718	$26,892	$31,749	$32,937
State Total (Royalty and Taxes)	**$296,997**	**$512,835**	**$828,065**	**$1,032,737**
Federal taxes	**$86,163**	**$253,041**	**$553,884**	**$765,806**
Industry net income	**$157,170**	**$489,302**	**$1,073,842**	**$1,486,064**

3.3.4 PBU – Midnight Sun PA

The Midnight Sun pool was discovered in 1997 and production from the Kuparuk formation was started in October 1998 (Table 2.7). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.4.1 Midnight Sun PA Engineering and Economics

The Midnight Sun pool is a recent satellite development targeting an accumulation of between 40 and 60 MMB OOIP of 25.5°API oil (AOGCC, 2000c). The OGIP is 130 BCF with 80 BCF contained in a gas cap. The operator estimates primary recovery to be 14% of the OOIP, secondary recovery another 15 to 25% for a technical recovery of between 29 and 39% of the OOIP (AOGCC, 2000c). Based on available information, the ultimate oil recovery is assumed to be about 33.5% of the OOIP.

The Midnight Sun pool production is processed by the PBU facilities at the maximum rates possible under gas and water handling constraints. Waterflooding started in October 2000. The initial rate was 1.9 MBOPD increasing to over 12 MBOPD by May 2002 before starting to decline. Although oil production increased during the last three months of 2004, the performance history indicates the pool is in its decline and the recent increase in production will not be sustained. The oil, water, and gas production history and forecasts are presented in Figure 3.15.

It is anticipated that production will average 4.5 MBOPD during 2005 and decline to 3.6 MBOPD by January 2006 at which time production will decline at 15%/yr to an assumed abandonment rate of 0.010 MBOPD resulting in a TRR of 9,705 MBO, and a TUR of 21,048 MBO.

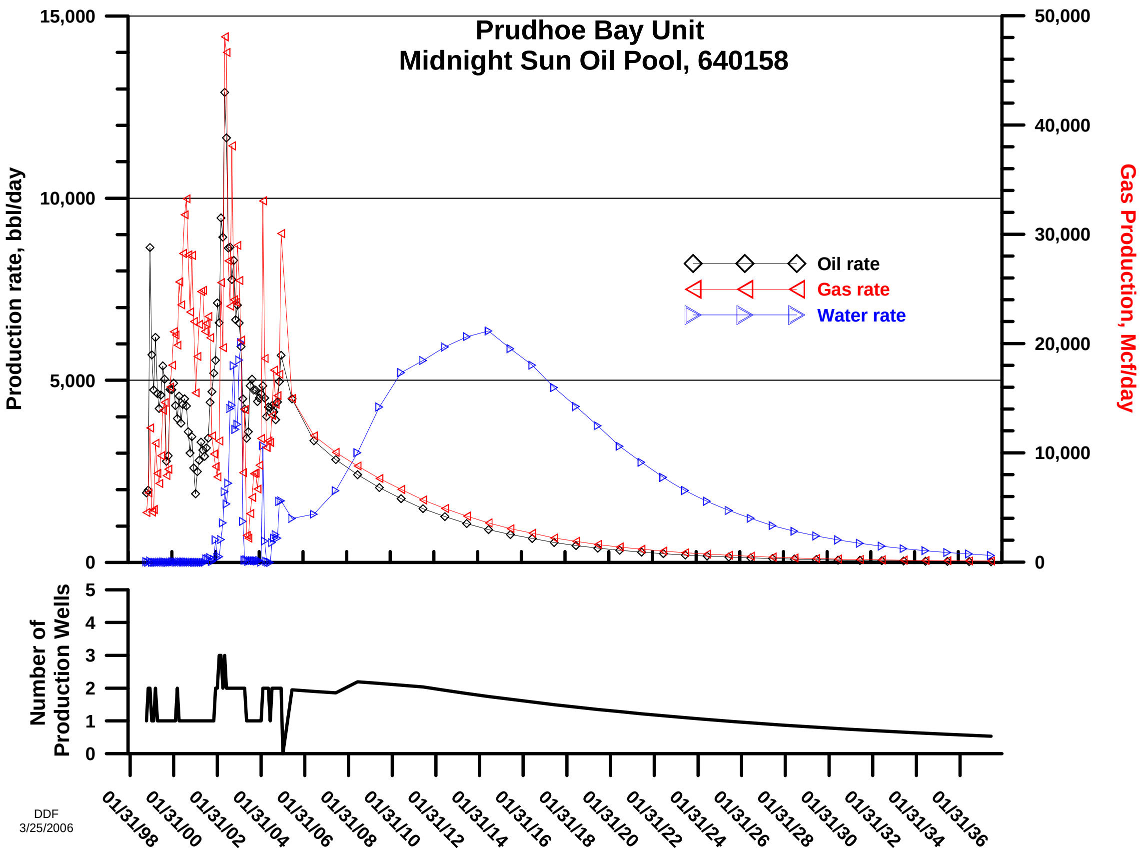


Figure 3.15. Prudhoe Bay Unit–Midnight Sun pool production history and forecasts.

Future water and gas production forecasts are developed from the historical water cut and dimensionless GOR_D curves. These plots are presented in Figure 3.16. It is assumed that produced gas is used in lease operations with excess gas injected into the PBU IPA.

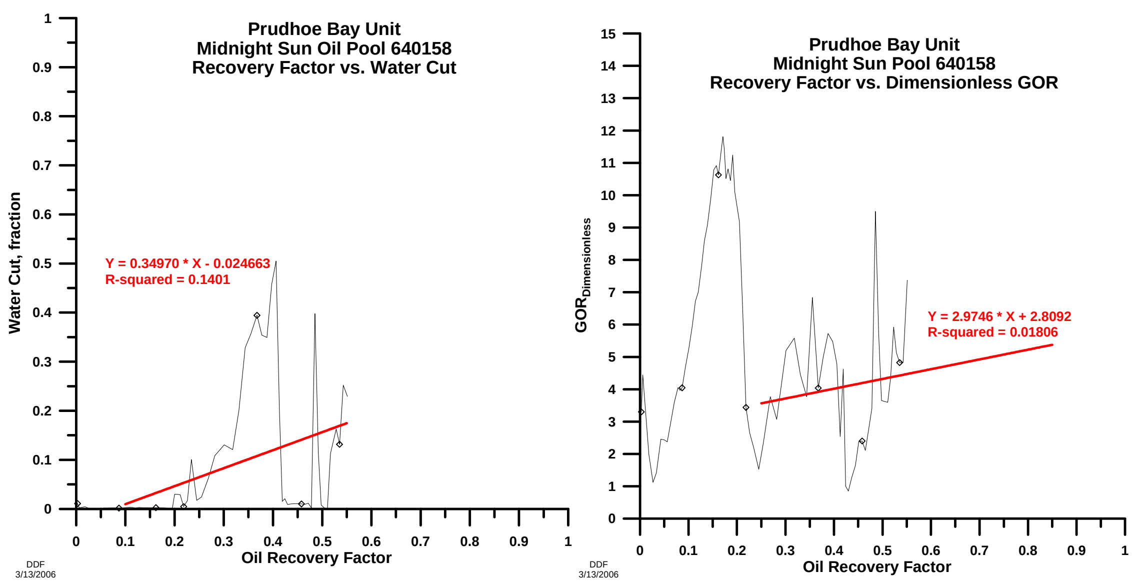


Figure 3.16. Prudhoe Bay Unit–Midnight Sun pool recovery factor versus water cut and GOR.

Midnight Sun historical oil, gas, and water cumulative production is presented in Table 3.16.

Table 3.16. Midnight Sun pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	11,343 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	11,343 MBO
Cumulative gas production	40,093 MMCF
Cumulative Reinjected gas	0 MMCF
Cumulative water	1,630 MB

Forecasts of Midnight Sun pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.17.

Table 3.17. Midnight Sun pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2015	2020	2024	2026
Oil and NGLs ERR (MB)	7,879	8,914	9,306	9,424
Future Gas forecast (MMCF)	28,474	32,641	34,244	34,732
Future water forecast (MB)	19,517	28,671	32,428	33,551
Oil and NGLs EUR (MB)	19,222	20,257	20,649	20,767
Ultimate gas production (MMCF)	68,567	72,734	74,337	74,825
Total gas reinjected (Est.) (MMCF)	0	0	0	0
Ultimate water production (MB)	21,147	30,301	34,058	35,181

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project is shown for all prices tracks in Table 3.18.

Table 3.18. Midnight Sun pool–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$10,420	$10,420	$10,420	$10,420
Total operating costs	$72,018	$102,328	$122,191	$131,072
State royalty	$19,754	$35,306	$57,124	$71,582
State taxes – Severance	$15,980	$25,252	$38,822	$47,850
State taxes – Income	$1,082	$2,998	$6,503	$8,984
State taxes – Other	$2,576	$3,556	$4,114	$4,308
State Total (Royalty and Taxes)	**$39,392**	**$67,112**	**$106,563**	**$132,724**
Federal taxes	**$14,356**	**$36,911**	**$76,075**	**$103,498**
Industry net income	**$26,770**	**$71,376**	**$147,608**	**$200,871**

3.3.5 PBU – Orion PA

The Orion pool was discovered in 1968 and production from the Schrader Bluff formation was started in April 2002 (Table 2.7). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.5.1 Orion PA Engineering and Economics

The Orion pool is another recent PBU satellite development that targets an OOIP accumulation of between 1.1 and 1.8 BBO of heavy oil with a variable gravity of 15 to 22° API. Anticipated primary recovery is 5 to 10% OOIP, 15% incremental with secondary recovery, and the EOR potential is under study (AOGCC, 2004). It is assumed the total pool recovery will be about 21% of the OOIP, about 250 MMBO, under primary and secondary field operations. If reservoir studies indicate EOR can be used at Orion, an additional 5% OOIP recovery could be attained. However, since technical and economic success has not been demonstrated, this potential EOR recovery is not used in the production forecast.

Production is processed by the PBU IPA facilities under the gas and water handling constraints. Production is from the Schrader Bluff O and N sands with field development using horizontal and multilateral wells. Development is expected to occur in three phases (AOGCC, 2004). The current development, Phase I, is a pilot area with a total of five production and three injection wells. The pool started first production in April 2002 and increased erratically to over 10 MBOPD by December 2004. This level is not expected to be maintained, even with the drilling of additional wells in 2007. The oil, gas, and water historical and forecast production are presented in Figure 3.17. It is assumed Phase I production will average 8 MBOPD in 2005 and then experience a 15%/yr decline to an assumed abandonment rate of 0.02 MBOPD, resulting in a TRR of 19,690 MBO, for Phase I. With about 2,310 MBO recovered through 12/31/2004, the TUR for Phase I is about 22,000 MBO.

The water cut and GOR_D history are presented in Figure 3.18. The data available are not sufficient to forecast future water and gas volumes. Hence, Orion PA forecasts are based on the Milne Point Schrader Bluff GOR_D and water-cut relationships (see Section 3.3.24). It is assumed all produced gas is used onsite for lease operations.

Orion historical oil, gas and water cumulative production is presented in Table 3.19.

Forecasts of the current Orion pool development future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.20. Results for Phase II and III expansions are presented in Section 3.4.8.

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for the four price tracks in Table 3.21.

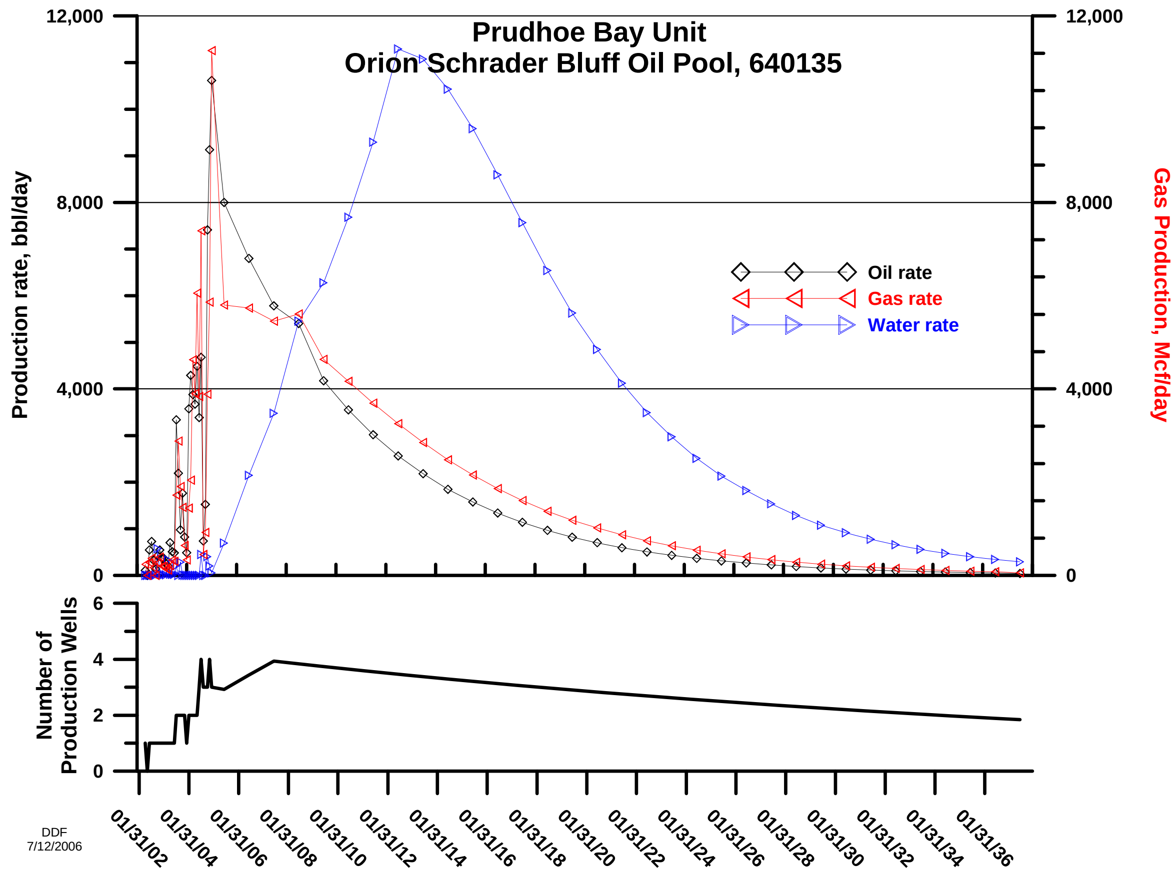
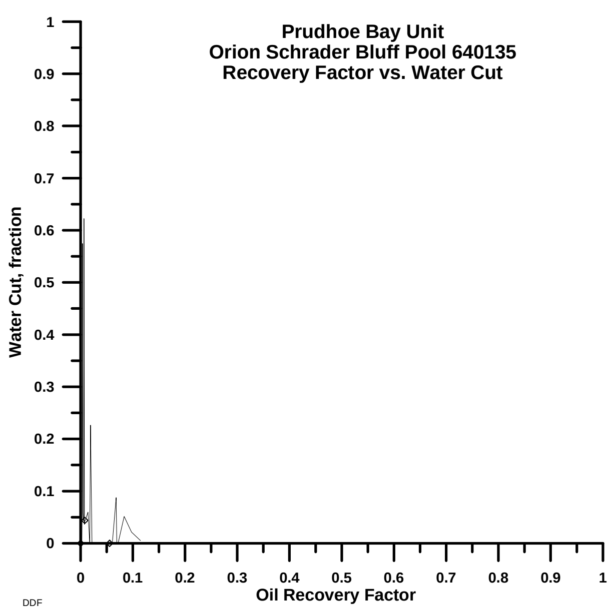


Figure 3.17. Prudhoe Bay Unit–Orion pool production history and forecasts.



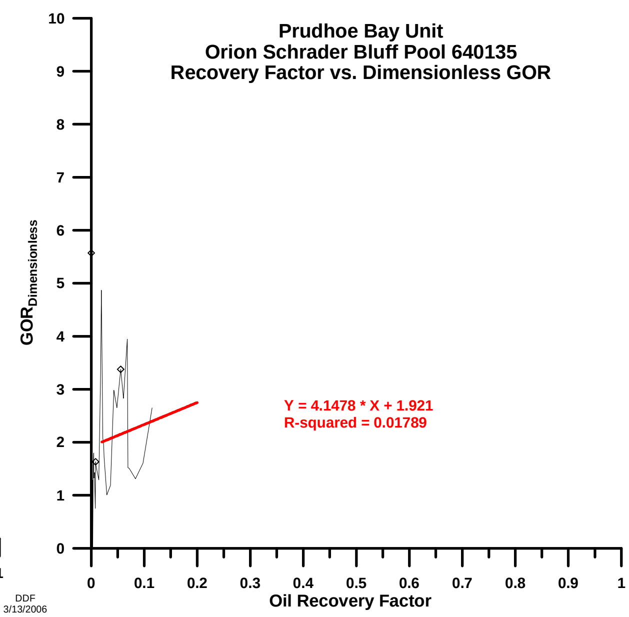


Figure 3.18. Prudhoe Bay Unit–Orion pool recovery factor versus water cut and GOR.

Table 3.19. Orion pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	2,310 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	2,310 MBO
Cumulative gas production	1,994 MMCF
Cumulative Reinjected gas	0 MMCF
Cumulative water	82 MB

Table 3.20. Orion pool current development–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2016	2020	2025	2026
Oil and NGLs ERR (MB)	16,388	17,944	18,891	19,004
Future Gas forecast (MMCF)	16,724	18,923	20,313	20,482
Future water forecast (MB)	28,253	38,591	45,141	45,919
Oil and NGLs EUR (MB)	18,698	20,254	21,201	21,314
Ultimate gas production (MMCF)	18,718	20,917	22,307	22,476
Total gas reinjected (Est.) (MMCF)	0	0	0	0
Ultimate water production (MB)	28,335	38,673	45,223	46,001

Table 3.21. Orion pool–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$13,488	$13,488	$13,488	$13,488
Total operating costs	$126,087	$169,017	$214,682	$223,227
State royalty	$37,566	$67,065	$112,165	$140,306
State taxes – Severance	$23,646	$37,583	$58,626	$72,249
State taxes – Income	$3,255	$7,604	$15,089	$20,293
State taxes – Other	$2,219	$2,741	$3,186	$3,245
State Total (Royalty and Taxes)	**$66,686**	**$114,993**	**$189,066**	**$236,093**
Federal taxes	**$36,886**	**$86,088**	**$168,776**	**$226,105**
Industry net income	**$70,904**	**$167,113**	**$327,321**	**$438,904**

3.3.5 PBU – Polaris PA

The Polaris pool was discovered in 1969 and production from the Schrader Bluff formation began in November 1999 (Table 2.7). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.5.1 Polaris PA Engineering

The Polaris pool is a PBU satellite development of the Schrader Bluff “O” sand with an estimated OOIP of 750,000 MBO of 20.5°API heavy oil. Anticipated primary recovery is 5 to 10% OOIP and 10 to 20% incremental with secondary recovery and no EOR potential at this time (AOGCC, 2003). Available information indicates waterflooding will be the only improved recovery technology applied with the reservoir pressure being maintained close to original conditions. It is assumed the recovery will be about 24% of the 550,000 MB OOIP in the "O" and 17.5% of the 200,000 MB OOIP in the remaining sands. This gives an estimated TUR of about 166,940 MBO.

The development plans consist of three phases, using horizontal and multilateral wells. Production is processed by the PBU IPA facilities. Phase I, the pilot area, started producing in November 1999 and has averaged about 3.0 MBOPD for the last 30 months. Historical and forecast oil, gas, and water production is presented in Figure 3.19. Oil production is assumed to increase to a maximum rate of 15 MBOPD by January 2011 and be maintained for three years before declining at 15%/yr. At an abandonment rate of 0.22 MBOPD, the TRR for Phase I is 64,900 MBO. With oil recovery to date, Phase I TUR is about 68,440 MBO. Orion Phase II and III are described in Section 3.4.9. The total forecast TUR for all three phases is 166,940 MBO.

The water cut and GOR_D history are presented in Figure 3.20. The available data are insufficient to be used to forecast future water and gas volumes. Therefore, the Polaris PA water and gas forecasts use the Milne Point Schrader Bluff water cut and GOR_D relationships (see Section 3.3.24). It is assumed all produced gas is used for lease operations.

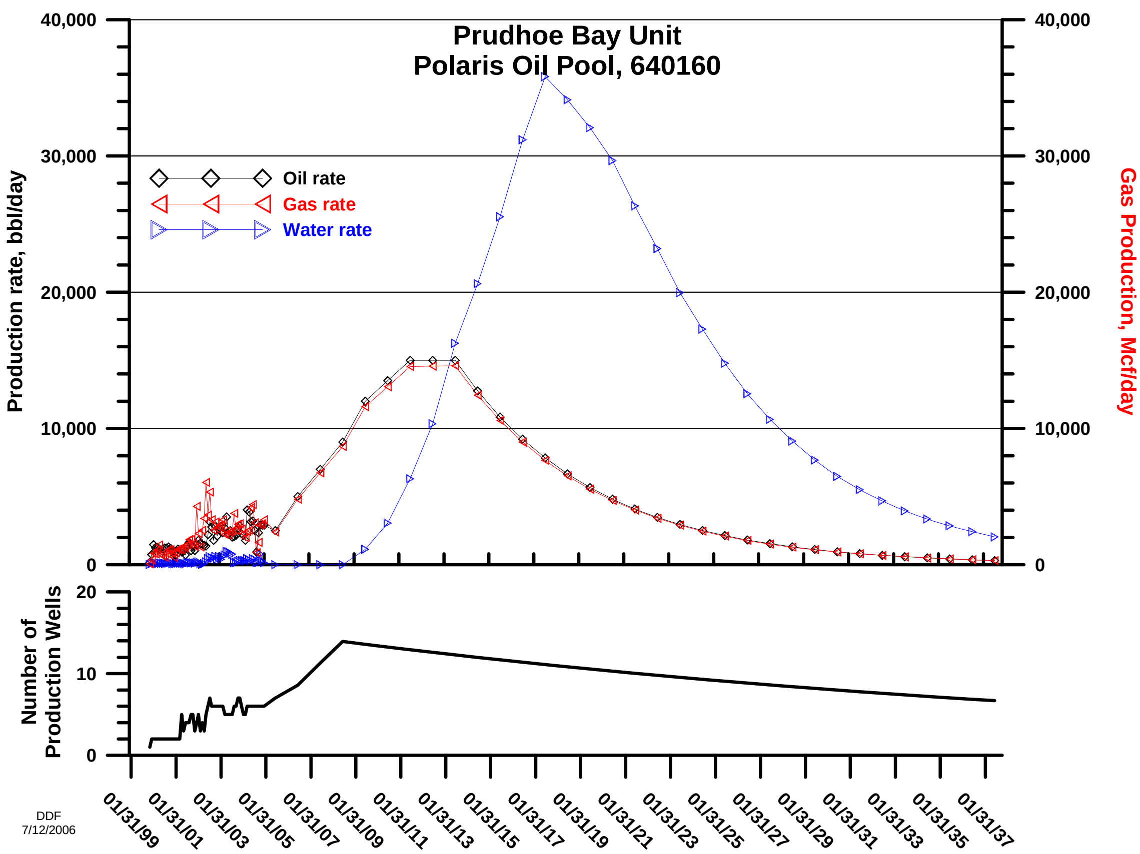
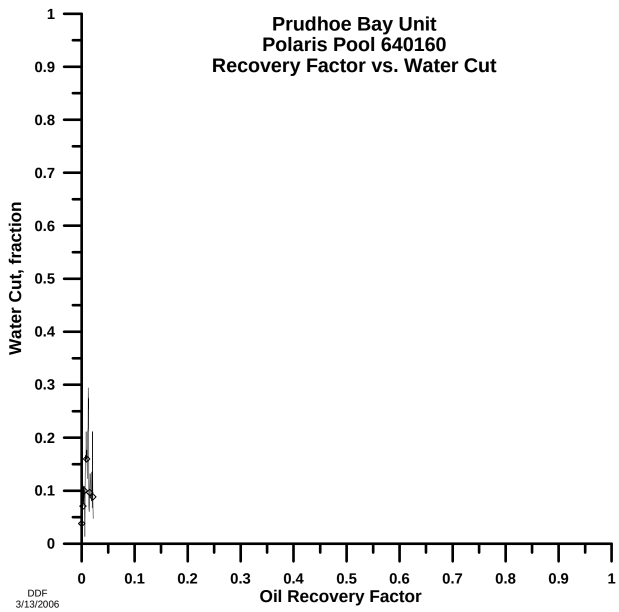


Figure 3.19. Prudhoe Bay Unit–Polaris pool production history and forecasts.



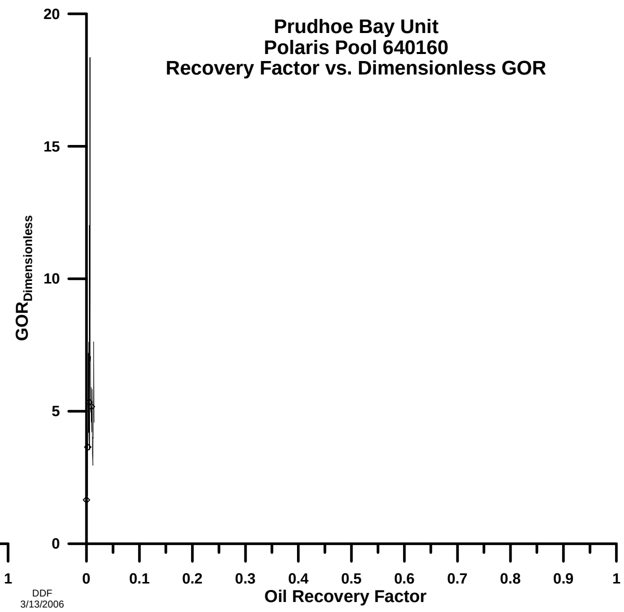


Figure 3.20. Prudhoe Bay Unit–Polaris pool recovery factor versus water cut and GOR.

Polaris historical oil, gas, and water cumulative production is presented in Table 3.22.

Table 3.22. Polaris pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	3,539 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	3,539 MBO
Cumulative gas production	4,087 MMCF
Cumulative Reinjected gas	0 MMCF
Cumulative water	528 MB

Forecasts of Polaris pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.23.

Table 3.23. Polaris pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2020	2025	2029	2031
Oil and NGLs ERR (MB)	53,633	60,141	62,621	63,373
Future Gas forecast (MMCF)	52,100	58,488	60,925	61,665
Future water forecast (MB)	80,264	123,087	140,251	145,407
Oil and NGLs EUR (MB)	57,172	63,680	66,160	66,912
Ultimate gas production (MMCF)	56,187	62,575	65,012	65,752
Total gas reinjected (Est.) (MMCF)	0	0	0	0
Ultimate water production (MB)	80,792	123,615	140,779	145,935

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.24.

Table 3.24. Polaris pool–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$129,344	$129,344	$129,344	$129,344
Total operating costs	$559,236	$764,227	$902,397	$967,010
State royalty	$135,119	$248,021	$408,849	$515,685
State taxes – Severance	$75,770	$125,330	$197,753	$245,936
State taxes – Income	$4,046	$18,960	$45,965	$64,972
State taxes – Other	$26,162	$31,392	$33,421	$33,602
State Total (Royalty and Taxes)	**$241,097**	**$423,703**	**$685,988**	**$860,195**
Federal taxes	**$46,050**	**$242,432**	**$544,650**	**$754,603**
Industry net income	**$146,244**	**$471,182**	**$1,056,691**	**$1,463,804**

3.3.7 PBU – Lisburne PA

The Lisburne pool was discovered in 1968 and production from the Lisburne formation was started in 1981 (Table 2.7). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.7.1 Lisburne PA Engineering

The Lisburne pool first started production June 1981 from an accumulation estimated to contain 3,000 MMB OOIP of 27°API oil. Due to poor reservoir quality, the primary recovery is estimated at 7% (AOGCC, 1985).

Oil production is being processed by the Lisburne PA facility. The Lisburne PA was produced intermittently from two wells until 1985 when fieldwide development occurred. Production increased rapidly under waterflooding as 64 production wells were drilled with peak production occurring in 1990 at slightly over 40 MBOPD. The tight formation and the natural fracturing rendered the reservoir difficult to water flood, with primary depletion occurring with oil moving from tight matrix to the higher permeability natural fractures, resulting in very low recovery efficiencies. Water injection into the Lisburne ceased in December 1989 due to the unsuccessful water flood after a total injection volume of 8.5 MMBW.

Oil from the Lisburne pool is being produced at the maximum rate possible under gas and water handling constraints. The historical and forecast oil, water, and gas productions versus time are shown in Figure 3.21. Historical oil production was used to estimate the future oil production decline rate. The oil production has entered an established decline of 10%/yr. Gas cycling of the excess produced gas is picking up some liquids and it is assumed the future NGL volumes will decline at 8%/yr with the actual abandonment rate determined when oil recovery is no longer economic. It is assumed oil production will average about 9.5 MBOPD for 2005 before declining at 10%/yr, to an assumed abandonment rate of 0.250 MBOPD. NGLs are assumed to average 1.15 MBPD for 2005 before declining at 8%/yr thru 2040. These assumptions result in oil TRR of 35,920 MBO and NGL TRR of 5,075 MB, resulting in an oil plus NGLs TRR of 40,995 MB. TUR is a total of 194,616 MB.

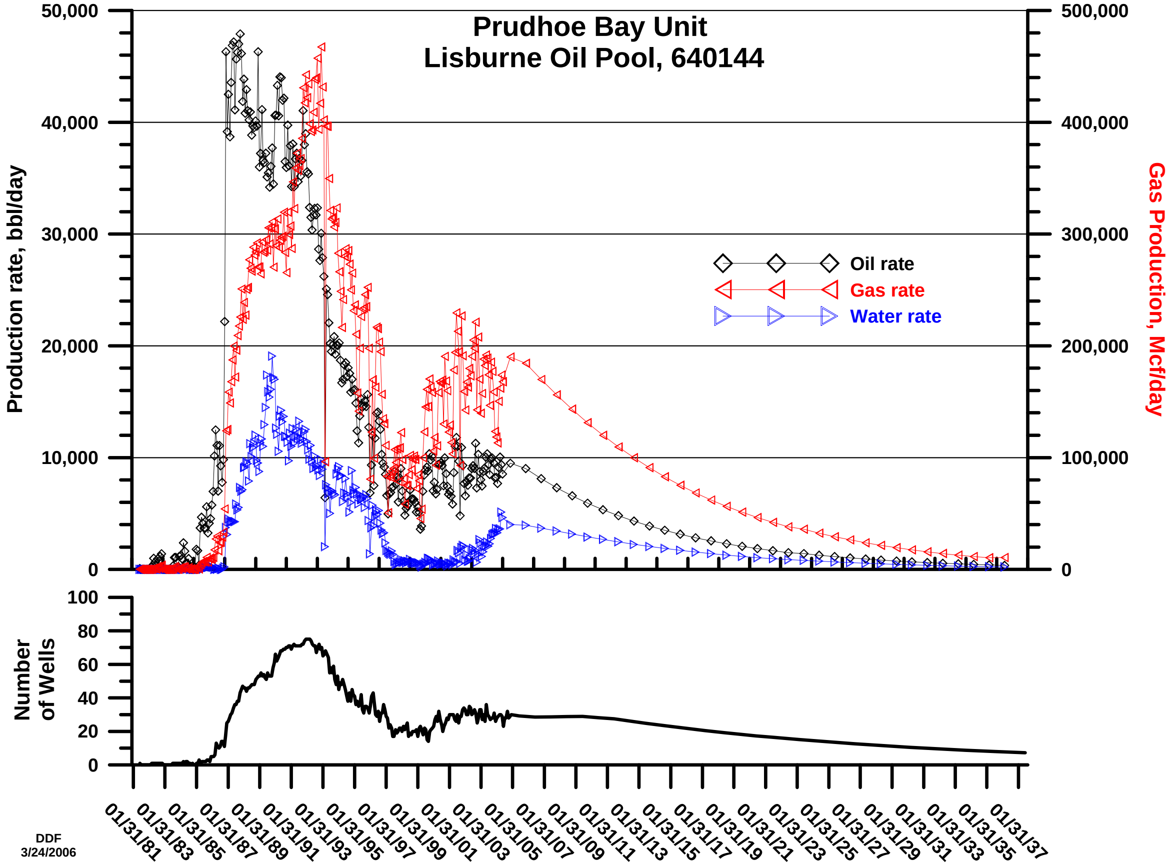


Figure 3.21. Prudhoe Bay Unit–Lisburne pool production history and forecasts.

It is believed most of the injected water has been recovered; hence the majority of future water production will be formation water. Water production will gradually decrease with time. Thus, the water-cut performance for the last four years is not a good indicator for estimating future water production. The recovery factor versus water cut relationship since 1989, Figure 3.21, provides reasonable estimates of future water production. The recovery factor versus GOR_D developed for Lisburne is used, Figure 3.22, to predict future gas production. Gas production is used for lease operations including gas cycling for NGL recovery. Excess gas from Point McIntyre, Niakuk, and West Beach is also injected. Some gas may be available for future gas sales.

Lisburne pool historical oil, gas, and water cumulative production is presented in Table 3.25.

Forecasts of Lisburne pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.26.

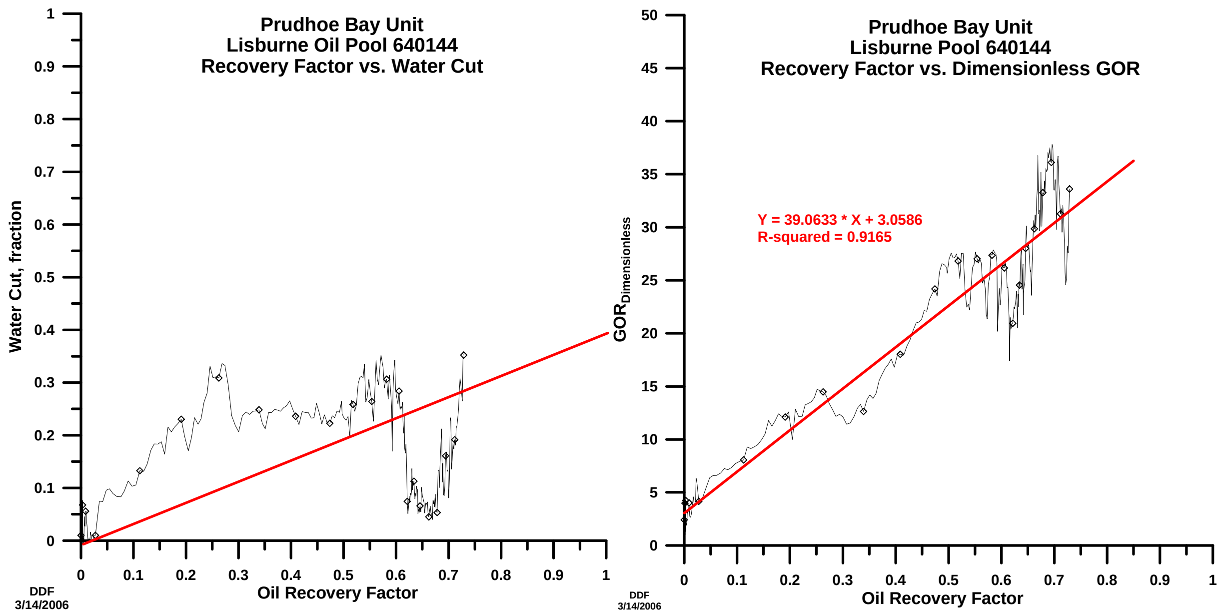


Figure 3.22. Prudhoe Bay Unit–Lisburne pool recovery factor versus water cut and GOR.

Table 3.25. Lisburne pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	139,711 MBO
Cumulative NGL recovery	13,910 MBO
Cumulative oil and NGL	153,621 MBO
Cumulative gas production	1,445,184 MMCF
Cumulative Reinjected gas	1,471,602 MMCF
Cumulative water	36,914 MB

Table 3.26. Lisburne pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2014	2022	2029	2033
Oil and NGLs ERR (MB)	24,998	34,280	38,110	39,337
Future Gas forecast (MMCF)	437,031	617,150	694,282	719,351
Future water forecast (MB)	10,422	14,945	16,922	17,570
Oil and NGLs EUR (MB)	178,619	187,901	191,731	192,958
Ultimate gas production (MMCF)	1,882,215	2,062,334	2,139,466	2,164,535
Total gas reinjected (Est.) (MMCF)	1,916,622	2,100,034	2,178,575	2,204,103
Ultimate water production (MB)	47,336	51,859	53,836	54,484

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.27.

Table 3.27. Lisburne pool–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$9,205	$9,205	$9,205	$9,205
Total operating costs	$346,751	$610,447	$803,309	$901,423
State royalty	$62,950	$140,555	$247,920	$320,153
State taxes – Severance	$54,842	$93,806	$148,651	$185,311
State taxes – Income	$0	$3,361	$16,895	$27,825
State taxes – Other	$47,224	$77,520	$90,067	$90,521
State Total (Royalty and Taxes)	**$165,016**	**$315,242**	**$503,533**	**$623,810**
Federal taxes	**$12,001**	**$79,032**	**$239,653**	**$362,334**
Industry net income	**$1,651**	**$147,252**	**$464,855**	**$703,028**

3.3.8 PBU – Niakuk PA

The Niakuk pool was discovered in 1985 and production from the Kuparuk C sandstone formation was started in 1994 (Table 2.7). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.8.1 Niakuk PA Engineering

The Niakuk started producing in April 1994 from an accumulation with an estimated OOIP of 219 MMB of 24.9°API oil (AOGCC, 1994). The reservoir is expected to recover 4% by primary and 36% by secondary, for 40% recovery of the OOIP. Maximum EOR potential is estimated at 8.5%, but is not included in this forecast.

Production is processed by Lisburne PA facilities at the maximum rate possible under gas and water constraints. Production reached a maximum of over 30 MBOPD in 1996, and exceeded 20 MBOPD through mid 2000. Oil production has established a decline since early 2001 of about 15%/yr while water production has increased significantly over time. Historical and forecast oil, gas, and water production is presented in Figure 3.23. There is no information to suggest this behavior will change, although assumed workovers and perhaps some redrills could moderate the decline.

TRR volumes are forecasted using a 15%/yr production decline with an abandonment rate of 0.050 MBOPD. This results in TRR of 17,920 MBO. The produced GOR over the last year averaged about 790 cubic feet per barrel (CF/BBL). This GOR is used as a constant value to estimate future NGL volumes. NGL reserves are estimated using the average recovery factor over the last three years of 0.0129 bbl/MCF. This results in an NGL TRR of 0.180 MB and a total liquid TRR of 18,100 MB and a TUR of 99,323 MB. The historical Niakuk water cut versus recovery factor was used to estimate future water volumes, Figure 3.24. This figure also shows the historical GOR_D versus cumulative recovery factor. It is assumed produced gas is consumed by lease operations with any excess gas being injected into the Lisburne reservoir.

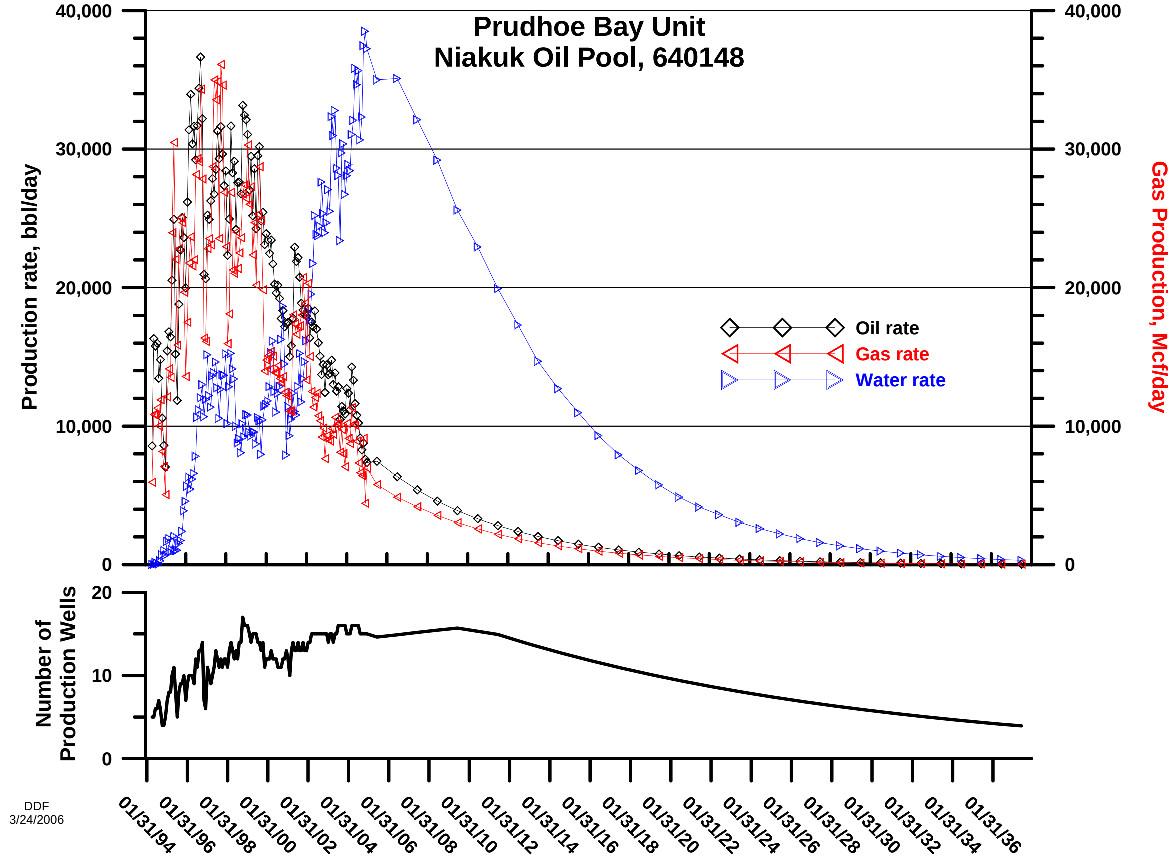


Figure 3.23. Prudhoe Bay Unit–Niakuk pool production history and forecasts.

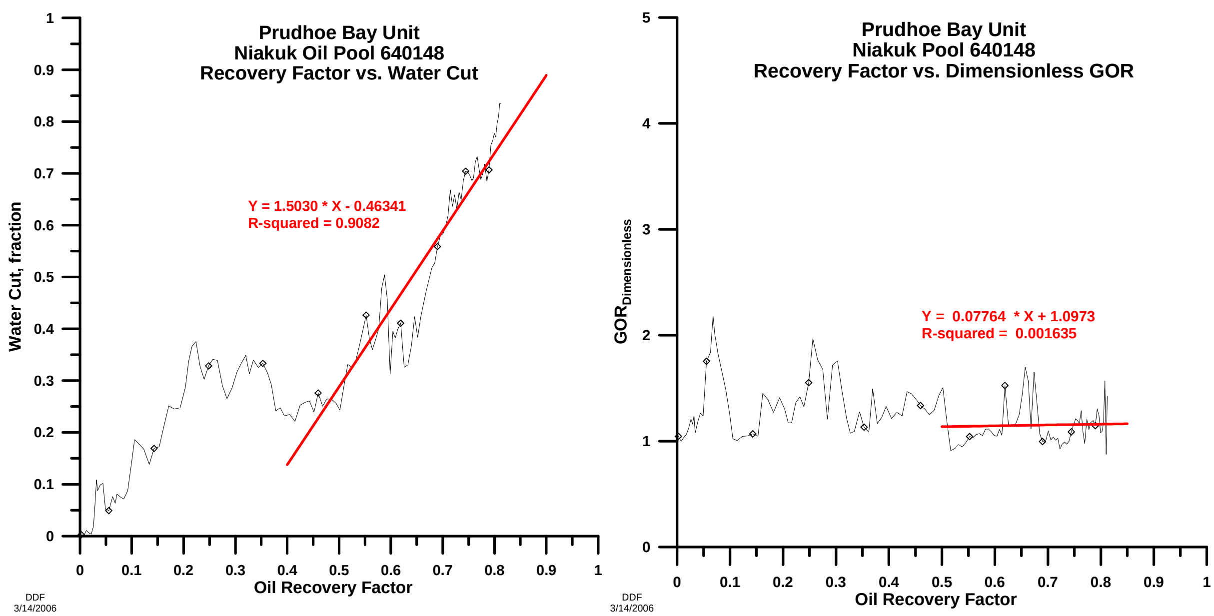


Figure 3.24. Prudhoe Bay Unit–Niakuk pool recovery factor versus water cut and GOR.

Niakuk pool historical oil, gas, and water cumulative production is presented in Table 3.28.

Table 3.28. Niakuk pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	80,268 MBO
Cumulative NGL recovery	955 MBO
Cumulative oil and NGL	81,223 MBO
Cumulative gas production	67,441 MMCF
Cumulative Reinjected gas	0 MMCF
Cumulative water	57,219 MB

Forecasts of Niakuk pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.29.

Table 3.29. Niakuk pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2010	2013	2017	2019
Oil and NGLs ERR (MB)	10,018	13,102	15,449	16,161
Future Gas forecast (MMCF)	7,760	10,158	11,987	12,542
Future water forecast (MB)	45,212	60,412	72,254	75,870
Oil and NGLs EUR (MB)	91,241	94,325	96,672	97,384
Ultimate gas production (MMCF)	75,201	77,599	79,428	79,983
Total gas reinjected (Est.) (MMCF)	0	0	0	0
Ultimate water production (MB)	102,431	117,631	129,473	133,089

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.30.

Table 3.30. Niakuk pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$8,685	$11,933	$11,933	$11,933
Total operating costs	$145,025	$227,734	$325,140	$369,433
State royalty	$23,551	$49,226	$91,494	$119,207
State taxes – Severance	$22,601	$44,037	$72,831	$90,771
State taxes – Income	$156	$1,911	$6,605	$10,495
State taxes – Other	$3,760	$5,834	$8,222	$9,242
State Total (Royalty and Taxes)	**$50,068**	**$101,008**	**$179,152**	**$229,715**
Federal taxes	**$4,118**	**$25,181**	**$79,393**	**$122,826**
Industry net income	**$202**	**$46,485**	**$154,118**	**$238,425**

3.3.9 PBU – North Prudhoe Bay PA

The North Prudhoe Bay pool was discovered in 1970 and production from the Ivishak sandstone formation was started in 1993 (Table 2.7). The estimated OOIP is between 12 and 65 MMBO (AOGCC, 1994b). The production test started in 1993 and produced a total of about 2

MMB before being shut in. The historical oil, gas, and water production is presented in Figure 3.25. No reserves are attributed to this pool.

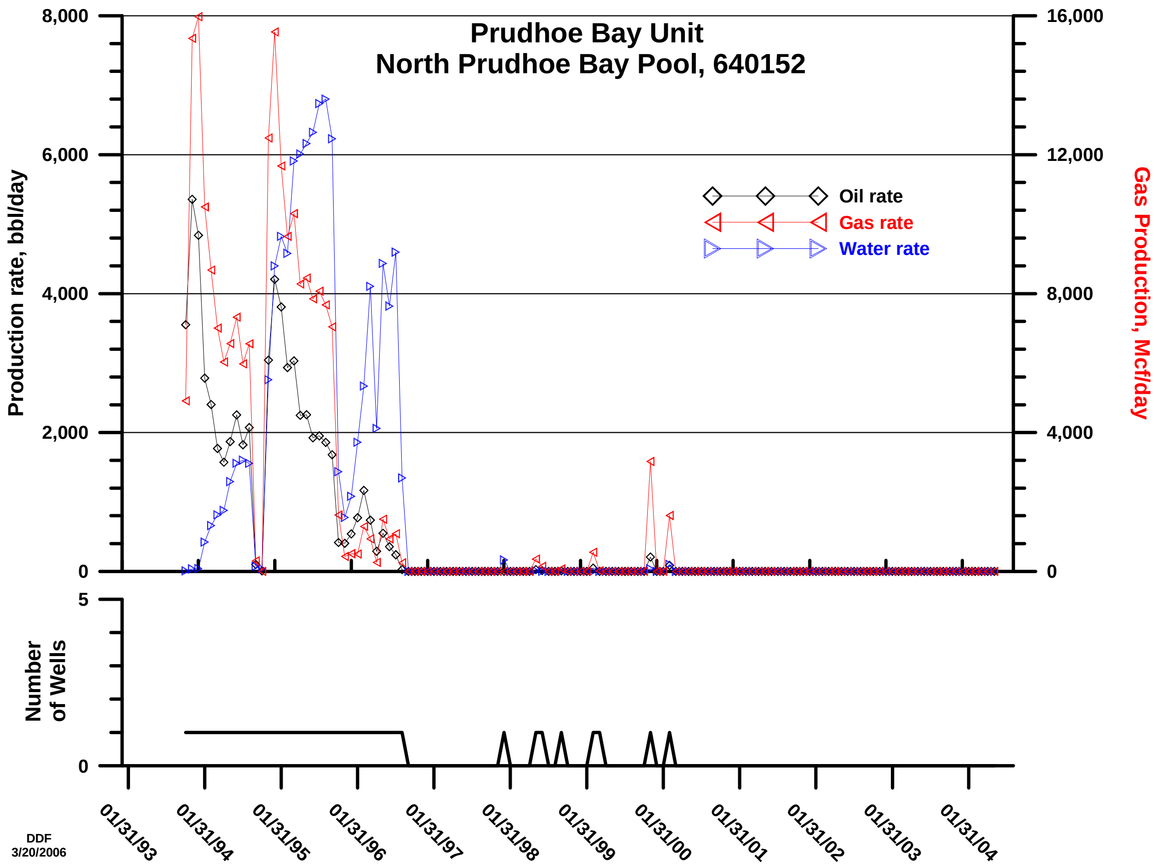


Figure 3.25. Prudhoe Bay Unit–North Prudhoe Bay pool production history.

North Prudhoe Bay pool historical oil, gas, and water cumulative production is presented in Table 3.31.

Table 3.31. North Prudhoe Bay pool production statistics as of 1/1/2005

VARIABLE	VOLUME
Cumulative oil recovery	1,985 MBO
Cumulative NGL recovery	85 MB
Cumulative oil and NGL	2,070 MBO
Cumulative gas production	6,616 MMCF
Cumulative Reinjected gas	0 MMCF
Cumulative water	2,498 MB

3.3.10 PBU – West Beach PA

The West Beach pool was discovered in 1976 and production from the Kuparuk C sandstone formation was started in 1993 (Table 2.7). The estimated OOIP is between 10 and 65 MMBO (AOGCC, 1993). The historical oil, gas, and water production is presented in Figure

3.26. The production totaled 3.3 MMBO through 2nd quarter of 2001 and was suspended at that time. No reserves are attributed to this pool.

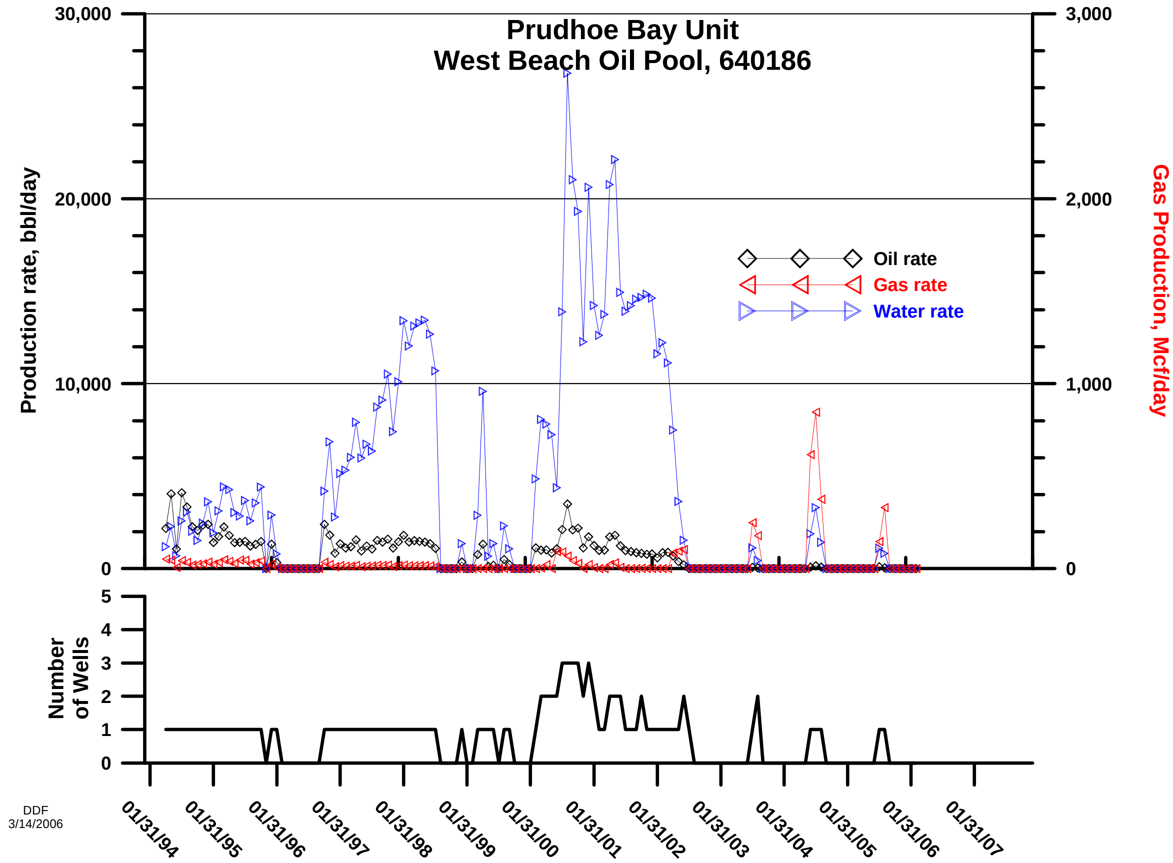


Figure 3.26. Prudhoe Bay Unit–West Beach pool production history.

West Beach pool historical oil, gas, and water cumulative production is presented in Table 3.32.

Table 3.32. West Beach pool production statistics as of 1/1/2005

VARIABLE	VOLUME
Cumulative oil recovery	3,361 MBO
Cumulative NGL recovery	220 MB
Cumulative oil and NGL	3,581 MBO
Cumulative gas production	20,012 MMCF
Cumulative Reinjected gas	0 MMCF
Cumulative water	20,012 MB

3.3.11 PBU – Point McIntyre PA

The Point McIntyre pool was discovered in 1988 and production from the Kuparuk C sandstone formation was started in 1993 (Table 2.7). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.11.1 Point McIntyre PA Engineering

The Point McIntyre reservoir has an estimated OOIP of between 750 to 800 MMB of 27°API oil. Recovery is estimated at 20 to 25% primary with secondary processes increasing recovery to 42 to 45% of OOIP. The enhanced recovery project is estimated to increase recovery by 6% for a total recovery of 48 to 51% of OOIP (AOGCC, 1993b, AOGCC, 2000b).
The Point McIntyre pool started first production in November 1993 at an initial rate of 46.6 MBOPD. Production is processed by the Lisburne PA facilities. Improved oil recovery operations began with produced gas reinjected upon the onset and water injection started in July 1994. Production rapidly climbed to over 160 MBOPD by June 1996 with production averaging about 162 MBOPD for 17 months before starting to decline November 1997. Historical and forecast oil, gas, and water production is presented in Figure 3.27. Cumulative recovery to date is 376 MMBO and the project is still producing 36 MBOPD, suggesting the estimate of OOIP is conservative.

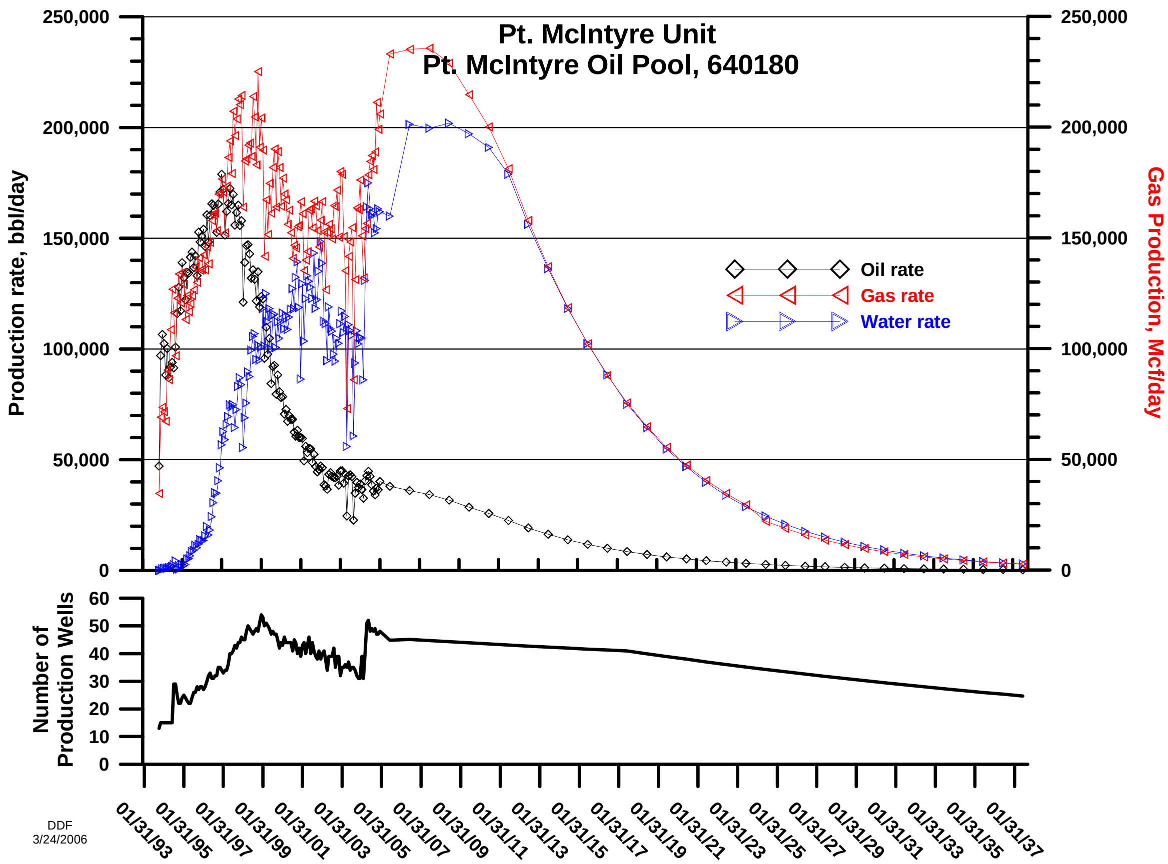


Figure 3.27. Prudhoe Bay Unit–Point McIntyre pool production history and forecasts.

Future reserves and total recovery volumes are based on the production performance with oil production exhibiting a low rate of decline of about 5%/yr over the last three years. It is assumed this low decline will gradually increase to long-term decline of 15%/yr by 2011. Reserves are forecast using an average of 36 MBOPD for 2005 with production declining 5%/yr to an average rate of 30 MBOPD in 2008. Production is declined at 10%/yr to an average of 21 MBOPD in 2011. At that time, production is declined at a rate of 15%/yr to an abandonment rate of 0.30 MBOPD. This results in a TRR of 118,724 MBO.

The NGL forecast assumes production of 2 MBOPD in 2005 declining in tandem with the oil production rates. This results in a TRR for NGLs of 6,586 MB. The total TUR for oil and NGLs is 509,413 MB.

Gas production is forecasted using the historical performance of the recovery versus GOR_D and water production is forecasted using the recovery versus water cut performance, Figure 3.28. It is assumed all gas in excess of lease operation needs is reinjected for production enhancement.

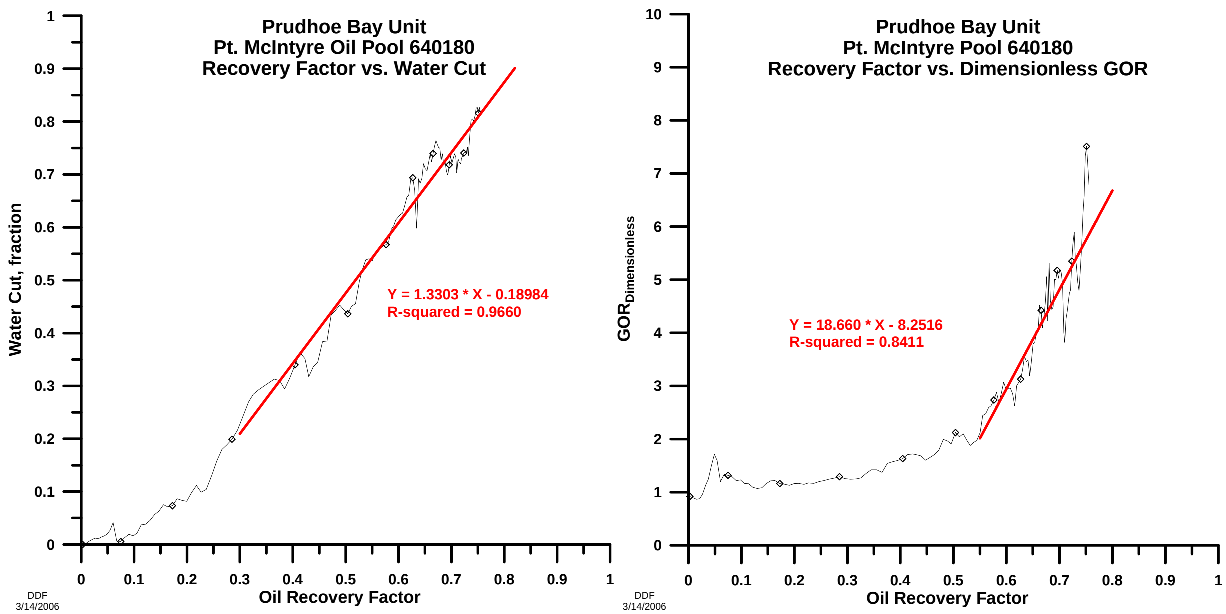


Figure 3.28. Prudhoe Bay Unit–Point McIntyre pool recovery factor versus water cut and GOR.

Point McIntyre historical oil, gas, and water cumulative production is presented in Table 3.33.

Table 3.33. Point McIntyre pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	376,072 MBO
Cumulative NGL recovery	8,031 MBO
Cumulative oil and NGL	384,103 MBO
Cumulative gas production	638,765 MMCF
Cumulative Reinjected gas	503,292 MMCF
Cumulative water	334,177 MB

Forecasts of Point McIntyre pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.34.

Table 3.34. Point McIntyre pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2016	2020	2023	2025
Oil and NGLs ERR (MB)	101,593	113,261	118,180	120,350
Future Gas forecast (MMCF)	716,606	817,156	860,652	880,048
Future water forecast (MB)	637,525	739,071	782,746	802,127
Oil and NGLs EUR (MB)	485,696	497,364	502,283	504,453
Ultimate gas production (MMCF)	1,355,371	1,455,921	1,499,417	1,518,813
Total gas reinjected (Est.) (MMCF)	1,067,916	1,147,141	1,181,412	1,196,694
Ultimate water production (MB)	971,702	1,073,248	1,116,923	1,136,304

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.35.

Table 3.35. Point McIntyre pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$34,060	$48,713	$48,713	$48,713
Total operating costs	$1,135,618	$1,492,670	$1,744,001	$1,907,163
State royalty	$258,765	$454,865	$735,006	$927,380
State taxes – Severance	$211,534	$332,652	$511,165	$631,279
State taxes – Income	$11,383	$37,415	$82,561	$114,470
State taxes – Other	$42,408	$53,751	$60,363	$63,726
State Total (Royalty and Taxes)	**$524,090**	**$878,683**	**$1,389,095**	**$1,736,855**
Federal taxes	**$165,934**	**$458,866**	**$959,719**	**$1,311,779**
Industry net income	**$318,467**	**$886,449**	**$1,862,981**	**$2,544,433**

3.3.12 Duck Island Unit – Endicott PA

The Endicott pool was discovered in 1978 and production from the Kekiktik conglomerate formation was started in 1986 (Table 2.7). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.12.1 Endicott PA Engineering

The Endicott pool was the first ANS offshore project. It was developed from a man-made island that is connected to shore with a gravel causeway. It targets an estimated accumulation of 1,059 MMB OOIP of 23ºAPI oil. Estimated total recovery including primary, incremental secondary and EOR ranges from about 48 to 53% (ADNR, 2004). These recovery factors give a TUR between 508 and 560 MMBO. These estimates are reasonable because cumulative recovery through December 2004 is 427 MMBO.

Production started August 1986 and increased to over 100 MBOPD by November 1987. Production is processed by the Duck Island Unit (DIU) IPA facilities. Water injection started January 1988. Oil production was maintained at an average rate of 103.9 MBOPD from

November 1987 through January 1994 before starting to decline. The pool is currently producing about 24.0 MBOPD. The historical and forecast oil, gas, and water production is presented in Figure 3.29.

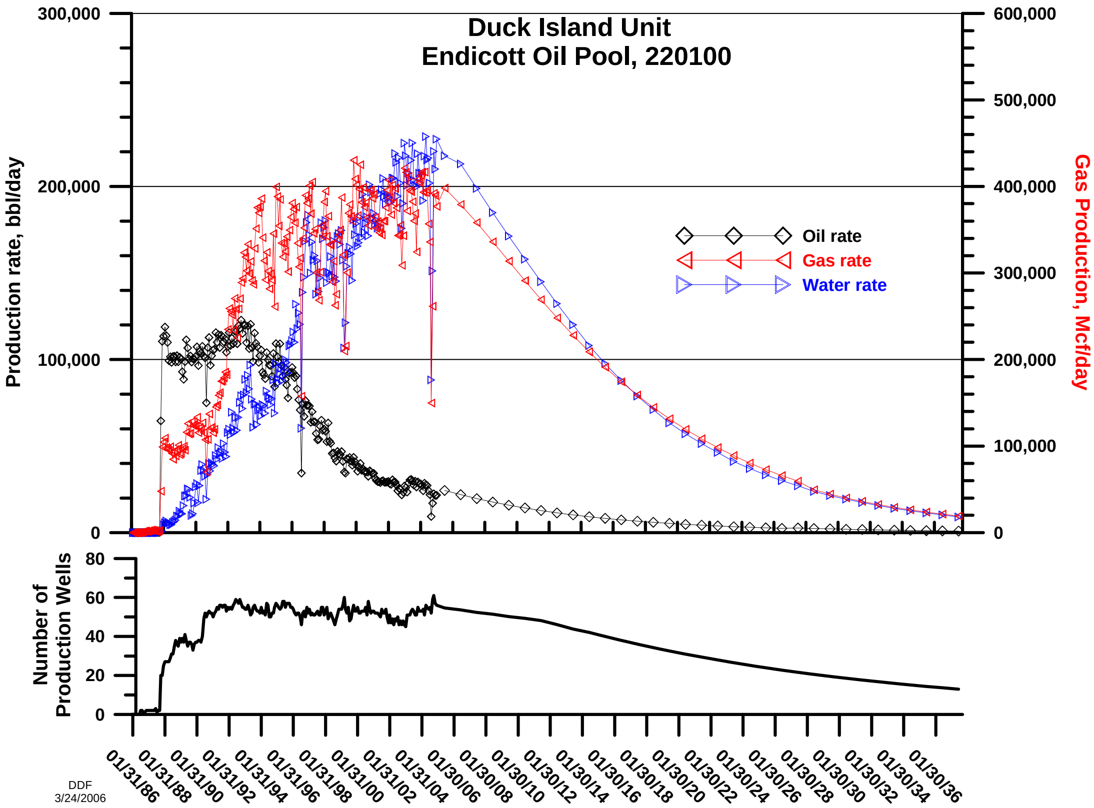


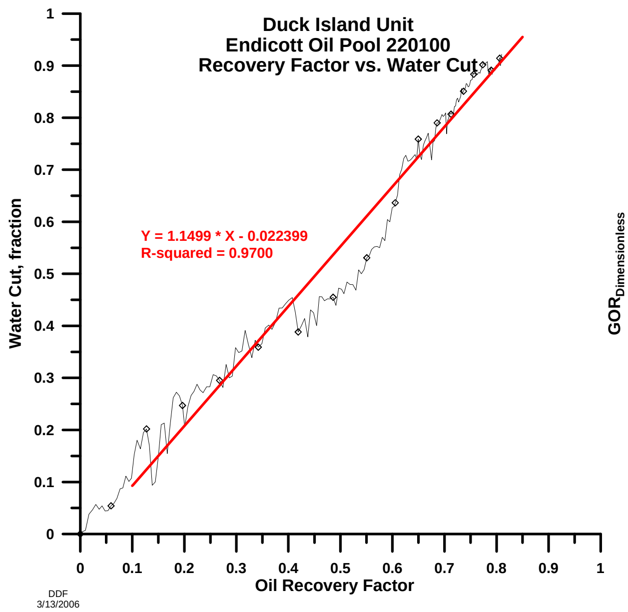
Figure 3.29. Duck Island Unit–Endicott pool production history and forecasts.

The forecast of reserves is based on the production performance of the last four years, which shows a 10%/yr decline. It is assumed this decline can be sustained by an active program of well workovers, redrills, and the continued success of the waterflood.

The operator has indicated an abandonment rate of 3.5 MBOPD (ADNR, 2002). Reserves for this study use a technical abandonment rate of 0.5 MBOPD and result in a TRR of 76,340 MBO.

Future production of NGLs is based on the last eight years of NGL and produced gas volumes. There has been a 5.5%/yr decline in the NGL yield factor (bbl NGL/MCF gas produced) in the last eight years from 0.0124 bbl/MCF to 0.0080 bbl/MCF. The current yield factor is declined at 5.5% per year and is used with the future forecast of produced gas volumes to forecast NGL reserves of 10,000 MB, giving an ultimate forecast of about 30,375 MB. The TRR for oil and NGLs is about 86,340 MG resulting in a TUR for oil and NGLs of about 533,952 MB.

The gas production forecast uses the historical recovery versus GOR_D and the water production forecast uses the historical recovery versus water cut behavior. These relationships are shown in Figure 3.30. All gas is used for lease operations or for enhanced oil recovery.



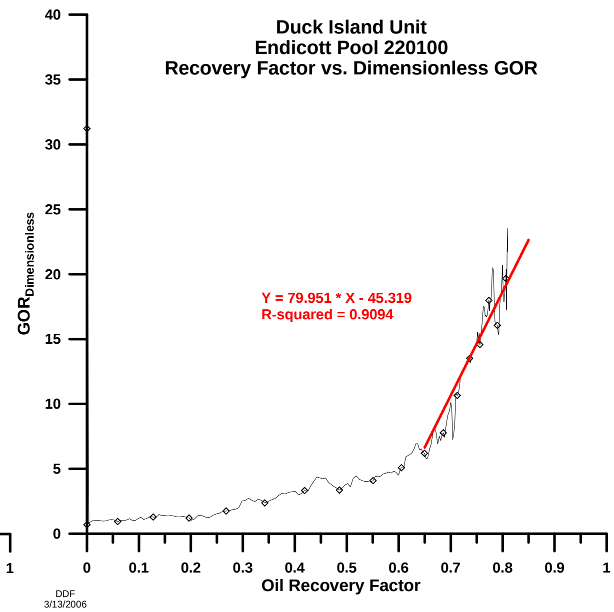


Figure 3.30. Duck Island Unit–Endicott pool recovery factor versus water cut and GOR.

Endicott historical oil, gas, and water cumulative production is presented in Table 3.36.

Table 3.36. Endicott pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	427,237 MBO
Cumulative NGL recovery	20,375 MBO
Cumulative oil and NGL	447,612 MBO
Cumulative gas production	1,824,602 MMCF
Cumulative Reinjected gas	1,631,154 MMCF
Cumulative water	733,762 MB

Forecasts of Endicott pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.37.

Table 3.37. Endicott pool – Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2008	2015	2024	2027
Oil and NGLs ERR (MB)	24,035	57,351	75,523	78,566
Future Gas forecast (MMCF)	397,865	1,072,685	1,501,112	1,577,038
Future water forecast (MB)	218,936	597,503	830,291	870,081
Oil and NGLs EUR (MB)	471,647	504,963	523,135	526,178
Ultimate gas production (MMCF)	2,222,467	2,897,287	3,325,714	3,401,640
Total gas reinjected (Est.) (MMCF)	1,986,836	2,590,110	2,973,115	3,040,991
Ultimate water production (MB)	952,698	1,331,265	1,564,053	1,603,843

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.38.

Table 3.38. Endicott pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$2,728	$13,102	$17,445	$17,445
Total operating costs	$355,042	$1,119,315	$1,882,893	$2,092,422
State royalty	$52,267	$212,074	$461,042	$603,201
State taxes – Severance	$0	$0	$0	$0
State taxes – Income	$0	$6,516	$32,425	$54,827
State taxes – Other	$49,540	$151,715	$242,627	$258,654
State Total (Royalty and Taxes)	**$101,807**	**$370,305**	**$736,094**	**$916,682**
Federal taxes	**$1,384**	**$89,190**	**$382,969**	**$632,363**
Industry net income	**-$7,965**	**$160,284**	**$732,269**	**$1,226,022**

3.3.13 Duck Island Unit – Eider PA

The Eider Pool of the DIU (Eider PA) was discovered in a 1998 (Table 2.7) and production started in 1998 from the Ivishak sandstone formation (ADNR, 2002). The production totaled 2.7 MMBO through December 2004. The OOIP is estimated to be 13.2 MMB of 23ºAPI oil (AOGCC, 2000c). Eider historical oil, gas, and water production is shown in Figure 3.31. As a result of the production of only about 200 bbls of oil in 2004, no reserves are attributed to this development.

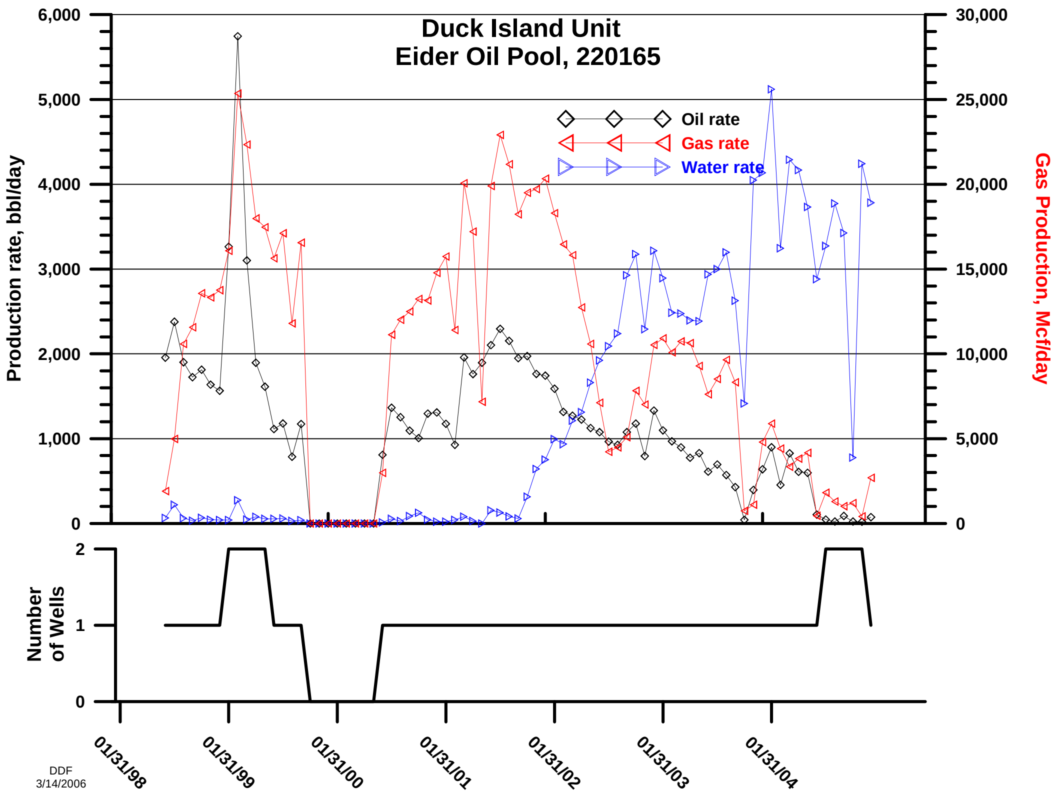


Figure 3.31. Duck Island Unit–Eider pool production history.

Eider pool historical oil, gas, and water production is presented in Table 3.39.

Table 3.39. Eider pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	2,687 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	2,687 MBO
Cumulative gas production	23,323 MMCF
Cumulative Reinjected gas	MMCF
Cumulative water	3,183 MB

3.3.14 Duck Island Unit – Sag Delta North PA

The Sag Delta North PA of the DIU was discovered in 1982 (Table 2.7) and consists of two formations, the Ivishak sandstone and the Alapah limestone of the Lisburne Group (AOGCC 1991). Commingled production began in 1989 from the OOIP of about 18 MMBO in the Ivishak/Alapah formations. Production totaled 7.9 MMBO through December 2004. It was shut down during late 2004 and no remaining reserves are attributed to this PA. Historical oil, gas, and water production is shown in Figure 3.32.

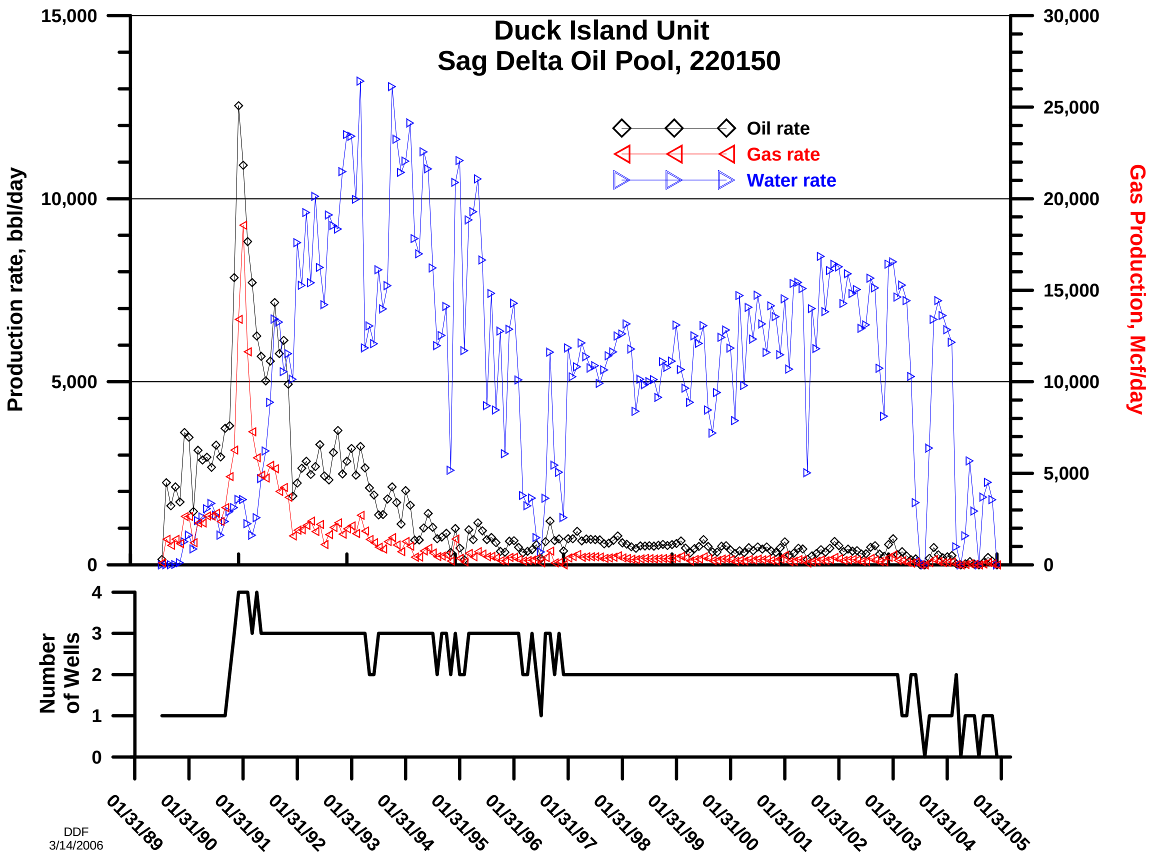


Figure 3.32. Duck Island Unit–Sag Delta North pool production history and forecasts.

Cumulative historical oil, gas, and water production for the Sag Delta North pool is shown in Table 3.40.

Table 3.40. Sag Delta North pool production statistics as of 1/1/2005

VARIABLE	VOLUME
Cumulative oil recovery	7,948 MBO
Cumulative NGL recovery	111 MBO
Cumulative oil and NGL	8,059 MBO
Cumulative gas production	6,508 MMCF
Cumulative Reinjected gas	0 MMCF
Cumulative water	31,245 MB

3.3.15 Northstar Unit – Northstar PA

The Northstar pool was discovered in 1984 and was known as Seal Island after discovery by the Seal #1 well (Table 2.7, ADNR 2004b). After the Northstar Unit (NU) was formed, production from the Sag River/Ivashak formation was started in 2001. NU is a recent offshore development, and is located in state of Alaska and federal waters of the Beaufort Sea. Development is from a totally contained offshore island and connected to shore by the first subsea pipeline on the ANS. Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.15.1 Northstar PA Engineering

Northstar pool development targets an accumulation of 285 MMB OOIP of 43 to 45°API oil (AOGCC, 2001b). It contains significant associated gas and a 7 BCF gas cap. Estimated primary recovery is 36.1%, with gas cycling providing an incremental 13.9% recovery, water flooding 2%, and miscible injectant an additional 12.5% incremental recovery. A TUR of 184 MMBO is indicated from the recovery factors and the OOIP estimate (AOGCC, 2001b).

Production started November 2001 at an initial rate of 11.6 MBOPD rapidly increasing to over 60 MBOPD by June 2002. Produced fluids are processed by the Northstar facility. Production for the 15 months from November 2003 through December 2004, averaged 68.2 MBOPD. Production over the last four months of 2004 averaged almost 75 MBOPD. It is assumed production has peaked and that it will begin to decline in 2005 at a rate of 15%/yr to an abandonment rate of 0.125 MBOPD. This results in a TRR of 168,260 MBO and a TUR of about 235,500 MBO. Reservoir performance to date indicates that the operator's recovery estimates may be conservative.

The historical and future oil, gas and water production versus time plot is shown in Figure 3.33.

Forecast gas volumes are based on the historical recovery versus GOR_D performance, and water production is based on the historical recovery versus water cut performance, Figure 3.34. It is assumed all gas production is used for lease operations and the balance injected for gas cycling and EOR purposes.

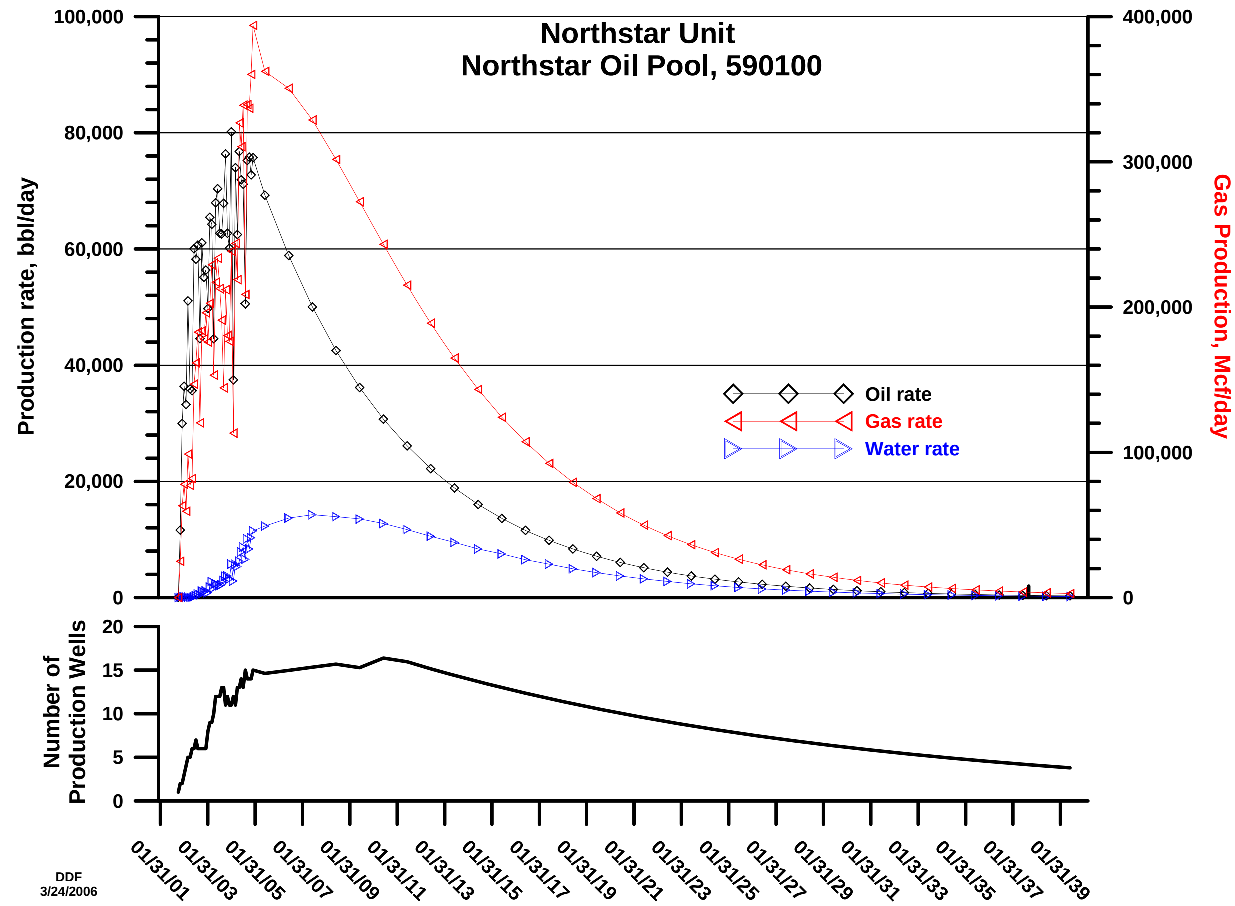
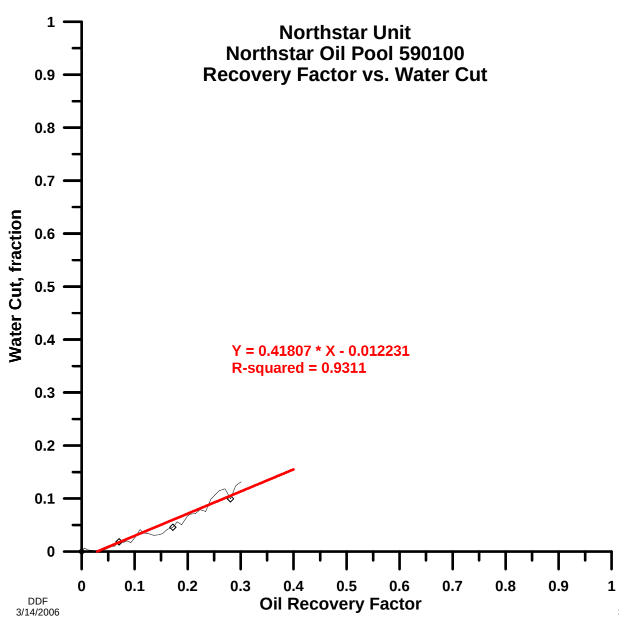


Figure 3.33. Northstar Unit–Northstar pool production history and forecasts.



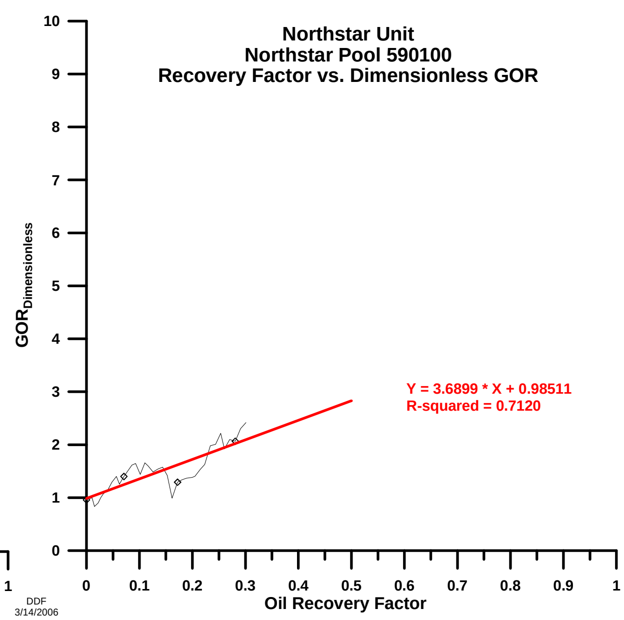


Figure 3.34. Northstar Unit–Northstar pool recovery factor versus water cut and GOR.

Northstar historical oil, gas and water cumulative production is presented in Table 3.41.

Table 3.41. Northstar pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	67,215
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	67,215 MBO
Cumulative gas production	255,546 MMCF
Cumulative Reinjected gas	300,863 MMCF
Cumulative water	3,871 MB

Forecasts of Northstar pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.42.

Table 3.42. Northstar pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2028	2032	2035	2037
Oil and NGLs ERR (MB)	164,506	166,424	167,232	167,588
Future Gas forecast (MMCF)	1,212,553	1,231,610	1,239,674	1,243,242
Future water forecast (MB)	61,683	62,961	63,505	63,745
Oil and NGLs EUR (MB)	231,721	233,639	234,447	234,803
Ultimate gas production (MMCF)	1,468,099	1,487,156	1,495,220	1,498,788
Total gas reinjected (Est.) (MMCF)	1,728,443	1,750,879	1,760,373	1,764,574
Ultimate water production (MB)	65,554	66,832	67,376	67,616

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.43.

Table 3.43. Northstar pool–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$62,276	$62,276	$62,276	$62,276
Total operating costs	$648,490	$715,751	$762,265	$791,674
State royalty	$674,103	$1,070,543	$1,661,546	$2,057,625
State taxes – Severance	$92,518	$133,712	$195,506	$236,700
State taxes – Income	$56,050	$100,095	$167,740	$213,165
State taxes – Other	$204,087	$206,813	$206,849	$206,866
State Total (Royalty and Taxes)	**$1,026,758**	**$1,511,163**	**$2,231,641**	**$2,714,356**
Federal taxes	**$527,667**	**$1,012,467**	**$1,756,208**	**$2,255,656**
Industry net income	**$1,020,250**	**$1,965,380**	**$3,409,114**	**$4,378,627**

3.3.16 Badami Unit – Badami Sand Field

The Badami pool was discovered in 1990 and is located 35 miles east of PBU. Production began from the Badami sand in 1998. Production totaled 4.3 MMBO through

December 2004. The OOIP is estimated to be 300 MMBO (Table 2.7). The field was shut-in during August 2003 after averaging about 1.3 MBOPD for 2003, as an uneconomical operation.

3.3.16.1 Badami Engineering

In late 2005, the operator applied to the state to restart production for a 3-yr period to test new recovery techniques designed specifically for this project. Work could include new drilling technology and well workovers. Higher oil prices also influenced the decision to restart the project (PN, 2005b).

Latest reported production was 2.0 MBOPD in mid-October 2005, with production averaging about 1.3 MBOPD for the first month's operation. Until the Unit can produce at a higher rate than 2.0 MBOPD, the project is marginally profitable at best. The operator will announce any redevelopment decisions in 2007 (PN, 2005d). Although production is currently taking place, no reserves are estimated for this Unit.

The historical oil and gas production is presented in Figure 3.35.

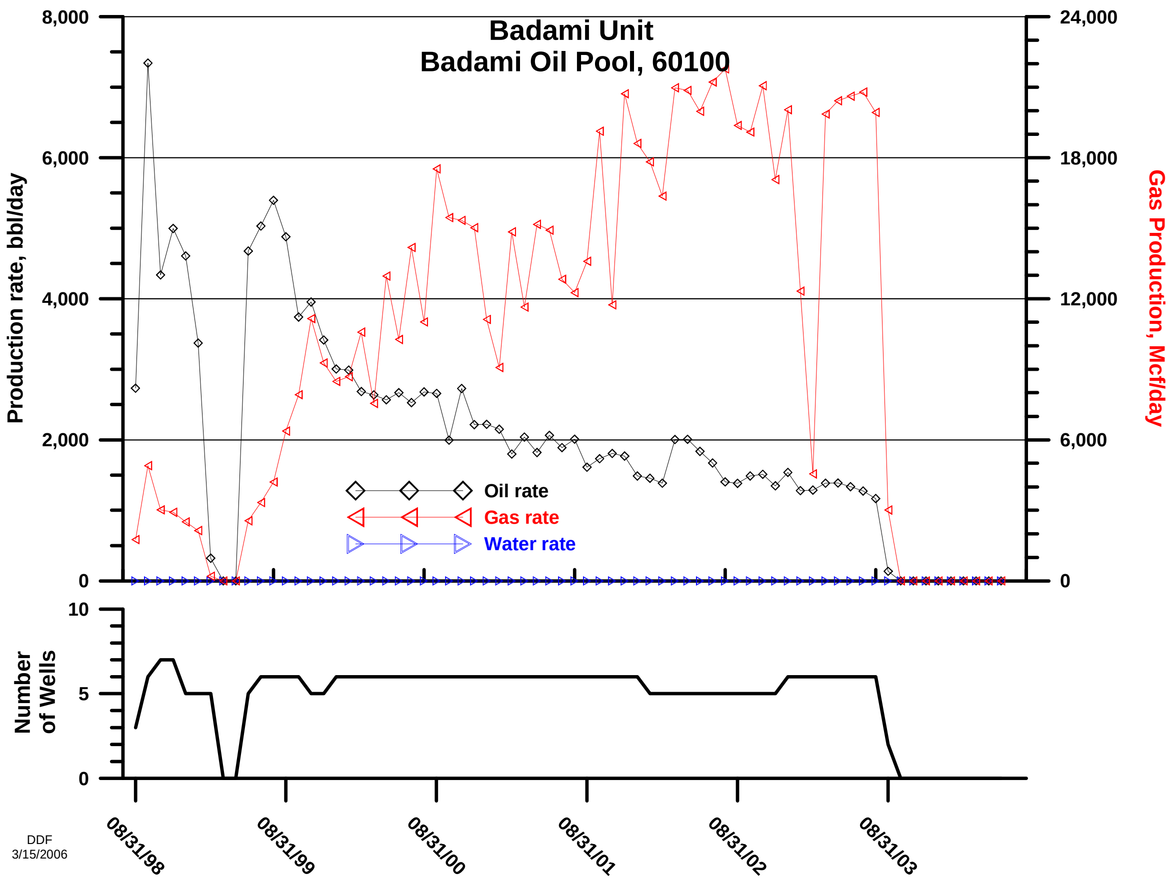


Figure 3.35. Badami pool production history.

Historical oil, gas, and water cumulative production is presented in Table 3.34.

Table 3.44. Badami pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	4,347 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	4,347 MBO
Cumulative gas production	22,891 MMCF
Cumulative Reinjected gas	20,511 MMCF
Cumulative water	0 MB

3.3.17 Kuparuk River Unit – Kuparuk River PA

The Kuparuk River pool was discovered in 1969 and production from the Kuparuk Formation was started in 1981 (Table 2.7). Engineering and economic analyses to determine economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.17.1 Kuparuk River PA Engineering

The Kuparuk River pool was the second field to be developed on the North Slope with an OOIP of 5.69 BBO (Table 2.7) of 24°API oil and an estimated OGIP of about 1.7 TCF (AOCCC 1994c). Recovery is estimated at 20% primary, 20% incremental secondary, and 8% EOR for a total recovery of 48% of the OOIP.

The Kuparuk River pool was unitized in December 1, 1981 as the Kuparuk River Unit (KRU) (AOGCC 1991b). First production began in December 1981 at an initial rate of 35.8 MBOPD. Production is processed by the Kuparuk River IPA facilities. Both gas injection and water injection commenced within 14 months of initial production. Production was increased to 300 MBOPD by February 1988, and averaged about 310 MBOPD for a little more than 7 years. Production began to decline in May 1995 and reached 147 MBOPD in December 2004. The historical and forecast oil, gas, and water production is presented in Figure 3.36.

The OOIP estimate and recovery factors suggest a TUR of about 2.7 BBO, which is used as a guideline for further analysis. Performance history and future recovery plans are used to estimate future reserves. Production has declined at about 5%/yr over the past four years as a result of EOR success, expanded recovery areas, new drilling, redrilled wells, and well workovers. It is assumed the MI process for EOR will be expanded to new areas, additional satellite areas will be developed, and the drilling and workover programs will continue until late in the field life (ADNR, 2004c). Thus, a 5%/yr decline is assumed until 1/1/2006, with production beginning a 7%/yr decline until 1/1/2025, at which time the decline will increase to 10%/yr through the remaining life of the field. An abandonment rate of 5.0 MBOPD is assumed and results in a TRR of 788,580 MBO, and a TUR of 2,763,120 MBO including NGLs.

The gas production forecast uses the historical recovery versus GOR_D and the water production forecast uses the historical recovery versus water cut behavior. These relationships are shown in Figure 3.37. All gas is used for lease operations or for enhanced oil recovery.

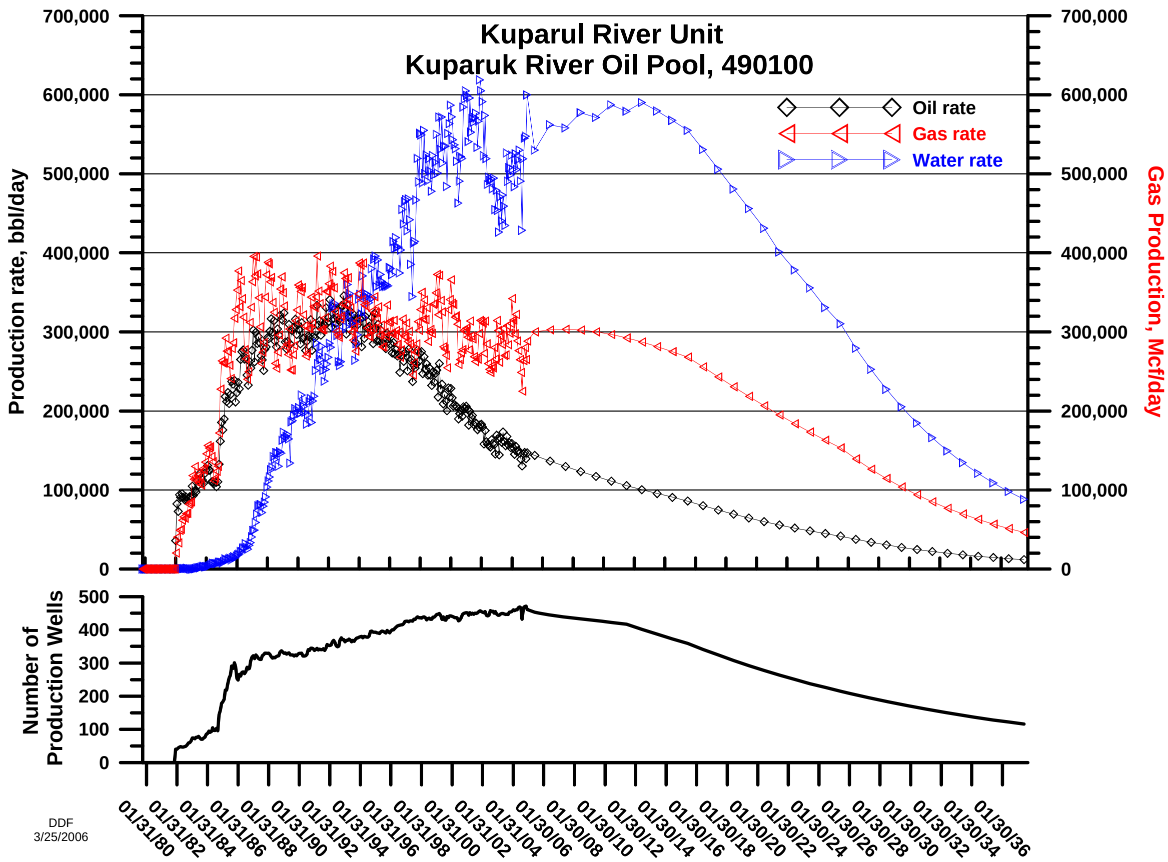


Figure 3.36. Kuparuk River Unit–Kuparuk pool production history and forecasts.

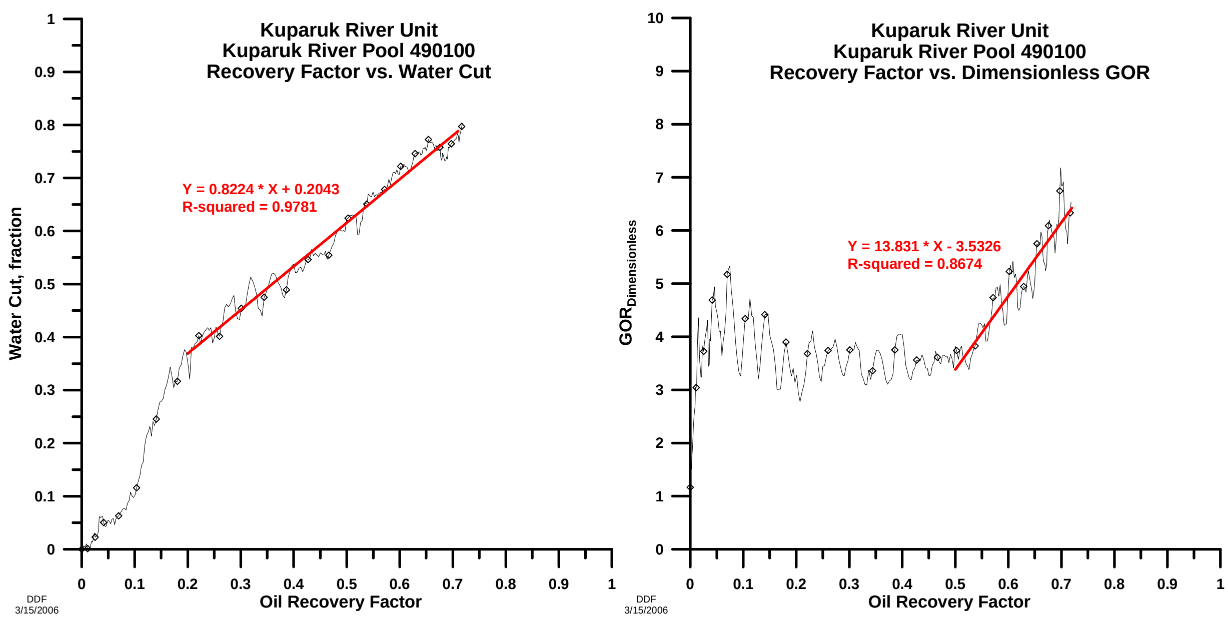


Figure 3.37. Kuparuk River Unit–Kuparuk pool recovery factor versus water cut and GOR.

Kuparuk River pool historical oil, NGL, gas, and water cumulative production is presented in Table 3.45.

Table 3.45. Kuparuk River pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	1,971,194 MBO
Cumulative NGL recovery	3,346 MBO
Cumulative oil and NGL	1,974,540 MBO
Cumulative gas production	2,385,927 MMCF
Cumulative Reinjected gas	1,903,526 MMCF
Cumulative water	2,468,909 MB

Forecasts of Kuparuk River pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.46.

Table 3.46. Kuparuk River pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2029	2040	2040	2040
Oil and NGLs ERR (MB)	704,852	776,739	776,739	776,739
Future Gas forecast (MMCF)	2,041,823	2,327,702	2,327,702	2,327,702
Future water forecast (MB)	4,123,503	4,661,792	4,661,792	4,661,792
Oil and NGLs EUR (MB)	2,679,392	2,751,279	2,751,279	2,751,279
Ultimate gas production (MMCF)	4,427,750	4,713,629	4,713,629	4,713,629
Total gas reinjected (Est.) (MMCF)	3,532,521	3,760,599	3,760,599	3,760,599
Ultimate water production (MB)	6,592,412	7,130,701	7,130,701	7,130,701

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.47.

Table 3.47. Kuparuk River pool–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$229,488	$229,488	$229,488	$229,488
Total operating costs	$12,873,209	$15,468,914	$15,468,914	$15,468,914
State royalty	$1,929,210	$3,494,118	$5,421,150	$6,705,839
State taxes – Severance	$35,277	$54,468	$83,255	$102,445
State taxes – Income	$0	$216,545	$619,859	$889,069
State taxes – Other	$545,338	$551,064	$551,064	$551,064
State Total (Royalty and Taxes)	**$2,509,825**	**$4,316,195**	**$6,675,328**	**$8,248,417**
Federal taxes	**$69,575**	**$2,845,311**	**$7,282,478**	**$10,241,982**
Industry net income	**$150,711**	**$5,523,247**	**$14,136,574**	**$19,881,490**

3.3.18 Kuparuk River Unit – Meltwater PA

The Meltwater pool was discovered in 2000 and production from the Bermuda Sandstone was started in November 2001 (Table 2.7). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.18.1 Meltwater PA Engineering

The Meltwater pool is a Kuparuk River Unit (KRU) satellite development targeting an accumulation of 132 MMBO OOIP of 37ºAPI oil. Recovery factors are estimated at 18% primary, 11% secondary, and 9% EOR for a total recovery factor of 38% (AOGCC, 2001c). The production data are insufficient to be the only data used for reserve determination. Therefore, OOIP and recovery factors are used to estimate a TUR. A conservative recovery factor estimate of 31.5% of OOIP for all processes gives a TUR of about 41.6 MMBO. It is assumed the pool is fully developed and the continued use of miscible water-alternating gas (MWAG) will be successful. It is assumed some infill wells, redrills, and workovers will be required during the future operating life.

Production is processed by the KRU IPA facilities. Production peaked at just over 11.0 MBOPD in May 2002 and declined to about 4.0 MBOPD in December 2003. Production then increased to about 8.0 MBOPD in December 2004. It is assumed that production will continue to increase to 12.0 MBOPD by January 2007, at which time a 15%/yr decline will start and production will decline to an abandonment rate of 0.05 MBOPD. This results in a TRR of 34,436 MBO, and a TUR of about 42,100 MBO.

The historical and future oil, gas, and water production is presented in Figure 3.38.

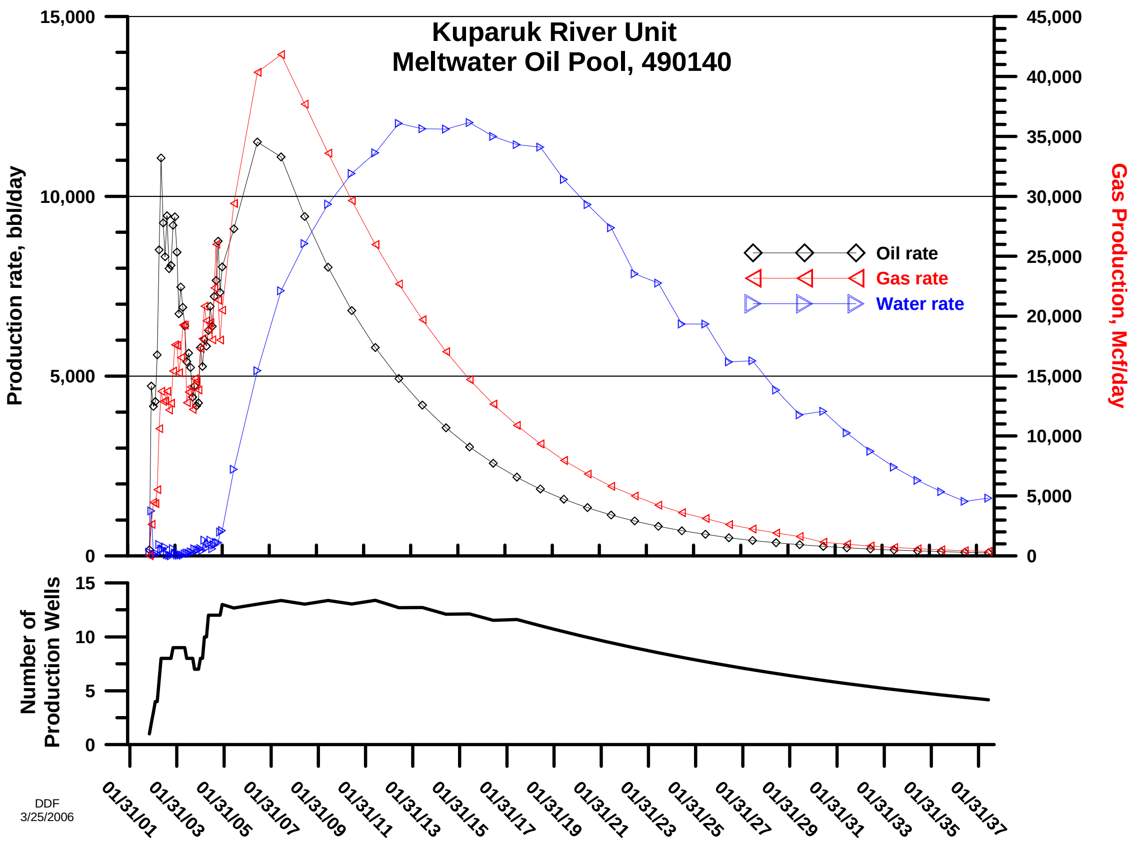
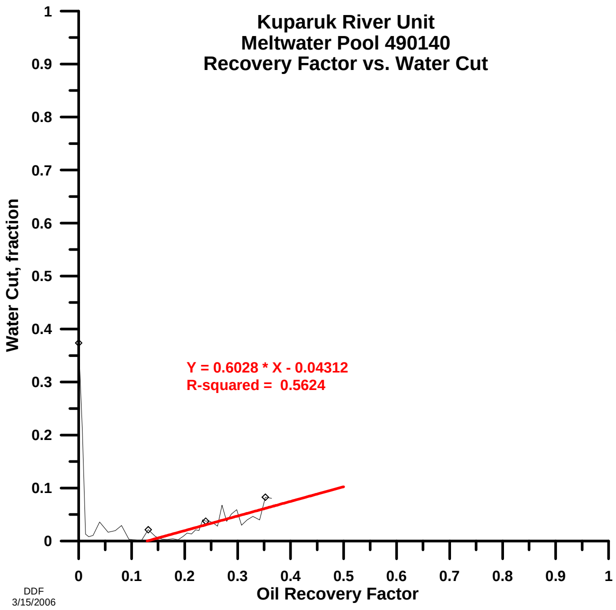


Figure 3.38. Kuparuk River Unit–Meltwater pool production history and forecasts.

Meltwater recovery versus GOR_D and water cut performance are presented in Figure 3.39. There are insufficient production data to develop useable recovery versus GOR_D and water cut relationships. Therefore, the Tarn GOR_D and water cut relationships are used to forecast future gas and water recovery volumes for Meltwater. It is assumed all produced gas is used for lease operations.



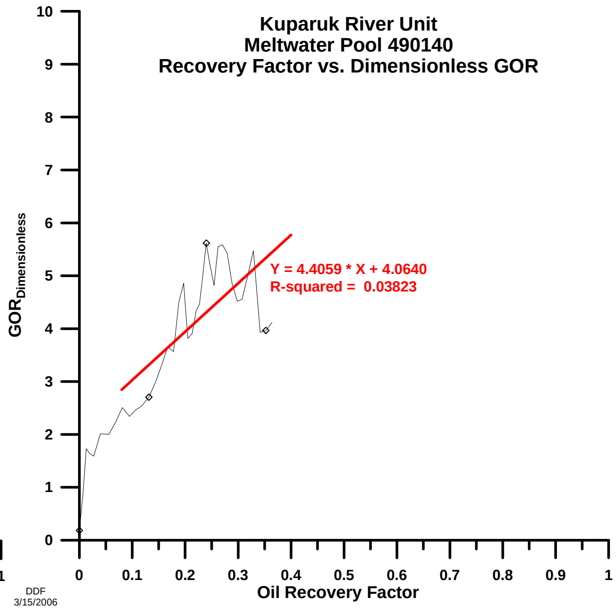


Figure 3.39. Kuparuk River Unit–Meltwater pool recovery factor versus water cut and GOR.

Historical oil, gas, and water cumulative production is presented in Table 3.48.

Table 3.48. Meltwater pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	7,658 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	7,658 MBO
Cumulative gas production	17,140 MMCF
Cumulative Reinjected gas	23,503 MMCF
Cumulative water	250 MB

Forecasts of Meltwater pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.49.

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.50.

Table 3.49. Meltwater pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2016	2020	2024	2026
Oil and NGLs ERR (MB)	28,285	31,280	32,840	33,315
Future Gas forecast (MMCF)	114,099	129,007	136,986	139,445
Future water forecast (MB)	38,867	56,035	69,548	74,809
Oil and NGLs EUR (MB)	35,943	38,938	40,498	40,973
Ultimate gas production (MMCF)	131,239	146,147	154,126	156,585
Total gas reinjected (Est.) (MMCF)	118,115	131,533	138,713	140,926
Ultimate water production (MB)	39,117	56,285	69,798	75,059

Table 3.50. Meltwater pool – Forecasts of economic results for ANS West Coast prices (then current $.

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$49,843	$79,165	$79,165	$79,165
Total operating costs	$288,534	$383,223	$462,594	$497,558
State royalty	$78,376	$132,345	$211,469	$263,757
State taxes – Severance	$0	$0	$0	$0
State taxes – Income	$4,365	$11,778	$24,930	$34,552
State taxes – Other	$21,513	$27,980	$32,889	$34,596
State Total (Royalty and Taxes)	**$104,254**	**$172,103**	**$269,288**	**$332,905**
Federal taxes	**$60,783**	**$146,727**	**$296,572**	**$404,940**
Industry net income	**$111,550**	**$274,452**	**$575,462**	**$786,064**

3.3.19 Kuparuk River Unit –Tabasco PA

The Tabasco pool was discovered in 1986 and production was started from the Tabasco sandstone in 1998 (Table 2.7). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.19.1 Tabasco PA Engineering

Tabasco pool is a KRU satellite development targeting an accumulation of between 48 and 131 MMBO OOIP of 16.5ºAPI oil. The estimated primary recovery is 5% and secondary recovery is from 16% to 25%. Using the above OOIP volumes this results in a TUR of between 10.0 MMBO and 39.0 MMBO (AOGCC, 1998). Because of this wide variation, production performance is used to estimate TRR.

Produced fluids are processed at the KRU IPA facilities. The pool began producing in April 1998 and production peaked at about 8.0 MBOPD in May 1999. Production began declining immediately. A low rate of 1.28 MBOPD was reached in February 2003. Since then production has fluctuated but increased to an average of 5.3 MBOPD in the last six months of 2004. The oil, gas, and water historical and forecast production is presented in Figure 3.40.

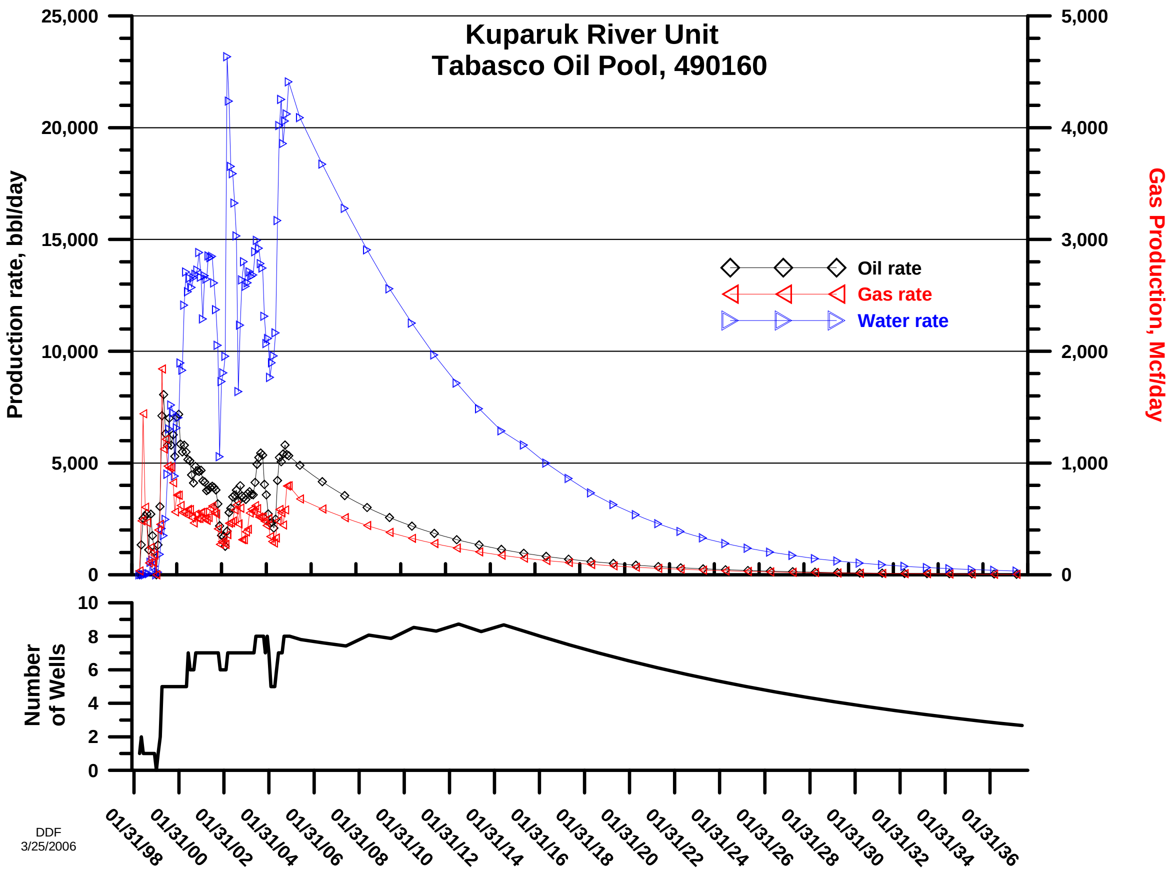


Figure 3.40. Kuparuk River Unit - Tabasco pool production history and forecasts.

Initially, 19 wells were planned for Tabasco, but after poor reservoir performance, this plan was abandoned after 10 wells were drilled. Currently, there are eight production wells and one water injection well. Water flooding began in June of 1998 and has continued intermittently. Reservoir performance has suggested a weak waterflood response with strong water slumping due to gravity segregation. The water cut has been quite high since 2000, suggesting water recycling in the reservoir with poor vertical sweep. Future recovery plans could include converting to gas gravity drainage. Reported results of reservoir modeling suggest the optimal time to convert to gas gravity drainage would be in the 2007 to 2009 time period (ADNR, 2004c). No additional reserves are included for this process since it has not been proven successful.

Future TRR volumes are estimated using an initial rate of 5.3 MBOPD, and declining immediately at a 15%/yr rate to an abandonment rate of 0.05 MBOPD. This results in a TRR of 11,835 MBO from the current recovery process and a TUR of about 21,570 MBO.

Gas and water forecasts are estimated using historical data. The results are valid unless a gravity recovery process is implemented, which would require revision of the relationships. Future gas production is derived from a recovery versus GOR_D historical behavior, and future water production from the historical trend of recovery versus water cut, Figure 3.41. Gas production in excess of lease use is used off lease. Additional gas volumes may be required if the gas gravity drainage process is used.

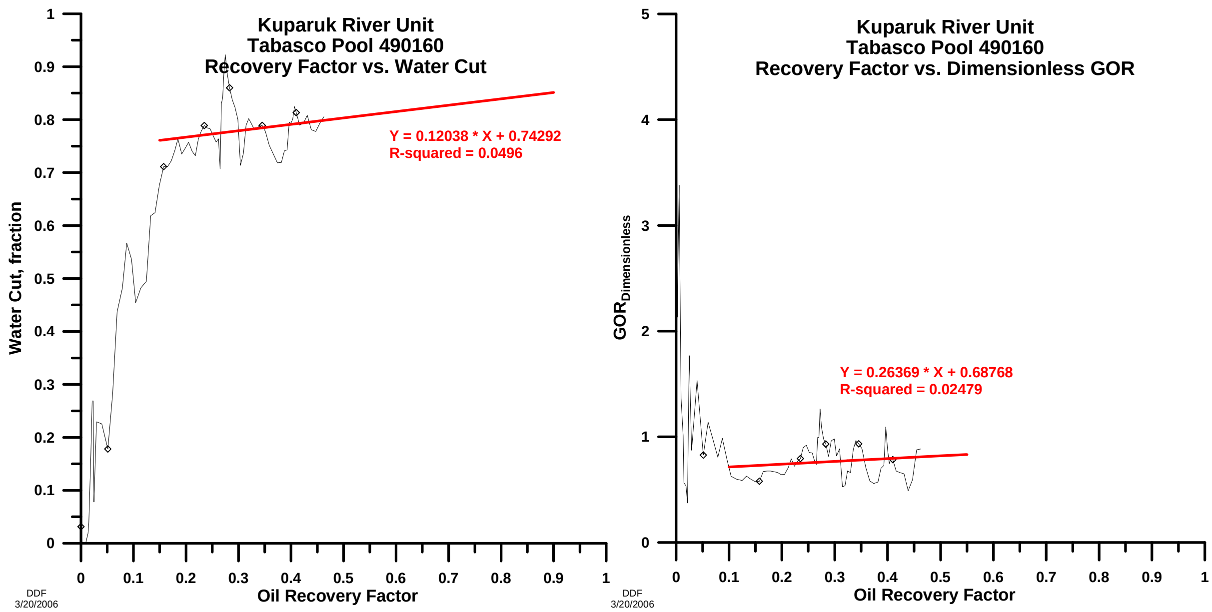


Figure 3.41. Kuparuk River Unit–Tabasco pool recovery factor versus water cut and GOR.

Tabasco pool historical oil, gas, and water cumulative production is presented in Table 3.51.

Table 3.51. Tabasco pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	9,735 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	9,735 MBO
Cumulative gas production	1,329 MMCF
Cumulative Reinjected gas	0 MMCF
Cumulative water	26,190 MB

Forecasts of Tabasco pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.52.

Table 3.52. Tabasco pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2026	2029	2033	2035
Oil and NGLs ERR (MB)	11,535	11,688	11,804	11,839
Future Gas forecast (MMCF)	1,701	1,726	1,744	1,749
Future water forecast (MB)	58,261	59,204	59,920	60,136
Oil and NGLs EUR (MB)	21,270	21,423	21,539	21,574
Ultimate gas production (MMCF)	3,030	3,055	3,073	3,078
Total gas reinjected (Est.) (MMCF)	0	0	0	0
Ultimate water production (MB)	84,451	85,394	86,110	86,326

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.53.

Table 3.53. Tabasco pool–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$35,321	$35,321	$35,321	$35,321
Total operating costs	$39,135	$44,360	$50,929	$54,050
State royalty	$27,671	$45,029	$71,374	$88,917
State taxes – Severance	$0	$0	$0	$0
State taxes – Income	$3,128	$6,460	$11,757	$15,348
State taxes – Other	$7,066	$7,390	$7,432	$7,434
State Total (Royalty and Taxes)	**$37,865**	**$58,879**	**$90,563**	**$111,699**
Federal taxes	**$39,063**	**$76,812**	**$135,483**	**$174,982**
Industry net income	**$74,443**	**$149,104**	**$262,996**	**$339,678**

3.3.20 Kuparuk River Unit – Tarn PA

The Tarn Pool was discovered in 1991 and production was started from the Seabee formation in 1998 (Table 2.7). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.20.1 Tarn PA Engineering

Tarn pool is a KRU satellite development targeting an accumulation of 255 MMBO (Table 2.7) of 37ºAPI oil. Based on production performance, that OOIP volume is low. Recovery factors are estimated at 10% primary with no recovery for secondary processes, and 21% incremental recovery for tertiary by a miscible water alternating gas (MWAG) process (AOGCC, 1998b).

Production is processed by the KRU IPA facilities. Production increased from about 8.8 MBOPD, to a peak rate of over 33,000 MBOPD in early 2002. Production remained above 30.0 MBOPD until July 2003 at which time the rate began to decline. The MWAG process has been successfully used since 2001. Historical and forecast oil, gas, and water production is presented in Figure 3.42

Future oil production is assumed to decline at 15% from 27.0 MBOPD to an abandonment rate of 0.05 MBOPD. This results in TRR of 60,722 MBO and a TUR of about 125,313 MBO.

Forecast gas volumes are based on historical performance of the oil recovery versus GOR_D. Water production is forecasted using historical water cut versus oil recovery, Figure 3.43. It is assumed all gas is used for lease operations and in the EOR process.

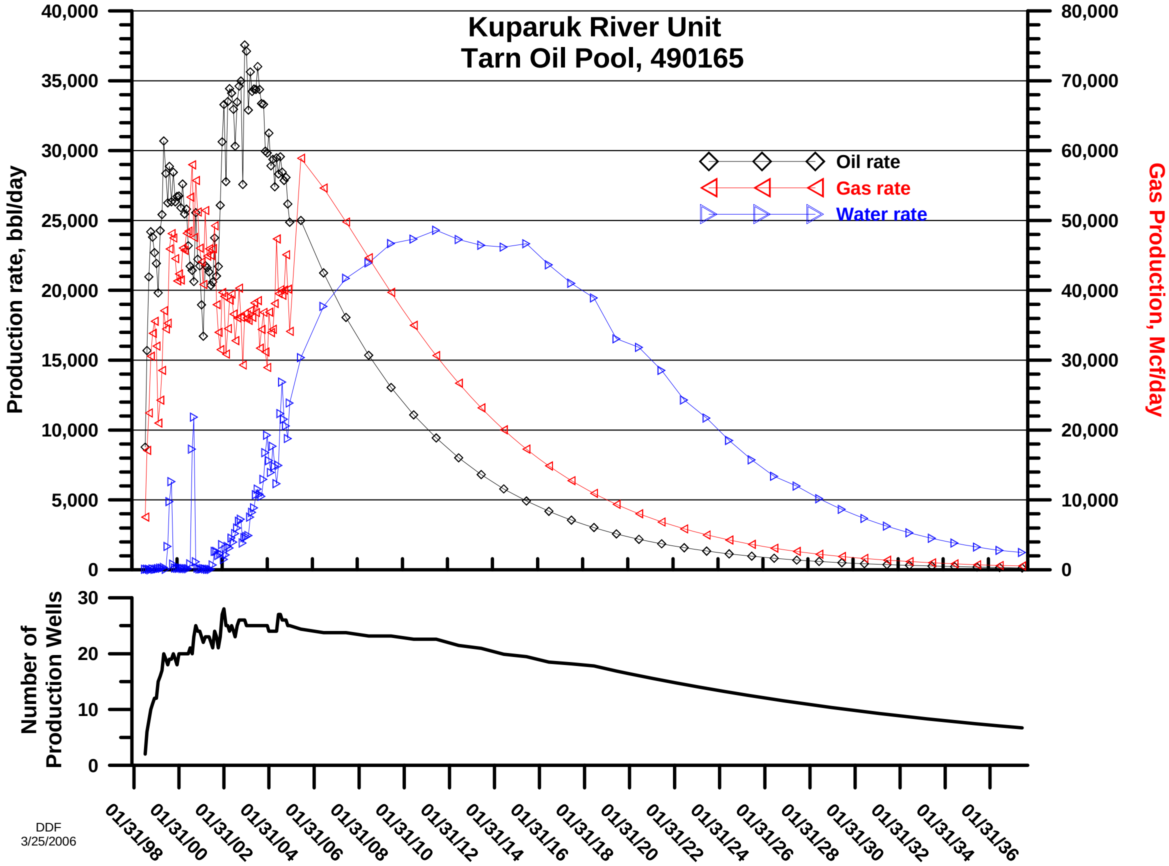


Figure 3.42. Kuparuk River Unit–Tarn pool production history and forecasts.

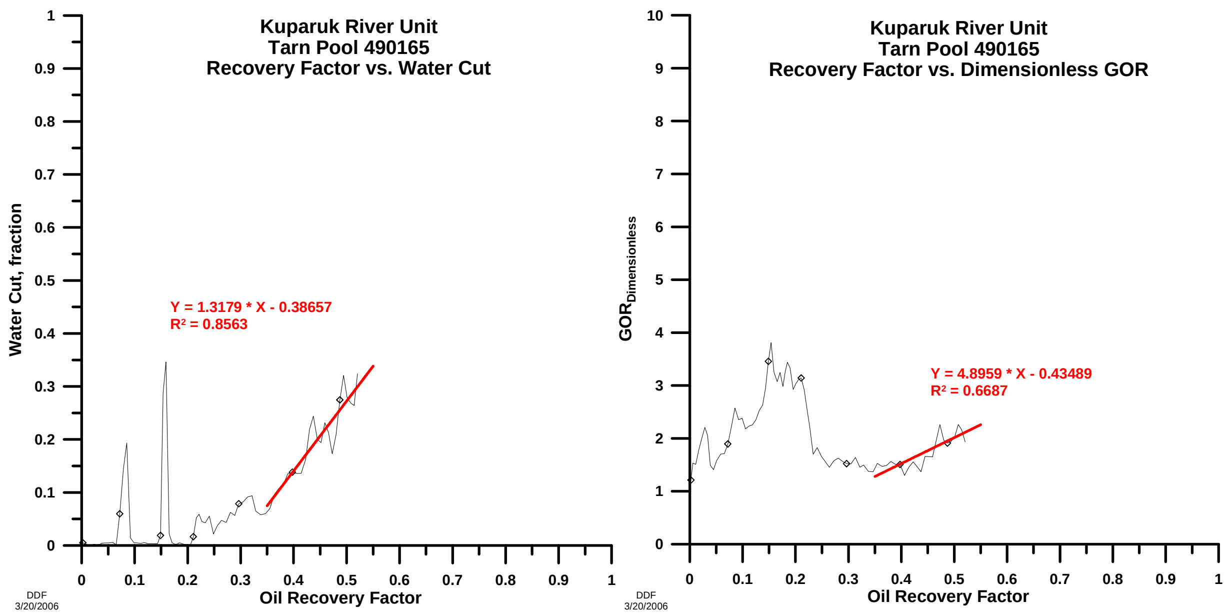


Figure 3.43. Kuparuk River Unit–Tarn Pool recovery factor versus water cut and GOR.

Tarn historical oil, gas and water cumulative production is presented in Table 3.54.

Table 3.54. Tarn pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	64,603 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	64,603 MBO
Cumulative gas production	91,407 MMCF
Cumulative Reinjected gas	101,830 MMCF
Cumulative water	7,431 MB

Forecasts of Tarn pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.55.

Table 3.55. Tarn pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2016	2019	2022	2024
Oil and NGLs ERR (MB)	52,483	56,413	58,825	59,891
Future Gas forecast (MMCF)	152,970	167,249	176,211	180,218
Future water forecast (MB)	103,061	132,134	156,591	168,297
Oil and NGLs EUR (MB)	117,086	121,016	123,428	124,494
Ultimate gas production (MMCF)	244,377	258,656	267,618	271,625
Total gas reinjected (Est.) (MMCF)	219,939	232,790	240,857	244,463
Ultimate water production (MB)	110,492	139,565	164,022	175,728

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.56.

Table 3.56. Tarn pool–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$41,658	$70,980	$87,420	$87,420
Total operating costs	$543,434	$675,313	$798,835	$874,150
State royalty	$144,157	$235,529	$372,755	$466,818
State taxes – Severance	$121	$179	$265	$323
State taxes – Income	$10,167	$24,305	$48,165	$65,071
State taxes – Other	$20,467	$25,017	$29,058	$31,193
State Total (Royalty and Taxes)	**$174,912**	**$285,030**	**$450,243**	**$563,405**
Federal taxes	**$146,940**	**$307,724**	**$573,675**	**$764,303**
Industry net income	**$277,896**	**$588,360**	**$1,113,287**	**$1,483,642**

3.3.21 Kuparuk River Unit – West Sak PA

The West Sak pool was discovered in 1971 (AOGCC 1997) and production from the Prince Creek Formation began in 1983 (Thomas et al., 1993). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.21 West Sak PA Engineering

The West Sak PA was formed in the early 1980s to test the West Sak accumulation believed to contain between 15 and 20 BBO with variable oil gravity from 10 to 22ºAPI (AOGCC, 1997).[28] The core development area is assumed to contain about 2 BBO; however, until current technology is proven, only 75% of this volume or 1.5 BBO is assumed to be economically developable. Under current technology, primary recovery is estimated at 8%, secondary 10%, and WAG at 4% OOIP for a total recovery of 22% OOIP (AJC, 2004).

Production is processed by the KRU IPA facilities. Initial production beginning in June 1983 and ending in December 1986 was a test program for the West Sak. Production using the earlier technology (vertical and hot water pilot flood) was uneconomical (Thomas et al. 1993). Current technology including the use of horizontal and multilateral wells has improved reservoir performance to justify further development of the core area (AJC, 2004). Production was restarted in mid-1998. The current development has 26 producers, 27 water injection wells, and 2 gas injection wells. The oil, gas, and water production history after 1997 and production forecasts for the initial development are presented in Figure 3.44.

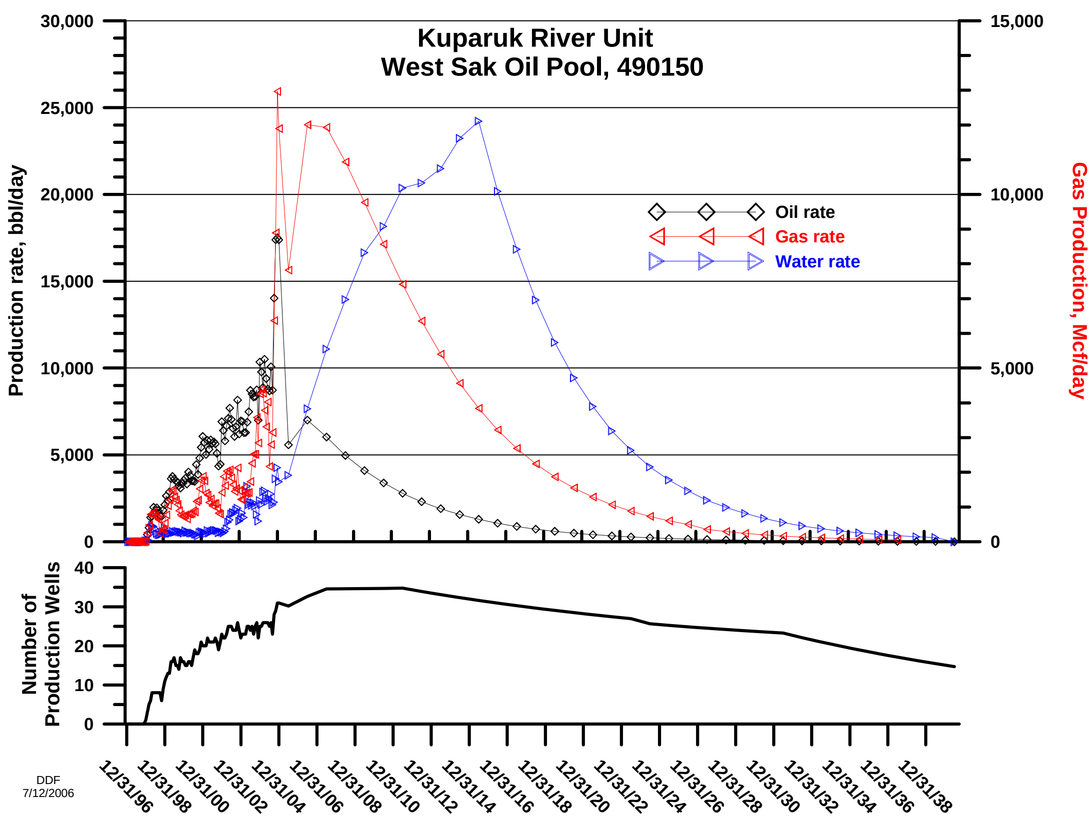


Figure 3.44. Kuparuk River Unit–West Sak pool production history and forecasts.

[28] This volume is combined West Sak and Schrader Bluff.

The initial development area containing an estimated 270,000 MB OOIP produced about 17 MBOPD during December 2004. Based on success of the current development, plans are to expand the initial development in Drill Site 1E and Drill site 1J by drilling 31 wells (ADNR, 2004e). Production is expected to increase to an average of 19.2 MBOPD during 2006, before beginning a decline of 17.5% per year. An assumed abandonment rate of about 0.150 MBOPD yields a TRR of 46,734 MBO and a TUR of 62,365 MBO.

A continuous development program is assumed until a maximum rate of 45 MBOPD is reached and will be maintained for seven years. Upon development of the entire core area, production is expected to decline at 17.5%/yr until an assumed abandonment rate of about 1.0 MBOPD is reached. This yields an estimated TRR of 329,539 MBO and with cumulative production to date gives a TUR of 345,170 MBO; about 23% of the 1.5 BBO OOIP. The economics of the future developments are given in Section 3.4.2

There are insufficient gas and water production data to be used to forecast future volumes. Historical water cut versus cumulative and GOR_D versus cumulative data for the initial development area are shown in Figure 3.45. Hence, the following methods are used. The solution GOR is very low at 200 CF/BBL; however, with gas injection for the WAG process, an increase will result throughout the productive life. It is assumed the GOR will gradually increase from an average of 400 CF/BBL in 2004 to 1000 CF/BBL at abandonment in all development areas. The water cut of the initial development area is about 0.2 at a recovery of 23% of TUR. It is assumed the water cut will gradually increase until it reaches 0.9 at abandonment. All produced gas will be used for lease operations and for the EOR process. The new areas to be developed will start at a water cut of 0.1 and increase to 0.9 at abandonment. The gas production forecast is made using an initial GOR of 200 CF/BBL that gradually increases to 1,000 CF/BBL at abandonment.

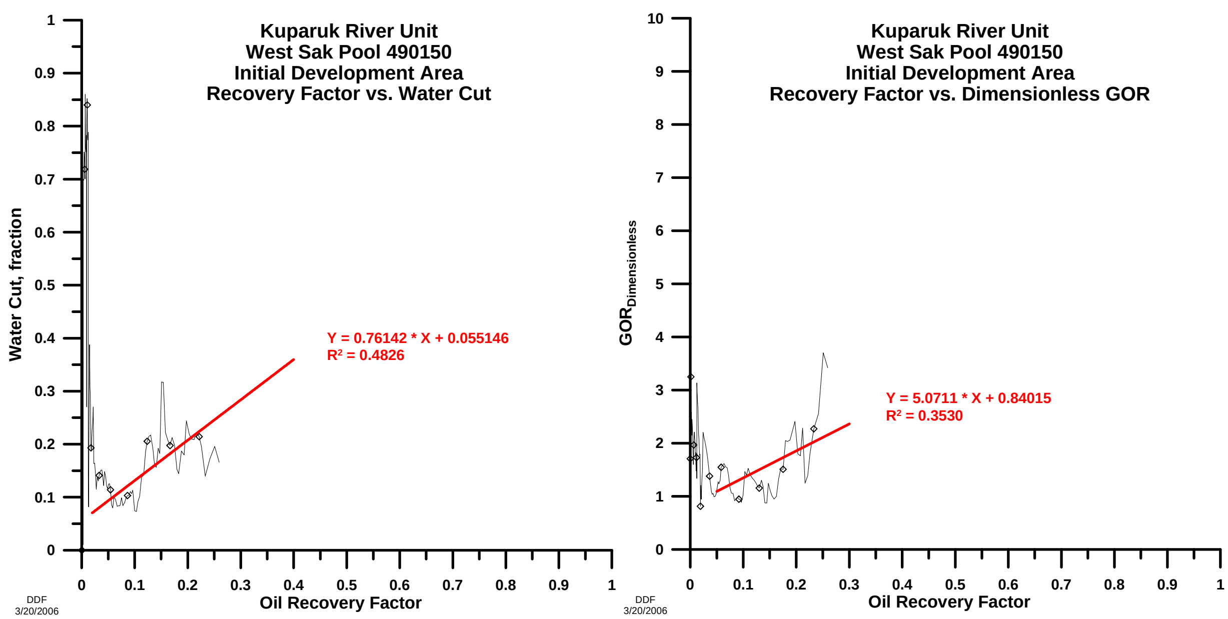


Figure 3.45. Kuparuk River Unit–West Sak pool recovery factor versus water cut and GOR.

West Sak historical oil, gas and water cumulative production for the total West Sak are presented in Table 3.57.

Table 3.57. West Sak pool production statistics as of 1/1/2005.

VARIABLE	VOLUME
Cumulative oil recovery	15,631 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	15,631 MBO
Cumulative gas production	5,256 MMCF
Cumulative Reinjected gas	292 MMCF
Cumulative water	5,182 MB

Forecasts of West Sak pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.58.

Table 3.58. West Sak pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2020	2016	2016	2016
Oil and NGLs ERR (MB)	23,582	33,857	39,627	40,920
Future Gas forecast (MMCF)	15,580	24,978	30,933	32,335
Future water forecast (MB)	12,605	33,018	57,951	66,817
Oil and NGLs EUR (MB)	39,213	49,488	55,258	56,551
Ultimate gas production (MMCF)	20,836	30,234	36,189	37,591
Total gas reinjected (Est.) (MMCF)	18,753	27,211	32,570	33,832
Ultimate water production (MB)	17,787	38,200	63,133	71,999

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.59.

Table 3.59. West Sak pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	2020	2016	2016	2016
Total operating costs	23,582	33,857	39,627	40,920
State royalty	15,580	24,978	30,933	32,335
State taxes – Severance	0	0	0	0
State taxes – Income	39,213	49,488	55,258	56,551
State taxes – Other	20,836	30,234	36,189	37,591
State Total (Royalty and Taxes)	18,753	27,211	32,570	33,832
Federal taxes	5,182	5,182	5,182	5,182
Industry net income	**-$12,400**	**$104,585**	**$399,382**	**$636,583**

3.3.22 Milne Point Unit – Kuparuk River IPA

The Kuparuk River pool of the Milne Point Unit (MPU) was discovered in 1969 and production started in 1985 from the Kuparuk River sandstone (Table 2.7). Continuous production commenced in 1989. Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.22.1 Milne Point Unit - Kuparuk River IPA Engineering

The MPU Kuparuk River pool is a development targeting an estimated accumulation of 525,000 MBO OOIP of 22°API oil (Table 2.7). Estimated primary and secondary recovery is 20% each with an additional 6 to 8% from EOR (AOGCC, 2002b). Based on production performance, a total technical recovery of 48% or 252,000 MBO is a reasonable estimate. This estimate is used as a guide in estimating the TRR.

Production is processed by the MPU IPA facilities. Production averaged 12.7 MBOPD from November 1985 through January 1987 at which time production was shut-in. Production was restarted April 1989 with production rising from 10 MBOPD to 50 MBOPD by August 1996. Production was sustained above 45 MBOPD for 49 months before starting on decline. The historical and forecast oil, water, and gas production is presented in Figure 3.46. No additional development is planned and it is assumed the reservoir is fully developed. Future activities will consist of redrilled wells, well workovers, injection conversions and an EOR process. It is anticipated that NGLs will be purchased from PBU and used with NGL production from the Milne Point Unit for WAG process.

The pool has been on decline since late 1999. Sufficient production history is available to forecast a 12% per year decline. Reserves are estimated using an initial rate of 30 MBOPD and declining production to an abandonment rate of 0.5 MBOPD. This results in a TRR of 84,330 MBO, and results in a TUR of about 264,600 MBO.

The water and gas forecast used the historical water cut and GOR_D trends given in Figure 3.47. The forecast of water production suggests the Milne Point production processing facility will reach water handling limits of 55 MBWPD in the intermediate term. It is assumed that all gas will be used for lease operations or in an EOR project.

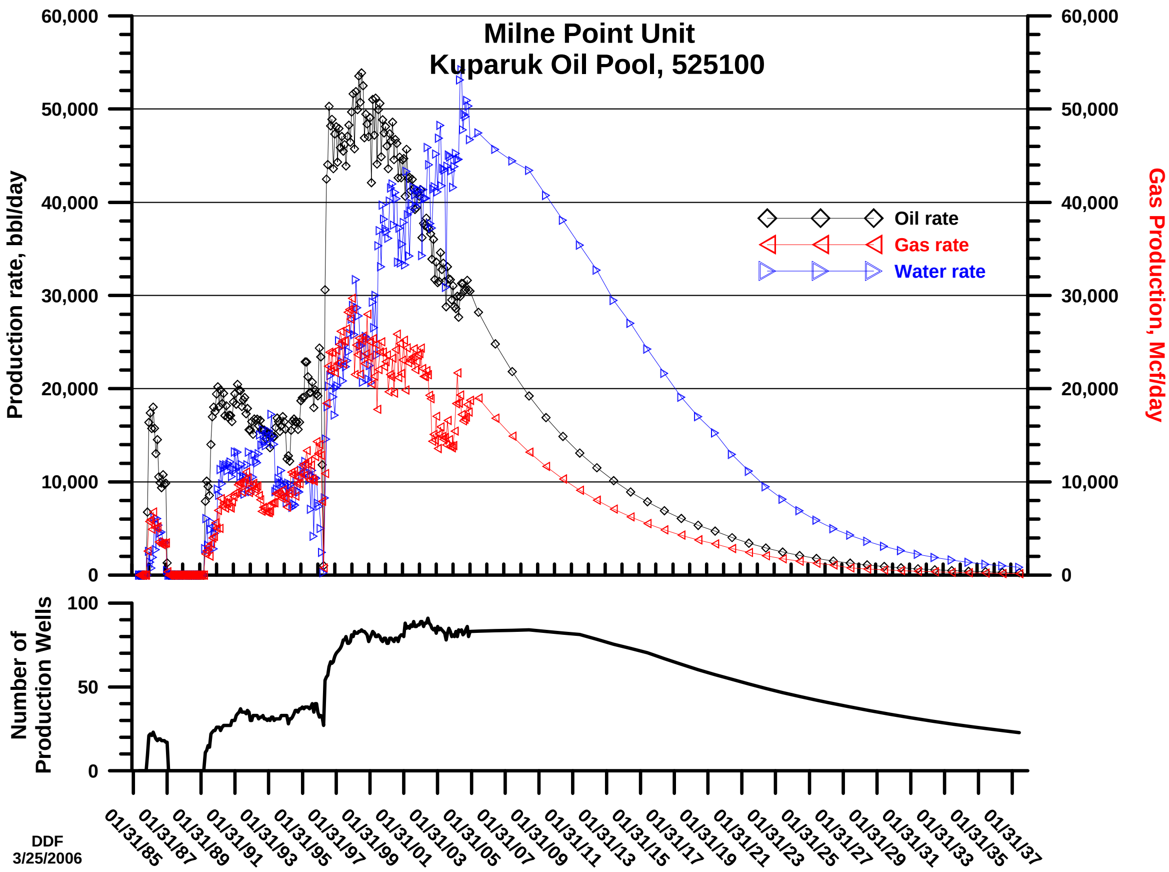


Figure 3.46. Milne Point Unit–Kuparuk pool production history and forecasts.

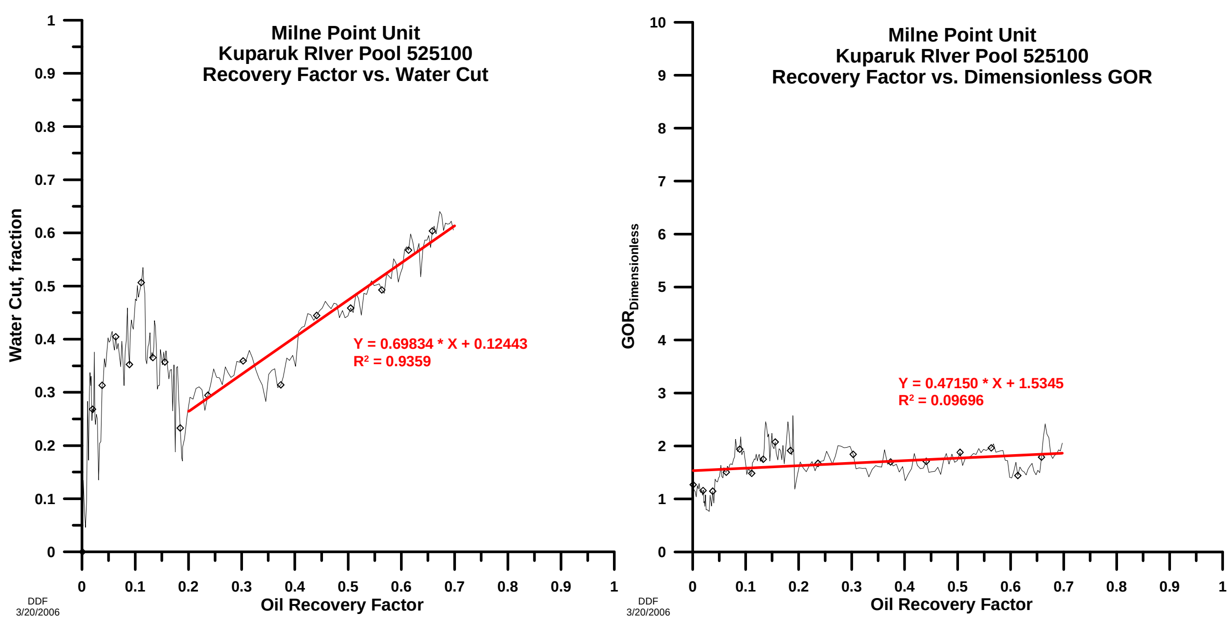


Figure 3.47. Milne Point Unit–Kuparuk pool recovery factor versus water cut and GOR

MPU Kuparuk pool historical oil, gas, and water cumulative production is presented in Table 3.60.

Table 3.60. Milne Point Unit - Kuparuk pool production statistics as of 1/1/2005

VARIABLE	VOLUME
Cumulative oil recovery	180,286 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	180,286 MBO
Cumulative gas production	91,492 MMCF
Cumulative Reinjected gas	74,697 MMCF
Cumulative water	137,201 MB

Forecasts of Milne Point Kuparuk pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.61.

Table 3.61. Milne Point Unit–Kuparuk pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2007	2010	2015	2018
Oil and NGLs ERR (MB)	19,350	40,505	61,875	69,485
Future Gas forecast (MMCF)	13,079	27,593	42,484	47,842
Future water forecast (MB)	34,661	82,849	143,162	167,005
Oil and NGLs EUR (MB)	199,636	220,791	242,161	249,771
Ultimate gas production (MMCF)	104,571	119,085	133,976	139,334
Total gas reinjected (Est.) (MMCF)	85,375	97,225	109,382	113,757
Ultimate water production (MB)	171,862	220,050	280,363	304,206

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.62.

Table 3.62. Milne Point Unit–Kuparuk pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$10,297	$45,034	$81,641	$99,534
Total operating costs	$317,570	$820,297	$1,620,038	$2,054,873
State royalty	$41,296	$142,027	$354,091	$503,180
State taxes – Severance	$0	$0	$0	$0
State taxes – Income	$0	$1,312	$16,316	$32,561
State taxes – Other	$22,230	$53,260	$97,061	$117,389
State Total (Royalty and Taxes)	**$63,526**	**$196,599**	**$467,468**	**$653,130**
Federal taxes	**$0**	**$47,055**	**$253,014**	**$444,848**
Industry net income	**($11,636)**	**$84,327**	**$487,926**	**$860,198**

3.3.23 Milne Point Unit – Sag River PA

The Sag River pool of the MPU was discovered in 1969 and production started in 1995 from the Sag River and Ivishak formations (Table 2.7). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.23.1 MPU Sag River PA Engineering

The Sag River pool is a development targeting an estimated accumulation of 62 MMBO OOIP. Estimated primary recovery was 15% and an additional 23% by water/gas injection (AOGCC 1998). Based on performance to date, these recovery estimates are high. Production performance is used to estimate reserves.

Production is processed by the MPU IPA facilities. The original development plan included 16 producers and 9 injectors. After four producers were drilled to test the accumulation, development plans were curtailed, apparently due to poor results. Currently there is one producer operating part time plus one injection well for both water and gas. The project recovered only 44.2 MBO during 2004 while producing for only about 6 months during the year. Historical oil, gas, and water production is presented in Figure 3.48.

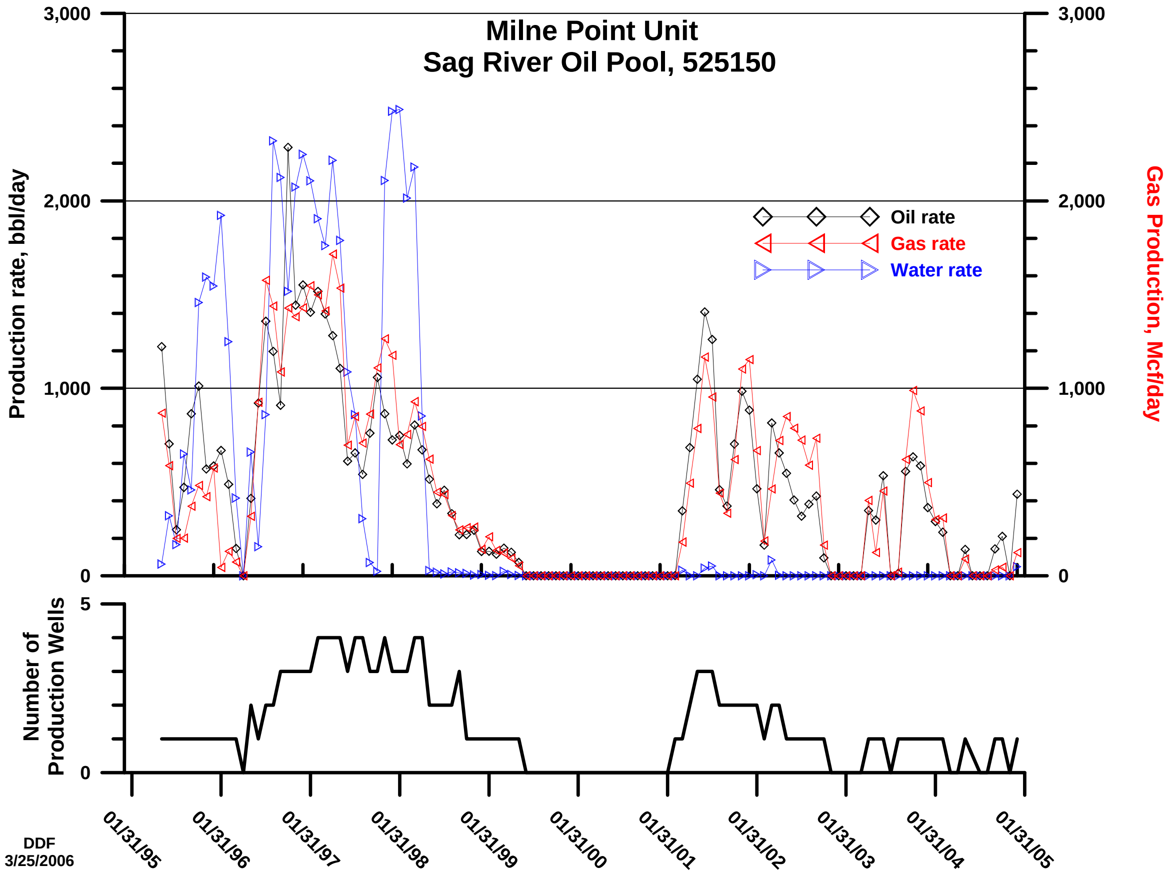


Figure 3.48. Milne Point Unit–Sag River pool production history

The operator is currently evaluating performance, and has no immediate plans for further development (ADNR, 2003b). Current performance does not justify assigning any TRR to this development. A future estimate of TRR may be required if the operator is successful in improving performance.

Sag River pool historical oil, gas, and water cumulative production is presented in Table 3.63.

Table 3.63. Sag River pool production statistics as of 1/1/2005

VARIABLE	VOLUME
Cumulative oil recovery	1,589 MBO
Cumulative gas production	1,596 MMCF
Cumulative Reinjected gas	249 MMCF
Cumulative water	1,414 MB

3.3.24 MPU – Schrader Bluff PA

The Schrader Bluff pool of the Milne Point Unit was discovered in 1969 and the production started in 1991 from the Schrader Bluff formation. Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.24.1 MPU Schrader Bluff PA Engineering

The Schrader Bluff PA was formed in the early 1990's to test the Schrader Bluff accumulation believed to contain between 15 and 20 BBO (AOGCC, 1997) of 17°API oil. This development targets an estimated accumulation of between 1.25 and 2 BBO OOIP in the main core area. It is assumed that only two-thirds of a total OOIP of 2 BBO will be economically developed. Primary and secondary recovery is estimated at about 11% each for a total of about 22% (AOGCC, 2002c). This gives an assumed TUR of about 293 MMBO, which is used as a guide in estimating the TRR for the project.

The initial area to be developed had 50 producers and 33 injection wells at year end 2004. It is assumed three additional developments will be required around E and H pads, S pad, and a new pad to be constructed. The initial development area is assumed to contain 373 MMBO of OOIP. The S pad area, E and H pad area, and the new pad area are assumed to contain the balance of the recoverable oil of 960 MMBO, which is equally divided between the three areas to be developed.

The production from the initial developed area has increased from about 3.0 MBOPD in 1992 to about 22.0 MBOPD in December 2004. Production is processed by the MPU IPA facilities. The initial developed is assumed to have reached a peak production. The historical and forecasted oil, gas, and water production is presented in Figure 3.49.

It is assumed production of 20.5 MBOPD will be sustained through 2006, at which time will decline at 20% per year to an abandonment rate of 0.2 MBOPD. This results in a TRR of about 48,325 MBO and a TUR of 86,451 MBO.

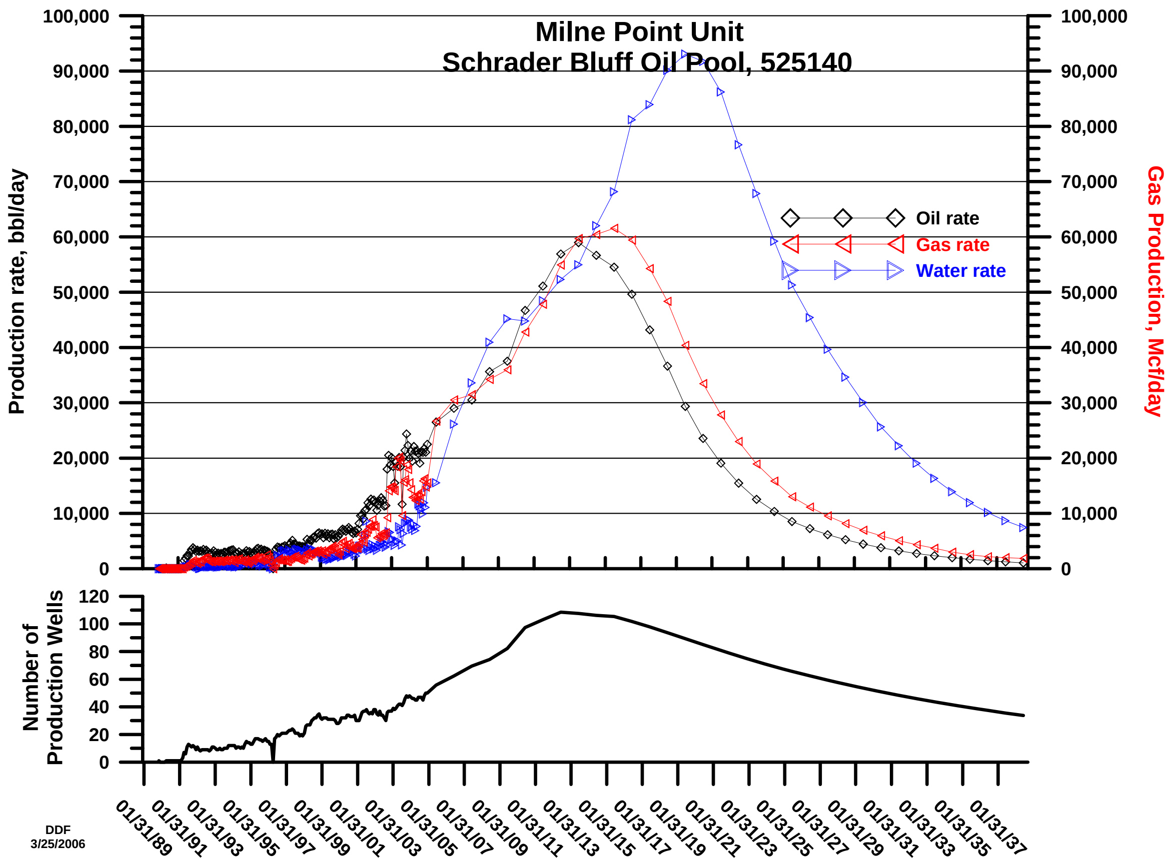


Figure 3.49. Milne Point Unit–Schrader Bluff pool production history and forecasts

The S-pad development is assumed to require between 30 and 50 wells to develop 320 MMBO OOIP with a total recovery of about 22% OOIP or 70 MMBO. Initial production is anticipated to start 2005 with production increasing to a peak of 20 MBOPD by January 2010 and plateauing for three years before starting a 20% per year decline to an abandonment rate of 0.2 MBOPD. This gives a TUR of 76,225 MBO.

The E and H pad development is assumed to require between 20 and 40 wells to develop 320 MMBO OOIP with a total recovery of about 22%. It is assumed production will start during 2008 and will achieve a peak of 20 MBOPD by January 2013 and remain at that level for three years before entering a decline of 20% per year to an abandonment of 0.2 MBOPD. This results in a TUR of 76,225 MBO.

The new pad development area has the same parameters as above with production beginning 2010 and reaching a peak by January 2015. The TUR is also estimated at 76,225 MBO.

These forecasts results in a total TRR volume of 277,000 MBO and a TUR of 315,126 MBO. This is a 23.6% recovery of the assumed 1.333 BBO of OOIP developed.

Historical recovery versus water cut and GOR_D for the initial development area, given in Figure 3.50, are used to forecast water and gas volumes. It is assumed that all gas production will be used for lease operations and the EOR process.

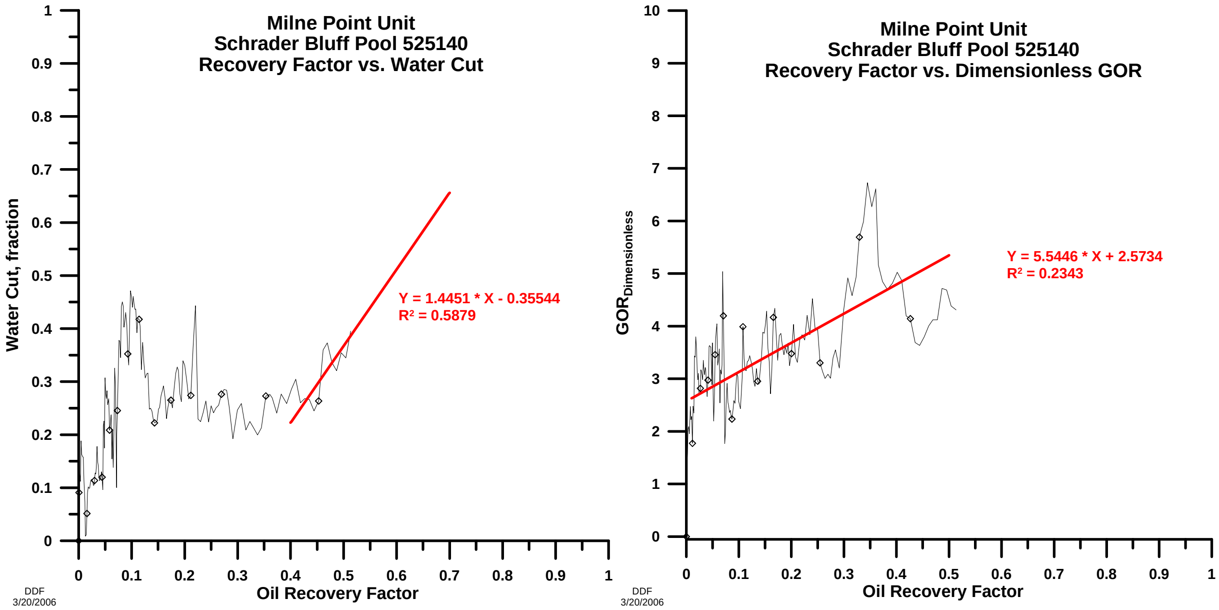


Figure 3.50. Milne Point Unit–Schrader Bluff pool recovery factor versus water cut and GOR

Schrader Bluff pool historical oil, gas and water cumulative production for all development areas are presented in Table 3.64.

Table 3.64. Milne Point Unit–Schrader Bluff pool production statistics as of 1/1/2005

VARIABLE	VOLUME
Cumulative oil recovery	38,126 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	38,126 MBO
Cumulative gas production	23,914 MMCF
Cumulative Reinjected gas	0 MMCF
Cumulative water	14,870 MB

Forecasts of Milne Point Schrader Bluff pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.65.

Table 3.65. Milne Point Unit–Schrader Bluff pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2008	2016	2016	2016
Oil and NGLs ERR (MB)	22,270	31,730	39,940	41,665
Future Gas forecast (MMCF)	26,861	40,051	52,333	55,012
Future water forecast (MB)	27,106	57,951	99,093	109,532

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Oil and NGLs EUR (MB)	60,396	69,856	78,066	79,791
Ultimate gas production (MMCF)	50,775	63,965	76,247	78,926
Total gas reinjected (Est.) (MMCF)	45,698	57,569	68,623	71,034
Ultimate water production (MB)	41,976	72,821	113,963	124,402

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.66.

Table 3.66. Milne Point Unit–Schrader Bluff pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$46,663	$85,593	$131,083	$131,083
Total operating costs	$329,047	$568,954	$905,995	$1,007,126
State royalty	$46,252	$108,878	$220,678	$287,883
State taxes – Severance	$0	$0	$0	$0
State taxes – Income	$0	$3,963	$15,858	$25,908
State taxes – Other	$2,555	$4,583	$7,765	$8,800
State Total (Royalty and Taxes)	$48,807	$117,424	$244,301	$322,591
Federal taxes	$0	$48,800	$184,818	$298,162
Industry net income	-$16,087	$89,523	$345,013	$578,786

3.3.25 Colville River Unit – Alpine Field IPA

The Alpine pool of the Coleville River Unit (CRU) was discovered in 1994 and production started in 2000 from the Alpine sandstone (Table 2.7). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.3.25.1 Alpine Field IPA Engineering

The Alpine pool is a development targeting and estimated accumulation of between 650 and 1,100 MMBO OOIP (AOGCC, 1999; ADNR, 2002b). This development was significant because of its size, light 40°API oil, and that it expanded development to the west of the KRU by about 20 miles. Information filed with AOGCC indicates this pool may not be fully delineated. Recovery estimates are for primary recovery between 10 and 15% with EOR adding between 45 and 50% for a total range of 55 to 65% (AOGCC 2002b).

Production started November 2000 at an initial rate of 17.5 MBOPD and quickly increased to 101.4 MBOPD by December 2001. Production averaged 98.8 MBOPD for 2004 with facilities expansion underway to increase production to 125 MBOPD in 2006. The historical and forecasted oil, gas, and water production is presented in Figure 3.51.

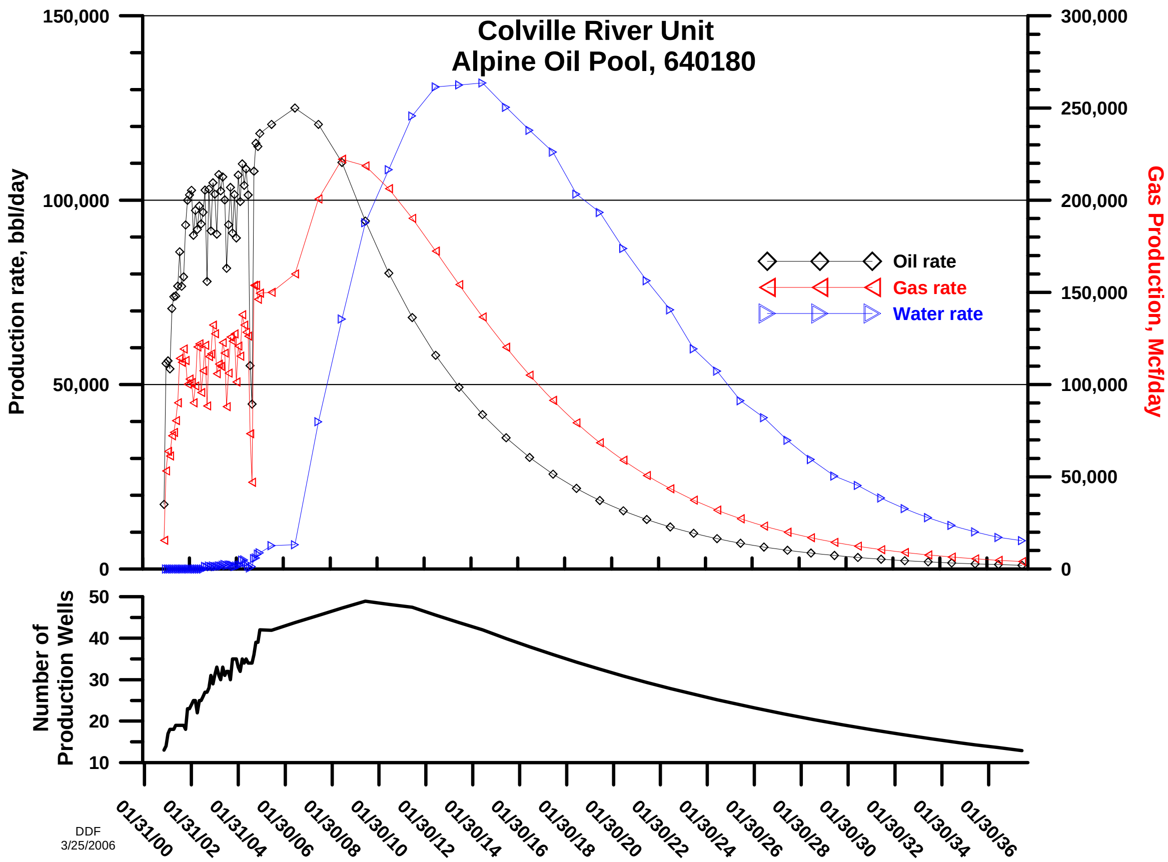


Figure 3.51. Colville River Unit–Alpine pool historical production and forecasts.

The original development plan called for a total of 94 wells, and at year-end 2004 there were 84 wells, so there may be some additional wells drilled to fully develop the core area. It is assumed there will be new wells, redrills, and workovers to recover the maximum reserves and maintain a high production rate. The Alpine IPA production facilities with initial capacities of 83 MBOPD oil, 10 MBWPD water, and 130 MMCF gas, have been expanded to a current capacity of 140 MBOPD oil, 100 MBWPD water, and 180 MMCFPD gas (PN, 2004e; ADNR, 2004d). A current study is being conducted for additional capacity expansion. The expansion of the producing infrastructure would allow satellite development, which will support Unit operations.

An estimate of 900 MMBO OOIP is used for this study, implying a recovery of over 500 MMBO. Based on production performance that estimate appears reasonable at this time. It assumes production will increase to 125 MBOPD by 2006 and hold constant through January 2007. Then the production will decline at 7.5%/yr until 2008 when the decline rate increases to 15%/yr to an abandonment rate of 0.6 MBOPD. This results in a TRR of 402,250 MBO and a TUR of about 539,900 MBO.

Gas and water production data used to forecast future gas recovery is limited, as shown in Figure 3.52, and no other project provides a good analog. Until sufficient performance data are available, it is assumed the GOR will increase linearly from a current 1,250 to 3,800 CFPB at abandonment. Similarly, water production data are limited from which to forecast future volumes. Water volumes are increasing; the water cut at year end 2004 was 0.036 at a recovery of 26% of the TUR. The water cut is expected to increase linearly to a water cut of 0.80 at 87.5% TUR before gradually increasing to 90% at depletion. All gas is used for lease operations or reinjected for the EOR process.

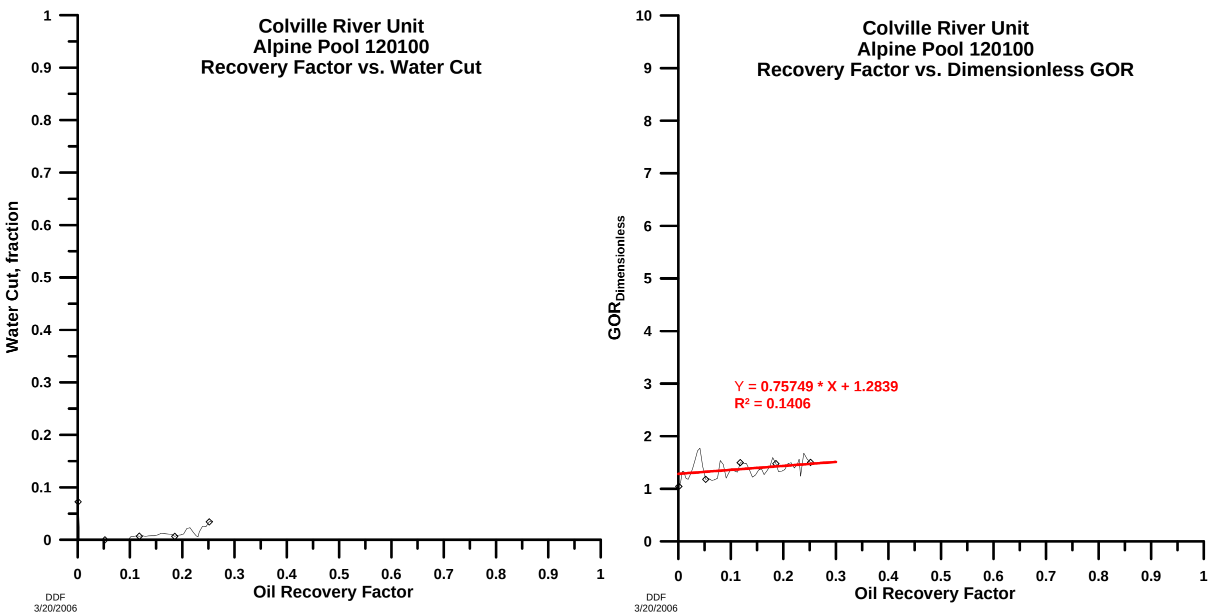


Figure 3.52. Colville River Unit–Alpine pool recovery factor versus water cut and GOR

Alpine pool historical oil, gas, and water cumulative production is presented in Table 3.67.

Table 3.67 Colville River Unit–Alpine pool production statistics as of 1/1/2005

VARIABLE	VOLUME
Cumulative oil recovery	137,639 MBO
Cumulative NGL recovery	0 MBO
Cumulative oil and NGL	137,639 MBO
Cumulative gas production	162,359 MMCF
Cumulative Reinjected gas	136,700 MMCF
Cumulative water	1,219 MB

Forecasts of Alpine pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.68.

Table 3.68. Colville River Unit–Alpine pool–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2023	2027	2031	2033
Oil and NGLs ERR (MB)	379,845	391,119	397,011	398,796
Future Gas forecast (MMCF)	886,547	930,264	953,513	960,614

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Future water forecast (MB)	617,014	691,820	734,214	747,534
Oil and NGLs EUR (MB)	517,484	528,758	534,650	536,435
Ultimate gas production (MMCF)	1,048,906	1,092,623	1,115,872	1,122,973
Total gas reinjected (Est.) (MMCF)	883,138	919,946	939,521	945,499
Ultimate water production (MB)	618,233	693,039	735,433	748,753

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.69.

Table 3.69. Colville River Unit–Alpine pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$326,883	$326,883	$326,883	$326,883
Total operating costs	$2,513,744	$2,900,148	$3,234,248	$3,386,188
State royalty	$1,003,684	$1,609,057	$2,513,328	$3,114,885
State taxes – Severance	$586,437	$885,310	$1,333,613	$1,632,482
State taxes – Income	$85,788	$189,725	$355,225	$467,971
State taxes – Other	$291,503	$319,864	$328,366	$328,450
State Total (Royalty and Taxes)	**$1,967,412**	**$3,003,956**	**$4,530,532**	**$5,543,788**
Federal taxes	**$1,099,798**	**$2,261,566**	**$4,088,400**	**$5,329,258**
Industry net income	**$2,127,675**	**$4,389,629**	**$7,936,310**	**$10,345,032**

3.3.26 Summary and Composite Curve of Producing fields

A summary of the currently producing fields are shown in Table 3.70. These currently producing fields had produced almost 14.8 BBO through 12/31/2005 and have an estimated TRR of about 4.7 BBO.

Table 3.70. ANS Currently Producing Fields.

POOL/FIELD NAME	OOIP (MBO)	TUR (MBO)	Production 12/31/2004 (MBO)	TRR (MBO)	Recovery Factor
Prudhoe Bay Unit (PBU)					
Initial Participating Area (IPA)	25,000,000	13,483,252	11,143,715	2,339,537	0.539
Aurora Participating Area (PA)	100,000	45,810	11,397	34,413	0.458
Borealis PA	263,000	105,189	30,849	74,340	0.400
Midnight Sun PA	60,000	21,048	11,343	9,705	0.351
Orion PA Phase I	92,000	21,735	2,310	19,690	0.236
Polaris PA	303,700	68,440	3,539	64,901	0.225
Lisburne PA	3,000,000	194,619	153,621	40,998	0.065
Niakuk PA	200,000	99,323	81,223	18,100	0.497
North Prudhoe PA	12,000	2,070	2,070	0	0.173
West Beach PA	15,000	3,591	3,591	0	0.239
Point McIntyre PA	800,000	506,413	384,103	122,310	0.633
Duck Island Unit (DIU)					
Endicott PA	1,059,000	533,952	447,612	86,340	0.504

POOL/FIELD NAME	OOIP (MBO)	TUR (MBO)	Production 12/31/2004 (MBO)	TRR (MBO)	Recovery Factor
Eider PA	13,000	2,687	2,687	0	0.207
Sag Delta North PA	16,000	8,059	8,059	0	0.504
Northstar Unit (NU)					
Northstar PA	284,700	235,500	67,215	168,260	0.591
Badami Unit (BU)	300,000	4,347	4,347	0	0.014
Kuparuk River Unit (KRU)					
Kuparuk River IPA	5,690,000	2,763,120	1,974,540	788,580	0.486
Meltwater PA	132,000	42,100	7,658	34,442	0.319
Tabasco PA	99,500	21,570	9,735	11,835	0.217
Tarn PA	255,000	125,313	64,603	60,710	0.491
West Sak PA	275,000	62,365	15,631	46,734	0.227
Milne Point Unit (MPU)					
Kuparuk River IPA	525,000	264,600	180,286	84,314	0.504
Sag River PA	62,000	1,589	1,589	0	0.026
Schrader Bluff PA	1,333,400	321,326	38,126	283,200	0.241
Colville River Unit (CRU)					
Alpine Oil	900,000	539,900	137,639	402,261	0.600
Total – currently producing fields	**40,790,300**	**19,477,918**	**14,787,488**	**4,690,670**	**0.478**

The forecasts for the technically recoverable production are shown in Figure 3.53 and in Appendix 3-F. These production forecasts are without consideration of any economic constraints such as price or operating cost.

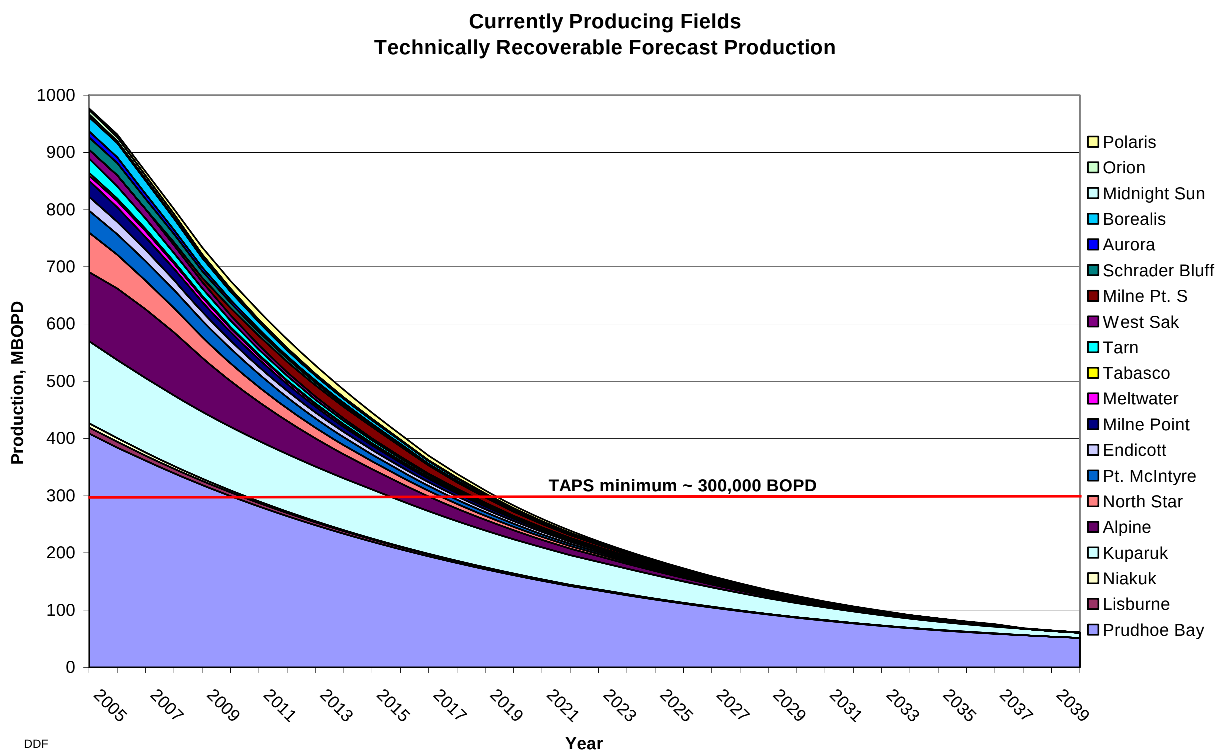


Figure 3.53. ANS currently producing fields–technically recoverable oil forecasts.

The composite results for the estimated economical recoveries for the currently producing fields for the four price tracks are shown in Table 3.71. These fields have a composite ERR ranging from 4.25 BBO at $25/bbl to 4.31 BBO at $60/bbl compared to the estimated TRR of 4.6 BBO.

Table 3.71. ANS currently producing fields–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Oil and NGLs ERR (MB)	3,716,575	4,156,360	4,240,495	4,264,156
Future Gas forecast (MMCF)	58,132,509	67,031,799	67,676,814	67,827,700
Future water forecast (MB)	15,541,817	18,474,783	19,063,922	19,222,997
Oil and NGLs EUR (MB)	18,481,720	18,921,505	19,005,640	19,029,301
Ultimate gas production (MMCF)	113,451,008	122,350,298	122,995,313	123,146,199
Total gas reinjected (Est.) (MMCF)	103,210,038	112,324,564	112,893,822	113,026,716
Ultimate water production (MB)	26,701,041	29,634,007	30,223,146	30,382,221

Table 3.72 shows the estimated revenue to the state and federal governments, and industry investments, operating costs, and revenue for these currently producing fields.

Table 3.72. ANS currently producing fields–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	**$25/bbl**	**$35/bbl**	**$50/bbl**	**$60/bbl**
Total investments	2,230,928	2,391,510	2,494,390	2,512,283
Total operating costs	49,077,439	63,187,031	66,676,308	68,195,676
State royalty	10,434,887	18,819,918	29,599,962	36,762,753
State taxes – Severance	4,299,374	6,904,203	10,502,262	12,899,477
State taxes – Income	427,484	1,575,706	3,560,004	4,906,390
State taxes – Other	2,832,504	3,096,035	3,287,829	3,337,311
State Total (Royalty and Taxes)	**17,937,373**	**30,318,373**	**46,860,247**	**57,813,286**
Federal taxes	**5,156,251**	**18,568,951**	**40,428,438**	**55,250,734**
Industry net income	**9,885,510**	**36,080,079**	**78,836,750**	**107,869,272**

3.4 Known Fields with Pending/Announced Development Plans

This section will describe the engineering characteristics of fields and pools with announced or pending development plans. The information is taken from publicly available sources and includes the following pools:, KRU – Placer, KRU – West Sak additional development, CRU – Fiord, CRU – Nanuq, CRU – Alpine West, CRU – Lookout, CRU – Spark, PBU – Orion Phase II and III, PBU – Polaris Phase II, Oooguruk, Nikaitchuq, Liberty, and Gwydyr Bay. See Figure 1.2 for field locations.

3.4.1 Placer Pool – Kuparuk River Unit

The Placer pool was discovered in 2004 and is a new proposed development located about 3 miles west of Palm extension to the KRU (OGJ, 2001; PN, 2004f). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.4.1.1 Placer Pool Engineering

Exploratory efforts are in progress and it is similar to, but believed smaller than, the Meltwater satellite. The OOIP is assumed to be 110 MMBO of 37°API oil with an overall recovery factor of about 32%. Based on this information, the TUR is about 35 MMBO.

It is assumed that initial development will occur in 2006 as an enlargement to the KRU. Production is assumed to begin in 2007 and will be processed by the KRU IPA facilities. Production is projected to reach 10 MBOPD by January 2009 and be maintained at that level through January 2011. Production is then assumed to decline at 15%/yr to an abandonment rate of 0.10 MBOPD. This results in a TUR of 36,620 MBO.

Water and gas volumes are determined using the historical production data for the Tarn satellite as an analog. The oil, gas, water production, and production well forecasts are presented in Figure 3.54. It is assumed that all produced gas will be used for lease operations.

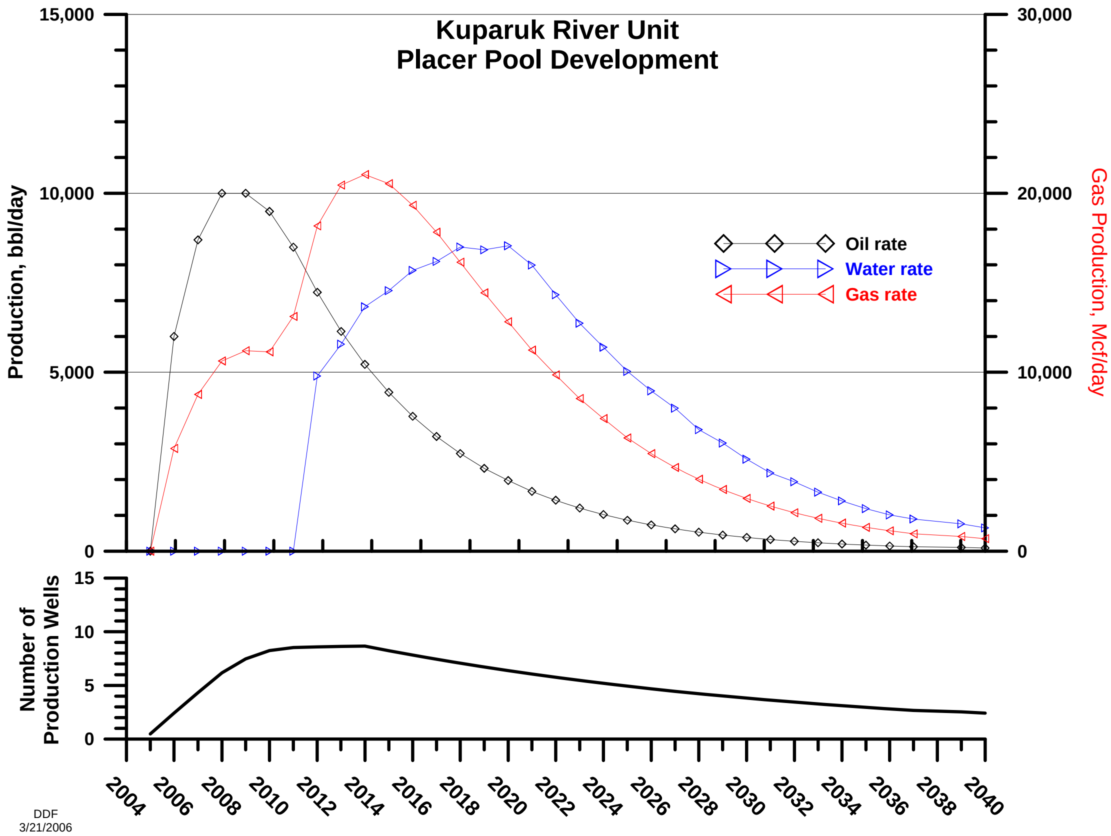


Figure 3.54. Placer Pool–Kuparuk River Unit production forecasts.

Forecasts of KRU Placer pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.71.

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.72.

Table 3.71. Kuparuk River Unit–Placer pool–Forecasts of ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2020	2025	2029	2032
Future Gas forecast (MMCF)	76,144	94,367	101,905	105,185
Future water forecast (MB)	24,445	37,966	44,360	47,288
Oil and NGLs EUR (MB)	32,023	34,692	35,704	36,130
Total gas reinjected (Est.) (MMCF)	63,961	79,269	85,600	88,355

Table 3.72. Kuparuk River Unit–Placer pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$167,753	$167,753	$167,753	$167,753
Total operating costs	$281,692	$367,643	$422,676	$458,282
State royalty	$92,292	$153,506	$240,515	$299,680
State taxes – Severance	$0	$0	$0	$0
State taxes – Income	$7,422	$16,882	$33,240	$44,579
State taxes – Other	$9,534	$12,071	$13,056	$13,147
State Total (Royalty and Taxes)	**$109,248**	**$182,459**	**$286,811**	**$357,406**
Federal taxes	**$72,576**	**$185,128**	**$367,565**	**$492,758**
Industry net income	**$140,863**	**$359,368**	**$713,513**	**$956,534**

3.4.2 Kuparuk River Unit – West Sak additional development

Additional West Sak development is planned after the initial area around Drillsites 1E and 1J is fully developed. Current development in the West Sak Core Area was discussed in Section 3.3.2.1.

3.4.2.1 West Sak Additional Development Pool Engineering

A continuous development program is assumed. The development will continue to use horizontal wells and it is assumed the WAG MI process will be used in the expansion areas. It is estimated that about 120 new wells will be required to complete the development of the expansion area, which is estimated to contain about 1.23 BB OOIP.

The development of the expansion area will be staged to maintain a total West Sak production of 45 MBOPD, which will be maintained for seven years. This staged development will result in this peak oil rate lasting through 2020 at which time production will begin to decline at about 17.5%/yr. Using a technical abandonment rate of 1.0 MBOPD, the TUR for the additional development area totals about 285,000 MBO.

The oil, gas, and water production forecasts for the expansion area are presented in Figure 3.55.

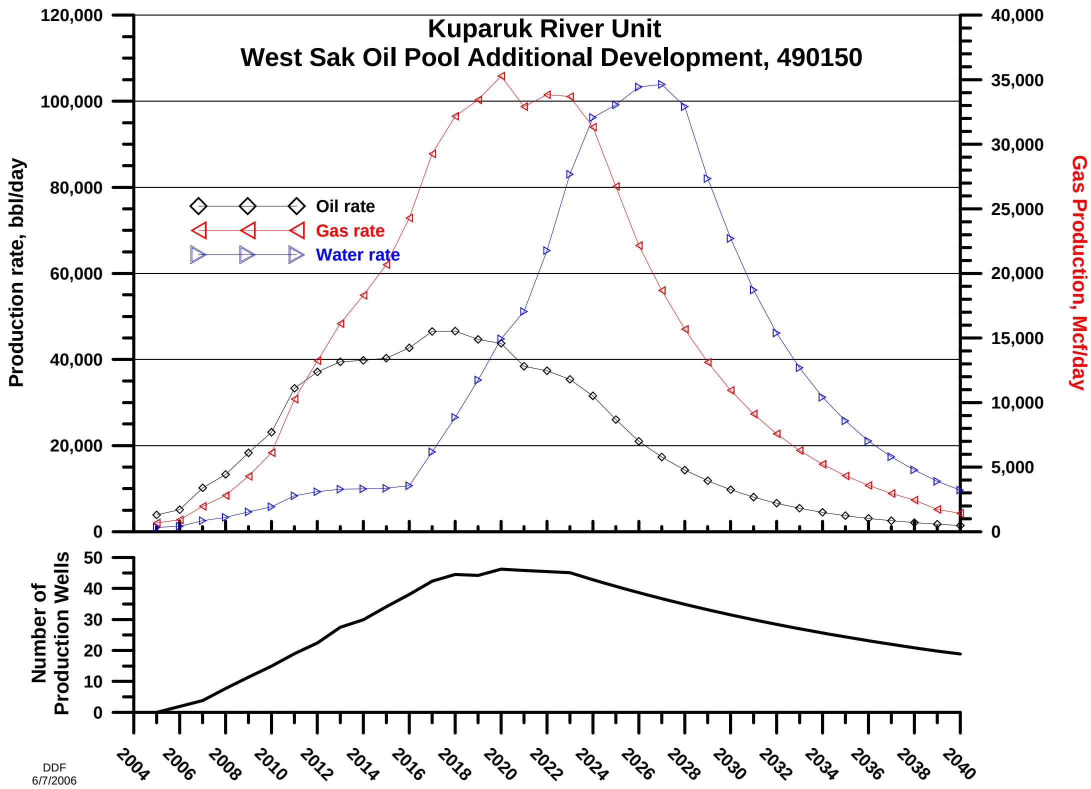


Figure 3.55. West Sak Pool additional development – Kuparuk River Unit production forecasts.

Forecasts of West Sak additional pool development future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.73.

Table 3.73. West Sak Additional pool–Forecasts of ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2027	2031	2036	2038
Future Gas forecast (MMCF)	149,099	174,958	190,533	193,900
Future water forecast (MB)	216,215	365,268	460,022	479,625
Oil and NGLs EUR (MB)	239,811	263,731	277,365	280,245
Total gas reinjected (Est.) (MMCF)	134,189	157,462	171,480	174,510

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.74.

Table 3.74. West Sak Additional pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$2,061,829	$2,061,829	$2,061,829	$2,061,829
Total operating costs	$2,895,801	$3,749,255	$4,558,338	$4,829,300
State royalty	$681,274	$1,229,848	$2,062,526	$2,599,810

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
State taxes – Severance	$51,614	$82,065	$127,737	$158,190
State taxes – Income	$23,874	$91,027	$233,766	$336,757
State taxes – Other	$86,546	$93,564	$94,208	$94,345
State Total (Royalty and Taxes)	**$843,308**	**$1,496,504**	**$2,518,237**	**$3,189,102**
Federal taxes	**$91,498**	**$1,066,134**	**$2,709,863**	**$3,852,532**
Industry net income	**$187,449**	**$2,069,552**	**$5,260,327**	**$7,478,443**

3.4.3 Coleville River Unit – Fiord Pool – CD3

The Fiord pool was discovered in 1992 and is an accumulation of about 150 MMBO OOIP (Table 2.7), in the Kuparuk River "C" and Nechelik sandstones. The Fiord pool is a satellite to the Alpine PA and about 5 miles north of the Alpine pool (ADNR, 2002d). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.4.3.1 Fiord Pool Engineering

The Fiord pool satellite is believed to contain 50 MMBO of TUR (PN, 2002), (Table 2.7). Development is expected to begin during the winter of 2005 and continue through 2008. Development drilling will begin with 17 to 18 wells (AOGCC, 2004b) and have a potential total of 40 wells (PN, 2005a). Production will be processed by the Alpine PA facilities. MWAG will be utilized (ADNR 2002b).

Production is assumed to begin in 2006 and increase to about 19 MBOPD by late 2008 (ConocoPhillips Onstream, 2005). Production will be level for one year before beginning to decline at 15%/yr to an abandonment rate of about 0.1 MBOPD. This results in a TUR of about 53,940 MBO.

Gas and water production volumes are be estimated using the GOR_D versus recovery and water cut versus recovery relationships from the Alpine PA. It is assumed all gas will be used for lease operations and the EOR process. The oil, gas, and water production forecasts are presented in Figure 3.56.

Forecasts of Colville River Unit Fiord pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.75.

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.76.

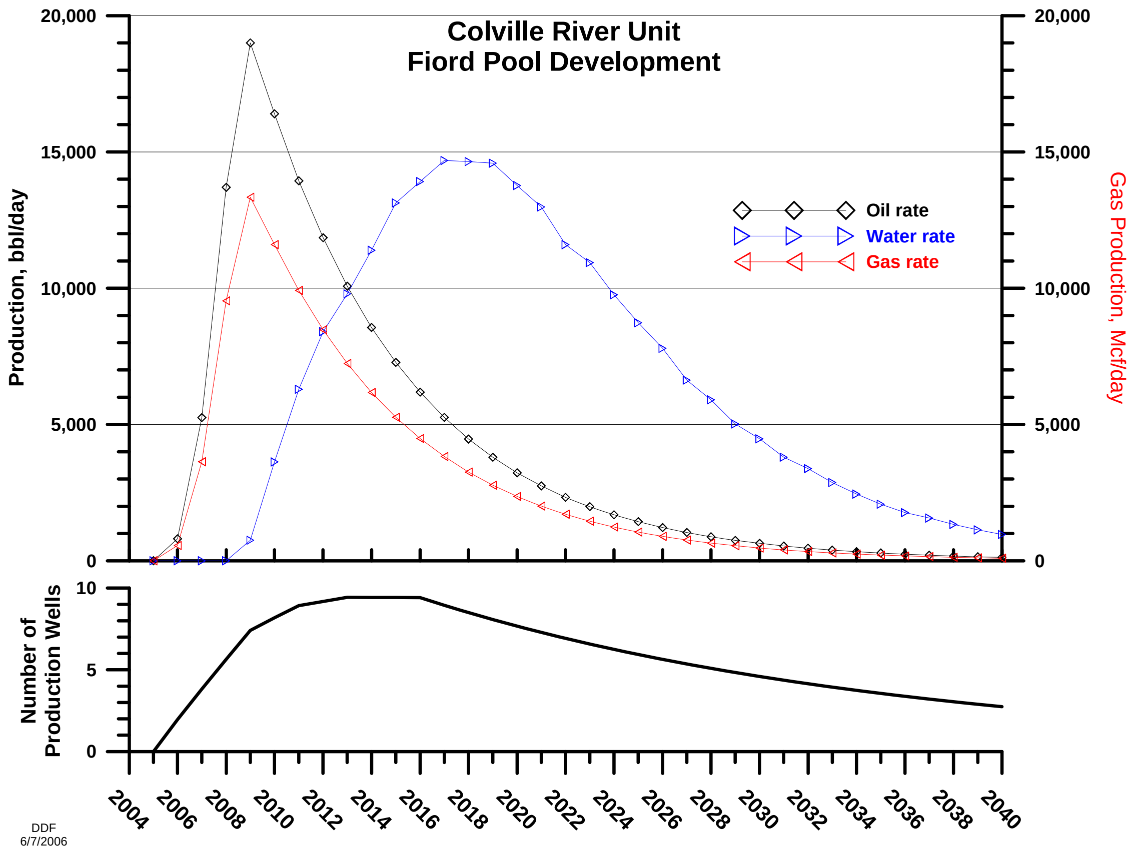


Figure 3.56. Fiord Pool–Colville River Unit production forecasts.

Table 3.75. Colville River Unit–Fiord pool–Forecasts of ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2021	2025	2029	2031
Future Gas forecast (MMCF)	33,785	36,122	37,347	37,719
Future water forecast (MB)	46,063	62,475	73,002	76,484
Oil and NGLs EUR (MB)	47,450	50,642	52,311	52,817
Total gas reinjected (Est.) (MMCF)	28,380	30,342	31,371	31,684

Table 3.76. Colville River Unit–Fiord pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$339,380	$339,380	$339,380	$339,380
Total operating costs	$393,052	$497,586	$586,402	$626,361
State royalty	$129,996	$217,579	$347,827	$434,276
State taxes – Severance	$1,023	$1,547	$2,333	$2,858
State taxes – Income	$9,291	$22,413	$46,400	$63,208
State taxes – Other	$19,296	$23,507	$25,658	$25,840
State Total (Royalty and Taxes)	**$159,606**	**$265,046**	**$422,218**	**$526,182**
Federal taxes	**$65,190**	**$231,674**	**$503,868**	**$691,066**
Industry net income	**$152,404**	**$473,916**	**$998,398**	**$1,359,180**

3.4.4 Colville River Unit – Nanuq Pool – CD4

The Nanuq pool was discovered in 2000 and is an accumulation of about 150 MMBO OOIP (Table 2.7) in the Nanuq sandstone. The Nanuq pool is a satellite to the Alpine PA and about 4 miles south of the Alpine pool (ADNR, 2002b). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.4.4.1 Nanuq Pool Engineering

The Nanuq pool satellite is believed to contain about 40 MMBO of TUR (Table 2.7). Development is expected to begin during the winter of 2005 and continue through 2008 (AOGCC, 2004b). Development drilling will begin with 18 to 21 wells and potentially have a total of 40 wells (PN, 2004g). Production will be processed by the Alpine PA facilities. EOR will be utilized (ADNR, 2002b).

Production is assumed to begin in 2006 and increase to 13.7 MBOPD by 2009. Production is assumed to be level for 2 years before beginning to decline at 15%/yr to an abandonment rate of about 0.1 MBOPD. This results in a TUR of about 43,920 MBO.

Gas and water production volumes will be estimated using the GOR_D versus recovery and water cut versus recovery relationships from the Alpine PA. It is assumed all gas will be used for lease operations and the EOR process. The oil, gas, and water production forecasts are presented in Figure 3.57.

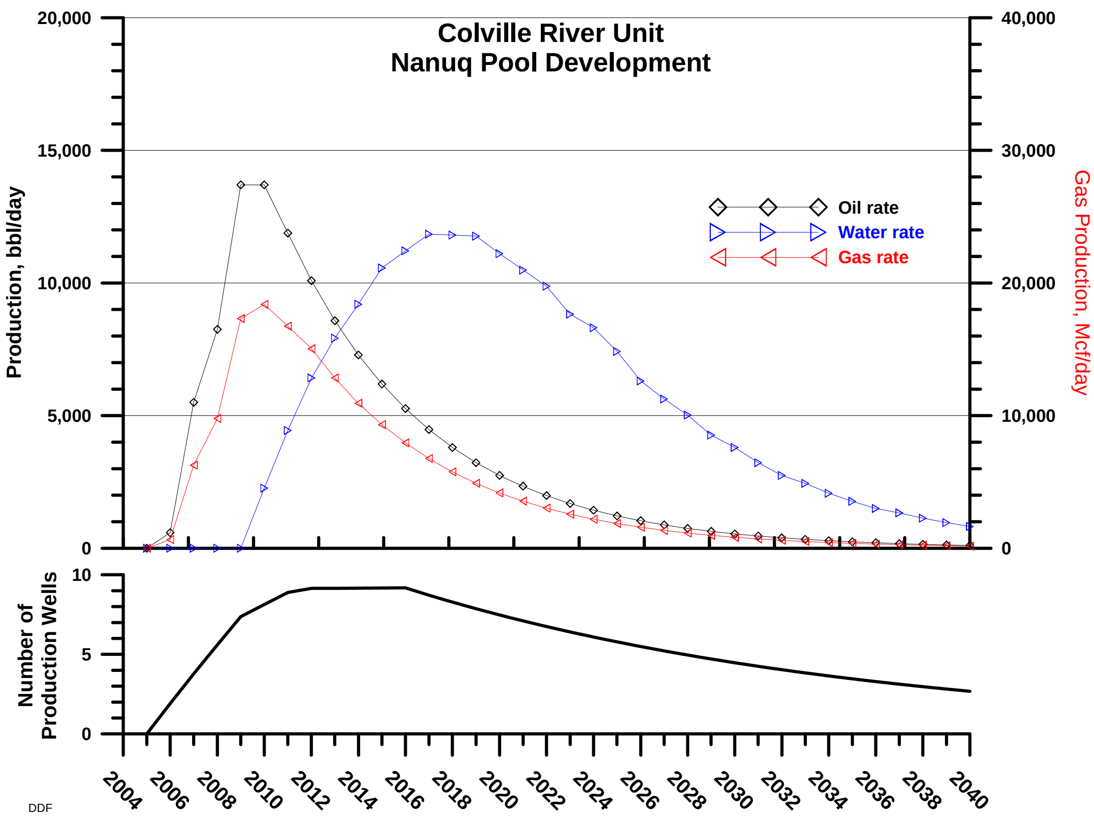


Figure 3.57. Colville River Unit–Nanuq Pool production forecasts

Forecasts of Nanuq pool future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.77.

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the Nanuq project are shown for all prices tracks in Table 3.78.

Table 3.77. Colville River Unit–Nanuq pool–Forecasts of ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2019	2024	2028	2030
Future Gas forecast (MMCF)	50,223	56,868	59,413	60,186
Future water forecast (MB)	27,380	46,052	55,803	59,099
Oil and NGLs EUR (MB)	36,241	40,614	42,283	42,789
Total gas reinjected (Est.) (MMCF)	42,187	47,769	49,907	50,556

Table 3.78. Colville River Unit–Nanuq pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$309,764	$309,764	$309,764	$309,764
Total operating costs	$322,075	$460,029	$551,295	$592,315
State royalty	$98,729	$174,540	$281,597	$352,591
State taxes – Severance	$16	$25	$38	$45
State taxes – Income	$5,911	$15,675	$34,481	$47,983
State taxes – Other	$14,805	$20,348	$22,799	$23,248
State Total (Royalty and Taxes)	**$119,461**	**$210,588**	**$338,915**	**$423,867**
Federal taxes	**$30,285**	**$153,308**	**$370,713**	**$521,707**
Industry net income	**$72,616**	**$320,525**	**$740,596**	**$1,031,825**

3.4.5 Colville River Unit Satellite – Alpine West Pool – CD5

The Alpine West pool was discovered in 2001 and is an accumulation of about 150 MMBO OOIP (Table 2.7) in the Alpine sandstone. The pool is a satellite to the CRU Alpine PA and is located about 8 miles west of the Alpine PA (PN, 2005a). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.4.5.1 Alpine West Pool Engineering

Until more information is available, a TUR of about 50 MMBO is used. Development is expected to begin in 2007 and continue through 2008 (PN 2005g). Development will include two road bridges. Drilling will begin in mid-2008 and be completed in 2010 and could include between 20 and 30 wells (DOI, 2004). It is assumed that 20 wells will be required initially. It is assumed that the produced fluids will be processed by the Alpine PA facilities (PN, 2005a) and that an EOR process utilizing gas will be employed (AOGCC, 2002b).

Production is assumed to begin in 2008 and increase to about 19.3 MBOPD by late 2009. Production will be level for one year before beginning a 15%/yr decline to an abandonment rate of about 0.2 MBOPD. This results in a TUR of 53,630 MBO.

Gas and water production volumes will be estimated using the GOR_D versus recovery and water cut versus recovery relationships from the Alpine PA. It is assumed all gas will be used for lease operations and the EOR process. The oil, gas, and water production forecasts are presented in Figure 3.58.

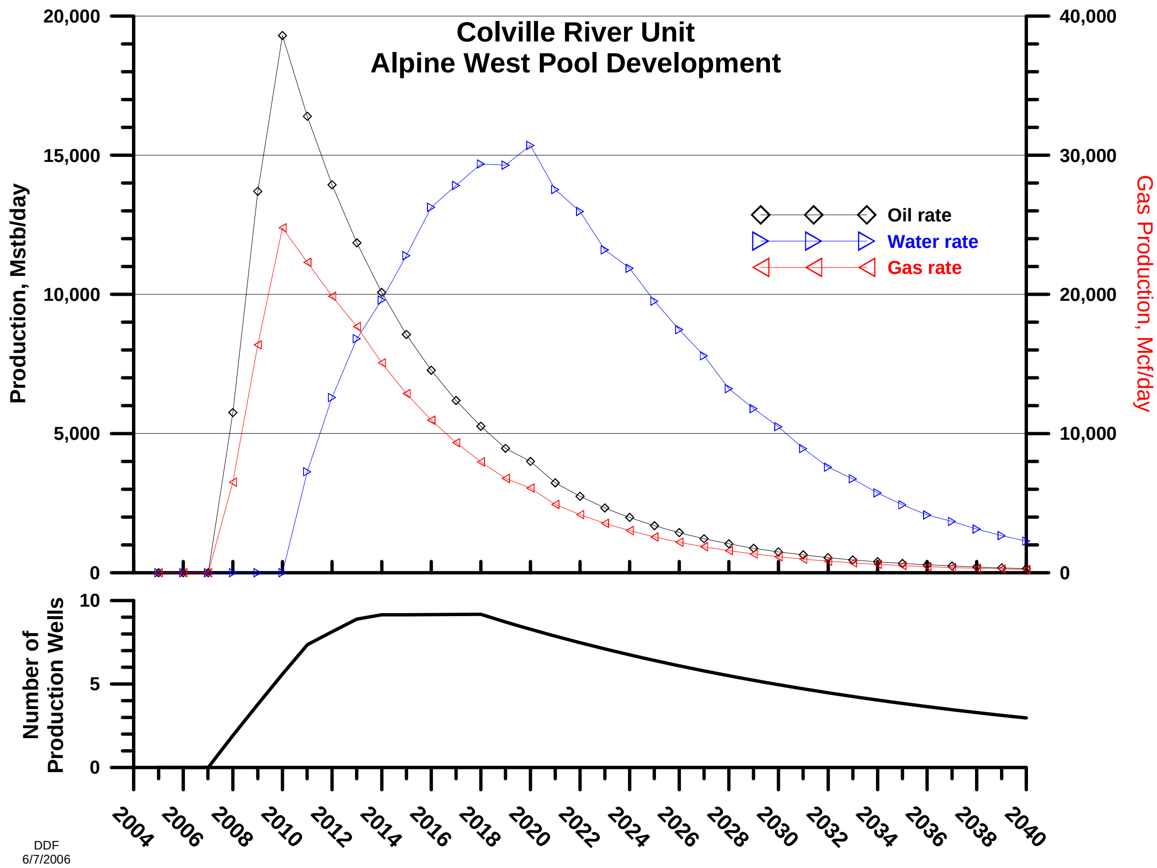


Figure 3.58 Alpine West–Colville River Unit production forecasts.

Forecasts of the Alpine West pool future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.79.

Table 3.79. Colville River Unit Satellite–Alpine West pool–Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2022	2026	2030	2032
Future Gas forecast (MMCF)	66,263	71,128	73,675	74,448
Future water forecast (MB)	48,021	65,250	76,284	79,931
Oil and NGLs EUR (MB)	47,446	50,639	52,307	52,813
Total gas reinjected (Est.) (MMCF)	55,661	59,747	61,887	62,536

The Alpine West pool revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.80.

Table 3.80. Colville River Unit Satellite–Alpine West pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$355,781	$355,781	$355,781	$355,781
Total operating costs	$383,231	$492,921	$585,929	$627,728
State royalty	$132,584	$222,216	$355,553	$444,067
State taxes – Severance	$2,633	$3,983	$6,011	$7,362
State taxes – Income	$10,427	$23,281	$47,438	$64,570
State taxes – Other	$18,577	$22,853	$24,662	$24,686
State Total (Royalty and Taxes)	**$164,221**	**$272,333**	**$433,664**	**$540,685**
Federal taxes	**$87,041**	**$244,095**	**$520,317**	**$710,601**
Industry net income	**$138,493**	**$473,432**	**$1,010,028**	**$1,379,410**

3.4.6 Colville River Unit Satellite – Lookout Pool – CD6

The Lookout Pool was discovered in 2002 and is an accumulation of 150 MMBO OOIP (Table 2.7), in the Alpine sandstone. The pool is a satellite to the CRU Alpine PA and is located about 15 miles southwest of the Alpine oil field (PN, 2005a). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.4.6.1 Lookout Pool – CD6 Engineering

The Lookout Pool satellite is believed to contain as much as 67.5 MMBO of TUR (Table 2.7). However, based on recent comments by the operator (PN, 2005e), a conservative volume of about 50 MMBO is used in the economic analysis. Production will be processed by the Alpine PA facilities. It will be transported through a 3-phase pipeline to connect to the 3-phase pipeline at the Alpine West production pad. The initial development work on this satellite is delayed until the Spark pool satellite is developed. This will allow for the 3-phase pipeline cost to be shared. It is assumed development work will commence in 2008 with initial wells being drilled in 2009 and that the same EOR program at the Alpine PA will be utilized at Lookout. Thus, 20 wells including producers and injectors will be required.

Production is assumed to begin in 2010 and reach a peak rate of about 19.2 MBOPD in late 2011. That peak rate will be maintained for a year before starting a 15%/yr decline rate to an abandonment rate of about 0.1 MBOPD. This results in a TUR of about 53,906 MBO.

Gas and water production volumes will be estimated using the GOR_D versus recovery and water cut versus recovery relationships from the Alpine PA. It is assumed all gas will be used for lease operations and the EOR process. The oil, gas, and water production forecasts are presented in Figure 3.59.

Forecasts of Lookout pool future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.81.

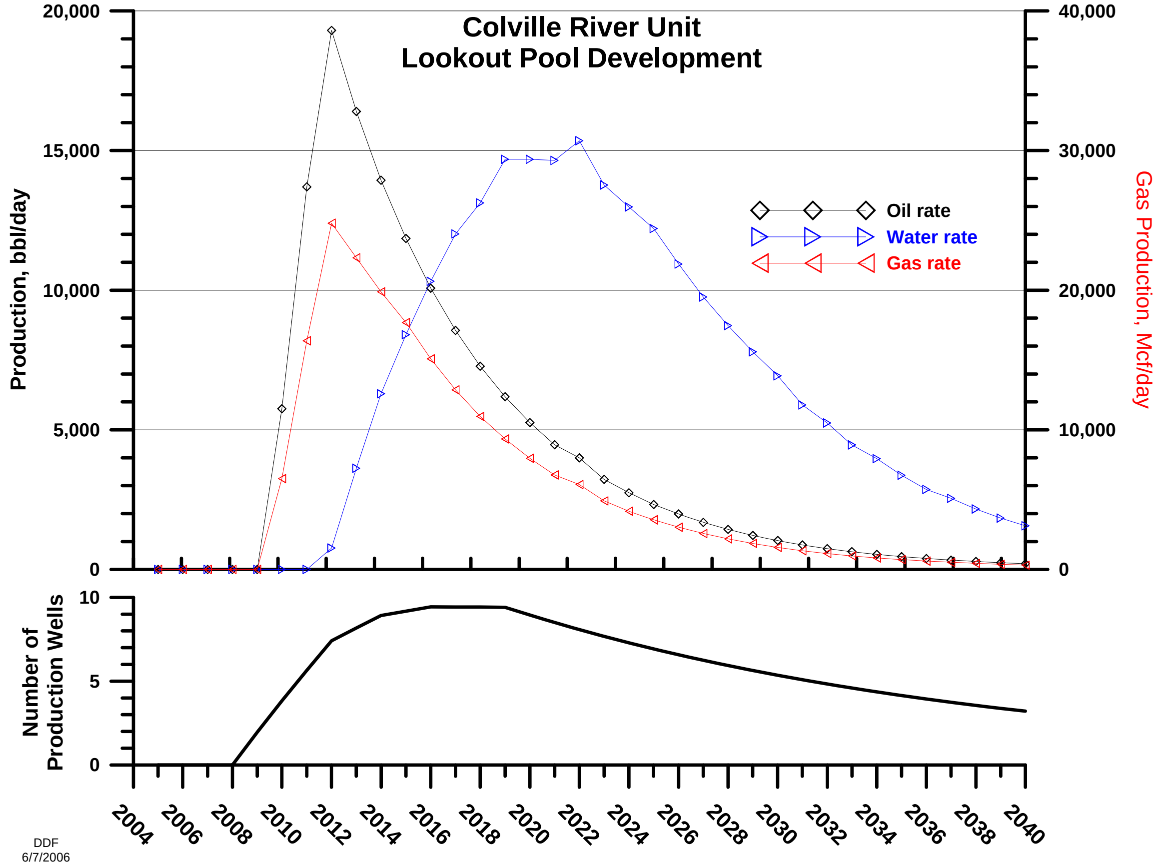


Figure 3.59. Lookout Pool production forecasts.

Table 3.81. Lookout pool–Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2024	2028	2032	2034
Future Gas forecast (MMCF)	66,197	71,059	73,604	74,376
Future water forecast (MB)	46,050	62,457	72,970	76,444
Oil and NGLs EUR (MB)	47,446	50,638	52,306	52,811
Total gas reinjected (Est.) (MMCF)	55,606	59,689	61,828	62,476

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the Lookout pool project are shown for all prices tracks in Table 3.82.

Table 3.82. Lookout pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$395,212	$395,212	$395,212	$395,212
Total operating costs	$431,035	$546,941	$645,410	$689,711
State royalty	$137,537	$231,368	$371,082	$463,859
State taxes – Severance	$1,218	$1,847	$2,790	$3,418
State taxes – Income	$8,896	$22,454	$47,969	$65,964

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
State taxes – Other	$19,991	$23,359	$24,014	$24,038
State Total (Royalty and Taxes)	**$167,642**	**$279,028**	**$445,855**	**$557,279**
Federal taxes	**$61,904**	**$234,875**	**$524,839**	**$724,413**
Industry net income	**$136,720**	**$483,270**	**$1,046,141**	**$1,433,546**

3.4.7 Colville River Unit Satellite – Spark Pool – CD7

The Spark Pool was discovered in 2000 and is an accumulation of 150 MMBO OOIP (Table 2.7), in the Alpine sandstone. The Spark pool is a satellite to the CRU Alpine PA and is located about 20 miles southwest of the Alpine oil field development (PN, 2005a). Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, the state of Alaska, and the federal government are described in this section.

3.4.7.1 Spark Pool – CD7 Engineering

The Spark Pool satellite is believed to contain as much as 67.5 MMBO of TUR (Table 2.7). However, a conservative estimate of about 50 MMBO is used. Indications are that produced fluids would be transported to the Alpine IPA facilities for processing. This may be the maximum distance 3-phase fluids can be transported on the North Slope (DOI, 2004b). A joint 3-phase line will be constructed with the Lookout Pool (see Section 3.4.6.1). It is assumed development work will commence in 2008 with initial wells being drilled in 2009 and that the same EOR program at the Alpine PA will be utilized in this pool. Thus, 20 wells including producers and injectors will be required.

Production is assumed to begin in 2010 and reach a peak rate of about 19.2 MBOPD in late 2011. That peak rate will be maintained for a year before starting a 15%/yr decline rate to an abandonment rate of about 0.1 MBOPD, resulting in a TUR of about 53,906 MBO.

Gas and water production volumes will be estimated using the GOR_D versus recovery and water cut versus recovery relationships from the Alpine PA. It is assumed all gas will be used for lease operations and the EOR process. The oil, gas, and water production forecasts are presented in Figure 3.60.

Forecasts of Spark Pool future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.83.

The revenue to the state and federal governments and net income, investment, operating costs to the operators for the life of the Spark Pool project are shown for all prices tracks in Table 3.84.

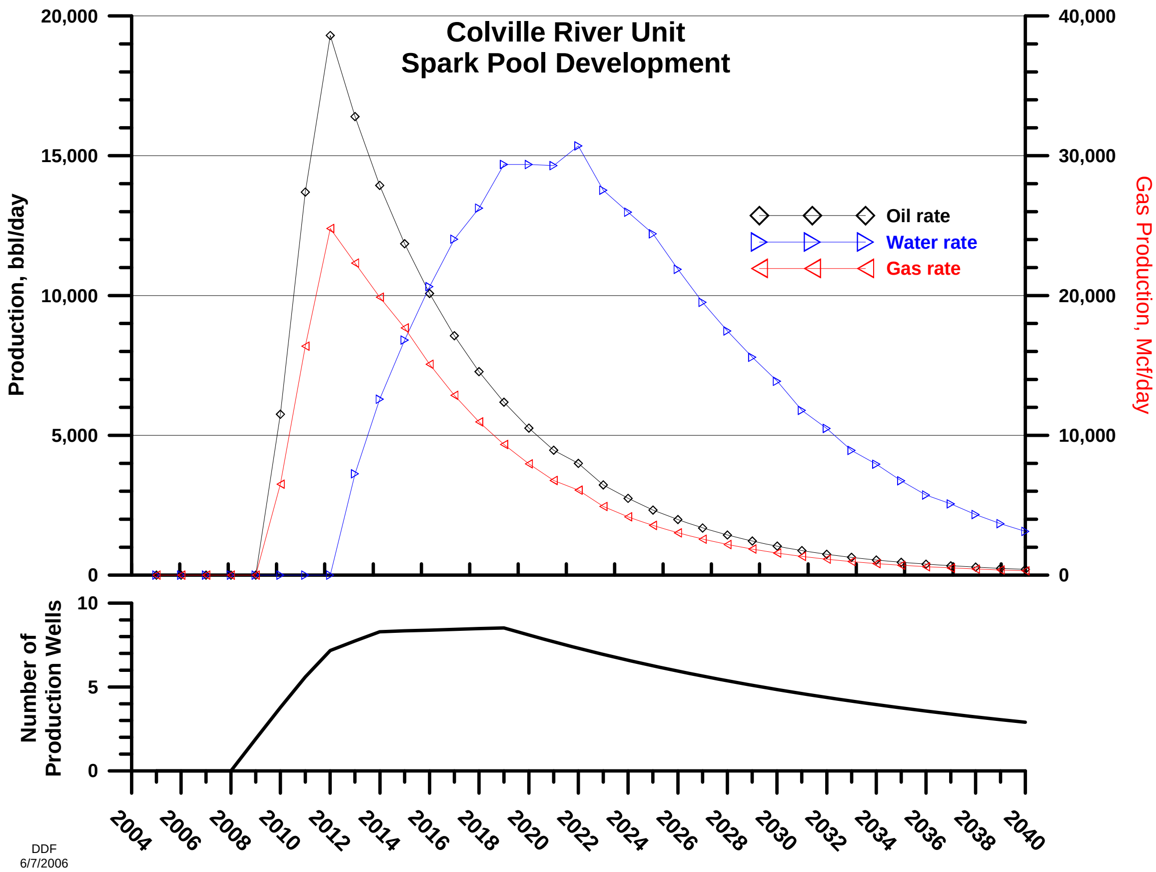


Figure 3.60. Spark Pool production forecasts.

Table 3.83. Spark pool–Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2024	2029	2033	2035
Future Gas forecast (MMCF)	47,592	51,304	52,720	53,148
Future water forecast (MB)	66,485	72,144	74,306	74,960
Oil and NGLs EUR (MB)	48,767	69,554	79,341	82,521
Total gas reinjected (Est.) (MMCF)	55,848	60,601	62,417	62,967

Table 3.84. Spark pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$381,604	$381,604	$381,604	$381,604
Total operating costs	$401,538	$530,656	$616,377	$654,948
State royalty	$138,015	$235,142	$374,890	$467,744
State taxes – Severance	$1,364	$2,069	$3,127	$3,832
State taxes – Income	$9,475	$23,677	$49,794	$68,016
State taxes – Other	$19,998	$23,772	$24,034	$24,055
State Total (Royalty and Taxes)	**$168,852**	**$284,660**	**$451,845**	**$563,647**
Federal taxes	**$67,459**	**$248,937**	**$543,166**	**$744,735**
Industry net income	**$160,626**	**$510,504**	**$1,081,715**	**$1,473,001**

3.4.8 Prudhoe Bay Unit – Orion Phase II and III

The Phase II and III expansions for Orion are assumed to have TUR volumes of about 114 MMBO and will require the same number of wells to fully develop. Phase II development is assumed to start in 2007 with first production occurring in 2008. Phase III development is assumed to start in 2009 and first production in 2010. Production from each phase will ramp up over five years to a peak rate of 24 MBOPD which will be held constant for four years. The peak production will be maintained by drilling of new wells and an active workover program before starting a 15%/yr decline to an assumed abandonment rate of 1.29 MBOPD for the combined phases. This results in a combined TUR of 228,970 MBO from Phase II and III. The total TUR for all three phases is about 250,810 MBO.

Gas and water production volumes will be estimated using the GOR_D versus recovery and water cut versus recovery relationships from the Orion PA. It is assumed all gas will be used for lease operations and the EOR process. The oil, gas, and water production forecasts are presented in Figure 3.61.

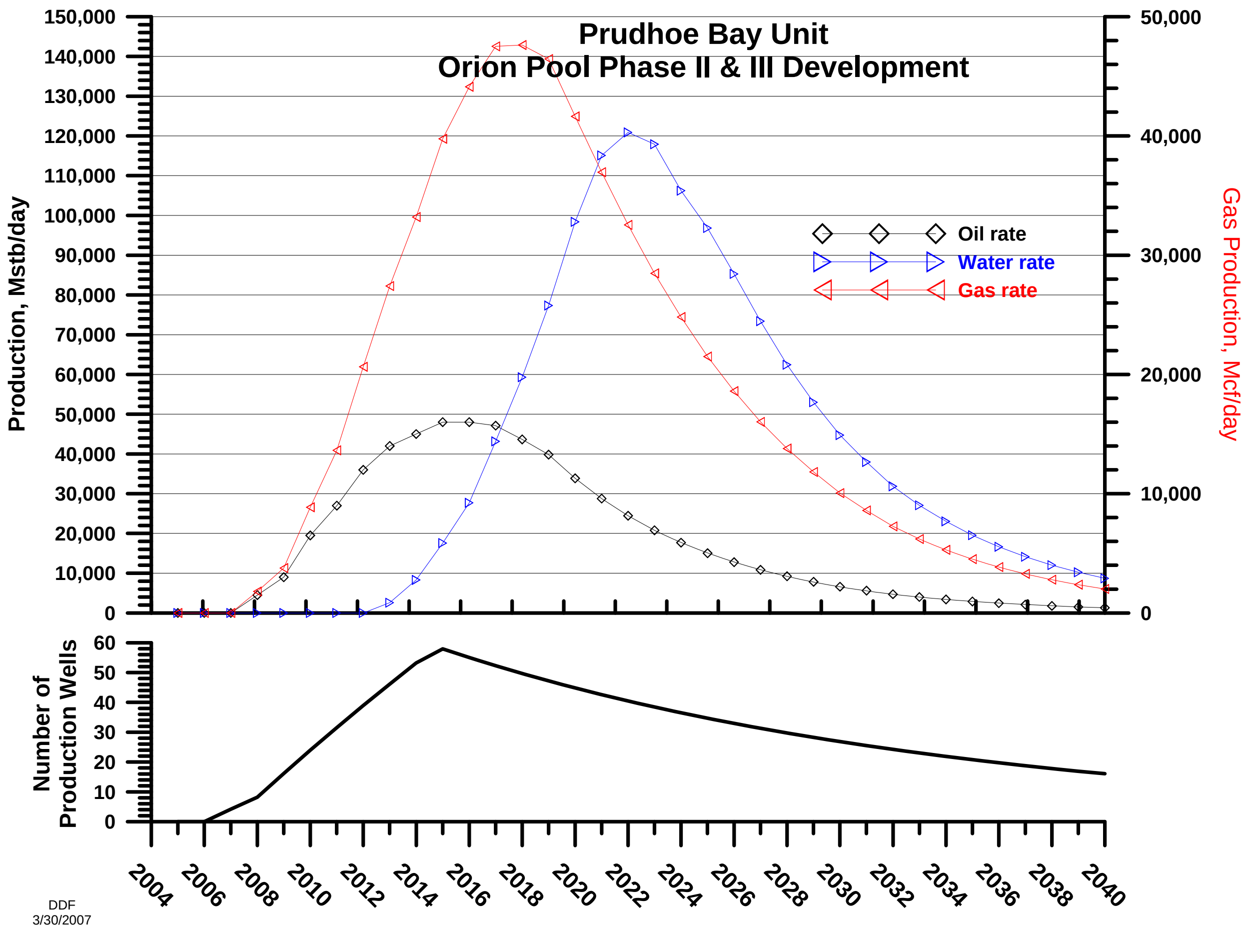


Figure 3.61. Orion Phase II and III–Prudhoe Bay Unit production forecasts.

Forecasts of PBU Orion Phase II and III pool future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.85.

Table 3.85. Orion Phase II and III pool–Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2023	2029	2033	2035
Future Gas forecast (MMCF)	181,306	212,825	221,550	224,015
Future water forecast (MB)	162,763	207,728	221,008	224,824
Oil and NGLs EUR (MB)	216,277	416,491	476,803	493,632
Total gas reinjected (Est.) (MMCF)	0	0	0	0

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project is shown for all prices tracks in Table 3.86.

Table 3.86. Orion Phase II and III pool–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$1,004,614	$1,004,614	$1,004,614	$1,004,614
Total operating costs	$2,156,837	$3,169,100	$3,655,788	$3,864,375
State royalty	$488,803	$952,626	$1,576,646	$1,989,240
State taxes – Severance	$162,743	$291,198	$468,341	$585,661
State taxes – Income	$16,087	$73,492	$182,839	$259,440
State taxes – Other	$51,128	$63,308	$64,157	$64,274
State Total (Royalty and Taxes)	**$718,761**	**$1,380,624**	**$2,291,983**	**$2,898,615**
Federal taxes	**$85,299**	**$812,010**	**$2,049,088**	**$2,894,151**
Industry net income	**$307,702**	**$1,640,293**	**$4,001,997**	**$5,642,413**

3.4.9 Prudhoe Bay Unit – Polaris Phase II and III

Phase II is assumed to recover about 90% as much oil as Phase I with development starting in 2006 and first production in 2007. Production will increase from an initial rate of 3 MBOPD in 2007 to a peak production of 15 MBOPD in 2014. Production will then begin to decline at 15%/yr to an assumed abandonment rate of 0.3 MBOPD, giving a TUR of 62,600 MBO.

Phase III is assumed to contain thinner beds of lower reservoir quality than the prior developments and will recover about 50% of the Phase I reserves. The project will commence in 2009 and with initial production in 2010. Production will average 2.5 MBOPD and increase to 8.5 MBOPD during 2017 before starting a decline of 15%/yr to an abandonment rate of 0.26 MBOPD giving a TUR of 35,900 MBO. Phase II and III production forecast is presented in Figure 3.62.

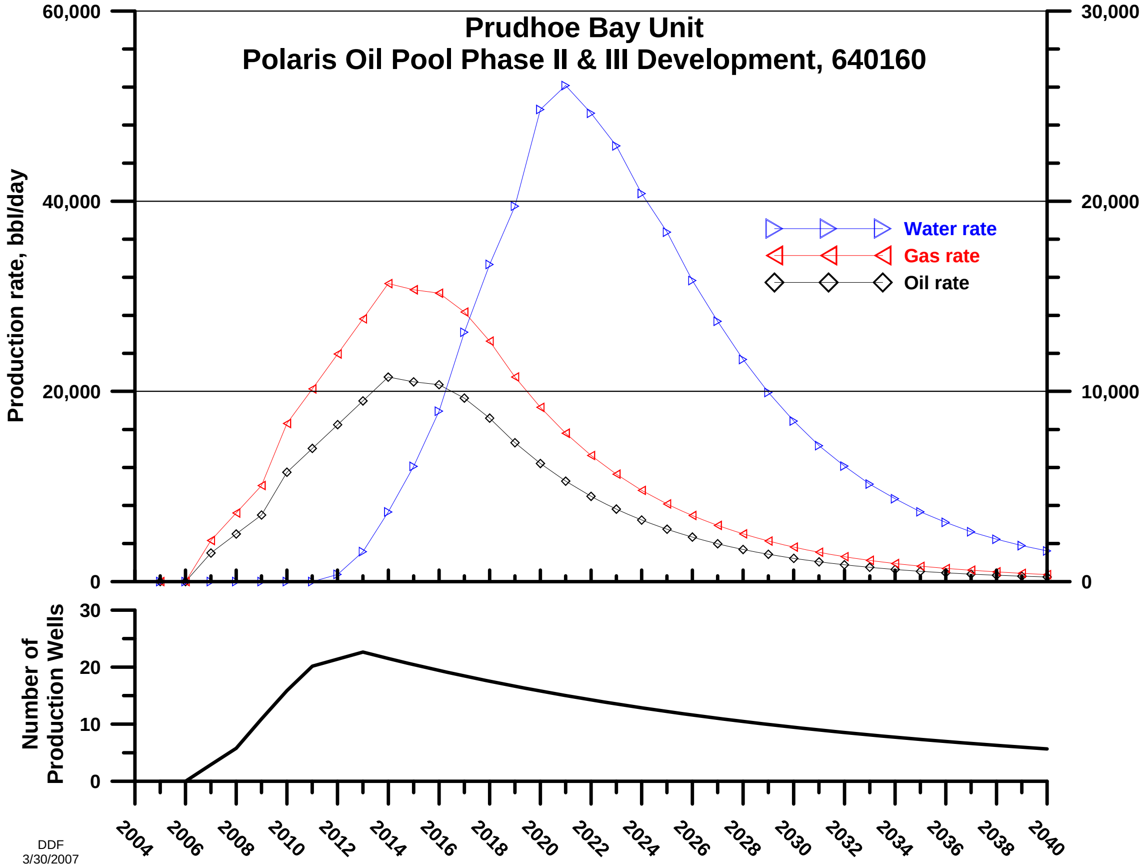


Figure 3.62. Polaris Phase II & III–Prudhoe Bay Unit production forecast.

Forecasts of PBU Polaris Phase II pool future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.87.

Table 3.87. Polaris II and III pool–Forecasts of ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2023	2029	2035	2037
Future Gas forecast (MMCF)	81,107	92,650	96,998	97,729
Future water forecast (MB)	59,261	67,821	71,053	71,597
Oil and NGLs EUR (MB)	109,601	185,416	215,314	220,235
Total gas reinjected (Est.) (MMCF)	0	0	0	0

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.88.

Table 3.88. Polaris II and III pool–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$429,225	$429,225	$429,225	$429,225
Total operating costs	$917,149	$1,273,989	$1,521,949	$1,590,982

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
State royalty	$217,413	$409,590	$682,733	$857,001
State taxes – Severance	$81,080	$140,051	$225,110	$280,176
State taxes – Income	$7,613	$33,345	$80,395	$113,167
State taxes – Other	$25,757	$30,782	$31,171	$31,205
State Total (Royalty and Taxes)	**$331,863**	**$613,768**	**$1,019,409**	**$1,281,549**
Federal taxes	**$20,479**	**$367,844**	**$899,949**	**$1,261,117**
Industry net income	**$179,991**	**$739,870**	**$1,746,090**	**$2,447,914**

3.4.10 Oooguruk Unit

The Oooguruk Unit is an accumulation in the Nuiqsut and Kuparuk Sands, which was discovered in 2003 (Table 2.8). It is located offshore northwest of the KRU (PN, 2005f). There are no published volumes of OOIP, or expected recoveries. Reserves and recovery rates are estimated using published reports.

The accumulation will be developed using one on-shore pad and one off-shore pad with initial development beginning in late 2005. A total of 40 wells are assumed for this project, with about 20 producers and 20 injectors. Drilling is expected to be completed by year-end 2011. Initial production is anticipated as early as the fourth quarter of 2008 with a peak rate of between 18 and 20 MBOPD being achieved. It is assumed water injection will be used for pressure maintenance and secondary recovery. The production life is expected to be about 25 years. Produced fluids will be processed through the KRU IPA (PN, 2006c).

The TUR is estimated using a 3-yr period to reach a maximum rate of 20 MBOPD. The peak rate will be maintained for 2-yr period before declining at a 15% rate to an ending rate of about 0.2 MBOPD. A TUR of about 71,600 MBO is estimated using these parameters. The gas and water forecasts are made using the Kuparuk River data for the KRU. It is assumed all gas will be used for lease operation and in secondary recovery processes. The production forecasts for oil, gas, and water are presented in Figure 3.63.

Forecasts of Oooguruk Unit future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.89.

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the Oooguruk project are shown for all prices tracks in Table 3.90.

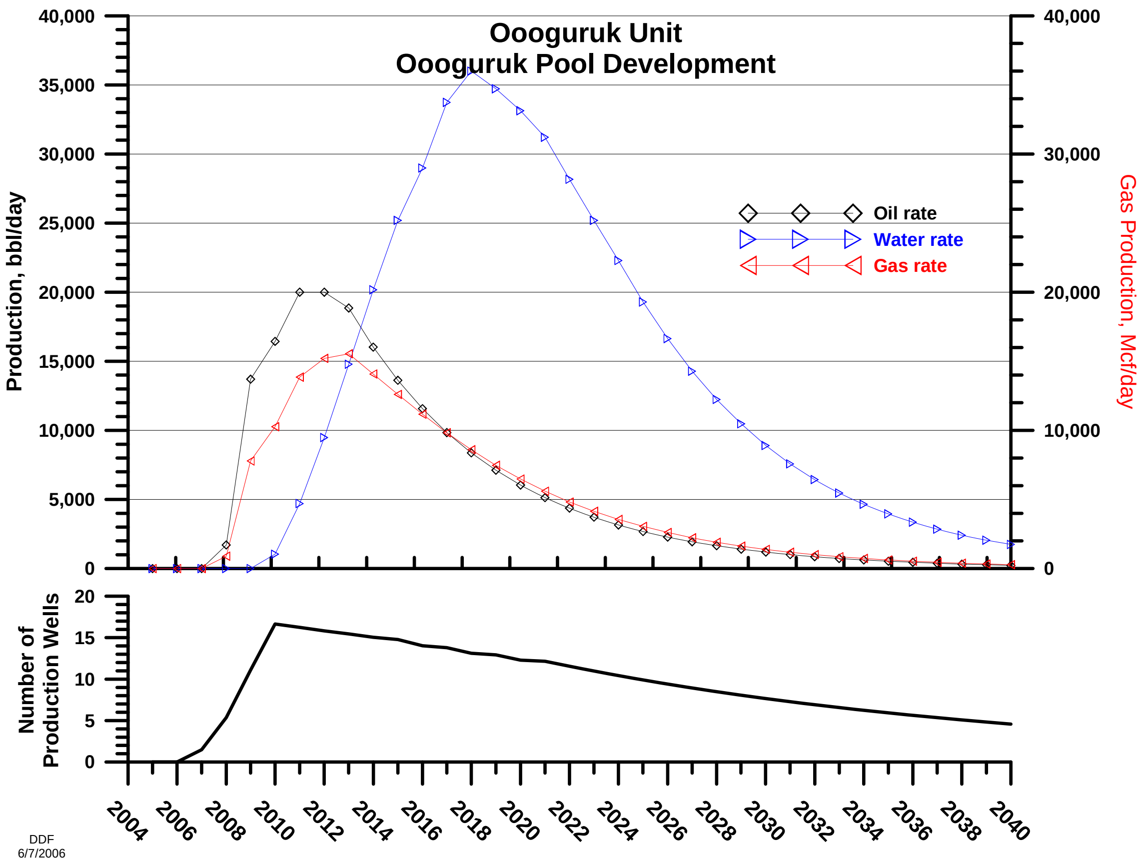


Figure 3.63. Ooguruk Unit production forecasts.

Table 3.89. Ooguruk Unit–Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2019	2023	2029	2031
Future Gas forecast (MMCF)	54,794	63,061	68,682	69,627
Future water forecast (MB)	43,724	52,611	58,988	60,087
Oil and NGLs EUR (MB)	65,216	112,667	153,025	160,106
Total gas reinjected (Est.) (MMCF)	36,729	44,193	49,550	50,473

Table 3.90. Ooguruk Unit–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$703,647	$737,760	$737,760	$737,760
Total operating costs	$700,066	$968,634	$1,265,355	$1,343,704
State royalty	$159,529	$285,770	$482,858	$604,261
State taxes – Severance	$104	$156	$234	$288
State taxes – Income	$0	$12,643	$41,755	$64,147
State taxes – Other	$71,520	$90,601	$106,023	$106,687
State Total (Royalty and Taxes)	**$231,153**	**$389,170**	**$630,870**	**$775,383**
Federal taxes	**$0**	**$33,682**	**$408,503**	**$663,759**
Industry net income	**-$271,620**	**$257,456**	**$914,926**	**$1,406,426**

3.4.11 Nikaitchuq Unit

The Nikaitchug Unit is an accumulation in the Nuiqsut and Sag River sandstones and the Schrader Bluff Formation, which was discovered in 2004 (Table 2.8). It is located offshore and north of the Kuparuk River and Milne Point Units. Recoverable reserves were indicated to be between 30 and 60 MMBO (PN, 2005i) and between 100 and 200 MMBOE by a more recent estimate (PN, 2006d). Reserves and production rates are estimate using the following information.

The accumulation will be developed using two on-shore and three off-shore pads with initial development occurring in 2006. The operator's news release (PN, 2005g, PN, 2005h) indicates that 20 wells will be drilled at the onshore drilling pads and 50 wells in each of the three off-shore pads. Drilling will begin in 2006 at the on-shore pad and require 2 to 3 years to complete. Drilling at the three off-shore pads will begin in 2008 and will also require 2 to 3 years to complete. For this study a total of 105 wells will be required with development drilling completed in 2012. Initial production from the on-shore pad could commence in late 2006. Production from the off-shore pads will be sent to the on-shore facilities through sub-sea pipelines. Total production from the project is expected to be 60 MBOPD (PN 2005k). Peak production from each pad has been indicated as: 15 MBOPD from the pad at Oliktok Point, 20 MBOPD from the west off-shore pad, 15 MBOPD from the central off-shore pad, and 10 MBOPD from the east off-shore pad (PN, 2005l).

Based on the indicated peak production rates, the oil reserves estimate is low, and based on the current horizontal well technology, the number of wells is believed to be high. The reserve estimate for this accumulation is based on the peak oil rates noted, and an abandonment rate of 0.4 BOPD for each pad. A decline rate of 15%/yr is used. This results in an estimate TUR of about 175,200 MBO. The gas and water forecasts are made using the Milne Point Schrader Bluff historical data. The oil, gas, and water production forecasts are presented in Figure 3.64.

Forecasts of Nikaitchug pool future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.91.

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the Nikaitchug project is shown for all prices tracks in Table 3.92.

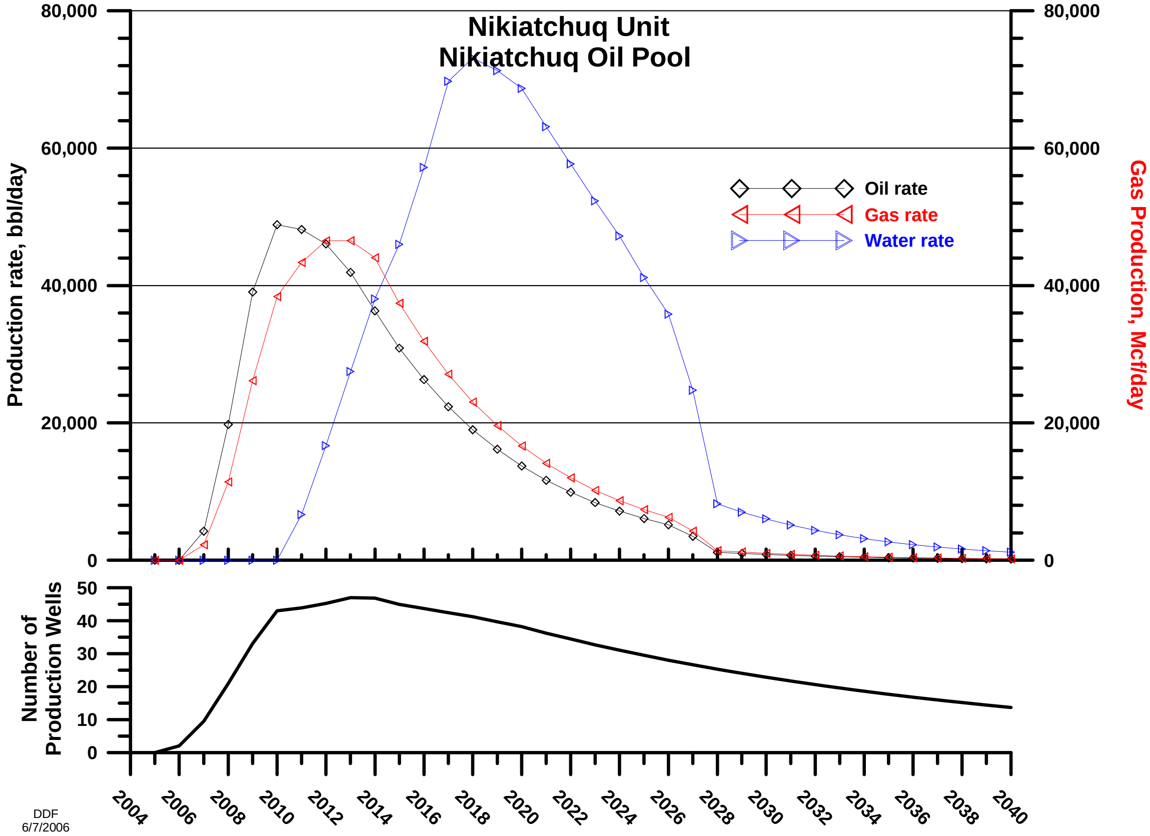


Figure 3.64. Nikaitchug Unit production forecasts.

Table 3.91. Nikaitchug Unit–Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2017	2029	2029	2029
Future Gas forecast (MMCF)	124,657	170,004	170,004	170,004
Future water forecast (MB)	119,646	174,608	174,608	174,608
Oil and NGLs EUR (MB)	72,321	299,570	299,570	299,570
Total gas reinjected (Est.) (MMCF)	100,503	146,670	146,670	146,670

Table 3.92. Nikaitchug Unit–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$1,588,524	$1,717,589	$1,717,589	$1,717,589
Total operating costs	$1,572,977	$2,945,169	$2,945,169	$2,945,169
State royalty	$327,459	$736,370	$1,139,591	$1,408,405
State taxes – Severance	$24,935	$38,327	$58,410	$71,801
State taxes – Income	$657	$24,321	$97,225	$153,080
State taxes – Other	$116,200	$209,784	$209,784	$209,784
State Total (Royalty and Taxes)	**$469,251**	**$1,008,802**	**$1,505,010**	**$1,843,070**
Federal taxes	**$0**	**$121,198**	**$1,084,052**	**$1,705,256**
Industry net income	**-$674,784**	**$475,242**	**$2,232,230**	**$3,417,004**

Based on estimates of development and operating costs, the Nikaitchug Unit would not provide a 10% rate of return at $25/bbl. However, the state receives an estimated $463,017,000 from this project at $25/bbl under the current state tax structure.

3.4.12 Liberty Unit

The Liberty Unit (LU) is an accumulation in the Kekiktuk Conglomerate formation discovered in 1982 Table 2.8). It is located off-shore between the Duck Island and Badami Units. Reserves are estimated at about 120 MMBO (PN, 2004h) to 150 MMBO (PN, 2006c).

Project approvals are anticipated in late 2007 with initial development beginning in 2008 (PN, 2004h) or 2009 (ADN, 2005). Plans include construction of an off-shore island for a drilling and production pad. Produced fluids will be transported to shore through a sub-sea pipeline with processing at either the Badami facility or the Duck Island facility. It is assumed a total of 50 producers and injectors will be required and will be drilled over a 5-yr period beginning in 2010 and that production will begin in 2010. The reservoir will be operated under a waterflood/pressure maintenance program initiated in 2010.

Reserves are estimated using a peak production rate of 35 MBOPD with 2 years at peak rate, then declining at 15%/yr. The abandonment rate is assumed to be about 0.2 MBOPD. This results in a TUR volume of about 125,000 MBO.

Gas and water forecasts are estimated using DIU historical data. The oil, gas, and water production forecasts are presented in Figure 3.65.

Forecasts of LU future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.93.

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the LU project are shown for all prices tracks in Table 3.94.

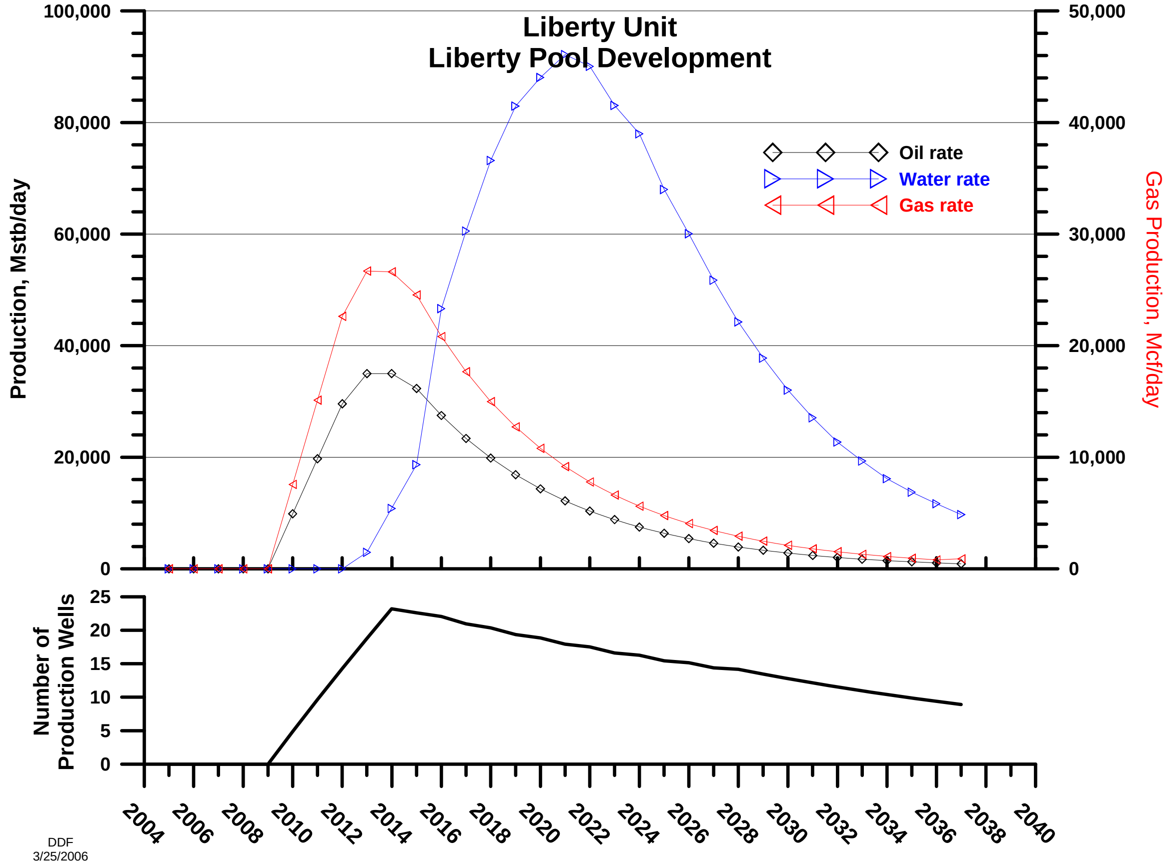


Figure 3.65. Liberty Unit production forecasts.

Table 3.93. Liberty Unit–Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2021	2025	2031	2034
Future Gas forecast (MMCF)	73,050	83,711	90,947	92,636
Future water forecast (MB)	129,061	242,961	338,148	360,287
Oil and NGLs EUR (MB)	96,165	110,356	120,010	122,266
Total gas reinjected (Est.) (MMCF)	61,362	70,317	76,395	77,814

Table 3.94. Liberty Unit–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$721,782	$758,325	$800,259	$800,259
Total operating costs	$1,165,647	$1,643,448	$2,164,837	$2,358,344
State royalty	$282,315	$510,695	$868,569	$1,097,819
State taxes – Severance	$15,045	$22,836	$34,522	$42,315
State taxes – Income	$10,910	$40,576	$96,442	$137,554
State taxes – Other	$33,335	$43,026	$49,251	$49,358
State Total (Royalty and Taxes)	**$341,605**	**$617,133**	**$1,048,784**	**$1,327,046**
Federal taxes	**$30,850**	**$405,661**	**$1,044,225**	**$1,505,906**
Industry net income	**$183,867**	**$854,659**	**$2,086,498**	**$2,985,152**

3.4.13 Gwydyr Bay Unit

The Gwydyr Bay Unit (GBU) is an accumulation in the Ivishak formation and was discovered in 1969 (Table 2.8). It is north of PBU and is located on both onshore tracts and offshore Beaufort Sea tracts. The unit is estimated to contain between 30,000 and 73,000 MBO of recoverable reserves (Table 2.8). A recovery of 55,000 MBO is assumed for this project.

Recent published releases indicate initial development could begin as early as 2005 with first production beginning in 2006 (PN, 2004i). It is assumed production will be processed by the PBU Lisburne PA facility.

The annual production rates and the TUR for the GBU are estimated using the following parameters. Initial development will commence in 2006 and will include pad and facility construction and well drilling. Production is assumed to begin in mid-2007. Although a recent release indicates development will require for 5 to 12 wells (PN, 2004i), based on other projects, it is assumed that a total of 20 wells, both producers and injectors, will be required. A peak rate of 15 MBOPD is assumed with a 2-yr peak production period. Rates are determined using a 15%/yr decline rate to an abandonment rate of about 0.1 MBOPD. This results in a TUR of about 53,870 MBO and a life of 21 years.

It is assumed both water and gas will be used for enhancing recovery, similar to the Northstar Ivishak project. Future gas and water recovery forecasts are determined estimated using NU gas and water performance history. The oil, gas, and water production forecasts are presented in Figure 3.66. All gas is assumed to be used on lease.

Forecasts of GBU future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.95.

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the GBU project are shown for all prices tracks in Table 3.96.

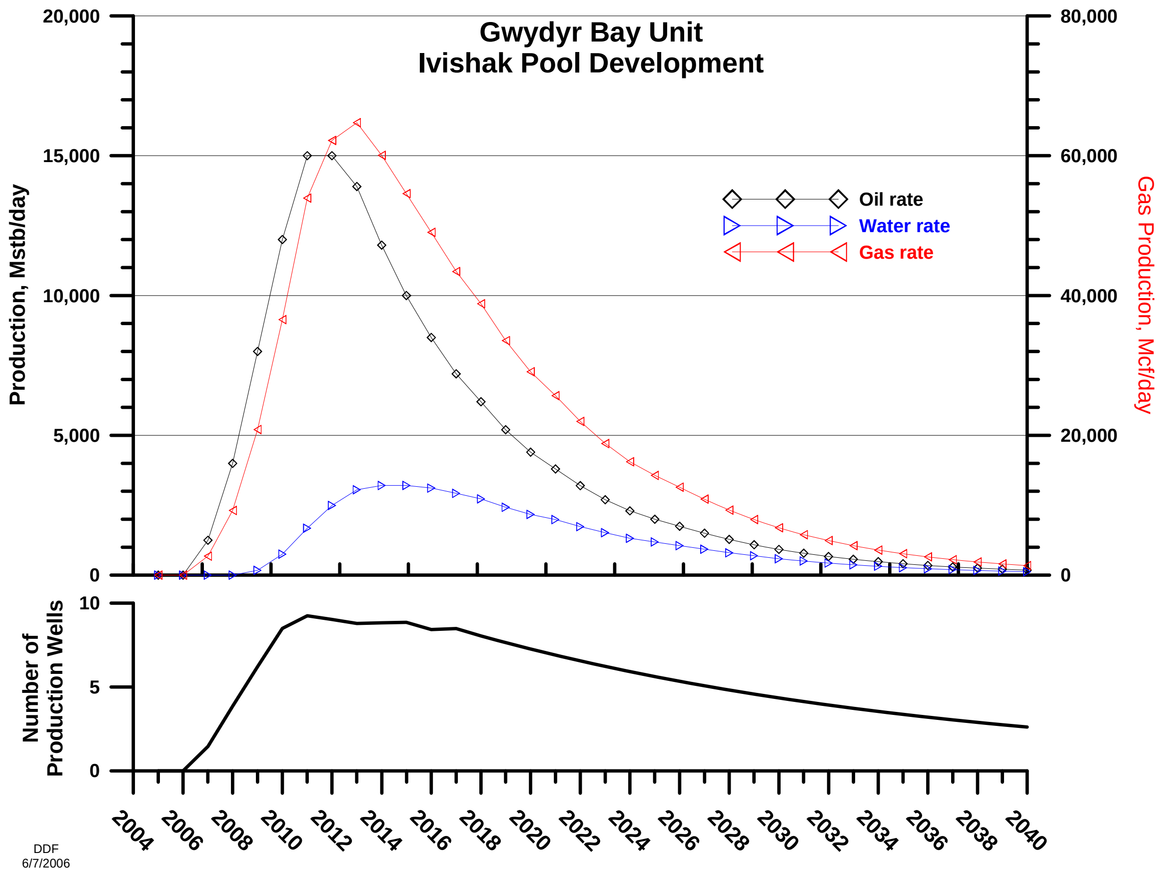


Figure 3.66. Gwydyr Bay Unit production forecasts

Table 3.95. Gwydyr Bay Unit--Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2021	2027	2032	2040
Future Gas forecast (MMCF)	44,694	50,443	52,473	52,923
Future water forecast (MB)	204,128	244,153	259,024	262,367
Oil and NGLs EUR (MB)	10,341	13,587	14,877	15,173
Total gas reinjected (Est.) (MMCF)	204,128	244,153	259,024	262,367

Table 3.96. Gwydyr Bay Unit–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$468,119	$468,119	$468,119	$468,119
Total operating costs	$485,138	$647,266	$750,039	$785,848
State royalty	$194,615	$352,654	$574,729	$719,115
State taxes – Severance	$32	$49	$74	$90
State taxes – Income	$679	$10,311	$32,666	$48,788
State taxes – Other	$43,114	$55,982	$58,233	$58,253
State Total (Royalty and Taxes)	**$238,440**	**$418,996**	**$665,702**	**$826,246**
Federal taxes	**$0**	**$109,252**	**$377,593**	**$557,666**
Industry net income	**-$94,665**	**$243,540**	**$737,457**	**$1,083,247**

3.4.14 Summary for Known Fields with Pending/Announced Development Plans

A summary of the known fields with pending or announced development plans are shown in Table 3.97. These fields will add an additional TRR of about 1.3 BBO to the TRR for the currently producing fields for a total of 5.9 BBO.

Table 3.97. ANS known fields with pending or announced development plans.

POOL/FIELD NAME	OOIP (MBO)	TUR (MBO)	Produced 12/31/2004 (MBO)	TRR (MBO)	Recovery Factor
KNOWN FIELDS WITH PENDING/ANNOUNCED DEVELOPMENT PLANS					
Kuparuk River Unit (KRU)					
Placer PA	110,000	36,620	0	36,620	0.333
West Sak Additional (Pad IE &IJ)	1,225,000	285,000	0	285,000	0.233
Colville River Unit (CRU)					
Fiord PA	150,000	53,940	0	53,940	0.360
Nanuq PA	150,000	43,920	0	43,920	0.293
Alpine West PA	150,000	53,630	0	53,630	0.358
Lookout Satellite	150,000	53,906	0	53,906	0.359
Spark Satellite	150,000	53,906	0	53,906	0.359
Prudhoe Bay Unit (PBU)					
Prudhoe Bay, Orion Phase II & III	978,000	228,970	0	228,970	0.234
Prudhoe Bay, Polaris Phase II & III	446,300	98,500	0	98,500	0.221
Oooguruk Unit (OU)	155,500	71,600	0	71,600	0.460
Nikaitchug Unit (NU)	485,700	175,200	0	175,200	0.361
Liberty Unit (LU)	271,000	125,000	0	125,000	0.461
Gwydyr Bay Unit (GBU)	150,000	53,870	0	53,870	0.359
Total–Fields with pending/announced development plans	**4,571,500**	**1,334,062**		**1,334,062**	**0.337**

The composite forecasts of estimated economic recoverable production for the known fields with pending or announced development plans are shown in Figure 3.67.

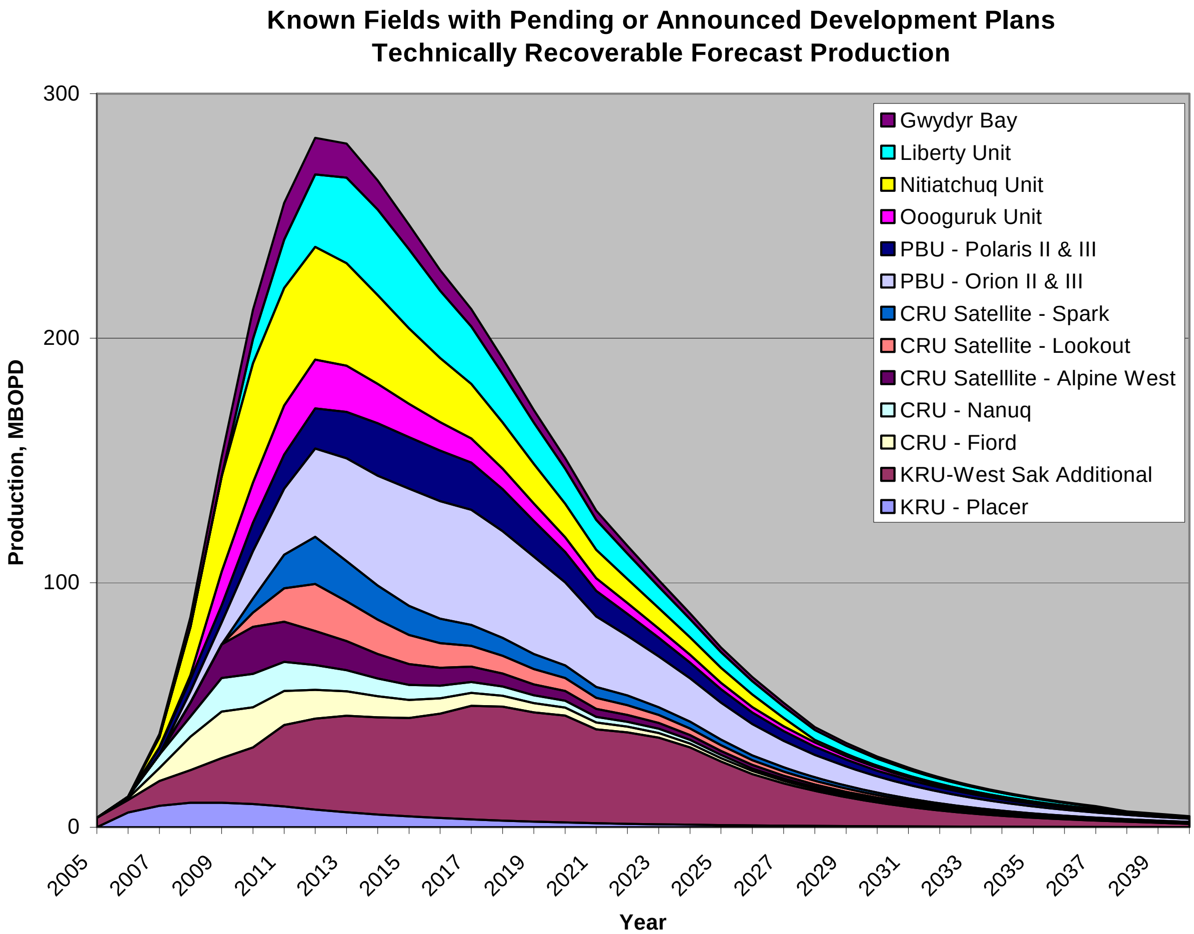


Figure 3.67. Technical production forecasts for known fields with announced or pending development plans.

Forecasts of the aggregated fields with announced or pending development plans future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table.3.98.

Table 3.98. Known fields with announced or pending development plans–Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Future Gas forecast (MMCF)	1,170,767	1,407,276	1,486,410	1,506,892
Future water forecast (MB)	1,059,761	1,979,714	2,359,518	2,450,395
Oil and NGLs EUR (MB)	1,080,733	1,241,599	1,294,714	1,307,317
Total gas reinjected (Est.) (MMCF)	805,891	961,148	1,014,685	1,028,430

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for aggregated fields with announced or pending development plans are shown for all prices tracks in Table 3.99.

Table 3.99. Known fields with announced or pending development plans - Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	8,927,234	9,126,955	9,168,889	9,168,889
Total operating costs	12,106,238	17,292,637	20,269,564	21,367,067
State royalty	3,080,561	5,711,904	9,359,116	11,737,868
State taxes – Severance	341,807	584,153	928,727	1,156,036
State taxes – Income	111,242	410,097	1,024,410	1,467,253
State taxes – Other	529,801	712,957	747,050	748,920
State Total (Royalty and Taxes)	**4,063,411**	**7,419,111**	**12,059,303**	**15,110,077**
Federal taxes	**612,581**	**4,213,798**	**11,403,741**	**16,325,667**
Industry net income	**619,662**	**8,901,627**	**22,569,916**	**32,094,095**

3.5 Known Fields with Near-Term Development Potential

There are several fields that are known but not developed. These are listed in Table 2.8 and described in Section 2.3.3 and 2.3.4. The fields that are anticipated to be developed in the near-term time from 2005 to 2015 are Sandpiper, Sambuca, Tuvaaq, Aturuq, and Sourdough. Additional fields in the Beaufort Sea, Kuvlum and Hammerhead, are likely to remain undeveloped until infrastructure is developed for the Point Thomson field, which moves them into the long term time frame of 2015 to 2050.

3.5.1 Sandpiper Prospect

The Sandpiper prospect is an accumulation in the Ivishak formation that was discovered in 1986 by Shell (Table 2.8) using a man-made gravel island. A unit was formed in 1992. It is located northwest of the NU in federal waters (Thomas et al., 1993). Reserves are believed to be about 150,000 MBO (AOGR, 2005).

Several leases in the Sandpiper area were acquired in a 2003 MMS lease sale (OGJ, 2003). No published information has been found regarding exploration and development activity in the former Sandpiper Unit area. It is assumed that potential development cannot occur before 2013. Development will include constructing a production and drilling pad north of a barrier island. It is assumed the pad will be positioned to allow long reach/horizontal wells to develop the accumulation and that produced fluids will be processed through an existing on-shore facility.

It is assumed both water and gas will be used for pressure maintenance and enhanced recovery. Future gas and water recovery forecasts are determined using the NU oil and water historical data. It is assumed gas not used in lease operations will be disposed of on-shore. The oil, gas, and water production forecasts are presented in Figure 3.68.

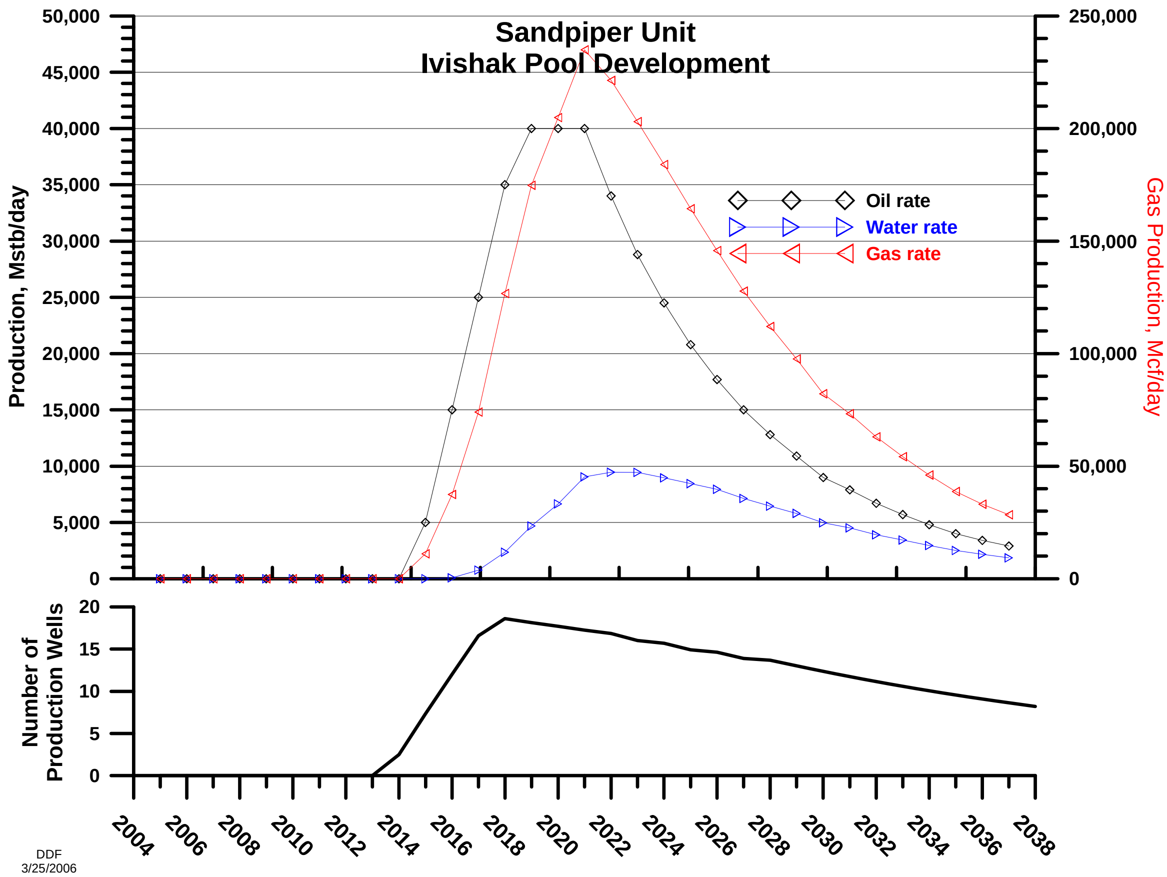


Figure 3.68. Sandpiper production forecasts.

Forecasts of Sandpiper pool future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.100.

Table 3.100. Sandpiper–Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2033	2038	2040	2040
Future Gas forecast (MMCF)	852,992	926,128	948,358	948,358
Future water forecast (MB)	37,191	41,921	43,399	43,399
Oil and NGLs EUR (MB)	141,657	149,249	151,502	151,502
Total gas reinjected (Est.) (MMCF)	716,513	777,948	796,621	796,621

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.101.

Table 3.101. Sandpiper–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$802,962	$802,962	$802,962	$802,962
Total operating costs	$1,829,490	$2,131,051	$2,278,776	$2,278,776

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
State royalty	$449,453	$768,049	$1,226,988	$1,522,539
State taxes – Severance	$68,247	$107,019	$165,175	$203,944
State taxes – Income	$20,372	$74,497	$164,109	$225,010
State taxes – Other	$35,363	$35,721	$35,828	$35,828
State Total (Royalty and Taxes)	**$573,435**	**$985,286**	**$1,592,100**	**$1,987,321**
Federal taxes	**$160,753**	**$818,213**	**$1,819,763**	**$2,496,039**
Industry net income	**$510,809**	**$1,689,919**	**$3,604,298**	**$4,897,198**

3.5.2 Sambuca Satellite

The Sambuca satellite is an accumulation in the Ivishak formation that was discovered in 1997 (Table 2.8). It is located within PBU and is adjacent to the Midnight Sun satellite. Reserves are thought to be about 19,000 MBO (Table 2.8).

It is assumed the wells for this accumulation will be drilled from the existing well pad used by the Midnight Sun satellite and that development will begin in 2008 and will require six total wells drilled over three years. Development will include the associated surface equipment. Production will be transported to the nearest PBU processing facility. Water injection will be used for pressure maintenance and secondary recovery.

The production forecast to recover the indicated ultimate reserves is made using mid-2008 as production start-up; a 2-yr period to reach a peak rate of 7.0 MBOPD, held for 1 yr; and then declined at 15%/yr to an assumed abandonment rate of about 0.03 MBOPD. This results in an estimated TUR of 20,700 MBO.

Until data become available for this satellite, gas and water production forecasts are determined using the historical production data from the Midnight Sun accumulation. The oil, gas, and water production forecasts are presented in Figure 3.69.

Forecasts of Sambuca pool future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.102.

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project is shown for all prices tracks in Table 3.103.

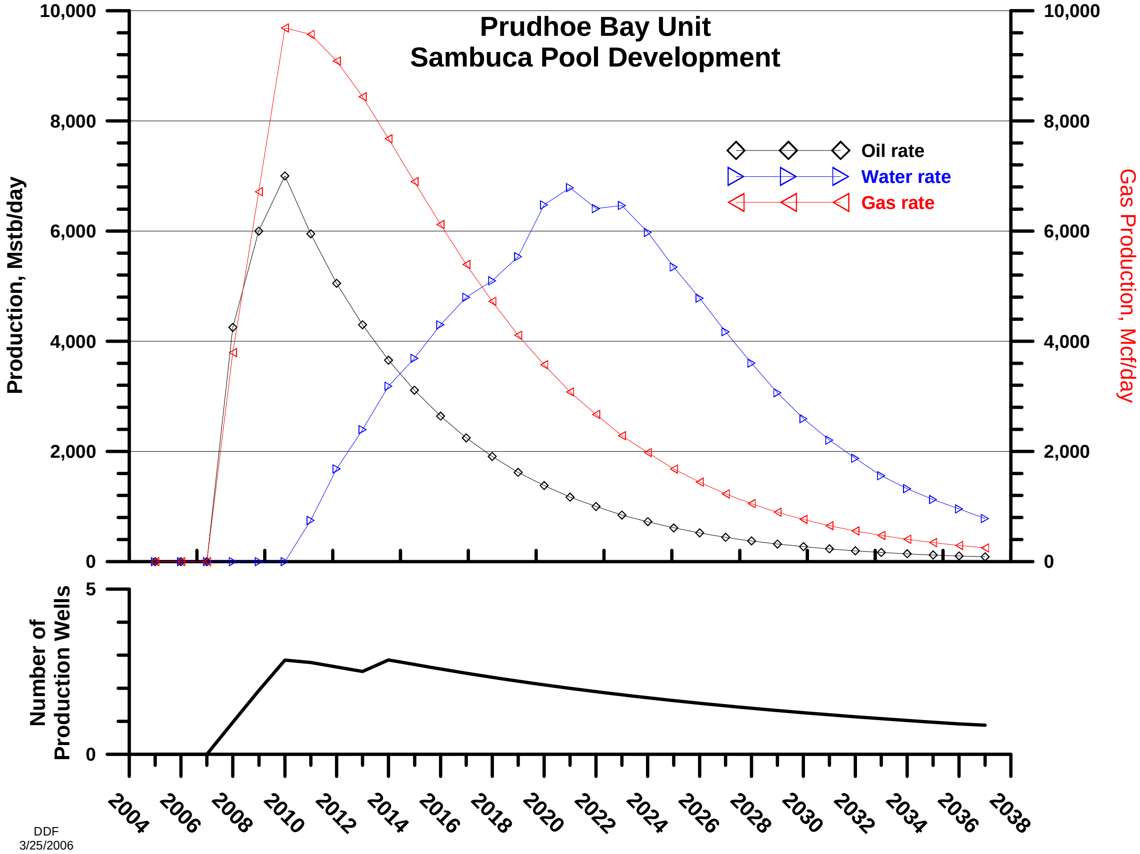


Figure 3.69. Sambuca production forecasts.

Table 3.102. Sambuca–Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2024	2028	2033	2035
Future Gas forecast (MMCF)	34,213	36,520	37,950	38,270
Future water forecast (MB)	21,493	29,067	33,919	34,966
Oil and NGLs EUR (MB)	19,026	19,863	20,371	20,483
Total gas reinjected (Est.) (MMCF)	28,739	30,677	31,878	32,147

Table 3.103. Sambuca–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$57,247	$57,247	$57,247	$57,247
Total operating costs	$134,794	$163,545	$192,567	$202,651
State royalty	$52,733	$86,581	$137,766	$171,273
State taxes – Severance	$25,787	$40,289	$62,102	$76,517
State taxes – Income	$5,221	$10,900	$20,094	$26,387
State taxes – Other	$3,967	$4,410	$4,504	$4,509
State Total (Royalty and Taxes)	**$87,708**	**$142,180**	**$224,466**	**$278,686**
Federal taxes	**$57,613**	**$121,445**	**$223,040**	**$292,342**
Industry net income	**$111,761**	**$235,746**	**$432,958**	**$567,487**

3.5.3 Tuvaaq Unit

The Tuvaaq Unit is an accumulation in the Schrader Bluff formation discovered in 2005 (Table 2.8). It is located off-shore in the Beaufort Sea between the Nikaitchug and Oooguruk Units (PN, 2005i). Because this unit is still in the exploratory phase, there are no reports of OOIP or recovery volumes. It is expected this accumulation will be large enough for development. Initial development is assumed to begin in 2010 and first production in 2013.

It is assumed this accumulation will be developed using a single drilling/production pad located on an off-shore gravel island or on an existing barrier island. A total of 30 wells are used in the forecast for this project. Subsea lines will be used to transport total fluid production to shore, and injection fluids back to the production pad. It is assumed water injection will be used for pressure maintenance and secondary recovery and that production will be processed at the KRU IPA facilities.

Recoverable reserves are assumed to be similar to those estimated for the offsetting units. The estimate for this accumulation is determined using a peak rate of 25 MBOPD for 1 yr., a decline rate of 15%/yr, and an abandonment rate of 0.25 MBOPD. This results in a TUR of about 74,500 MBO.

Gas and water production forecasts are determined using MPU Schrader Bluff historical production data. It is assumed all produced gas is used from lease operations. The oil, gas, and water production forecasts are presented in Figure 3.70.

Forecasts of Tuvaaq pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.104.

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.105.

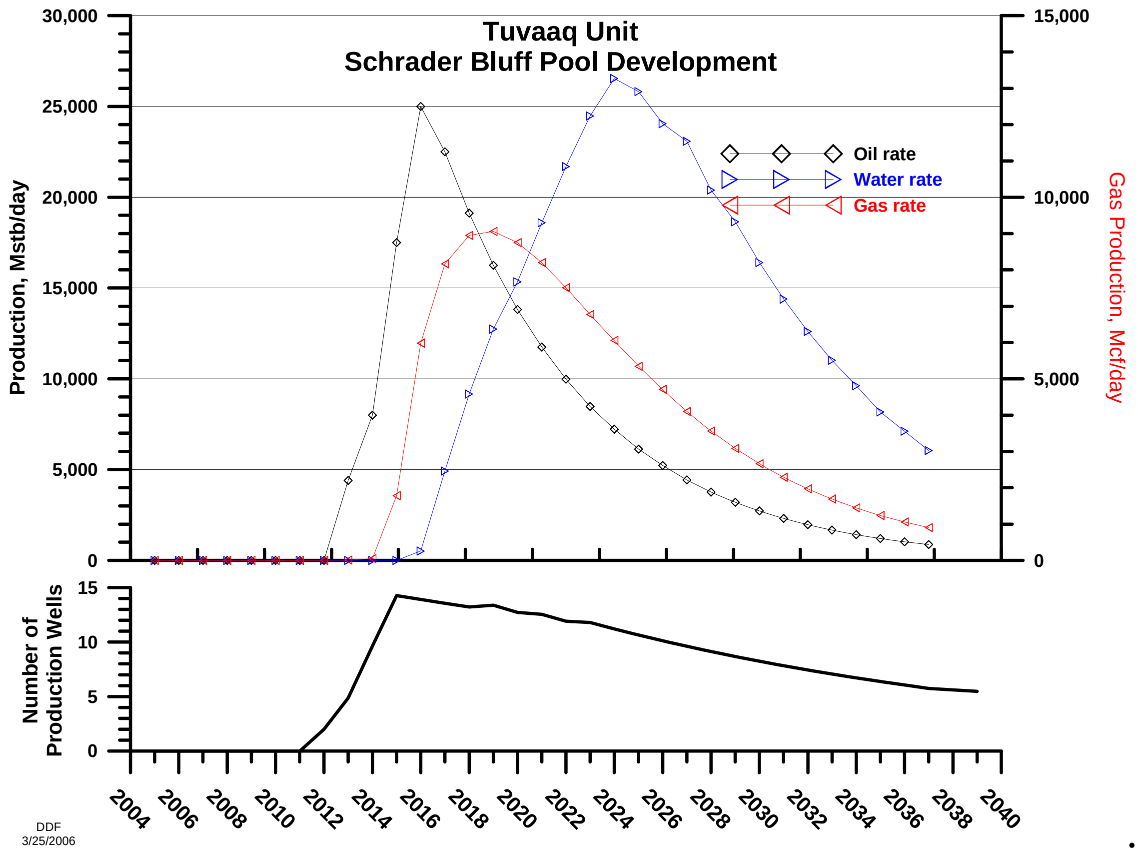


Figure 3.70. Tuvaaq Unit production forecasts.

Table 3.104. Tuvaaq–Forecasts of future and ultimate economical recoveries for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2016	2032	2040	2040
Future Gas forecast (MMCF)	308	51,424	56,020	56,020
Future water forecast (MB)	0	103,908	129,126	129,126
Oil and NGLs EUR (MB)	1,606	70,003	73,675	73,675
Total gas reinjected (Est.) (MMCF)	259	43,197	47,057	47,057

Table 3.105. Tuvaaq–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	**$25/bbl**	**$35/bbl**	**$50/bbl**	**$60/bbl**
Total investments	$666,225	$990,106	$990,106	$990,106
Total operating costs	$34,696	$1,276,523	$1,472,713	$1,472,713
State royalty	$5,377	$434,512	$735,732	$915,713
State taxes – Severance	$0	$2,993	$4,660	$5,772
State taxes – Income	$0	$3,151	$36,556	$63,445
State taxes – Other	$8,734	$75,642	$75,807	$75,807
State Total (Royalty and Taxes)	**$14,111**	**$516,298**	**$852,755**	**$1,060,737**
Federal taxes	**$0**	**$0**	**$326,617**	**$638,439**
Industry net income	**-$70,039**	**$21,756**	**$972,974**	**$1,532,827**

3.5.4 Ataruq Unit

The Ataruq Unit, also known as the Two Bits Prospect, is located on the west edge of KRU and north of the Palm development (PN, 2005i). Although no information has been released in the two wells drilled in this unit, it is assumed there is an accumulation similar to the Placer satellite Kuparuk River Sand formation.

With exploration efforts just beginning, it is assumed that initial development will begin in 2007 and that first production will occur in 2009 and will be processed by stand-alone facilities (PN, 2005j). Although there is other information published (PN 2005h), it is assumed that development will require 18 wells, both producers and injectors, and that the wells will be drilled from the improved West Sak gravel pad (PN, 2004j). The following factors are used to forecast TUR and the annual oil production volumes: a 2-yr period for production to reach a peak rate of 11 MBOPD, a 2-yr period of peak production, and a 15%/yr decline rate to an abandonment rate of about 0.1 MBOPD. This results in a TUR of about 37,000 MBO.

The gas and water forecast are made using the production history data from the Tarn satellite. It is assumed that all gas produced is used for lease operations or for secondary recovery processes. The oil, gas, and water production forecasts are presented in Figure 3.71.

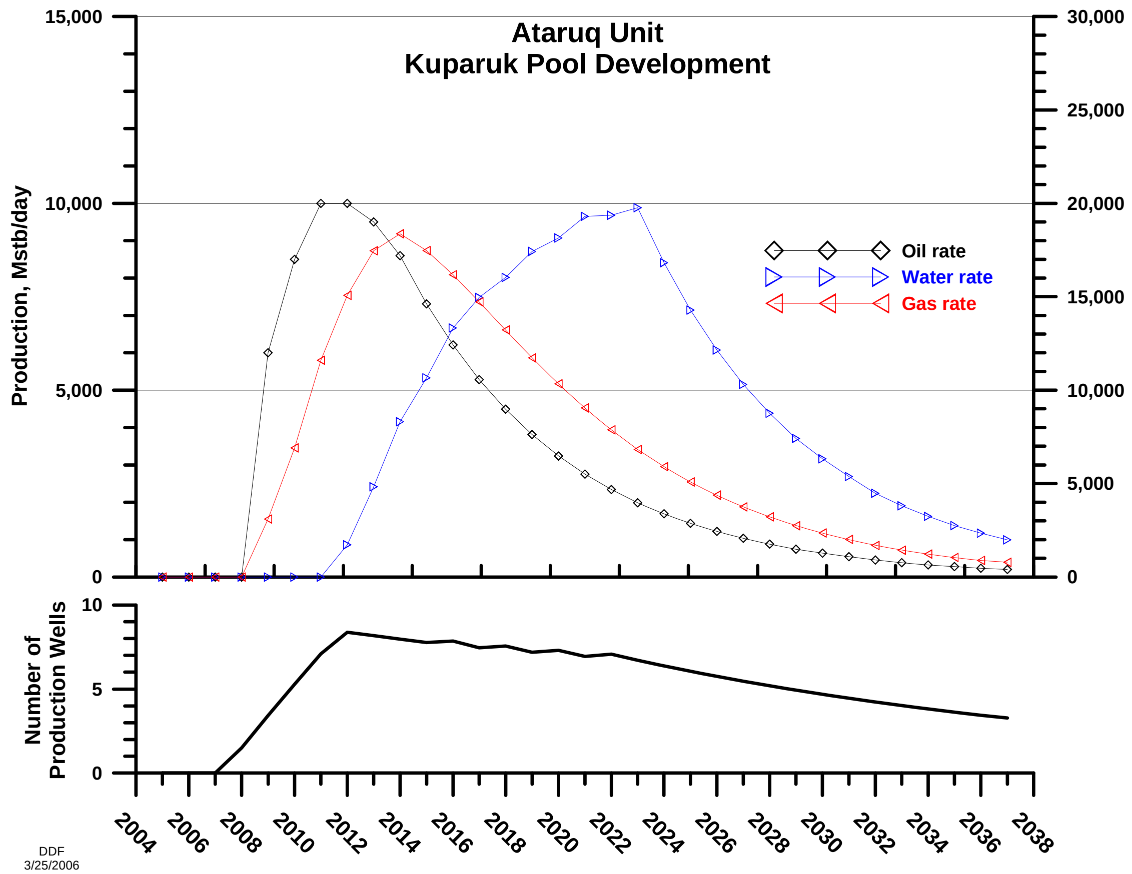


Figure 3.71. Ataruq Unit production forecasts.

Forecasts of Ataruq Unit future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.106.

Table 3.106. Ataruq–Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2022	2025	2029	2031
Future Gas forecast (MMCF)	59,614	67,042	72,963	74,798
Future water forecast (MB)	22,256	32,543	43,016	46,672
Oil and NGLs EUR (MB)	31,279	33,474	35,142	35,646
Total gas reinjected (Est.) (MMCF)	50,076	56,315	61,289	62,830

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.107.

Table 3.107. Ataruq–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$309,456	$323,284	$323,284	$323,284
Total operating costs	$312,019	$391,873	$484,013	$525,195
State royalty	$95,057	$156,061	$250,891	$313,575
State taxes – Severance	$0	$0	$0	$0
State taxes – Income	$3,827	$12,681	$28,586	$40,215
State taxes – Other	$31,266	$36,264	$39,911	$40,208
State Total (Royalty and Taxes)	**$130,150**	**$205,006**	**$319,388**	**$393,998**
Federal taxes	**$30,051**	**$138,598**	**$322,773**	**$453,718**
Industry net income	**$58,912**	**$272,210**	**$635,558**	**$889,749**

3.5.5 Sourdough Field

The Sourdough Field is an oil accumulation in an unspecified formation that was discovered in 1994 by BP and Chevron. It is located south of the Point Thomson Unit (PTU) and adjacent to ANWR. Three exploration wells have been drilled with a successful test about one mile from the ANWR boundary. The accumulation is about 50 miles east of PBU and 35 miles from the Badami Pipeline, the nearest oil pipeline (OGJ, 1998). The 35-mile sales line would encounter five major river crossings and be in the coastal plain (Thomas et al., 1996).

It is estimated that the Sourdough accumulation contains 100 MMBO of recoverable oil reserves (OGJ, 1998) and this volume is used to estimate the economics of development. It is assumed both gas and water injection will be used for pressure maintenance and secondary recovery, and that a total of 30 wells, injectors and producers are required to develop this accumulation.

The future oil recovery forecast is prepared using a production starting date of 2015, a peak oil rate of 30 MBOPD, peak rate maintained for 2 yrs, an abandonment rate of about 0.2 MBOPD, and a production decline rate of 15%/yr. This results in a TUR of 104,400 MBO. The gas and water production forecasts are made using the historical gas and water production data from the Point McIntyre PA. It is assumed all gas will be used in lease operations and in secondary recovery processes. The oil, gas, and water production forecasts are presented in Figure 3.72.

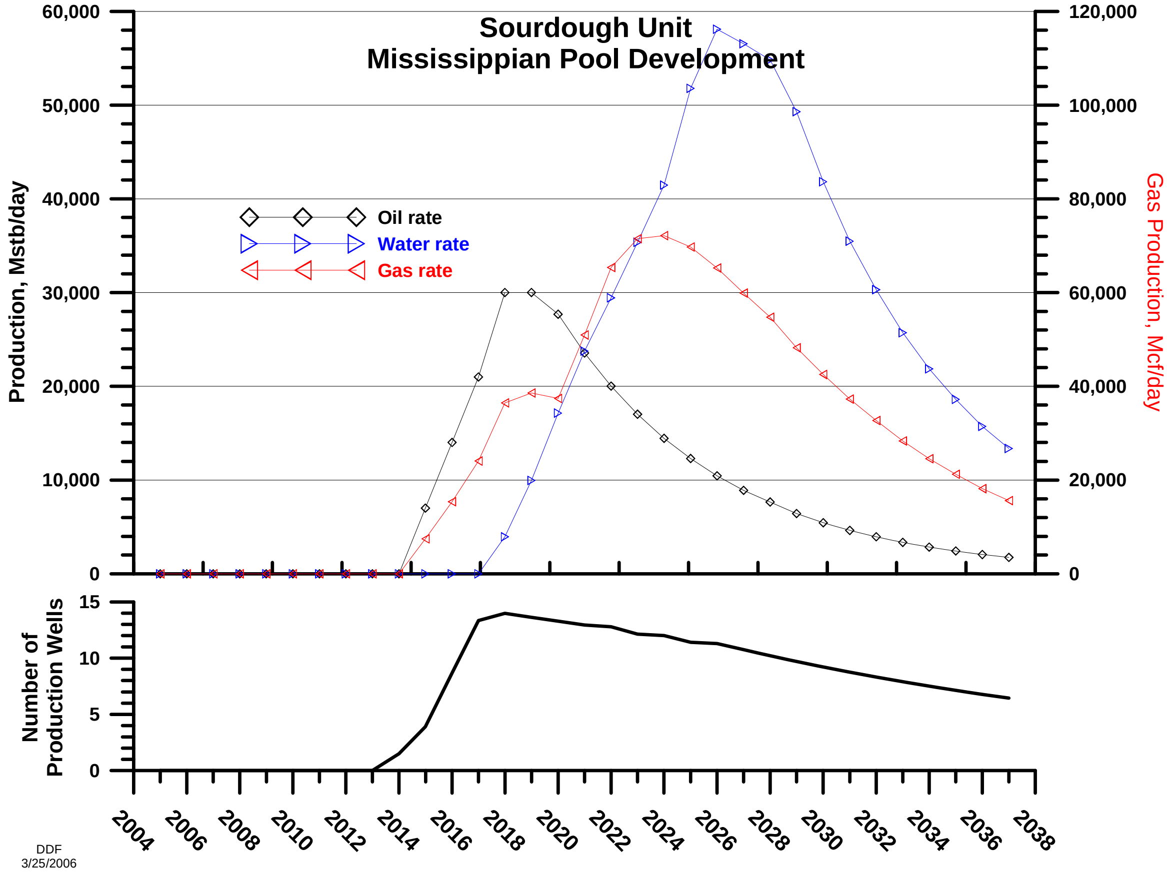


Figure 3.72. Sourdough production forecasts.

Forecasts of Sourdough field future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.108.

Table 3.108. Sourdough–Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $)

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2027	2032	2038	2038
Future Gas forecast (MMCF)	202,280	290,842	342,149	342,149
Future water forecast (MB)	102,340	192,429	245,645	245,645
Oil and NGLs EUR (MB)	83,038	95,101	101,075	101,075
Total gas reinjected (Est.) (MMCF)	169,916	244,307	287,405	287,405

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.109.

Table 3.109. Sourdough–Forecasts of economic results for ANS West Coast prices (then current $)

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$1,056,872	$1,056,872	$1,056,872	$1,056,872
Total operating costs	$1,087,319	$1,526,852	$1,837,677	$1,837,677
State royalty	$253,437	$474,080	$801,612	$994,543
State taxes – Severance	$16,542	$25,934	$40,024	$49,415
State taxes – Income	$0	$24,396	$80,593	$120,829
State taxes – Other	$86,842	$93,297	$93,580	$93,580
State Total (Royalty and Taxes)	**$356,821**	**$617,707**	**$1,015,809**	**$1,258,367**
Federal taxes	**$0**	**$202,425**	**$895,567**	**$1,347,327**
Industry net income	**-$170,652**	**$677,342**	**$1,874,973**	**$2,716,391**

This development appears to be marginally economic at $25/bbl for the economic parameters as a stand-alone development including fluid processing facilities and an oil sales pipeline. This field could possibly be developed in conjunction with the PTU and improve the economics.

3.5.6 Summary of Known Fields with Near-Term Development Potential

A summary of the known fields with near-term development potential are shown in Table 3.110. These fields will add an additional TRR of about 0.4 BBO to the TRR for the currently producing fields and fields with announced or pending development for a total of 6.3 BBO.

Table 3.110. ANS known fields with short-term develop potential.

POOL/FIELD NAME	OOIP (MBO)	TUR (MBO)	Produced 12/31/2004 (MBO)	TRR (MBO)	Recovery Factor
KNOWN FIELDS WITH DEVELOPMENT POTENTIAL					
Sandpiper	430,000	151,502	0	151,502	0.352
Sambuca	57,500	20,700	0	20,700	0.360
Tuvaaq	200,000	74,500	0	74,500	0.373
Ataruq	103,000	37,000	0	37,000	0.359
Sourdough	290,000	104,400	0	104,400	0.360
Total – Fields with Short-Term Development Potential	**1,074,570**	**388,102**	**0**	**388,102**	**0.361**

The composite forecast of estimated economic recoverable production for the known fields with short-term development potential are shown in Figure 3.73.

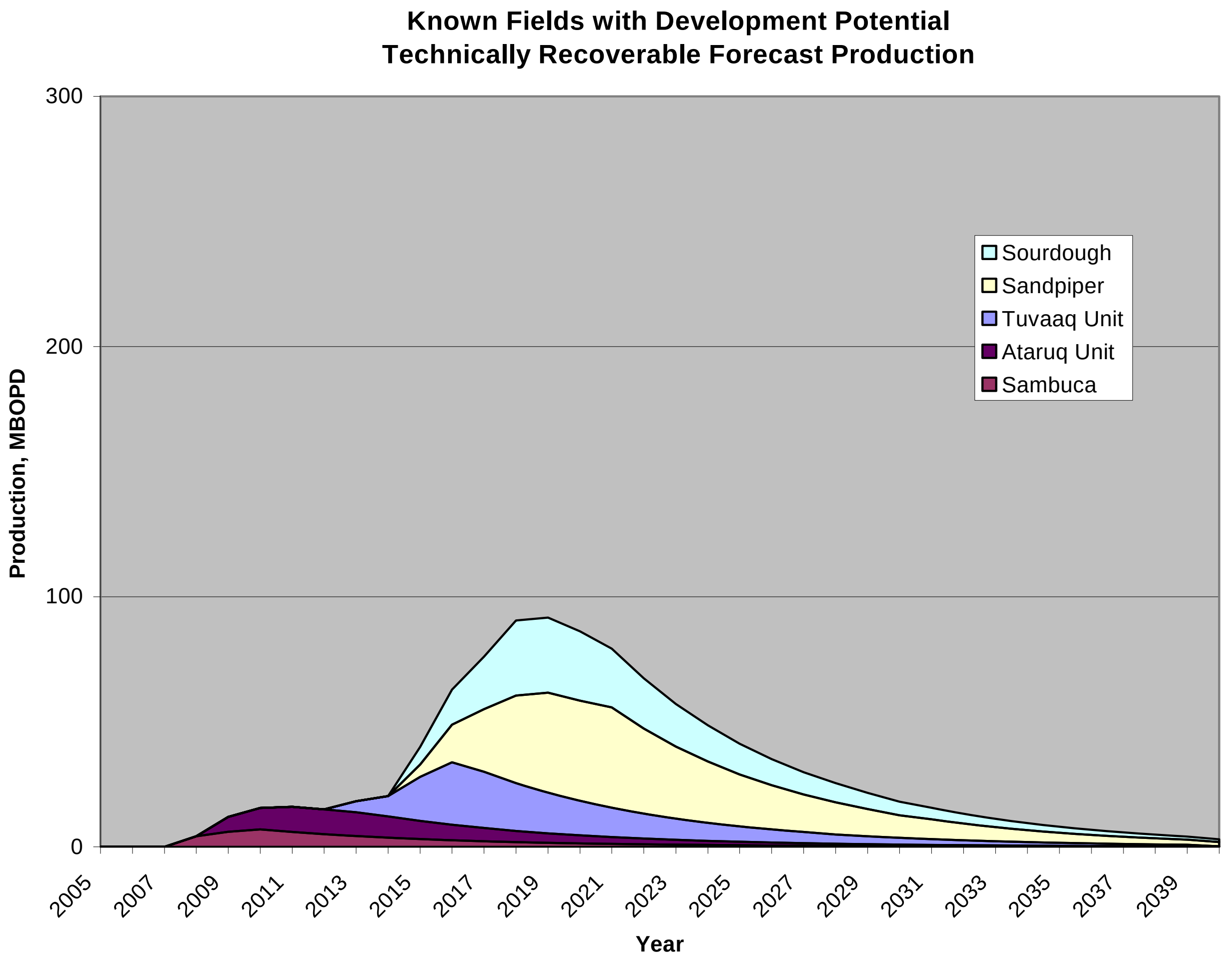


Figure 3.73. Technical production forecasts for known fields with near-term development potential.

Forecasts of the aggregated fields with development potential ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table.3.111.

Table 3.111. Known fields with near-term development potential – Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Future Gas forecast (MMCF)	1,149,407	1,371,956	1,457,440	1,459,595
Future water forecast (MB)	183,280	399,869	495,105	499,807
Oil and NGLs EUR (MB)	276,604	367,690	381,765	382,381
Total gas reinjected (Est.) (MMCF)	965,502	1,152,443	1,224,250	1,226,060

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for aggregated fields with short-term development potential are shown for all prices tracks in Table 3.112.

Table 3.112. Known fields with near-term development potential – Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	2,892,762	3,230,471	3,230,471	3,230,471
Total operating costs	3,398,318	5,489,844	6,265,746	6,317,012
State royalty	856,057	1,919,283	3,152,989	3,917,643
State taxes – Severance	110,576	176,235	271,961	335,648
State taxes – Income	29,420	125,625	329,938	475,886
State taxes – Other	166,172	245,334	249,630	249,932
State Total (Royalty and Taxes)	**1,162,225**	**2,466,477**	**4,004,518**	**4,979,109**
Federal taxes	**248,417**	**1,280,681**	**3,587,760**	**5,227,865**
Industry net income	**440,791**	**2,896,973**	**7,520,761**	**10,603,652**

3.6 Summary and Composite Curve w/o Major Gas Sales

The TRR and production forecasts for the currently producing fields described in Section 3.3 are the most accurate forecasts because of existing production history. The next category, described in Section 3.4, is the known fields with pending or announced development plans that provide information in the public record that assists in developing forecasts, but these estimates are more speculative than those with production history. The most speculative projects are those described in Section 3.5 that have been discovered but for which there are no announced or pending development plans. The data for those fields is sparse. The composite results for OOIP, TUR, TRR, and production through December 31, 2004 for each pool category are summarized in Table 3.113. The TRR estimates for these fields total 6.413 BBO.

Table 3.113. ANS fields–Currently producing fields, fields with development plans, and fields with near-term development potential.

POOL/FIELD NAME	OOIP (MBO)	TUR (MBO)	Produced 12/31/2004 (MBO)	TRR (MBO)	Ultimate Recovery Factor
CURRENTLY PRODUCING FIELDS					
Prudhoe Bay Unit (PBU)					
Initial Participating Area (IPA)	25,000,000	13,483,252	11,143,715	2,339,537	0.539
Aurora Participating Area (PA)	100,000	45,810	11,397	34,413	0.458
Borealis PA	263,000	105,189	30,849	74,340	0.400
Midnight Sun PA	60,000	21,048	11,343	9,705	0.351
Orion PA Phase I	92,000	21,735	2,310	19,690	0.236
Polaris PA	303,700	68,440	3,539	64,901	0.225
Lisburne PA	3,000,000	194,619	153,621	40,998	0.065
Niakuk PA	200,000	99,323	81,223	18,100	0.497
North Prudhoe PA	12,000	2,070	2,070	0	0.173
West Beach PA	15,000	3,591	3,591	0	0.239
Point McIntyre PA	800,000	506,413	384,103	122,310	0.633
Duck Island Unit (DIU)					
Endicott PA	1,059,000	533,952	447,612	86,340	0.504
Eider PA	13,000	2,687	2,687	0	0.207

POOL/FIELD NAME	OOIP (MBO)	TUR (MBO)	Produced 12/31/2004 (MBO)	TRR (MBO)	Ultimate Recovery Factor
Sag Delta North PA	16,000	8,059	8,059	0	0.504
Northstar Unit (NU)					
Northstar PA	284,700	235,500	67,215	168,260	0.591
Badami Unit (BU)	300,000	4,347	4,347	0	0.014
Kuparuk River Unit (KRU)					
Kuparuk River IPA	5,690,000	2,763,120	1,974,540	788,580	0.486
Meltwater PA	132,000	42,100	7,658	34,442	0.319
Tabasco PA	99,500	21,570	9,735	11,835	0.217
Tarn PA	255,000	125,313	64,603	60,710	0.491
West Sak PA	275,000	62,365	15,631	46,734	0.227
Milne Point Unit (MPU)					
Kuparuk River IPA	525,000	264,600	180,286	84,314	0.504
Sag River PA	62,000	1,589	1,589	0	0.026
Schrader Bluff PA	1,333,400	321,326	38,126	283,200	0.241
Colville River Unit (CRU)					
Alpine Oil	900,000	539,900	137,639	402,261	0.600
Total – currently producing fields	**40,790,300**	**19,477,918**	**14,787,488**	**4,690,670**	**0.478**
KNOWN FIELDS WITH PENDING/ANNOUNCED DEVELOPMENT PLANS					
Kuparuk River Unit (KRU)					
Placer PA	110,000	36,620	0	36,620	0.333
West Sak Additional (Pad IE &IJ)	1,225,000	285,000	0	285,000	0.233
Colville River Unit (CRU)					
Fiord PA	150,000	53,940	0	53,940	0.360
Nanuq PA	150,000	43,920	0	43,920	0.293
Alpine West PA	150,000	53,630	0	53,630	0.358
Lookout Satellite	150,000	53,906	0	53,906	0.359
Spark Satellite	150,000	53,906	0	53,906	0.359
Prudhoe Bay Unit (PBU)					
Prudhoe Bay, Orion Phase II & III	978,000	228,970	0	228,970	0.234
Prudhoe Bay, Polaris Phase II & III	446,300	98,500	0	98,500	0.221
Oooguruk Unit (OU)	155,500	71,600	0	71,600	0.460
Nikaitchug Unit (NU)	485,700	175,200	0	175,200	0.361
Liberty Unit (LU)	271,000	125,000	0	125,000	0.461
Gwydyr Bay Unit (GBU)	150,000	53,870	0	53,870	0.359
Total – Fields with pending/announced development plans	**4,571,500**	**1,334,062**		**1,334,062**	**0.337**
KNOWN FIELDS WITH DEVELOPMENT POTENTIAL					
Sandpiper	430,000	151,502	0	151,502	0.352
Sambuca	57,500	20,700	0	20,700	0.360
Tuvaaq	200,000	74,500	0	74,500	0.373

POOL/FIELD NAME	OOIP (MBO)	TUR (MBO)	Produced 12/31/2004 (MBO)	TRR (MBO)	Ultimate Recovery Factor
Ataruq	103,000	37,000	0	37,000	0.359
Sourdough	290,000	104,400	0	104,400	0.360
Point Thomson was not analyzed in the No-Major-Gas Sales case. The estimated technically recoverable oil is 50,000 MBO and 350,000 MB condensate. See Table S.14 for gas volumes.					
Total – Fields with Development potential	**1,074,570**	**388,102**	**0**	**388,102**	**0.361**
Total	**46,442,300**	**21,200,080**	**14,787,488**	**6,412,834**	**0.456**

Historical oil production and future technically recoverable oil production forecasts for all the pools and fields listed in Table 3.113 are shown in Figure 3.74.

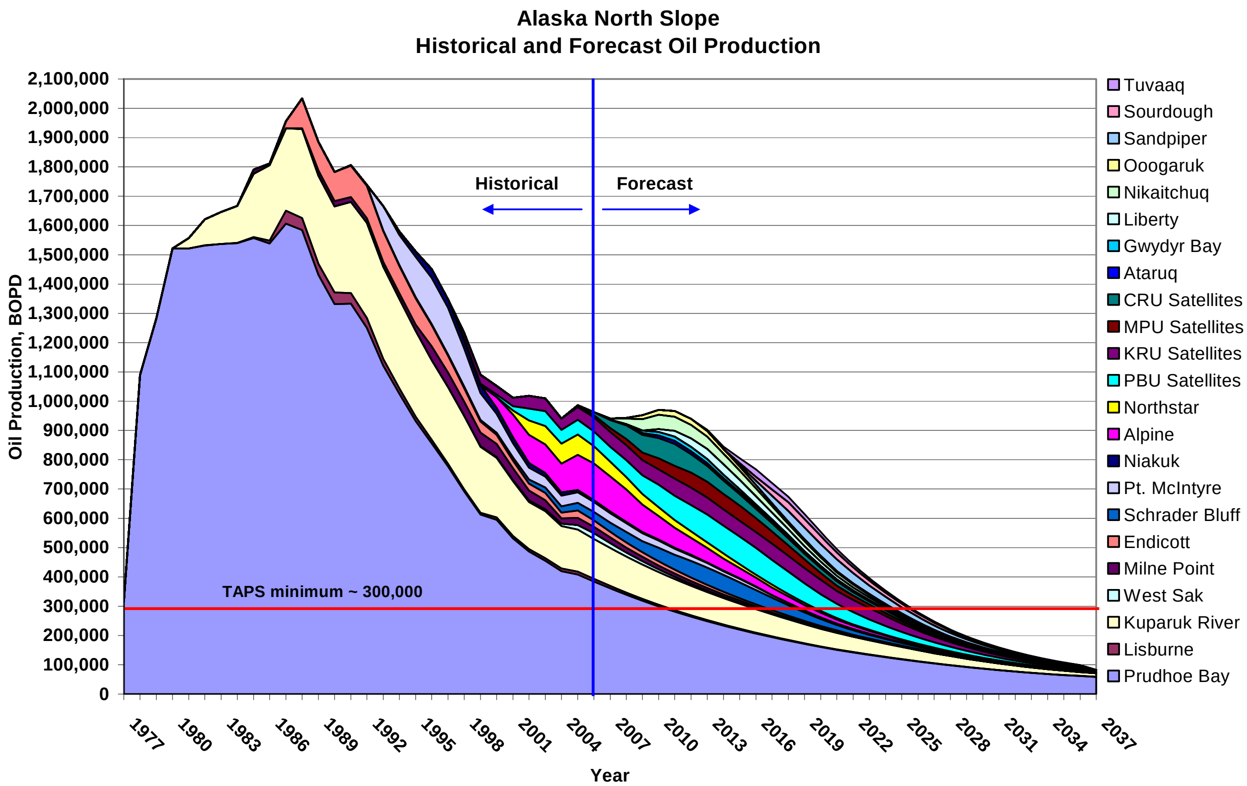


Figure 3.74. ANS composite forecasts of technically recoverable oil without Major Gas Sales.

Unless additional fields are discovered and developed, the minimum TAPS volume of about 300,000 MBOPD could occur in 2025. Any technical and economic reserves remaining at that time, which could be as much at 1 BBO, could be produced but could not be transported through TAPS. New discoveries and/or reserves growth, which were discussed in Section 2.5.2 and shown in Table 2.33, are required to extend the life of the ANS oil production. The long lead times of 7 to 10 yrs or greater required for frontier areas in the arctic means that exploration and development needs to continue or accelerate to maintain the future of the ANS oil production (EIA, 2002; EIA 2004; Section 2.4.1). As has been described in Section 2, the construction of an AGP is needed to accelerate ANS exploration. Opening of the 1002 Area of

ANWR, which is a small area relative to NPRA and the OCS areas, could also increase the likelihood of major oil discoveries and rapid development.

The aggregated revenues to all the stakeholders, the state and federal governments and industry, for all the pools and fields listed in Table 3.113 are shown in Table 3.114 for the four ANS West Coast oil prices.

Table 3.114. ANS aggregated economic results without Major Gas Sales: Currently producing fields, fields with pending or announced development plans, and fields with near-term development potential (ANS West Coast prices, then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	14,050,924	14,748,936	14,893,750	14,911,643
Total operating costs	64,581,995	85,969,512	93,211,618	95,879,755
State royalty	14,371,505	26,451,105	42,112,067	52,418,264
State taxes – Severance	4,751,757	7,664,591	11,702,950	14,391,161
State taxes – Income	568,146	2,111,428	4,914,352	6,849,529
State taxes – Other	3,528,477	4,054,326	4,284,509	4,336,163
State Total (Royalty and Taxes)	**23,163,009**	**40,203,961**	**62,924,068**	**77,902,472**
Federal taxes	**6,017,249**	**24,063,430**	**55,419,939**	**76,804,266**
Industry net income	**10,945,963**	**47,878,679**	**108,927,427**	**150,567,019**

Figure 3.75 shows the results for state, federal, and industry revenue shares at the four ANS West Coast oil prices (2005$) as percentage distributions for the aggregated results shown in Table 3.114.[29] The industry share of revenues increases from 27% to 47% as the oil prices increases from $25/bbl to $60/bbl. Concurrently, the state share decreases as a percent of total revenue from 59% to 25% and the federal take increases from 15% to 24%. The column on the right shows the state total revenue share breakdown between royalty and taxes. This split will change when the new Petroleum Profits Tax law passed by the Alaska legislature on August 11, 2006 is implemented.

[29] These results are based on the Economic Limit Factor (ELF) Alaska petroleum tax law. The Petroleum Profits Tax (PPT) enacted by the state of Alaska in August 2006 will change the relative revenue shares and will increase the state share as oil prices increase.

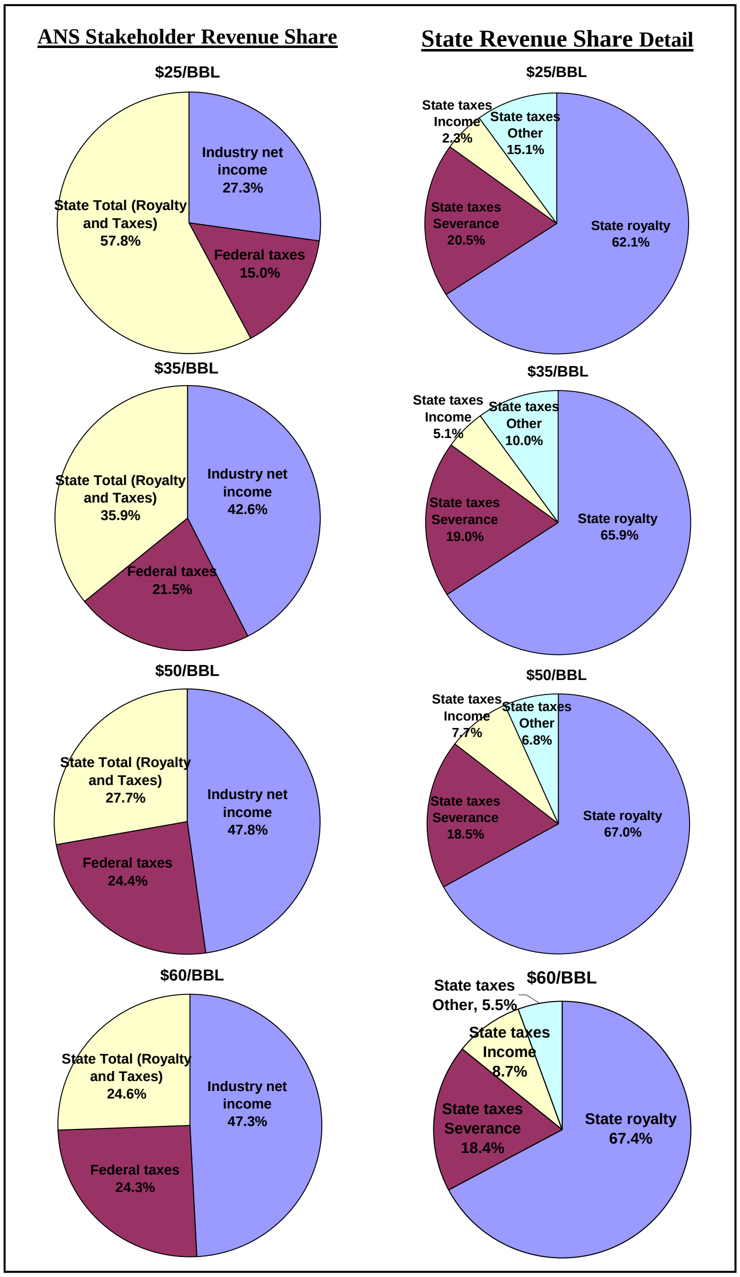


Figure 3.75. ANS total economic results for industry, state, and federal stakeholders without major gas sales case (ANS West Coast Prices, 2005$).

3.6.1 Sensitivity to Discount Rate

The analysis results presented was conducted at a discount rate of 10%. A series of runs was made to investigate sensitivity of the cumulative PW of the total cash flow (Cum PW) of the project to the discount rate. Three additional discount rates were used to investigate this sensitivity, 15%, 20%, and 30%. The pro forma reports generated in the economic analyses include the Cum PW. The results of the sensitivity analysis are shown in Tables 3.115 through 3.118.

Table 3.115. Cum PW (M$) at a discount rate of 10%.

Pool	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Colville River, Alpine Oil	$1,738,979	$3,089,284	$5,136,916	$6,506,488
Endicott, Endicott Oil	($6,966)	$134,677	$513,650	$795,352
Kuparuk River, Kuparuk River Oil	($25,360)	$1,526,578	$3,866,207	$5,426,052
Kuparuk River, West Sak Oil	$4,281	$101,903	$327,075	$496,912
Kuparuk River, Meltwater Oil	$113,751	$225,636	$414,900	$542,932
Kuparuk River, Tabasco Oil	$55,689	$101,821	$171,045	$217,255
Kuparuk River, Tarn Oil	$228,616	$447,101	$796,460	$1,035,288
Milne Point, Kuparuk River Oil	($3,206)	$81,579	$392,853	$652,756
Milne Point, Schrader Bluff Oil	$13,553	$60,330	$204,729	$340,872
Milne Point, Schrader Bluff Oil, E - pad	($224,149)	$27,818	$319,015	$515,368
Milne Point, Schrader Bluff Oil, S - pad	($239,175)	$56,904	$416,807	$664,928
Milne Point, Schrader Bluff Oil, new pad	($246,986)	($28,769)	$221,264	$391,188
Northstar, Northstar Oil	$878,350	$1,453,153	$2,317,700	$2,894,527
Prudhoe Bay, Aurora Oil	$87,942	$190,306	$352,895	$462,508
Prudhoe Bay, Borealis Oil	$191,886	$420,009	$787,568	$1,037,004
Prudhoe Bay, Lisburne Oil	$11,111	$111,702	$287,209	$407,821
Prudhoe Bay, Niakuk Oil	$1,299	$39,927	$118,866	$176,431
Prudhoe Bay, Prudhoe Oil	$3,140,615	$8,878,018	$17,547,339	$23,326,888
Prudhoe Bay, Polaris	$53,743	$214,285	$475,361	$651,168
Prudhoe Bay, Orion I, Schrader Bluff Oil	$59,837	$125,991	$229,583	$299,555
Prudhoe Bay, Midnight Sun Oil	$25,842	$57,262	$107,033	$140,720
Prudhoe Bay, Point McIntyre Oil	$249,032	$623,083	$1,222,668	$1,629,021
Kuparuk River, Placer Pool Oil	$73,401	$190,659	$371,182	$492,348
Kuparuk River, West Sak Add. (IE &IJ)	($153,526)	$398,159	$1,261,580	$1,843,037
Colville River, Fiord	$103,559	$261,942	$507,476	$672,089
Colville River, Nanuq	$56,274	$182,322	$379,065	$511,217
Colville River, Alpine West	$65,974	$217,398	$448,364	$603,615
Colville River, Lookout	$75,349	$205,607	$406,623	$541,602
Colville River, Spark	$82,969	$182,844	$346,054	$455,735
Prudhoe Bay, Orion Phase II & III	($31,044)	$428,856	$1,148,470	$1,636,777
Prudhoe Bay, Polaris Phase II & III	($33,509)	$179,047	$509,611	$733,789
Oooguruk	($43,458)	$203,999	$484,770	$684,539
Nikaitchug	($558,614)	$13,963	$757,215	$1,250,937
Liberty	$80,412	$342,704	$769,065	$1,062,721
Gwydyr Bay	($138,073)	$14,670	$211,829	$345,590
Sandpiper	$81,390	$311,221	$662,830	$896,556
Sambuca	$47,500	$97,249	$173,308	$224,283
Tuvaaq	$166,892	$124,995	$371,880	$507,512
Ataruq	$12,331	$102,773	$246,512	$343,748
Sourdough	$48,574	$248,431	$495,060	$662,644
Point Thomson - major gas sales	$1,302,388	$2,960,729	$5,448,236	$7,106,578
TOTAL (M$)	**$7,347,473**	**$24,606,166**	**$51,226,273**	**$69,186,351**

Table 3.116. Cum PW (M$) at a discount rate of 15%.

Pool	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Colville River, Alpine Oil	$1,498,871	$2,612,830	$4,292,824	$5,414,368
Endicott, Endicott Oil	($6,473)	$124,881	$446,317	$676,301
Kuparuk River, Kuparuk River Oil	($28,700)	$1,019,586	$2,582,980	$3,625,263
Kuparuk River, West Sak Oil	$2,321	$93,889	$294,746	$442,475
Kuparuk River, Meltwater Oil	$102,188	$199,226	$357,351	$463,601
Kuparuk River, Tabasco Oil	$49,551	$88,360	$146,509	$185,294
Kuparuk River, Tarn Oil	$208,029	$398,699	$697,609	$900,002
Milne Point, Kuparuk River Oil	($4,074)	$77,145	$357,307	$582,509
Milne Point, Schrader Bluff Oil	$10,512	$53,439	$183,191	$300,881
Milne Point, Schrader Bluff Oil, E - pad	($193,804)	($19,476)	$178,742	$309,543
Milne Point, Schrader Bluff Oil, S - pad	($223,122)	($46)	$279,736	$468,523
Milne Point, Schrader Bluff Oil, new pad	($188,063)	($48,848)	$108,064	$211,733
Northstar, Northstar Oil	$761,447	$1,243,707	$1,967,862	$2,450,756
Prudhoe Bay, Aurora Oil	$79,728	$166,748	$302,099	$392,865
Prudhoe Bay, Borealis Oil	$175,697	$371,465	$679,520	$886,947
Prudhoe Bay, Lisburne Oil	$12,581	$98,634	$240,304	$336,187
Prudhoe Bay, Niakuk Oil	$1,683	$37,406	$106,799	$156,269
Prudhoe Bay, Prudhoe Oil	$2,602,595	$6,902,001	$13,366,693	$17,676,489
Prudhoe Bay, Polaris	$25,583	$146,862	$336,650	$463,364
Prudhoe Bay, Orion I, Schrader Bluff Oil	$54,232	$111,298	$199,296	$258,388
Prudhoe Bay, Midnight Sun Oil	$23,991	$51,296	$93,692	$122,200
Prudhoe Bay, Point McIntyre Oil	$222,117	$538,767	$1,035,682	$1,370,216
Kuparuk River, Placer Pool Oil	$57,130	$148,262	$287,040	$379,866
Kuparuk River, West Sak Add. (IE &IJ)	($118,629)	$218,448	$735,598	$1,082,001
Colville River, Fiord	$77,266	$195,582	$376,817	$497,623
Colville River, Nanuq	$40,269	$135,312	$280,104	$376,566
Colville River, Alpine West	$46,930	$154,949	$318,140	$427,394
Colville River, Lookout	$49,488	$134,873	$265,138	$352,180
Colville River, Spark	$54,436	$116,538	$217,540	$285,155
Prudhoe Bay, Orion Phase II & III	($57,307)	$236,703	$677,288	$974,958
Prudhoe Bay, Polaris Phase II & III	($54,388)	$89,022	$299,974	$442,099
Oooguruk	($52,359)	$124,293	$323,971	$459,935
Nikaitchug	($496,944)	($69,563)	$457,000	$802,965
Liberty	$39,201	$212,911	$483,517	$667,339
Gwydyr Bay	($122,201)	($13,239)	$122,589	$213,832
Sandpiper	$27,815	$141,067	$310,869	$423,114
Sambuca	$33,837	$68,756	$121,685	$157,057
Tuvaaq	$104,096	$59,276	$197,723	$272,768
Ataruq	$2,018	$64,854	$162,119	$227,478
Sourdough	$16,751	$121,150	$245,843	$329,503
Point Thomson - major gas sales	$459,637	$1,281,480	$2,514,242	$3,336,085
TOTAL (M$)	**$5,508,802**	**$17,688,543**	**$36,651,170**	**$49,402,092**

Table 3.117. Cum PW (M$) at a discount rate of 20%.

Pool	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Colville River, Alpine Oil	$1,316,468	$2,263,272	$3,687,327	$4,637,262
Endicott, Endicott Oil	($6,019)	$116,323	$394,775	$589,195
Kuparuk River, Kuparuk River Oil	($27,054)	$723,607	$1,837,181	$2,579,567
Kuparuk River, West Sak Oil	$1,071	$87,270	$268,131	$398,525
Kuparuk River, Meltwater Oil	$92,638	$177,922	$313,380	$404,074
Kuparuk River, Tabasco Oil	$44,820	$78,425	$128,754	$162,313
Kuparuk River, Tarn Oil	$190,877	$359,750	$620,926	$796,734
Milne Point, Kuparuk River Oil	($4,756)	$73,339	$327,899	$526,238
Milne Point, Schrader Bluff Oil	$8,134	$47,809	$165,110	$267,938
Milne Point, Schrader Bluff Oil, E - pad	($166,140)	($41,812)	$98,605	$189,422
Milne Point, Schrader Bluff Oil, S - pad	($230,418)	($37,574)	$187,228	$336,055
Milne Point, Schrader Bluff Oil, new pad	($144,199)	($52,603)	$50,041	$116,215
Northstar, Northstar Oil	$673,760	$1,090,748	$1,716,489	$2,133,686
Prudhoe Bay, Aurora Oil	$72,914	$148,438	$264,375	$341,904
Prudhoe Bay, Borealis Oil	$161,967	$333,039	$598,037	$775,700
Prudhoe Bay, Lisburne Oil	$13,469	$88,331	$207,014	$286,734
Prudhoe Bay, Niakuk Oil	$2,019	$35,218	$97,068	$140,426
Prudhoe Bay, Prudhoe Oil	$2,222,969	$5,667,838	$10,839,242	$14,286,845
Prudhoe Bay, Polaris	$7,175	$102,373	$246,413	$341,933
Prudhoe Bay, Orion I, Schrader Bluff Oil	$49,630	$99,829	$176,490	$227,801
Prudhoe Bay, Midnight Sun Oil	$22,450	$46,596	$83,611	$108,405
Prudhoe Bay, Point McIntyre Oil	$200,380	$473,950	$897,137	$1,180,915
Kuparuk River, Placer Pool Oil	$45,409	$118,352	$228,736	$302,449
Kuparuk River, West Sak Add. (IE &IJ)	($94,406)	$125,685	$458,778	$681,319
Colville River, Fiord	$58,562	$149,606	$287,998	$379,865
Colville River, Nanuq	$29,090	$102,762	$212,976	$285,937
Colville River, Alpine West	$33,892	$113,349	$232,790	$312,589
Colville River, Lookout	$33,152	$91,119	$178,914	$237,402
Colville River, Spark	$36,630	$76,622	$141,668	$185,126
Prudhoe Bay, Orion Phase II & III	($64,240)	$132,458	$416,979	$608,699
Prudhoe Bay, Polaris Phase II & III	($60,831)	$40,492	$182,614	$277,839
Oooguruk	($54,565)	$74,579	$221,170	$317,854
Nikaitchug	($441,633)	($115,805)	$272,651	$524,837
Liberty	$16,886	$135,560	$314,192	$434,436
Gwydyr Bay	($107,312)	($27,132)	$70,425	$135,362
Sandpiper	$7,202	$66,244	$153,229	$210,416
Sambuca	$24,695	$50,027	$88,254	$113,765
Tuvaaq	$66,670	$27,421	$108,593	$152,360
Ataruq	($3,496)	$41,468	$109,740	$155,457
Sourdough	$4,011	$60,782	$127,354	$171,511
Point Thomson - major gas sales	$146,181	$582,119	$1,236,029	$1,671,968
TOTAL (M$)	**$4,178,052**	**$13,727,796**	**$28,248,323**	**$37,987,078**

Table 3.118. Cum PW (M$) at a discount rate of 30%.

Pool	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Colville River, Alpine Oil	$1,059,972	$1,788,832	$2,882,893	$3,612,352
Endicott, Endicott Oil	($5,212)	$102,223	$321,737	$471,105
Kuparuk River, Kuparuk River Oil	($20,488)	$411,910	$1,050,377	$1,476,021
Kuparuk River, West Sak Oil	($126)	$76,907	$227,078	$332,326
Kuparuk River, Meltwater Oil	$77,847	$145,986	$251,067	$321,205
Kuparuk River, Tabasco Oil	$37,937	$64,650	$104,674	$131,355
Kuparuk River, Tarn Oil	$164,009	$301,304	$510,340	$650,231
Milne Point, Kuparuk River Oil	($5,718)	$67,067	$282,153	$442,121
Milne Point, Schrader Bluff Oil	$4,762	$39,197	$136,518	$217,165
Milne Point, Schrader Bluff Oil, E - pad	($121,474)	($53,282)	$24,150	$72,504
Milne Point, Schrader Bluff Oil, S - pad	($214,885)	($79,012)	$77,896	$178,389
Milne Point, Schrader Bluff Oil, new pad	($86,913)	($43,966)	$4,585	$34,672
Northstar, Northstar Oil	$551,407	$882,649	$1,379,540	$1,710,806
Prudhoe Bay, Aurora Oil	$62,312	$121,979	$212,351	$272,653
Prudhoe Bay, Borealis Oil	$140,041	$276,381	$483,931	$622,556
Prudhoe Bay, Lisburne Oil	$14,190	$73,269	$163,267	$223,380
Prudhoe Bay, Niakuk Oil	$2,551	$31,592	$82,392	$117,241
Prudhoe Bay, Prudhoe Oil	$1,730,041	$4,220,828	$7,957,334	$10,448,338
Prudhoe Bay, Polaris	($12,946)	$51,225	$142,927	$203,000
Prudhoe Bay, Orion I, Schrader Bluff Oil	$42,565	$83,177	$144,569	$185,548
Prudhoe Bay, Midnight Sun Oil	$20,010	$39,688	$69,431	$89,294
Prudhoe Bay, Point McIntyre Oil	$167,659	$381,906	$707,992	$925,844
Kuparuk River, Placer Pool Oil	$30,223	$80,216	$155,430	$205,599
Kuparuk River, West Sak Add. (IE &IJ)	($64,537)	$45,508	$208,774	$317,670
Colville River, Fiord	$34,914	$92,699	$179,712	$237,093
Colville River, Nanuq	$15,379	$62,687	$131,627	$176,776
Colville River, Alpine West	$18,329	$64,557	$133,811	$180,011
Colville River, Lookout	$15,618	$44,679	$88,317	$117,274
Colville River, Spark	$17,666	$35,714	$65,282	$85,006
Prudhoe Bay, Orion Phase II & III	($57,533)	$40,701	$175,281	$265,591
Prudhoe Bay, Polaris Phase II & III	($56,809)	($571)	$72,605	$121,091
Oooguruk	($50,170)	$23,151	$108,204	$162,029
Nikaitchug	($350,089)	($150,481)	$80,708	$227,185
Liberty	($1,393)	$58,411	$143,931	$200,851
Gwydyr Bay	($82,177)	($35,427)	$19,886	$56,023
Sandpiper	($2,669)	$15,668	$41,882	$58,923
Sambuca	$13,965	$28,354	$49,980	$64,401
Tuvaaq	$29,293	$4,262	$35,163	$51,887
Ataruq	($7,464)	$17,305	$53,950	$78,408
Sourdough	($2,265)	$16,315	$37,874	$51,895
Point Thomson - major gas sales	($13,823)	$128,470	$341,914	$484,209
TOTAL (M$)	**$3,093,999**	**$9,556,728**	**$19,341,533**	**$25,880,028**

This analysis shows that twelve pools are uneconomic at $25/bbl and a 10% discount rate. Three of the fields, Endicott, Kuparuk River, and MPU Kuparuk, are currently producing and are older producing fields. The remaining nine fields are the three MPU Schrader Bluff projects (new-, E-, and S-pad), Kuparuk River Additional pad, the two Prudhoe Bay projects (Orion Phase II & III, Polaris Phase II & III), Oooguruk, Nikaitchug, and Gwydyr Bay. Additional fields become uneconomic as the discount rate is increased. At a $35/bbl price track only the MPU Schrader Bluff new pad project is uneconomic at a 10% discount rate. At the $50/bbl and $60/bbl price tracks all projects at 10%, 15%, 20%, and 30% discount rates are economic. Thus, the current oil price environment is sufficient to support additional development on the ANS. Actual project timing will depend on investment capital opportunities available elsewhere for an operator. Changes in fiscal policy, such is increased taxes, could increase the number of fields and projects that would not pass industry investment criteria using the discount rate as a primary economic metric.

3.7 Producing Fields with Major Gas Sales Potential

At present there are two fields, PBU and PTU, with significant gas reserve that can supply gas to a gas sales pipeline. PBU has been producing oil and gas since 1977, with most of the gas injected back into the reservoir for EOR and recycling as shown in Figure 3.8 (p 3-24). The development of PTU is currently dependent on the ability to monetize its gas reserves. Other projects, such as DIU, Lisburne, NSU, MPU, and CRU, may supply some sales gas also. These potential sales depend on installation of economic gathering systems for these fields; therefore they are not included in this analysis. The frequently quoted estimate for ANS known recoverable hydrocarbon gas reserves is 35 TCF (PN, 2005k).

A 35-yr project delivering 4.5 BCF/D to the AGP on the North Slope requires a total of 57.5 TCF of hydrocarbon gas. In Section 2.4, Table 2.21, the near term (2005 to 2015) estimate of additional gas is 12 TCF and the long-term estimate (2015 to 2050) is 125 TCF for a total of 137 TCF. The assurance of a gas pipeline to transport the gas to market is needed to encourage exploration and development of sufficient gas reserves to support the gas sales project. The potential life of the gas sales project could easily exceed a 35-yr life for a 4.5 BCF/D rate by many years if the potential of ANS gas reserves is realized.

The estimated net hydrocarbon gas for sale from the PBU is 23.7 TCF and PTU is 8.0 TCF for a total volume of sales gas of 31.7 TCF for transport in the AGP from these two fields. The estimated gas disposition is shown in Table 3.119 and Figure 3.76.

Table 3.119. PBU and PTU Gas disposition.

	PBU Gas Sales Disposition		**PTU Gas Sales Disposition**	
OGIP	47.4 TCF		13.2 TCF	30.0%
Non-recoverable gas	11.5 TCF	24.3%	4.0 TCF	7.0%
Lease use, local sales, and shrinkage	9.0 TCF	19.0%	0.9 TCF	2.5%
CO_2 in gas to conditioning plant*	3.2 TCF	6.8%	0.3 TCF	60.5%
Net Sales Gas to AGP	23.7 TCF	50.0%	8.0 TCF	30.0%
Total Sales Gas to AGP = 31.8 TCF				
*** PBU 12% CO_2, PTU 4% CO_2**				

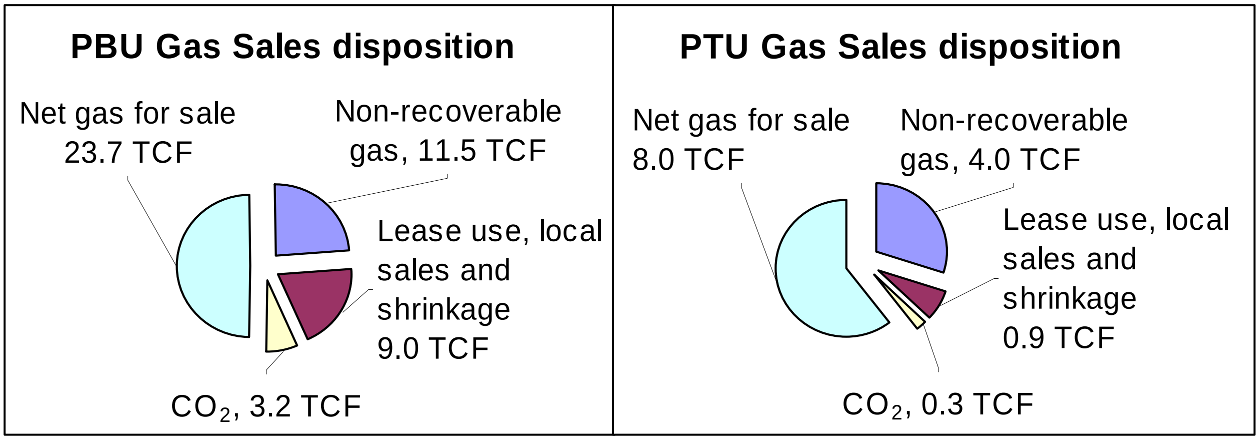


Figure 3.76. PBU and PTU gas sales disposition.

The engineering and economic evaluations of PBU and PTU with major gas sales are described in the following sections.

3.7.1 PBU – Major Gas Sales Case

The PBU has been operated since 1987 as an oil recovery project utilizing the gas cap (gas volume and pressure support) to increase the amount of liquids recovered from the oil rim. Some of the NGLs in the gas cap gas have been produced as well. This section presents an engineering and economic analysis to determine the economic reserves, both liquid and gas, and their value to the Unit owners, the state of Alaska, and the federal government with major gas sales being made.

3.7.1.1 PBU Engineering

Highly accurate estimates of oil production rates and reserves under major gas sales would require a complex analysis using a full-field compositional reservoir simulation model. It is most likely some reduction in oil and condensate production will occur after major gas sales commence in 2015. However, because earliest gas sales are assumed to commence after more that 93% of the TRR volumes are recovered, the effect on ultimate recovery will be minimized. Although beyond the scope of this study, some offsetting effect of the oil rim liquid losses could occur by recovery of additional NGLs from gas production from up-structure areas of the gas cap. Until more definitive information becomes available in the public domain, the following assumptions are made. The oil/condensate recovery volumes forecasted for PBU in Section 3.3.1 are revised as shown in Table 3.120.

Table 3.120. Impact of major gas sales on oil/condensate recovery in PBU

Year	% Oil/Condensate loss
2014	0
2015	0
2016	5
2017	10
2018	15
2019 to abandonment	20

This results in an estimated loss of about 138.5 MMB of oil and condensate after 2015, or a loss of about 1% of TUR. The revised oil/condensate volumes are given in the Table 3.121. This table includes the oil forecast for the PBU IPA crude oil forecast without major gas sales as described in 3.3.1 for reference.

Table 3.121. PBU TRR Oil and Gas Forecast with Major Gas Sales.

Year	% Loss	Oil w/o Gas Sales MMBOPY	Oil w Gas Sales MMBOPY	Annual Oil Loss MMBOPY	NGLs MMBOPY	Total Liquid Sales	Wet Gas Prod. MMCFD	Gas Sales MMCFD
2005	0	123.76	123.76	0	25.45	149.21	7800	0
2006	0	116.02	116.02	0	24.18	140.2	7800	0
2007	0	108.77	108.77	0	22.97	131.74	7800	0
2008	0	101.98	101.98	0	21.82	123.8	7800	0
2009	0	95.6	95.6	0	20.73	116.33	7800	0
2010	0	89.63	89.63	0	19.77	**109.4**	7800	0
2011	0	84.02	84.02	0	18.7	**102.72**	7800	0
2012	0	78.77	78.77	0	17.77	96.54	7800	0
2013	0	73.85	73.85	0	16.88	90.73	7800	0
2014	0	69.23	69.23	0	16.04	85.27	7800	0
2015	0	64.91	64.91	0	15.23	80.14	7800	3440
2016	5	60.85	57.81	3.04	14.47	72.28	7800	3440
2017	10	57.05	51.35	5.7	13.75	65.1	7500	3440
2018	15	53.48	45.46	8.01	13.06	58.52	7200	3440
2019	20	50.14	40.11	10.03	12.41	52.52	6900	3440
2020	20	47	37.6	9.4	11.79	49.39	6600	3440
2021	20	44.07	35.26	8.81	11.2	46.46	6300	3440
2022	20	41.31	33.05	8.26	10.64	43.69	6000	3440
2023	20	38.73	30.98	7.75	10.11	41.09	5700	3440
2024	20	36.31	29.05	7.26	9.61	38.66	5400	3440
2025	20	34.04	27.23	6.81	9.13	36.36	5100	3440
2026	20	31.91	25.53	6.38	8.67	34.2	4800	3440
2027	20	29.92	23.94	5.98	7.53	31.47	4500	3200
2028	20	28.05	22.44	5.61	7.37	29.81	4200	3000
2029	20	26.29	21.03	5.26	6.84	27.87	3900	2800
2030	20	24.65	19.72	4.93	6.04	25.76	3600	2550
2031	20	23.11	18.49	4.62	5.36	23.85	3300	2300
2032	20	21.67	17.34	4.33	4.73	22.07	3000	2100
2033	20	20.31	16.25	4.06	4.16	20.41	2700	1900
2034	20	19.04	15.23	3.81	3.61	18.84	2400	1700
2035	20	17.85	14.28	3.57	3.12	17.4	2100	1400
2036	20	16.74	13.39	3.35	2.66	16.05	1800	1200
2037	20	15.69	12.55	3.14	2.53	15.08	1500	1000
2038	20	14.71	11.71	3.00	1.86	13.57	1200	540
2039	20	13.79	11	2.79	0	11.00	900	0
2040	20	12.93	10.3	2.63		10.30	600	0
Total		**1786.18 MMB**	**1647.64 MMB**	**138.54 MMB**	**400.19 MMB**	**2047.83 MMB**	**69,642,000 MMCF**	**23,714,050 MMCF**

Until additional information is available, it is assumed the NGL forecast after 2015 will continue at the decline rate used in the PBU forecasts in the No-Major-Gas-Sales case. The revised technical oil and gas production forecasts for the gas sales case are presented in Figure 3.77. The gas production schedule assumes that Prudhoe Bay and Point Thomson will use the available gas pipeline capacity of 4.5 BCFPD. Nomination of gas from other sources is not considered in this analysis, although it is likely that gas nominations will occur from additional fields besides Prudhoe Bay and Point Thomson for shipment in the AGP.

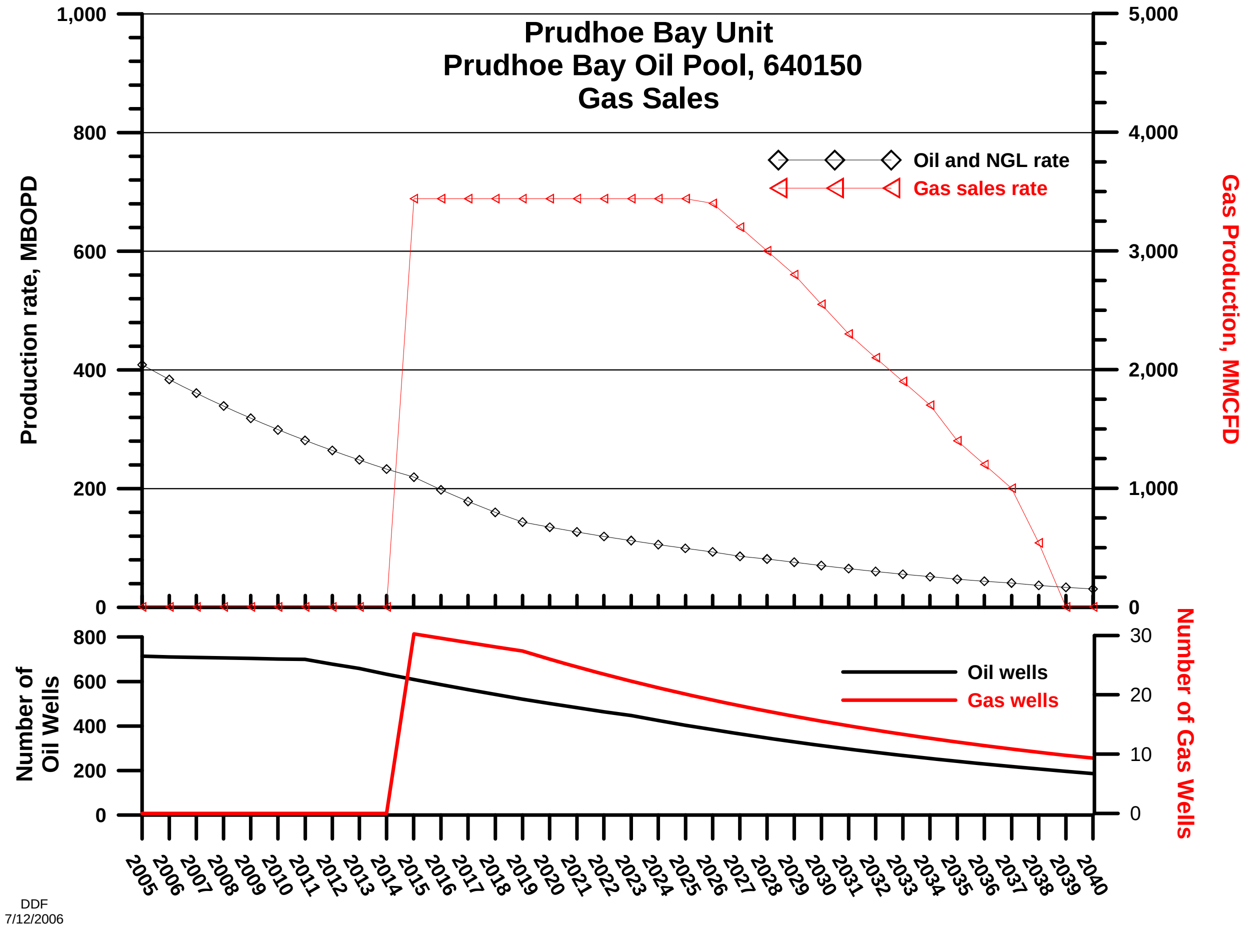


Figure 3.77. PBU oil and gas production with Major Gas Sales.

Forecasts of PBU major gas sales case of oil and gas production pool future and ultimate economical recoveries as of 1/1/2005 for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.122. The gas tariff described in Section 3.2.1.6 is used to obtain the wellhead gas price for use in the economics. This estimated gas tariff includes the cost of the gas conditioning plant, compression, and the AGP from PBU to Chicago.

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.123. The incremental value of gas sales from PBU as forecasted for this case can be seen by comparing Table 3.122 with Table 3.9.

Table 3.122. Prudhoe Bay Gas Sales–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2040	2040	2040	2040
Oil and NGLs ERR (MB)	2,038,716	2,038,716	2,050,104	2,050,104
Future Gas Sales forecast (MMCF)	23,699,450	23,699,450	23,699,450	23,699,450
Future water forecast (MB)	9,440,982	9,440,982	9,512,886	9,512,886
Oil and NGLs EUR (MB)	2,038,716	2,038,716	2,050,104	2,050,104
Ultimate gas production (MMCF)	23,699,450	23,699,450	23,699,450	23,699,450
Total gas reinjected (Est.) (MMCF)	19,907,538	19,907,538	19,907,538	19,907,538
Ultimate water production (MB)	9,440,982	9,440,982	9,512,886	9,512,886

Table 3.123. Prudhoe Bay Gas Sales Case–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$1,163,293	$1,163,293	$1,163,293	$1,163,293
Total operating costs	$35,803,202	$35,803,202	$36,514,623	$36,514,623
State royalty	$14,528,253	$23,889,822	$38,065,096	$47,459,707
State taxes – Severance	$8,577,750	$14,090,196	$22,358,862	$27,871,308
State taxes – Income	$1,390,522	$3,003,865	$5,437,562	$7,065,205
State taxes – Other	$1,499,332	$1,499,332	$1,499,870	$1,499,870
State Total (Royalty &Taxes)	**$25,995,857**	**$42,483,215**	**$67,361,390**	**$83,896,090**
Federal taxes	**$16,073,001**	**$33,809,016**	**$60,579,919**	**$78,473,143**
Industry net income	**$31,200,534**	**$65,629,260**	**$117,596,318**	**$152,330,216**

3.7.2 Point Thomson Unit

The PTU is a high pressure condensate field located about 50 miles east of TAPS PS-1. The unit contains about 83,800 acres, much of which is offshore (Thomas, et al., 1993; Thomas et al. 1966). The field was discovered in 1977. The estimated potential reserves have increased from about 300 MMBO and 5 TCF of gas to the current estimate of a total of 400 MMBO of condensate and oil and 8 TCF of gas. Reservoir pressure is about 10,000 pounds per square inch. The wells will be expensive and a lot of compression will be required for reinjection of gas to maintain pressure to keep the condensate from forming a separate liquid phase in the reservoir (PN, 2004k). The Unit operator, ExxonMobil, reported to the state in July 2005 that a standalone gas cycling project was not economic leading to discussion of options for development including no gas cycling or partial gas cycling that would allow sales of gas and condensate and improve the economics of the project (PN 2005m). The Unit owners submitted a revised 22nd Plan of Development to the state on August 31, 2005 that did not include an exploration well in 2006 as required by the last Unit expansion; the Unit was declared in default by the state (PN, 2005n; PN, 2005o). Following a year of additional discussion and delays, Alaska officially terminated the Point Thomson leases in February 2007 and the Unit owners have filed a lawsuit in Alaska Superior Court appealing the decision (PN, 2007a; PN 2007b).

Engineering and economic analysis to determine the economic reserves and the value to the Unit owners, state of Alaska, and the federal government are described in this section.

3.7.2.1 Point Thomson Unit Engineering

The reserves of 8 TCF and 329 MMBO carried by the ADNR (ADNR, 2005) are used as a guide for this analysis. These reserve volumes represent an increase in reserves above those presented in the 1993 DOE report (Thomas et al., 1993). This increase is assumed to result from improved technology, including 3-D seismic, and especially advancements the industry has made in long-reach horizontal drilling capability. In addition to better well performance, the improved drilling technology will require fewer wells to develop more of the reservoir volumes including the oil deposits located adjacent to Flaxman Island.

The following assumptions are made for this analysis.

1. A North Slope gas sales system will be completed by 2015.
2. Gas will be delivered to a treating plant at the PBU area for CO_2 removal.
3. Development begins in 2009 with first production in 2015.
4. A total of 41 wells will be required to develop this field.
5. Total hydrocarbon gas recovered is assumed to be 8 TCF.
6. PTU will deliver 700 MMCFPD to the gas sales line, resulting in a 32-yr life.
7. Wet gas production of 815 MMCFD is required before accounting for 10% for lease fuel and shrink and 4% for CO_2 content.
8. The engineering methods used in the 1993 DOE report (Thomas et al., 1993) are valid for estimating condensate recovery. That work is adapted to the increase in rates and reserves.
9. No estimate of oil reserves is found in publicly available information. Total estimated reserves for the oil reservoirs are 50 MMBO.

The production forecasts of gas and liquid recoveries given in Table 3.124 were made based on these assumptions.

Table 3.124. Point Thomson oil, condensate, and gas forecasts.

Year	Condensate		Oil (MBPD)	Sales Liquids (MBPD)	Gas	
	Ratio (BBL/MMCF)	Recoverable(MBPD)			Wet Gas (MMCF/D)	Gas Sales (MMCF/D)
2015	73.2	98.3	20.0	118.3	1343	1160
2016	78.3	105.2	17.8	123.0	1343	1160
2017	78.6	105.6	15.8	121.4	1343	1160
2018	75.7	101.7	14.0	115.7	1343	1160
2019	70.8	95.1	12.5	107.6	1343	1160
2020	60.5	81.2	11.2	92.4	1343	1160
2021	51.4	69.0	9.9	78.9	1343	1160
2022	38.9	52.3	8.8	61.6	1343	1160
2023	30.5	41.0	7.9	48.9	1343	1160
2024	25.7	34.5	7.0	41.5	1343	1160
2025	21.1	28.4	6.3	34.7	1343	1160
2026	18.8	23.6	5.8	29.4	1255	1085
2027	17.3	20.2	0	20.2	1170	1010
2028	15.1	16.4	0	16.4	1085	935
2029	13.1	13.3	0	13.3	1015	875

Year	Condensate		Oil (MBPD)	Sales Liquids (MBPD)	Gas	
	Ratio (BBL/MMCF)	Recoverable(MBPD)			Wet Gas (MMCF/D)	Gas Sales (MMCF/D)
2030	11.9	11.2	0	11.2	940	815
2031	11.2	9.8	0	9.8	875	755
2032	10.3	8.3	0	8.3	805	695
2033	9.0	6.7	0	6.7	745	645
2034	7.8	5.3	0	5.3	675	585
2035	7.0	4.3	0	4.3	610	525
2036	0	0	0	0	540	465
2037	0	0	0	0	470	405
2038	0	0	0	0	420	365

These forecasts result in TUR's of 50 MMB of oil, 350 MMB of condensate, and 8 TCF of hydrocarbon gas. The forecast oil and gas production is shown in Figure 3.78.

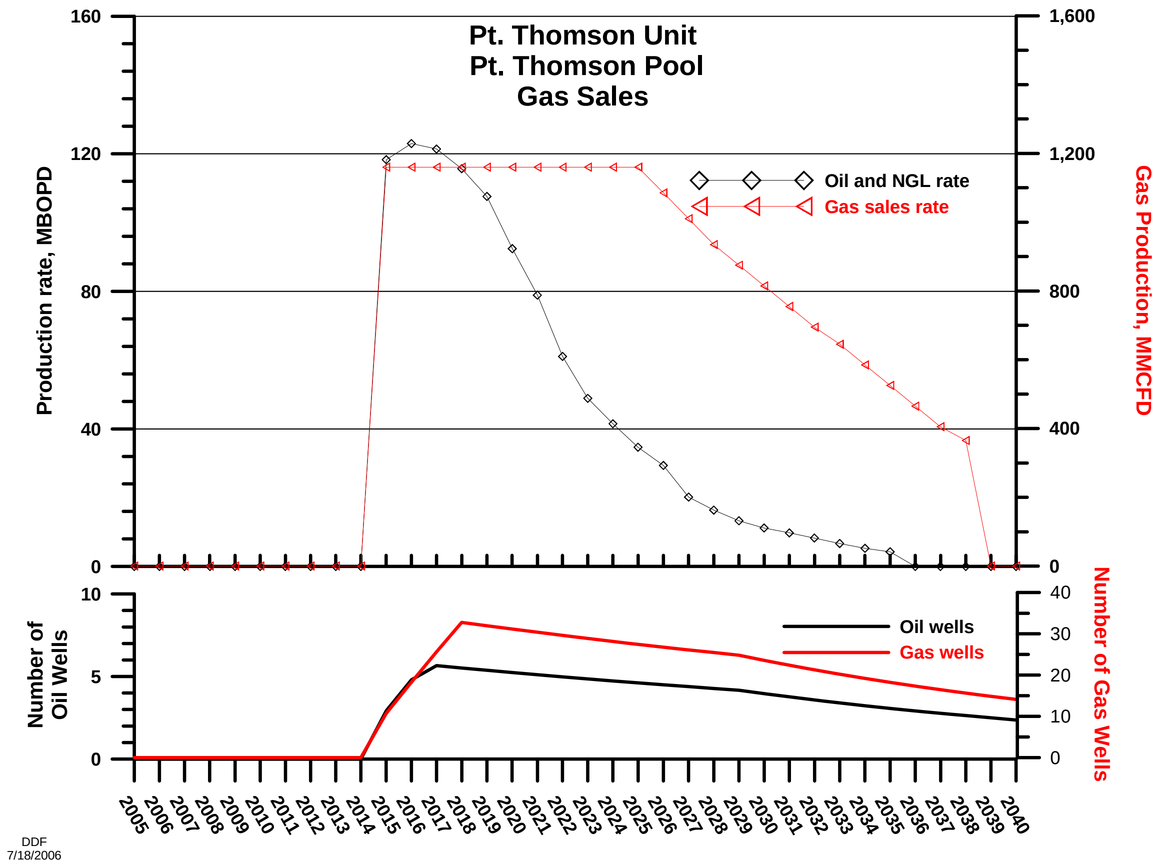


Figure 3.78. Oil and gas production from Point Thomson for major gas sales case.

Forecasts of the Point Thomson oil and gas production future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.125. The economic analysis includes the capital costs for gas facilities and oil and gas pipelines to transport the gas and condensate and oil to PS-1 as well as drilling costs (see

Apendix D, Table D.21). The estimated gas tariff for the AGP and TAPS tariffs are then applied to determine Point Thomson wellhead oil and gas prices.

Table 3.125. Point Thomson–Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2036	2036	2036	2036
Future Gas Sales (MMCF)	7,200,720	7,200,720	7,200,720	7,200,720
Future water forecast (MB)	1,876	1,876	1,876	1,876
Oil and NGLs EUR (MB)	389,966	389,966	389,966	389,966
Total gas reinjected (Est.) (MMCF)	6,048,605	6,048,605	6,048,605	6,048,605

The revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.126.

Table 3.126. Point Thomson–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$4,639,810	$4,639,810	$4,639,810	$4,639,810
Total operating costs	$528,964	$528,964	$528,964	$528,964
State royalty	$3,912,862	$6,450,479	$10,256,900	$12,794,517
State taxes – Severance	$2,847,429	$4,630,958	$7,306,252	$9,089,781
State taxes – Income	$512,468	$936,974	$1,573,737	$1,998,244
State taxes – Other	$441,063	$441,063	$441,063	$441,063
State Total (Royalty & Taxes)	**$7,713,822**	**$12,459,474**	**$19,577,952**	**$24,323,605**
Federal taxes	**$5,980,620**	**$10,647,378**	**$17,647,510**	**$22,314,268**
Industry net income	**$11,653,704**	**$20,712,700**	**$34,301,198**	**$43,360,197**

3.7.3 Summary ANS Fields with Major Gas Sales

The ANS technically recoverable production forecast for the major gas sales case is shown in Figure 3.79. The gas sales volumes on this figure are converted to barrels of oil equivalent per day (BOEPD) using 6 MCF/bbl to allow comparison to the oil production. In BOEPD, the composite production reaches a maximum rate of about 1.6 MMBOEPD. This is still considerably below the maximum oil production rate achieved in 1988 of 2.2 MMBOPD. The TAPS minimum throughput rate of 300,000 BOPD will still be reached by 2026 even with the addition the Point Thomson condensate and NGLs, if no additional oil is discovered and developed before that time.

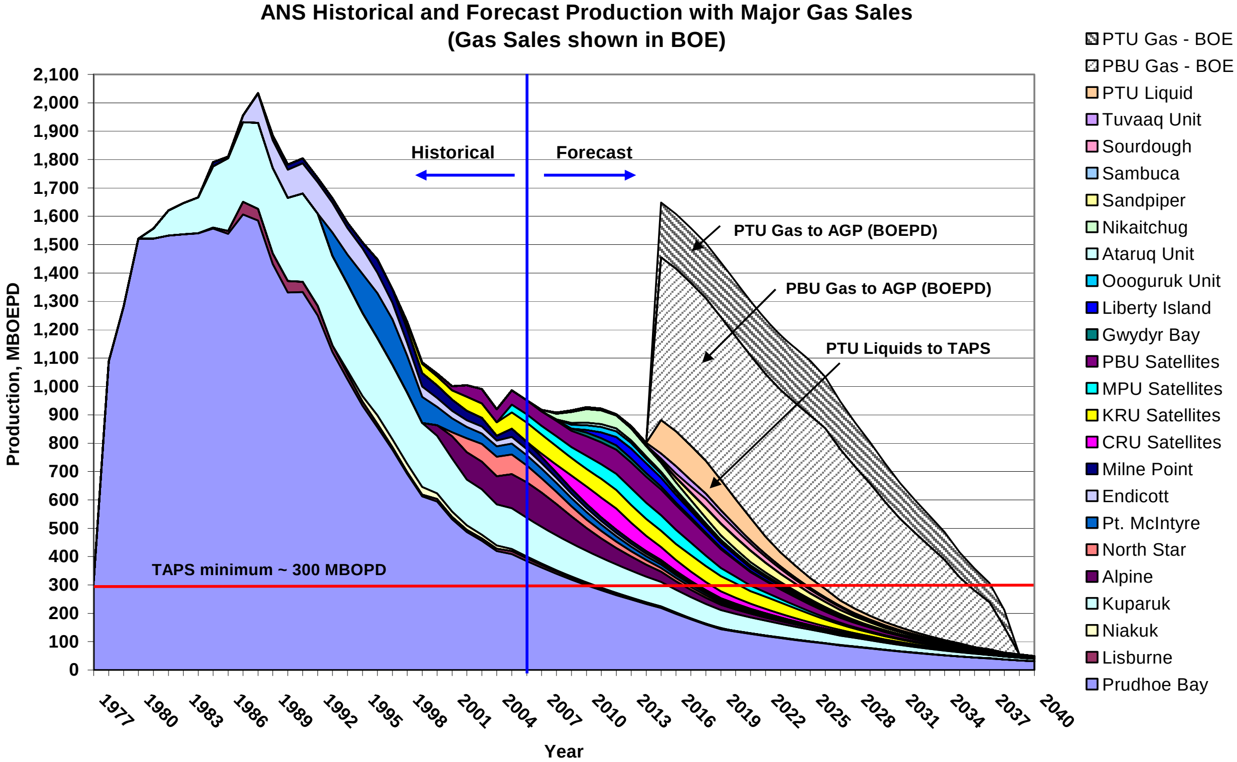


Figure 3.79. ANS production with Major Gas Sales (gas in barrels of oil equivalent (BOEPD) at 6 MCF/bbl).

The aggregated results with Major Gas Sales including ANS Currently producing, fields with pending development plans, fields with development potential as listed in Table 3.113 including major gas sales and in incremental oil and condensate are presented in Table 3.127.

Table 3.127. ANS production with Major gas sales–Forecasts of future and ultimate economical recoveries as of 1/1/2005 for ANS West Coast prices.

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Oil and NGLs ERR (MB)	5,517,325	5,981,054	6,143,767	6,180,647
Future Gas forecast (MMCF)	39,477,615	41,342,102	42,151,735	42,325,257
Future water forecast (MB)	17,114,198	19,719,013	20,855,095	21,109,751
Oil and NGLs EUR (MB)	9,138,755	9,602,484	9,765,197	9,802,077
Ultimate gas production (MMCF)	46,608,814	48,473,301	49,282,934	49,456,456
Total gas reinjected (Est.) (MMCF)	39,349,031	40,904,628	41,599,230	41,747,678
Ultimate water production (MB)	20,958,928	23,563,743	24,699,825	24,954,481

The sum of the economic results for the pools listed in Table 3.113 with major gas sales from PBU and PTU is presented in Table 3.128.

Table 3.128. ANS aggregated economic results with major gas sales (ANS West Coast prices, then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	18,690,734	19,388,746	19,533,560	19,551,453
Total operating costs	73,002,343	86,426,258	94,379,785	97,047,922
State royalty	27,142,525	46,431,084	74,442,978	92,927,560
State taxes – Severance	13,179,122	21,504,474	33,955,104	42,251,502
State taxes – Income	2,271,511	5,188,283	9,955,158	13,204,812
State taxes – Other	3,972,066	4,487,142	4,717,863	4,769,517
State Total (Royalty and Taxes)	46,508,348	77,533,494	122,981,293	153,060,746
Federal taxes	25,280,099	58,101,155	111,064,461	146,899,283
Industry net income	48,444,356	113,996,164	216,987,543	286,678,076

The stakeholder's revenue share as a percent of the total revenue is shown in Figures 3.80 for the Major Gas Sales case. The industry share increases from 40% to 49%, the state revenue share decreases from 39% to 26%, and the federal share increases from 21% to 25%.

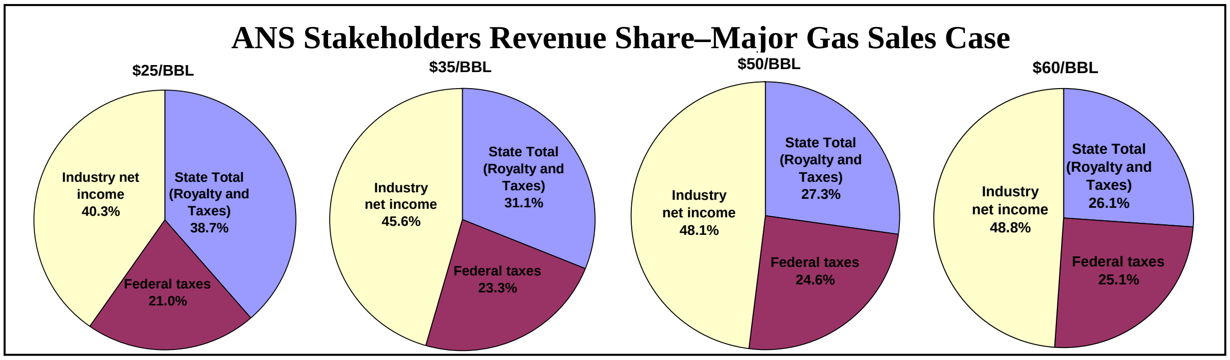


Figure 3.80 ANS Stakeholder Revenue Shares–Major Gas Sales Case at ANS West Coast prices, 2005$.

The estimated incremental economic impact of major gas sales from PBU and PTU over the no-major-gas-sales case is shown in Figure 3.129 (Table 3.128 minus Table 3.114). The sale of gas from PBU and PTU almost doubles the revenue stream received by the stakeholders and represents a significant new operating environment for the ANS.

Table 3.129. Increase in forecast economic results for ANS fields with Major Gas Sales minus ANS fields without Major Gas Sales for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	4,639,810	4,639,810	4,639,810	4,639,810
Total operating costs	8,420,348	456,746	1,168,167	1,168,167
State royalty	12,771,020	19,979,979	32,330,911	40,509,296
State taxes – Severance	8,427,365	13,839,883	22,252,154	27,860,341
State taxes – Income	1,703,365	3,076,855	5,040,806	6,355,283
State taxes – Other	443,589	432,816	433,354	433,354
State Total (Royalty and Taxes)	**23,345,339**	**37,329,533**	**60,057,225**	**75,158,274**
Federal taxes	**19,262,850**	**34,037,725**	**55,644,522**	**70,095,017**
Industry net income	**37,498,393**	**66,117,485**	**108,060,116**	**136,111,057**

3.8 Minimum Economic Field Size (MEFS)

Minimum economic field sizes (MEFS) are estimated for each of the exploration regions described in Section S.4. These regions include the core region of the Central Alaska North Slope, NPRA, 1002 Area of ANWR, Beaufort Sea OCS, and Chukchi Sea OCS. A gas field MEFS is estimated for the gas prone southern portion of the Central Alaska North Slope, the Foothills area. The MEFS analysis considered both continued development of satellite accumulations and frontier exploration. The costs to explore, find, develop, produce and transport oil or gas at varying distances from existing infrastructure are analyzed to illustrate the impact of distance, infrastructure, and location. An additional analysis considers project timing on the MEFS to gauge the impact of project delays and cash flow structure on a project's economic viability. The estimates for MEFS (OOIP, OGIP) were determined at each of the four oil and gas prices tracks. The approach is described below.

3.8.1 MEFS Assumptions and Methodology

General assumptions and methodology used in the MEFS analysis are:

1. Two to four exploration wells will be required to find and delineate a discovery prior to investment and field development. Smaller accumulations will require two wells and larger ones will require four wells.

2. Exploration GG&E costs are assumed to include $50 million (2005$) for seismic, processing, geologic interpretation, geoscience activities to support siting an exploration well, and the construction of ice roads for exploration drilling and project development. These costs are used in the Alaska Exploration Tax Credit calculation.

3. Exploration and development timing varies across the region due to project availability, distance from infrastructure, land access, and other factors. The assumed timing for exploration, development and first production across the ANS is presented in Table 3.130. In the Central Arctic and Eastern NPRA, it is assumed for the MEFS comparison that development could occur rapidly after a discovery because of proximity to existing infrastructure. For the other regions, the 1002 Area of ANWR, Beaufort OCS, Chukchi OCS, and the Foothills gas case, first exploration, first development, and first production are timed to begin later as shown and longer times assumed before first production.

Table 3.130. Production Schedule for Onshore MEFS Study.

Region	First Exploration	First Development	First production
Central Arctic–core area	2008	2009	2010
Eastern NPRA	2008	2009	2010
1002 ANWR	2010	2013	2015
Foothills Gas	2011	2014	2015
Beaufort Sea OCS	2010	2014	2015
Chukchi Sea OCS	2010	2014	2015

4. The number of development wells required is a function of field size. It is assumed larger fields will have higher production rate wells and average well recovery will

increase with OOIP as shown in Figure 3.82. Development drilling is assumed to occur over four years with 20%, 30%, 30%, and 20% of the total required number of development wells drilled each of four years. Half of the development wells are producers and the other half injection wells for oil reservoirs to support pressure maintenance and enhanced oil recovery; gas reservoirs utilize all production wells.

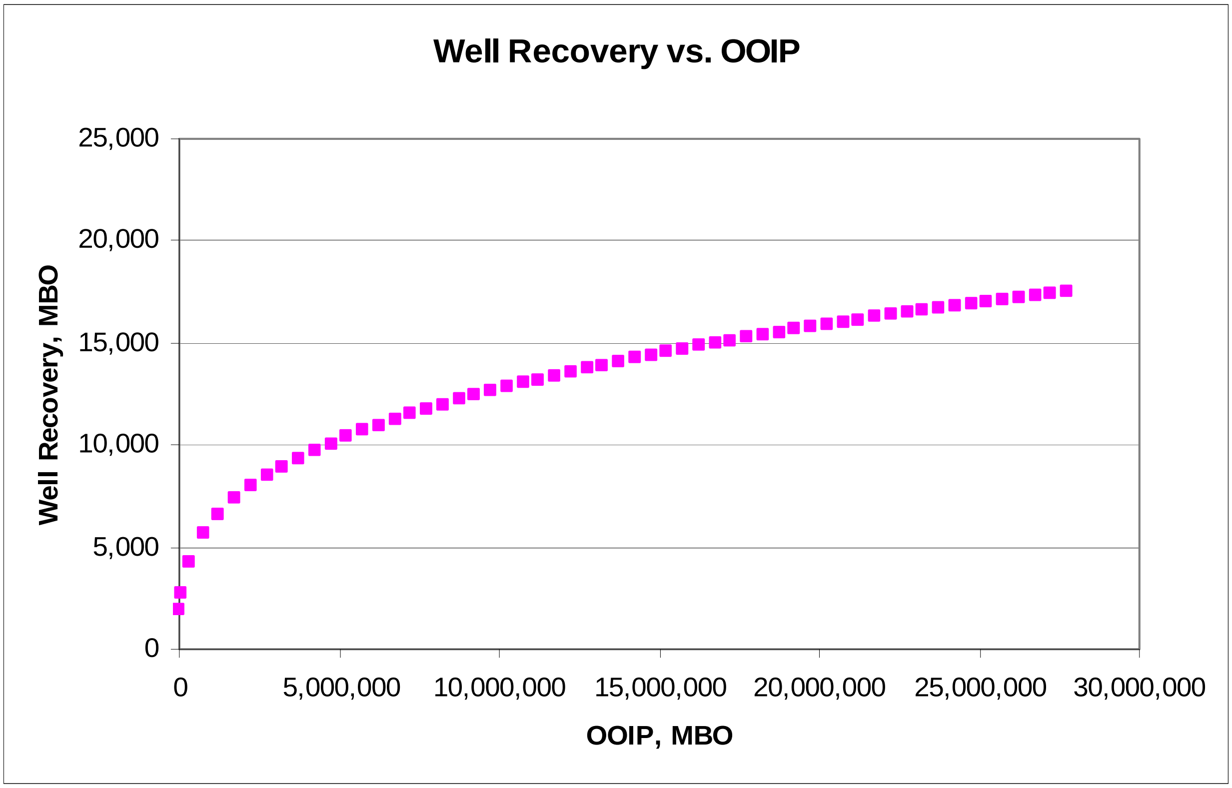


Figure 3.81. Well Recovery as a Function of OOIP.

5. Recoverable reserves use a 35% recovery factor for oil and 85% for dry gas reservoirs.
6. An algorithm is used to size the pipelines and field production facilities. Based on empirical evidence it is assumed that the peak rate is related to the accumulation size with a peak rate of 1 BOPD per 3,430 bbl of reserves. The production schedule is based on a percentage of the reserves as shown in Table 3.131.

Table 3.131. Production schedule for MEFS study.

Year	Percent Recovery
1	3
2	6
3	9
4	10.65
5	10.65
>5	15% nominal exponential decline

7. The required pipeline size to deliver oil or gas to market is related to the peak flow rate calculated for the accumulation. For the range of flow rates considered, a throughput rate of 884 BOPD per square inch of cross-sectional area is used. This value is consistent across a wide range of pipeline sizes on the ANS. The gas pipeline sizing methodology is described in Appendix F.
8. Pipeline capital costs to transport hydrocarbons to existing infrastructure are $20 per diameter-inch-foot (2005$) except for offshore Chukchi Sea, which uses $50 per diameter-inch-foot for the extreme arctic conditions offshore.
9. Oil operating costs use the cost structure described in Section S.5.5.2.
10. The discounted cash flow economic model is solved for the MEFS required for a cumulative PW = 0 at a 10% discount rate at the end of the project economic life. This analysis was conducted for each of the ANS West Coast price tracks.

Area-specific assumptions are described below.

Central Arctic core area: The MEFS analysis for the core area examined continuing satellite development at distances of five and ten miles from producing fields and support infrastructure. A number of smaller accumulations have been previously identified and processing facilities have unused capacity for new projects. The development assumptions are:

- Two exploration wells at $17 million (2005$) each.
- Development wells are $8.5 million each.
- Produced fluids are transported by feeder pipelines and processed at existing facilities for a facility sharing fee.
- Feeder pipeline costs are included in the investment costs.

NPRA: The MEFS analysis for NPRA examined exploration and development at distances of 50 and 100 miles west from the Alpine field along the Barrow Arch. Development assumptions are as follows:

<u>Scenario 1:</u>

- Two exploration wells at $17 million each are required to discover and delineate an accumulation of sufficient size to support the installation of infrastructure remote from the Alpine field.
- Development wells are $8.5 million each.
- A stand-alone development will require a minimum 8-inch pipeline to the Alpine field pipeline and transport to PS-1 through existing pipelines.

<u>Scenario 2:</u>

- A 170-mile trunk pipeline with a minimum diameter of 24-inches from the field location 100 miles west of the Alpine field to PS-1. This analysis is predicated on a stand-alone project to determine the MEFS. The discovery a field of this magnitude can support the expansion of infrastructure into the NPRA along the pipeline corridor.

1002 Area of ANWR: The MEFS analysis for the 1002 Area of ANWR considered exploration and development at distances of 110 and 160 miles east from Pump Station 1. Assumptions are as follows:

- Three exploration wells at $17 million each.
- Development wells are $8.5 million each.

- A stand-alone development will require a minimum 8-inch pipeline for transport to PS1.
- The capital costs for a pipeline at a distance of 160 miles from PS-1 include $133 million for an intermediate pump station.

Alternatives for ANWR development could include a larger pipeline to accommodate the peak field production rate similar to the NPRA Scenario 2 described above or a pipeline to the existing Badami pipeline or to a Point Thomson development. These scenarios are not analyzed.

Beaufort Sea OCS: Offshore development opportunities are located in the relatively shallow portions of the Beaufort Sea shelf between Harrison Bay and the mouth of the Canning River. Discoveries are anticipated to occur within 5 to 25 miles offshore. Exploration will likely be offshore from the currently developed infrastructure, targeting structural plays and/or areas near the undeveloped Hammerhead and Kuvlum discoveries. Assumptions are as follows:

- Field development 20 miles offshore using a gravel island or ice-resistant platform costing $300 million (2005$), a sub-sea pipeline to shore, and a 10-mile feeder line to a regional pipeline for transport through existing field pipelines to PS-1.
- Capital costs for four exploration and delineation wells are $25 million (2005$) each.
- Development wells are $20 million each.

Chukchi Sea OCS: The potentially large oil and gas accumulations in the Chukchi Sea represent especially promising exploration targets and potential development after 2015. Cost estimates for exploration and development wells, an offshore platform, production facilities, and a pipeline to shore are difficult to estimate for this frontier area with significant winter ice and arctic conditions. Assumptions are as follows:

- An offshore platform will be located 50 miles offshore and will cost $750 million (2005$).
- Exploration wells will require a drill ship and are assumed to cost $50 million (2005$) each for four exploration and delineation wells.
- Development wells are assumed to cost $20 million.
- Development costs include 50 miles of subsea gathering lines to collect and transport the oil to a central facility located on the platform and a 50-mile subsea pipeline to transport the oil to shore. The cost for the offshore subsea arctic pipelines is assumed to be $50 per diameter-inch-foot.
- A 300-mile 24-inch diameter onshore pipeline from the western edge of the North Slope to PS-1 at a cost of $20 per diameter-inch-foot for a total cost of $760 million.

Development of infrastructure including roads and pipelines into western NPRA connecting developments the Central Arctic and to PS-1 could potentially reduce the Chukchi Sea MEFS. This scenario was not analyzed due to the high level of uncertainly in such a scenario.

Central Arctic Foothills: The natural-gas-prone Foothills region could be a key production source for the AGP. The MEFS base case analysis assumed exploration would start in 2011 and require four exploration and delineation wells. Development drilling following a discovery would start in 2014 with first gas production in 2015. Assumptions are as follows:

- Capital costs are estimated at $20 million and $10 million, respectively, for exploration and development wells due the remote area and absence of infrastructure.
- Pipeline costs are estimated at $20 per diameter-inch-foot for a minimum 24-inch pipeline at distances of 50 and 100 miles.
- Facilities costs are estimated at $37.5 per MMCFPD peak rate.
- Gas operating costs are based on a cost algorithm developed for Cook Inlet operations (DOE, 2004) and increased 1.5 times for ANS operations.
- It is assumed each development well will recover 75 BCF.

3.8.2 Exploration Focus

Exploration focus for the 2005 to 2015 time frame is expected to be primarily oil until construction of a gas pipeline is assured and the timing for startup is known (see Section 2.4.1). Exploration activity will continue in the core area of the ANS to support satellite development and extend to the eastern NPRA where Alpine- and Tarn-like plays are the primary targets; and exploration drilling east of the Colville Delta to Gwydyr Bay for Alpine and Kuparuk/Milne Point-like fields

The 2015 to 2050 time frame is expected to be dual oil and gas exploration, provided an AGP is developed as assumed (see Section 2.4.2). Oil exploration will continue to the west along the Barrow Arch of the NPRA, while it is assumed gas exploration will be into the Foothills region of the ANS. Oil exploration in the Beaufort Sea up to 25 miles offshore will occur.

3.8.3 MEFS Results

The results of the MEFS analysis are shown in Table 3.132. The table contains the estimates of OOIP or OGIP equivalent to a cumulative PW = 0 at the last year of the project life at the economic limit using the project timing in Table 3.130 for the four price tracks and the assumptions listed above.

Table 3.132. MEFS forecasts by region (OOIP or OGIP) for ANS West Coast price tracks.

MEFS Case		OOIP/OGIP (MB/MMCF)			
		$25/bbl	$35/bbl	$50/bbl	$60/bbl
Core–5 miles	Oil & NGLs (MB)	9,450	5,730	3,600	2,880
Core–10 miles	Oil & NGLs (MB)	11,950	7,241	4,547	3,644
NPRA–50 mi. west of Alpine	Oil & NGLs (MB)	402,300	84,160	33,220	23,350
NPRA–100 mi. west of Alpine	Oil & NGLs (MB)	894,100	147,700	63,530	44,340
NPRA–100 mi. west of Alpine with pipeline to PS-1	Oil & NGLs (MB)	1,918,000	610,800	278,100	205,400
ANWR–110 mi. east of PS-1	Oil & NGLs (MB)	1,684,000	195,900	82,930	58,830
ANWR–160 mi. east of PS-1	Oil & NGLs (MB)	3,335,000	560,600	209,500	151,000
Beaufort Sea–20 mi. offshore	Oil & NGLs (MB)	1,322,000	1,019,800	249,900	165,500
Chukchi Sea–50 mi. offshore	Oil & NGLs (MB)	15,562,000	3,393,000	983,500	614,600
Foothills gas–50 mi. to AGP	Gas (MMCF)	1,181,000	458,800	232,700	173,300
Foothills gas–100 mi. to AGP	Gas (MMCF)	2,166,000	837,100	431,200	328,200

The NPRA 100-mi. case with a pipeline to PS-1 and the ANWR 160-mi. case are similar distances from PS-1and have the same assumed cost structure; however, the ANWR case results in a significantly larger MEFS as a result of the five-year delay in project timing reflecting the impact of escalation on capital and operating costs.

The impact of project timing and delays on the MEFS is examined by two special cases: Case 1–All regions are analyzed for first exploration in 2008, first development in 2009, and first production in 2010. Case 2–All regions are analyzed for first exploration in 2010, first development in 2014, and first production in 2015. These results are shown in Table 3.133 and Table 3.134, respectively. The gray-shaded cells below indicate the base case start year for the projects.

Table 3.133. MEFS forecasts by region (OOIP or OGIP) for ANS West Coast price tracks, 2010 start of production.

MEFS Case		OOIP/OGIP (MB/MMCF)			
		$25/bbl	$35/bbl	$50/bbl	$60/bbl
Core–5 miles	Oil & NGLs (MB)	9,450	5,730	3,600	2,880
Core–10 miles	Oil & NGLs (MB)	11,950	7,241	4,547	3,644
NPRA–50 mi. west of Alpine	Oil & NGLs (MB)	402,300	84,160	33,220	23,350
NPRA–100 mi. west of Alpine	Oil & NGLs (MB)	894,100	147,700	63,530	44,340
NPRA–100 mi. west of Alpine with pipeline to PS-1	Oil & NGLs (MB)	1,918,000	610,800	278,100	205,400
ANWR–110 mi. east of PS-1	Oil & NGLs (MB)	708,400	148,500	65,910	49,130
ANWR–160 mi. east of PS-1	Oil & NGLs (MB)	1,881,000	383,300	177,900	131,800
Beaufort Sea–20 mi. offshore	Oil & NGLs (MB)	5,058,000	603,200	192,500	132,200
Chukchi Sea–50 mi. offshore	Oil & NGLs (MB)	9,497,000	2,346,000	771,500	538,300
Foothills gas–50 mi. to AGP	Gas (MMCF)	1,204,000	423,600	218,300	161,900
Foothills gas–100 mi. to AGP	Gas (MMCF)	2,245,000	785,500	402,800	304,000

Table 3.134. MEFS forecasts by region (OOIP or OGIP) for ANS West Coast price tracks, 2015 start of production.

MEFS Case		OOIP/OGIP (MB/MMCF)			
		$25/bbl	$35/bbl	$50/bb l	$60/bbl
Core–5 miles	Oil & NGLs (MB)	11,090	6,600	4,110	3,280
Core–10 miles	Oil & NGLs (MB)	13,710	8,144	5,060	4,038
NPRA–50 mi. west of Alpine	Oil & NGLs (MB)	1,458,000	140,100	53,270	35,430
NPRA–100 mi. west of Alpine	Oil & NGLs (MB)	2,304,000	222,200	87,430	61,980
NPRA–100 mi. west of Alpine with pipeline to PS-1	Oil & NGLs (MB)	2,983,000	796,500	339,000	242,100
ANWR–110 mi. east of PS-1	Oil & NGLs (MB)	1,684,000	195,900	82,930	58,830
ANWR–160 mi. east of PS-1	Oil & NGLs (MB)	3,335,000	560,600	209,500	151,000
Beaufort Sea–20 mi. offshore	Oil & NGLs (MB)	1,322,000	1,019,800	249,900	165,500
Chukchi Sea–50 mi. offshore	Oil & NGLs (MB)	15,562,000	3,393,000	983,500	614,600
Foothills gas–50 mi. to AGP	Gas (MMCF)	1,181,000	458,800	232,700	173,300
Foothills gas–100 mi. to AGP	Gas (MMCF)	2,166,000	837,100	431,200	328,200

These results demonstrate the significant price and time sensitivity for large frontier projects requiring large capital expenditures and long lead times, illustrating the combined effect of price risk and project delay on the MEFS. The larger frontier projects tend to have greater sensitivity and more pronounced increases in the required MEFS at the lower price tracks.

The above estimates of MEFS initial hydrocarbon in place for economic development under these assumptions are subject to a large range of uncertainty. Another way to present the results is to use the USGS field class nomenclature, in which the field size doubles as the field class increases. This has the advantage of expressing the MEFS in a broader range of field sizes and avoids implying more certainty in the estimates than may be warranted. The USGS uses field class size as a measure of field size and a basis for comparison of recent USGS calculations of recoverable undiscovered hydrocarbons on the NPRA and 1002 Area of ANWR. The field class size classification for oil and gas fields is shown in Table 3.135.

Table 3.135. USGS field size classification.

Class	**Oil field size**	**Gas field size**
	(Millions barrels)	*(Billions cubic feet)*
1	0.03125 - 0.0625	0.1875 - 0.375
2	0.0625 - 0.125	0.375 - 0.750
3	0.125 - 0.25	0.75 - 1.50
4	0.25 - 0.5	1.50 – 3
5	0.5 - 1	3.00 - 6.00
6	1 - 2	6 – 12
7	2 - 4	12 – 24
8	4 - 8	24 – 48
9	8 - 16	48 – 96
10	16 - 32	96 – 192
11	32 - 64	192 – 384
12	64 - 128	384 – 768
13	128 - 256	768 – 1536
14	256 - 512	1536 – 3072
15	512 -1024	3072 – 6144
16	1024 - 2048	6144 – 12288
17	2048 - 4096	12288 – 24576
18	4096 - 8192	24576 – 49152
19	8192 - 16384	49152 - 98304
20	16384 - 32768	98304 - 196608

Table 3.136 recasts the results in terms of USGS field class size.

Table 3.136. MEFS – USGS field class size for ANS West Coast Flat price tracks for the base case project start up.

MEFS Case	USGS Field Class Size			
	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Core–5 miles	9	8	7	7
Core–10 miles	9	8	8	7
NPRA–50 mi. west of Alpine	14	12	11	10
NPRA–100 mi. west of Alpine	15	13	11	11
NPRA–100 mi. west of Alpine with pipeline to PS-1	16	15	14	13
ANWR–110 mi. east of PS-1	16	13	12	11
ANWR–160 mi. east of PS-1	17	15	13	13
Beaufort Sea–20 mi. offshore	16	15	13	13
Chukchi Sea–50 mi. offshore	19	17	15	15
Foothills gas–50 mi. to AGP	13	12	11	10
Foothills gas–100 mi. to AGP	14	13	12	11

These results show that the MEFS outside of the core area will require oil fields in Field Class Sizes of 14 to 19 (256 MMBO to 16 BBO) for the $25/bbl case decreasing to Field Class Sizes of 12 to 17 (64 MMBO to 4 BBO) for the $35/bbl price track, Field Class Sizes of 11 to 15 (32 MMBO to 1 BBO) for the $50/bbl price track, and Field Class Sizes of 10 to 15 (16 MMBO to 1 BBO) for the $60/bbl price track. Fields of this size are well within the expected range of field sizes especially for the higher price tracks.

Gas exploration and development in the Foothills at 50 and 100 miles from the ANS gas pipeline corridor will require Field Class Sizes of 13 to (768 BCF to 3 TCF), respectively, at a $25/bbl ($3.12/MCF). At $60/bbl ($7.50/MCF) the Field Class Size required are 10 to 11 (96 MCF to 384 BCF).

The remote and harsh environment of the Chukchi Sea is reflected in the large MEFS required. A field class size of 19 (8.192 to 16.384 BBO) is required at a price track of $25/bbl. At higher price tracks the MEFS drops dramatically to field class size of 17 to 15 (4.096 BBO to 512 MMBO) at prices of $35 to $60/bbl. Development of the Chukchi Sea will be significantly impacted by expansion of a petroleum producing infrastructure to the Western NPRA to facilitate exploration and development activities and the transport oil and gas to PS 1 or the gas processing plant for the AGP and to market.

3.9 Facility Sharing

Facility sharing is not a new concept on the ANS. Facility sharing has been used for many years, but to date, only within a unit boundary between an initial PA and unit satellites. With the discovery of smaller oil and gas accumulations that cannot support stand-alone facilities and to minimize the need to expand infrastructure where not essential, the possibility of processing their produced fluids in an existing facility is now actively discussed. This is becoming even more important and potentially more complicated by the involvement of independent operators new to the ANS. Issues relating to facility sharing and availability of capacity in pipelines were discussed in detail in a 2004 study (PRA, 2004). That study identifies factors and trade-offs that involved parties must resolve and agree on before a facility-sharing agreement is executed.

In addition to compensating the facility owners for their backed-out oil, the outside party must compensate them for certain costs applicable only to the outside party's production. These costs will most likely be, but not necessarily limited to, those in Table 3.137 (PRA 2004, p. 27)

Table 3.137. Facility Owner's Fees

TYPE	FEE
Facility Access	Capital Access
	Capital Access Surcharge
	Abandonment
	Abandonment Surcharge
Operation and Maintenance Costs	Plant Liquid Processing
	Plant Gas Processing
	Common Drillsite
	Water Fee
	Ad Valorem Tax

Most of the existing processing facilities are currently operating under certain fluid constraints. These are shown on Table 3.138 (PRA, 2004).

Table 3.138. ANS Facility Capacity Status.

FACILITY	CAPACITY STATUS			
	Oil	**Gas**	**Water Producing**	**Water Injection**
Alpine PA(1)	Spare Cap.	Spare Cap.	Spare Cap.	Spare Cap.
Badami Unit	Spare Cap.	Spare Cap.	Spare Cap.	Spare Cap.
Endicott PA(3)	Spare Cap.	At Cap.	At Cap.	At Cap.
Kuparuk River Unit IPA(3)	Spare Cap.	At Cap.	At Cap.	At Cap.
Milne Point Unit IPA(2) (3)	Spare Cap.	Spare Cap.	Spare Cap.	Spare Cap.
Northstar Unit	Spare Cap.	Marginal	Spare Cap.	Spare Cap.
Prudhoe Bay Unit IPA(3)	Spare Cap.	At Cap.	At Cap.	AT Cap.
Lisburne PA(3)	Spare Cap.	Spare Cap.	Spare Cap.	Spare Cap.

(1) Satellite development (Fiord, Nanuq) will offset capacity.
(2) Schrader Bluff development will most likely offset capacity.
(3) Facilities sharing now.

In addition to fluid processing facility constraints, the pipelines transporting oil to TAPS Pump Station 1 have volume limitations. Table 3.139 lists the crude oil lines and their capacities (PRA, 2004).

Table 3.139. North Slope Crude Oil Pipeline Capacities.

PIPELINE	CAPACITY – MBOPD
Alpine	100
Badami	35
Endicott	100
Kuparuk	400

PIPELINE	CAPACITY – MBOPD
Milne Point	65
Northstar	65
TAPS	1,400

The above capacity volumes could be misleading because the Badami line feeds into the Endicott line, and both Alpine and Milne Point lines feed into the Kuparuk line. As new projects are placed on production, it is likely that some pipeline capacities will be exceeded. For example, the Alpine pipeline is shipping oil at capacity now. It is assumed individual studies will determine whether line capacity will be expanded or if sales volumes will be limited.

There are several potential developments where facility sharing is being investigated. Some are already in effect in PBU and other units with multiple PA's. Proposed projects for which facility sharing agreements are desired are: (a) Alpine PA and it satellites; (b) KRU IPA with both the Tuvaaq Unit and the Oooguruk Unit, (c) Badami Unit or DIU IPA and the LU, and (d) Lisburne Facility and GBU.

3.9.1 Facility Sharing Example

The example chosen to investigate the economics of facility sharing is the LU. The production forecast developed for the LU described in Section 3.4.9 is used and it is assumed that it will be processed by the DIU facility. This example considers oil, gas, and water production and water injection (handling) constraints and associated costs. Some cost factors not included are allowance for supplying electrical power and oil quality adjustment. A recent month's well-by-well production statistics for the Endicott PA are used, and it is assumed for illustration that these statistics will apply when Liberty is placed on production.

As shown on Table 3.138, the DIU (Endicott PA) processing facility has excess oil handling capability, but gas processing, water processing, and water handling capacity are at maximum volumes. For LU Unit production to be processed at DIU, production from some high GOR and high water-cut wells in Endicott PA must be backed out (shut in) to provide both gas and water handling capacity. These wells will likely have the highest operating cost and lowest economic value to the Endicott PA.

The evaluation performed in Section 3.4.9 for LU shows the forecasts for the first-year of production for oil, gas, and water are about 10 MBOPD, 7.6 MMCFD, and 0 BWPD. It is assumed this annual daily average is representative of the first month's production from the LU. Although no water production is forecasted for LU at initial production, the unit needs injection water for EOR and pressure maintenance. The injection water volume needed is estimated to be 1.4 BW per 1.0 BO, or 14 MBWPD for the first month's operation of an EOR project. Examination of the Endicott PA wells with the highest GOR and water cuts shows production from five wells must be backed out to provide the required gas and water handling capacities. These wells produce a total of about 430 BOPD, 7,650 MCFPD and 13,800 BWPD. The LU must compensate the Endicott PA for the 430 BOPD backed-out oil with any applicable quality adjustments and the future loss of associated production. An examination of facility-sharing impacts and requirements such as this will need to be made periodically and a production adjustment made. The methodology and timing for such adjustments will need to be agreed to by the involved parties in the facility-sharing agreement. This will assure that the least economical wells with the highest GOR's and water cuts, regardless of ownership, are shut in and meet the state's requirements for conservation of resources.

In addition to the 430 BOPD received by the Endicott PA in compensation, the LU owners must pay the fees outlined in Table 3.140.

Table 3.140. Facility Sharing Fees.

FEE TYPE	FEE COST (2005$)	FIRST MONTHS FEE (2005$)
Capital Access(1)	$1.68/BO	$488,750
Abandonment(2)	$0.15/BO	$443,650
Plant Liquid Processing(2)	$0.12/BLiquids	$434,900
Plant Gas Processing(2)	$0.05/MCF	$11,050
Common Drillsite(2)	$0.13/BLiquids	$37,850
Excess Water Fee(2) (3)	$0.06/BW	$25,550
Ad Valorem Tax(1)	$0.05/BO	$14,550
	TOTAL	**$656,250**

(1) From DIU evaluation – Section 3.5.12.; it is assumed that no facilities are added to DIU so no Capital Access Surcharge fee is added.
(2) The PRA (2004) study is used as a guide.
(3) Injection water volume estimated as 1.4 BW/BO.

The facility sharing algorithm combined the fees as shown below on a daily rate.

$$Fee = (\$1.88 * Oil\ \ production + \$0.05 * Gas\ \ production + \$0.084 * Water\ \ production + \$0.25 * Total\ liquid)$$

The fee is then multiplied by 365 days a year and adjusted for general inflation.

This example is intended as an interpretation of the methodology for determining the effect on both parties to a facility agreement. The actual results will be determined by the provisions of the Facility Agreement that will be negotiated by the parties based on the specific factors pertaining to the fluids from both projects and the facilities on the receiving project.

An economic comparison is made of the impacts of facility sharing with a stand-alone development using the LU. The stand-alone development scenario used the facility cost algorithm consistent with the MEFS section (Section 3.8). The results for the Liberty project as a stand-alone development for future and ultimate economical recoveries for four ANS West Coast flat oil prices in then current dollars are presented in Table 3.141.

Table 3.141. LU Stand Alone (w/o facility sharing)–Forecasts of ultimate economical recoveries for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Date of last production	2024	2029	2033	2035
Future Gas forecast (MMCF)	81,658	89,265	92,161	93,039
Future water forecast (MB)	217,693	315,788	354,120	365,494
Oil and NGLs EUR (MB)	107,620	117,765	121,633	122,804
Total gas reinjected (Est.) (MMCF)	68,593	74,983	77,416	78,152

The potential revenue to the state and federal governments and net income, investment, operating costs to the pool operators for the life of the project are shown for all prices tracks in Table 3.142.

Table 3.142. LU Stand Alone (w/o facility sharing)–Forecasts of economic results for ANS West Coast prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	$1,156,055	$1,222,016	$1,261,212	$1,261,212
Total operating costs	$1,027,250	$1,396,221	$1,632,818	$1,736,511
State royalty	$320,358	$552,756	$884,485	$1,104,733
State taxes – Severance	$19,337	$29,316	$44,284	$54,263
State taxes – Income	$11,922	$42,789	$100,558	$141,905
State taxes – Other	$88,393	$103,849	$105,020	$105,076
State Total (Royalty and Taxes)	$440,010	$728,710	$1,134,347	$1,405,977
Federal taxes	$77,074	$493,883	$1,165,836	$1,636,329
Industry net income	$203,945	$954,091	$2,263,090	$3,176,402

The LU base case results have been previously present in Tables 3.92 and 3.93. Comparisons between LU as a facilities-sharing project with LU as a stand-alone project are presented in Tables 3.143 and 3.144, where the deltas are for the facility-sharing case minus the stand alone case.

Table 3.143. Δ comparison of LU with Facility Sharing minus Stand Alone–Forecasts of future and ultimate economical recoveries for ANS West Coast Flat prices (then current $).

VARIABLE	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Future Gas forecast (MMCF)	(8,609)	(5,555)	(1,215)	(403)
Future water forecast (MB)	(88,631)	(72,827)	(15,972)	(5,207)
Oil and NGLs EUR (MB)	(11,456)	(7,410)	(1,622)	(538)
Total gas reinjected (Est.) (MMCF)	(7,231)	(4,666)	(1,020)	(338)

Table 3.144. Δ comparison of LU with Facility Sharing minus Stand Alone–Forecasts of economic results for ANS West Coast Flat prices (then current $).

VARIABLE (M$)	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Total investments	(455,544)	(484,962)	(482,224)	(482,224)
Total operating costs	138,397	247,227	532,019	621,833
State royalty	(38,043)	(42,061)	(15,916)	(6,914)
State taxes – Severance	(4,292)	(6,480)	(9,762)	(11,948)
State taxes – Income	(578)	(1,664)	(3,506)	(3,719)
State taxes – Other	(55,058)	(60,823)	(55,769)	(55,718)
State Total (Royalty and Taxes)	(97,971)	(111,028)	(84,953)	(78,299)
Federal taxes	(46,393)	(88,417)	(121,815)	(130,636)
Industry net income	(20,345)	(99,788)	(176,994)	(191,663)

This analysis shows that facility sharing results in a reduction in required investment, with most of the investment occurring early in the life of the project offset by an increase in operating costs. The avoided investment varies for the facility-sharing base case from $455 million at the low price track to $482 million for the higher prices. This economic benefit is offset by the higher operating costs for facility sharing. However, these costs are spread out over the life of the project and thus have a lower present value when discounted back to the present. The lost production due to the higher operating costs from facility sharing is 11.5 MMBO at $25/bbl, declining to 7.4 MMBO at $35/bbl and 1.6 and 0.54 MMBO at $50 and $60/bbl price tracks respectively. The cumulative PW of the total cash flow for the two cases and the four prices tracks is shown in Table 3.145 and illustrates the positive impact that facility sharing can have on a project.

Table 3.145. Cumulative Present Worth (discount rate of 10%) comparison of the impact of facility sharing, thousands 2005$s.

Scenario	$25/bbl	$35/bbl	$50/bbl	$60/bbl
Cum PW with facility sharing	**($23,338)**	**$238,943**	**$665,296**	**$958,948**
Cum PW without facility sharing	**($102,672)**	**$165,787**	**$596,970**	**$890,540**
Delta Cum PW (FS – w/o FS)	$79,334	$73,156	$68,326	$68,408

This economic benefit of facility sharing is greatest at the $25/bbl price track. At the higher price tracks the delta Cum PW declines somewhat, but is still significant. Thus, facility sharing is a trade-off between lower recoveries at the lower price tracks offset against the avoided capital costs of the facility investments. From a Cum PW analysis, facility sharing has a higher cum PW than stand alone facilities and, where applicable, would result in the conservation of capital.

Another way to view the results from an investment perspective is to look at the investment per recoverable barrel. The facility-sharing base case has investment costs of $6.37 to $7.28 per barrel of recoverable oil. The investment costs for the stand-alone development are $10.27 to $10.74 per barrel recoverable. The reduction in investment costs with facility sharing provides a distinct economic advantage. Given the current high oil price environment, the additional cost of facility sharing is more than covered by the increased revenue.

3.10 Summary of Engineering and Economic Evaluations

- The TRR's estimated for the current producing ANS fields total 4.7 BBO and the current estimated average recovery factor is 48%. For the known fields with pending or announced development plans, the TRR's total 1.3 BBO. For the known fields with near-term development potential the TRR's total 388 MMBO. The total TRR for this grouping of fields analyzed in the no-major-gas-sales case is 6.4 BBO.

- For the major gas sales case the PTU condensate and oil results in an addition of 400 MMBO from PTU and an estimated decrease from PBU of 138 MMBO for a total from all categories of fields including PTU of about 6.8 BBO remaining reserves. Development of these fields should provide production rates of about 900,000 BOPD until about 2015. Production is then expected to decline to about 300,000 BOPD by 2025 to 2026 unless new discoveries are made, other known fields are developed, or the decline is offset by reserves growth in developed fields.

- The investment required by industry to achieve the forecast production is estimated to be over $15 billion dollars (then current dollars). This does not include the cost for construction of the AGP system. The operating expenses are estimated to be about $90 billion (then current dollars).

- The TAPS minimum rate of about 300,000 BOPD, absent new developments or reserves growth beyond the forecasted TRR's, will be reached in 2025. An AGP and gas sales from PTU and the associated oil and condensate would provide another boost to oil production and extend the life of TAPS for about one year to 2026. However, in either case, a shut down of TAPS would potentially strand up to about 1 BBO of oil reserves. The certainty of a gas pipeline is expected to increase exploration activity across the ANS areas and should result in new discoveries and expansion of the infrastructure and results in additional oil as well as gas discoveries and extend the life of TAPS.

- Other significant issues include the possibility of exploration in the 1002 Area of ANWR, which is likely to contain an estimated mean of 10.4 BBO in a 1.9 million acre area (5,475 BO/acre). The opening of the ANWR 1002 Area would be expected to significantly increase exploration activity and lead to increased reserves of oil and gas.

- The construction of an AGP by 2015 and the ability to sell gas from PBU and PTU will almost double the revenue to the stakeholders (state of Alaska, federal government, and industry).

- These MEFS estimates and the geological evidence for the ANS areas indicate that oil and gas fields of sufficient size could be found to support development for the anticipated oil and gas prices regimes provided access to the areas, adequate oil and gas prices, and the fiscal and regulatory environment is supportive of the large investments that will be required.

- A field developed with a facility-sharing agreement requires less capital investment than would be required for a stand-alone development and results in a higher project Cumulative PW that a stand-alone development. The effect is higher for the lower oil prices. Hence, facility sharing has the potential to be a positive factor in future developments and is more valuable with lower oil prices.

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4. ENVIRONMENTAL AND REGULATORY ISSUES

4.1 Role of Government in North Slope Resource Development

Development of petroleum resources on the North Slope of Alaska requires input from numerous agencies of the local, state, and federal government. The purpose of this section is to list the various government agencies that play roles in exploration, production, and delivery of petroleum from the North Slope, and to provide brief descriptions of the role each agency plays in resource development. The regulatory basis supporting these roles is discussed in Section 4.2, along with summaries of the various acts, regulations, and permits applicable to North Slope oil and gas exploration and development.

Many of the agencies involved with North Slope development maintain regulatory authority over some aspect of oil and gas exploration and development. In some cases, this authority relates directly to the management of the land on which development is occurring or proposed. More often, however, the role of a particular agency relates to the mission and associated regulatory authority of the agency, and is not related to land management responsibility *per se*.

Historically, most of the development on Alaska's North Slope occurred on state-owned lands. This includes Prudhoe Bay and Kuparuk oil fields as well as most of the surrounding satellite fields. As development of North Slope resources has expanded over the past two decades, however, an increasing proportion of the development has occurred and continues to occur on lands administered by agencies of the federal government. This includes current and anticipated development on NPRA (administered by the Bureau of Land Management) and various offshore areas of the Beaufort and Chukchi Seas beyond the three-mile limit (administered by the Minerals Management Service). If exploration and development occur in ANWR, the U.S. Fish and Wildlife Service would function in a land management capacity.

A summary of the various federal, state, and local agencies involved with oil and gas exploration and production is provided below.

4.1.1 Federal Government

North Slope oil and gas exploration and production involves several agencies of the federal government. The roles that the different federal agencies play range from land management to regulatory to advisory.

4.1.1.1 Environmental Protection Agency (EPA)

The basic mission of the EPA is to protect human health and the environment. Among the components of this mission is to ***develop and enforce regulations*** that implement environmental laws enacted by Congress. EPA is also responsible for ***researching and setting national standards*** for a variety of environmental programs. Where national standards are not met, EPA also has the authority to ***issue sanctions*** and take other steps to assist the states and tribes in reaching the desired levels of environmental quality. EPA's legal authority is provided by numerous environmental laws enacted by Congress. Among those most pertinent to oil and gas development on the North Slope are the following:

- 1948 Federal Water Pollution Control Act (also known as the Clean Water Act)
- 1955 Clean Air Act
- 1965 Shoreline Erosion Protection Act
- 1965 Solid Waste Disposal Act
- 1970 National Environmental Policy Act
- 1972 Coastal Zone Management Act
- 1972 Marine Protection, Research, and Sanctuaries Act
- 1972 Ocean Dumping Act
- 1973 Endangered Species Act
- 1974 Safe Drinking Water Act
- 1974 Shoreline Erosion Control Demonstration Act
- 1975 Hazardous Materials Transportation Act
- 1976 Resource Conservation and Recovery Act
- 1976 Toxic Substances Control Act
- 1980 Comprehensive Environmental Response, Compensation, and Liability Act
- 1986 Emergency Planning and Community Right to Know Act
- 1988 Lead Contamination Control Act
- 1988 Ocean Dumping Ban Act
- 1988 Shore Protection Act

Federal regulations administered by the EPA often contain language that allows the agency to delegate the responsibility for issuing permits and for monitoring and enforcing compliance to states and tribes that choose to accept primacy in the area. In Alaska, for example, the state maintains primacy for most air quality regulations through the state Department of Environmental Conservation (ADEC). The wastewater permit program established in the Clean Water Act has historically been administered by the EPA. In August 2005, however, Governor Murkowski signed a bill directing ADEC to assume primacy for this program. It is anticipated that ADEC will take over the wastewater permit program in the near future.

4.1.1.2 Department of the Interior:

Several agencies within the U.S. Department of the Interior (DOI) play important roles in oil and gas development on the North Slope. In recent years, agencies within the DOI have become increasingly involved with the development of North Slope petroleum resources because development has been spreading to lands administered by these agencies.

- **Bureau of Land Management (BLM):** Much of the land area within the state of Alaska is under federal ownership, and a large fraction of this federal land is administered by the BLM. In addition to their primary responsibility of managing public lands, BLM in Alaska is also responsible for providing interagency wild land fire management, overseeing the Joint Pipeline Office (a partnership with the state and other federal agencies with oversight responsibility of the Trans Alaska Pipeline System), and responding to the public demand for use of public land. On the North Slope, BLM administers NPRA, an area covering 23.5 million acres that is currently undergoing increased exploration and development activities. Within the NPRA, BLM currently manages resource development in three major planning areas.

- **Minerals Management Service (MMS):** The MMS is the federal agency that manages petroleum and other resources on the outer continental shelf (OCS) beyond the three-mile limit from the shore. The agency also collects, accounts for and disburses revenues from Federal offshore mineral leases and from onshore mineral leases on federal and Indian lands. The Alaska OCS Region encompasses 600 million acres and more than 6,000 miles of coastline containing a diversity of ecosystems. With respect to resource development on the North Slope, the goal of the MMS is to provide the opportunity for development while preserving the quality of the environment and the lifestyle of the people living adjacent to its coast.
- **U.S. Fish and Wildlife Service (FWS):** Among the responsibilities of the FWS are to (1) conserve natural resources; (2) enforce federal wildlife laws; (3) protect endangered species; (4) manage populations of migratory birds; (5) restore and maintain nationally significant fisheries; and (6) protect, conserve and restore critical wildlife habitat such as wetlands. On the ANS, the FWS also functions in a land management role, administering the Arctic National Wildlife Refuge (ANWR). If exploration and development is allowed to proceed within the 1002 Area of ANWR, the role of the FWS in oil and gas exploration and permitting will expand much as that of BLM has over the past few years.
- **National Park Service (NPS).** The NPS is responsible for administering the Native American Graves Protection and Repatriation Act of 1990, which requires that discovery or disturbance of any human remains in project area must be accounted for and protected and/or properly returned to the tribe of origin. The NPS also administers the American Indian Religious Freedom Act which helps to protect sites considered sacred to Native Americans.

4.1.1.3 Department of Commerce:

- **National Oceanic and Atmospheric Administration (NOAA) Fisheries:** Formerly the National Marine Fisheries Service, NOAA Fisheries is responsible for the stewardship of living marine resources. Their goal is to conserve, protect, and manage marine biota in a way that ensures their continuation as functioning components of marine ecosystems while affording economic opportunities and enhancing the quality of life for the public.

4.1.1.4 Department of the Army:

- **Army Corps of Engineers:** The Department of the Army regulatory program is administered by the U.S. Army Corps of Engineers (ACE). The program is authorized by section 10 of the Rivers and Harbors Act of 1899, section 404 of the Clean Water Act (CWA), and section 103 of the Marine Protection, Research and Sanctuaries Act. The permit program authorizes activities in, on, or affecting, navigable waters as well as the discharge of dredge or fill into waters of the United States. For purposes of administration, waters of the United States include wetlands, which encompass much of the ANS. The most common oil and gas activity requiring an ACE permit is the discharge or placement of fill, generally gravel or ice, on "wetlands."

4.1.1.5 Department of Transportation:

- **U.S. Coast Guard (USCG):** The USCG was part of the Department of Transportation (DOT) until March 2003 when it was transferred to the Department of Homeland Security (DHS). In addition to providing maritime support by patrolling the nation's shores and conducting emergency rescue operations, the USCG is involved with the cleaning up of oil spills. The Coast Guard also maintains authority under the Rivers and Harbors Act of 1899 to approve construction of any bridge across navigable waters to ensure safe navigability of waterways. Finally, the USCG is charged with preventing the unauthorized obstruction or alteration of the nation's navigable waters. On the North Slope, the USCG authorizes any bridge or other proposed potential obstruction to the major rivers and their tributaries.

4.1.2 State Of Alaska

4.1.2.1 Alaska Department of Natural Resources (ADNR).

The mission for the ADNR is "to develop, conserve, and enhance natural resources for present and future Alaskans". Several divisions within ADNR play active roles in oil and gas development on the ANS and elsewhere in Alaska, the most prominent of which is the Division of Oil and Gas (ADOG). The Division of Geological and Geophysical Surveys (DGGS) and the Division of Mining, Land, and Water (DMLW) are also involved to a lesser degree.

- **Alaska Division of Oil and Gas (ADOG):** The ADOG is responsible for advocating petroleum resource development throughout the state. The Division is charged with ensuring that lands within the state that are promising from an oil and gas resource standpoint are made available for competitive leasing on a timely and predictable basis, and ensuring that the state receives full value for the sale of these resources. ADOG identifies prospective lease areas, performs geologic, economic, environmental and social analyses of potential lease areas, develops leasing schedules, and conducts public reviews of proposed sales. ADOG then conducts competitive oil and gas lease sales and ensures that all royalty, rental and bonus revenues due the state from leasing and production are received, and that shared federal royalties are properly received and allocated. Furthermore, ADOG is charged with ensuring that the surface operations of lessees and permittees are conducted in an environmentally, socially, and economically sound manner. Programs for encouraging exploration on state and private lands are also implemented by ADOG. Finally, ADOG is responsible for providing technical and policy support on oil and gas issues for the ADNR Commissioner's and Governor's office and Alaska's congressional delegation.

- **Division of Geological and Geophysical Surveys (DGGS):** The DGGS is responsible for generating, analyzing and interpreting data on geologic resources and natural conditions within Alaska, and for developing and maintaining maps and inventories of mineral and energy resources on state land for use by government, private industry, scientists, educators and the public.

- **Division of Mining, Land, and Water (DMLW):** The DMLW has the primary responsibility for managing Alaska's land holdings. DMLW's responsibilities include: (1) ensuring the state's title; (2) preparing land-use plans and easement atlases; (3) classifying land; (4) leasing and permitting state land for recreation, commercial and industrial uses; and (5) coordinating and overseeing the needed authorizations for major development on the ANS. DMLW also manages water resources, as well as mineral resources excluding oil and gas, coalbed methane, and geothermal energy. The division allocates and manages the state's water resources on all lands in Alaska, adjudicates water rights, provides technical hydrologic support, and assures dam safety.

Other Divisions within ADNR play minor roles in the development of oil and gas resources in Alaska. The Division of Forestry, for example, is responsible for wildfire suppression throughout the state. The Support Services Division includes a Land Administration System and a Geographic Information System for mapping lands within the state.

4.1.2.2 Alaska Department of Fish and Game (ADFG)

The mission of the ADFG is to protect, maintain, and improve the fish, game, and aquatic plant resources of the state, and to manage their use and development for the maximum benefit of the people of the state, consistent with the sustained yield principle. The goals of ADFG are (1) to optimize economic benefits from fish and wildlife resources; (2) to optimize public participation in fish and wildlife pursuits; and (3) to increase public knowledge and confidence that wild populations of fish and wildlife are responsibly managed.

4.1.2.3 Alaska Oil and Gas Conservation Commission (AOGCC)

The AOGCC is an independent, quasi-judicial agency of the State of Alaska established under the Alaska Oil and Gas Conservation Act (AS 31). The AOGCC oversees oil and gas drilling, development and production, reservoir depletion, and metering operations on all lands subject to the state's police powers. They also act to prevent waste, protect correlative rights, improve ultimate recovery, protect underground freshwater, and administer the Underground Injection Control (UIC) program for enhanced oil recovery and underground disposal of oil field waste in Alaska.

4.1.2.4 Alaska Department of Environmental Conservation (ADEC)

The mission of the ADEC is to ***"conserve, improve, and protect its natural resources and environment and control water, land, and air pollution, in order to enhance the health, safety, and welfare of the people of the state and their overall economic and social well being."*** With respect to North Slope oil and gas development,

- **Division of Air Quality (DAQ):** The air quality services of the division are designed around three programs: managing non-point and mobile sources of air pollution; managing stationary out-of-stack discharges of air pollution through a permit and compliance program; and field air monitoring to measure progress and understand problems.
    - **Air Monitoring and Quality Assurance Program:** Operates and oversees air quality monitoring networks throughout Alaska.
        - Operates ambient air quality monitoring networks to assess compliance with the National Ambient Air Quality Standards (NAAQS) for carbon monoxide, particulates, nitrogen dioxide, sulfur oxide, and lead.
        - Assesses ambient air quality for ambient air level of air toxics. Provides technical assistance in developing monitoring plans for air monitoring projects.
        - Issues Air Advisories to inform the public of hazardous air conditions

- **Air Non-Point and Mobile Sources Program:** Responsible for mobile and area sources of air contaminants pursuant to the 1970 Clean Air Act. Establishes air quality programs to regulate air emissions from stationary, mobile and other sources which pose a risk to human health and the environment.
- **Air Permit Program:** The mission of the Air Permit Program is to protect the Alaskan environment by ensuring that air emissions from industrial operations in the state do not create unhealthy air. This is accomplished through permitting actions and compliance assurance inspections.

- **Division of Spill Prevention and Response (SPAR):** The mission of SPAR is to (1) prevent spills of oil and hazardous substances; (2) prepare for when a spill occurs; and (3) rapidly and effectively respond to a spill so as to maximize protection of human health and the environment. SPAR ensures that regulated operators engage in proper spill prevention techniques through review of prevention plans that required as part of an oil discharge prevention and contingency plan. SPAR also conducts corrosion monitoring, leak detection, inspections of overflow alarms, secondary containment, tank inspections, pipeline testing, and tanker escort systems and evaluates technologies subject to the Best Available Technology (BAT) requirements. In responding to spills, SPAR's primary objectives include: (1) protection of public safety, public health and the environment from the direct or indirect effects of spills; (2) adequate cleanup of spills; (3) assessment and restoration of damages to property, natural resources and the environment; and (4) recovery of costs from the responsible party to the Response Fund. In partnership with industry and other government agencies, SPAR has developed the Alaska Incident Management System (AIMS), a standardized Incident Command System for spill response.

- **Division of Water:** The general mission of the Division of Water is to improve and protect water quality. This is accomplished by (1) establishing standards for water cleanliness; (2) regulating discharges to waters and wetlands; (3) providing financial assistance for water and wastewater facility construction and waterbody assessment and remediation; (4) training, certifying, and assisting water and wastewater system operators; and (5) monitoring and reporting on water quality.

- **Division of Environmental Health (EH):** The Division of Environmental Health is involved with safe drinking water, food and sanitary practices. The Division provides standards for protecting the environment and providing safe food and drinking water. The EH solid waste program ensures that municipal and industrial landfills and waste collection facilities are properly located based on risk factors, adequately operated, and correctly closed.

4.1.2.5 Alaska Division of Governmental Coordination (ADGC)

The ADGC implements the Alaska Coastal Management Program (ACMP), including responding to federal consistency certifications required by Section 307 of the Coastal Zone Management Act (CZMA), and rendering conclusive consistent determinations for projects requiring two or more state agency or federal permits.

4.1.3 Local Government

4.1.3.1 North Slope Borough (NSB)

The NSB has adopted a comprehensive plan and land management regulations under Title 29 of the Alaska Statutes (AS 29.40.020-040). These regulations are Title 19 of the NSB Municipal Code and require borough approval for certain activities necessary for exploration and development of lease contracts. The Borough can assert its land management powers to the fullest extent permissible under law to address any outstanding concerns regarding impacts to the area's fish and wildlife species, and habitat and subsistence activities.

Any onshore or offshore development that has the potential to disrupt subsistence activities requires consultation with the potentially affected subsistence communities and NSB to discuss potential conflicts with the siting, timing, and methods of proposed operations and safeguards or mitigating measures which could be implemented by the operator to prevent unreasonable conflicts. Through this consultation, the lessee shall make reasonable efforts to assure that exploration, development, and production activities are compatible with subsistence hunting and fishing activities and will not result in unreasonable interference with subsistence harvests.

The NSB also plays an integral role in the Coastal Zone Management Plan. NSB has a coastal management plan and participates in ACMP consistency reviews for projects located inside the coastal district. The NSB also participates in ACMP consistency reviews for projects located outside the coastal district if it is determined that the project may have direct and significant impacts on the coastal zone or resources.

4.2 Regulatory Basis for North Slope Oil and Gas Development

The legal authority for regulating the exploration and production of oil and gas resources on Alaska's North Slope is found under various federal, state, and local laws and regulations.

4.2.1 Federal Laws and Regulations

4.2.1.1 Clean Water Act (CWA) - 33 U.S.C. §§ 1251-1387

The CWA was first authorized in 1948, and was reauthorized in 1972 with the passage of the Federal Water Pollution Control Act (FWPCA). The CWA represents the primary federal statute protecting navigable waters and adjoining shorelines from pollution, and provides the basis for regulations detailing specific requirements for pollution prevention and response measures. The CWA is administered jointly by the EPA and ACE. Three major programs within the CWA impact oil and gas operations: (1) Section 311 - Oil and Hazardous Substance Liability; (2) Section 402 - the National Pollutant Discharge Elimination System (NPDES); and (3) Section 404 - Discharges of Dredge and Fill materials into U.S. Wetlands.

- **CWA Section 311 – Oil and Hazardous Substance Liability:** Section 311 of the CWA establishes procedures, methods and equipment, and other requirements for preventing the discharge of oil and other hazardous substances into or upon the navigable waters of the United States or adjoining shorelines from onshore and offshore facilities not related to transportation. It provides EPA and USCG with the authority to establish a program for preventing, preparing for, and responding to oil spills that occur in navigable waters of the United States, and to determine liability for the cost of cleanup. Under Section 311, the EPA requires the development and implementation of a Spill Prevention, Control, and Countermeasure (SPCC) plan by owners or operators of any facility storing a total capacity of 1,320 gallons of fuel in aboveground storage tanks (AST). The SPCC plan must be developed and implemented before oil production begins, and must describe the location of the fuel storage tank and methods of spill prevention to be implemented at the proposed facility. The State of Alaska requires that the ADEC have the opportunity to review all SPCC plans.

- **CWA Section 402 – NPDES Water Discharge Permit:** Section 402 was authorized through an amendment to the CWA, and regulates discharges into U.S. waters from point sources. Point sources are discrete conveyances such as pipes or man-made ditches. Effluent limitations are imposed, which restrict the quantities, rates, and concentrations of pollutants, and dictate relevant compliance schedules. Section 402 of the CWA establishes guidelines for effluent discharges from point sources to the waters of the United States for facilities, including oil and gas facilities and for the NPDES permitting program. The EPA issues a NPDES Permit and Fact Sheet under Section 402, Federal Water Pollution Control Act of 1972, as amended (CWA) for discharges of pollutants, including oil and gas, from a point source into water of the United States. Point-source discharges that require a NPDES permit include, but are not limited to, sanitary and domestic wastewater, gravel pit and construction dewatering, and hydrostatic test water, storm water discharges, etc. In most cases, the NPDES permit program is administered by authorized states. Alaska is one of the few states that have not selected to administer the NPDES program, so the program remains under authority of the EPA. However, in August 2005, the Governor signed a bill that directs ADEC to seek and assume primacy for the NPDES wastewater permit program established in the CWA. ADEC will submit a primacy application to EPA for their approval before July 1, 2006.

- **CWA Section 404 – Discharges of dredge and fill materials into U.S. wetlands:** Section 404 of the CWA is intended to prevent the discharge of dredged or fill material if a practicable alternative exists that is less damaging to the aquatic environment or if the nation's waters would be significantly degraded. Applicants for a 404 permit must take steps to avoid or minimize potential impacts to wetlands where practicable, and must provide compensation for any remaining, unavoidable impacts through activities to restore or create wetlands. Section 404 is administered by both the ACE and the EPA. ACE administers the day-to-day 404 permit program while EPA is responsible for developing and interpreting environmental criteria used in evaluating permit applications, determining the scope of geographic jurisdiction, approving overseeing State assumption, identifying activities that are exempt, and reviewing and commenting on individual permit applications. EPA also maintains authority to veto ACE permit decisions and has some enforcement authority. At the State level, the ADEC issues a Certificate of Reasonable Assurance for Section 404 Permits.

4.2.1.2 Oil Pollution Act (OPA) – 33 U.S.C. § 2701 et seq.

Authorized in 1990 largely in response to public concerns following the Exxon Valdez incident, the OPA amended the CWA to require the development of facility (EPA) and tank vessel (USCG) response plans and an area-level planning and coordination structure to coordinate federal, regional, and local government planning efforts with the industry. The OPA therefore improved the ability to prevent and respond to oil spills by establishing provisions that expand the federal government's ability, and provide the money and resources necessary, to respond to oil spills. The OPA also created the national Oil Spill Liability Trust Fund, which is available to provide up to one billion dollars per spill incident. In addition, the OPA provided new requirements for contingency planning both by government and industry. The OPA also amended the CWA’s requirements for contingency planning. The National Oil and Hazardous Substances Pollution Contingency Plan (NCP) was expanded in a three-tiered approach involving federal, state and local government. OPA also increased penalties for regulatory noncompliance, broadened the response and enforcement authorities of the Federal government, while preserving State authority to establish law governing oil spill prevention and response. In Alaska, the ADEC reviews and approves the Oil Discharge Prevention and Contingency Plan (ODPCP) and the Certification of Financial Responsibility submitted for storage or transport of oil.

The OPA also created two citizen advisory groups for Alaska - the Prince William Sound and the Cook Inlet Regional Citizens Advisory Councils. These non-profit organizations provide citizen oversight of terminal and tanker operations. They also help to foster a partnership between industry, government and citizens and carry out responsibilities identified in section 5002 of the OPA, including providing recommendations on policies, permits and site-specific regulations for terminal and tanker operations and maintenance and port operations, monitoring terminal and tanker operations and maintenance, and reviewing contingency plans for terminals and tankers and standards for tankers.

4.2.1.3 Rivers and Harbors Act (RHA) -- 33 USC 403

Originally enacted in 1899, the RHA authorizes the ACE to issue Section 10 permits for structures or work within or potentially impacting, navigable waters of the United States. The purpose or the RHA is to prevent unauthorized obstruction or alteration of any navigable waters of the United States by dams, dikes, or other structures. The RHA also gives the U.S. Coast Guard (USCG) the authority to approve construction of any bridge across navigable waters to ensure safe navigability of waterways.

4.2.1.4 Hazardous Materials Transportation Act (HMTA) -- 49 USC 1801-1819

The Hazardous Materials Transportation Act of 1975 (as amended) requires that hazardous materials be transported according to USDOT regulations. The Secretary of Transportation must protect the nation adequately against risks to life and property that are inherent in the transportation of hazardous materials. The HMTA empowered the Secretary of Transportation to designate as hazardous material any "particular quantity or form" of a material that "may pose an unreasonable risk to health and safety or property." Enforcement of the HMTA is shared by several different administrations under delegations from the Secretary of the DOT, depending primarily on the mode of transportation of the hazardous material. These include the Federal Highway Administration (for transport by road), Federal Railroad

Administration (by rail), Federal Aviation Administration (by air), and U.S. Coast Guard (by water).

4.2.1.5 Fish and Wildlife Coordination Act (FWCA) 16 USC 661 et seq. FWCA of 1980 16 USC 2901

FWS provides consultation on effects to fish and wildlife resources for any project. FWS also consults with the state agency responsible for fish and wildlife resources Alaska Department of Fish and Game (ADFG) to conserve or improve wildlife resources in Alaska. The FWCA is intended to ensure that fish and wildlife resources receive equal consideration to other project features. The goal is to conserve and promote conservation of nongame fish and wildlife species and their habitats.

4.2.1.6 Bald and Golden Eagle Protection Act -- 16 USC 668

Through the Bald and Golden Eagle Protection Act, FWS has the authority to permit the relocation of bald eagle or golden eagle nests that interfere with resource development or recovery operations, with the goal of protecting bald eagle populations.

4.2.1.7 Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) 42 U.S.C. §§ 9601-9675

Authorized in 1980 and reauthorized in 1986 as the Superfund Amendments and Reauthorization Act (SARA), CERCLA is administered by the EPA. The purpose of CERCLA is to protect public health and the environment from risks posed by uncontrolled hazardous waste sites. CERCLA requires that certain releases ("Reportable Quantities") of hazardous substances from a facility or vessel be reported to the National Response Center. CERCLA authorizes federal response to a release or a "substantial threat" of a release into the environment of a hazardous substance or a pollutant or contaminant if it poses an "imminent and substantial danger to the public health or welfare." CERCLA regulations also contain the National Oil and Hazardous Substances Pollution Contingency Plan. Under these regulations, the spiller must plan to prevent and immediately respond to oil and hazardous substance spills and be financially liable for any spill cleanup. If the pre-designated Federal On-Scene Coordinator (FOSC) determines that neither timely nor adequate response actions are being implemented, the federal government will respond then seek to recover cleanup costs from the responsible party.

4.2.1.8 Safe Drinking Water Act (SDWA)-42 U.S.C. §§ 300f et seq.

Originally authorized in 1974, the SDWA was reauthorized in 1986. The SDWA is administered nationally by the EPA, and portions are administered in Alaska by AOGCC and ADEC. The goal of the SDWA is to ensure protection of the quality of public water supplies and all sources of drinking water. The Act establishes programs that regulate public drinking water systems and protect underground sources of drinking water. EPA has established a list of contaminants with enforceable drinking water limits. Regulatory responsibilities include the management of the UIC program and the direct implementation of Class I and Class V injection wells in Alaska for injection of non-hazardous and hazardous waste through a permitting process for fluids that are recovered from down hole, as well as municipal waste, stormwater, and other fluids that did not come up from down hole (40 CFR 124A, 40 CFR 144, 40 CFR 146). The EPA oversees the Class II program delegated to the State of Alaska that is managed by AOGCC, which includes Class II enhanced oil recovery, storage, and disposal wells that may receive non-hazardous produced fluids originating from down hole, including muds and cuttings (40 CFR 147). The EPA issues an UIC Class 1 Industrial Well permit for underground injection of Class 1 (industrial) waste materials. The UIC program was established to provide safeguards so that injection wells do not endanger current and future underground sources of drinking water. At the State level, the ADEC reviews and approves all public water systems including plan review, monitoring program, and operator certification.

4.2.1.9 Coastal Zone Management Act (CZMA) - 16 U.S.C. §§ 1451-1464

Authorized in 1972, the CZMA is administered by the U.S. Department of Commerce (DOC). The CZMA provides a cooperative federal and state mechanism to protect the coastal zone and to resolve conflicts among competing uses, and provides standards and funding for coastal states to prepare coastal management programs. Section 307 of the CZMA, the Federal Consistency Provision, requires federal activities affecting the coastal zone to be conducted to the maximum extent practicable consistent with approved State programs, and requires that applicants for federal licenses and permits affecting the coastal zone certify that their activities, including those on the outer continental shelf, are consistent with state programs coastal zone management programs. CZMA regulations have special provisions relating to energy production, including the requirement that the exploration and production activities on OCS be consistent with the state coastal zone management program. State programs must also provide adequate consideration of the national interest in the planning and siting of energy facilities. For the State of Alaska, the ADNR conducts a Coastal Zone Consistency review and issues determination of consistency of proposed development within the coastal zone.

4.2.1.10 Resource Conservation and Recovery Act (RCRA) - 42 U.S.C. §§ 6901-6991

Initially authorized in 1976, RCRA has been amended in 1980 and 1984 and was itself an amendment to the Solid Waste Disposal Act. RCRA is administered by the EPA and the State of Alaska, and requires "cradle to grave" management of hazardous wastes. The goal of RCRA is to ensure the protection of human health and the environment from the potential hazards of waste disposal, conservation of energy and natural resources, waste reduction, and environmentally sound waste management. Wastes uniquely associated with oil and gas exploration and production operations are exempt from regulation under RCRA. This includes drilling fluids, produced waters, and many other wastes associated with the exploration, development, or production of crude oil, natural gas, or geothermal energy. Any other hazardous waste generated at the facility is subject to the hazardous waste regulations. Under the authority of RCRA, the EPA also regulates underground storage tanks that store petroleum or certain chemical products.

4.2.1.12 Emergency Planning and Community Right-to-Know Act -- 42 USC 9601; 40 CFR 255, 370, and 372

The EPA implements facility reporting requirements to state and federal agencies for releases of hazardous substances in excess of specified amounts. The prevention of an accidental release of an extremely hazardous substance from any facility and, in the event of a release, to provide a mechanism for emergency response through state and local emergency planning teams and emergency response plans.

4.2.1.14 Clean Air Act (CAA) - 42 U.S.C. §§ 740l-7642

Authorized in 1970 and reauthorized in 1977, the CAA is administered by the EPA and the State of Alaska. The goal of the CAA is to protect and enhance the quality of the nation's air resources by controlling emissions of designated air pollutants by stationary and mobile sources. The CAA established National Ambient Air Quality Standards (NAAQS) for six priority pollutants: SO_2, NO_x, particulates, Pb, CO, and O_3. The CAA also requires pollutant source controls to comply with the "best available control technology" (BACT) for existing sources, and "new source performance standards" for major new sources or major source modifications. The primary standards are designed "to protect human health with an adequate margin of safety", while the secondary standards represent the levels "necessary to protect the public welfare from adverse effects". The CAA also established National Emission Standards for Hazardous Air Pollutants (NESHAPS) and "Prevention of Significant Deterioration" increments for SO_2, NOx, and particulates. Under Sections 165 and 502 of the CAA (42 USC §7401 et seq.), the State of Alaska is delegated authority to issue air quality permits for facilities operating within state jurisdiction for the Title V operating permit (40 CFR 70) and the Prevention of Significant Deterioration (PSD) permit (40 CFR 52.21) to address air pollution emissions. The EPA maintains oversight authority of the state's program. Under Section 309 of the CAA (42 USC §7401 et seq.), the EPA has the responsibility to review and comment on and Environmental impact Statement (EIS) for compliance with the Council on Environmental Quality (CEQ) Regulations for implementing the procedural provisions of the National Environmental Protection Act (NEPA – see Section 4.2.1.17) (40 CFR Parts 1500–1508). The EPA conducts a review and evaluation of the Draft and Final EIS for compliance with Section 309 of the CAA, and maintains oversight of ADEC's implementation of the federal PSD program through its state implementation plan.

4.2.1.15 Toxic Substances Control Act (TSCA) - 15 U.S.C. §§ 2601-2655

Authorized in 1976, TSCA is administered by the EPA for the purpose of imposing regulatory control over all toxic chemicals produced or used in the United States. These controls include testing, recordkeeping, reporting, and notice requirements. Management regulations to control the handling and disposal requirements were established under TSCA for some chemical substances and mixtures, including polychlorinated biphenyls (PCBs) and asbestos. The EPA develops and implements regulatory requirements for the testing of new and existing chemical substances and regulates the treatment, storage, and disposal of certain toxic substances.

4.2.1.16 National Ocean Pollution Planning Act - 33 U.S.C. §§ 1701-1709

The Ocean Pollution Research and Development and Monitoring Planning Act of 1978, more generally known as the Ocean Pollution Planning Act, was passed in response to the recognized need for a national program to investigate the fate and effects of pollutants on the marine environment. NOAA was charged with lead-agency responsibility for developing and implementing a continuous five-year plan for such a program.

4.2.1.17 National Environmental Policy Act (NEPA) - 42 U.S.C. §§ 4321-4347

Authorized in 1969 and administered by the EPA, NEPA requires all federal agencies to prepare a detailed statement of the environmental effects of a proposed federal action (such as the authorization of oil and gas development) that may significantly affect the quality of the environment. The intent is to protect the environment through the implementation of procedures that ensure that environmental information is available to public officials and citizens before decisions are made or actions are taken. NEPA established long-term national policy with the goal of promoting "conditions under which man and nature can exist in productive harmony, and fulfill the social, economic, and other requirements of present and future generations." Every federal agency must consider the environmental impacts of "proposals for legislation or other federal actions significantly affecting the quality of the human environment". The results of an agency's evaluation are to be contained in a detailed EIS, unless a "Finding of No Significant Impact" (FONSI) indicates that an EIS is not required. An EIS is subject to the review of other federal, state, and local agencies, as well as the general public. NEPA also authorized creation of a CEQ designed to ensure that federal agencies meet their NEPA obligations.

4.2.1.18 Endangered Species Act (ESA) - 16 U.S.C. §§ 1531-1543

Authorized in 1973, the ESA is administered by FWS and NOAA Fisheries. The purpose of the ESA is to protect wildlife, fish, and plant species in danger of becoming extinct, and conserve the ecosystems on which endangered and threatened species depend. ESA states that no federal agency may take any action (e.g. issue a permit) that might "jeopardize the continued existence of an endangered species", as determined by FWS or NOAA Fisheries. Under the ESA, endangered species cannot be "harassed, hunted, captured, or killed". Offshore drilling has been determined to "harass" bowhead and gray whales, resulting in the need for an "incidental take permit". Since 1979, a seasonal drilling restriction has prohibited, or more recently restricted the types of activities that can be conducted while bowhead whales are present. Operations conducted in areas occupied by other endangered species (e.g. the peregrine falcon) may also be restricted so as not to jeopardize their existence. NOAA Fisheries and FWS provide consultation on effects to threatened or endangered species.

4.2.1.19 Fish and Wildlife Coordination Act (FWCA) –16 U.S.C. §§ 661-666(c)

Authorized in 1934, the FWCA is administered by FWS, the NOAA Fisheries, and EPA. The Act requires other federal agencies to consult with these agencies when any stream or other water body is to be modified. Commenting agencies are then to recommend means of preventing loss of fish and wildlife and of environmental improvement. This act provides the opportunity for resource agencies to comment on permit applications, often resulting in permit stipulations. NOAA Fisheries provides consultation regarding effects on fish and wildlife resources. Ensure that fish and wildlife resources receive equal consideration to other project features. The ADFG consults with FWS about fish and wildlife resources to conserve or improve wildlife resources. The goal is to conserve and promote conservation of nongame fish and wildlife species and their habitats. The ADFG provides comments and recommendations to federal agencies pursuant to the FWCA.

4.2.1.20 Magnuson-Stevens Fishery Management and Conservation Act –16 USC §§ 1801-1883

NOAA Fisheries provides consultation on the effects on Essential Fish Habitat. Essential Fish Habitat includes habitats necessary to a species for spawning, breeding, feeding, or growth to maturity. The purpose of the Act is to protect fish habitats and populations.

4.2.1.21 Ocean Dumping Ban Act (Marine Protection, Research and Sanctuaries Act) - 33 U.S.C. §§ 1401-1445

The Ocean Dumping Act of 1988 amended the Marine Protection, Research and Sanctuaries Act and gives EPA the responsibility for regulating the dumping of all materials except dredged material, which is regulated by ACE. Banned entirely are the ocean disposal of radiological, chemical and biological warfare agents and high-level radioactive wastes. The standard for permit issuance is whether the dumping will "unreasonably degrade or endanger" human health, welfare, or the marine environment. EPA is charged with developing ocean dumping criteria to be used in evaluating permit applications, and is also responsible for designating recommended sites for ocean dumping.

4.2.1.22 Marine Mammal Protection Act (MMPA) - 16 U.S.C. §§ 1361-1407

The MMPA was authorized in 1972, and is administered by FWS and NOAA Fisheries. The purpose of the MMPA is to ensure that marine mammal populations are maintained at (or in some cases restored to) healthy population levels. With certain exceptions, the "taking" (defined as "the harassing, hunting, capturing, or killing") of sea mammals is prohibited. FWS is responsible for sea otters, walrus, and polar bears, while NOAA Fisheries is responsible for seals, sea lions, whales and porpoises. When operations occur that may result in the harassment of marine mammals, an "Incidental Take" permit is required. Conducting research on marine mammals requires a scientific research permit. Oil industry operations must also be designed to "minimize interference with native hunting of these animals." FWS issues a Letter of Authorization for incidental takes of marine mammals including polar bear and walrus.

4.2.1.23 Migratory Bird Treaty Act - 16 U.S.C. §§ 703-711

The FWS implements provisions of the Migratory Bird Protection Act. The objective is to protect birds that have common migration patterns between the United States and Canada, Mexico, Japan, and Russia.

4.2.1.24 National Historic Preservation Act (NHPA) - 16 U.S.C. § 470 et seq.

Authorized in 1966, the NHPA gives federal agencies the responsibility to ensure the protection of historical, cultural, and archaeological sites and resources. The intent is to consider the values of historic properties in carrying out federal activities, and to make reasonable efforts to identify and mitigate impacts to significant historic properties.

4.2.1.24 Native American Graves Protection and Repatriation Act (NAGPRA) -- 25 USC 3001

Enacted in 1990, the NAGPRA is administered by NPS. The act requires that discovery or disturbance of any human remains in project area must be accounted for and protected and/or properly returned to the tribe of origin. The intent is to protect Native American sacred and grave sites.

4.2.1.26 American Indian Religious Freedom Act (AIRFA) -- 42 USC 1996

Authorized in 1978, the AIRFA requires federal agencies to consider protection of sites considered sacred to Native Americans. AIRFA is administered by NPS for the purpose of reaffirming the inherent right of Native Americans to religious freedom, "including but not limited to access to sites, use and possession of sacred objects, and the freedom to worship through ceremonial and traditional rites”. It verifies the policy of the United States to protect and preserve for American Indians their inherent right of freedom to believe, express, and exercise the traditional religions of the American Indian, Eskimo, Aleut, and Native Hawaiians, including but not limited to access to sites, use and possession of sacred objects, and the freedom to worship through ceremonials and traditional rites.

4.2.1.27 Alaska National Interest Lands Conservation Act (ANILCA)--16 USC 410hh-3233; 43 USC 1602-1784

Authorized in 1980, ANILCA is administered by the DOI and U.S. Department of the Agriculture (USDA). This Act designated major conservation units for federally owned lands in Alaska, significantly expanding the lands administered by NPS and FWS. ANILCA set aside 80 million acres for inclusion within the national forests, national parks, wildlife refuges and wild and scenic rivers. Section 1003 of ANILCA prohibits oil and gas leasing and other development leading to production unless authorized by an Act of Congress. Title VIII of ANILCA establishes procedures for federal agencies to evaluate impacts on subsistence uses and needs and means to reduce or eliminate such impacts (16 USC § 3120). Section 810 of ANILCA charged federal agencies with the responsibility to evaluate and provide a proposed finding of effects of proposed development on subsistence life styles with the intent of ensuring that rural Alaska residents continue to be provided with the opportunity to continue to engage in a subsistence way of life. The potential ramifications associated with ANILCA are critical to the ultimate disposition of petroleum reserves within ANWR. Passage of the ANILCA in 1980 doubled the size of the ANWR to 19 million acres while closing it to all petroleum exploration. Recognizing the oil and gas potential of ANWR, however, Section 1002(b) of ANILCA set aside the 1.5 million acres within the northern-most part of the coastal plain of the refuge for further study. The Act mandated a comprehensive inventory and assessment of the biological resources of the ANWR coastal plain and potential impacts of oil and gas exploration, development and production. Known as the "1002 Area," a reference to Section 1002(b) of ANILCA, the DOI conducted a five-year resource evaluation of the oil potential and environmental consequences of 1002 Area. As land manager of ANWR, FWS was given the task of preparing the resource assessment, which was published as a Final EIS in April 1987. The EIS recommended that all the 1002 Area be opened to oil and gas leasing, concluding that "the Coastal Plain is the nation's best single opportunity to increase significantly domestic oil production over the next 40 years" (U.S. Department of Interior, 1987). Should leasing ultimately be permitted, activities will be conducted under authorizations issued by the FWS as land manager, as well as by other agencies. Leasing and other activities leading to oil and gas production within the ANWR must first be authorized by Congress.

4.2.1.28 Alaska Native Claims Settlement Act (ANCSA) -- 14 USC 33 1601-1629g

Authorized in 1971, ANCSA established Alaska Native land entitlements, authorizing Alaska Natives to select and receive title to 44 million acres of public land in Alaska, and $962,000,000 in cash as settlement of their aboriginal claim to land in the State. ANCSA established a system of village and regional Native corporations to manage the lands and cash payments, and made extensive provisions regarding the operations of the corporations. Special provisions were made for, and restrictions placed on, selection of lands within existing National Wildlife Refuges. ANSCA also required the Secretary of the Interior to withdraw up to 80 million acres of existing public land for specific consideration as new national wildlife refuges, national parks, national forests and wild and scenic rivers. These lands were to remain in a special withdrawal category until Congress completed action on the proposals or until December 1978. On October 14, 1978, the 95th Congress adjourned without passing the necessary legislation or an extension of the existing protection for these lands.

4.2.1.29 Federal Land Policy and Management Act (FLPMA) -- 43 USC § 1732

The FLPMA gives BLM the authority to grant permits and regulate the use, occupancy, and development of the public lands, and to take whatever action is required to prevent unnecessary or undue degradation of the public lands. The Act provides for multiple uses of public lands while protecting these lands from unnecessary or undue degradation. Under the FLPMA, the Secretary of the Interior has broad authority to regulate the use, occupancy, and development of public lands and to take whatever action is required to prevent unnecessary or undue degradation of public lands (43 USC § 1732). In accordance with the FLPMA, the BLM manages its Alaska lands and their uses to: (1) ensure healthy and productive ecosystems; (2) establish public land policy; (3) establish guidelines for its administration; (4) provide for the management, protection, development, and enhancement of the public lands; and for other purposes.

4.2.1.30 Naval Petroleum Reserves Production Act (NPRPA) -- 42 USC § 6500

The NPRPA provides the Secretary of the Interior with the authority to conduct oil and gas leasing and development in NPRA (42 USC § 6508); protect "environmental, fish and wildlife, and historical or scenic values" in the reserve [42 USC § 6503(b)]; and provide "conditions, restrictions, and prohibitions as the Secretary deems necessary or appropriate to mitigate reasonably foreseeable and significantly adverse effects on the surface resources of the National Petroleum Reserve- Alaska" [42 USC § 6508(1)]. The NPRPA also directs that development in designated Special Areas "shall be conducted in a manner which will assure the maximum protection of such surface resources to the extent consistent with the requirements of [the] NPRPA for the exploration of the reserve" [42 USC §§ 6504(b), 6508]. There are portions of two such Special Areas in the Plan Area — the Teshekpuk Lake Special Area (TLSA) and the Colville River Special Area (CRSA) (Figure 1.1.3-1).

4.2.1.31 Executive Orders

- **Executive Order 11988 – Floodplain Management:** Requires that all federal agencies establish procedures to ensure that the potential effects of flood hazards and floodplain management are considered for actions undertaken in a floodplain. This is designed to avoid impacts to floodplains to the extent practicable.

- **Executive Order 11990 – Protection of Wetlands:** As the name implies, this executive order is designed to help protect wetlands by requiring all federal agencies to avoid short- and long-term adverse impacts to wetlands whenever a practicable alternative exists.

- **Executive Order 12898 – Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations:** This executive order requires that all federal agencies develop Environmental Justice (EJ) strategies to identify and address disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations (including Native American tribes). The goal is to protect the health and environment of minority and low-income populations.

- **Executive Order 13007 – Indian Sacred Sites:** Requires federal agencies to accommodate access to and ceremonial use of Indian sacred sites by Indian religious practitioners and avoid adversely affecting the physical integrity of such sacred sites. The objective is to protect and accommodate access to Native American sites.

- **Executive Order 13112 – Invasive Species:** This Executive Order was issued to help prevent the introduction of invasive species and provide for their control. It requires that all federal agencies ensure that the introduction of invasive species is prevented, and the control of those that are introduced, and provide for the restoration of native species.

- **Executive Order 13175 – Consultation and Coordination with Indian Tribal Governments:** Requires that federal agencies must establish regular and meaningful consultation and collaboration with tribal officials in the development of federal policies that have tribal implications, strengthen the government-to-government relationships with Indian tribes, and reduce the imposition of unfunded mandates upon Indian tribes. Encourage communication and active cooperation between the federal government and Native American tribal governments.

- **Executive Order 13186 – Responsibilities of Federal Agencies to Protect Migratory Birds:** Requires that federal agencies avoid or minimize the impacts of their actions on migratory birds and take active steps to protect birds and their habitat. Protect migratory bird habitat and populations.

- **Executive Order 13212 – Actions to Expedite Energy-Related Projects:** Requires all federal agencies take appropriate actions, to the extent consistent with applicable law, to expedite projects that will increase the production, transmission, or conservation of energy. Increase production and transmission of energy in a safe and environmentally sound manner.

- **Executive Order 11514 – Protection and Enhancement of Environmental Quality:** The EPA reviews and evaluates the Draft and Final EIS for compliance with Council on Environmental Quality (CEQ) guidelines. This Executive Order details the responsibilities of federal agencies and the CEQ in directing their policies, plans, and programs to meet national environmental goals.

4.2.2 State Regulatory Authorities

State regulation of oil and gas activities on the North Slope is also a complex process involving numerous state agencies. Table 4-1 contains a summary list of Alaska statutes and administrative code sections that apply to North Slope resource development and additional information on some of the most pertinent state regulations relating to environmental issues.

Table 4.1. Summary of Alaska Statutes and Administrative Code Sections Applicable to North Slope Oil and Gas Development (Source: NRC, 2003, page 235; ADNR, 1999)

Alaska Department of Natural Resources	
AS 38.05.027	Management of legislatively designated state game refuges and critical habitat areas is the co-responsibility of ADFG (AS 16.20.050-060) and ADNR. Lessees are required to obtain permits from both ADNR and ADFG.
AS 38.35.010-260	Right-of-way leasing for pipeline transportation of crude oil and natural gas is under the control of the commissioner of ADNR. The commissioner shall not delegate the authority to execute the leases.
AS 38.05.127	Provides for reservation of easements to ensure free access to navigable or public water.
11 AAC 53.330	Implementing regulations for the reserving of easements to ensure free access to navigable or public water.
11 AAC 83.158(a)	A plan of operations must be approved by the commissioner, ADNR, if (1) state owns all or a part of the surface estate, (2) lease reserves a net profit share to the state, (3) state owns all or part of the mineral estate, but the surface estate is owned by a party other than the state, and the surface owner requests such a plan.
11 AAC 96.010	Operations requiring permits, including the use of explosives and explosive devices, except firearms.
11 AAC 96.140	Land use activities are subject to general stipulations that will minimize surface damage or disturbance of drainage systems, vegetation, or fish and wildlife resources.
Alaska Department of Natural Resources – Division of Oil And Gas	
AS 38.05.035(a)(9)(C)	Requires geological and geophysical data to be kept confidential upon request of supplier.
AS 38.05.130	Allows the director, ADOG, to approve oil and gas exploration and development activities in the case where the surface estate is not held by the state or is otherwise subject to third party interests, provided the director determines that adequate compensation has been made to the surface estate holder for any damages which may be caused by lease activities.
AS 38.05.180	Establishes an oil and gas leasing program to provide for orderly exploration and development of petroleum resources belonging to the state of Alaska.
11 AAC 96.010-150	Geophysical Exploration Permit provides controls over activities on state lands in order to minimize adverse activities
Alaska Department of Natural Resources – Division of Lands	
AS 38.05.075	Establishes leasing procedures under public auction, including tide and submerged lands, bidding qualifications, and competitive or non-competitive bidding methods.
AS 38.05.850	Authorizes the director to issue permits, rights-of-way or easements on state land for recovery of minerals from adjacent land under valid lease.
11 AAC 80.005-055	Pipeline Right-of-way Leasing Regulations.
11 AAC 93.040-130	Requires a Water Rights Permit for the appropriation of state waters for beneficial uses.
11 AAC 96.010-140	Land use permit activities not permitted by a multiple land use permit or lease operations approval.
Alaska Department of Natural Resources – DMLW	
11 AAC 93.210-220	Provides for temporary water use permits and procedures for application.
Alaska Department of Natural Resources – Division of Forestry	
AS 41.17.082	Alaska Forest Resources Practices Act. Requires that all forest clearing operations and silvicultural systems be designed to reduce the likelihood of increased insect infestation and disease infections that threaten forest resources.
11 AAC 95.195	Describes the approved methods of disposal or treatment of downed spruce trees to minimize the spread of bark beetles and reduce the risk of wildfire.
11 AAC 95.220	Requires the lessee to file a detailed plan of operations with the state forester.
Alaska Department of Fish & Game	

AS 16.05.840	A permit is required from ADFG prior to obstruction of fish passage.
AS 16.05.870	Provides for the protection of anadromous fish and game in connection with construction or work in the beds of specified water bodies, and calls for approval of plans by the commissioner, ADFG, for any diversion, obstruction, change, or pollution of these water bodies.
AS 16.20	Management of legislatively designated game refuges and critical habitat areas.
AS 16.20.060	The commissioner, ADFG, may require submission of plans for the anticipated use, construction work, and proper protection of fish and game. Written approval must be obtained.
AS 16.20.180-210	Requires measures for the continued conservation, protection, restoration, and propagation of endangered fish and wildlife.
5 AAC 95.010-990	Fish and Game Habitat Authority.
5 AAC 95.420-430	Requires a Special Area Permit for certain activities within a special area, defined as a state game refuge, a state game sanctuary, or a state fish and game critical habitat area.
Alaska Oil and Gas Conservation Commission	
AS 31.05.005	Establishes and empowers the AOGCC.
AS 31.05.030(d)(9)	Requires an oil and gas operator to file and obtain approval of a plan of development and operation.
AS 46.03.900(35)	Definition of waters.
AS 46.03.100	Accumulation, storage, transportation and disposal of solid or liquid waste standards and limitations.
20 AAC 25.005-570	Requires a permit to drill to help maintain regulatory control over the drilling and completion activities in the state.
20 AAC 25.140	Requires a Water Well Authorization to allow abandoned oil and gas wells to be converted to freshwater wells and to assure there is no contamination of the fresh water source.
Alaska Department of Environmental Conservation	
AS 46.03	Provides for environmental conservation including water and air pollution control, radiation and hazardous waste protection.
AS 46.03.100	Requires solid waste disposal permits.
AS 46.03.759	Establishes the maximum liability for discharge of crude oil at $500 million.
AS 46.03.900(35)	Definition of waters.
AS 46.04.010-900	Oil and Hazardous Substance Pollution Control Act. This act prohibits the discharge of oil or any other hazardous substance unless specifically authorized by permit; requires those responsible for spills to undertake cleanup operations; and holds violators liable for unlimited cleanup costs and damages as well as civil and criminal penalties.
AS 46.04.030	Requires lessees to provide oil discharge prevention and contingency plans (C-plans). Also, provides regulation of above-ground storage facilities with over 5,000 bbl of crude oil or 10,000 bbl of non-crude oil.
AS 46.04.050	Exemption for above-ground storage facilities for fewer than 5,000 bbl of crude oil or 10,000 of non-crude oil.
18 AAC 15	Requires a Certificate of Reasonable Assurance (Water Quality Certification) in order to protect the waters of the state from becoming polluted. Assures that the issuance of a Federal Permit will not conflict with Alaska's Water Quality Standards.
18 AAC 50	Provides for air quality control including permit requirements, permit review criteria, and regulation compliance criteria.
18 AAC 50.300	Sets up standards for air quality at certain facilities including oil and gas facilities at the time of construction, operation, or modification.
18 AAC 60.220	Requires proof of financial responsibility before a permit for operation of a hazardous waste disposal facility may be issued.
18 AAC 60.220-240	Requires a Solid Waste Disposal Permit to control or eliminate detrimental health, environmental, and nuisance effects of improper solid waste disposal practices and to operate a solid waste disposal facility.
18 AAC 60.520	General requirement for containment structures used for disposal of drilling wastes.
18 AAC 72	Requires a Wastewater Disposal Permit in order to prevent water pollution (and public health problems) due to unsafe wastewater disposal systems and practices.
18 AAC 75	Provides for oil and hazardous substance pollution control including oil discharge contingency plan (18 AAC 75.305-.395).
18 AAC 75.005-025	Requirements for oil storage facilities for oil pollution prevention.
18 AAC 75.065-075	Requirements for oil storage tanks and surge tanks.

18 AAC 75.080	Facility piping requirements for oil terminal, crude oil transmission pipeline, exploration, and production facilities.
Division of Governmental Coordination	
AS 44.19.155	Establishes and empowers the Alaska Coastal Policy Council.
AS 46.40	Establishes the Alaska Coastal Management Program.
6 AAC 50	Requires the sale to be consistent with the ACMP, including approved district programs.
6 AAC 80.070(b)(3)	Requires that facilities be consolidated to the extent feasible and prudent.
6 AAC 80.070(b)(10)	Requires that facilities be sited to the extent feasible and prudent where development will necessitate minimal site clearing, dredging, and construction.
6 AAC 80.070(b)(11) and(12)	Requires that facilities be sited to the extent feasible and prudent to allow for the free passage and movement of fish and wildlife.
6 AAC 80.130(c)(3)	Requires that wetlands and tide flats be managed to assure adequate water flow, avoid adverse effects on natural drainage patterns, and the destruction of important habitat.
6 AAC 85	Establishes guidelines for district coastal management programs.
AS 26.23.195	Establishes the State Emergency Response Commission.
AS 39.50.20	Establishes Hazardous Substance Spill Technology Review Council within State Emergency Response Commission for research, testing spill technologies, and to serve as a clearinghouse for containment and cleanup technology.
AS 24.20.600	Citizens Oversight Council established a five-member council to serve as watchdog of state and federal agencies having responsibility for prevention of and response to oil spills, to help ensure compliance with environmental laws and regulations.

4.2.2.1 Establishment of Drilling Units -- AS 31.05.100, AS 31.05.110

These statues allow ADOG to establish drilling units covering oil pools where leases are held by more than one operator. They also require the development of unit plans of operation to maximize equitable returns to leaseholders and royalty recipients.

4.2.2.2 Public Land Act; Material Sales -- AS 38.05.110; Permits -- AS 38.05.850; Mining Sites Reclamation Plan Approvals -- AS 27.19.

These state statutes authorize DMLW to issue Material Sales Contracts for the mining and purchase of gravel from state lands. DMLW is also authorized to issue Right-of-Way and Land Use permits for use of state land, ice road construction on state land, and state waters. The DMLW is charged with approving mining reclamation plans on state, federal, municipal, and private land and water.

4.2.2.3 Right of Way Leasing Act -- AS 38.35.020

The ADNR Joint Pipeline Office is authorized to issue pipeline right-of-way leases for the construction and operation of pipelines across state lands. The leases are signed by the Commissioner of the ADNR, and the leases are managed by the State Pipeline Coordinator. ADOG issues Lease Operation approvals for oil and gas development on state leases.

4.2.2.4 Alaska Oil and Gas Conservation Act -- AS 31.05 and 20AAC 25

These state regulations authorize AOGCC to regulate the drilling of wells on all lands within the state, including lands owned by the U.S. government. This allows AOGCC to regulate the drilling and production of oil and gas resources, prevent contamination of fresh water, protect correlative rights, and prevent waste.

4.2.2.5 Drinking Water Standards -- 18 AAC 72

(Federal *Clean Water Act of 1972,* Amended 1977 -- 33 USC 1251)

ADEC – Division of Water regulates wastewater discharges to waters and wetlands in Alaska to ensure the protection of water quality. The Division provides approval for collection, treatment, and disposal plans for domestic wastewaters, and for plans for the treatment and disposal of industrial wastewaters.

4.2.2.6 Oil and Hazardous Substance Pollution Control (OHSPC) – 18 AAC 75

The OHSPC statute authorizes ADEC to review and approve any road stabilizing chemical or additive prior to its use, and to establish leak detection system requirements for crude oil transmission pipelines. ADEC is the agency responsible for implementing state oil spill response and planning regulations. ADFG and ADNR assist ADEC in these efforts by providing expertise and information. Industry must file oil spill prevention and contingency plans with ADEC before operations commence. ADNR and ADFG review and comment to ADEC regarding the adequacy of the industry oil discharge prevention and contingency plans.

4.2.2.7 Class I Well Wastewater Permit -- AS 46.03.020.050 and .100

The ADEC – Division of Water is authorized to issue Class I Well Wastewater permits for underground injection of non-domestic wastewater under.

4.2.2.8 Water Use -- AS 46.15

DMLW is authorized to issue Temporary Water Use Authorizations for water necessary for construction and operations. DMLW is also authorized to issue a Water Rights Permit for the appropriation of a significant amount of water on other than a temporary basis. This statute is designed to allow DMLW to manage the use of Alaska's water resources.

4.2.2.9 Disposal Permits -- 20AAC 25.080

This statute authorizes AOGCC to regulate the disposal of RCRA exempt wastes using annular disposal in a manner that ensures that waste is isolated and contained while maintaining the quality of fresh water if fresh water is present.

4.2.2.10 Injection permits -- 20AAC 25.252 (Federal regulation 40 CFR 147.100)

This statute authorizes AOGCC to administer the Class II portion of the UIC program in a manner that ensures compliance with the Federal RCRA regulations on Class II wells (i.e., that injection wells are properly constructed and that injected fluids are contained within the intended subsurface formation). It also authorizes AOGCC to issue permits for the disposal injection into Class II wells.

4.2.2.11 Enhanced Oil and Gas permits -- 20AAC 25.402-460

This statute authorizes ADOG to issues permits for enhanced oil and gas recovery. Also authorizes the ADOG, in conjunction with the EPA and AOGCC, to exempt fresh water aquifers as needed for Class II wells under the UIC Program.

4.2.2.12 Authorization of Work -- 20AAC 25.280

The intent of the Authorization of Work statute is to maximize recovery and conservation of petroleum products. The statute enables AOGCC to issue notices required to authorize work on existing wells. The statue calls for AOGCC to require the submission of reservoir or pool development plans. It also requires that AOGCC verify the function of custody transfer metering systems, and review and approve well work and well abandonment.

4.2.2.13 Fishway Act -- AS 41.14.840

The goal of this act is to protect fish migration and spawning habitat. It requires that an individual or governmental agency notify and obtain authorization from the ADNR for activities within or across a stream used by fish if the ADNR determines that such uses or activities could represent an impediment to the efficient passage of fish.

4.2.2.14 Anadromous Fish Act -- AS 41.14.870

As with the Fishway Act, the Anadromous Fish Act is designed to protect fish migration and spawning habitat. It requires that an individual or governmental agency notify and obtain authorization from ADNR "to construct a hydraulic project or use, divert, obstruct, pollute, or change the natural flow or bed" of a specified anadromous water body or "to use wheeled, tracked, or excavating equipment or log-dragging equipment in the bed" of a specified anadromous water body.

4.2.2.15 Alaska Historic Preservation Act -- AS 41.35.010 to .240

Federal *National Historic Preservation Act of 1966 (NHPA)* -- 16 U.S.C 470 et seq.; 36 CFR 800 Sections 106 and 110; Federal *Archeological Resources Protection Act of 1979* -- 16 USC 470

Section 106 of the NHPA requires consultation with the Alaska State Historic Preservation Office (SHPO) and, when there are effects on cultural resources listed on or eligible for inclusion in the National Register of Historic Places (NRHP), with the President's Advisory Council on Historic Preservation. SHPO issues a Field Archaeology Permit for archaeological fieldwork on state lands, and is consulted by the ACE. ADNR issues a Cultural Resources Concurrence for developments that may affect historic or archaeological sites. Collectively, the goal of these federal and state statutes are: (1) to protect cultural and archaeological resources; (2) to ensure consideration of the values of historic properties in carrying out federal activities and to make efforts to identify and mitigate impacts to significant historic properties; (3) to secure the protection of archaeological resources and sites on public and Indian lands; and (4) to encourage the exchange of information between involved individuals and entities.

4.2.2.16 Alaska Coastal Management Program (ACMP) Act of 1977 - AS 46.40

The NSB has a coastal management plan and participates in ACMP consistency reviews for projects located inside the coastal district. NSB participates in ACMP consistency reviews for projects located outside the coastal district if the project may have direct and significant impacts on the coastal zone or resources. NSB involvement in the ACMP provides the opportunity to address uses sensitive to development and issues of local concern, accessing traditional and contemporary local knowledge in order to achieve a balance in conservation of the coastal zone and the development and use of natural resources.

4.2.3 North Slope Borough

NSB Land Management Regulations - (NSBMC §§ 19.10.010 – 19.70.060)

NSB requires compliance with its zoning and permitting ordinances and issues permits for development, uses, and activities on land within NSB. NSB regulates land uses and activities within the borough to provide for the protection of the health, safety, and welfare of NSB residents and to ensure compliance with environmental policies of local concern.

4.3 Leasing and Permitting Processes for North Slope Oil and Gas Development

Oil and gas lease sales are the initial step in the process of leasing state lands to provide for oil and gas development and the subsequent economic benefits. For leasing on lands not administered by the Federal government, this process is described in the ADOG annual reports (ADOG, 2005). Since 1959 the state has held more than 100 competitive lease sales in which it has offered millions of acres throughout Alaska. The MMS Alaska section web site (http://www.mms.gov/alaska/lease/lease.htm) contains a description of the leasing process for MMS OCS administered regions. Descriptions of leasing activities for federal onshore lands administered by the BLM can be found at the BLM web site (http://www.blm.gov/ak). These sales and the results were described in Section 2.3, Table 2.5 (page 2-66).

4.4 Summary of Environmental Issues, Potential Impacts and Mitigation

The continued development of the North Slope of Alaska and adjacent offshore areas for oil production requires the consideration of numerous environmental issues (e.g., impacts to wetlands, air quality, and fish and wildlife). Many of the environmental impacts associated with these issues can be ameliorated through the application of mitigative measures, the types and extent of which are determined primarily by the state and federal permitting process summarized above. A few environmental issues, however, may be controversial enough to delay further development substantially, or to even prevent development of a particular field. In 1990, we identified three issues that could conceivably prevent development from occurring in certain areas (DOE 1991):

1. "no net loss" of wetlands;
2. construction of solid-fill causeways; and
3. construction of pipelines connecting new fields to the TAPS.

Other issues, although probably not capable of preventing development independently, could increase the costs of exploration and production (E&P). Various combinations of restraints associated with these more "minor" issues could collectively preclude development in certain areas, however.

The primary differences between the exploration and development of oil reserves on the ANS and other areas of the United States involve the extreme environmental conditions found in the Arctic that impact the choice and use of oilfield technologies, the remoteness of the area, and the presence of permafrost. Designs for technologies for operating at sub-zero temperatures draw heavily on advanced concepts in technologies such as metallurgy, elastomers, lubricants, and fuels. All drilling rigs and production facilities where people work must be enclosed and heated. Exterior steel structures must be built from special arctic-grade steel to prevent brittleness associated with very low temperatures. Most pipelines and flowlines are insulated either to prevent water from freezing, to avoid increased viscosity of the crude oil from cooling, or to avoid permafrost melting. Because of the harshness of the climate and the remoteness of the North Slope, typical on-site construction methods are difficult and expensive. Major ANS facilities are therefore built in huge modules in the Lower 48 states, barged to the ANS, and installed on prepared foundations.

The State of Alaska and BLM have developed a series of general mitigation measures to minimize impacts to air quality, water quality, and habitat for wildlife species. Additional project-specific and site-specific mitigation measures may also be applied to particular exploration and development proposals as additional information becomes available. Despite these protective measures, some impacts may occur.

It is not the intent of this section to provide a comprehensive review of the issues facing development of the North Slope. This section contains: (1) a general description of the impacts associated with each issue; (2) the jurisdiction (or permit process) of the state and federal agencies; (3) potential mitigative measures for impacts associated with each issue; and (4) the potential implications for future development. As stated in the introduction to this section, we have taken an objective approach to summarizing the environmental issues described below.

4.4.1 Air Quality Issues

North Slope air quality is generally very good, with ambient concentrations of pollutants that are considerably lower than the maximum concentrations allowed by EPA and ADEC. Air quality is dependant on a variety of factors, including meteorology, geography, and the types and quantities of fuel and equipment used. Meteorological conditions that govern the transport of air pollutants generated on the ANS differ from those found in the rest of the United States. Exhaust stacks are usually kept short, due to the high winds typical of the ANS. A small number of centralized facilities are used where gathering and production activities are concentrated.

Many of the activities associated with oil and gas E&P are capable of impacting air quality on a local or regional scale. Regulated priority air pollutants emitted during North Slope E&P include nitrogen oxides (NO_X), carbon monoxide (CO), sulfur dioxide (SO_2), and particulate matter (PM). Volatile organic compounds (VOC's) are also emitted. However, VOC’s are of primary concern as precursors to ozone formation, which is extremely low on the ANS because of the low incident sunlight and ambient temperatures.

Engine exhaust and dust are produced by trucks, heavy construction equipment and earth moving equipment, and may occur during installation of pipelines and utility lines, excavation and transportation of gravel, mobilization and demobilization of drill rigs, and during construction of gravel pads, roads, and support facilities. Emissions are also produced by engines or turbines used to provide power for drilling, oil pumping, and water injection. Other vehicles such as aircraft, supply boats, personnel carriers, and rollogons also produce emissions. Elevated levels of airborne emissions from vehicles and equipment are generally localized and temporary, diminishing fairly rapidly.

Other sources of air pollution include evaporative losses (VOC’s) from oil/water separators, pump and compressor seals, valves and storage tanks. Venting and flaring may provide an intermittent source of VOC’s and SO_2. Gas blowouts, evaporation of spilled oil and burning of spilled oil may also affect air quality. Collectively, there is increasing concern that the airborne pollutants present in the Arctic – regardless of their source – may enter food chains, ultimately impacting plants and animals living in the region. However, to date there has been no indication that population declines of fish or terrestrial mammal can be linked to industrial emissions emanating from existing ANS oil and gas facilities.

The primary sources of air emissions from current ANS oil and gas production facilities are turbines and process or utility heaters fired by natural gas. This equipment is required to supply the power necessary to produce and transport crude oil and natural gas; to separate gas, oil, and water; and to reinject gas and water into reservoirs. Due to their size, number, and proximity to one another, these sources are considered to be the dominant contributors to ANS inventories. The principal emissions of concern from natural-gas fired turbines located on the ANS are nitrogen oxides (NO_x), although varying quantities of particulate matter, sulfur dioxide (SO_2), carbon monoxide (CO), and hydrocarbons (HC) are also emitted.

Arctic haze is a phenomenon that was first described as early as 1956 - well before any oil development on the ANS - and is a generic term for pollutant-laden aerosols distributed throughout the Polar Regions. It is believed to result from both man-made contaminants reaching the Arctic from the south, and from the long-range transport of particulate and aerosol pollutants originating in the industrial areas of Asia. Concentrations of arctic haze are typically low at ground level, increase with elevation to a maximum concentration usually at an altitude of several thousand meters, before eventually decreasing. The haze undergoes a pronounced seasonal variation characterized by a winter maximum and a summer minimum. This pattern can be correlated with the seasonal variation exhibited in atmospheric transport and removal mechanisms associated with pollutant transport from the middle latitudes of Eurasia. In late spring, these materials may be deposited on snow covered land masses, and brown snow events may occur intermittently. Despite the seasonal long-distance transport of contaminants into the Arctic, air pollutant levels on the ANS remain considerably below maximum allowable standards.

Part of the necessary safety system associated with oil processing facilities is a ***flare system*** to which, under normal conditions, excess gas is diverted and burned cleanly. Under occasional abnormal operating conditions when the exact mixture of gases and heat cannot be controlled (i.e., equipment failure), a build-up of excessive gas pressures may occur. For the purpose of safety, this build-up must be relieved immediately by diverting large volumes of gas to a secondary burning system. These occurrences, which are infrequent and short lived, generate a sooty ***"black smoke."*** Although combustion remains around 95% complete, the black smoke generated in this manner is visible, resulting in a brief degradation of visibility that can extend for over 100 miles, as well as contributing to the atmospheric concentrations of criteria pollutants. The principal components of the unburned fraction are CO, CH_4, and soot. Even an emission concentration of 0.5% soot results in a sooty appearance for the flame.

All industrial emissions in the United States must comply with the provisions of the CAA and state air quality standards. In Alaska, the ADEC is responsible for air quality control, new source performance testing, black smoke reporting, ambient air monitoring, and prevention of significant deterioration (PSD) permitting. Both the EPA and the ADEC have established limits for atmospheric pollutants on the ANS. Through the National Ambient Air Quality Standards (NAAQS) program, EPA has established safe levels for ambient concentrations of six priority pollutants: CO, O_3, NO_2, SO_2, Pb, and total suspended particles. These levels represented the maximum concentrations in micrograms/cubic meter ($\mu g/m^3$) of these pollutants allowable in the ambient air, and are designed to protect human health. Both primary and secondary standards have been issued for each criteria pollutant, based on various time frames for measurement of ambient airborne concentrations (e.g., 3 hours, 24 hours, one month, etc.). These standards are shown in Table 4-2.

Table 4.2. Federal and State of Alaska Air Quality Standards ($\mu g/m^3$)

Pollutant/Time Frame	NAAQS		ADEC
	Primary	Secondary	
NO_x annual average	100	100	100
O_3 /1-hour maximum	235	235	235
CO /1-hour maximum	40000	40000	40000
CO /8-hour maximum	10000	10000	10000
SO_2 /3-hour maximum	–	1300	1300
SO_2 /24-hour maximum	365	–	365
SO_2 /annual average	80	–	–
TSP /24-hour maximum	260	150	150
TSP /annual geometric mean	75	60	60
NMHC /6 to 9 A.M. maximum	160	160	169

With the exception of NOx, however, emissions of EPA priority pollutants are minimal on the North Slope. Emissions of SO_2 are small because the H_2S content of North Slope natural gas is very low, generally around 10 to 15 parts per million (ppm). The natural gas is free of lead, so lead emissions in the area are also negligible. Low concentrations of CO (10 ppm or less) can be attributed to the nearly complete oxidation of the carbon in the fuel. Hydrocarbon emissions, the precursors to O_3, are minimal. Natural gas and dry controls incorporated into the combustion chamber design result in the control of NO_x emissions from the gas turbines. Other priority pollutants are also limited by the fuel type used, which contains low concentrations of sulfur and ash.

The 1977 amendments to the CAA required that limits be established for allowable increases in ambient concentrations in those areas meeting the NAAQS values. This provision is referred to as PSD, and resulted in the implementation of additional limitations on NO_x, SO_2, and total-suspended-particulate (TSP) matter on the North Slope. These incremental limits are designed to prevent pollutant concentrations from ever reaching the maxima established by the ambient standards.

The CAA also requires pollutant source controls to comply with the "best available control technology" (BACT) for existing sources, and "new source performance standards" for major new sources or major source modifications. The CAA established National Emission Standards for Hazardous Air Pollutants (NESHAPS), and "prevention of significant deterioration" (PSD) increments for SO_2, NOx, and particulates in Class I and Class II areas.

4.4.1.1 Air Quality – Mitigation Measures

- Lessees are required to comply with all federal and state clean air standards.

- Lessees are encouraged to adopt conservation measures to reduce hydrocarbon emissions (DNR, 1999).

4.4.2 Water Quality Issues

Although surface water quality throughout the North Slope is generally very good, oil and gas exploration and production activities have the potential for impacting water quality on a localized scale. Water quality characteristics potentially altered by industry activities include pH, total suspended solids, organic matter, calcium, magnesium, sodium, iron, nitrates, chlorine, and fluoride. According to the Alpine Satellite Development Plan Final Environmental Impact Statement (BLM, 2004), potential surface water quality impacts on the ANS fall into three general source categories: (1) accidental release of fuels and other substances (including oil spills); (2) changes in dissolved oxygen and/or ion concentrations in lake waters; and (3) increasing turbidity and suspended solids concentrations.

Spills of fuel and other substances: Regardless of the care taken during the exploration, construction, or operation phase of development, spills of fuels and other materials have occurred and will continue to occur on a regular basis. Most spills that occur on the ANS are small in volume, although more substantial spills occur on occasion. Historically, many of the spills that have occurred have been small releases of fuel, motor oil, hydraulic fluids, antifreeze, or lubricants. The extent and duration of water quality degradation resulting from accidental spills depends on the type and volume of the material spilled, the location of the spill, the season and duration of the spill or leak, and the timeliness and effectiveness of clean-up response. Under standard ADNR permit conditions for off-road activity, fuel and hazardous substances must be equipped with a secondary containment apparatus. Furthermore, a secondary containment or surface liner must be placed under all container or vehicle fuel tank inlet and outlet points. In addition to potential impacts to surface water quality, spills of oil or other substances may impact fish and wildlife and their habitat, as well as air quality. Because of the variety of impacts possible, spills are discussed separately in Section 4.4.4.

The federal CWA established the National Pollutant Discharge Elimination System (NPDES) to permit discharges of pollutants into U.S. waters by point sources, such as industrial and municipal facilities. Currently in Alaska, the EPA issues NPDES permits, designed to maximize treatment and minimize harmful effects of discharges as water quality and technology improvements are made. ADEC certifies that these discharge permits will not violate the state's water quality standards. ADEC issues permits for industrial and municipal wastewaters, and monitors wastewater discharges and the quality of waters receiving the discharges. Industrial wastewater facilities are inspected annually by the ADEC, and ADEC also certifies ACE dredge and fill permits in wetlands and navigable waters to ensure compliance with state water quality standards, and provides technical assistance for design, installation, and operation of industrial and municipal wastewater systems.

Changes in dissolved oxygen and/or ion concentrations in lake waters: Dissolved oxygen (DO) in lakes will change during winter conditions due to natural processes and water use (winter pumping). The level of change due to water use is not well defined but some lakes used throughout the winter have high levels of DO at the end of winter (Hinzman and others, 2006). Changes in dissolved ion concentrations in lakes during winter are also a natural process associated with lake-ice formation. As lake ice forms, dissolved ions are rejected from the ice matrix and increase in the underlying lake water (Hinzman and others, 2006). Water-quality changes in lakes used by industry, under the current levels of permitted water use, have been found to be negligible. Adapting future water-management strategies to meet local hydrology conditions will help meet the changing water-use needs in current and future E&P operations.

Increases in turbidity and suspended solids: Terrestrial erosion and sedimentation caused by disturbance of surface lands during construction and operation of oil fields may result in increased turbidity and suspended solids loads in surface waters. These parameters vary seasonally as streamflow parameters change, typically reaching their maximum during peak runoff periods following spring breakup.

4.4.2.1 Water Quality - Mitigation Measures

Several common mitigation measures and lessee advisories have been implemented on both federal and state lands to protect water quality from oil and gas E&P activities. The following are summaries of some of the applicable water quality mitigation measures. Note that other mitigation measures that also pertain to water quality are provided in the sections on spills and waste management.

- **Wetland and riparian protection –** Lessees must avoid siting facilities in key wetlands and sensitive habitat areas.

- **Facility siting –** Onshore facilities (other than docks, or road and pipeline stream crossings), may not be sited within 500 feet of fish-bearing streams. Permanent facilities may not be sited within one-half mile of the banks of major rivers. Artificial gravel islands and bottom founded structures shall not be located in river mouths or active stream channels on river deltas, except by permit in consultation with ADFG, ADEC, and ADNR. The NSB must also determine that the structure is necessary for development, and that no feasible and prudent alternatives exist.

- **Turbidity Reduction --** Exploration facilities, with the exception of artificial gravel islands, must be temporary and must be constructed of ice unless the Director of the DEC determines that no feasible and prudent alternative exists. Re-use of abandoned gravel structures may be permitted on a case-by-case basis by DMLW, after consultation with ADFG. Equipment, other than marine vessels may not enter open water areas of a watercourse during winter to avoid or minimizes increases in erosion, turbidity, and suspended solids in a drainage area. Ice roads, ice bridges, or approach ramps constructed near river, slough, or stream crossings must be free of extraneous material before break-up. Alteration of river banks, except for approved permanent crossings, is prohibited.

- **Gravel mining –** Gravel mining sites required for E&P activities will be restricted to the minimum necessary to develop the field efficiently and with minimal environmental damage. Where feasible and prudent, gravel sites must be designed and constructed to function as water reservoirs for future use. Gravel mine sites required for exploration activities must not be located within an active floodplain of a watercourse unless the

DMLW, after consultation with ADFG, determines that there is no feasible and prudent alternative, or that a floodplain site would enhance fish and wildlife habitat after mining operations are completed and the site is closed. Mine site development and rehabilitation within floodplains must follow the procedures outlined in McLean, R. F. 1993, *North Slope Gravel Pit Performance Guidelines*, ADFG Habitat and Restoration Division Technical Report 93-9.

- **Causeways -** The State of Alaska discourages the use of continuous-fill causeways, preferring alternatives such as the use of buried pipelines, onshore directional drilling, or elevated structures. Approved causeways must be designed, sited, and constructed to prevent significant changes to nearshore oceanographic circulation patterns and water quality characteristics (e.g., salinity, temperature, suspended sediments) that result in exceedances of water quality criteria, and must maintain free passage of marine and anadromous fish. Causeways must be permitted by the appropriate agency, in consultation with ADFG and ADEC. The NSB must also determine that a causeway is necessary for development, and that no feasible and prudent alternatives exist. A monitoring program may be required to address the objectives of water quality and free passage of fish, and further mitigation may be required. Causeways and docks may not be located in river mouths or deltas.

- **Pollution prevention -** Vehicle refueling is prohibited within the annual floodplain or tidelands (ADGC, 1995). Trails, campsites and work areas must be kept clean. Trash, survey markers, and other debris that may accumulate in camps or along seismic lines and travel routes that are not recovered during the initial cleanup must be picked up and properly disposed of prior to freeze-up the following winter. Vehicle maintenance, campsites, and the storage or stockpiling of material on the surface of lakes, ponds, or rivers are prohibited (ADGC, 1995). The operation of equipment, excluding boats, in open water areas of rivers and streams is prohibited.

4.4.3 Water Use Issues

Water use on the North Slope has increased substantially over the past few years as exploration has become increasingly dependent on the construction and use of ice roads and ice pads. The construction and use of ice roads and ice pads during exploration has resulted in a dramatic reduction in the use of gravel fill, in turn resulting in a significant reduction in the development “footprint”. The construction of ice roads and ice pads relies on a ready and plentiful supply of water drawn from rivers or lakes.

Despite the benefits of replacing gravel fill roads and pads, the construction and use of ice roads and pads is not without its environmental impacts. A typical North Slope ice road requires 1 to 2 million gallons of water per mile, and an ice pad may require on the order of 0.5 million gallons of water. Furthermore, exploration of a given area often requires more than one drilling season, with new ice roads and pads built each year. To reduce damage to tundra, ice roads may be offset from previous ice road sites by a distance of at least a road width if local conditions indicate this is needed.

Although the state limits the pumping of arctic lakes with sensitive fish species to 15% of the under-ice water volume with seven feet of ice growth assumed, a sa general condition, there is little scientific basis for this value. Concerns have been expressed that the extraction of large volumes of water may endanger fish and drinking water sources. Furthermore, areas such as ANWR have low lake densities and a reliable source for water to build ice roads and pads may not be available. Current research continues on the appropriate use levels for water in the construction of ice pads and roads (Hinzman and others, 2006).

4.4.3.1 Water Use – Mitigation Measures

Several common mitigation measures and lessee advisories are aimed at restricting or controlling water use during oil and gas E&P activities (BLM 1999). The following are summaries of some applicable mitigation measures:

- Water Conservation -- Removal of water from fishbearing rivers, streams, and natural lakes shall be subject to prior written approval by DMWM and ADF&G.

4.4.4 Spills of Oil and Other Substances:

Spills on the ANS may consist of produced fluids, crude oil, seawater, or other chemicals. Petroleum exploration and production may also generate chronic low volume spills involving refined fuels and other petroleum products associated with normal operation of drilling rigs, vessels and other facilities for gathering, processing, loading, and storing of crude oil. Spills may also be associated with the transportation of refined products to provide fuel for generators, marine vessels and other vehicles used in exploration and development activities. Companies do not store large volumes of crude at their ANS facilities. Produced oil is processed and piped out as quickly as possible. This reduces the possible size of a potential spill on the ANS.

Regardless of the measures taken to prevent them, spills cannot be eliminated entirely. During the construction phase, spills tend to be relatively small, with most resulting from vehicle and construction equipment fueling and maintenance activities. Spills that occur during exploration and production, however, may be substantially larger, resulting from pipeline leaks, well blowouts, accidents, or other uncontrolled releases. Although spills may initially be contained by gravel or ice pads or roadbeds, the spilled material may eventually reach the tundra or water bodies. Spills of oil, produced water, seawater, or chemicals could directly impact the tundra adjacent to the spill source, and may impact water quality and aquatic biota once the spill reaches a water body. Spills from pressurized pipelines may spray into the air as a mist, enabling the material to be carried a substantial distance from the source. Depending upon proximity and season, the oil and/or seawater could also reach wet tundra, tundra ponds and lakes, creeks, larger rivers, estuaries, bays, and the near shore Beaufort Sea. Cataclysmic spills are rare at the exploration and production stages because spill sizes are limited by production rates and by the amount of crude stored at the exploration or production facility.

The pipeline system that carries ANS crude from the development areas includes gathering lines and pipelines which carry the crude to treatment facilities and to Pump Station 1 where the oil enters TAPS for transport to the port of Valdez. Pipelines vary in size, length and amount of oil contained. A 14-inch pipeline can store about 1,000 bbl per mile of pipeline length. Under static conditions, if oil were lost from a five-mile stretch of this pipeline (a hypothetical distance between emergency block valves), a maximum of 5,000 bbl of oil could be discharged if the entire volume of oil in the segment drained from the pipeline.

A number of measures contribute to the prevention of oil spills during the exploration, development, production, and transportation of crude oil. The oil industry employs many techniques and operating procedures to help reduce the possibility of spilling oil. The techniques that may be used during exploration include:

- Use of existing facilities and roads.
- Waterbody protection, including proper location of onshore oil storage and fuel transfer areas.
- Use of proper fuel transfer procedures.
- Use of secondary containment, such as impermeable liners and dikes.
- Proper management of oils, waste oils, and other hazardous materials to prevent ingestion by bears and other wildlife.

During oil field development, additional measures may be taken, including:

- Consolidation of facilities.
- Placement of facilities away from fishbearing streams and critical habitats.
- Siting pipelines to facilitate spilled oil containment and cleanup.
- Installation of pipeline leak detection and shutoff devices.

Leak detection systems and effective emergency shut-down equipment and procedures are used extensively to help prevent pipeline leaks but are not yet fool proof as the March 2006 oil spill at the Prudhoe Bay field demonstrated (PN, 2006f). Pressure Point Analysis (PPA) is a technique that uses measured changes in the pressure and velocity of the fluid flowing in a pipeline to detect and locate leaks. PPA has successfully detected holes as small as 1/8-inch in diameter within a few seconds to a few minutes following a rupture (Farmer, 1989). However, in the incident in March 2006, this technology did not result in early detection of the leak (Petroleum News, 2006f). Once a leak is detected, valves at both ends of the pipeline, as well as intermediate block valves, can be manually or remotely closed to limit the amount of discharge. The approximate location of a leak can be determined from the sensors along the pipeline. These and other automated leak detection systems operate continuously and can be installed at remote sites. Information from the sensors can be transmitted by radio, microwave, or over a hard wire system.

"Smart pigs," data collection devices that are run through the pipeline while it is in operation, have increased the ability to detect internal and external corrosion and differential pipe settlement in pipelines. These pigs are sent through the pipeline on a regular schedule to detect changes over time and give advance warning of any potential problems.

Well blowouts can result in very dramatic spills. These take place when high pressure gas is encountered in the well and preventive precautions such as increasing the weight of the drilling mud are not effective. The result is that fluids (oil, gas, or mud) are suddenly and violently expelled from the well bore, followed by uncontrolled flow from the well. Blowout preventers, which immediately close off the open well to prevent or minimize any discharges, are required for all drilling and work-over rigs and are routinely inspected by the AOGCC. A blowout that results in an oil spill is extremely rare and has never occurred in Alaska, (ADNR, 1999). However, natural gas blowouts have occurred. A gas blowout occurred in 1992 at the Cirque No. 1 well. The accident occurred during drilling of an exploratory well and hit a shallow zone of natural gas. Drilling mud spewed from the well and natural gas escaped. It took two weeks to plug the well. In 1994, a gas kick occurred at the Endicott field 1-53 well. BP Exploration was forced to evacuate personnel and shut down most wells on the main production island. No oil was released to the surface, as the well had not yet reached an oil-bearing zone. There were no injuries, and the well was killed three days later by pumping heavily weighted drilling muds into it (Schmitz, 1994; Anchorage Daily News, 1994a; ADNR, 1999).

Wells must have a blowout prevention program before it is drilled. Bottom-hole pressure data from existing wells nearby, along with seismic data are reviewed to help predict the pressures might be expected in the well to be drilled. Engineers use this information to design a drilling mud program with sufficient hydrostatic head to overbalance the formation pressures from surface to the total depth of the well. They also design the casing strings to prevent various formation conditions from affecting well control performance. Blowout prevention equipment is installed on the wellhead after the surface casing is set and before actual drilling begins. Blowout prevention stacks are routinely tested in accordance with government requirements. (BP, 1996).

Blowout preventers are installed on the surface and only removed when the well is plugged and abandoned. Blowout preventers are large, high-strength valves which close hydraulically on the drill pipe to prevent the escape of fluids to the surface.

The current rate of oil and seawater spills on the ANS is likely to be considerably lower than that of earlier years. However, the March 2006 leak in a 34-inch transit line that delivers oil to TAPS from Gathering Center 2 in the Prudhoe Bay oil field resulted in a spill estimated to be around 200,000 gals [50,000 bbls] (PN, 2006f). The leak was caused by internal corrosion resulting in a one-quarter-inch hole in the bottom of the transit pipeline in a portion that was buried under a caribou crossing resulting in a slow leak that went undetected for several days. The oil was contained on frozen tundra and has apparently caused little long term damage. This incident illustrates the vigilance and improved technology that will be required as the oil infrastructure and operations on the ANS age. The combination of more stringent agency regulations, continually improving industry operating practices, and advancements in Best Available Control Technology (BACT) will all be required to reduce the rate and impacts of spills.

4.4.4.1 Environmental Impacts from Spills

Impacts of spills to fish and fish habitat: The total number of fish killed by a spill that reaches a water body will depend on the volume of oil discharged, the time of year of the spill, and the effectiveness of the response of clean-up crews. The shallow nearshore waters of the Beaufort Sea provide feeding areas for anadromous fish. A very large oil spill into marine waters during the open season may prevent the fish to reach overwintering areas and spawning streams. Adult fish are likely to avoid an oil spill and not suffer great mortality; but larvae, eggs, and juveniles are more vulnerable because they are more sensitive and less mobile. Species with floating eggs, such as Arctic cod, could suffer extensive mortality depending on the extent and amount of oil spilled.

The deltas of the Colville, Sagavanirktok, and Canning rivers also represent important habitat for anadromous fishes. Summertime oil spills reaching these river deltas could impact anadromous fish populations. Once again, adult fish would be expected to be less susceptible to spilled oil by simply avoiding the spill by swimming upstream. Less motile juveniles in late summer would more susceptible as they would typically be found near the surface.

Impacts of spills to birds and bird habitat: Direct contact with spilled oil by birds is commonly fatal, with mortality being due to hypothermia, shock, or drowning. Oil ingestion from preening oily feathers or consumption of oil-contaminated foods may reduce reproductive ability, and could lead to chronic toxicity through the accumulation of hydrocarbon residues. Contamination of eggs by oiled feathers of parent birds may decrease the hatching rate due to toxic effects on chick embryo or abandonment of the nest by parent birds (MMS 1996). Indirectly, the presence of humans, aircraft, boat and vehicular traffic during cleanup operations may cause disruptions in nesting, molting, and feeding of birds in the oiled areas, and may contribute to reduced reproductive success (MMS 1996). The number of birds impacted by a spill would depend on the time of year and the density of local bird populations.

Impacts of spills to terrestrial mammals and habitat: Oil spills in terrestrial habitats may result in contamination of individual mammals, habitats, or food sources. Spills of oil, produced water, seawater, or chemicals may all damage terrestrial habitats, with the extent of the damage related primarily to the volume of the contaminant and the area covered by the contamination. Tundra vegetation killed by spills results in a loss of cover and of food for mammal and bird species. Damage to tundra from spills can last for decades. Furthermore, the presence of humans and traffic from vehicles and aircraft during spill cleanup may cause additional disturbance and displacement of animals such as muskoxen, moose, and bears. Bears often feed on fish that are concentrated at overwintering and spawning areas, and may also feed on beached marine mammal carcasses along the coast (Ott, 1997). Spills to water bodies (freshwater or marine) may therefore also impact bears through contaminated food sources. Bears, wolves, foxes, and other furbearers may be attracted to dead dying waterfowl or other wildlife at a spill site.

Impacts of spills to marine mammals and habitats: Polar bears are extremely sensitive to external and internal oil contamination. They have also been observed to consume hydraulic fluid, antifreeze, and other petroleum-based lubricants (Ott 1990). Polar bears may also contact oil directly by swimming or wallowing in contaminated areas, or indirectly by scavenging oiled carcasses or injured wildlife along the beach. Polar bears must maintain their fur in a clean state in order to get the maximum benefit from its insulative qualities (MMS, 1993), and they may ingest oil as they preen. As with other wildlife, the presence of humans and their associated boat, vehicle, and aircraft traffic operating in the area during cleanup operations may cause disturbance and displacement of polar bears during cleanup operations in coastal areas. However, polar bears may be attracted to a spill site by the presence of dead birds or other animals killed by the spill (MMS, 1996b). For pinnipeds, direct contact with spilled oil may result in mortality. Newborn seal pups may lose their thermo-insulation capabilities and die from hypothermia after coming into contact with oil. However, adult seals are capable of metabolizing and excreting or absorbing oil.

Impacts of spills to terrestrial vegetation and habitat: Spilled oil will affect tundra depending on time of year, the type and quantity of vegetation present, and the local terrain. Oil spilled on the tundra will migrate both horizontally and vertically, with the flow dependent on factors such as the volume spilled, the type of cover (plant or snow) present, the slope, the presence of cracks or troughs, the moisture content of soil, temperature, wind direction and velocity, the thickness of the oil, and ability of the ground to absorb the oil (Linkins, et al., 1984). The spread of oil is less when the oil is thicker, cooler, or is exposed to chemical weathering. Absorption of the oil by the tundra itself will also limit flow and reduce the area contaminated. If there is a vertical crack through different soil horizons, oil will migrate down to the permafrost. If no cracks are present in the soil layers beneath the tundra, oil moves laterally in the organic material, does not penetrate the mineral soils beneath, and oil contamination would be restricted to the top few centimeters of the soil layer. If oil penetrates the soil layers and remains in the plant root zone, mortality or reduced regeneration would occur in following summers.

Under proper conditions of oxygen, temperature, soil moisture, and the composition of the crude being spilled, bacteria assist in the break-down of hydrocarbons in soils. Petroleum-contaminated soils are commonly treated with fertilization, raking, and tilling (bioremediation). Considerable research is ongoing in the use of microbes to assist the natural break down of petroleum in soils and gravel.

4.4.4.2 Spills – Mitigation Measures

Recognition of the difficulties of containment and cleanup of oil spills on the North Slope has encouraged the incorporation of innovative and effective methods for preventing spills and for responding to spills if they occur. Oil spill prevention, response, and cleanup and remediation techniques receive considerable attention from state and federal agencies and the oil industry. Although the risk of a spill cannot be reduced to zero, risks can be minimized through preventive measures, monitoring, and rigorous response capability. For this reason, lessees are required to develop contingency plans that address the method to be used to detect, respond to, and control blowouts. Also under this measure, contingency plans must identify the location of oil spill cleanup equipment; the location and availability of suitable alternative drilling equipment; and develop a plan of operations to mobilize and drill a relief well.

- **Oil Spill Prevention and Control -** Lessees must prepare contingency plans addressing prevention, detection, preparedness, response capability, and cleanup of oil spills. Pipelines must be located so as to facilitate the containment and cleanup of a spill, and must be constructed to provide adequate protection from water currents, storm and ice scouring, subfreezing conditions, and other hazards. Onshore pipelines generally must be located on the upslope side of roadways and construction pads, and must utilize existing transportation corridors and be buried where soil and geophysical conditions permit. Oil or fuel storage tanks must be lined and diked, and buffer zones must be provided to separate oil storage facilities from marine and freshwater supplies. Additional site-specific measures may be required as determined by ADNR, with the concurrence of

ADEC, and will be addressed in the existing review of project permits or Oil Discharge Prevention and Contingency Plans (C-Plans). Secondary containment shall be provided for fuel or hazardous substances. Rules apply to the use of container marking, surface liners, and the storage, handling and transfer of fuel.

- **Oil Spill Response -** C-Plans must describe methods for detecting, responding to, and controlling blowouts; the location and identification of oil spill cleanup equipment; the location and availability of suitable alternative drilling equipment; a plan of operations to mobilize and drill a relief well. Appropriate spill response equipment must be on hand during any transfer or handling of fuel or hazardous substances. Spills must be reported immediately.

- **Community participation -** Local residents should be included in the operations planning process, as they may provide critical input and traditional knowledge to operations and oil spill prevention and response plans.

4.4.5 Waste Management

The impacts associated with waste management practices on the North Slope are diverse, and depend on the waste type, the volume of waste generated, and the treatment and/or disposal methods used. A number of different classifications of waste are generated on the North Slope. Some are directly related to oil production while others result from support activities.

4.4.5.1 Hazardous Wastes

Most of the oilfield wastes generated on the North Slope are not hazardous, and of those that are, some are regulated under the Resource Conservation and Recovery Act (RCRA), whereas others are not. Generally, wastes that are uniquely associated with oil and gas exploration and production operations are exempt from regulation under under Subtitle C of the RCRA hazardous waste regulations. These **RCRA-exempt wastes** include drilling muds, drill cuttings, produced water and associated wastes, and consist primarily of natural substances contaminated with very small concentrations of chemical additives.

Drilling muds are fluids that are used to lubricate the drill bit and help to control pressures in the underground formations and to prevent uncontrolled releases of oil or gas from the well. Muds are typically comprised of water-based mixtures of clays and weighting material, to which small amounts of various materials have been added. They are normally recycled many times during a drilling operation. This recycling involves cleaning the circulating mud to prevent buildup of drill bit cuttings and other solids in the mud. Oil-based muds are occasionally used to drill a well. These muds are recycled as many times as possible before being injected into a formation for disposal. Drilling muds have a variety of brand names, but all consist of three basic components: a base liquid (typically fresh or salt water), a viscosifier (a clay and/or polymer), and a weighting material (commonly barite). A mix of special additives may also be used to enhance properties of the mud and meet the range of temperature, pH, viscosity, deflocculant and corrosion needs.

Drill cuttings are small fragments of rock and soil that are removed from the well bore by the drill bit. These materials are carried up from the drill bit, and are removed from the drilling muds when the muds are recycled. An exploratory drilling operation generates approximately 12,000 cubic feet of solid drill cuttings.

Produced water is groundwater that comes to the surface mixed with oil. This water is usually highly saline, and must be separated from the oil before the oil can be sent to the Trans-Alaska Pipeline. The separation of produced water from crude oil occurs at the gathering centers and flow stations, and the majority is reinjected into the oil reservoir, which helps in the recovery of additional oil by helping to maintain reservoir pressure. The remaining produced water not suitable for use in the enhanced oil recovery program is injected in approved disposal wells with Class II injection permits.

Traditionally, drilling muds and cuttings were disposed of in unlined **reserve pits** built as part of the gravel pads. Depending on the content of the reserve pit fluids, these materials were historically permitted by the ADEC to be discharged to the tundra or to the roads or gravel pads, a practice that was discontinued some time ago. Liquid reserve pit wastes contain small amounts of metals (e.g. aluminum, arsenic, barium, cadmium, chromium, lead, mercury, silver, and zinc), along with hydrocarbons derived from oil-bearing formation cuttings and other hydrocarbon components such as paraffins and olefins, and various chemical additives. Seepage through the embankments of some of these unlined reserve pits was known to have occurred in the past, and the release of materials from unlined reserve pits was implicated in the increased concentrations of salts and metals in adjacent waters observed at some sites. In sufficient quantities, and with sufficient exposure times, many of these toxic components of liquid reserve pit wastes can be harmful to aquatic organisms and to waterfowl and other animals.

In recent years, the use of permanent reserve pits has been strongly discouraged, and most operators on the North Slope now store drilling solids and fluids in tanks until they can be disposed of, generally down the annulus of a disposal well. Frozen cuttings may be temporarily stored on the pad until but, in most cases, they are transported to a grind and inject facility for disposal in a formation. These storage sites must involve the use of impermeable liners in the pit embankments, and the pits must be maintained as fluid-free as possible. A comprehensive monitoring program is used to ensure that the state standards are being met. The petroleum industry has therefore discontinued the practice of using reserve pits for the disposal of oily muds and cuttings and associated wastes on the North Slope. Current management practices include the storage of solids in completely lined surface impoundments and injection of liquids in Class II disposal wells. See Section 4.4.9 for a discussion on the UIC program. A large number of unclosed reserve pits remain at remote exploration well sites. No adequate plan is in effect to handle the potential contamination to the environment from poorly sealed and covered pits (NRC, 2003).

"Associated wastes" include several other types of wastes generated by processes associated with oil and gas production. Most of these wastes are water-based materials containing suspended solids and oil. Some associated wastes are potentially hazardous due to their hydrocarbon content, but are covered by the RCRA oil and gas exemption because they are unique to oil and gas production. The volume of these wastes generated every year on the North Slope may approach 1.65 million barrels. Examples of associated wastes include:

- Tank bottom sludges,

- Spill residues and contaminated soils,
- Truck/tank/cellar wastewaters,
- Dehydration unit wastes from the gathering centers,
- Pipeline pigging wastes,
- Wastes from well workovers
- Miscellaneous wastes.

RCRA hazardous wastes are those wastes that are not uniquely associated with the exploration and production of oil or gas resources are therefore not exempt from the RCRA hazardous waste regulations. Management of these wastes must comply fully with the RCRA hazardous waste regulations regarding packaging, characterization, labeling, and shipping to permitted hazardous waste disposal/treatment facilities.

During drilling oil field operations, it is possible that wastes containing naturally occurring **radioactive materials** are generated. This may occur when drill pipes are cleaned to remove the scale that accumulates on the surfaces. Depending on the uranium and thorium content of the strata through which the well was drilled, the scale may contain small quantities of these materials and their radioactive daughter products (including radium and radon). To date, wastes with elevated natural radioactivity has not been a problem on the North Slope.

Solid Wastes are non-hazardous and non-radioactive wastes that are not subject to specific waste management regulations. These wastes are disposed of at permitted solid waste landfills. For Prudhoe Bay and surrounding fields, disposal of solid wastes has traditionally been at the landfill at Deadhorse that is administered by the North Slope Borough.

4.4.5.1 Waste Disposal – Mitigation Measures

Drilling muds and cuttings:

- The preferred method for disposal of muds and cuttings from oil and gas activities is by underground injection, as regulated by AOGCC through the UIC Program for oil and gas wells. Annular disposal of muds and cuttings associated with drilling an exploratory well is permitted by ADEC.
- Surface discharge of drilling muds and cuttings into lakes, streams, rivers, and high value wetlands is prohibited.
- Surface discharge of drilling muds and cuttings into reserve pits is allowed only when determined that alternative disposal methods are not feasible and prudent. The operator must demonstrate the advantages of a reserve pit over other disposal methods, and must describe methods to be employed to reduce the disposed volume.
- On-pad temporary cuttings storage is allowed as necessary to facilitate annular injection in disposal well and/or backhaul operations.

Produced Water:

- Unless authorized by NPDES or state permit, disposal of wastewater into freshwater bodies, including wetlands, is prohibited.
- Surface discharge of reserve pit fluids is prohibited unless authorized by ADEC permit.
- Discharge of produced waters into open or ice-covered marine waters of less than 10 meters (33 feet) in depth is prohibited. ADEC may approve discharges into waters

greater than 10 meters in depth based on a case-by-case review of environmental factors and consistency with the conditions of a state certified development and production phase NPDES permit issued for the sale area.

Solid Waste and wastewater disposal

- Garbage and putrescible waste must be disposed of properly to minimize attraction to wildlife. Garbage and domestic combustible refuse must be incinerated, and nonburnables must be disposed of at an approved upland site. An alternative method of disposal is on-site frozen storage in animal-proof containers with backhaul to an approved waste disposal facility.
- All solid wastes, including incinerator residue, shall be backhauled to a solid waste disposal site approved by ADEC.
- Disposal of wastewater, such as domestic greywater, into fresh waterbodies is prohibited.

4.4.6 Disturbance to Terrestrial Vegetation, Permafrost, and Soils

Permafrost exists throughout much of the North Slope, reaching thicknesses of up to approximately 500 meters (Osterkamp and Payne, 1981). During the summer, the top most layers melt, generally to a depth of less than one meter. Ground settlement due to thawing may result whenever a heated structure is placed on the surface unless stringent engineering measures are taken to support the structure while preventing heat transferred from the building to melt the underlying permafrost. Basically, any activity that increases the heat flux to permafrost can initiate thermokarst and compromise the integrity of overlying or adjacent infrastructure. Vegetation on the North Slope ranges from grasses and sedges to willows and other short shrubs. Soils are generally poorly drained, highly organic and poorly developed because of the freeze/thaw cycles and resulting mixing.

In addition to oil spills described above, terrestrial vegetation (and therefore habitat for multiple species) on the North Slope can be impacted by a variety of activities associated with petroleum exploration and production. Brief summaries of some of the more relevant E&P activities and how they may impact terrestrial vegetation are provided below.

Seismic surveys: Winter seismic surveys can impact tundra vegetation directly, with the extent of the damage depending on factors such as snow depth, type of vehicle(s) used, traffic pattern for the vehicle(s), as well as the local vegetation type. Winter seismic trails can create small depressions in the tundra surface, resulting in a somewhat wetter microenvironment and reduced vegetation cover during the summer growing season. Although the wetter conditions may have a positive effect on certain vegetation (e.g. *C. aquatalis* and *E. angustifolium*) this comes at the expense of other species that need a drier microsite (Felix and Raynolds, 1989). Furthermore, damage to shrub-dominated tundra generally recovers slower than other vegetation types (Jorgenson and Martin, 1997). Seismic trails may result in a flattening of tundra vegetation by the vehicles that is evident during the next growing season and beyond. Tundra may also be damaged in the vicinity of seismic camps.

DMLW has historically limited tundra travel to areas with a minimum of 12 inches of frozen ground and six inches of snow cover and other practices such as avoiding minimum radius turns. Based on research conducted in 2003 and 2004, the DMLW used the following criteria for opening the tundra for the 2005 season (ADNR, 2005b) resulting in an earlier opening than in recent years:

> DNR will implement tundra opening for general cross country travel in wet sedge tundra when a minimum 15 cm (6 inches) of snow cover is available and ground hardness reaches a minimum of 75 drops of the slide hammer to penetrate one foot of ground. At this combination of ground and snow conditions, no significant change in the depth of active layer, soil moisture, or vegetation composition and structure is anticipated. DNR has determined that once a minimum threshold of 23 cm (9 inches) of snow cover and a ground hardness of 25 drops of the slide hammer for one foot of soil penetration have been attained, general tundra opening in tussock tundra can proceed without a significant change in active layer depth, soil moisture, or vegetation community composition and structure."

In areas where damage has been extensive in the past, and natural recovery is very slow, restoration may be required of operators (Schultz, 1996). A recent improvement in seismic technology has been the development of 3-D seismic capabilities. Although application of 3-D seismic exploration has improved the accuracy and precision of estimates of resources in place, the method requires grid spacings of a few hundred feet between lines as opposed to several kilometers used in a standard 2-D program. This close spacing has the potential to affect a greater amount of the tundra surface and increase the disturbance to denning bears and other animals.

Ice roads and pads: Ice roads and pads constructed on tundra result in compaction of the tundra causing small depressions to develop in the microtopography that becomes evident following spring thaw. The summer thaw depth may also increase for several years because of the compaction, and the area may also be wetter until the thaw depth stabilizes to pre-ice road levels. Tussock vegetation compressed by ice roads may take several years to recover (Walker, et al., 1987). Ice roads and pads may also impact regeneration of tundra, with certain species recovering faster after summer melt than others.

Most ice roads and pads constructed to date have been in place for a single season, and leave a very limited trace upon melting. However, multi-season ice pads are now being constructed on the North Slope. These pads are equipped with an insulated cover to prevent the pad from melting during the summer. Multi-season ice pads can result in a more substantial (but still limited) short-term impact particularly if the tundra vegetation around the perimeter of the pad is allowed to thaw while the padding still blocks the sunlight. Several variations to the pad design used for multi-season ice pads are being evaluated on the North Slope to minimize impacts to the tundra surface (Hazen, 1997).

Construction and Gravel Infilling: Construction of gravel pads, roads, and pipelines results in a direct loss of terrestrial habitat from gravel infilling. As mentioned in Section 4.2.8 and 4.4.3 (Water Use), gravel placement also alters the surface hydrology, and this in turn can impact terrestrial vegetation. Construction operations may also result in an increase in the amount of dust deposited on vegetation surface, potentially to the point of reducing net photosynthesis and plant growth. Road construction, vehicular passage, and oil spills may alter surface albedo or water drainage patterns, resulting in thaw and subsidence or inundation.

When an oil field is abandoned, some degree of land rehabilitation will likely be required to restore areas impacted by oil and gas activities. The effectiveness of wetland recovery following removal of gravel infilling, if required, will vary depending on soil moisture content and amount of available soil organic matter (Jorgenson and Joyce, 1994). Several plant cultivation treatments have been used on the North Slope including fertilizer only, native-grass cultivation, *Arctophila* transplantation, and sedge-plug transplantation. Optimum recovery of the tundra marsh would include reestablishing vegetation, soil microbiotic, phytoplankton, aquatic invertebrate, and wildlife communities at the impacted site (Kidd, et al., 1997).

4.4.6.1 Land Habitat -- Mitigation Measures

The following are summaries of some applicable mitigation measures that would mitigate potential impacts to land habitat:

- **Tundra protection -** Except for approved off-road travel, exploration activities must be supported only by ice roads, winter trails, existing road systems or air service. Winter and summer off-road vehicular traffic is restricted and must be approved. Wintertime off-road travel across tundra and wetlands may be approved in areas where snow and frost depth are sufficient to protect the ground surface (See Section 4.4.6). Summertime off-road travel across tundra and wetlands may be authorized subject to time periods and vehicle types. Vehicles shall be operated in a manner such that the vegetative mat is not disturbed, and blading or removal of vegetative cover is prohibited except as approved by ADNR. Filling of low spots and smoothing using snow and ice is allowed. Ice road and pad construction begins during middle to late December when ambient temperatures are cold enough for relatively fast construction (Hazen, 1997).

- **Wetland protection –** Facilities may not be sited in key wetlands or identified sensitive habitat areas unless no feasible and prudent alternative exists, and impacts must be minimized in these areas. Key wetlands are those wetlands that are important to fish, waterfowl, and shorebirds because of their high value or scarcity in the region.

- **Habitat loss minimization** - Exploration facilities must not be constructed of gravel (ice roads and pads are the preferred method). Gravel mining is restricted to the minimum necessary to develop the field efficiently. Except for approved stream crossings, equipment must not be operated within willow stands (Salix spp.). Sensitive Areas Lessees are advised that certain areas are especially valuable for their concentrations of marine birds, marine mammals, fishes, or other biological resources; cultural resources; and for their importance to subsistence harvest activities.

- **Rehabilitation –** The state maintains the option to require that roads and pads must be either abandoned and the sites rehabilitated by the lessee, or left intact.

4.4.7 Fish – Impacts to populations and habitat

Several major streams occur on the North Slope, including the Canning, Colville, Sagavanirktok, Shaviovik, and Kadleroshilik river systems. Numerous minor stream systems exist in the area as well. Collectively these river systems provide spawning and overwintering habitat for several species of anadromous fish. Title 16 of the Alaska Statutes requires protection of documented anadromous streams from disturbances associated with development. In addition to the threats posed by spills of oil or other materials discussed above, potential impacts to fish habitats from oil and gas development generally involve one of two mechanisms: those that affect winter habitat, or those which affect feeding and spawning areas or access to these areas.

Overwintering habitat is limited in several areas on the North Slope. Removal of water from lakes where fish are overwintering may affect the viability of overwintering fish, and longer term effects of lake drawdown may impede the ability of fish to return to the lake in subsequent years. Removal of snow from lakes may increase the freeze depth of the ice, kill overwintering and resident fish, and adversely affect the ability of fish to utilize the lake in future years. A current research project, "Physical, Biological and Chemical Implications of Mid-Winter Pumping of Tundra Lakes," at the University of Alaska Fairbanks in collaboration with ADFG, BLM, GW Scientific, BP, and ConocoPhillips, funded by the DOE, is assessing the impacts of pumping from tundra lakes (UAF, 2005).

Erosion following disturbance of the land surface may cause siltation and sedimentation of water bodies receiving runoff from the disturbed area, which in turn may cause a reduction or alteration of stream flow ultimately degrading fish overwintering habitat.

Sedimentation resulting from erosion can affect fish and other aquatic organisms by interfering with respiration and vision, and by smothering benthic habitat. Proper siting of bridges, roads, and other infrastructure are the key to avoiding this problem. Bridge approaches that extend into the floodplain terraces may alter flow during flood stages. Funneling and the accompanying increased flow rates in years of unusually high flooding could affect fish movement. Road networks may cause changes in the regional surface hydrology, resulting in an interruption of fish movements. Failure of culverts may also result in the impoundment of large volumes of water and change flow velocity of streams. Changes in stream morphology may also result downstream of culverts as a result of altered flow.

The construction of ice roads or airstrips on fish over-wintering areas may cause freezing to the bottom and block fish movement if state requirements to maintain fish passage are not met. Road systems (both ice roads and gravel roads) may facilitate increased human access to fishing areas, potentially increasing subsistence fishing pressures.

Excessive **withdrawal of water** from North Slope lakes for the construction of winter ice roads and pads may cause overcrowding of the lake or may reduce the dissolved oxygen in the lake to a level below that which can sustain fish. These impacts are controlled through the enforcement of permitted limits on the amounts of water that may be withdrawn from a lake during the winter.

Gravel mining may impact fish if the mining occurs within the floodplains of rivers. Although closely regulated now, gravel removal from fishbearing streams to support oil and gas activities may have once impacted anadromous fish populations. Gravel removal may result in increased sediment loads, changes in stream bed course, destruction of spawning habitat, or may create obstacles to fish migration. Gravel removal from stream beds may also cause potential damage to overwintering fish populations. Gravel mine sites can be restored as overwintering habitat and thus add to total available fish habitat.

Construction and placement of ***causeways***, particularly continuous-fill causeways into the nearshore seas or in river deltas, may alter patterns of nearshore sediment transport, water discharge, and temperature and salinity regimes in areas near the causeway. The extent of alterations depends on the size or length of the causeway, its location relative to nearby islands and river mouths or deltas, and pre-causeway oceanographic characteristics. Minimizing alterations is accomplished by proper siting, minimal size, and by ensuring that breaches are sized and located to maximize goals. Changes to the physical environment may alter patterns of use of the deltaic area by anadromous and marine fishes.

Seismic activities may also impact fish or fish habitat, especially where explosives are used. Pressure waves from high explosives may kill or injure fish near the explosion. Overpressures may kill fish with swim bladders, especially juvenile salmonids. Shock waves from explosions may also shock and jar fish eggs at sensitive stages of development (Linton et al., 1985). These types of impacts are mitigated by restricting the use of explosives in open water or in close proximity to fish-bearing lakes and streams.

Many of the potential impacts described above are generally localized and temporary and thus would have negligible effects on fish populations within the impacted areas. Careful planning, appropriate engineering specification and design, and rigorous safety measures should minimize impacts and ensure the reproductive sustainability of stocks overall. Localized impacts could pose a more serious threat to if they were to occur in or near prime spawning, nursery, or over-wintering sites. Additional mitigation measures provided in the sections describing spills and waste management are also pertinent to the protection of fish populations and habitat.

4.4.7.1 Mitigation Measures – Fish Populations and Habitat

- **Habitat Protection -** Lessees may be required to construct ice and/or snow bridges if ice thickness at a crossing is insufficient to protect the streambed and the stream bank. Bridges are the preferred watercourse crossings in fish spawning and important rearing habitats. Removal of snow cover from fishbearing rivers, streams, and natural lakes shall be subject to prior written approval by ADFG. Compaction of snow cover overlying fishbearing waterbodies will be prohibited except for approved crossings. In areas where culverts are used, they must be designed, installed, and maintained to provide efficient passage of fish. Any removal of water from fishbearing streams, rivers, and natural lakes requires written approval. When a fishbearing waterbody is used as a water source, lessees must use appropriate measures to avoid entrainment of fish (prevent fish from being drawn into the intake pipe). Lessees must locate, develop, and rehabilitate gravel mine sites in accordance with ADFG guidelines.

- **Stream Buffers -** Onshore facilities other than roads, docks, and airstrips must not be sited within 500 feet of fishbearing streams and lakes. Facilities may not be sited within 1/2 mile of identified Dolly Varden overwintering and spawning areas on the Colville, Canning and Sagavanirktok, Kavik, Shaviovik, Kadleroshilik, Echooka, Ivishak, Kuparuk, Toolik, Anaktuvuk and Chandler Rivers. Road and pipeline crossings must be perpendicular to watercourses to prevent buffer erosion.

- **Obstructions to Migration and Movement -** Causeways, docks or other structures must be designed, sited, and constructed so as to maintain free passage of marine and anadromous fish, and shall not cause significant changes to nearshore oceanographic circulation patterns and water quality characteristics. Continuous fill causeways are discouraged. Causeways may not be located in river mouths or deltas. Activities that may block fish passage in anadromous streams are prohibited. Alteration of river banks, except for approved crossings is prohibited. If bridges are not feasible, culverts used for stream crossings must be designed, installed, and maintained to provide efficient passage for fish.

- **Protection from Seismic Surveys -** Lessees must follow requirements for the use of explosives during onshore seismic activities. Explosives may not be detonated within, beneath, or in close proximity to fishbearing waters if the detonation of the explosive produces a pressure rise in the waterbody greater than 2.5 pounds per square inch (psi) unless the waterbody is solidly frozen. Explosives must not produce a peak particle velocity greater than 0.5 inches per second (ips) in a spawning bed during the early stages of egg incubation. Minimum acceptable offsets from fishbearing streams and lakes have been established for various size buried charges. The lessee will consult with the NSB prior to proposing the use of explosives for seismic surveys. The director may approve the use of explosives for seismic surveys after consultation with the NSB.

4.4.8 Birds – Impacts to populations and habitat

The Arctic coastal plain contains abundant wetlands that attract large numbers of migratory waterbirds on an annual basis. Numerous studies on North Slope birds have been conducted over the years of oil and gas development, and results and interpretation of these studies vary. Some nesting, molting, and staging bird species appear to be sensitive to activities associated with development, although responses tend to be influenced by a number of factors, including the species exposed, the physiological or reproductive state of the birds, the distance from the disturbance, the type, intensity, and duration of the disturbance, etc. (MMS, 1996).

Impacts to birds are more likely to occur after the exploration phase, as few resident species are present during winter when exploration occurs. These impacts generally take the form of habitat loss, alteration or enhancement, disturbance and displacement, obstructions to movement, or direct mortality. Other impacts leading to a loss of productivity are difficult to quantify. Potential impacts include: habitat loss, barriers to movement, disturbance during nesting and brooding, changes in food abundance and availability, and oil spills.

Habitat loss - birds: Habitat loss does not involve the direct loss of active nests because activities such as gravel placement, construction of ice roads and ice pads, and snow removal and disposal occur primarily during the time of the year when nests are not active. However, siting of onshore infrastructure, including drill pads, roads, airfields, pipelines, housing, oil storage facilities, etc., may eliminate some area of wetland or other preferred bird habitat. Habitat changes from oil and gas development are not expected to cause a measurable reduction in the total numbers of birds on the North Slope, as birds that have been displaced have been found nesting in nearby, undisturbed areas. The availability of suitable habitat does not likely limit most bird populations at Prudhoe Bay.

Disturbance and displacement: Human activities such as air traffic and foot traffic near nesting waterfowl, shorebirds, and seabirds, may cause North Slope bird species to temporarily abandon important nesting, feeding and staging areas. Tundra swans, for example, are particularly sensitive to humans on foot, and may abandon their nests when humans approach within 500 to 2000 m of the nest (MMS, 1996b).

Pipeline corridors with service roads may cause additional impacts to birds from traffic, noise and dust. Birds may avoid the areas adjacent to infrastructure due to disturbance effects. A 1993 study on bird use in the Prudhoe Bay area concluded that only about 5% of the birds in the Prudhoe Bay oil field may have been displaced by gravel placement and other activities, but that these displaced birds most likely occupied nearby undisturbed areas (TERA, 1993). A monitoring program was conducted from 1985 to 1990 to assess the effects of construction and operation of the Lisburne Oil Field on White-fronted Geese, Brant, Snow Geese, and Tundra Swans to determine whether development-related disturbance and habitat loss have caused changes in the extent and nature of use of the area by these species. The study concluded that the development did not alter the extent or nature of use by geese and swans during construction and the first three years of operation of the oil field (Murphy and Anderson, 1993). Although individual birds may be impacted by disturbance, it is generally believed that disturbance does not necessarily translate into a population reduction.

Barriers to movement - birds: Concerns have been expressed that periodic nesting failures in black brant populations have been resulted from barriers to brant movements caused by roads, causeways, and other structures during brood-rearing periods when both adults and juveniles are flightless. Similarly, there was concern that the Endicott causeway could act as a barrier to the movements of brood-rearing snow geese. However, no clear indication has surfaced that either the black brant or snow goose populations have been measurably impacted by causeways and other structures.

4.4.8.1 Bird Populations and Habitat – Mitigation Measures

The following are summaries of some applicable mitigation measures to mitigate potential impacts to birds:

Habitat Protection – Sensitive habitat areas must be identified and avoided, and permanent facilities must be sited outside of identified nesting and brood-rearing areas for brant, white-fronted goose, snow goose, tundra swan, king eider, common eider, Steller's eider, spectacled eider, and yellow-billed loon. Lessees must comply with FWS recommended protection measures for Spectacled Eiders during the nesting and brood rearing periods.

Disturbance - NSB Municipal Code requires that vehicles, vessels, and aircraft that are likely to cause significant disturbance must avoid areas where sensitive species are concentrated. Horizontal and vertical buffers will be required. Lessees must comply with the Recommended Protection Measures for Spectacled Eiders developed by the FWS to ensure adequate protection of spectacled eiders during the nesting and brood rearing periods. Lessees shall comply with the Recommended Protection Measures for Steller's eider once they are developed by the FWS. Peregrine falcon nesting sites are known to occur in the Sale 87 area. Lessees are advised that disturbing a peregrine falcon nest violates federal law. Lessees are required to comply with the federal resource recovery plan for the arctic peregrine falcon.

4.4.9 Terrestrial Mammals – Impacts to populations and habitat

The ANS is home to numerous species of terrestrial mammals. Caribou have received special interest on the North Slope, and considerable debate continues regarding the impacts of oil and gas development on caribou populations. Caribou population characteristics (e.g. calf production and survival, adult mortality), habitat use, movement and distribution, and behavior have been studied on the ANS since the mid-1970s. Whereas some attribute caribou population declines to oil and gas development, others believe that caribou populations are subject to natural cycles in the carrying capacity of the habitat, while others view caribou numbers as being influenced by a complex, interacting suite of factors including disease, nutrition, predator and insect pest population dynamics, and weather.

Among the more high-profile terrestrial mammals found on the ANS, and in addition to the ubiquitous caribou, are moose, muskoxen, brown bears, wolves, foxes, and wolverines. **Muskoxen** may be found across the ANS, although their total numbers are fairly small. Furthermore, their numbers and range appear to be expanding. Moose occur throughout ANS with a large concentration along the Colville River and its tributaries. **Moose** are most commonly found in the foothills or along river corridors. **Brown bears** are also common throughout the ANS, although their densities are generally lowest along the coastal plain. The ANS represents the northern limit of brown bear range, where the availability of food is limited and their reproductive potential is low (ADFG, 1986a). Populations of **fox** species on the ANS are generally quite large, but vary substantially in response to fluctuations in prey availability. High populations of fox could cause near total nest failure of all waterfowl and shorebirds, as foxes prey on eggs and young birds. **Wolves**, and particularly **wolverines,** are present in much lower densities, but occur throughout the ANS.

Impacts to populations of terrestrial mammal from oil field development may occur during any phase of development – exploration, construction, production, and dismantlement, removal and restoration. These impacts may take the form of habitat loss, disturbance, barriers to movement, or direct mortality.

Habitat Loss – Terrestrial Mammals: Development of petroleum resources on the North Slope may alter the habitats used by terrestrial mammals in several ways. Undeveloped land covered with gravel fill and the areas excavated to obtain the gravel result in habitat loss, but this is generally a small percentage of the land in the development area. The amount of habitat types preferred by caribou or other terrestrial species that is directly lost by filling with gravel is generally a very small proportion of the available habitat.

Caribou are subject to mosquito harassment from mid-to-late June through July, and to oestrid fly harassment from mid-July to late August. During these periods of high insect activity, caribou typically move from inland feeding areas to the vegetation-free coastal areas where the insects are limited and wind speeds are generally higher. If these or other areas used for insect relief are not available to caribou, extensive insect harassment may result in weight loss and increased parasitism from skin warbles and nasal bot flies. If caribou are delayed or prevented from free access to insect-relief habitat, the result may be deterioration in body condition resulting in decreased growth, increased winter mortality, and lowered herd productivity (USFWS, 1987). Feeding opportunities are limited in windswept insect relief areas, so caribou move inland to better foraging areas whenever insect harassment temporarily subsides, and return to the coast when harassment increases (Shideler, 1986).

Much of the attention to mammals on the North Slope has been focused on caribou. Despite this focus, many questions remain unanswered regarding the effects of oil field development on caribou populations. The central arctic herd (CAH) has grown considerably over the past 35 years coinciding with the period of oil field development, but lack of pre-development data makes assessment of effects of oil field development difficult. Also, the understanding of the population dynamics of the ANS caribou herds is incomplete and no firm conclusions about the effects of oil field development on reproductive success of the herd can be drawn. Based upon comparisons with other herds, there have been no apparent effects of oil field development on the growth of CAH, but this does not suggest an absence of impacts in the future. It is also questionable whether information on the CAH can be extrapolated with any degree of confidence to the other herds on the North Slope (i.e., the Porcupine and Western Arctic herds).

There have also been reports of habitat enhancement from oil development, although conclusive evidence is generally lacking. For example, it has been noted that dust accumulation along roads in the spring may lead to earlier snow melt and green-up of vegetation, providing caribou and other grazing species with better early-season food sources. Similarly, the observed congregation of caribou on gravel pads and roads, and in areas shaded by facilities, suggests a benefit in terms of providing insect relief, particularly from oestrid flies (Johnson and Lawhead, 1989; Lawhead 1990). However, it has also been note that use of facilities for insect relief habitat may cause caribou to avoid preferred foraging areas further from development. Overall, it does not appear that the loss of high quality tundra due to oil and gas development is a primary factor in the fluctuations of caribou populations. However, the local distribution and behavior of caribou is affected by infrastructure and human activities within producing oil fields.

Moose prefer riparian habitat, particularly those with substantial stands of willow and brush. Brown bears also use riparian areas, often traveling along major river corridors and feeding nearby. Mitigation measures that are currently being implemented on the North Slope aimed at preventing alteration of river banks and requiring facilities to be sited away from rivers serve to minimize the loss of this riparian habitat. Displacement of muskoxen from their preferred habitat may impact muskoxen populations, but the magnitude of such effects are difficult to predict, but would likely be related to the magnitude and duration of the displacement. However, muskoxen populations are generally increasing on the ANS despite 35 years of development, implying that habitat loss has not been an important factor.

Habitat destruction would primarily affect arctic and red foxes through destruction of den sites. Although oil and gas infrastructure may destroy den sites or causes foxes to den elsewhere, foxes have been known to use culverts and other construction materials for denning (FWS, 1986). For wolves, the direct effects of habitat loss on wolves are likely to be negligible as their abundance is generally a function of prey availability. Reduction in prey species due to habitat loss of other factors may reduce wolf populations (FWS, 1987).

Development of advanced technology for directional and horizontal drilling has reduced required well spacing allowing an increase in the number of wells at drill sites and reducing the number of drill sites required for development. The centralization of power plants and utility systems, and the joint use of roads, pipeline corridors, and airports all contribute to less area impacted by oil field infrastructure, therefore to less loss of habitat for terrestrial mammals.

Disturbance – Terrestrial mammals: Construction and operations of oilfields undoubtedly cause some degree of disturbance of terrestrial mammals. This disturbance could in turn displace mammals from preferred habitats even if the habitat is not directly impacted by the development. Noise and human activities associated with exploration (e.g. seismic surveys), construction, vehicle and aircraft traffic, pipeline operations could disturb caribou, moose, muskoxen, and grizzly bears in the vicinity, causing animals to move away from the source of the disturbance. Displacement is most likely early in the life of the project, because most terrestrial species show some degree of habituation to human activities over time. Disturbance of caribou, moose and muskoxen is most likely during the calving period in late May to early June, and such impacts may be reduced by avoiding development within important calving areas. Muskoxen remain relatively sedentary in the winter, and the energetic costs associated with forced movements during winter may be significant, although there are indications that muskoxen may become habituated to aircraft and seismic disturbance (USF&WS, 1987). Little is known regarding the influence of roads, traffic, and pipelines on musk ox movements (Ott, 1996). In contrast, moose adapt readily and habituate easily to human activity and are not easily disturbed (USFWS, 1987). However, moose may become agitated and be more sensitive to disturbance when calves are present.

Foxes and wolves readily habituate to human activity, although some disturbance from seismic activities and air and ground traffic may occur. The same can be said for bears, although human activities may serve to attract bears, especially to refuse disposal areas. As development occurs, access to land by local residents can be facilitated. This in turn could increase the disturbance to caribou, moose, muskoxen, and bears particularly in areas where hunting is allowed. The close spacing of the 3-D seismic traverses may also increase the risk that denning bears may be disturbed. This risk could be reduced by studies of bear denning sites and planning the acquisition programs accordingly.

Barriers to Movement – Terrestrial Mammals: The best-known example of perceived barriers to movement caused by ANS development in the issue of above-ground pipelines as a potential barrier restriction caribou movement. Facilities built during the early days of Prudhoe Bay development included flow and gathering pipelines that were elevated only slightly (one to four feet) above the tundra surface. These pipelines formed an effective barrier to caribou crossing. During the development of the Kuparuk field, pipelines were elevated to a height of five feet above the tundra surface, and the service roads were separated from the pipelines. This configuration has been shown to allow easy movement of caribou within the oil field. Pipelines elevated to a height of at least 5 ft and separated from roads by more than 300 ft are thought to allow passage of caribou and other terrestrial mammals.

Direct Mortality – Terrestrial Mammals: Direct mortality of terrestrial mammals due to oil field development is generally due to road kills. In the case of bears, however, there is an increased likelihood that bears will be killed resulting from defense of life and property (DLP) incidents. Indirectly, the increased accessibility of ANS areas due to development may increase access by local residents, resulting in increased hunting mortality. Collectively, these mortalities pertain to relevant to individual animals, and it is unlikely these impacts would have a negative impact at the population level.

4.4.9.1 Caribou -- Mitigation Measures

The following are summaries of some applicable mitigation measures to mitigate potential impacts to caribou:

- Pipelines must be designed and constructed to accommodate caribou movement and migration patterns. Above-ground pipelines must be elevated a minimum of five feet. Ramps or pipeline burial may be required to facilitate caribou movement. Lessees are advised in planning and design activities to consider the recommendations for oil field design and operations contained in the final report to the Alaska Caribou Steering Committee (Cronin, M. et al, 1994). ADNR may, after consultation with ADFG, require additional measures to mitigate impacts to wildlife movement and migration
- Aircraft should avoid caribou concentrations to ensure access to insect relief and calving habitat.
- Facilities must be sited so as to avoid sensitive habitats and wetlands.
- To the extent feasible and prudent, all aircraft should maintain an altitude of greater than 1,500 feet or a lateral distance of one mile, excluding takeoffs and landings, from caribou and muskoxen concentrations.

4.4.9.2 Muskoxen and Moose -- Mitigation Measures

Potential impacts to muskoxen and moose would be mitigated by the following:

- Pipelines must be designed and constructed to accommodate muskoxen movement and migration patterns.
- To the extent feasible and prudent, all aircraft should maintain an altitude of greater than 1,500 feet or a lateral distance of one mile, excluding takeoffs and landings, from caribou and muskoxen concentrations.

4.4.9.3 Brown Bears -- Mitigation Measures

The following are summaries of some applicable mitigation measures that have been imposed on the ANS to mitigate potential impacts to brown bear.

- Development of bear interaction plans are recommended for areas with potential bear interactions. These plans should include measures to minimize attraction of bears, organize layout of buildings and work areas to minimize human/bear interactions, warn personnel of bears near or on drillsites and the proper procedures to take if bears are

- Appropriate methods of garbage and putrescible waste disposal must be used to minimize attracting bears.
- Exploration or development activities must avoid the vicinity of occupied dens by one-half mile unless alternative mitigative measures to minimize disturbance are authorized by ADNR after consultation with ADFG. Known den locations may be obtained from ADFG prior to starting operations. Occupied dens encountered in the field must be reported, and subsequently avoided, or approval must be obtained for alternative mitigating measures.

4.4.9.4 Fur Bearers -- Mitigation Measures

The following are summaries of some applicable mitigation measures. Mitigation measures and lessee advisories that would mitigate potential impacts to wolves, wolverines, and foxes are:

- Habitat protection -- Exploration facilities must be temporary and must utilize ice roads and pads. Facilities may not be sited within waterbody buffers utilized by furbearers.
- Waste management -- lessees must use appropriate methods of garbage and putrescible waste disposal to minimize attracting wolves, wolverines, and foxes.

4.4.10 Marine mammals – Impacts to populations and habitat

The ANS is home to a several important species of marine mammals, including whales, pinnipeds, and polar bears. Exploration, construction, and production activities associated with the development of ANS petroleum resources may cause disturbance of marine mammals in a number of ways. Unlike the situation with terrestrial species, the loss of habitat is not a major problem with respect to marine mammals. Rather, most impacts involve some sort of disturbance during exploration, construction, or production to individuals. Furthermore, with the exception of oil spills that may ultimately reach the marine environment, activities that occur on land do not generally impact marine mammals other than polar bears, which spend portions of their lives on land. However, as development extends offshore into the Beaufort and Chukchi Seas, impacts to marine mammals will become increasingly important.

Pinnipeds found in the Beaufort and Chukchi Seas include ringed, spotted and bearded seals, and walrus, although walrus are only rarely observed east of Point Barrow. Oil and gas exploration and development in the Beaufort Sea could impact seals, ultimately resulting in temporary localized displacement. Onshore development very near the coast could also disturb a small number of pinnipeds, although the amount of displacement is likely to be small in comparison with the natural variability in seasonal habitat use and is not expected to affect seal populations. The primary sources of noise and disturbance of pinnipeds would come from marine traffic, air traffic, and geophysical surveys. A secondary source would be low frequency noises from drilling operations. Most of these disturbances would have only a very short-term effect on pinnipeds.

Whales may also be impacted by oil and gas exploration and production. Migrating bowhead whales, for example, have been deflected by noises generated by offshore seismic exploration and drilling.

Polar bears are more subject to disturbance from oil field development because they spend a portion of the year on land for denning, and because they pose a potential threat through interactions with humans. Construction of offshore oil and gas infrastructure including pipelines, gravel islands, causeways, and production platforms may have short term local effects on ice movements and fast ice formation around the structures which in turn could have a brief impact to polar bear (MMS, 1996b). The primary sources of noise disturbance would come from air and marine traffic. Seismic activities and low-frequency noise from drilling operations would also be a source of noise. Disturbance from human activities, such as ice road construction and seismic work, may cause pregnant females to abandon dens early. Early abandonment of maternal dens can be fatal to cubs.

Polar bears spend much of their time searching for food. If a bear discovers a food source in a field camp or production site, it will almost certainly return to the area. This behavior has resulted in numerous encounters between polar bears and humans, with some polar bears being killed. Although some such losses are unavoidable, they represent a small source of mortality on the polar bear population. Polar bears are protected under the Marine Mammals Protection Act (MMPA) of 1972. In Alaska, the protection of polar bears under the MMPA is the responsibility of USFWS, and prohibits the "taking" of marine mammals. By interpretation, taking is said to occur whenever human activity causes a polar bear to change its behavior.

4.4.10.1 Marine Mammals -- Mitigation Measures

- Lessees must comply with the provisions of the MMPA of 1972 as amended.
- Requirements and advisories to mitigate potential impacts to grizzly bears are also applicable to polar bears.
- Explosives will not be allowed for conducting offshore geophysical surveys in open water areas.

4.4.11 Threatened and Endangered Species:

The three species listed as endangered or threatened under the Endangered Species Act (ESA) that are of concern on the ANS are the bowhead whale (*Balaena mysticetus*) and two bird species, the spectacled eider (*Somateria fischeri*) and Steller's eider (*Polysticta stelleri*). The Arctic peregrine falcon (*Falco peregrinus tundrius*) was removed from the Endangered Species List in 1994, with monitoring of the population required until 1999.

Bowhead whales occur in seasonally ice-covered seas, generally remaining close to the pack ice edge. During spring and fall migrations, bowhead whales generally remain far offshore in the lead system of the Beaufort Sea, although they can occur near the shore. The species was classified as endangered under the ESA in 1970, and as depleted under the MMPA. However, no critical habitat has been designated for the bowhead whale, and it has recently been suggested that the species be delisted in Bering, Chukchi, and Beaufort Sea region (Shelden et al. 2001). Although onshore oil and gas activities are not expected to impact bowhead whales, there is considerable concern regarding potential offshore development and disturbance to the migration, feeding, breeding, and survival.

The **spectacled eider** was listed as a threatened species under the ESA in 1993 because of significant declines in the North American breeding population of the species, particularly on the Yukon-Kuskokwim Delta where the number of pairs declined by 96% 1970 through 1990 (Stehn et al. 1993; Ely et al. 1994). The cause of the decline is uncertain, but may relate factors such as climate change (and related changes in populations of marine invertebrates and spring ice dynamics), parasites and disease, subsistence harvest, and predation. Although the FWS has designated several areas in Alaska as critical habitat, none of occur on the ANS (BLM, 2004). Concerns relating to this species from resource development involve potential for habitat loss or alteration, disturbance and displacement, obstructions to movement, and direct mortality.

Steller's eider is an uncommon or rare species on the ANS, although a few sightings have been recorded (Johnson and Stickney 2001; Johnson et al., 2003). The Alaska breeding population of the species was listed as threatened in 1997. Although Steller's eider was known historically to nest throughout much of coastal areas of western and northern Alaska, nesting now is generally limited to areas of arctic Russia, with relatively few nests in Alaska (Kertell 1991; Quakenbush and Cochrane 1993; Flint and Herzog 1999). Nesting of Steller's eiders is tightly associated with years of high lemming populations (Quakenbush and Suydam 1999), but is probably less than 1000 in Alaska during suitable years (Larned et al. 2003).

4.4.11.2 Threatened and Endangered Species -- Mitigation Measures

- The provisions of the federal and state Endangered Species Acts and the federal Marine Mammal Protection Act must be adhered to at all times.
- No activity will be permitted that jeopardizes the continued existence of an endangered species or results in the destruction or adverse modification of habitat of such species.

4.5 Changes in Technology and Practices on Exploration and Development

Over the history of active petroleum exploration and production on Alaska's North Slope, dramatic changes have occurred both in terms of the technologies applied to petroleum development and the practices implemented during exploration and production. In general, the changes that have occurred in technologies and practices have had two goals: (1) reducing the costs of exploration and production; and (2) reducing the environmental impacts that may potentially result from exploration and production activities. In many cases, both of these goals were attained simultaneously, with new technologies and/or practices resulting in a reduction in the environmental "footprint" from E&P activities while also decreasing the costs of E&P.

During the exploration phase of development, most of the important technological advances have been focused on enabling industry to locate oil and gas deposit more accurately and to estimate the quantities of these resources more precisely, replacing older, less-efficient and often less environmentally-friendly options. In doing so, these technologies have served to reduce the number exploration wells drilled, thereby reducing exploration costs (DOE 1999) while simultaneously reducing the environmental impacts resulting from exploration.

Newer technologies and practices applied during the production phase of oil and gas resources have also helped to substantially reduce the extent of the environmental "footprint" resulting from development. Production wells are now much more closely spaced, allowing production to occur over substantially greater geographic areas from a single, often smaller pad while making it easier for developers to avoid disturbance of critical habitat. Drilling muds used today are considerably less toxic than those used in the past, and the practice of collecting fluids in reserve pits has been discontinued on the ANS. Requirements for gravel, water, and other materials during the production phase have been greatly reduced, thereby reducing the potential for negative impacts to the environment.

Below are a series of brief summaries of how some of the more significant changes in technologies and practices that have occurred in recent years have altered the impacts E&P have had on the environment of the ANS. Much of the information provided in this section was taken from Appendix D (Oil-Field Technology and the Environment) of the recent National Research Council (NRC) report on cumulative environmental effects of oil and gas development on the ANS (NRC, 2003). Additional information on the history of development on the ANS and the effects on the environment from these activities is provided in the NRC report.

4.5.1 Advances in Seismic Exploration Technologies

Technologies applied to the collection of subsurface data during exploration have undergone significant advances over the past 30 years. Specifically, recent improvements in 3-D seismic data acquisition and related exploration technologies now allow for improved location and quantification of oil and gas resources. Data collected using 3-D seismic techniques provide multidimensional representations of the subsurface, allowing for a much better understanding of the geologic structures and their properties. These technologies have been responsible for much of the increase in drilling success rates, which have improved from an estimated 17% in 1970 to around 50% or more today (NRC, 2003; DOE, 1999).

By adding a time component to the 3-D database, a 4-D visualization of the geologic structure is possible. As fluids are produced, measured parameters such as fluid viscosity, saturation, and temperature are analyzed in conjunction with the time-lapse three-dimensional analysis of fluid movements in the reservoir (DOE, 1999). Additional data including well logs, production information, and reservoir pressure may also be integrated into the 4-D visualization. The resulting information yields improved data for exploration by providing from the greater ability to predict the best locations for exploratory drilling. The resulting data is also useful in reservoir management.

Collectively, 3-D data acquisition and 4-D visualization technologies provide several tangible environmental benefits (DOE 1999). The more accurate siting of exploration wells results in a reduction in the number of dry holes and therefore in a reduction in the number and length of ice roads and the number of ice pads required during exploration. This in turn can provide a reduction in the volume of drilling wastes generated, reducing the likelihood of a spill or other accident. These technologies also increase the ability of operators to design development in a manner that will protect sensitive environments, as fewer wells are required to evaluate and produce reserves.

One potential adverse effect of these technologies is that a tighter spacing of seismic lines may be required for 3-D seismic activities. This tighter spacing may result in increased physical disturbance to tundra vegetation and disturbance to denning bears.

4.5.2 Remote Sensing

The use of remote sensing on the North Slope has increased over the past few years, especially during oil and gas exploration. Remote sensing is now used to help design and locate facilities, roads and pads so as to reduce the potential impacts to terrestrial and aquatic habitats. An extensive habitat mapping program using satellite infrared (IR) photography was used in the development of the Alpine field to select the locations of pads and other structures to avoid sensitive, critical habitat (Lance 2000). The environmental benefits of increased utilization of remote sensing are to help design facilities and infrastructure to avoid critical habitat and to site facilities in preferred locations. Several potential applications of Forward Looking IR (FLIR) are being evaluated, including an airborne FLIR unit to survey pipelines for corrosion and leak detection. The technology is also being examined for monitoring the movement of spills under ice and snow, and to locate polar bear dens.

4.5.3 Off-Road Travel Vehicles

Travel on the North Slope is increasingly relying on the use of rolligons – vehicles that ride on oversized, low-pressure tires that put only about four or five pounds of pressure per square inch on the tundra. These vehicles have been used on the North Slope in recent years for moving drill rigs to remote locations. They are used to provide access to locations that are far from current infrastructure and where the economics of the operation favors their use over the building of an ice road.

4.5.4 Roads and Pads - Replacement of Gravel with Ice

Exploration for and development of petroleum resources requires construction of considerable infrastructure, including roads, drilling pads, living quarters, and gathering stations. This infrastructure must be constructed on a solid base that prevents the underlying permafrost from melting. Traditionally, roads, pads and other infrastructure were constructed on gravel bases thick enough to insulate the underlying permafrost – usually between 10 and 15 ft thick. If not properly designed and constructed, gravel fill can adversely affect thermal stability of the tundra and hydrology through thermokarsting and increased ponding. To date, an estimated 60 million yards of gravel have been mined on the ANS for use in oil fields (Van Tuyn 2000), and much of this gravel remains in place where it was initially used.

Use of large amounts of gravel to support infrastructure results in a variety of potential environmental impacts both at the site where the gravel is produced as well as the site of its final disposition. State and federal resource agencies are concerned that gravel mining may adversely affect water quality and fish habitat at the site of the gravel mine. All gravel removal operations follow prescribed guidelines, and where large pits have been created by gravel removal this has often been done in a manner designed to provide fish and wildlife habitat after the mine site is abandoned (USDI, 1987).

Placement of gravel on tundra to provide a base for infrastructure removes and alters wetlands and other habitats. In addition, use of gravel may result in several ancillary impacts, such as increased levels of fugitive dust, and potential behavioral changes animals, altering or reducing wildlife populations locally, especially birds (FWS, 1987). Although some such impacts may occur, the total area covered by gravel on the ANS remains very small (Bickley and Brown, 1989), and the overall status of North Slope ecosystems has not been impacted in a significant manner. Furthermore, the industry has attempted to avoid high-value wetlands habitat and minimizing overall disturbance of wildlife and habitat.

Although gravel is still used for production facilities, exploration on the ANS has increasingly been conducted only during the winter supported by roads and drilling pads constructed of ice. Today on the ANS, all onshore exploration drilling is done during winter, with the drilling rig and all of the other infrastructure, materials and equipment necessary for drilling wells transported to and from well locations on ice roads. Ice pads provide a solid, stable base from which to drill an exploration well. After the drilling has been completed, the drill rig and support facilities are removed and the pad is allowed to melt. In some instances, specifically where drilling and evaluation are expected to require either extended drilling season or two drilling seasons, insulated ice pads have been used. These insulating pads remain in place over the summer between the two drilling seasons, allowing drilling to start two months ahead before what would be possible from a new ice pad.

Use of ice roads and ice pads during exploration has significantly reduced the environmental impacts associated with exploration. In comparison with gravel, Ice roads and pads minimize the damage to the tundra from exploration and do not negatively impact surface hydrology. However, ice roads and pads still have the potential for causing short-term damage to tundra, particularly in areas that have either experienced low snowfall or removal of snow by high winds. To date, however, has been little evidence of long term damage to tundra and other resources from ice roads and pads.

Exploration from ice roads and pads also has resulted in a much reduced need for gravel on the ANS. Not only are smaller volumes of gravel mined for a given field, but less area is covered by gravel during development. Older technologies relying primarily on gravel fill had considerably greater potential for causing serious damage to tundra and permafrost, with impacts generally persisting for many years.

Although truly roadless construction may not be feasible for most areas on the North Slope, the current trend is toward reducing road building to a bare minimum. For the Alpine field, for example, construction was done during winter with equipment, personnel, and modules transported to the site via ice roads. The pipeline from Alpine to existing infrastructure at Kuparuk was also built using ice roads. For the entire Alpine facility, gravel was used to build two production pads, a three mile road between the two Alpine pads, and an airstrip – covering a collective total of only about 97 acres.

It is likely that future development will be based on variations of the Alpine model, minimizing the use of gravel. However, the availability of water for building ice roads and pads may me limited in some areas. Pipelines for the Alpine field were also constructed from ice roads during winter months. These pipelines do not have gravel maintenance roads along side them, removing a potential barrier to the movement of caribou or other wildlife, in addition to reducing the volume of gravel required.

4.5.5 Pipeline Construction Technologies

In addition to being built without gravel maintenance roads, development of the Alpine field incorporated several other new technologies and practices regarding pipeline construction. This development required a pipeline to cross the Colville River, a major river that can have a width of up to a kilometer during spring breakup and associated flooding. To protect the pipeline from damage, ARCO Alaska, Inc. used horizontal directional drilling to situate the pipeline deep (100 ft) beneath the river channel (Lance, 2000). Leak containment was accomplished using large vertical loops instead of the more conventional block valves. Collectively, these techniques serve to reduce environmental effects to tundra while improving safety and reducing the probability and potential size of spills.

4.5.6 Horizontal and Multilateral Drilling

Tremendous reductions in the overall “footprint” of development have resulted from the development and implementation of horizontal (directional) and multilateral drilling technologies. These heavily computerized technologies have allowed for a greater number of wells to be drilled per pad, with closer well spacing on the pad. The result is that fewer well pads are needed, thus minimizing the cost and the surface impact of drilling, production, and transportation facilities. This technology can be used to reach resources located beneath an environmentally sensitive area, and allow development of some nearshore resources from the land.

Horizontal wells are drilled from an initially vertical well bore, and may penetrate the formation up to five miles or more from the vertical well bore, allowing substantially more oil to drain into the well. By way of comparison, the Prudhoe Bay Drillsite 1 drilled in 1971 covered 65 acres and had an effective reach radius of about 1 mile, thereby producing from an area of about 2,010 acres. In comparison, the recent Alpine Pad #2 covers a total of only 13 acres, but has an effective reach radius of 4 miles, producing from an area of over 32,000 acres. Multilateral drilling represents a variation of the horizontal drilling technology whereby an interconnecting network of separate, pressure-isolated and reentry accessible horizontal or high-angle boreholes is created surrounding a single primary borehole (DOE 1999).

Directional drilling is not always economically feasible. Factors such as where the oil deposit is in relation to the drilling rig, the size and depth of the deposit, and the geology of the area, are all important elements in determining whether directional drilling is cost effective.

From an environmental standpoint, the principal advantage of using horizontal and multilateral drilling technologies is a drastic reduction in the surface footprint from development. Much less habitat is disrupted by the construction of pads as fewer pads are required for a given surface area or volume of oil. This in turn results in reductions in the volume of water needed and in the volume of wastes generated.

4.5.7 Coiled Tubing

Coiled tubing is a continuous flexible coil mounted on a large reel that is fed into the hole as the drilling progresses. The technology was developed in the 1980s, and has become common on the ANS. Conventional drilling methods are often used to drill the initial hole, with coiled tubing then used for drilling horizontal segments or multilateral completions. This technology eliminates the need for the frequent stopping of the drilling process to add additional pipe segments, resulting in a significant reduction in the volume of drilling fluids needed. Mud volumes used with coiled tubing are also reduced by approximately 50% in comparison with what is required using conventional drilling practices (DOE 1999), and coiled tubing also has better leak-prevention characteristics because there are no (or few) pipe connections. Coiled tubing is also quieter than traditional techniques, and results in lower fuel consumption and emissions.

4.5.8 Enhanced Oil Recovery (EOR)

Although the concept of enhanced oil recovery has been applied for many years, advances in EOR technologies have allowed for greater volumes of oil and gas to be produced from existing wells. The general process involves the injection of formation and source water, natural gas, and miscible fluids into the producing reservoir to increase the formation pressure, thereby increasing the amount of hydrocarbons recovered. The principal environmental benefit of EOR include (1) a greater recovery of oil without a proportionately greater number of wells and their associated impacts: (2) an acceptable means for disposing of produced waters (by returning them to the formation from which they originated); and (3) a reduction in the emissions that would occur due to the flaring of excess produced gas.

4.5.9 Reserve Pit Closure Program

Until the 1980s, most wastes associated with well drilling were either stored in reserve pits or handled through incineration or another means of surface disposal. Liquid reserve pit wastes contain small amounts of metals (e.g. aluminum, arsenic, barium, cadmium, chromium, lead, mercury, silver, and zinc), along with aromatic hydrocarbons (derived from oil-bearing formation cuttings), other hydrocarbon components such as paraffins and olefins, and various chemical additives. Seepage has been known to occur in the past through the embankments of some of these unlined reserve pits. Release of materials from some of these unlined reserve pits has been implicated in the observed increases in the concentrations of salts and metals in adjacent waters. In sufficient quantities, and with sufficient exposure times, many of these components of liquid reserve pit wastes can be harmful to aquatic organisms and to waterfowl and other birds (i.e. bioaccumulation of heavy metals and/or other contaminants in water fowl and other local wildlife). Reserve pit closure program instituted in 1996 has closed about 600 reserve pits. Closure plans have been submitted to ADEC for all other sites. However, a large number of unclosed reserve pits remain.

4.5.10 Underground Injection Control Program:

As an alternative to reserve pits, most drilling wastes are now disposed of through underground injection. The AOGCC has primacy for UIC program wells designated as Class II (i.e., oil and gas), while the EPA maintains primacy for all other classes. There are three types of Class II wells – oilfield waste disposal wells, EOR wells, and hydrocarbon storage wells. The goal of the UIC program is to protect underground sources of drinking water from contamination by oil and gas injection activities. The UIC program requires the Commissioner of the AOGCC to verify the mechanical integrity of injection wells, determine if appropriate injection zones and overlying confining strata are present, determine the presence or absence of freshwater aquifers, and ensure their protection, and prepare quarterly reports of both in-house and field monitoring for the EPA.

4.6 Cost of Environmental Regulation and Compliance

As described in earlier sections of this report, many of the environmental impacts potentially associated with past, current, and future development of petroleum resources on Alaska's North Slope may be ameliorated through the application of mitigative measures the types and extent of which are stipulated in the various permits summarized above. A few environmental issues, however, may be contentious enough to substantially delay or even prevent development in certain areas. In these cases, it is not the cost of compliance *per se* that prevents or restricts development, but rather, the issue results in the need for a "go or no go" decision regarding development. Other issues, although probably not capable of preventing development independently, could increase the costs of exploration and production to the point where development is not economically viable. However, quantification of the cost of these issues is difficult.

4.6.1 Summary of 1990 "Showstoppers"

An earlier study (Thomas et al., 1991) identified three general issues as falling into the "go or no go" category – "showstoppers" that were thought to have the potential for preventing or severely restricting development in certain areas. These three issues were: (1) a strict application of the "no net loss" of wetlands policy; (2) the construction and use of solid-fill causeways for near-shore development; and (3) the construction and routing of pipelines connecting new fields to TAPS. A summary of these three issues is provided below, along with the current status of each.

4.6.1.1 No-Net-Loss of Wetlands:

In 1990, the oil industry and regulatory agencies were grappling with the interpretation of a requirement of the CWA that called for the preservation of the nation's wetlands. A nationwide policy for prohibiting any reduction of wetlands was being promoted. For most of the United States, where large percentages of the total historical wetland area had already been destroyed, and the "no-net-loss" policy was intended to preserve the limited remaining wetland areas. Wetlands are defined by the CWA as "*those areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil condition*." Under this definition, much of the land area on Alaska's North Slope was categorized as wetland.

Most wetlands losses on the ANS occur from the placement of gravel for roads and for the construction of drill pads, living areas, and pump stations (BP Exploration [Alaska], Inc., 1989a). Prior to 1990, oil development had directly affected approximately 30,000 acres of wetlands habitat in Alaska, corresponding to an estimated two one-hundreds of one percent (0.02%) of the historic level of 170 million acres (BP Exploration [Alaska], Inc., 1989a). In 1990, however, Congress was considering a strict nationwide application of the "no-net-loss" policy. If applied in Alaska, development of ANS resources would have been severely restricted, if not eliminated altogether.

Current status – Wetlands protection: Ultimately, a strict policy of no-net-loss was not applied to Arctic development. However, a series of mitigative measures aimed at limiting impacts to wetlands are now applied to developers. These collectively help to minimize the loss of wetlands through a strategy that includes the early planning and interaction between design engineers and environmental specialists. Facility consolidation, winter construction, and rehabilitation research are also factors that have been employed to help reduce the impact of development in Arctic wetlands. Efforts are made to identify and protect critical habitats, rather than applying a blanket policy that prevents development of any wetland area.

4.6.1.2 Solid Fill Causeways:

The construction of solid fill causeways to connect nearshore production units to the mainland was a contentious issue in 1990, and remains an issue today. Development of nearshore resources requires the transportation of produced fluids to the existing, onshore infrastructure, as well as the transport of equipment onshore. One of the methods used for these purposes is through pipelines supported by solid-fill gravel causeways (Mitchell, 1989). Causeways simply provide an elevated surface consisting of gravel that extends for some distance offshore. Solid-fill gravel causeways may be of two types (Padron, 1989) – unbreached (i.e., providing a continuous road-pipeline corridor made of gravel extending offshore to a pump station) or breached (causeways with one or more areas spanned by bridges). These breaches or open areas allow water and fish movement through the causeway. Causeways may be used to (1) access deeper water for EOR; (2) dock barges carrying large modules and other equipment; or (3) access nearshore production facilities and to support pipelines for transportation of produced fluids through nearshore areas. Causeways have been constructed at Endicott and West Dock.

Among the concerns associated with solid-fill causeways are alterations to physical processes such as flow patterns and upwelling processes, as well as impacts to temperature and salinity patterns that may impact anadromous fish habitat (EPA, 1988). In 1990, the regulatory basis for permitting causeway construction or alternative technologies included requirements for permits under Part 404 of the CWA as well as CZMA, ESA, MMPA, and the Outer Continental Shelf Lands Act. The West Dock causeway, for example, was found to divert nearshore currents such that colder, more saline water entered a lagoon that was previously warmer and less saline before construction of the causeway. These nearshore areas are important for fish migration. After West Dock was constructed and later extended, there was concern that the structure restricted the ability of fish to avoid cold saline water during their migration. However, studies have indicated that fish movements have not been impacted by either the Endicott or West Dock causeways (Gallaway et al., 1991; Colonell & Gallaway, 1990), although eventually the Endicott was breached to provide fish access. Despite extensive research into their effects, evidence that the two causeways have had significant population level impacts on anadromous fish remains inconclusive.

Several alternatives to solid-fill causeways exist for transporting fluids to onshore infrastructure. These include: (1) directional drilling; (2) use of subsea pipelines; (3)

construction of elevated pipelines; and (4) construction of elevated causeways. While all of the above alternatives are technically feasible, some will require more technical development and environmental analysis than others. Thus, the reliability of estimates of construction cost, schedule, and environmental impacts varies considerably among the alternatives.

Because of the concern over causeway permitting, ARCO Alaska elected to drill from shore rather than building the proposed *Lisburne Causeway* in the late 1980s (Johnson, 1988). In this instance, ARCO felt that directional drilling was an economically viable alternative to causeway construction (Johnson, 1988), and improved capabilities in directional drilling may provide reasonable alternatives for several nearshore fields. However, industry would still like to construct a causeway for development of the Liberty field, and may determine that this field is not economical if alternative technologies are required.

Current status – Causeways: Solid fill causeways are still a potential showstopper for fields such as Liberty that are located within a few miles of the shoreline in the Beaufort or Chukchi Seas. The State of Alaska now strongly discourages the construction and use of solid fill causeways, and requires that any proposed causeway be permitted on a case-by-case basis. Such a permit requires a determination that the causeway (or other structure) is necessary for field development and that no feasible and prudent alternatives exist. The permit likely would require a monitoring program to address the objectives of water quality and free passage of fish, and mitigation shall be required where significant deviation from objectives occurs. Causeways and docks cannot be located in river mouths or deltas. If approved, a causeway must be designed, sited, and constructed to prevent significant changes to nearshore oceanographic circulation patterns and water quality characteristics (e.g., salinity, temperature, suspended sediments) that result in the exceedance of water quality criteria, and must maintain free passage of marine and anadromous fish. Although other methods may be technologically feasible for transporting oil and gas from nearshore facilities to the TAPS system, the costs of using these other technologies may be excessive enough to make the development of a field such as Liberty uneconomical.

4.6.1.3 Pipeline Issues:

The third potential "show-stopper" issue identified in the 1990 report (DOE, 1991) involved the construction of additional pipelines on the ANS, as all oil and gas development are anticipated to involve pipelines to connect newly-developed fields to the existing TAPS pipeline. At the time, new fields were being considered for development that were located outside of the infrastructure area of the existing Prudhoe and Kuparuk fields. The concern at the time was that pipelines crossing major rivers or critical habitats would not be permitted, hence restricting or eliminating the means for oil to be transported to the TAPS. Among the strategies employed over the years to mitigate potential impacts to wildlife included: (1) adjusting pipeline height, (2) separating the pipeline from a busy road, (3) providing ramps for caribou to cross, (4) routing roads to avoid major migration routes, and (5) construction during the winter.

On the ANS, buried or elevated pipelines represent the only practical means for transporting oil and gas from the field to the TAPS. Elevated pipelines are most commonly used on North Slope. By elevating the pipeline several feet above the tundra surface, heat transfer from the hot oil in the pipeline to frozen soils is prevented, thus protecting the permafrost.

Maintenance and leak detection are also easier for elevated pipelines. However, concerns remain regarding the potential for above-ground pipelines to serve as barriers to caribou and other wildlife unless the pipelines are constructed so as to ensure their safe passage. Pipelines elevated to a height of at least five feet above the tundra surface are generally considered to be effective in allowing caribou and other wildlife to cross. However, it has also been observed that roads running parallel to pipelines may create a barrier to caribou crossing. The Alaska Caribou Steering Committee has concluded that the most effective configuration is achieved when pipelines and roads are separated by a distance of at least 500 ft (Cronin et al., 1994).

Buried pipelines are more expensive to install and maintain than elevated pipelines, but remain a viable alternative on the ANS provided that the integrity of the frozen soils is maintained. Where pipelines are buried, special precautions must be taken to ensure that heat from the pipe does not melt the permafrost. Although buried pipe is more difficult to monitor and maintain, significant technological advances in leak detection systems have made it easier to monitor buried pipelines. Buried pipelines also generally require gravel fill, and may at times not be feasible from an engineering standpoint because of the thermal stability of fill and underlying substrate (Cronin et al., 1994).

For the Alpine development site, a buried oil pipeline was built under the Colville River, installed at a depth of approximately 50 ft or greater beneath the river bed using horizontal directional drilling methods (Parametrix Inc., 1996). The buried pipeline is insulated and operates such that the oil temperature will ensure that thaw settlement will be within tolerable limits. A state-of-the-art leak detection system has also been incorporated that employs real-time monitoring supplemented by the use of inspection pigs (ARCO, 1996).

As development has continued and additional fields have been explored and brought on line both east and west of Prudhoe Bay, the construction of additional pipelines to tie into the TAPS has effectively been removed from the “showstopper” category. Pipelines are designed and built to provide adequate protection from geophysical and other hazards, and to minimize impacts to the movement of caribou and other wildlife species.

Current status – Pipelines: Since 1990, the North Slope pipeline system has expanded east and west from the Prudhoe and neighboring fields. New technologies and careful planning have enabled pipelines to be constructed from outlying fields to the TAPS.

4.6.2 2005 “Showstoppers”

A number of issues have been identified as potential “showstoppers” in 2005 and beyond. Each of these issues has the potential for preventing development of a given field or set of fields. Some may be solved by further advances in technology. Others, however, may ultimately prevent development in a given location.

4.6.2.1 Land access:

Oil and gas resources cannot be developed if the oil industry does not have access to the land containing the oil. While most state and federal lands on the ANS are open for resource development, ANWR remains closed. Development of resources in the 1002 Area along the coast in the northwest corner of the ANWR has long been a contentious issue on the North

Slope. Recent congressional actions have increased the probability that the 1002 Area will be opened for development, but until the area is opened, oil and gas will not be developed from the area.

4.6.2.2 Critical Habitat Issues:

The ESA requires that areas of critical habitat be protected. Although careful planning between industry and regulatory and resource agencies has generally allowed for development to proceed with minimal impacts to recognized critical habitat, the designation of large areas of critical habitat may still prevent development in some areas, such as the Teshekpuk Lake area in the NPRA.

4.6.2.3 Water Availability

Although sources of fresh water for the construction of ice roads and ice pads are abundant in many areas of the ANS, as development progresses to the south and east of existing development, these sources of water become less frequent. Construction of ice roads and pads requires abundant water sources along the entire route – and these sources may not be available in areas such as the foothills.

4.6.2.4 Total roadless development

The success of the Alpine development area, which was completed with the construction of almost no roads, has led to a desire by some resource agencies to require future development to occur without road construction. Although such total roadless development may be feasible for some satellite fields, development of other fields may not be economically feasible without roads.

4.6.2.5 Marine Mammal Protection

As technologies advance, the petroleum industry is becoming increasingly interested in exploration and development of potential offshore fields in the Beaufort and Chukchi Seas. The North Slope Borough and others have expressed concerns over development of offshore resources and their potential impacts on bowhead whales and other marine mammals from seismic exploration, drilling, and spills. Interpretation of the Marine Mammals Protection Act and other regulations will be required to ensure that exploration and development can be performed while affording protection to these species. Truncated seasonal operating times could make offshore projects uneconomical.

4.6.2.6 Air permitting

As more and more development occurs on the ANS, air emissions necessarily increase. At present, the only priority air pollutant of concern from a permitting standpoint on the ANS is NOx. Since development cannot increase without increasing NOx emissions, new permits will have to be issued. This will require that industry show no degradation to the North Slope's Class I airshed.

4.6.2.7 Dismantlement, Removal, and Restoration (DR&R)

At the request of Congress, the General Accounting Office (GAO) recently issued a report on the status of DR&R on the ANS (GAO, 2002). Specifically GAO was tasked to determine the following:

1. The nature and extent of DR&R requirements for existing oil industry activities on state-owned land on the ANS, including how these requirements compare to those of other oil-producing states.
2. Whether any cost estimates exist for the DR&R of the infrastructure and for the restoration of ANS state-owned land.
3. What financial assurances the state of Alaska has that funds will be available to cover the eventual DR&R costs and how these assurances compare to those of other oil-producing states.
4. The nature and extend of DR&R requirements and financial assurances governing future oil industry activities on federal lands located on the ANS, and how these compare with requirements and financial assurances in other related industries such as mining and nuclear power.

Among the conclusions of the GAO report was that current requirements for DR&R on state lands for existing production sites were very general, with little or no specific requirements regarding what infrastructure must be ultimately be removed or to what condition lands used for resource development must be restored. Oil production requires the construction of a considerable infrastructure of, among other things, drilling pads, production facilities, pipelines, roads, airstrips, and gravel mines. Because most of this infrastructure has been built on state lands, the state is primarily responsible for regulating oil industry activity, including any requirements for dismantling and removing the infrastructure and restoring the land after oil production ceases. However, new oil production in the Arctic Ocean, combined with new oil discoveries in the NPRA and the potential opening of the ANWR to oil exploration has elevated the importance of federal jurisdiction on the North Slope.

Alaska's regulation of DR&R for the ANS oil industry is principally divided among four state agencies: AOGCC, ADNR, ADEC, and ADFG. AOGCC issues permits for drilling oil wells throughout Alaska regardless of land ownership. ADNR leases state lands for oil and gas activities and collects royalties on oil and gas production in the state. These leases stipulate how the land will be returned to the state after production ceases. ADEC regulates waste management practices at exploration, development, and production facilities on private, state, and federal lands. ADFG oversees habitat issues and have a limited (and principally advisory) role in regard to DR&R.

Several federal agencies also have responsibility for regulating oil activities on the ANS. The BLM manages the NPRA and issues and oversees leases for oil activities on any federal lands. MMS regulates activities on the OCS, defined as three or more miles from shore. The ACE issues permits for dredging or fill activities in U.S. waters, including wetlands. Almost the entire ANS is designated wetland and, because gravel underlies most production facilities, airstrips, and roads, the ACE has a permitting role in basically all oil company construction activities. FWS, EPA, and NOAA Fisheries can offer advisory comments to the ACE as part of the permit evaluation process. Further, EPA also has veto authority over ACE permits. If Congress authorizes oil industry activities in ANWR, FWS would oversee the issuance of right-of-way permits, while BLM would issue and oversee the federal leases. This regulatory construct assumes that the ANWR would be managed similarly to other refuges, but it remains unclear as to what FWS's role and regulatory authority would be. ACE, NSB, and native landowners have not imposed their authority to institute DR&R requirements. Although AOGCC regulations impose specific requirements on oil companies for plugging and abandoning wells, they do not dictate requirements for surface restoration beyond the immediate well site. ADNR lease agreements contain only general language regarding DR&R requirements.

The costs associated with DR&R will depend on what DR&R requirements are imposed, which has not been established. Lack of specific requirements from the state and uncertain timeframes for restoration complicate any cost estimates. Other factors identified by include: (1) the addition of new infrastructure as development continues; (2) dismantlement and removal of some facilities, including plugging of wells, before units are abandoned; (3) increases in the cost of services such as labor and transportation; (4) future market value of useable equipment and scrap material; (5) technological advances in drilling, production, and rehabilitation; (6) inflation; (7) alternative uses for facilities or gravel, such as for natural gas production; (8) changes in environmental regulations or abandonment stipulations.

A complete inventory of current ANS infrastructure is not available. However, using information obtained from BP, the State, and data in recent EIS's, the GAO identified the following infrastructure summary:

- Gravel Fill: 10,653 acres (16.6 square miles) excluding the Dalton Highway and reclaimed and/or exploratory sites.
- Gravel mines: 15 mines covering 1601 acres (2.5 square miles)
- Roads: 264 miles (excluding Dalton Highway), including 22 river crossings
- Well pads: 109
- Well sites: 3520
- Pipelines: 520 miles (excluding TAPS)
- Facilities: 13 production facilities, 14 industrial plants, 5 docks and causeways, 5 airstrips

The end of oil and gas production on the ANS will likely render much of the current infrastructure of production facilities, pipelines, and roads unnecessary. Responsibility for regulating and overseeing the dismantlement and removal of this infrastructure and restoring the land on which it was built will be the shared responsibility of the state, federal, and local governments, depending in part on which party owns the land.

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Appendix A. *Pro Forma* and Detail Reports

The economics model used generates a wealth of detail on the capital and operating structure of each pool studied. While the economics model contains over 400 variables, most of these are used internally. Two standardized reports were developed, a *pro forma* cash flow statement and a details statement that provide per barrel metrics derived from the pro forma reports. The *pro forma* report is structured to present the cash flow as discussed in Section 3.2.1. The reports cover the time frame from 2005 through 2040. An example of this report is presented in Figure A.1.

PBU - Prudhoe Bay Pool-$60
PRO FORMA
07/20/06 AT 13:40

	2005	2006	2007	2008	2009	2010	2011	2012	2013
REFERENCE OIL PRICE, $ bbl	60.30	60.90	61.51	62.13	62.75	63.38	64.01	64.65	65.30
REFERENCE GAS PRICE, $ Mcf	10.05	10.15	10.25	10.35	10.46	10.56	10.67	10.77	10.88
OIL PRODUCTION RATE, Mstbd	408.668	384.263	361.200	339.397	318.718	299.162	281.392	264.608	248.729
GAS PRODUCTION RATE, MMscfd	8,394.781	8,232.027	8,037.099	7,816.081	7,572.776	7,313.336	7,060.486	6,799.899	6,533.695
GAS SALES RATE, MMscfD	.000	.000	.000	.000	.000	.000	.000	.000	.000
WATER PRODUCTION RATE, Mbbld	1,328.663	1,318.855	1,303.816	1,283.963	1,259.485	1,231.085	1,202.450	1,171.080	1,137.271
******************************** CASH FLOW IN THOUSANDS OF DOLLARS ********************************									
GROSS REVENUE	8,219,279	7,730,675	7,309,624	6,935,132	6,568,172	6,215,151	5,887,175	5,585,038	5,271,862
ROYALTY	1,008,335	948,399	896,844	851,050	806,145	762,931	722,763	685,779	647,373
NET REVENUE	7,210,943	6,782,276	6,412,780	6,084,082	5,762,026	5,452,220	5,164,412	4,899,259	4,624,488
TOTAL OPERATING COST	399,889	394,913	390,711	386,056	380,915	375,368	370,154	364,623	358,815
SEVERANCE TAX	975,217	902,025	830,830	762,778	690,520	615,883	538,566	455,949	363,264
CONSERVATION TAX	522	491	461	434	407	382	359	338	318
CONSERVATION SURTAX	6,526	6,136	5,768	5,420	5,090	4,777	4,493	4,225	3,972
AD VALOREM	84,991	83,853	82,599	81,222	79,717	78,077	76,295	74,364	72,277
BFIT	5,743,798	5,394,858	5,102,411	4,848,172	4,605,377	4,377,734	4,174,544	3,999,760	3,825,843
STATE DEPRECIATION	188,556	180,314	172,751	165,832	159,495	153,747	148,976	144,764	141,079
STATE INCOME TAX	166,657	156,436	147,890	140,470	133,376	126,720	120,767	115,650	110,543
NET AFTER STATE INC TAX	5,577,141	5,238,422	4,954,521	4,707,702	4,472,001	4,251,014	4,053,777	3,884,110	3,715,300
EXP INTANG INV	24,794	25,389	25,998	26,622	27,261	27,916	28,586	29,272	29,974
AMORT IDC	7,805	9,981	12,210	14,492	16,828	11,416	11,690	11,971	12,258
FED DEPRECIATION	14,902	17,536	19,685	21,719	17,977	14,285	16,468	16,864	17,268
NET BEFORE FED INCOME TAX	5,529,640	5,185,516	4,896,628	4,644,869	4,409,934	4,197,398	3,997,033	3,826,004	3,655,800
FED INCOME TAX BEFORE TAX CREDIT	1,880,078	1,763,075	1,664,854	1,579,256	1,499,378	1,427,115	1,358,991	1,300,841	1,242,972
NET INCOME	3,649,562	3,422,440	3,231,775	3,065,614	2,910,557	2,770,282	2,638,042	2,525,163	2,412,828
OP CASH FLOW	3,697,063	3,475,346	3,289,668	3,128,447	2,972,623	2,823,899	2,694,786	2,583,269	2,472,328
TOTAL CASH FLOW	3,645,856	3,421,652	3,233,365	3,069,409	2,910,717	2,758,986	2,626,720	2,511,896	2,397,489
PBU - Prudhoe Bay Pool-$60 INVESTMENTS									
TOTAL DEV COST	50,600	51,814	53,058	54,331	55,635	56,971	58,338	59,738	61,172
TOTAL FACILITIES COST	0	0	0	0	0	0	0	0	0
TOT INV	51,207	53,695	56,303	59,038	61,906	64,913	68,066	71,372	74,839
CUM TOT INV	51,207	104,902	161,205	220,243	282,148	347,061	415,127	486,500	561,339
PBU - Prudhoe Bay Pool-$60 ECONOMIC RESULTS									
PW OP CASH FLOW	3,521,013	3,008,958	2,589,270	2,238,522	1,933,659	1,669,923	1,448,701	1,262,500	1,098,437
PW TOTAL CASH FLOW	3,472,244	2,962,469	2,544,955	2,196,278	1,893,390	1,631,536	1,412,109	1,227,619	1,065,187
CUM PW OP CASH FLOW	3,521,013	6,529,971	9,119,241	11,357,763	13,291,422	14,961,344	16,410,046	17,672,546	18,770,983
CUM PW TOTAL CASH FLOW	3,472,244	6,434,713	8,979,668	11,175,946	13,069,336	14,700,872	16,112,981	17,340,600	18,405,787

Figure A.1. ***Pro forma* report for Prudhoe Bay pool, 2005 through 2013.**

A second report is structured to present the above information in greater detail on a per barrel basis. Additional information includes well counts (oil, water, and gas production wells), development wells, well attrition, producing water cut, gas-oil-ratio, recovery factor, and the ELF factor for the calculation of severance taxes. An example is presented below in Figure A.2.

PBU – Prudhoe Bay Pool-$60
07/20/06 AT 13:41

	2005	2006	2007	2008	2009	2010	2011	2012	2013
PRODUCTION METRICS									
OIL PRODUCTION RATE, Mstbd	408.668	384.263	361.200	339.397	318.718	299.162	281.392	264.608	248.729
GAS PRODUCTION RATE, MMscfd	8,394.781	8,232.027	8,037.099	7,816.081	7,572.776	7,313.336	7,060.486	6,799.899	6,533.695
GAS SALES RATE, MMscfD	.000	.000	.000	.000	.000	.000	.000	.000	.000
WATER PRODUCTION RATE, Mbbld	1,328.663	1,318.855	1,303.816	1,283.963	1,259.485	1,231.085	1,202.450	1,171.080	1,137.271
OIL PRODUCTION WELLS	695.210	675.460	656.697	638.872	621.938	605.851	590.569	575.290	560.776
INJECTION WELLS	187.340	181.963	176.855	172.002	167.392	163.012	158.852	155.659	152.626
GAS PRODUCTION WELLS	.000	.000	.000	.000	.000	.000	.000	.000	.000
DEVELOPMENT WELLS	20.000	20.000	20.000	20.000	20.000	20.000	20.000	20.000	20.000
WELL ATTRITION	44.128	42.871	41.678	40.544	39.467	38.443	37.471	36.547	35.670
WATER CUT	.765	.774	.783	.791	.798	.805	.810	.816	.821
RECOVERY FACTOR	.842	.853	.863	.872	.881	.889	.896	.904	.910
GOR, Mscf per stb	20.542	21.423	22.251	23.029	23.760	24.446	25.091	25.698	26.268
AVERAGE OIL WELL RATE, Mstbd	.588	.569	.550	.531	.512	.494	.476	.460	.444
ELF	.904	.889	.866	.838	.801	.755	.697	.622	.525
ECONOMIC METRICS PER BARREL									
REFERENCE OIL PRICE	$ 60.30	$ 60.90	$ 61.51	$ 62.13	$ 62.75	$ 63.38	$ 64.01	$ 64.65	$ 65.30
REFERENCE GAS PRICE, $ Mcf	$ 10.05	$ 10.15	$ 10.25	$ 10.35	$ 10.46	$ 10.56	$ 10.67	$ 10.77	$ 10.88
TRANSPORTATION	5.03	5.62	5.90	5.98	6.12	6.29	6.52	6.65	7.06
GRAVITY ADJUSTMENT	(.17)	(.17)	(.17)	(.17)	(.17)	(.17)	(.17)	(.17)	(.17)
WELLHEAD OIL PRICE	55.10	55.12	55.44	55.98	56.46	56.92	57.32	57.83	58.07
ROYALTY	6.76	6.76	6.80	6.87	6.93	6.99	7.04	7.10	7.13
DIRECT OP COST	2.68	2.82	2.96	3.12	3.27	3.44	3.60	3.78	3.95
FIXED OP COST	.55	.57	.60	.62	.66	.69	.73	.77	.81
VARIABLE OP COST	1.96	2.06	2.17	2.28	2.39	2.51	2.63	2.74	2.86
WELL WORKOVER COST	.18	.19	.20	.21	.22	.24	.25	.27	.28
COST SHARING FEE PER BBL	.00	.00	.00	.00	.00	.00	.00	.00	.00
PRODUCTION TAXES	6.59	6.48	6.35	6.20	5.98	5.69	5.29	4.77	4.05
PROPERTY TAXES	.57	.60	.63	.66	.69	.72	.74	.77	.80
STATE INCOME TAX	1.12	1.12	1.12	1.13	1.15	1.16	1.18	1.20	1.22
FEDERAL DEDUCTIONS	.32	.38	.44	.51	.53	.49	.55	.60	.66
FEDERAL INCOME TAX	12.60	12.57	12.63	12.75	12.89	13.07	13.23	13.47	13.69
NET INCOME	24.47	24.40	24.51	24.75	25.02	25.37	25.68	26.15	26.58
OPERATING CASH FLOW	24.79	24.78	24.95	25.25	25.55	25.86	26.24	26.75	27.23
PRESENT WORTH	23.61	21.45	19.64	18.07	16.62	15.29	14.11	13.07	12.10
CAPITAL COST	1.58	1.66	1.75	1.85	1.90	1.90	2.00	2.10	2.21
CAPITAL AND OP COST	4.26	4.48	4.71	4.96	5.18	5.34	5.61	5.88	6.16
INVESTMENT	.34	.38	.43	.48	.53	.59	.66	.74	.82
OP COST PER WELL	575	585	595	604	612	620	627	634	640

Figure A.2. Details report for Prudhoe Bay pool, 2005 through 2013.

Similar reports were generated for all the pools studied and for each of the four oil price tracks.

Appendix B. Gas Pipeline Tariff

Introduction

The pipeline tariffs are used to calculate the net back of the natural gas price received from the final delivery point to the wellhead. For this analysis it was assumed the AGP would deliver gas to market in Chicago and requires an estimation of natural gas tariffs for the 52-inch pipeline from the ANS to Chicago. This section presents the tariff methodology.

The tariff calculation used a full life-cycle cost basis that included the capital cost of: (a) the pipeline, (b) gas separation plant on the North Slope for the removal of CO_2 and other contaminates, (c) compressors, and (d) estimated decommissioning costs after the useful life of the pipeline. Other costs included operating costs, compressor gas usage, capital depreciation, ad valorem, state and federal income taxes, and the allowable regulatory return on the installed book value of the capital components. The yearly cost of service is the sum of the cost components; operating costs, depreciation, return on the installed book value, ad valorem, state and federal income taxes, and the yearly amount of the sinking fund for pipeline decommissioning. The tariff is the total annual amount divided by the yearly gas volume throughput for the system.

Data used for tariff calculations includes:

- Cost of capital
- Capital cost for pipeline, compressors, and liquid separation facilities
- Regulatory Commission of Alaska filings
- Capital costs are estimated at $25/diameter-inch ft

Economic Model

The Interactive Financial Planning System (IFPS) software package is used to develop an economics model that is used to determine the cost of service calculations and the tariff requirements.

The following assumptions are used in the economics model:

1. A 30-year project life
2. Pipeline costs include the pipe, compression, and a gas plant on the North Slope for the removal of natural gas contaminates
3. An ad valorem rate of 2% of the adjusted property tax basis, with no ad valorem during the construction period
4. The property tax basis is adjusted for inflation, divided by the remaining project life
5. Straight-line depreciation is used, calculated at mid-year
6. Income taxes are assessed at a 35% federal rate and a 9.4% state rate
7. General inflation is not used
8. The capital structure uses a 50% equity and 50% debt basis
9. Capital and non-fuel operating expenses are based on 2005$
10. Non-fuel operating costs are 2.5% of the installed capital
11. Fuel consumption is 1.1% of the pipeline gas volume
12. Pipeline decommissioning costs are 2% of the installed capital

13. The weighted cost of capital is 9.97%
14. The discount rate is 12%.

Cost of Service

The annual cost of service was used to estimate the yearly tariffs required to achieve a return of capital levelized for the life of the project. The annual cost of service is the sum of the operating costs, depreciation, the regulatory return on the installed capital, decommissioning costs (as a sinking fund), ad valorem, and state and federal income taxes. The annual tariff is the cost of service divided by the annual pipeline volume, Q_t. The tariffs used in the economic model are averaged over the time period 2015 and 2027 are in 2005$s. Mathematically, the annual tariff is:

$$tarifff_t = \frac{\sum_{2015}^{n} OpEx_t + Depr_t + Captial\ R_t + Decomm_t + Ad\ V_t + Income\ Tax_t}{Q_t}$$

The tariff time series was then averaged over the 12-year period for a levelized tariff for illustration of the impact of flow rate. The annual tariffs vary due differences primarily in the timing of depreciation, interest on debt, operating cost inflation, and property valuation methodology. The operating cost is assumed to be 2.5% of the cumulative capital cost and to increase 2.4%. Depreciation used a double declining balance switching over to straight-line with mid-year calculations. The return on capital is the weighted average cost of capital times the book value of the capital asset. Decommissioning costs are 2% of the cumulative installed capital expensed as a sinking fund. The property valuation is determined by:

$$Valuation_t = \left(Valuation_{t-1} + \frac{Valuation_{t-1}}{(T-t)} \right)(1+f)^t + Capital_t$$

The current year valuation is a function of the previous year valuation adjusted for the remaining project life *(T-t)* and inflation and any capital expended in the current year. Income taxes are the statutory rate times the BFIT. State income taxes are a deduction for federal taxes.

Appendix C. Dimensionless Production Analysis

One of the difficulties of forecasting future oil, water, and gas production for ANS fields is the wide variation of reservoir properties, fluid properties, plans of development, well design, improved oil recovery processes, and other engineering and operational considerations. Without having access to the reservoir engineering data (well tests, well completions, recovery technologies, etc.) and reservoir simulation tools to generate synthetic type curves, a method to reduce the complexity of the analysis is to transform the production data to dimensionless variables. The production data were transformed for each field using the water cut and gas-oil ratio (GOR), as defined below in Equation C1 and Equation C2. q_w is the monthly water production and q_o the monthly oil production. The dimensionless gas-oil ratio (GOR_D) is the ratio of GOR_t, the current *gas-oil ratio,* and $GOR_{initial}$, which is the ratio at discovery reflecting initial conditions of pressure and saturation.

$$Water\ Cut = \frac{q_w}{q_w + q_o} \quad \text{Eq. C1}$$

$$GOR_D = \frac{GOR_t}{GOR_{initial}} \quad \text{Eq. C2}$$

The water cut and GOR_D are plotted versus the recovery factor, defined in Eq. C3. The TUR is determined for the individual fields using standard petroleum engineering reserves forecasting methods. The recovery factor is based on an estimated technical recovery, which reduces the cumulative recovery, N_p , to a scalar quantity assisting in direct comparison of the various fields. Presenting the water-cut and *GOR* in this fashion allows direct comparison of the increase in water-cut and *GOR* between different pools. Using the TUR normalizes the abscissa for a recovery factor comparison of the individual pool performance.

$$\mathrm{Recov}ery\ Factor = \frac{N_p}{TUR} \quad \text{Eq. C3}$$

Examples of the utility of this methodology are presented for the Prudhoe Bay and Kuparuk pools in Figure 3-C.1 and Figure 3-C.2. The figures show the TUR, the linear regression equation, and the coefficient of determination, R^2. Pools with similar formations, reservoir fluids, and displacement mechanisms are observed to have similar production responses when using this dimensionless approach.

This empirical observation is the basis for the forecast methodology for future water and gas production and is used in currently developed, discovered undeveloped, and hypothetical cases. Undeveloped and newly developed fields used analogous field curves for equivalent formations and displacement processes for forecasting of gas and water production. This approach provides a great deal of flexibility in forecasting water and gas production. The forecasts of water- and gas-phase production are tied directly to historical field performance, providing an additional level of realism in the forecast of future production. A full presentation of the historical production data is presented with each pool analysis.

The Prudhoe Bay pool is undergoing a number of different oil recovery processes; secondary recovery, miscible rich-as injection (MI), gravity drainage, and gas cap cycling for condensate recovery. The MI process and gas cap reinjection utilize 7 to 8 BCFPD of natural gas, yet the recovery factor versus GOR_D has a high degree of linearity, see Figure 3-C.1. This linearity is assumed to continue to depletion.

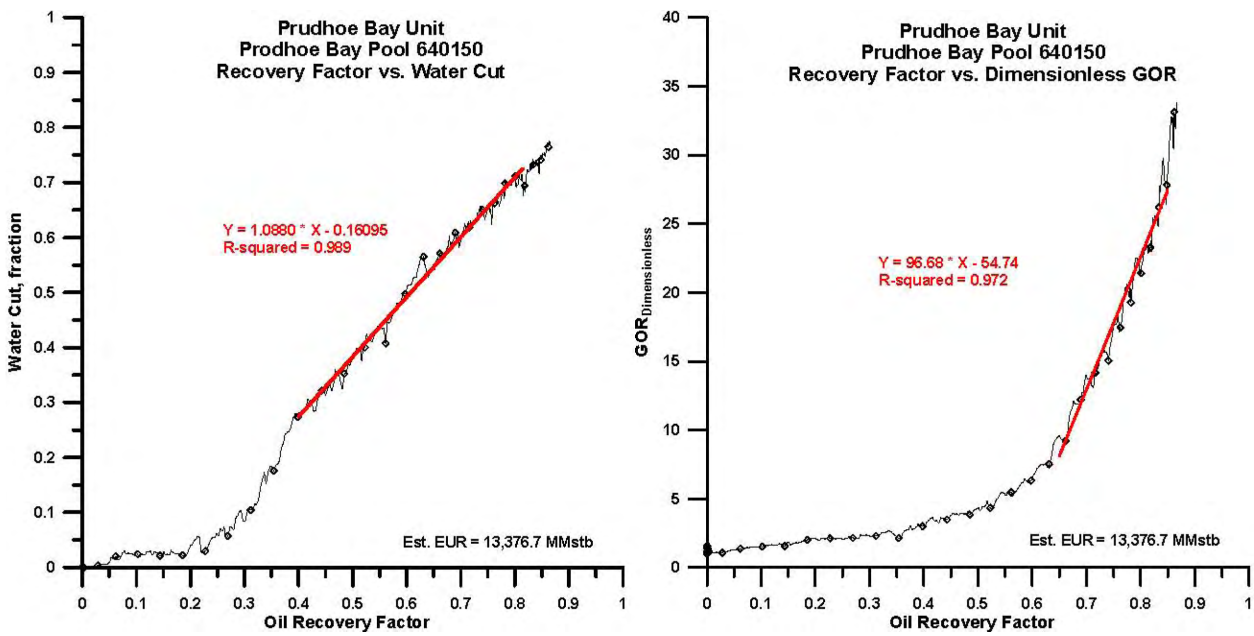

Figure C.1. Prudhoe Bay water cut and dimensionless GOR versus recovery factor response.

The Kuparuk River pool GOR_D behavior is shown in Figure 3-C.2. Water flooding was started early in the field life with the miscible injection process started later. An increase in GOR occurred later in the life of the reservoir. The slope in the recovery factor versus water cut is very similar to Prudhoe Bay, suggesting similar responses to secondary recovery.

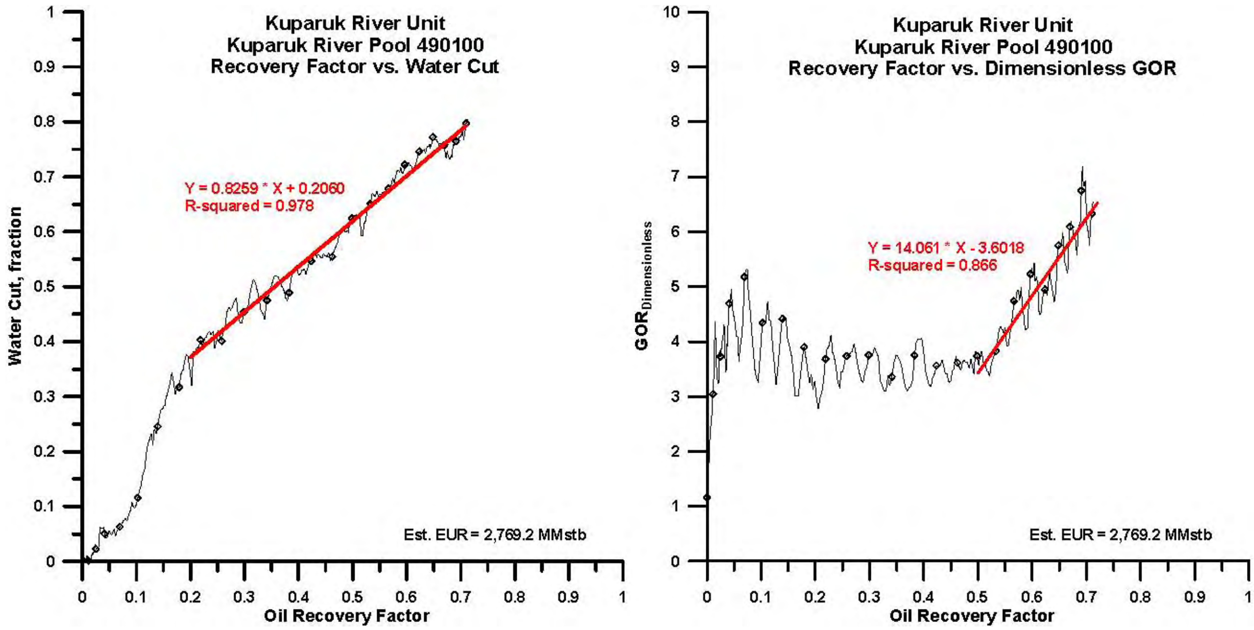

Figure C. 2. Kuparuk River pool water cut and dimensionless GOR versus recovery factor.

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Appendix D. Investment Schedules for Pools

Investment schedules for drilling wells and facilities, pipelines, and other tangible capital expenses are provide in the following tables for the four ANS West Coast oil price cases. Investment schedules in current dollars are provided for the total ANS, ANS Units, and the pools analyzed in Section 3. Tables D.1 to D.7 are the schedules for the $25/bbl ANS West Coast price case, Tables D.8–D.14 for the $35/bbl case. The investment schedules for $50/bbl and $60/bbl case as the same and are shown in Tables D.15–D.21.

Table D.1. Investment Schedule for Total ANS ($25/bbl ANS West Coast Prices).

Year	Total Alaska North Slope (M$)		
	Drilling	Facilities, pipelines, other tangible capital	Total Capital
2005	0	0	0
2006	260,500	0	260,500
2007	680,067	188,905	868,972
2008	1,105,951	486,985	1,592,936
2009	1,386,775	290,739	1,677,513
2010	1,869,933	201,217	2,071,150
2011	1,953,837	253,488	2,207,326
2012	1,357,751	236,869	1,594,620
2013	1,313,609	393,612	1,707,221
2014	1,292,101	180,191	1,472,292
2015	1,041,793	514,087	1,555,880
2016	914,017	68,815	982,832
2017	655,306	49,855	705,161
2018	587,864	65,014	652,878
2019	395,146	49,855	445,001
2020	215,495	29,074	244,569
2021	232,108	54,541	286,649
2022	174,621	27,045	201,666
2023	177,921	30,066	207,987
2024	171,554	33,317	204,871
2025	19,561	0	19,561
2026	40,492	0	40,492
2027	20,955	0	20,955
2028	21,688	0	21,688
2029	22,447	0	22,447
2030	0	0	0

Table D.2. Investment Schedules for ANS Units ($25/bbl ANS West Coast Oil Price Case, M$)

Year	Colville River Unit (M$)			Duck Island Unit (M$)		Kuparuk River Unit			Milne Point Unit		Northstar Unit		Prudhoe Bay Unit	
	Drilling	Facilities, pipelines, other tangible capital	Total Capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Total Capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	14,245	171	14,245	0	0	14,245	171	14,416	146,209	0	0	0	82,372	0
2007	125,847	4,567	125,847	2,728	0	125,847	4,567	130,414	168,052	0	10,912	0	133,135	0
2008	129,707	7,932	129,707	0	0	129,707	7,932	137,639	165,387	0	11,566	0	411,236	0
2009	124,094	10,749	124,094	0	0	124,094	10,749	134,843	134,833	0	12,257	0	416,757	0
2010	131,940	14,870	131,940	0	0	131,940	14,870	146,810	228,644	0	0	0	560,228	0
2011	118,431	16,509	118,431	0	0	118,431	16,509	134,940	439,214	0	27,536	0	525,958	0
2012	136,334	22,734	136,334	0	0	136,334	22,734	159,068	208,670	0	0	0	500,517	0
2013	119,098	23,196	119,098	0	0	119,098	23,196	142,294	306,219	0	0	0	414,477	0
2014	188,920	42,210	188,920	0	0	188,920	42,210	231,130	126,210	0	0	0	439,283	0
2015	127,580	32,253	127,580	0	0	127,580	32,253	159,833	114,654	0	0	0	364,810	0
2016	160,752	45,470	160,752	0	0	160,752	45,470	206,222	141,768	0	0	0	333,246	0
2017	142,610	44,730	142,610	0	0	142,610	44,730	187,340	42,930	0	0	0	48,783	0
2018	159,901	55,195	159,901	0	0	159,901	55,195	215,096	45,499	0	0	0	51,702	0
2019	114,575	43,248	114,575	0	0	114,575	43,248	157,823	24,111	0	0	0	54,796	0
2020	52,705	21,636	52,705	0	0	52,705	21,636	74,341	25,553	0	0	0	58,076	0
2021	122,736	54,541	122,736	0	0	122,736	54,541	177,277	0	0	0	0	61,551	0
2022	56,459	27,045	56,459	0	0	56,459	27,045	83,504	0	0	0	0	65,233	0
2023	58,435	30,066	58,435	0	0	58,435	30,066	88,501	0	0	0	0	69,137	0
2024	60,480	33,317	60,480	0	0	60,480	33,317	93,797	0	0	0	0	73,274	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table D.3. Investment Schedules for Colville River Unit Pools and Satellite Developments ($25/bbl ANS West Coast Price Case, M$)

Year	Alpine (M$)		Fiord (M$)		Nanuq (M$)		Alpine West (M$)		Lookout (M$)		Spark (M$)	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	17,504	0	0	0	0	0	0	0	0	0	0	0
2007	55,654	0	46,337	13,608	42,125	13,608	0	6,804	0	34,021	0	20,413
2008	58,985	0	47,959	0	43,599	0	0	0	0	0	0	0
2009	62,514	0	49,637	0	45,125	0	49,637	0	0	0	0	0
2010	66,255	0	51,375	0	46,704	0	51,375	0	51,375	0	51,375	0
2011	11,703	0	26,586	0	24,169	0	53,173	0	53,173	0	53,173	0
2012	12,404	0	27,517	0	25,015	0	55,034	0	55,034	0	55,034	0
2013	13,146	0	14,240	0	12,945	0	28,480	0	56,960	0	56,960	0
2014	13,933	0	14,738	0	13,399	0	29,477	0	29,477	0	29,477	0
2015	14,766	0	15,254	0	13,867	0	15,254	0	30,508	0	30,508	0
2016	0	0	15,788	0	14,353	0	15,788	0	15,788	0	15,788	0
2017	0	0	16,341	0	14,855	0	16,341	0	16,341	0	16,341	0
2018	0	0	0	0	0	0	16,913	0	16,913	0	16,913	0
2019	0	0	0	0	0	0	17,505	0	17,505	0	17,505	0
2020	0	0	0	0	0	0	0	0	18,117	0	18,117	0
2021	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0

Table D.4. Investment Schedules for Kuparuk River Unit pools and satellites ($25/bbl ANS West Coast Price Case, M$).

Year	Kuparuk River Field		Meltwater		Placer		Tabasco		Tarn		West Sak		West Sak A	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	8,237	0	0	0	6,178	0	0	0	0	0	0	0	0	0
2007	8,730	0	7,898	287	26,190	0	0	0	0	0	52,380	0	33,700	1,222
2008	18,505	0	8,175	500	27,757	0	0	0	8,674	0	37,010	0	34,879	2,133
2009	19,612	0	0	0	29,418	0	7,355	0	0	0	0	0	72,200	6,254
2010	20,786	0	8,757	987	23,384	0	0	0	9,743	0	0	0	74,727	8,422
2011	22,030	0	0	0	16,523	0	8,261	0	0	0	0	0	77,342	10,782
2012	23,347	0	9,381	1,564	8,756	0	0	0	10,945	0	0	0	90,055	15,018
2013	24,745	0	0	0	9,279	0	9,279	0	0	0	0	0	82,851	16,136
2014	26,226	0	10,049	2,245	9,834	0	0	0	12,293	0	0	0	139,345	31,134
2015	27,795	0	0	0	10,423	0	10,423	0	0	0	0	0	88,752	22,436
2016	29,459	0	0	0	0	0	0	0	0	0	0	0	137,787	38,975
2017	0	0	0	0	0	0	0	0	0	0	0	0	142,610	44,730
2018	0	0	0	0	0	0	0	0	0	0	0	0	159,901	55,195
2019	0	0	0	0	0	0	0	0	0	0	0	0	114,575	43,248
2020	0	0	0	0	0	0	0	0	0	0	0	0	52,705	21,636
2021	0	0	0	0	0	0	0	0	0	0	0	0	122,736	54,541
2022	0	0	0	0	0	0	0	0	0	0	0	0	56,459	27,045
2023	0	0	0	0	0	0	0	0	0	0	0	0	58,435	30,066
2024	0	0	0	0	0	0	0	0	0	0	0	0	60,480	33,317
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table D.5. Investment Schedules for Milne Point Unit Pools ($25/bbl ANS West Coast Price Case, M$).

Year	Milne Point Unit			Milne Pt. - Kuparuk		Schrader Bluff		Schrader Bluff E & H Pads		Schrader Bluff New Pad		Schrader Bluff S Pad	
	Drilling	Facilities, pipelines, other tangible capital	Total Capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	146,209	0	146209	10,296	0	22,652	0	0	0	0	0	113,260	0
2007	168,052	0	168052	0	0	24,007	0	0	0	0	0	144,045	0
2008	165,387	0	165387	0	0	0	0	0	0	0	0	165,387	0
2009	134,833	0	134833	0	0	0	0	134,833	0	0	0	0	0
2010	228,644	0	228644	0	0	0	0	171,483	0	0	0	57,161	0
2011	439,214	0	439214	0	0	0	0	196,889	0	132,932	18,532	90,872	0
2012	208,670	0	208670	0	0	0	0	0	0	165,101	27,532	16,051	0
2013	306,219	0	306219	0	0	0	0	68,049	0	185,120	36,054	17,012	0
2014	126,210	0	126210	0	0	0	0	108,181	0	0	0	18,030	0
2015	114,654	0	114654	0	0	0	0	19,109	0	61,017	15,425	19,109	0
2016	141,768	0	141768	0	0	0	0	20,252	0	94,729	26,795	0	0
2017	42,930	0	42930	0	0	0	0	21,465	0	16,341	5,125	0	0
2018	45,499	0	45499	0	0	0	0	22,749	0	16,913	5,838	0	0
2019	24,111	0	24111	0	0	0	0	0	0	17,505	6,607	0	0
2020	25,553	0	25553	0	0	0	0	0	0	18,117	7,438	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0

Table D.6. Investment Schedules for Prudhoe Bay IPA, PA's, and Satellite Pools ($25/bbl ANS West Coast Price Case, M$).

Year	Prudhoe Bay IPA		Aurora		Borelis		Lisburne		Midnight Sun		Niakuk	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	66,927	0	0	0	0	0	0	0	0	0	0	0
2007	93,849	0	0	0	0	0	0	0	0	0	2,728	0
2008	234,782	0	8,674	500	17,349	0	2,891	0	0	0	2,891	0
2009	239,023	0	0	0	0	0	3,064	0	10,419	0	3,064	0
2010	313,084	0	9,743	987	19,487	0	3,248	0	0	0	0	0
2011	297,401	0	0	0	0	0	0	0	0	0	0	0
2012	286,739	0	0	0	0	0	0	0	0	0	0	0
2013	245,902	0	0	0	0	0	0	0	0	0	0	0
2014	260,619	0	0	0	0	0	0	0	0	0	0	0
2015	204,120	0	0	0	0	0	0	0	0	0	0	0
2016	189,637	0	0	0	0	0	0	0	0	0	0	0
2017	48,783	0	0	0	0	0	0	0	0	0	0	0
2018	51,702	0	0	0	0	0	0	0	0	0	0	0
2019	54,796	0	0	0	0	0	0	0	0	0	0	0
2020	58,076	0	0	0	0	0	0	0	0	0	0	0
2021	61,551	0	0	0	0	0	0	0	0	0	0	0
2022	65,233	0	0	0	0	0	0	0	0	0	0	0
2023	69,137	0	0	0	0	0	0	0	0	0	0	0
2024	73,274	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0

Table D.6 (Continued). Investment Schedules for Prudhoe Bay PA's, and Satellite Pools ($25/bbl ANS West Coast Price Case, M$).

Year	Orion I		Orion II		Polaris I		Polaris II		Pt. McIntyre		Sambuca	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	15,445	0	0	0	0	0	0	0
2007	6,548	0	0	0	24,553	0	0	0	5,457	0	0	0
2008	6,939	0	48,575	0	43,371	0	43,371	0	2,891	0	0	0
2009	0	0	51,482	0	45,967	0	45,967	0	3,064	0	14,709	0
2010	0	0	109,125	0	0	0	87,690	0	3,248	0	15,589	0
2011	0	0	115,656	0	0	0	92,937	0	3,442	0	16,523	0
2012	0	0	122,575	0	0	0	87,554	0	3,648	0	0	0
2013	0	0	129,911	0	0	0	34,797	0	3,866	0	0	0
2014	0	0	137,685	0	0	0	36,880	0	4,098	0	0	0
2015	0	0	145,924	0	0	0	0	0	4,343	0	10,423	0
2016	0	0	143,609	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0

Table D.7. Investment Schedules for New Development Units and Pools ($25/bbl ANS West Coast Price Case, M$).

Year	Ooguruk Unit		Nikaitchug Unit		Liberty Unit		Gwydyr Bay Unit		Sandpiper		Tuvaaq	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	32,737	98,942	0	0	0	0	0	0	0	0
2008	32,699	281,216	130,112	202,636	0	0	29,492	0	0	0	0	0
2009	90,250	0	220,637	207,505	0	0	52,095	35,356	0	0	0	0
2010	140,113	0	253,326	0	116,760	63,814	55,212	72,406	0	0	0	0
2011	145,016	0	227,180	0	120,847	0	58,516	74,144	0	0	0	94,119
2012	0	0	43,777	0	125,077	0	24,807	0	0	0	50,031	192,755
2013	0	0	57,995	0	129,454	0	0	18,089	0	0	77,673	251,647
2014	0	0	73,759	0	133,985	0	0	0	0	0	0	0
2015	0	0	26,058	0	0	0	14,766	0	69,337	127,004	0	0
2016	14,353	0	13,809	0	0	0	15,650	0	143,528	0	0	0
2017	0	0	0	0	0	0	0	0	148,552	0	0	0
2018	0	0	0	0	15,375	0	17,579	0	153,751	0	0	0
2019	0	0	0	0	0	0	0	0	79,566	0	0	0
2020	0	0	0	0	16,470	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	18,261	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	19,561	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	20,955	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	22,447	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0

Table D.7 (Continued). Investment Schedules for New Development Units and Pools ($25/bbl ANS West Coast Price Case, M$).

Year	Ataruq		Sourdough		Point Thomson							
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0						
2006	0	0	0	0	0	0						
2007	0	0	32,737	98,942	0	0						
2008	0	0	130,112	202,636	0	0						
2009	18,387	41,623	220,637	207,505	0	0						
2010	25,982	54,601	253,326	0	0	0						
2011	27,536	55,912	227,180	0	0	0						
2012	29,184	0	43,777	0	0	0						
2013	23,198	0	57,995	0	0	775,992						
2014	0	0	73,759	0	104,232	1,304,892						
2015	0	0	26,058	0	276,172	1,343,554						
2016	0	0	13,809	0	292,698	0						
2017	9,757	0	0	0	279,191	0						
2018	0	0	0	0	263,020	0						
2019	10,960	0	0	0	0	0						
2020	0	0	0	0	0	0						
2021	12,310	0	0	0	0	0						
2022	0	0	0	0	0	0						
2023	0	0	0	0	0	0						
2024	0	0	0	0	0	0						
2025	0	0	0	0	0	0						
2026	0	0	0	0	0	0						
2027	0	0	0	0	0	0						
2028	0	0	0	0	0	0						
2029	0	0	0	0	0	0						
2030	0	0	0	0	0	0						

Table D.8. Investment Schedule for Total ANS ($35/bbl ANS West Coast Prices, M$)

Year	Total Alaska North Slope (M$)		
	Drilling	Facilities, pipelines, other tangible capital	Total Capital
2005	0	0	0
2006	260,500	0	260,500
2007	680,067	188,905	868,972
2008	1,106,450	486,485	1,592,935
2009	1,386,775	290,739	1,677,513
2010	1,850,133	200,230	2,050,363
2011	1,931,808	253,488	2,185,297
2012	1,334,404	236,869	1,571,273
2013	1,293,504	393,612	1,687,116
2014	1,283,906	180,191	1,464,097
2015	1,037,450	514,087	1,551,537
2016	914,017	68,815	982,832
2017	655,306	49,855	705,161
2018	587,864	65,014	652,878
2019	378,707	49,855	428,562
2020	215,495	29,074	244,569
2021	232,108	54,541	286,649
2022	174,621	27,045	201,666
2023	177,921	30,066	207,987
2024	171,554	33,317	204,871
2025	19,561	0	19,561
2026	20,246	0	20,246
2027	20,955	0	20,955
2028	0	0	0
2029	22,447	0	22,447
2030	0	0	0

Table D.9. Investment Schedules for ANS Units ($35/bbl ANS West Coast Oil Price Case, M$)

Year	Colville River Unit (M$)			Duck Island Unit (M$)		Kuparuk River Unit			Milne Point Unit		Northstar Unit		Prudhoe Bay Unit	
	Drilling	Facilities, pipelines, other tangible capital	Total Capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Total Capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	17,298	207	17,505	0	0	14,245	171	14,416	146,209	0	0	0	82,372	0
2007	142,171	90,403	232,574	2,728	0	125,847	4,567	130,414	178,965	0	10,912	0	133,135	0
2008	147,147	3,399	150,546	0	0	129,707	7,932	137,639	202,397	0	11,566	0	411,736	0
2009	201,933	4,984	206,917	3,064	0	142,144	12,313	154,457	160,574	0	12,257	0	416,757	0
2010	311,752	6,711	318,463	0	0	131,940	14,870	146,810	228,644	0	0	0	561,214	0
2011	220,546	1,432	221,978	3,442	0	137,767	19,204	156,971	439,214	0	27,536	0	525,958	0
2012	228,266	1,772	230,038	0	0	136,334	22,734	159,068	208,670	0	0	0	500,517	0
2013	180,589	2,143	182,732	3,866	0	119,098	23,196	142,294	306,219	0	0	0	414,477	0
2014	127,957	2,544	130,501	0	0	188,920	42,210	231,130	126,210	0	0	0	439,283	0
2015	117,178	2,980	120,158	0	0	127,580	32,253	159,833	114,654	0	0	0	364,810	0
2016	77,505	0	77,505	0	0	182,282	51,560	233,842	141,768	0	0	0	333,246	0
2017	80,219	0	80,219	0	0	142,610	44,730	187,340	42,930	0	0	0	48,783	0
2018	50,739	0	50,739	0	0	182,963	63,157	246,120	45,499	0	0	0	51,702	0
2019	52,515	0	52,515	0	0	114,575	43,248	157,823	24,111	0	0	0	54,796	0
2020	36,234	0	36,234	0	0	52,705	21,636	74,341	25,553	0	0	0	58,076	0
2021	0	0	0	0	0	122,736	54,541	177,277	0	0	0	0	61,551	0
2022	0	0	0	0	0	56,459	27,045	83,504	0	0	0	0	65,233	0
2023	0	0	0	0	0	58,435	30,066	88,501	0	0	0	0	69,137	0
2024	0	0	0	0	0	60,480	33,317	93,797	0	0	0	0	73,274	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table D.10. Investment Schedules for Colville River Unit Pools and Satellite Developments ($35/bbl ANS West Coast Price Case, M$)

Year	Alpine (M$)		Fiord (M$)		Nanuq (M$)		Alpine West (M$)		Lookout (M$)		Spark (M$)	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	17,504	0	0	0	0	0	0	0	0	0	0	0
2007	55,654	0	46,337	13,608	42,125	13,608	0	6,804	0	34,021	0	20,413
2008	58,985	0	47,959	0	43,599	0	0	0	0	0	0	0
2009	62,514	0	49,637	0	45,125	0	49,637	0	0	0	0	0
2010	66,255	0	51,375	0	46,704	0	51,375	0	51,375	0	51,375	0
2011	11,703	0	26,586	0	24,169	0	53,173	0	53,173	0	53,173	0
2012	12,404	0	27,517	0	25,015	0	55,034	0	55,034	0	55,034	0
2013	13,146	0	14,240	0	12,945	0	28,480	0	56,960	0	56,960	0
2014	13,933	0	14,738	0	13,399	0	29,477	0	29,477	0	29,477	0
2015	14,766	0	15,254	0	13,867	0	15,254	0	30,508	0	30,508	0
2016	0	0	15,788	0	14,353	0	15,788	0	15,788	0	15,788	0
2017	0	0	16,341	0	14,855	0	16,341	0	16,341	0	16,341	0
2018	0	0	0	0	0	0	16,913	0	16,913	0	16,913	0
2019	0	0	0	0	0	0	17,505	0	17,505	0	17,505	0
2020	0	0	0	0	0	0	0	0	18,117	0	18,117	0
2021	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0

Table D.11. Investment Schedules for Kuparuk River Unit pools and satellites ($35/bbl ANS West Coast Price Case, M$).

Year	Kuparuk River Field		Meltwater		Placer		Tabasco		Tarn		West Sak		West Sak A	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	8,237	0	0	0	6,178	0	0	0	0	0	0	0	0	0
2007	8,730	0	7,898	287	26,190	0	0	0	0	0	52,380	0	33,700	1,222
2008	18,505	0	8,175	500	27,757	0	0	0	8,674	0	37,010	0	34,879	2,133
2009	19,612	0	0	0	29,418	0	7,355	0	0	0	19,612	0	72,200	6,254
2010	20,786	0	8,757	987	23,384	0	0	0	9,743	0	0	0	74,727	8,422
2011	22,030	0	0	0	16,523	0	8,261	0	0	0	22,030	0	77,342	10,782
2012	23,347	0	9,381	1,564	8,756	0	0	0	10,945	0	0	0	90,055	15,018
2013	24,745	0	0	0	9,279	0	9,279	0	0	0	0	0	82,851	16,136
2014	26,226	0	10,049	2,245	9,834	0	0	0	12,293	0	0	0	139,345	31,134
2015	27,795	0	0	0	10,423	0	10,423	0	0	0	0	0	88,752	22,436
2016	29,459	0	10,765	3,045	0	0	0	0	13,809	0	0	0	137,787	38,975
2017	0	0	0	0	0	0	0	0	0	0	0	0	142,610	44,730
2018	0	0	11,531	3,981	0	0	0	0	15,510	0	0	0	159,901	55,195
2019	0	0	0	0	0	0	0	0	0	0	0	0	114,575	43,248
2020	0	0	0	0	0	0	0	0	0	0	0	0	52,705	21,636
2021	0	0	0	0	0	0	0	0	0	0	0	0	122,736	54,541
2022	0	0	0	0	0	0	0	0	0	0	0	0	56,459	27,045
2023	0	0	0	0	0	0	0	0	0	0	0	0	58,435	30,066
2024	0	0	0	0	0	0	0	0	0	0	0	0	60,480	33,317
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table D.12. Investment Schedules for Milne Point Unit Pools ($35/bbl ANS West Coast Price Case, M$).

Year	Milne Point Unit			Milne Pt. - Kuparuk		Schrader Bluff		Schrader Bluff E & H Pads		Schrader Bluff New Pad		Schrader Bluff S Pad	
	Drilling	Facilities, pipelines, other tangible capital	Total Capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	146,209	0	146,209	10,296	0	22,652	0	0	0	0	0	113,260	0
2007	178,965	0	178,965	10,912	0	24,007	0	0	0	0	0	144,045	0
2008	202,397	0	202,397	11,566	0	25,444	0	0	0	0	0	165,387	0
2009	160,574	0	160,574	12,257	0	13,483	0	134,833	0	0	0	0	0
2010	228,644	0	228,644	0	0	0	0	171,483	0	0	0	57,161	0
2011	439,214	0	439,214	0	0	0	0	196,889	0	132,932	18,532	90,872	0
2012	208,670	0	208,670	0	0	0	0	0	0	165,101	27,532	16,051	0
2013	306,219	0	306,219	0	0	0	0	68,049	0	185,120	36,054	17,012	0
2014	126,210	0	126,210	0	0	0	0	108,181	0	0	0	18,030	0
2015	114,654	0	114,654	0	0	0	0	19,109	0	61,017	15,425	19,109	0
2016	141,768	0	141,768	0	0	0	0	20,252	0	94,729	26,795	0	0
2017	42,930	0	42,930	0	0	0	0	21,465	0	16,341	5,125	0	0
2018	45,499	0	45,499	0	0	0	0	22,749	0	16,913	5,838	0	0
2019	24,111	0	24,111	0	0	0	0	0	0	17,505	6,607	0	0
2020	25,553	0	25,553	0	0	0	0	0	0	18,117	7,438	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0

Table D.13. Investment Schedules for Prudhoe Bay IPA, PA's, and Satellite Pools ($35/bbl ANS West Coast Price Case, M$).

Year	Prudhoe Bay IPA		Aurora		Borelis		Lisburne		Midnight Sun		Niakuk	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	66,927	0	0	0	0	0	0	0	0	0	0	0
2007	93,849	0	0	0	0	0	0	0	0	0	2,728	0
2008	234,782	0	8,674	500	17,349	0	2,891	0	0	0	2,891	0
2009	239,023	0	0	0	0	0	3,064	0	10,419	0	3,064	0
2010	313,084	0	9,743	987	19,487	0	3,248	0	0	0	0	0
2011	297,401	0	0	0	0	0	0	0	0	0	0	0
2012	286,739	0	0	0	0	0	0	0	0	0	0	0
2013	245,902	0	0	0	0	0	0	0	0	0	0	0
2014	260,619	0	0	0	0	0	0	0	0	0	0	0
2015	204,120	0	0	0	0	0	0	0	0	0	0	0
2016	189,637	0	0	0	0	0	0	0	0	0	0	0
2017	48,783	0	0	0	0	0	0	0	0	0	0	0
2018	51,702	0	0	0	0	0	0	0	0	0	0	0
2019	54,796	0	0	0	0	0	0	0	0	0	0	0
2020	58,076	0	0	0	0	0	0	0	0	0	0	0
2021	61,551	0	0	0	0	0	0	0	0	0	0	0
2022	65,233	0	0	0	0	0	0	0	0	0	0	0
2023	69,137	0	0	0	0	0	0	0	0	0	0	0
2024	73,274	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0

Table D.13 (Continued). Investment Schedules for Prudhoe Bay PA's, and Satellite Pools ($35/bbl ANS West Coast Price Case, M$).

Year	Orion I		Orion II		Polaris I		Polaris II		Pt. McIntyre		Sambuca	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	15,445	0	0	0	0	0	0	0
2007	6,548	0	0	0	24,553	0	0	0	5,457	0	0	0
2008	6,939	0	48,575	0	43,371	0	43,371	0	2,891	0	0	0
2009	0	0	51,482	0	45,967	0	45,967	0	3,064	0	14,709	0
2010	0	0	109,125	0	0	0	87,690	0	3,248	0	15,589	0
2011	0	0	115,656	0	0	0	92,937	0	3,442	0	16,523	0
2012	0	0	122,575	0	0	0	87,554	0	3,648	0	0	0
2013	0	0	129,911	0	0	0	34,797	0	3,866	0	0	0
2014	0	0	137,685	0	0	0	36,880	0	4,098	0	0	0
2015	0	0	145,924	0	0	0	0	0	4,343	0	10,423	0
2016	0	0	143,609	0	0	0	0	0	4,603	0	0	0
2017	0	0	0	0	0	0	0	0	4,879	0	0	0
2018	0	0	0	0	0	0	0	0	5,171	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0

Table D.14. Investment Schedules for New Development Units and Pools ($35/bbl ANS West Coast Price Case, M$).

Year	Ooguruk Unit		Nikaitchug Unit		Liberty Unit		Gwydyr Bay Unit		Sandpiper		Tuvaaq	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0		0	0		0	0	0	0	0	0
2006	0	0		0	0		0	0	0	0	0	0
2007	0	0		32,737	98,942		0	0	0	0	0	0
2008	32,699	281,216		130,112	202,636		0	0	0	0	0	0
2009	90,250	0		220,637	207,505		0	0	0	0	0	0
2010	140,113	0		253,326	0		116,760	63,814	0	0	0	0
2011	145,016	0		227,180	0		120,847	0	0	0	0	94,119
2012	0	0		43,777	0		125,077	0	0	0	50,031	192,755
2013	0	0		57,995	0		129,454	0	0	0	77,673	251,647
2014	0	0		73,759	0		133,985	0	0	0	133,985	0
2015	0	0		26,058	0		0	0	69,337	127,004	138,675	0
2016	14,353	0		13,809	0		0	0	143,528	0	0	0
2017	0	0		29,270	0		0	0	148,552	0	0	0
2018	0	0		31,022	0		15,375	0	153,751	0	0	0
2019	0	0		32,878	0		0	0	79,566	0	15,913	0
2020	16,470	0		17,423	0		16,470	0	0	0	0	0
2021	0	0		18,465	0		0	0	0	0	17,047	0
2022	17,643	0		0	0		17,643	0	0	0	0	0
2023	0	0		0	0		0	0	18,261	0	18,261	0
2024	0	0		0	0		18,900	0	0	0	0	0
2025	0	0		0	0		0	0	19,561	0	0	0
2026	0	0		0	0		0	0	0	0	0	0
2027	0	0		0	0		0	0	20,955	0	0	0
2028	0	0		0	0		0	0	0	0	0	0
2029	0	0		0	0		0	0	22,447	0	0	0
2030	0	0		0	0		0	0	0	0	0	0

Table D.14 (Continued). Investment Schedules for New Development Units and Pools ($35/bbl ANS West Coast Price Case, M$).

Year	Ataruq		Sourdough		Point Thomson							
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0						
2006	0	0	0	0	0	0						
2007	0	0	0	0	0	0						
2008	0	0	0	0	0	0						
2009	18,387	41,623	0	0	0	0						
2010	25,982	54,601	0	0	0	0						
2011	27,536	55,912	0	0	0	0						
2012	29,184	0	0	0	0	0						
2013	23,198	0	0	71,686	0	775,992						
2014	0	0	40,196	146,812	104,232	1,304,892						
2015	0	0	69,337	349,222	276,172	1,343,554						
2016	0	0	143,528	0	292,698	0						
2017	9,757	0	148,552	0	279,191	0						
2018	0	0	30,750	0	263,020	0						
2019	10,960	0	0	0	0	0						
2020	0	0	0	0	0	0						
2021	12,310	0	0	0	0	0						
2022	0	0	17,643	0	0	0						
2023	13,827	0	0	0	0	0						
2024	0	0	18,900	0	0	0						
2025	0	0	0	0	0	0						
2026	0	0	20,246	0	0	0						
2027	0	0	0	0	0	0						
2028	0	0	0	0	0	0						
2029	0	0	0	0	0	0						
2030	0	0	0	0	0	0						

Table D.15. Investment Schedule for Total ANS ($50/bbl & $60/bbl ANS West Coast Price cases, M$)

Year	Total Alaska North Slope (M$)		
	Drilling	Facilities, pipelines, other tangible capital	Total Capital
2005	0	0	0
2006	260,500	0	260,500
2007	680,067	188,905	868,972
2008	1,106,450	486,485	1,592,935
2009	1,386,775	290,739	1,677,513
2010	1,870,919	200,230	2,071,149
2011	1,953,837	253,488	2,207,326
2012	1,357,751	236,869	1,594,620
2013	1,313,609	393,612	1,707,221
2014	1,292,101	180,191	1,472,292
2015	1,041,793	514,087	1,555,880
2016	914,017	68,815	982,832
2017	655,306	49,855	705,161
2018	587,864	65,014	652,878
2019	395,146	49,855	445,001
2020	215,495	29,074	244,569
2021	232,108	54,541	286,649
2022	174,621	27,045	201,666
2023	177,921	30,066	207,987
2024	171,554	33,317	204,871
2025	19,561	0	19,561
2026	40,492	0	40,492
2027	20,955	0	20,955
2028	21,688	0	21,688
2029	22,447	0	22,447
2030	0	0	0

Table D.16. Investment Schedules for ANS Units ($50/bbl & $60/bbl ANS West Coast Oil Price Cases, M$)

Year	Colville River Unit (M$)			Duck Island Unit (M$)		Kuparuk River Unit			Milne Point Unit		Northstar Unit		Prudhoe Bay Unit	
	Drilling	Facilities, pipelines, other tangible capital	Total Capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Total Capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	17,298	207	17,505	0	0	14,245	171	14,416	146,209	0	0	0	66,138	794
2007	142,171	90,403	232,574	2,728	0	125,847	4,567	130,414	178,965	0	10,912	0	90,569	3,285
2008	147,147	3,399	150,546	0	0	129,707	7,932	137,639	202,397	0	11,566	0	221,266	13,533
2009	201,933	4,984	206,917	3,064	0	142,144	12,313	154,457	160,574	0	12,257	0	219,983	19,058
2010	311,752	6,711	318,463	0	0	131,940	14,870	146,810	249,430	0	0	0	284,311	32,044
2011	220,546	1,432	221,978	3,442	0	137,767	19,204	156,971	461,243	0	27,536	0	261,031	36,388
2012	228,266	1,772	230,038	0	0	136,334	22,734	159,068	232,018	0	0	0	245,775	40,985
2013	180,589	2,143	182,732	3,866	0	129,454	25,213	154,667	313,952	0	0	0	205,832	40,088
2014	127,957	2,544	130,501	0	0	188,920	42,210	231,130	134,405	0	0	0	213,038	47,598
2015	117,178	2,980	120,158	4,343	0	127,580	32,253	159,833	114,654	0	0	0	162,943	41,191
2016	77,505	0	77,505	0	0	182,282	51,560	233,842	141,768	0	0	0	151,422	42,832
2017	80,219	0	80,219	0	0	142,610	44,730	187,340	42,930	0	0	0	40,852	12,813
2018	50,739	0	50,739	0	0	182,963	63,157	246,120	45,499	0	0	0	42,282	14,595
2019	52,515	0	52,515	0	0	126,510	47,753	174,263	24,111	0	0	0	39,783	15,017
2020	36,234	0	36,234	0	0	52,705	21,636	74,341	25,553	0	0	0	41,176	16,903
2021	0	0	0	0	0	122,736	54,541	177277	0	0	0	0	42,617	18,937
2022	0	0	0	0	0	56,459	27,045	83504	0	0	0	0	44,108	21,130
2023	0	0	0	0	0	58,435	30,066	88501	0	0	0	0	45,652	23,490
2024	0	0	0	0	0	60,480	33,317	93797	0	0	0	0	47,250	26,029
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table D.17. Investment Schedules for Colville River Unit Pools & Satellite Developments ($50/bbl & $60/bbl ANS West Coast Price Cases, M$)

Year	Alpine (M$)		Fiord (M$)		Nanuq (M$)		Alpine West (M$)		Lookout (M$)		Spark (M$)	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	17,504	0	0	0	0	0	0	0	0	0	0	0
2007	55,654	0	46,337	13,608	42,125	13,608	0	6,804	0	34,021	0	20,413
2008	58,985	0	47,959	0	43,599	0	0	0	0	0	0	0
2009	62,514	0	49,637	0	45,125	0	49,637	0	0	0	0	0
2010	66,255	0	51,375	0	46,704	0	51,375	0	51,375	0	51,375	0
2011	11,703	0	26,586	0	24,169	0	53,173	0	53,173	0	53,173	0
2012	12,404	0	27,517	0	25,015	0	55,034	0	55,034	0	55,034	0
2013	13,146	0	14,240	0	12,945	0	28,480	0	56,960	0	56,960	0
2014	13,933	0	14,738	0	13,399	0	29,477	0	29,477	0	29,477	0
2015	14,766	0	15,254	0	13,867	0	15,254	0	30,508	0	30,508	0
2016	0	0	15,788	0	14,353	0	15,788	0	15,788	0	15,788	0
2017	0	0	16,341	0	14,855	0	16,341	0	16,341	0	16,341	0
2018	0	0	0	0	0	0	16,913	0	16,913	0	16,913	0
2019	0	0	0	0	0	0	17,505	0	17,505	0	17,505	0
2020	0	0	0	0	0	0	0	0	18,117	0	18,117	0
2021	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0

Table D.18. Investment Schedules for Kuparuk River Unit pools and satellites ($50/bbl &$60/bbl ANS West Coast Price Cases, M$).

Year	Kuparuk River Field		Meltwater		Placer		Tabasco		Tarn		West Sak		West Sak A	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	8,237	0	0	0	6,178	0	0	0	0	0	0	0	0	0
2007	8,730	0	7,898	287	26,190	0	0	0	0	0	52,380	0	33,700	1,222
2008	18,505	0	8,175	500	27,757	0	0	0	8,674	0	37,010	0	34,879	2,133
2009	19,612	0	0	0	29,418	0	7,355	0	0	0	19,612	0	72,200	6,254
2010	20,786	0	8,757	987	23,384	0	0	0	9,743	0	0	0	74,727	8,422
2011	22,030	0	0	0	16,523	0	8,261	0	0	0	22,030	0	77,342	10,782
2012	23,347	0	9,381	1,564	8,756	0	0	0	10,945	0	0	0	90,055	15,018
2013	24,745	0	0	0	9,279	0	9,279	0	0	0	12,372	0	82,851	16,136
2014	26,226	0	10,049	2,245	9,834	0	0	0	12,293	0	0	0	139,345	31,134
2015	27,795	0	0	0	10,423	0	10,423	0	0	0	0	0	88,752	22,436
2016	29,459	0	10,765	3,045	0	0	0	0	13,809	0	0	0	137,787	38,975
2017	0	0	0	0	0	0	0	0	0	0	0	0	142,610	44,730
2018	0	0	11,531	3,981	0	0	0	0	15,510	0	0	0	159,901	55,195
2019	0	0	0	0	0	0	0	0	16,439	0	0	0	114,575	43,248
2020	0	0	0	0	0	0	0	0	0	0	0	0	52,705	21,636
2021	0	0	0	0	0	0	0	0	0	0	0	0	122,736	54,541
2022	0	0	0	0	0	0	0	0	0	0	0	0	56,459	27,045
2023	0	0	0	0	0	0	0	0	0	0	0	0	58,435	30,066
2024	0	0	0	0	0	0	0	0	0	0	0	0	60,480	33,317
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table D.19. Investment Schedules for Milne Point Unit Pools ($50/bbl &$60/bbl ANS West Coast Price Cases, M$).

Year	Milne Point Unit			Milne Pt. - Kuparuk		Schrader Bluff		Schrader Bluff E & H Pads		Schrader Bluff New Pad		Schrader Bluff S Pad	
	Drilling	Facilities, pipelines, other tangible capital	Total Capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	146,209	0	146,209	10,296	0	22,652	0	0	0	0	0	113,260	0
2007	178,965	0	178,965	10,912	0	24,007	0	0	0	0	0	144,045	0
2008	202,397	0	202,397	11,566	0	25,444	0	0	0	0	0	165,387	0
2009	160,574	0	160,574	12,257	0	13,483	0	134,833	0	0	0	0	0
2010	228,644	0	228,644	6,496	0	14,291	0	171,483	0	0	0	57,161	0
2011	439,214	0	439,214	6,884	0	15,145	0	196,889	0	132,932	18,532	90,872	0
2012	208,670	0	208,670	7,296	0	16,051	0	0	0	165,101	27,532	16,051	0
2013	306,219	0	306,219	7,733	0	0	0	68,049	0	185,120	36,054	17,012	0
2014	126,210	0	126,210	8,195	0	0	0	108,181	0	0	0	18,030	0
2015	114,654	0	114,654	0	0	0	0	19,109	0	61,017	15,425	19,109	0
2016	141,768	0	141,768	0	0	0	0	20,252	0	94,729	26,795	0	0
2017	42,930	0	42,930	0	0	0	0	21,465	0	16,341	5,125	0	0
2018	45,499	0	45,499	0	0	0	0	22,749	0	16,913	5,838	0	0
2019	24,111	0	24,111	0	0	0	0	0	0	17,505	6,607	0	0
2020	25,553	0	25,553	0	0	0	0	0	0	18,117	7,438	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0

Table D.20. Investment Schedules for Prudhoe Bay IPA, PA's, and Satellite Pools ($50/bbl &$60/bbl ANS West Coast Price Cases, M$).

Year	Prudhoe Bay IPA		Aurora		Borelis		Lisburne		Midnight Sun		Niakuk	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	66,927	0	0	0	0	0	0	0	0	0	0	0
2007	93,849	0	0	0	0	0	0	0	0	0	2,728	0
2008	234,782	0	8,175	500	17,349	0	2,891	0	0	0	2,891	0
2009	239,023	0	0	0	0	0	3,064	0	10,419	0	3,064	0
2010	316,332	0	8,757	987	19,487	0	3,248	0	0	0	3,248	0
2011	297,401	0	0	0	0	0	0	0	0	0	0	0
2012	286,739	0	0	0	0	0	0	0	0	0	0	0
2013	245,902	0	0	0	0	0	0	0	0	0	0	0
2014	260,619	0	0	0	0	0	0	0	0	0	0	0
2015	204,120	0	0	0	0	0	0	0	0	0	0	0
2016	194,240	0	0	0	0	0	0	0	0	0	0	0
2017	53,662	0	0	0	0	0	0	0	0	0	0	0
2018	56,873	0	0	0	0	0	0	0	0	0	0	0
2019	54,796	0	0	0	0	0	0	0	0	0	0	0
2020	58,076	0	0	0	0	0	0	0	0	0	0	0
2021	61,551	0	0	0	0	0	0	0	0	0	0	0
2022	65,233	0	0	0	0	0	0	0	0	0	0	0
2023	69,137	0	0	0	0	0	0	0	0	0	0	0
2024	73,274	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0

Table D.20 (Continued). Investment Schedules for Prudhoe Bay PA's and Satellite Pools ($50/bbl & $60/bbl ANS West Coast Price Cases, M$).

Year	Orion I		Orion II		Polaris I		Polaris II		Pt. McIntyre		Sambuca	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	15,445	0	0	0	0	0	0	0
2007	6,548	0	0	0	24,553	0	0	0	5,457	0	0	0
2008	6,939	0	48,575	0	43,371	0	43,371	0	2,891	0	0	0
2009	0	0	51,482	0	45,967	0	45,967	0	3,064	0	14,709	0
2010	0	0	109,125	0	0	0	87,690	0	3,248	0	15,589	0
2011	0	0	115,656	0	0	0	92,937	0	3,442	0	16,523	0
2012	0	0	122,575	0	0	0	87,554	0	3,648	0	0	0
2013	0	0	129,911	0	0	0	34,797	0	3,866	0	0	0
2014	0	0	137,685	0	0	0	36,880	0	4,098	0	0	0
2015	0	0	145,924	0	0	0	0	0	4,343	0	10,423	0
2016	0	0	143,609	0	0	0	0	0	4,603	0	0	0
2017	0	0	0	0	0	0	0	0	4,879	0	0	0
2018	0	0	0	0	0	0	0	0	5,171	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0

Table D.21. Investment Schedules for New Development Units and Pools ($50/bbl &$60/bbl ANS West Coast Price Cases, M$).

Year	Ooguruk Unit		Nikaitchug Unit		Liberty Unit		Gwydyr Bay Unit		Sandpiper		Tuvaaq	
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	32,737	98,942	0	0	0	0	0	0	0	0
2008	32,699	281,216	130,112	202,636	0	0	29,492	0	0	0	0	0
2009	90,250	0	220,637	207,505	0	0	52,095	35,356	0	0	0	0
2010	140,113	0	253,326	0	116,760	63,814	55,212	72,406	0	0	0	0
2011	145,016	0	227,180	0	120,847	0	58,516	74,144	0	0	0	94,119
2012	0	0	43,777	0	125,077	0	24,807	0	0	0	50,031	192,755
2013	0	0	57,995	0	129,454	0	0	18,089	0	0	77,673	251,647
2014	0	0	73,759	0	133,985	0	0	0	0	0	133,985	0
2015	0	0	26,058	0	0	0	14,766	0	69,337	127,004	138,675	0
2016	14,353	0	13,809	0	0	0	15,650	0	143,528	0	0	0
2017	0	0	29,270	0	0	0	0	0	148,552	0	0	0
2018	0	0	31,022	0	15,375	0	17,579	0	153,751	0	0	0
2019	0	0	32,878	0	0	0	0	0	79,566	0	15,913	0
2020	16,470	0	17,423	0	16,470	0	0	0	0	0	0	0
2021	0	0	18,465	0	0	0	0	0	0	0	17,047	0
2022	17,643	0	0	0	17,643	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	18,261	0	18,261	0
2024	0	0	0	0	18,900	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	19,561	0	0	0
2026	0	0	0	0	20,246	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	20,955	0	0	0
2028	0	0	0	0	21,688	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	22,447	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0

Table D.21 (Continued). Investment Schedules for New Development Units and Pools ($50/bbl &$60/bbl ANS West Coast Price Cases, M$).

Year	Ataruq		Sourdough		Point Thomson							
	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital	Drilling	Facilities, pipelines, other tangible capital
2005	0	0	0	0	0	0						
2006	0	0	0	0	0	0						
2007	0	0	0	0	0	0						
2008	0	0	0	0	0	0						
2009	18,387	41,623	0	0	0	0						
2010	25,982	54,601	0	0	0	0						
2011	27,536	55,912	0	0	0	0						
2012	29,184	0	0	0	0	0						
2013	23,198	0	0	71,686	0	775,992						
2014	0	0	40,196	146,812	104,232	1,304,892						
2015	0	0	69,337	349,222	276,172	1,343,554						
2016	0	0	143,528	0	292,698	0						
2017	9,757	0	148,552	0	279,191	0						
2018	0	0	30,750	0	263,020	0						
2019	10,960	0	0	0	0	0						
2020	0	0	0	0	0	0						
2021	12,310	0	0	0	0	0						
2022	0	0	17,643	0	0	0						
2023	13,827	0	0	0	0	0						
2024	0	0	18,900	0	0	0						
2025	0	0	0	0	0	0						
2026	0	0	20,246	0	0	0						
2027	0	0	0	0	0	0						
2028	0	0	0	0	0	0						
2029	0	0	0	0	0	0						
2030	0	0	0	0	0	0						

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Appendix E. Technical Oil Production Forecast

This section presents in tabular form the annual forecast production through 2040 for the currently producing fields, fields with announced or pending development plans, and pools with near-term development potential.

Table E.1. Currently producing fields, MBOPD.

	Alpine	Endicott	Kuparuk	Meltwater	Tabasco	Tarn	West Sak	Milne Point	MPU Schrader Bluff	North Star
2005	120.550	24.323	143.699	9.096	4.900	25.000	15.283	28.205	21.507	69.250
2006	125.000	21.874	136.507	11.507	4.165	21.250	19.200	24.808	21.507	58.865
2007	120.550	19.652	129.699	11.096	3.540	18.065	16.507	21.836	18.000	50.035
2008	110.220	17.642	123.205	9.438	3.010	15.350	13.618	19.219	14.397	42.530
2009	94.350	15.836	117.000	8.027	2.560	13.050	11.235	16.904	11.521	36.150
2010	80.190	14.205	111.151	6.822	2.175	11.090	9.269	14.877	9.219	30.730
2011	68.165	12.742	105.589	5.795	1.850	9.430	7.647	13.096	7.370	26.120
2012	57.945	11.427	100.315	4.932	1.570	8.015	6.309	11.521	5.904	22.200
2013	49.250	10.242	95.301	4.192	1.335	6.815	5.205	10.137	4.726	18.870
2014	41.865	9.182	90.534	3.562	1.135	5.790	4.294	8.918	3.781	16.040
2015	35.585	8.234	86.000	3.027	0.965	4.920	3.542	7.863	3.019	13.635
2016	30.245	7.376	80.096	2.575	0.820	4.185	2.923	6.904	2.414	11.590
2017	25.710	6.613	74.493	2.192	0.700	3.555	2.411	6.082	1.436	9.852
2018	21.850	5.932	69.274	1.863	0.590	3.025	1.989	5.342	1.220	8.374
2019	18.575	5.317	64.425	1.575	0.503	2.570	1.641	4.726	1.037	7.118
2020	15.790	4.766	59.918	1.342	0.430	2.185	1.354	4.017	0.882	6.050
2021	13.420	4.274	55.726	1.137	0.366	1.855	1.117	3.415	0.749	5.143
2022	11.410	3.834	51.822	0.973	0.311	1.580	0.921	2.902	0.637	4.371
2023	9.695	3.440	48.192	0.822	0.264	1.340	0.760	2.467	0.541	3.715
2024	8.240	3.087	44.822	0.699	0.224	1.140	0.627	2.097	0.460	3.158
2025	7.000	2.768	41.685	0.603	0.191	0.970	0.517	1.782	0.391	2.684
2026	5.955	2.484	37.521	0.504	0.162	0.825	0.427	1.515	0.333	2.282
2027	5.065	2.637	33.767	0.430	0.138	0.700	0.352	1.288	0.283	1.940
2028	4.305	2.373	30.384	0.366	0.117	0.595	0.291	1.095	0.240	1.649
2029	3.659	2.136	27.342	0.311	0.100	0.505	0.240	0.930	0.204	1.401
2030	3.111	1.922	24.616	0.264	0.085	0.429	0.198	0.791	0.174	1.191
2031	2.644	1.730	22.151	0.225	0.072	0.365	0.163	0.672	0.148	1.012
2032	2.247	1.557	19.932	0.191	0.061	0.310	0.135	0.571	0.125	0.861
2033	1.910	1.401	17.945	0.162	0.052	0.264	0.111	0.486	0.107	0.731
2034	1.624	1.261	16.151	0.138	0.044	0.224	0.092	0.413	0.091	0.622
2035	1.380	1.135	14.529	0.117	0.038	0.190	0.076	0.351	0.077	0.528
2036	1.173	1.022	13.079	0.100	0.032	0.162	0.062	0.298	0.065	0.449
2037	0.997	0.919	11.770	0.085	0.027	0.138	0.051	0.254	0.056	0.382
2038	0.000	0.000	10.860	0.000	0.000	0.000	0.042	0.216	0.047	0.325
2039	0.000	0.000	9.774	0.000	0.000	0.000	0.035	0.183	0.040	0.276
2040	0.000	0.000	8.797	0.000	0.000	0.000	0.029	0.156	0.034	0.234
Total	**401,382**	**85,169**	**776,745**	**34,371**	**11,874**	**60,549**	**46,965**	**82,613**	**48,451**	**168,032**

Table E.2. Currently producing fields, MBOPD.

	Prudhoe Bay	Aurora	Borelis	Lisburne	Midnight Sun	Niakuk	Orion	Polaris	Point McIntyre
2005	408.668	10.685	25.000	10.650	4.493	7.400	8.000	2.500	38.000
2006	384.263	10.082	25.000	10.083	3.342	6.290	6.800	5.000	36.100
2007	361.200	8.685	23.125	9.096	2.822	5.345	5.781	7.000	34.293
2008	339.397	7.397	19.655	8.205	2.411	4.545	5.403	9.000	31.766
2009	318.718	6.301	16.707	7.403	2.055	3.866	4.175	12.000	28.596
2010	299.162	5.288	14.200	6.679	1.753	3.285	3.551	13.500	25.734
2011	281.392	4.493	12.071	6.026	1.479	2.789	3.019	15.000	22.615
2012	264.608	3.808	10.260	5.438	1.260	2.375	2.564	15.000	19.215
2013	248.729	3.288	8.721	4.907	1.068	2.016	2.181	15.000	16.339
2014	233.671	2.795	7.411	4.428	0.904	1.715	1.849	12.750	13.881
2015	219.436	2.411	6.301	3.996	0.767	1.460	1.575	10.840	11.798
2016	206.712	2.000	5.466	3.607	0.658	1.241	1.340	9.210	10.032
2017	193.901	1.699	4.553	3.255	0.548	1.055	1.140	7.830	8.532
2018	182.521	1.578	3.871	2.938	0.466	0.896	0.964	6.655	7.243
2019	171.770	1.341	3.288	2.652	0.396	0.759	0.819	5.655	6.161
2020	160.767	1.140	2.795	2.394	0.337	0.644	0.701	4.810	5.234
2021	151.140	0.969	2.375	2.161	0.286	0.548	0.595	4.085	4.454
2022	141.978	0.824	2.019	1.950	0.243	0.471	0.504	3.475	3.789
2023	134.110	0.700	1.716	1.761	0.207	0.401	0.430	2.950	3.211
2024	125.879	0.595	1.459	1.656	0.176	0.340	0.364	2.510	2.734
2025	118.060	0.506	1.240	1.490	0.149	0.289	0.310	2.135	2.325
2026	111.425	0.430	1.054	1.341	0.127	0.246	0.266	1.810	1.968
2027	104.373	0.366	0.896	1.207	0.108	0.209	0.225	1.540	1.679
2028	98.449	0.311	0.761	1.087	0.092	0.178	0.189	1.310	1.426
2029	92.027	0.264	0.647	0.978	0.078	0.151	0.159	1.114	1.213
2030	86.734	0.224	0.550	0.880	0.066	0.128	0.135	0.946	1.031
2031	81.715	0.191	0.468	0.792	0.056	0.109	0.115	0.805	0.867
2032	76.970	0.162	0.397	0.713	0.048	0.093	0.098	0.684	0.737
2033	72.444	0.138	0.338	0.642	0.041	0.079	0.083	0.581	0.627
2034	68.164	0.117	0.287	0.577	0.035	0.067	0.071	0.494	0.533
2035	64.904	0.100	0.244	0.520	0.029	0.057	0.060	0.420	0.453
2036	61.848	0.085	0.207	0.468	0.025	0.048	0.051	0.357	0.385
2037	58.982	0.072	0.176	0.421	0.021	0.041	0.043	0.303	0.327
2038	56.296	0.000	0.000	0.000	0.000	0.000	0.000	0.258	0.000
2039	53.777	0.000	0.000	0.000	0.000	0.000	0.000	0.219	0.000
2040	51.416	0.000	0.000	0.000	0.000	0.000	0.000	0.186	
Total	**2,221,246**	**28,851**	**74,190**	**40,296**	**9,689**	**17,936**	**19,549**	**64,945**	**125,304**

Table E.3. Fields with announced plans or pending development, MBOPD.

	Fiord	Nanuq	West Alpine	Lookout	Spark	Placer	West Sak Additional Pad	MPU E Pad
2005	0.000	0.000	0.000	0.000	0.000	0.000	3.895	0.000
2006	0.810	0.585	0.000	0.000	0.000	6.000	5.101	0.000
2007	5.250	5.500	0.000	0.000	0.000	8.699	10.205	0.000
2008	13.700	8.250	5.750	0.000	0.000	10.000	13.302	5.000
2009	19.000	13.700	13.700	0.000	0.000	10.000	18.304	7.500
2010	16.400	13.700	19.300	5.750	5.750	9.493	23.108	12.500
2011	13.940	11.880	16.400	13.700	13.700	8.493	33.303	16.250
2012	11.850	10.085	13.940	19.300	19.300	7.233	37.098	18.500
2013	10.070	8.575	11.850	16.400	16.400	6.137	39.458	20.000
2014	8.560	7.285	10.070	13.940	13.940	5.219	39.759	20.000
2015	7.275	6.190	8.560	11.850	11.850	4.438	40.301	20.000
2016	6.185	5.265	7.275	10.070	10.070	3.767	42.704	18.000
2017	5.260	4.475	6.185	8.560	8.560	3.205	46.482	14.400
2018	4.470	3.800	5.260	7.275	7.275	2.726	46.588	11.520
2019	3.800	3.230	4.470	6.185	6.185	2.315	44.658	9.215
2020	3.230	2.745	4.000	5.260	5.260	1.973	43.756	7.375
2021	2.745	2.335	3.230	4.470	4.470	1.671	38.433	5.900
2022	2.330	1.985	2.745	4.000	4.000	1.425	37.371	4.720
2023	1.985	1.685	2.330	3.230	3.230	1.205	35.409	3.775
2024	1.685	1.435	1.985	2.745	2.745	1.027	31.558	3.209
2025	1.435	1.220	1.685	2.330	2.330	0.863	26.038	2.727
2026	1.220	1.037	1.435	1.985	1.985	0.734	21.009	2.318
2027	1.037	0.881	1.220	1.685	1.685	0.624	17.336	1.971
2028	0.881	0.749	1.035	1.435	1.435	0.530	14.303	1.675
2029	0.749	0.637	0.880	1.220	1.220	0.450	11.800	1.424
2030	0.637	0.541	0.748	1.035	1.035	0.383	9.735	1.210
2031	0.541	0.460	0.636	0.880	0.880	0.325	8.031	1.029
2032	0.460	0.391	0.540	0.748	0.748	0.277	6.625	0.874
2033	0.391	0.332	0.459	0.636	0.636	0.235	5.466	0.743
2034	0.332	0.283	0.390	0.540	0.540	0.200	4.509	0.632
2035	0.283	0.240	0.332	0.459	0.459	0.170	3.720	0.537
2036	0.240	0.204	0.282	0.390	0.390	0.144	3.069	0.456
2037	0.204	0.173	0.240	0.332	0.332	0.123	2.532	0.388
2038	0.174	0.147	0.204	0.282	0.282	0.104	2.089	0.330
2039	0.148	0.125	0.173	0.240	0.240	0.089	1.723	0.280
2040	0.125	0.107	0.147	0.204	0.204	0.000	1.422	0.238
Total	**53,802**	**43,885**	**53,821**	**53,704**	**53,704**	**36,602**	**281,123**	**78,364**

Table E.4. Fields with announced plans or pending development, MBOPD.

	MPU New Pad	MPU S Pad	Orion II & III	Polaris II & III	Gwydyr Bay	Liberty	Oooguruk	Nikattchuq
2005	0.000	5.000	0.000	0.000	0.000	0.000	0.000	0.000
2006	0.000	7.493	0.000	0.000	0.000	0.000	0.000	0.000
2007	0.000	12.507	0.000	3.000	1.250	0.000	0.000	4.225
2008	0.000	16.247	4.501	5.000	4.000	0.000	1.710	19.775
2009	0.000	18.507	9.000	7.000	8.000	0.000	13.700	39.050
2010	5.000	20.000	19.501	11.500	12.000	9.865	16.440	48.850
2011	7.500	20.000	27.000	14.000	15.000	19.725	20.000	48.150
2012	12.500	20.000	36.000	16.500	15.000	29.590	20.000	46.050
2013	16.250	18.000	42.000	19.000	13.900	35.000	18.850	41.925
2014	18.500	14.397	45.000	21.500	11.800	35.000	16.020	36.325
2015	20.000	11.521	48.000	21.000	10.000	32.340	13.620	30.875
2016	20.000	9.219	48.000	20.700	8.500	27.490	11.575	26.300
2017	20.000	7.370	47.129	19.300	7.200	23.365	9.840	22.350
2018	18.000	5.904	43.660	17.180	6.200	19.860	8.365	19.000
2019	14.400	4.712	39.838	14.600	5.200	16.880	7.110	16.175
2020	11.520	3.781	33.860	12.410	4.400	14.350	6.040	13.725
2021	9.215	3.214	28.781	10.555	3.800	12.200	5.135	11.650
2022	7.375	2.732	24.460	8.965	3.200	10.370	4.365	9.900
2023	5.900	2.322	20.792	7.625	2.700	8.815	3.710	8.400
2024	4.720	1.974	17.679	6.465	2.300	7.495	3.150	7.150
2025	3.725	1.678	15.022	5.505	2.000	6.370	2.680	6.070
2026	3.166	1.426	12.778	4.680	1.750	5.415	2.280	5.165
2027	2.691	1.212	10.852	3.975	1.500	4.605	1.935	3.495
2028	2.288	1.030	9.230	3.375	1.275	3.910	1.645	1.160
2029	1.944	0.876	7.838	2.869	1.084	3.325	1.400	0.986
2030	1.653	0.744	6.611	2.438	0.921	2.825	1.190	0.838
2031	1.405	0.633	5.616	2.073	0.783	2.405	1.010	0.712
2032	1.194	0.538	4.712	1.762	0.666	2.040	0.859	0.606
2033	1.015	0.457	4.005	1.498	0.566	1.735	0.730	0.515
2034	0.863	0.389	3.405	1.273	0.481	1.475	0.620	0.437
2035	0.733	0.330	2.894	1.082	0.409	1.254	0.527	0.372
2036	0.623	0.281	2.460	0.920	0.347	1.066	0.448	0.316
2037	0.530	0.239	2.091	0.782	0.295	0.906	0.381	0.269
2038	0.450	0.203	1.777	0.664	0.251	0.000	0.324	0.228
2039	0.383	0.172	1.511	0.565	0.213	0.000	0.275	0.194
2040	0.325	0.147	1.284	0.480	0.181	0.000	0.234	0.165
Total	**78,062**	**78,567**	**228,961**	**98,637**	**53,718**	**123,981**	**71,601**	**172,062**

Table E.5. Known fields with near-term development potential, MBOPD.

	Ataruq	Sandpiper	Sambuca	Sourdough	Tuvaaq
2005	0.000	0.000	0.000	0.000	0.000
2006	0.000	0.000	0.000	0.000	0.000
2007	0.000	0.000	0.000	0.000	0.000
2008	0.000	0.000	4.250	0.000	0.000
2009	6.000	0.000	6.000	0.000	0.000
2010	8.500	0.000	7.000	0.000	0.000
2011	10.000	0.000	5.950	0.000	0.000
2012	10.000	0.000	5.050	0.000	0.000
2013	9.500	0.000	4.300	0.000	4.400
2014	8.600	0.000	3.655	0.000	8.000
2015	7.310	5.000	3.110	7.000	17.500
2016	6.210	15.000	2.640	14.000	25.000
2017	5.280	25.000	2.245	21.000	22.500
2018	4.490	35.000	1.910	30.000	19.125
2019	3.810	40.000	1.620	30.000	16.250
2020	3.240	40.000	1.380	27.700	13.815
2021	2.755	40.000	1.170	23.550	11.750
2022	2.340	34.000	1.000	20.025	9.975
2023	1.985	28.800	0.845	17.025	8.475
2024	1.690	24.500	0.725	14.450	7.225
2025	1.435	20.800	0.610	12.300	6.125
2026	1.220	17.700	0.520	10.450	5.225
2027	1.035	15.000	0.440	8.895	4.430
2028	0.880	12.800	0.375	7.655	3.765
2029	0.745	10.900	0.319	6.425	3.200
2030	0.635	9.000	0.271	5.450	2.720
2031	0.540	7.900	0.230	4.625	2.310
2032	0.450	6.700	0.196	3.950	1.964
2033	0.383	5.700	0.166	3.350	1.669
2034	0.325	4.800	0.141	2.850	1.419
2035	0.276	4.000	0.120	2.425	1.206
2036	0.235	3.400	0.102	2.050	1.025
2037	0.200	2.900	0.087	1.743	0.871
2038	0.170	2.400	0.074	1.481	0.741
2039	0.144	2.040	0.063	1.259	0.629
2040	0.123	1.734	0.053	1.070	0.000
Total	**36,684**	**151,502**	**20,665**	**102,466**	**73,479**

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Appendix F. Technical Discussion on Pipeline-Sizing Algorithm

The sizing of a natural gas pipeline can use the empirical Panhandle Eastern equation (Katz, et al. 1959).

$$Q = 883E\left(\frac{p_1^2 - p_2^2}{L}\right)^{0.5394} d^{2.6182} \quad \text{.......} \quad \textit{Eq. D1}$$

Where:

Q = flow rate measured at standard temperature and pressure, scf/day
E = pipeline efficiency, varies from 85 to 95%, an average of 92% is commonly used
p_1 = inlet pressure, psia
p_2 = outlet pressure, psia
L = length of pipe, miles
d = internal pipe diameter, inches

This equation was used to examine the relationship between flowrate, pipeline size and capital costs.

The sizing of a liquid pipeline relied on the empirical observation that flow rate is linearly related to the cross-sectional area by a factor of 884 BOPD/square inch. This can be checked by noting that the 48-inch TAPS pipeline had a design capacity of 1,600 MBOPD. This results in a cross-sectional area of 1809 inch^2 and a flowrate per square inch of 884 BOPD. Similarly, checking smaller pipelines for the ANS results in a very similar factor. Thus, this empirical observation was used to size liquid pipeline for the MEFS analysis.