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ALASKA NORTH SLOPE NATIONAL ENERGY STRATEGY INITIATIVE

Analysis of Five Undeveloped Fields

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May 1993

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Prepared for
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Assistant Secretary for Fossil Energy

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ALASKA NORTH SLOPE NATIONAL ENERGY STRATEGY INITIATIVE (ANALYSIS OF FIVE UNDEVELOPED FIELDS)

ABSTRACT

The U.S. Department of Energy was directed in the National Energy Strategy to establish a federal interagency task force to identify specific technical and regulatory barriers to the development of five undeveloped North Slope Alaska fields and make recommendations for their resolution. The five fields are West Sak, Point Thomson, Gwydyr Bay, Seal Island/Northstar, and Sandpiper Island. Analysis of environmental, regulatory, technical, and economic information, and data relating to the development potential of the five fields leads to the following conclusions:

- Development of the five fields would result in an estimated total of 1,055 million barrels of oil and 4.4 trillion cubic feet of natural gas and total investment of $9.4 billion in 1992 dollars.

- It appears that all five of the fields will remain economically marginal developments unless there is significant improvement in world oil prices. However, the analysis indicates that improved technology and reduced costs through the combined cooperative efforts of industry and government could make it economically feasible to develop some of these fields.

- Costs of regulatory compliance and mitigation, and costs to reduce or maintain environmental impacts at acceptable levels influence project investments and operating costs and must be considered in the development decision making process. These costs can result in reduced reserves and delays in development. Efforts to reduce these costs and impacts would be beneficial to the development of the five fields and other potential discoveries.

- The development of three of the fields (West Sak, Point Thomson, and Gwydyr Bay) that are marginally feasible would have an impact on North Slope production over the period from about 2000 to 2014 but cannot replace the decline in Prudhoe Bay Unit production or maintain the operation of the Trans-Alaska Pipeline System (TAPS) beyond about 2014 with the assumption that the TAPS will shut down when production declines to the range of 400 to 200 thousand barrels of oil/day.

- Recoverable reserves left in the ground in the currently producing fields and soon to be developed fields, Niakuk and Point McIntyre, would range from 1 billion to 500 million barrels of oil corresponding to the time period of 2008 to 2014 based on the TAPS shutdown assumption.

EXECUTIVE SUMMARY

1. Introduction

The National Energy Strategy (NES) issued in February 1991 sets out two fundamental objectives to enhance energy security. One objective is to expand U.S. and worldwide oil production capacity and strategic stocks; the second is to reduce U.S. oil consumption through a combination of measures aimed at increased efficiency, introduction of alternative transportation fuels, and aggressive research and development of new energy and oil saving technology. As part of the objective to expand oil production capacity, the NES calls for accelerated development of five undeveloped Alaskan North Slope fields. These five fields are West Sak, Point Thomson, Gwydyr Bay, Seal Island/Northstar, and Sandpiper Island. These five fields are referred to throughout the report as the five NES fields. The U.S. Department of Energy (DOE) was directed in the NES to establish a task force to identify specific technical and regulatory barriers to the development of these fields and make recommendations for their resolution. DOE has established an interagency task force consisting of representatives from DOE, U.S. Department of Interior, Environmental Protection Agency, Department of Defense (Army Corps of Engineers), Council on Environmental Quality, and Department of Commerce (National Marine Fisheries Service) to identify specific technical and regulatory hurdles to development of these fields and make recommendations for their resolution.

The five NES fields are known resource accumulations that have not been developed because of technical or economic conditions or both. These five fields are diverse in terms of geographic location, size of resources (potential reserves), areal extent, depth of productive horizon, type and quality of hydrocarbons, age and lithologic character of the rocks of the productive horizons, physiographic position, and other factors that ultimately must be addressed in the decision-making process. All of the fields are currently in a non-producing status and most will require further exploration/delineation before development decisions can be made. One result of this non-producing status is that public information is limited on all five fields.

This report provides the environmental, regulatory, technical, and economic information and data relating to the development potential of the five discovered but undeveloped fields. Information and data were obtained from open literature, industry, federal agencies, and state and local agencies in Alaska. The production forecasts, investment forecasts, and operating costs used in the analyses were developed

by the authors based on the available information and were not provided by any agency or company. The environmental, regulatory, and technical issues and the interaction of these issues with the economic factors that control the development of each of the five NES fields are analyzed. Sensitivity analyses illustrate the relative influence of these factors for a variety of potential technical, regulatory, and economic options providing the basis for the interagency task force to develop recommendations to assist in the development of these fields.

Summary of Approach

In 1990, the DOE Office of Fossil Energy, in cooperation with the state of Alaska, conducted a study of the Alaska North Slope oil and gas resources. A report titled, "Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity?" was released in March 1991. The report presented an analysis of several potential scenarios concerning future production from the North Slope. The five North Slope producing oil fields (Prudhoe Bay, Kuparuk, Lisburne, Milne Point, and Endicott), two fields that were nearing development (Niakuk and Point McIntyre), four of the five NES fields (West Sak, Gwydyr Bay, Seal Island/Northstar, and Sandpiper), and the potential development of three exploration areas were analyzed for their effect on the lifetime of the Trans-Alaska Pipeline System (TAPS). The same basic methods used in the 1991 DOE report are used for this analysis.

The status of the five currently producing North Slope oil fields (Prudhoe Bay, Kuparuk, Lisburne, Milne Point, and Endicott) and the two fields nearing productive status (Niakuk and Point McIntyre) are updated to provide a background for operations on the North Slope and expectations for continued operation of North Slope infrastructure. Production forecasts and economics are updated to 1/1/92 using actual 1990 and 1991 production. An important factor affecting the future of these fields and all future development on the North Slope is the continued operation of TAPS. Although the actual minimum throughput rate for TAPS has not been established, a range of 400 to 200 MBPD is assumed to illustrate the effects of a shutdown of TAPS. The minimum rate for operation of TAPS will be determined by both mechanical and economic factors.

The development decision-making process for development of new fields on the North Slope of Alaska is driven by economic considerations and acceptability of the environmental impacts. Although the development decision-making process may differ by company, the fundamental steps are (a) defining the scope, (b) designing environmentally acceptable development plans, (c) estimating uncertainty,

(d) optimizing project design, and (e) finalizing the development decision. The analysis of the five NES fields is designed to take into account the evolving business environment, which includes (a) increasing labor and materials costs, (b) increasing technological costs and risks associated with developing more marginal prospects in a harsh environment, (c) an increasing level of industry responsibility and costs in dealing with environmental laws and regulations, (d) highly unstable oil prices, and (e) the continuing need for additional revenue by both federal and state sectors.

The method used to quantify the value of the projects is the present worth (PW) of the project, where PW is the cumulative after tax cash flow generated from the project's time sequenced revenues and expenses discounted to 1992 dollars. Nominal discount rates of 10 to 15% are used in the analysis. An inflation rate of 3.5% is used. Four oil price cases are used to show the effects of oil price on the project economics. The four cases include the NES Low oil price case from the *Technical Annex 2, Integrated Analysis Supporting the National Energy Strategy: Methodology, Assumptions and Results*, U.S. Department of Energy, 1991 (DOE/S-0086P) and three cases for the Energy Information Administration's (EIA) *Assumptions for the Annual Energy Outlook 1992*, January 1992 [DOE/EIA-0527(92)]. The NES Low oil price case lies between the EIA Mid-level and Low price cases as shown in **Table 1.** These are world oil prices defined as the average cost to U.S. refiners of acquiring imported oil. All four cases contain some level of real price increase and include the effects of economic growth, conservation, fuel substitution, and supply.

Table 1. World oil price cases ($/BBL, constant 1/1/92$).

	1992	1995	2000	2005	2010	2015	2020
EIA High	22.07	26.97	33.90	39.34	42.86	45.04	47.35
EIA Mid-Level	20.15	22.17	28.15	32.52	35.61	38.36	41.32
NES Low[a]	20.41	15.86	22.01	27.03	29.47	30.61	32.50
EIA Low	15.88	17.06	19.08	21.43	24.09	26.87	29.95

a. NES Current Policy Base Case includes three oil price projections, High, Base, and Low.

Economic uncertainty is addressed through sensitivity analyses performed to test the economic effect of changes in the variables including oil price, recovery and rate, operating costs, capital investment, federal and state taxes, and discount rate. Methods such as Monte Carlo techniques, sometimes applied by industry and government agencies, are not used. Effects of changes in individual

Major Fields--Prudhoe Bay and Kuparuk fields are the No. 1 and No. 2 producing rate fields in the U.S. and produce about 18% of the nation's daily output of oil or about 1.6 million barrels (MMB) of the total 8.9 MMB. Prudhoe Bay production is declining; Kuparuk production is expected to remain fairly steady for several more years before a significant decline begins.

Remaining reserves are estimated at 5,300 MMB for Prudhoe Bay and 1,300 MMB for Kuparuk. It is these two fields with their reserves and rate of production that dominate predictions for the duration of economic oil production on the North Slope of Alaska. Using a TAPS shutdown ranging from year-end 2008 (400 MBPD) to year-end 2014 (200 MBPD), the possible "lost" recoverable liquids from these two fields would be about 1,000 MMB to 500 MMB, respectively.

The impact of the Prudhoe Bay field discovery, development, and creation of infrastructure, including TAPS, can be appreciated in total only by realizing that all of the other producing fields and all of the potentially productive fields are dependent upon the existing infrastructure. If TAPS does, in fact, shut down by year-end 2008, then the timeline for bringing discovered fields on production is rapidly approaching criticality because of the lengthy period between decision to develop and first production. The time factor is even more critical for potential undiscovered fields, such as in ANWR or offshore, because the time from lease sale to first production is greater than 10 years.

Recently Developed Fields--The recently developed fields, Endicott, Milne Point (including Schrader Bluff), and Lisburne, provide examples of fields that have been developed with the benefit of the infrastructure and TAPS that are in place as a result of the discovery and development of the super-giant Prudhoe Bay field. These fields illustrate the advancement of arctic technology that has reduced the size of the footprint required in the arctic since the start of Prudhoe Bay development. Factors influencing these technological advances are low oil prices, environmental and regulatory concerns, and relatively small reserves.

Although sizable by Lower 48 standards, Endicott, Milne Point, and Lisburne fields are not major factors on the North Slope in terms of reserves or production rate. Nevertheless, these three fields are more typical of the five NES fields. Their history provides a comparison for evaluation of factors affecting future development.

Long delays ensued between discovery and production of the recently developed fields; i.e., Endicott - 9 years; Milne Point - 16 years; Lisburne - 18 years. A similar pattern can be assumed for other relatively small North Slope fields, discovered or undiscovered.

These three fields combine to total 592 MMBO of remaining reserves and begin to decline in 1993 for Endicott, 1994 for Lisburne, and 2008 for Milne Point/Kuparuk and Schrader Bluff. Production limits are reached in 2010, 2007, and 2016, respectively, for the three fields. Except for a minor amount by Schrader Bluff, they have no effect on extending TAPS beyond 2010.

The major lessons to be learned from these fields are the economic and environmental benefits derived from careful engineering design for facilities down-sized for lower reserves and rates than those of the Prudhoe Bay field. Another major factor in viability of these fields is the use of, and integration into, the Prudhoe Bay infrastructure.

From an industry perspective, the additional 650 ft breach in the Endicott causeway adds a $56 MM burden to capital investment totalling $106 MM over the remaining productive life of the 240 MMBO reserve. At an ultimate reserve total of 404 MMBO, Endicott ranks third among North Slope fields. Smaller fields, or large ones with lesser remaining reserves, may be unable to achieve or continue economic recovery under similar circumstances.

Fields with Development Potential (Point McIntyre and Niakuk)--Contrary to the normal long delays between discovery and production, Point McIntyre field should set a record of only 6 years from the 1988 discovery to the 1994 beginning of production. Located adjacent to Prudhoe Bay and Lisburne fields, Point McIntyre benefits from proximity to existing infrastructure to a remarkable degree. In addition, it benefits (as does Niakuk) from the pending agreement to share in the Lisburne Participating Area (LPA) production facilities. Investment savings to Point McIntyre total about $262 MM, indicating the substantial positive impact facilities sharing can have on prospects on the North Slope. Facilities sharing also reduces environmental impact through reduction of footprint size.

Reserves are estimated at 300 MMBO for Point McIntyre and 70.4 MMBO (53.4 MMBO proven) for Niakuk. Production will begin in 1994 from both fields. Point McIntyre will begin to decline in 2002 and could produce through 2015. Niakuk begins to decline in 1998 and maintains production through 2008. Thus, the later production from these fields helps to offset the earlier declines of

production from the bigger fields. Nevertheless, the impact is insufficient to alter the overall North Slope production decline to an extent that would prolong the life of TAPS. Many more Point McIntyre size fields or one or more super-giant field discoveries are necessary to significantly prolong the life of TAPS.

The Niakuk Kuparuk field was discovered in 1985, followed by two confirmation wells. The initial plan provided for development from an enlarged offshore island connected to shore by a causeway. Plans to develop from the offshore island were abandoned in 1991 and a study of development from shore was undertaken. Onshore development includes facilities sharing with the LPA and reduces the investment required by about $70 MM (1/1/92$). A loss of 29 MMBO of recoverable oil (proven plus potential) is expected from onshore development because the reservoir that can be reached from shore is limited by current directional drilling technology. The estimated recoverable oil volume (proven plus potential) from the onshore development is about 70.4 MMBO.

Summary of Currently Producing Fields and Fields with Development Potential--The total estimated remaining recoverable oil in the seven fields described above is about 7,600 MMBO. It is evident that the declines of Prudhoe Bay and Kuparuk fields impose the dominant time constraint on future North Slope production and exploration.

West Sak--West Sak sands are encompassed by three producing units, the Prudhoe Bay Unit (PBU) established in 1977, the Milne Point Unit (MPU) established in 1979, and the Kuparuk River Unit (KRU) established in 1981. West Sak and Ugnu sands containing low gravity, heavy oil sands of Upper Cretaceous and Tertiary age have been demonstrated to extend over an area of about 200,000 acres and contain an estimated total of between 25 and 44 billion barrels in place (BBOIP). West Sak sands contain oil at depths from 2,000 to 4,500 ft in the MPU and KRU, with the deepest portion in the northeast in the MPU. Average depth of permafrost in the area is less than 1,500 ft. Oil production from the Schrader Bluff oil pool in the MPU operated by Conoco started in March 1991. The "O" sands of the Schrader Bluff sands are equivalent to the West Sak sands in the KRU but the "N" sands are more equivalent to the lower Ugnu sands. Reservoir temperatures range from 45 to 100°F in West Sak sands with Schrader Bluff averaging 90°F at 4,000 ft subsea. Hence, direct comparisons of Schrader Bluff with the balance of the West Sak area should be approached with caution.

West Sak contains the largest resource volume of the five NES fields, with estimates of up to 20 BBOIP. West Sak crude properties and reservoir conditions present formidable challenges to economic

development. Low gravity, high viscosity oil in a shallow, thin bedded, low temperature reservoir that is highly faulted presents a number of problems to be resolved before any development can take place. With production coming from unconsolidated beds, completion techniques must be developed or existing techniques adopted to the West Sak conditions. Laboratory testing and a hot-water injection pilot indicate that a miscible water-alternating-gas (WAG) process, using close well spacing is the most likely recovery process. Further work may be required before final selection of a process is made. Because of the shallow depth of the reservoir, drilling pads would be required on every section developed, which would result in more numerous and concentrated surface impacts on the environment. Environmental concerns could lead to pattern changes to reduce surface environmental concerns resulting in loss of reserves because of the concentrated pads and facilities necessary to develop the shallow reservoir.

Although considerable study has apparently been conducted by the operator, little of this proprietary information is public. Based on available data, is it estimated that between 500 and 600 MMBO can be recovered from better quality reservoir on about 30,000 acres. The timing of the development of these potential reserves is dependent on having an adequate oil price and an economical source of miscible injectant (MI). The volume of MI on the North Slope is limited at present and will be used in the most economical projects first. This places West Sak at least third behind PBU and KRU. The timing of obtaining MI for West Sak is critical when considering the time frame of TAPS shutdown. About 239 MMBO would be unrecovered under these development scenarios, if TAPS shuts down at year-end 2008.

Results of the economic evaluation of West Sak, using the four oil price scenarios indicate that the EIA Mid-level oil price case is required to obtain a rate of return between 10 and 15%. These economic results clearly indicate that West Sak is an economically marginal project for development.

Point Thomson--The Point Thomson Unit (PTU) covers a gas condensate field about 50 mi east of TAPS pump station (PS) No. 1. The unit contains about 83,800 acres, much of which is offshore. The current reserve estimates for the PTU carried by the Alaska Department of Natural Resources are 5 TCF gas and 300 MMB of oil and condensate. Recent seismic results indicate that the reservoir may be about one-third smaller than originally thought. Thus, a reduction in reservoir size is considered for comparison purposes.

The magnitude of the impact on project economics by changes (on the order of 10 to 15%) in selected factors and combinations of factors for the five NES fields show that various combinations of reductions in investments and operating costs, reserves increases, and reductions in taxes, royalties, and net profits interests could potentially provide rates of return between 10 and 15% for portions of West Sak, Point Thomson, Gwydyr Bay, and Seal Island/Northstar. Basic technical requirements for development to be feasible include availability of MI for West Sak, a gas pipeline from the North Slope for Point Thomson, confirmation of adequate reserves in Gwydyr Bay, and adaptation of existing offshore pipeline technology to arctic North Slope environments for development of Seal Island/Northstar.

Summary Observations

(1) Under the assumptions used, the economic results for three of the five NES fields (West Sak, Point Thomson, and Gwydyr Bay) indicate that only price forecasts with significant real growth can provide industry with a positive PW at a discount rate of 10%. The two offshore fields (Seal Island/Northstar and Sandpiper) do not provide a positive PW at a 10% discount rate for any of the price scenarios.

(2) The economic sensitivity analyses show that combinations of reduced operating costs, investments, tax and royalty rates, net profits interests, and increased reserves could make development of these five fields potentially economic provided the following requirements are met:

- MI is available for use in West Sak, which will be at least third after PBU and KRU.
- A gas sales line is developed for PBU gas before Point Thomson can be developed.
- The potential reserves at Gwydyr Bay must be proven and the uncertainty of costs related to development in the Kuparuk River delta resolved.
- The Northstar Unit does not appear feasible without removal of the NPI burden.
- Larger reserves at Sandpiper must be confirmed.

(3) The Alaska North Slope production profile (**Figure 1**) is based on the EIA Mid-level oil price. At these prices, using a cut-off of a 10% discount rate, West Sak, Point Thomson, and Gwydyr Bay provide a positive PW and are included in the production profile. Point Thomson and Gwydyr Bay also provide a 10% rate of return at the NES Low oil price. Seal Island/Northstar and Sandpiper do not meet this economic hurdle rate and are not included. At the EIA Low oil price case none of the five NES fields provide a positive PW at a 10% discount rate and result in an Alaska North Slope production profile as shown in **Figure 2**.

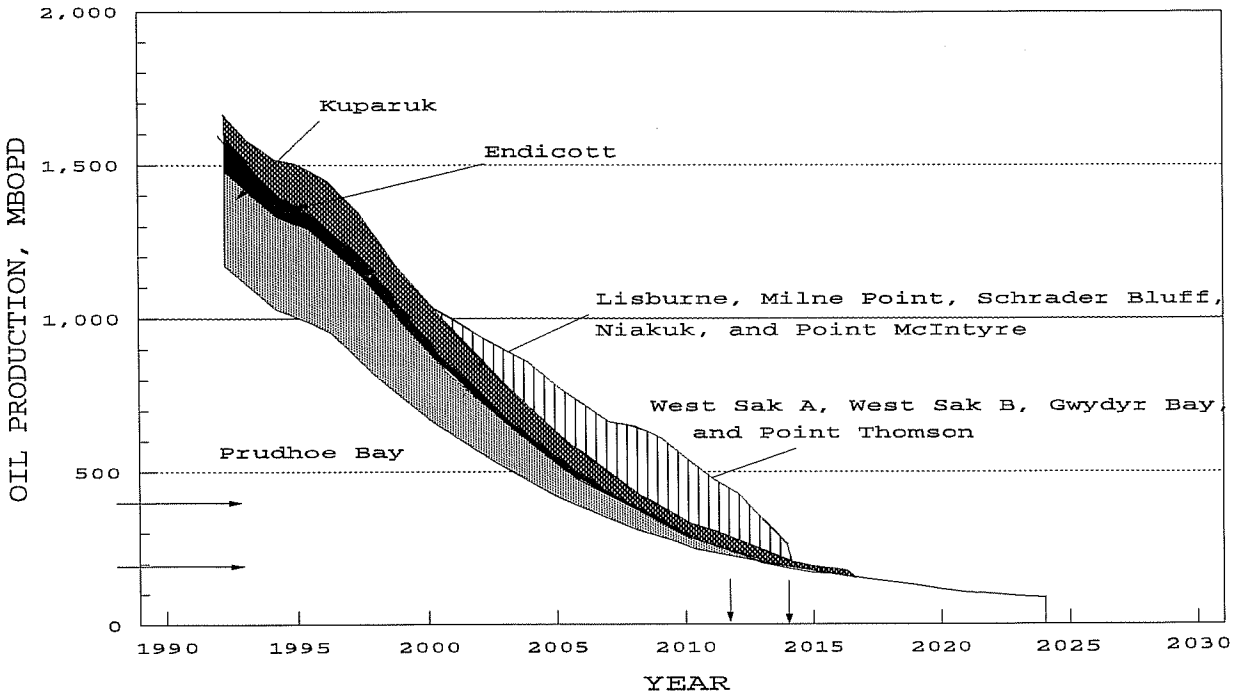

Figure 1. Alaska North Slope production rate forecast including forecasted production from West Sak, Point Thomson, and Gwydyr Bay (arrows indicate the potential range of TAPS shutdown).

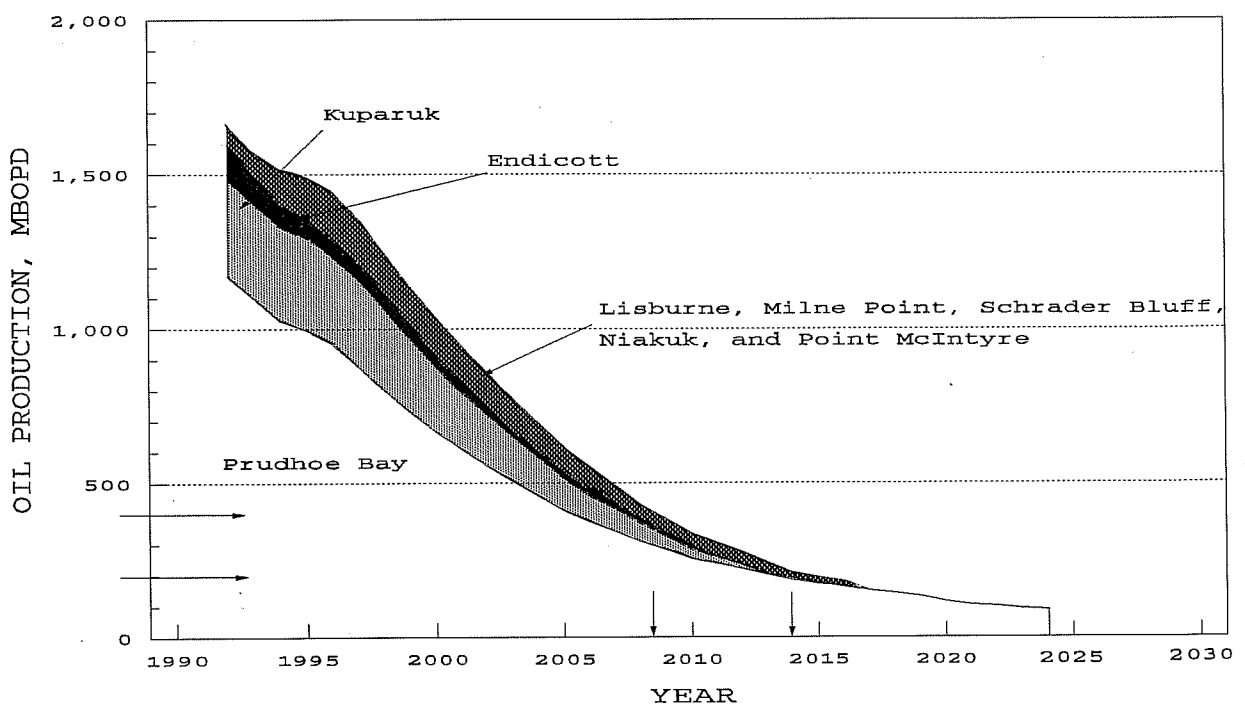

Figure 2. Composite production for seven North Slope fields (arrows indicate the potential range of TAPS shutdown).

(4) Alternate investment opportunities would be expected to seriously compete with the investment capital for the five NES fields at any oil price that provides industry with only a 10% rate of return.

(5) State benefits from the development of each of the five NES fields are significant. Federal benefits, although limited at the two lowest oil price cases, are significant at the higher oil price cases. State and federal benefits and those for industry demonstrate the different levels of benefit that accrue to industry and to state and federal governments with the current royalty and tax rates and illustrate the possibility for share redistribution to encourage development.

(6) State and federal benefits from the currently producing fields are significant. Prudhoe Bay has been beneficial to all parties (industry and state and federal governments). The other four producing fields have provided value to the state and to industry. The federal government has benefitted to a lesser degree. However, these four fields, on a stand-alone basis, have not provided a positive cumulative discounted (10%) after-tax cash flow to the industry (1992 base year) and may not unless oil prices increase to levels at or above the EIA Mid-Level oil price scenario. It is significant that the decision to develop all four of these fields was made during the period of time between 1975 and 1986 when world oil prices were about $30/BBL or above.

(7) Stable world oil prices, high enough to provide adequate rates of return to offset the financial risks involved in development in the harsh environmental conditions of the North Slope, would be the most sure guarantee of development of the five NES fields and other similar fields on the North Slope. However, the sensitivity analyses indicate that reductions in operating costs and investments and increases in recovery volume through combinations of improved technology and streamlined processes for environmental and regulatory requirements or both can feasibly move some of these fields to development. Reductions in tax and royalty rates would provide additional incentive.

Conclusions

- Development of the five fields would result in an estimated total of 1,055 million barrels of oil and 4.4 trillion cubic feet of natural gas and total investment of $9.4 billion in 1992 dollars.

- It appears that all five of the fields will remain economically marginal developments unless there is significant improvement in world oil prices. However, the analysis indicates that improved

technology and reduced costs through the combined cooperative efforts of industry and government could make it economically feasible to develop some of these fields.

- Costs of regulatory compliance, mitigation, and costs to reduce or maintain environmental impacts at acceptable levels influence project investments and operating costs and must be considered in the development decision making process. These costs can result in reduced reserves and delays in development. Efforts to reduce these costs and impacts would be beneficial to the development of the five fields and other potential discoveries.

- The development of three of the fields (West Sak, Point Thomson, and Gwydyr Bay) that are marginally feasible would have an impact on North Slope production over the period from about 2000 to 2014 but cannot replace the decline in Prudhoe Bay Unit production or maintain the operation of TAPS beyond about 2014 with the assumption that the Trans-Alaska pipeline (TAPS) will shut down when production declines to the range of 400 to 200 thousand barrels of oil/day.

- Recoverable reserves left in the ground in the currently producing fields and soon to be developed fields, Niakuk and Point McIntyre, would range from 500 million to 1 billion barrels of oil corresponding to the time period of 2008 to 2014 based on the TAPS shutdown assumption.

ACRONYMS AND ABBREVIATIONS

3-L site	Kuparuk Drill Site 3-L
AAC	Alaska Administrative Code
AAPG	American Association of Petroleum Geologists
ACMP	Alaska Coastal Management Program
ADEC	Alaska Department of Environmental Conservation
ADFG	Alaska Department of Fish and Game
ADID	advanced identification
ADL	Alaska Division of Lands
ADNR	Alaska Department of Natural Resources
ADR	Alaska Department of Revenue
AEDP	Area Evaluation and Decision Process
ANILCA	Alaska National Interest Lands Conservation Act
ANWR	Arctic National Wildlife Refuge
AOGCC	Alaska Oil and Gas Conservation Commission
API	American Petroleum Institute
ARCO	Atlantic Richfield Company
BACT	best available control technology
BBL	barrel
BBO	billion barrels of oil
BBOIP	billion barrels of oil in place
BCF	billion cubic feet
BCFD	billions cubic feet per day
BLM	Bureau of Land Management
BOPD	barrels of oil per day
BP	British Petroleum
BPAF	barrels per acre-ft
BPD	barrels per day
BP Exploration	BP Exploration [Alaska] Inc.
BPT	best practicable control technology
BSTB	billion stock tank barrels
BTF	barrels of total fluid
BWPD	barrels of water per day
CAA	Clean Air Act
CEQ	Council on Environmental Quality
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFR	Code of Federal Register
CMP	Coastal Management Plan
Corps	U.S. Army Corps of Engineers
CWA	Clean Water Act
CWP	Comprehensive Wetlands Plan
CZMA	Coastal Zone Management Act
CZMP	Coastal Zone Management Plan
DGC	Division of Governmental Coordination
DIU	Duck Island Unit
DOE	U.S. Department of Energy
DOG	Division of Oil and Gas (ADNR)
DOI	U.S. Department of the Interior
DOT	Department of Transportation

DST	drill stem test
EA	environmental assessment
EIA	Energy Information Administration
EIS	environmental impact statement
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
ER	environmental report
ESA	Endangered Species Act
FONSI	finding of no significant impact
FWCA	Fish and Wildlife Coordination Act
FWPCA	Federal Water Pollution Control Act
FWS	U.S. Fish and Wildlife Service
GBU	Gwydyr Bay Unit
GHX	gas handling expansion
GOC	gas/oil contact
GOR	gas oil ratio
IBR	information base review
KPA	Kuparuk Participating Area
KRU	Kuparuk River Unit
LPA	Lisburne Participating Area
LPC	Lisburne Production Center
MB	thousand barrels
MBD	thousand barrels per day
MBOPD	thousand barrels of oil per day
md	millidarcy
MD	measured depth
MEFS	minimum economic field size
MFS	minimum, flat sustained (price)
MI	miscible injectant
MM	million
MMB	million barrels
MMBBLS	millions barrels
MMBO	million barrels of oil
MMBW	million barrels of water
MMCFPD	million cubic feet gas per day
MMPA	Marine Mammal Protection Act
MMS	Mineral Management Service
MOA	Memorandum of Agreement
MPKPA	Milne Point Kuparuk Participating Area
MPU	Milne Point Unit
NAAQA	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NES	National Energy Strategy
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	natural gas liquid
NMFS	National Marine Fisheries Service
NOI	notice of intent
NORM	naturally occurring radioactive material
NPDES	National Pollutant Discharge Elimination System
NPI	net profits interest

NPR-A	National Petroleum Reserve - Alaska
NPS	National Park Service
NSB	North Slope Borough
NU	Northstar Unit
NWFB	North West Fault Block
OCS	outer continental shelf
OCSLA	Outer Continental Shelf Lands Act
OGJ	Oil & Gas Journal
OOIP	original oil in place
OWC	oil - water contact
PAAM	Proposed Action and Alternatives Memorandum
PBMGP	Prudhoe Bay Miscible Gas Project
PBU	Prudhoe Bay Unit
PIC	Petroleum Information Corporation
POD	Plan of Development
PS	pump station
PSD	Prevention of Significant Deterioration (Air Quality)
PTU	Point Thompson Unit
PW	present worth
RCRA	Resource Conservation and Recovery Act
RFIC	request for interest and comments
RHA	River and Harbors Act
SARA	Superfund Amendments and Reauthorization Act
SDWA	Safe Drinking Water Act
STD	standard
TAPS	Trans-Alaska Pipeline System
TCF	trillion cubic feet
TVD	true vertical depth
USDA	U.S. Department of Agriculture
USGC	U.S. Coast Guard
WAG	water alternating gas
WI	water injection

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ALASKA NORTH SLOPE NATIONAL ENERGY STRATEGY INITIATIVE (ANALYSIS OF FIVE UNDEVELOPED FIELDS)

1. INTRODUCTION

The National Energy Strategy (NES) issued in February 1991 sets out two fundamental objectives to enhance energy security (NES 1991, p. 76). One objective is to expand U.S. and worldwide oil production capacity and strategic stocks; the second is to reduce U.S. oil consumption through a combination of measures aimed at increased efficiency, introduction of alternative transportation fuels, and aggressive research and development of new energy and oil saving technology. As part of the objective to expand oil production capacity, the NES calls for accelerated development of five undeveloped Alaskan North Slope fields (NES 1991, p. 80). These five fields are West Sak, Point Thomson, Gwydyr Bay, Northstar/Seal Island, and Sandpiper Island. The U.S. Department of Energy (DOE) is directed in the NES to establish a task force to identify specific technical and regulatory barriers to the development of these fields and make recommendations for their resolution. DOE has established an interagency task force consisting of representatives from DOE, U.S. Department of Interior (DOI), Environmental Protection Agency (EPA), Department of Defense [Army Corps of Engineers (Corps)], Council on Environmental Quality (CEQ), and Department of Commerce [National Marine Fisheries Service (NMFS)] to identify specific technical and regulatory hurdles to development of these fields and make recommendations for their resolution.

This report provides the environmental, regulatory, technical, and economic information and data relating to the development potential of the five discovered but undeveloped fields. These fields will be referred to throughout this report as the five NES fields. Information and data were obtained from open literature; industry; and federal, state, and local agencies in Alaska. The environmental, regulatory, and technical issues and the interaction of these issues with the economic factors that control the development of each of the five NES fields are analyzed. Sensitivity analyses are presented to illustrate the relative influence of these factors for a variety of potential technical, regulatory, and economic options and to provide the basis for the interagency task force to develop recommendations to assist in the development of these fields.

1.1 Background

In 1990, the DOE Office of Fossil Energy, in cooperation with the state of Alaska, conducted a study of the Alaska North Slope oil and gas resources. A report titled, "Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity?" was released on March 12, 1991 (DOE 1991). The report presented an analysis of several potential scenarios concerning future production from the North Slope. The five North Slope producing oil fields (Prudhoe Bay, Kuparuk, Lisburne, Milne Point, and Endicott), two fields that were nearing development (Niakuk and Point McIntyre), four of the five NES fields (West Sak, Gwydyr Bay, Seal Island/Northstar, and Sandpiper), and the potential development of three exploration areas were analyzed for their effect on the lifetime of the Trans-Alaska Pipeline System (TAPS).

The history of exploration and development up to early 1990 is described in the previous DOE publication, (DOE 1991). In that report it is pointed out that all North Slope producing fields and most of the oil and gas accumulations lie along or close to the Barrow Arch, a regional anticline extending 375 mi from northwest to southeast, generally paralleling the coast as shown in **Figure 1.1**. All of the fields and accumulations described in detail in this report are located on, or in proximity to, the Barrow Arch. A generalized map of the North Slope, **Figure 1.2**, shows the location of the fields and accumulations on a regional scale. **Figure 1.3** is a more localized map that includes all the fields to be discussed. The ages and stratigraphic positions of the various accumulations are shown in **Figure 1.4**.

To understand the decision-making process leading to the development of North Slope oil fields it is first necessary to establish a framework of reference. **Table 1.1** lists accumulations of oil and gas that have been discovered on the North Slope. Oil accumulations that are in the process of being evaluated by delineation drilling to determine the feasibility of economic production represent examples of one step in the decision-making process. Delineation drilling is the step by which resources in a previously discovered accumulation make the transition to reserves. Reserves are defined as resources demonstrated with reasonable certainty to be recoverable from known accumulations under existing economic and operating conditions. **Table 1.2** shows fields on the North Slope that have already made the transition to producing status.

An update of the status of the five currently producing North Slope oil fields (Prudhoe Bay, Kuparuk, Lisburne, Milne Point, and Endicott) and the two fields nearing productive status (Niakuk and Point McIntyre) is included in **Appendix A**. Production forecasts and economics are updated to 1/1/92

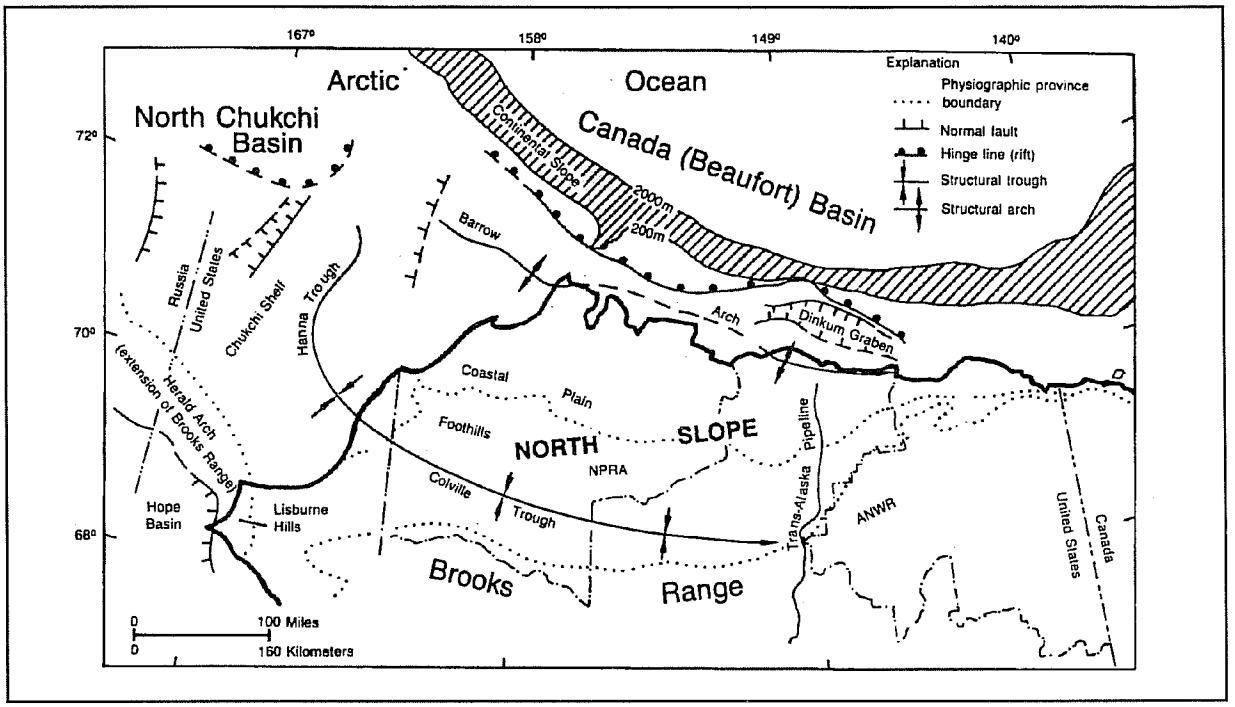


Figure 1.1. Generalized structural features and geological framework of onshore and offshore northern Alaska (after Bird 1991).

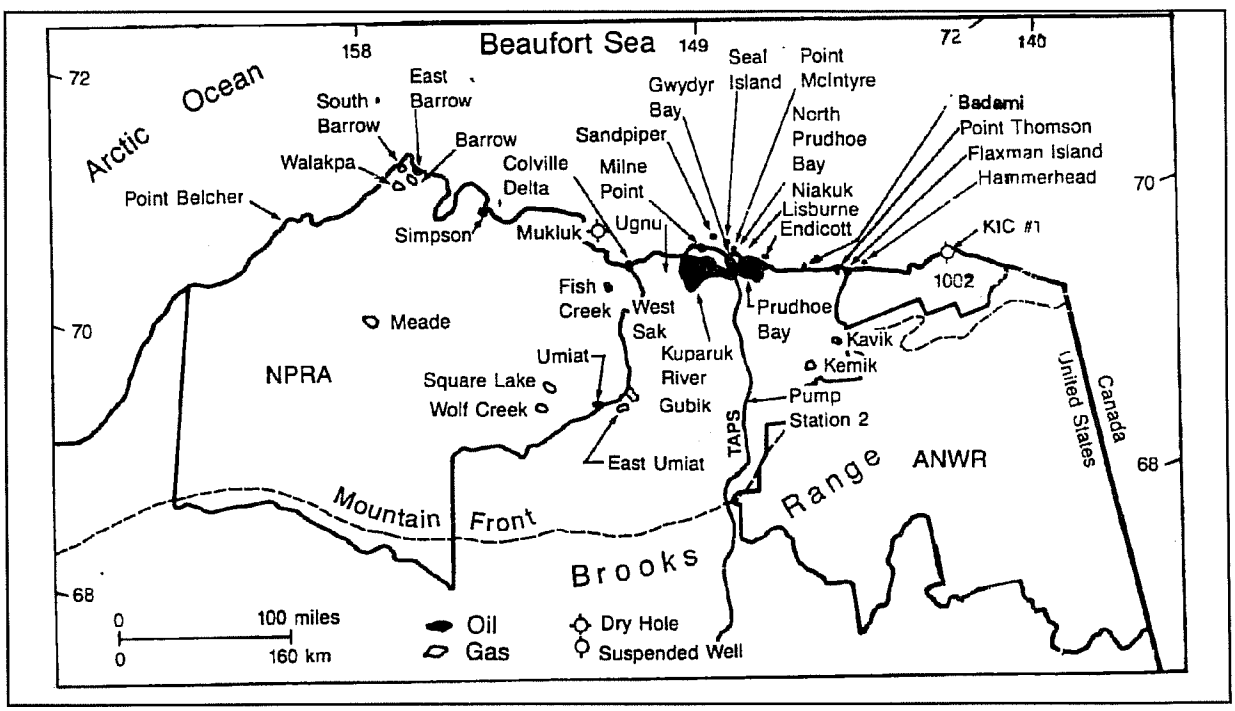
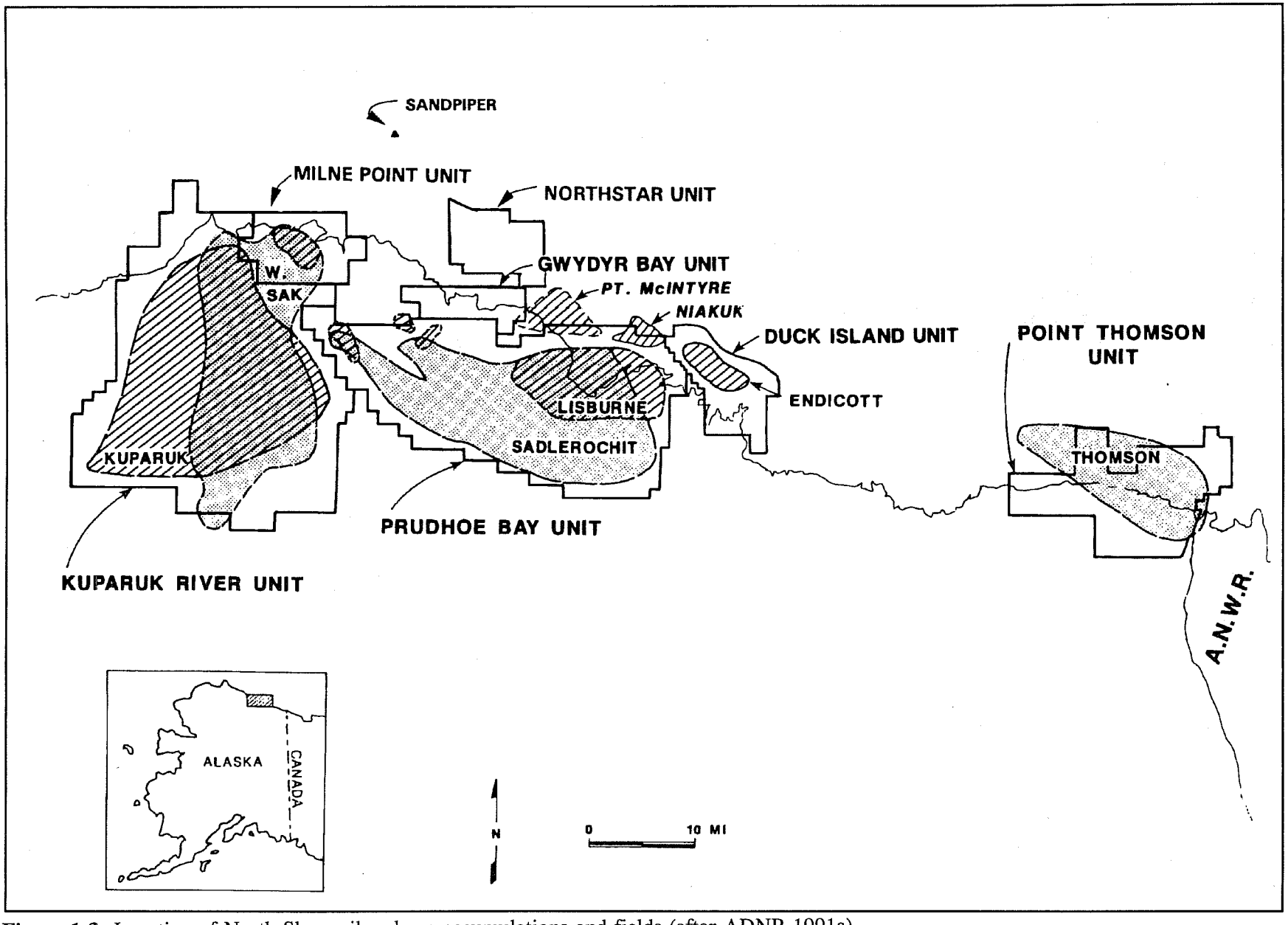


Figure 1.2. Known oil and gas accumulations, selected dry holes and suspended wells, and NPRA-ANWR boundaries, North Slope Alaska (DOE 1991, ADNR 1991a).



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ALASKA NORTH SLOPE NATIONAL ENERGY STRATEGY INITIATIVE (ANALYSIS OF FIVE UNDEVELOPED FIELDS)

1. INTRODUCTION

The National Energy Strategy (NES) issued in February 1991 sets out two fundamental objectives to enhance energy security (NES 1991, p. 76). One objective is to expand U.S. and worldwide oil production capacity and strategic stocks; the second is to reduce U.S. oil consumption through a combination of measures aimed at increased efficiency, introduction of alternative transportation fuels, and aggressive research and development of new energy and oil saving technology. As part of the objective to expand oil production capacity, the NES calls for accelerated development of five undeveloped Alaskan North Slope fields (NES 1991, p. 80). These five fields are West Sak, Point Thomson, Gwydyr Bay, Northstar/Seal Island, and Sandpiper Island. The U.S. Department of Energy (DOE) is directed in the NES to establish a task force to identify specific technical and regulatory barriers to the development of these fields and make recommendations for their resolution. DOE has established an interagency task force consisting of representatives from DOE, U.S. Department of Interior (DOI), Environmental Protection Agency (EPA), Department of Defense [Army Corps of Engineers (Corps)], Council on Environmental Quality (CEQ), and Department of Commerce [National Marine Fisheries Service (NMFS)] to identify specific technical and regulatory hurdles to development of these fields and make recommendations for their resolution.

This report provides the environmental, regulatory, technical, and economic information and data relating to the development potential of the five discovered but undeveloped fields. These fields will be referred to throughout this report as the five NES fields. Information and data were obtained from open literature; industry; and federal, state, and local agencies in Alaska. The environmental, regulatory, and technical issues and the interaction of these issues with the economic factors that control the development of each of the five NES fields are analyzed. Sensitivity analyses are presented to illustrate the relative influence of these factors for a variety of potential technical, regulatory, and economic options and to provide the basis for the interagency task force to develop recommendations to assist in the development of these fields.

1.1 Background

In 1990, the DOE Office of Fossil Energy, in cooperation with the state of Alaska, conducted a study of the Alaska North Slope oil and gas resources. A report titled, "Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity?" was released on March 12, 1991 (DOE 1991). The report presented an analysis of several potential scenarios concerning future production from the North Slope. The five North Slope producing oil fields (Prudhoe Bay, Kuparuk, Lisburne, Milne Point, and Endicott), two fields that were nearing development (Niakuk and Point McIntyre), four of the five NES fields (West Sak, Gwydyr Bay, Seal Island/Northstar, and Sandpiper), and the potential development of three exploration areas were analyzed for their effect on the lifetime of the Trans-Alaska Pipeline System (TAPS).

The history of exploration and development up to early 1990 is described in the previous DOE publication, (DOE 1991). In that report it is pointed out that all North Slope producing fields and most of the oil and gas accumulations lie along or close to the Barrow Arch, a regional anticline extending 375 mi from northwest to southeast, generally paralleling the coast as shown in **Figure 1.1**. All of the fields and accumulations described in detail in this report are located on, or in proximity to, the Barrow Arch. A generalized map of the North Slope, **Figure 1.2**, shows the location of the fields and accumulations on a regional scale. **Figure 1.3** is a more localized map that includes all the fields to be discussed. The ages and stratigraphic positions of the various accumulations are shown in **Figure 1.4**.

To understand the decision-making process leading to the development of North Slope oil fields it is first necessary to establish a framework of reference. **Table 1.1** lists accumulations of oil and gas that have been discovered on the North Slope. Oil accumulations that are in the process of being evaluated by delineation drilling to determine the feasibility of economic production represent examples of one step in the decision-making process. Delineation drilling is the step by which resources in a previously discovered accumulation make the transition to reserves. Reserves are defined as resources demonstrated with reasonable certainty to be recoverable from known accumulations under existing economic and operating conditions. **Table 1.2** shows fields on the North Slope that have already made the transition to producing status.

An update of the status of the five currently producing North Slope oil fields (Prudhoe Bay, Kuparuk, Lisburne, Milne Point, and Endicott) and the two fields nearing productive status (Niakuk and Point McIntyre) is included in **Appendix A**. Production forecasts and economics are updated to 1/1/92

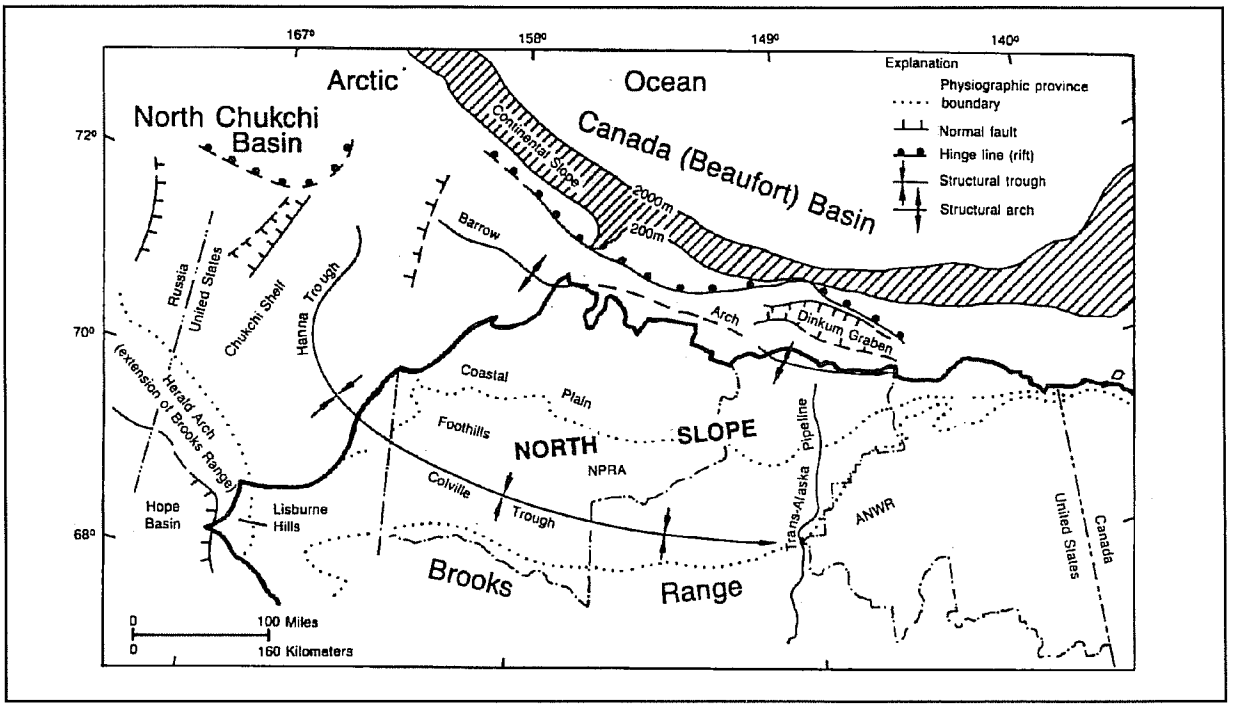

Figure 1.1. Generalized structural features and geological framework of onshore and offshore northern Alaska (after Bird 1991).

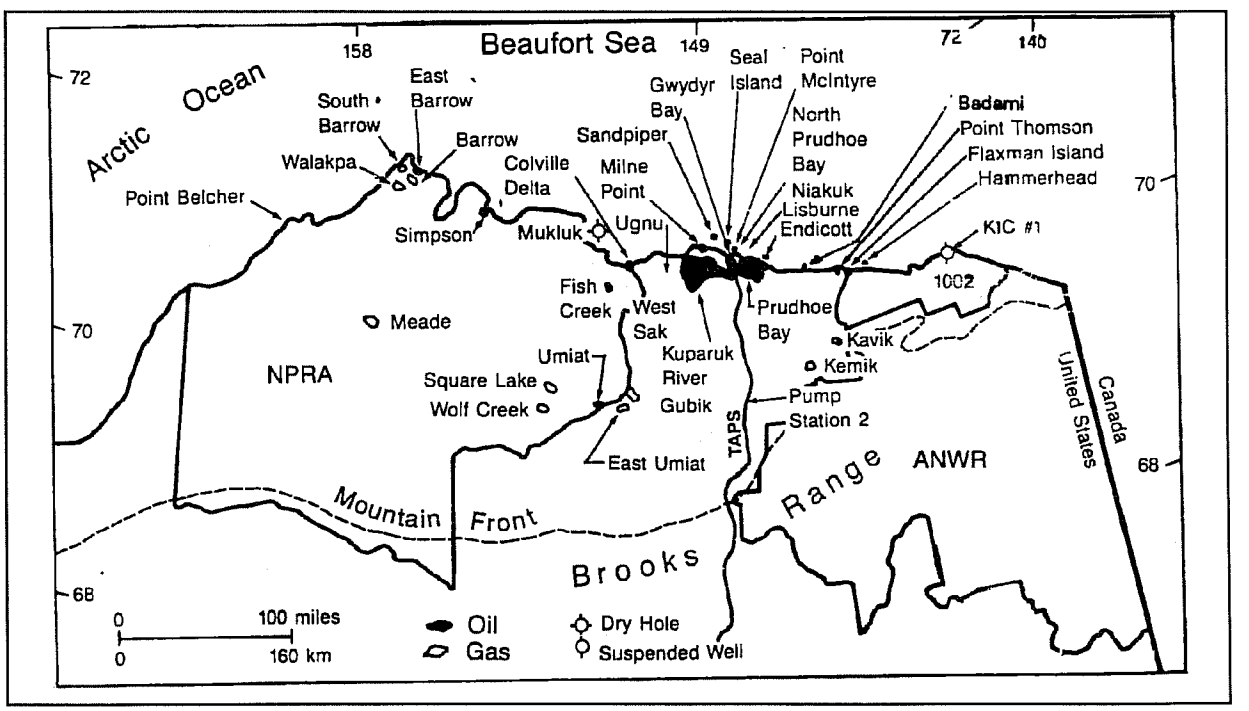

Figure 1.2. Known oil and gas accumulations, selected dry holes and suspended wells, and NPRA-ANWR boundaries, North Slope Alaska (DOE 1991, ADNR 1991a).

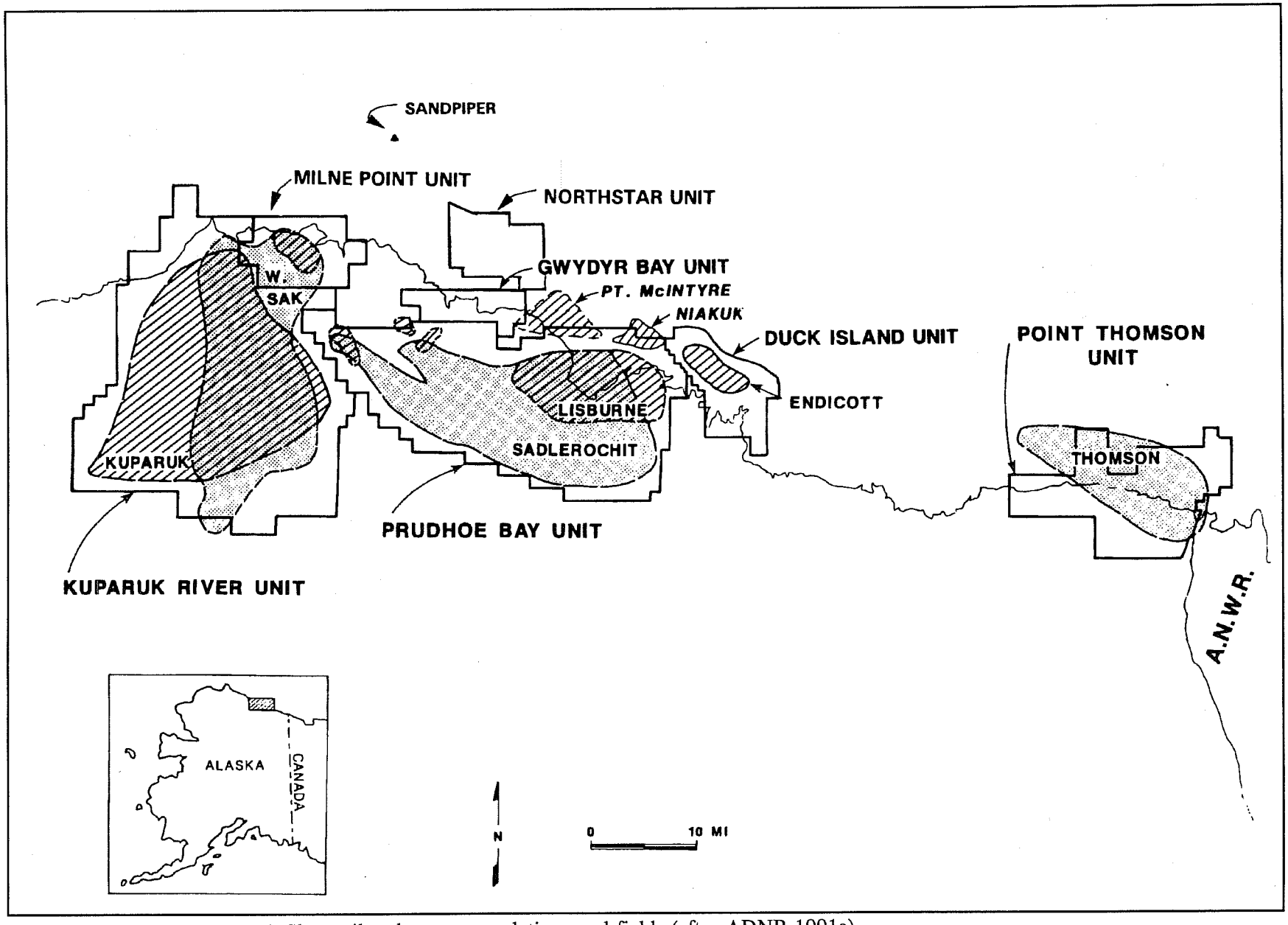

Figure 1.3 Location of North Slope oil and gas accumulations and fields (after ADNR 1991a).

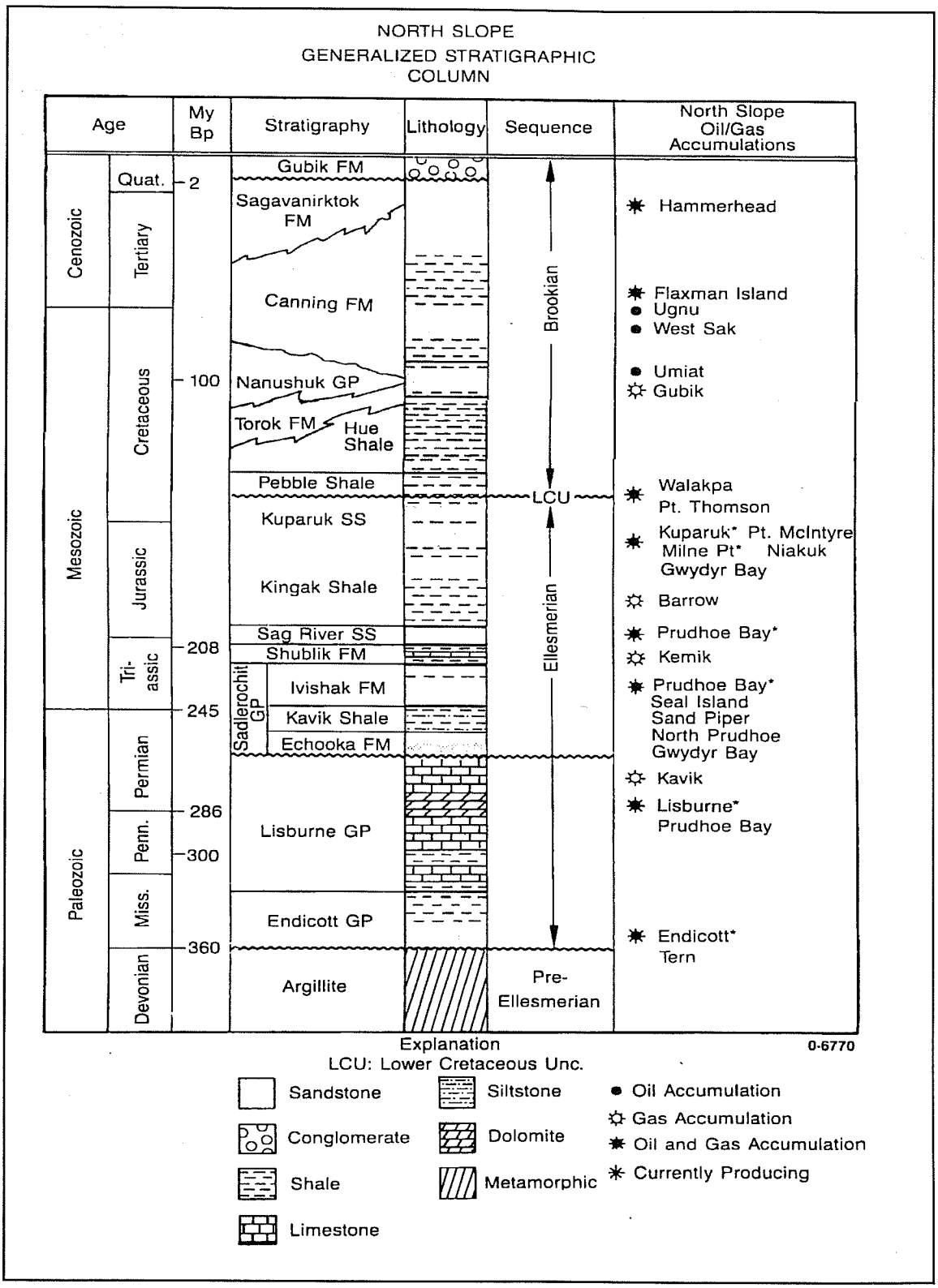

Figure 1.4. Generalized columnar section for the North Slope showing stratigraphic relations, age, lithology, and positions of known oil and gas accumulations (Bird 1991, Jamison 1980).

Table 1.1. North Slope undeveloped oil and gas accumulations as of January 1, 1992 (after Bird 1991).

Discovered Resources		
Location	**Year**	**Amount**
Umiat	1946	70 MMBO
Fish Creek	1949	Oil
Simpson	1950	12 MMBO
Meade	1950	20 BCF
Wolf Creek	1951	Gas
Gubik	1951	600 BCF
Square Lake	1952	58 BCF
E. Umiat	1963	4 BCF
Kavik	1969	Gas
West Sak	1969	0-1200 MMBO[a]
Ugnu	1969	Heavy Oil
Gwydyr Bay	1969	30-60 MMBO
No. Prudhoe	1970	75 (?) MMBO
Kemik	1972	Gas
Flaxman Island	1975	Oil
Point Thomson	1977	300 MMBO,[b] 5000 BCF
Walakpa	1980	Gas
Niakuk	1981	58 MMBO, 30 BCF
Tern Island	1982	Oil
Seal Island	1984	150 MMBO
Hammerhead	1985	Oil
Colville Delta	1985	Oil
Sandpiper	1986	Oil and Gas
Barrow	1988	Gas
Point McIntyre	1988	300 MMBO
Badami	1990	Oil

a. Heavy oil
b. Condensate

Table 1.2. North Slope oil and gas fields (as of January 1, 1992).[a]

Field Name	Discovery Date	Estimated Original Recoverable Reserves	Production Start-up Date	Cumulative Production	Remaining[b] Reserves/Resource	Estimated Current Total Recoverable Reserves[b,d]
Prudhoe Bay	4/68	28,500 BCF	10/69 (Tests)	1374 BCF[c]	25,313 BCF	26,687 BCF
		9590 MMBO	7/77 (Pipeline)	7663 MMB[d]	4539 MMB[d]	12,202 MMB[d]
Kuparuk River[e]	4/69	640 BCF	-----	209 BCF[c]	468 BCF	677 BCF
		1600 MMBO	12/81	836 MMBO	1054 MMBO	1890 MMBO
Prudhoe Bay (Lisburne Pool)	4/68	635 BCF	11/83 (Tests)	46 BCF[c]	870 BCF	916 BCF
		400 MMBO	3/85	82 MMB[d]	89 MMB[d]	171 MMB[d]
Milne Point[f]	10/69	0	5/85-1/87	(5.7 BCF[c])[h]	0	0 BCF
		60 MMBO	11/85	23 MMBO	97 MMBO	120 MMBO
Endicott[g]	3/78	731 BCF	10/87	38 BCF[c]	762 BCF	800 BCF
		375 MMBO	-----	165 MMB[d]	254 MMB	419 MMB[b,d]
S. Barrow	4/49	25.2 BCF	8/49	20.6 BCF	5.3 BCF	25.9 BCF
E. Barrow	5/74	12.4 BCF	12/83	6.2 BCF	6.4 BCF	12.6 BCF
Totals		30,544 BCF		1694 BCF[c]	27,425 BCF	29,119 BCF
		12,065 MMBO		8769 MMB[d]	6033 MMB[d]	14,802 MMB[d]

a. After Alaska Department of Natural Resources (ADNR 1991a, ADNR 1991b, AOGCC 1991)
b. A resource is changed to reserves when a field is developed for production and a transportation system is under development or in-place to move the product to market. The only gas volumes currently considered reserves are the volumes used as Fuel Gas for North Slope operations. Current gas reserves are not given in this table. ADNR gas resource volumes are given.
c. Production less reinjection.
d. Includes Natural Gas Liquids (NGL).
e. Excludes West Sak. West Sak cumulative production is 750 MBO and 326 MMCF.
f. Milne Point Includes Schrader Bluff.
g. Endicott includes Sag Delta North.
h. Milne Point gas production not included in the total as ADNR shows no reserves.

using actual 1990 and 1991 production. The resulting composite production curve for these seven fields is shown in **Figure 1.5**. As shown by this curve and discussed in **Appendix A**, the decline in production from the currently producing fields is dominated by the decline in the Prudhoe Bay field. The lack of productive capacity of the fields nearing development to arrest the decline in production from the North Slope confirms the need to immediately address the exploration and development of additional prospective areas on the North Slope.

An important factor that may affect not only the five NES fields, but also several of the currently producing fields is the minimum throughput capability of TAPS and the possible timeframe when that

level of throughput might be reached. A definitive minimum throughput volume has not been established. On January 6, 1992, in remarks to the Anchorage Chamber of Commerce, James B. Hermiller, President, Alyeska Pipeline Service Company, stated that the pipeline is likely to cease operating when output falls to 300 to 400 MBPD, depending on oil prices and other factors. Hemiller also said, "If the state imposed excessive financial burdens on the owners of the production going through the line or the pipeline system itself, the line will close sooner than later." (Platts 1992). As the actual minimum throughput capability of TAPS is unknown, a range of 400 to 200 MBPD is considered reasonable. These rates correspond to shutdown dates of 2008 and 2014 as shown on **Figure 1.5**. This points out the need to develop existing fields and discover and develop new fields on the North Slope of Alaska if the pipeline is to remain operational for a longer period of time.

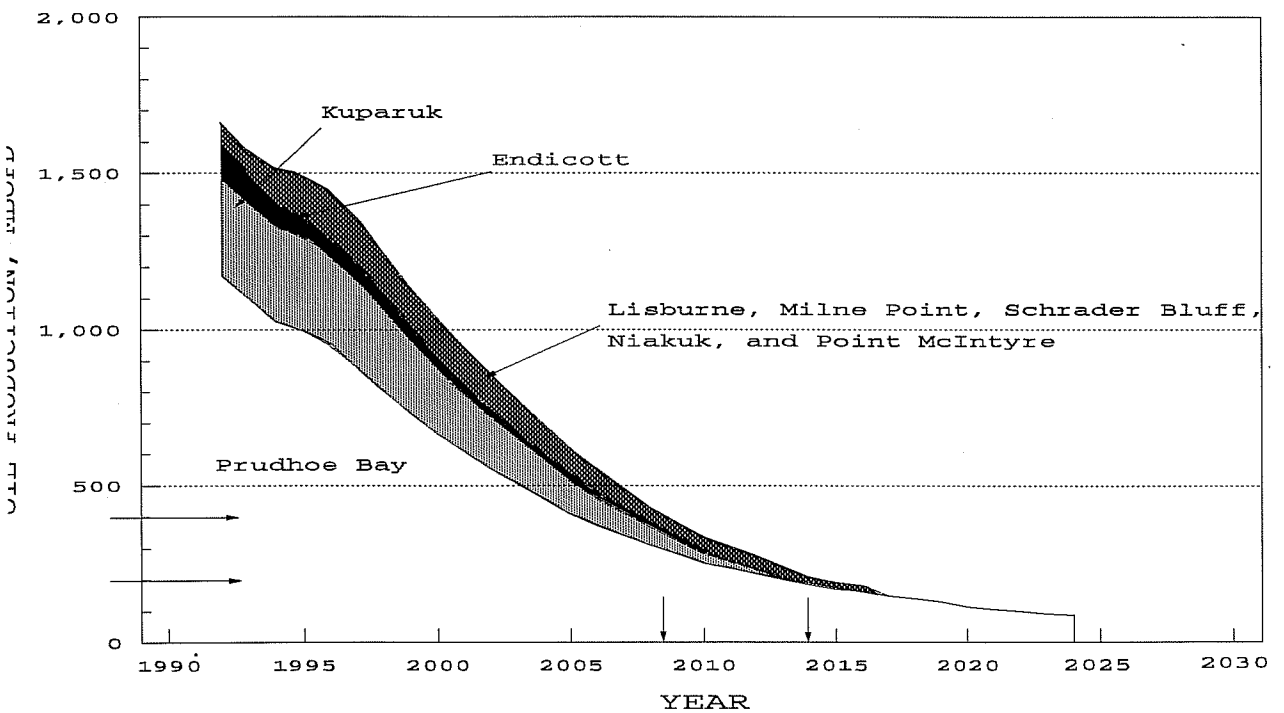

Figure 1.5. Composite production forecast for seven North Slope fields (arrows indicate the potential range of TAPS shutdown).

A more complete discussion of TAPS operations and throughput limitations can be found in Section 4 of the previous DOE publication (1991).

The five NES fields that are the primary subject of the Alaska North Slope NES Initiative are known resource accumulations that have not been developed because of technical or economic conditions

or both. These five fields are diverse in terms of geographic location, size of resources (potential reserves), areal extent, depth of productive horizon, type and quality of hydrocarbons, age and lithologic character of the rocks of the productive horizons, physiographic position, and other factors that ultimately must be addressed in the decision-making process.

1.2 Development Decision-Making Process

The development decision-making process with respect to developing new fields on the North Slope of Alaska is driven by economic considerations and acceptability of the environmental impacts. Although the development decision-making process may differ by company, the fundamental steps are (a) defining the scope, (b) designing environmentally acceptable development plans, (c) estimating uncertainty, (d) optimizing project design, and (e) finalizing the development decision.

The decision-making process used to evaluate the potential constraints to the development of the five NES fields takes into account the evolving business environment. This includes (a) increasing labor and materials costs, (b) increasing technological costs and risks associated with developing more marginal prospects in a harsh environment, (c) an increasing level of industry responsibility and costs in dealingwith environmental laws and regulations, (d) highly unstable oil prices, and (e) the continuing need for additional revenue by both federal and state sectors. To maximize stockholder value, the decision-making process of oil companies will generally include:

- An economic hurdle rate based on a company's internal financial status and expected return on investment.
- Exclusion of projects that do not meet the economic hurdle rate.
- Prioritization of projects based on individual project value with higher value projects being pursued first.
- Continued focus on cost reduction actions such as restructuring, reductions in force, internal cost control programs, and lowest-cost methods of operation.

1.2.1 Environmental and Regulatory

The key environmental issues and processes that have the greatest potential for impacting the development of the five NES fields include a) wetlands habitat (e.g., gravel roads and pads), b) impact on subsistence hunting and fishing, and c) permit and National Environmental Policy Act (NEPA)

documentation processes. In addition, issues related to waste disposal, gravel removal, and restoration will become increasingly important as fields mature and field shutdown becomes a reality.

Intertwined with these environmental issues are the regulatory requirements concerned with the protection of environmental resources on the North Slope. These include regulations pursuant to Sections 401 and 404 of the Clean Water Act, the Coastal Zone Management Act, and NEPA. The key agencies involved with permitting responsibilities related to the five NES fields include the Army Corps of Engineers (Corps), Mineral Management Service (MMS), Alaska Department of Natural Resources (ADNR), Alaska Department of Environmental Conservation (ADEC), and Alaska Division of Governmental Coordination (DGC). Several agencies play key roles in the review of permits. They include the U.S. Fish and Wildlife Service (FWS), National Marine Fisheries Service (NMFS), and North Slope Borough (NSB). In addition to their review role, the FWS, NMFS, and NSB have regulatory authority through other acts and regulations; e.g., Endangered Species Act, Marine Mammal Protection Act, Migratory Bird Act, and the NSB Land Management Regulations.

1.2.2 Technical

It is general practice by both government and industry to develop a minimum economic field size (MEFS) for a particular prospect, a set of prospects in a play, or plays within an area. (For a more detailed discussion of North Slope MEFS see DOE 1991, pp. 2-40, 2-44, 3-64, and 3-66.) This is particularly appropriate on the North Slope where harsh environment, remoteness of the area, high cost of exploration and drilling, and regulatory and environmental factors play such an important part in the decision-making process.

After an initial discovery well has been drilled, the two fundamental technical questions first asked are:

1. How big is it?
2. At what rate will it produce?

Obviously many other factors enter into the initial evaluation process almost immediately but these two factors are the most critical in determining whether or not a commercial discovery has been made. Data from the discovery well are used to revise the initially estimated MEFS to provide a framework in

which the discovery can be evaluated. If the potential resource is about equal to or greater than the revised MEFS, then the decision-making process proceeds to delineation of the resource, which involves drilling one or more delineation wells. If reservoir thickness, hydrocarbon quality, areal extent, and productivity are sufficient, then evaluation of development, production, and transportation economics can proceed.

1.2.3 Economic Evaluation

After a technical, environmental, and economics evaluation has been completed for a project, the decision whether to invest in a project is based on the expected project value compared to individual company requirements and to the estimated value of other investment opportunities that a company may have. As a general rule, lower valued projects are undertaken after higher valued investment opportunities are exhausted.

Multiple lease ownership is the general rule on the North Slope. The majority ownership is generally limited to major oil companies but large and small independents, native corporations, and individual groups of investors have ownership in some leases. Hence, the investment requirements will vary significantly among lease owners. Even among major companies, economic hurdle rates can vary significantly depending on many factors. For this reason, the decision-making process described herein is limited to individual project economics and no attempt has been made to evaluate the projects using integrated economics. This would involve additional evaluation including TAPS ownership, shipping, refining, and marketing activities for major integrated oil companies.

1.2.3.1 Project Value. The method most widely used to quantify the value of a project is the present worth (PW) of the project where PW is expressed in relation to a specific discount rate (Brealy 1988). The PW of a project is the cumulative after tax cash flow generated from the project's time sequenced revenues using the company's internally determined price forecast and expenses discounted to current year dollars; e.g., 1992 dollars for this study. The rate at which future cash flows are discounted represents the minimum return a project must earn. Therefore, a project that produces exactly a 10% return is defined as $PW_{10} = 0$, indicating that the investment earns a 10% return, after tax, measured in current year dollars.

An assessment of uncertainty needs to be included in economic evaluations. An assessment of economic uncertainty may include an evaluation of the probability and the consequence of changing variables such as oil price, recovery and rate, operating costs, capital investment, federal and state taxes, and discount rate. For this study, uncertainty is addressed through sensitivity analyses performed to test the effect of a change in the variables. More sophisticated methods such as Monte Carlo techniques are sometimes applied by industry and government agencies.

1.3 Alternate Investment Opportunities

As discussed in **Section 1.2**, the values of projects that meet company requirements are compared to the values of other investment opportunities a company may have available. Given the duty of publicly held companies to maximize value to the shareholders, projects that provide higher value will be selected before projects that also meet company requirements but provide lesser value. This section includes a discussion of the investment competition that the five NES fields face on the North Slope and throughout the world. The alternate investment opportunities considered in the comparison are limited to those that compare to North Slope opportunities, which require large amounts of capital. The comparisons are limited to upstream (exploration and production) projects. Only general observations of current conditions and future trends are used to generate an overview of the subject.

To relate to geographic arenas of opportunities, the North Slope, the Lower 48, and the rest of the world have been selected as separate frames of reference.

1.3.1 Other North Slope Opportunities

North Slope alternative investments have overshadowed the five NES fields for as long as two decades in some instances. It is instructive to note the times of discovery of these fields and also to compare them to the times of discovery and production for the five producing fields on the North Slope and the two with current development potential (see **Table 1.3**).

Comparisons with Kuparuk and Lisburne times of development are of particular significance. A 12-year delay ensued between discovery and production for Kuparuk, the second largest producing-rate field in the U.S. with estimated reserves of 1.9 BBO (ADNR 1991a). Although Kuparuk was situated adjacent to Prudhoe Bay and its infrastructure, which includes TAPS, the combination of high investment

Table 1.3. Discovery dates of North Slope fields/pools and actual or anticipated production startup dates.[a]

Field/Pool Name	Discovery Year	Production Year
Prudhoe Bay	1968	1977
Kuparuk River	1969	1981
Lisburne	1968	1986[b]
Milne Point	1969	1985
Schrader Bluff	1971	1991
Endicott	1978	1987
Niakuk	1985[c]	199(4)?
Point McIntyre	1989	199(3)?
West Sak	1971	?[d]
Northstar/Seal Island	1982/1985[e]	?
Gwydyr Bay	1969/1976[f]	?
Sandpiper Island	1986	?
Point Thomson	1975	?

a. After DOE 1991; ADNR 1991a and ADNR 1991b.
b. Limited production began in 1985
c. Minor Sag River discovery in 1977
d. Pilot waterflood test (1984-1986)
e. Shell (1982)/Amerada Hess (1985)
f. Hamilton Bros. Pt. Storkerson 1969/Mobil G. B. South 1976

levels, low oil prices, anticipated relatively low per-well producing rates, and the drain on available capital required for Prudhoe Bay (for working interest owners in both fields) resulted in the long delay. Lisburne production was deferred for 18 years under similar circumstances.

Although large by Lower 48 standards, only West Sak (up to 1,200 MMBO), Point Thomson (300 MMB condensate and 5 TCF gas), and Seal Island/Northstar (150 MMBO) qualify as big North Slope fields (**Table 1.1**). Gwydyr Bay (30 to 60 MMBO) and Sandpiper Island (no estimate)[a] are both small and poorly located geographically (**Table 1.1**). Given the experience from recently developed fields such as Milne Point and Lisburne, offshore prospects in the Beaufort and Chukchi Seas and possibly in the Arctic National Wildlife Refuge (ANWR) have held greater attraction for the industry. Enhanced recovery and exploration close to the big fields also were more attractive for upstream dollar investments.

a. An estimate of 87 MMBO is used for analysis (see **Section 3.3.4.3**).

Examples of these efforts include Point McIntyre, Niakuk, the Sag Delta North expansion of the Endicott field area, and continued enhanced oil recovery (EOR) projects in Prudhoe Bay and Kuparuk.

Failure in the U.S. Congress to include the opening of ANWR to exploration and development in the 1992 energy bill removed the most attractive North Slope investment alternative. Results of the last two offshore sales in the Beaufort and Chukchi Seas indicate industry has drastically scaled down its interest in those areas. In June 1991, Outer Continental Shelf (OCS) Sale 124 in the Beaufort had only $16.8 million in apparent high bids for 57 tracts. The previous sale in 1988 garnered $119 million for 218 tracts and even earlier sales had $1 to $2 billion in high bids (OGJ 1991a). The August 1991 OCS Sale 126 in the Chukchi Sea drew only $7.1 million in apparent high bids on 28 tracts. The previous Chukchi sale took in more than $478 million (OGJ 1991b). After the Beaufort sale, "Industry officials in Alaska cited increased resistance by native and environmental groups to drilling off the North Slope as a factor along with the region's high cost and technical hurdles."

In September 1991, ARCO Alaska, Inc. announced a staff reduction of 250 or about 10% of its work force (ANCH 1991). Other recent industry developments included Amoco and Shell closing their Anchorage offices in March 1992.

ARCO, contrary to the mostly negative events, plans to spend $600 MM in exploration in Alaska over the next 5 years.[a] ARCO stated that they expected to see 15 to 25 exploration wells drilled in Alaska in 1992 and that they would participate in 75 to 80% of those wells. These wells include delineation of the recent discovery at the Sunfish prospect in the Cook Inlet, drilling of the Cabot prospect in federal OCS offshore Barrow (drilled and abandoned), five wells in the Colville River delta west of the Kuparuk field, and the Kuvlum prospect in the Eastern Beaufort sea.

The discovery announced on October 14, 1992 by ARCO at the ARCO Kuvlum No. 1 in the eastern Beaufort Sea 60 miles east of Prudhoe Bay and 16 miles offshore, could significantly improve the prospects for continued interest in the area.

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a. J. Davis, ARCO Alaska, Inc., "Address to Alaska Legislature," February 4, 1992.

1.3.2 Lower 48 Opportunities

In contrast to the somewhat limited alternate investment opportunities on the North Slope, most of the major and large independent companies have numerous options for utilizing capital in the Lower 48 states. However, exploration opportunities for prospects of major size (100 MMBO or gas equivalent) are generally perceived to be extremely rare or virtually non-existent, especially onshore. Offshore prospects in the Gulf of Mexico continue to be leased, drilled, and developed, but all other areas of the Lower 48 federal OCS are under leasing moratoria imposed by Congress or Presidential deferral.

Many of the companies are involved in various forms of developing inferred reserves, which is also called reserve growth, by means of extension and infill drilling in existing fields, enhanced recovery projects, and new pool completions. Taken on a national scale this effort from 1977 through 1988 resulted in 82% of oil additions and 86% of gas additions to the reserve base (Fisher 1991). The total reserve growth (additions) for oil amounted to 24.3 BBO and for gas 172.5 TCF. These are impressive volumes, but were spread throughout the total industry and throughout the known oil and gas fields of the entire Lower 48 and Alaska. Nevertheless, the volumes of oil and gas that remain as targets for development from both the known and undiscovered resource base are large by any standards (Fisher 1991). **Figure 1.6** illustrates the relative proportions estimated for the total endowment of both oil and gas for the U.S., including Alaska. The economically recoverable components that can be converted to reserves under given price and technology conditions are the major question marks for all scenarios. The Energy Information Administration (EIA) current estimates are shown in **Table 1.4** for both the Lower 48 and Alaska. As a result of anticipated lower oil prices, a recent analyst's forecast reduced U.S. exploration and production spending by 25% in 1992 compared to an earlier forecast of an 11% decline (OGJ 1992c). Current activity in the Lower 48 and Alaska, as measured by drill rig tallies, reached the lowest level since 1986 (OGJ 1992a, OGJ 1992b).

1.3.3 Worldwide Opportunities

Many of the major oil companies and larger independents have been involved in international operations for decades. What has occurred in the last decade, and more specifically in the latter half of the 1980's, is the rapid growth in the share of capital spending for foreign ventures as compared to domestic projects. One recent study by Petroleum Finance Co. showed that 18 domestic companies had lowered their exploration and production share of spending in the U.S. from 60% in 1985 to 20% in

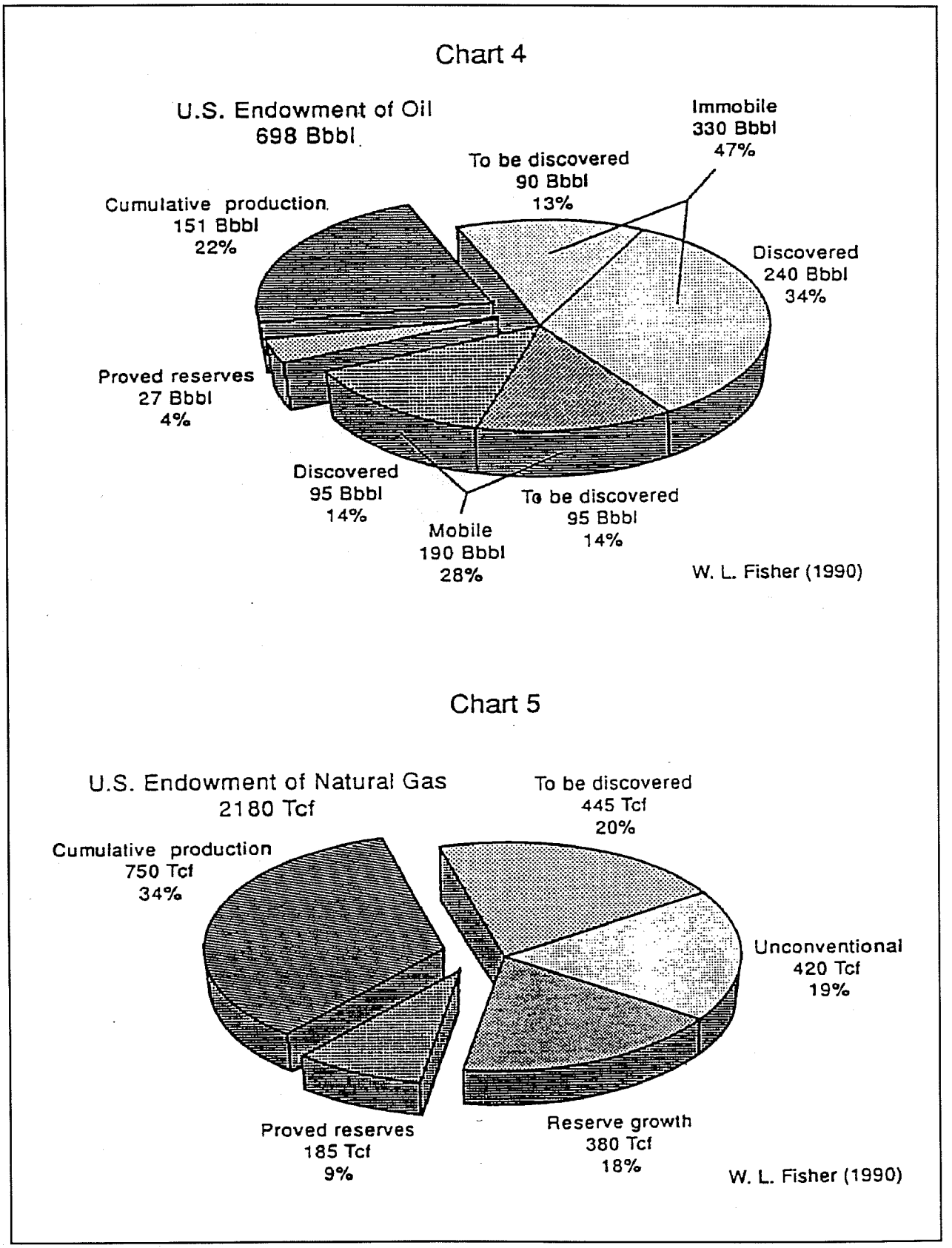

Figure 1.6. U.S. endowment of oil and gas (Fisher 1990).

Table 1.4. U.S. economically recoverable resource base (assumes access and advanced technology; after Fisher 1991).

Oil, BBO	Lower 48	Alaska	Total
1988 Ultimate	169.5	14.7	184.2
Cumulative Production	148.2	7.8	156.0
Proved Reserves	21.3	7.0	28.3
To-be-discovered	35.2		
Reserve Growth, Existing Fields	51.0	30.0[a]	126.0[b]
Bitumen and Heavy Oil	9.8		
Total	265.5	44.7	310.2
Natural Gas, TCF			
1988 Ultimate	922.6	14.1	936.7
Cumulative Production	754.8	5.0	759.8
Proved Reserves	167.8	9.0	176.8
To-be-discovered	326.5		
Reserve Growth, Existing Fields	265.0	107.3[a]	1,201.8[c]
Unconventionals	503.0		
Total	2,017.1	121.4	2,138.5
Natural Gas Liquids, BBO			
1988 Ultimate	27.7	1.7	29.4
Cumulative Production	22.6	1.3	23.9
Proved Reserves	5.1	0.4	5.5
To-be-discovered	8.8	1.3	10.1
Reserve growth, Existing Fields	14.6	1.4	16.0
Total	51.1	4.4	55.5

a. Remaining economic resources not differentiated for Alaska.
b. Includes to-be-discovered, reserve growth (Lower 48 and Alaska), bitumen and heavy oil.
c. Includes to-be-discovered, reserve growth (Lower 48 and Alaska), and unconventional gas.
Sources: DOE/EIA
1990: U.S. Oil and Gas Reserves
1990: Domestic Oil and Gas Recoverable Resource Base

1990. The total shift represented a $5 billion loss of domestic expenditures (ADN 1991a). During 1991, the shift increased and is expected to accelerate even more in 1992. In looking at the spending forecast of the international petroleum industry for 1992, Salomon Brother's yearly survey, covering 241 companies, shows a 1.3% increase for total worldwide exploration and production, from $53.1 billion

in 1991 to $53.7 billion in 1992. The only rise in budget for 1992 is outside North America where 80 companies have allocated $33.6 billion, a 9.1% increase (OGJ 1992d).

Numerous upstream opportunities have opened up for private companies in countries where they once were not welcome. Many countries with production potential need investment capital or technical assistance and thus have offered prospects to international operators on improved participation terms (OGJ 1992e). "Because countries known to have large oil reserves, such as Saudi Arabia, Iran, Iraq, Venezuela, and Kuwait, are generally closed to U.S. participation in oil production or marketing, the quest for overseas resources has touched off oil searches in several countries not known as oil powers, including Congo, Bolivia, Vietnam, and Yemen. These are areas of high-cost exploration with high risk of failure, analysts said, but the big oil companies do it because the potential returns are vast if they find an 'elephant' as major oil discoveries are called" (ADN 1991a). This is the same philosophy once applicable in the U.S., especially during the last 2 or 3 decades to the federal OCS waters and to Alaska.

1.3.4 Conclusions

Taken in overall context, it appears that alternative upstream investment options on the North Slope, onshore or offshore, are not real deterrent factors in competition with the five NES Fields. If these fields prove to be economical, the true hazard lies in the competing opportunities in the lower cost, lower risk, and higher potential return areas outside of Alaska. Although most of the decline in investment and overall activity in the U.S. can be attributed to low oil and gas prices, other factors also contribute. For example, the American Petroleum Institute, representing major oil companies, charged that limited access to public lands and impediments posed by U.S. tax laws have caused drilling and output to fall and have soured the investment climate (ADN 1992a). If the ARCO Kuvlum discovery proves to be large enough to support development of a pipeline to TAPS, it could improve the likelihood of development of Point Thomson, Badami, Hammerhead, and other areas along the pipeline corridor.

1.4. References

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2. ENVIRONMENTAL AND REGULATORY ISSUES

2.1 Overview

The purpose of this section is to describe those environmental issues and regulatory processes that are pertinent to the development of oil and gas resources on the North Slope of Alaska. A list of the agencies involved in the regulatory process at the federal, state, and local levels of government is provided for the five-National Energy Strategy (NES) Fields. In addition, Section 2.2 discusses the respective role of each agency within the permitting process. Section 2.3 summarizes important environmental regulation applicable to the development of North Slope petroleum reserves. Section 2.4 outlines the permit processes in place on the North Slope. Section 2.5 presents various types of past mitigative measures applicable to North Slope petroleum exploration and development activities. Finally, Section 2.6 discusses sensitive environmental issues and evaluates the potential effects that the regulatory process may have on the development of the five NES fields.

Each aspect of oil and gas exploration and development (including transportation) is subject to many laws, regulations, policies, and ordinances of government. It is not the purpose of this discussion to provide an exhaustive description of all federal, state, and local laws that may be applicable to such activities. This report describes those environmental issues and associated regulations that have the **greatest potential** for seriously affecting the economic viability of the five NES fields. The key issues that provide the focus for this discussion include (a) an adherence to the National Environmental Policy Act (NEPA) documentation process, (b) the development of wetlands (e.g., the construction of gravel roads and pads), and (c) the impact of subsistence hunting and fishing rights by indigenous peoples (e.g., marine mammal protection, monitoring obligations, facility modifications). In addition, waste disposal, gravel removal, and restoration issues will become increasingly important as fields mature and field closing becomes a reality. This is especially true if development bears the cost of past and future waste disposal, gravel removal, and restoration.

Environmental regulations governing industrial activities on the North Slope stem largely from the expected ecological effects of the activities. The environmental issues described in this section are subject to several regulatory requirements concerned with the environmental protection of resources on

the North Slope. Environmental issues of concern on the North Slope of Alaska include construction of causeways, development of wetlands, disturbance of flora and fauna, etc. Regulations include federal, state, and local requirements pursuant to Sections 401 and 404 of the Clean Water Act (CWA), the Coastal Zone Management Act (CZMA), Clean Air Act (CAA), Oil Pollution Act, and the NEPA. These Federal Acts and their associated regulations are discussed later in this report. Sometimes wetland regulations have been subject to change. It is not the purpose of this document to attempt to predict future changes in government regulations pertinent to oil development on the North Slope. In certain cases, however, we have attempted to show how a particular change might influence development.

It is also not the goal of this document to predict or describe specific technologies or methods that will be applied to the five NES fields. For example, this report assumes that waste disposal operations will be consistent with requirements set forth in specific permits issued for the project. It is unrealistic at this time to predict what these requirements will be and how they will be met.

2.2 Regulatory, Land Management and Resource Agencies and Local Governments

The regulatory framework associated with environmental compliance of oilfield leasing and operation activities is extremely complex, and involves many agencies at the federal, state, and local levels of government. Some agencies have regulatory authority over industrial development by issuing permits. These include the U.S. Army Corps of Engineers (Corps), Mineral Management Service (MMS), Bureau of Land Management (BLM), Environmental Protection Agency (EPA), Alaska Department of Environmental Conservation (ADEC), Alaska Department of Fish and Game, (ADFG) and the Alaska Department of Natural Resources (ADNR). Other agencies may be involved in the review of the permit applications providing recommendations regarding specific aspects of the permit, but do not issue permits. These agencies include the U.S. Fish and Wildlife Service (FWS) and National Marine Fishery Service (NMFS). Some agencies, such as the EPA may fall into both categories depending on which permit is being sought. This section gives a brief description of how the different agencies are involved with the permitting process.

Most of the currently producing fields on the North Slope are located on state-owned lands, and are therefore administered primarily by agencies of the government of Alaska. These include the operating fields at Prudhoe Bay Unit, Kuparuk River Unit, Milne Point Unit, and Endicott (Duck Island Unit). This also includes Niakuk and Point McIntrye, which will soon be producing oil and gas. Other known fields are on federally-administered lands for which various agencies within the federal government have the administrative lead. For example, the BLM of the U.S. Department of Interior (DOI) oversees those fields in the National Petroleum Reserve Alaska. The location of any particular development area relative to the coastline also helps determine which agencies are involved in the permitting process for a given field. Agency involvement depends on whether the development will occur onshore, offshore (outside the three-mile limit), nearshore (within the three-mile limit), or on "navigable waters." Navigable waters may include nearshore and onshore areas, if, for example, the area includes wetlands.

ADNR has regulatory responsibility for all onshore and nearshore (< 3 mi) oil and gas leases and operations on state lands or waters. The DOI through the MMS has responsibility for offshore (> 3 mi) oil and gas lease developments. Through Section 404 of the CWA, the Corps and EPA regulate the discharge of dredged or fill material into waters of the United States, including wetlands. The five NES fields and the agencies responsible for most of the leasing, exploratory and development permit process and NEPA documentation are listed in **Table 2-1**.

2.2.1 Federal Government Agencies

Federal agencies involved in the permitting process on the North Slope include the DOI through BLM, MMS, and FWS; the Department of Defense through the Corps; the Department of Commerce through the NMFS; the Department of Transportation (DOT); U.S. Department of Agriculture (USDA); and the EPA. In this report we discuss those permits and regulations considered to potentially have a significant impact on the economic viability of development of the five NES fields. The responsibilities of the primary agencies involved in permitting the oil and gas development on the North Slope are briefly summarized below.

2.2.1.1 Army Corps of Engineers (Corps). Regulatory control of the navigable U. S. waters has been the responsibility of the Corps since enactment of the Rivers and Harbors Act in 1899. Since

2.2.1.3 Fish and Wildlife Service (FWS) and National Marine Fisheries Service (NMFS). Under the Fish and Wildlife Coordination Act (FWCA),[a] the FWS and NMFS have an advisory role in the permit process. These agencies comment on major actions that affect federal lands or wildlife and wildlife resources[b] managed by the FWS and NMFS. Exceptions to this advisory role occur where the proposed action affects migratory birds (Migratory Bird Act), marine mammals (Marine Mammal Protection Act [MMPA]), or endangered species (Endangered Species Act [ESA]) (see **Section 2.3**). In Alaska the FWS and NMFS generally comment on actions occurring in wetlands through the Corps' 404 permit process. The FWS is primarily interested in those actions that occur onshore, while the NMFS is concerned with similar actions offshore.

2.2.1.4 Mineral Management Service (MMS). The Outer Continental Shelf Act of 1953 (and amendments) guide the leasing and management of oil and gas operations on the Outer Continental Shelf (OCS). While other federal agencies have some responsibilities for the OCS, the MMS carries out most of the provisions of this act. This includes issuing leases for exploring and developing oil and gas resources on federal lands of the continental shelf. Industry explores, develops, and produces oil and gas on OCS lands that are leased from the federal government. The leasable area currently involves the submerged land generally three geographic miles from a state's coast to a line about 200 miles offshore (DOI 1986).

The MMS is also responsible for the regulation and monitoring of oil and gas activities to ensure the safe, efficient, and environmentally sound development of the Nation's OCS hydrocarbon resources. The Oil Pollution Act of 1990 delegates, to the MMS, responsibility for the prevention of oil spills offshore.

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a. Fish and Wildlife Coordination Act of 1934, amended 1946, 1958, 1977 (U.S.Code 661-667e).

b. The terms "wildlife" and "wildlife resources" include birds, fishes, mammals, and all other classes of wild animals and all types of aquatic and land vegetation upon which wildlife is dependent.

2.2.2 State and Local Governments

The Division of Governmental Coordination (DGC) coordinates the involvement of state and local governments in the oil and gas permit process. The DGC acts as a clearinghouse for comments from all state agencies and local governments. Roles of the state and local governments with primary responsibilities for regulating oil and gas development are discussed in the following sections.

2.2.2.1 Division of Governmental Coordination (DGC). The DGC implements the Alaska Coastal Management Program (CMP), including responding to federal consistency certifications required by Section 307 of the CZMA, and rendering conclusive consistent determinations for projects requiring two or more state permits. The Alaska Coastal Management Act, passed in 1977 (Alaska Statues [AS] 46.40), coordinates the activities of different state agencies and local governments in relation to activities on the coastal plains. Considering information from different state agencies, the DGC, coordinates the findings of various state agencies. The goal of this coordinated effort is to develop a unified state position on an action.

2.2.2.2 Alaska Department of Natural Resources (ADNR). ADNR has broad responsibilities for managing natural resources on state lands, including oil and gas, minerals, forests, water, and agriculture. ADNR is the lead state agency on lease agreements and is responsible for issuing and enforcing the leases. Other state agencies do not become officially involved in the leasing process until an action such as an exploration or a development plan is proposed. The ADNR has three separate divisions involved in the permit process with responsibilities divided as follows:

Division of Oil and Gas - This division of ADNR is responsible for the management and regulation of oil and gas resources for the state. This includes the development and implementation of a 5-year lease sale program, which is updated annually. In addition, ADNR approves plans for exploration and development for all activities on state oil and gas leases.

Division of Land and Division of Water - These divisions of ADNR are responsible for the regulation of miscellaneous land use activities on state lands. In terms of oil exploration and development, this includes issuance of land-use permits, temporary water-use permits, water-rights permits, pipeline right-of-way leases, and oil and gas activities not covered under the oil and gas lease.

These divisions are also responsible for reviewing and commenting on other state permit applications with respect to land and water use considerations.

2.2.2.3 Alaska Department of Environmental Conservation (ADEC). The ADEC is responsible for air quality control, new source performance testing, black smoke reporting, ambient air monitoring, and Prevention of Significant Deterioration permitting within the state of Alaska. Responsibilities of the ADEC also include implementation of solid waste management programs, regulation of the disposal of oily waste, drill mud and cuttings, and other nonhazardous oilfield wastes, and maintenance of water quality standards including drinking water monitoring. However, some of these wastes are not exempt from regulation as hazardous wastes (RCRA Subtitle C, see **Section 2.2.1.2**) and are therefore the responsibility of the EPA. The state of Alaska reviews federal permits, including the NPDES and 404, to determine compliance with state water quality standards. If standards are met, the ADEC issues a water quality certification. ADEC manages wastewater disposal regulations covering all discharges to state lands and waters not already covered by federal NPDES permit. ADEC reviews NPDES permit applications for water and waste water certification. Also, ADEC, examines and cleans up sites contaminated by oil or hazardous substances and requires contingency plans for many types of facilities. It also administers the drinking water program for protection of community water systems under the SDWA, and is responsible for pesticide control.

2.2.2.4 Alaska Department of Fish and Game (ADFG). ADFG is responsible for the management of fish and game resources within the state. Regulatory responsibilities of ADFG include management of commercial fisheries, hunting, and habitat protection. Regulatory authority on the North Slope is provided to ADFG by the

- Fish Passage Act
- Anadromous Fish Act
- Refuges, Sanctuaries, and Critical Habitat
- Alaska CZMP
- FWCA.

The ADFG, empowered by the Fish Passage and Anadromous Fish Acts, issue permits for activities that include construction and use of equipment in anadromous fish streams.

2.2.2.5 Alaska Oil and Gas Conservation Commission (AOGCC). The AOGCC has authority to administer the Class II portion of the Underground Injection Control program that covers enhanced oil recovery wells and Class II disposal wells handling produced water and wastewater associated with oil and gas production. This includes industrial wastes that are exempt from RCRA.

2.2.2.6 Local Government. The North Slope Borough (NSB) is also involved in regulating oil exploration and development activities on the North Slope. Local regulatory involvement stems from several sections from the NSB Code of Ordinances. Some more important sections from the code include Consistency with Coastal Management Plan (Section 19.10.050), Conservation (Section 19.40.070), Offshore Development Policies (Section 19.70.040), and Coastal Management and Area Wide Policies (Section 19.70.050) (NSB 1990).

The CMP is a component of the NSB Comprehensive Plan, and the policies contained in the CMP are included as part of these regulations and govern development in the coastal area. Issuance of any permit or approval within the coastal area shall contain a recommendation of determination addressing consistency of the proposed development or use with the policies of the NSB CMP. A recommendation of determination includes justification of any conditions required to make the proposed development or use consistent with the policies of the NSB CMP (NSB 1990). The NSB makes recommendations to the DGC on the "consistency" of permit applications with its programs.

The NSB has developed policies that identify general and specific courses of action to achieve region-wide comprehensive plan goals and the implementation of the CMP. These actions are guides for development activities anywhere in the NSB. These policies contain the approval criteria that are the standards used to evaluate a proposed activity for consistency to the CMP (NSB 1990).

In addition, the NSB is divided into several *Zoning Districts*, each of which provides guidelines on the types of development activities allowed within the district. For instance, the Conservation District encompasses the undeveloped areas of the NSB. The Conservation District conserves the natural ecosystem for the various plants and animals upon which NSB residents depend for subsistence. Subject to this general intent, it can adapt resource exploration and development on a limited scale, but major resource development projects must apply for rezoning to the Resource Development District (NSB 1990).

The NSB provides policies on the exploration and development in offshore areas to guide the approval of uses in the portion of the Beaufort Sea within the NSB boundary. The purpose of these policies is to minimize impact to subsistence activities.

2.3 Acts, Regulations, and Permits

NEPA requires that all federal activity proposing legislation and other major actions significantly affecting the quality of the human environment consult with other agencies having jurisdiction by law or special expertise over such environmental considerations. Section 102(2)(C) of NEPA requires a detailed statement for every major federal action significantly affecting the quality of the human environment. This detailed statement includes a discussion of

- the environmental impacts of the proposed activity
- the adverse environmental effects that cannot be avoided
- alternatives to the proposed activity
- relationship between short-term uses and long-term productivity
- any irreversible and irretrievable commitments of resources.

Pursuant to Section 102(2)(C) of NEPA and Section 309 of the CAA, the EPA has the responsibility to review and comment upon the federal activities affecting the quality of the environment. Regulation and permitting of oil and gas exploration are usually considered a major action, and are therefore subject to the NEPA.

Besides NEPA, many environmental regulations and permits affect the exploration and development of oil and gas on the North Slope of Alaska. Major legislation and associated permit regulations that have the potential for affecting the economic viability of development of new fields on the North Slopes are shown in **Table 2-2**. These include the coastal zone consistency determination (DGC), 401 water quality certification (ADEC), 404 permit (Corps), MMPA and ESA (FWS, NMFS), and Title 16 permits (ADFG). Other permits, not included in the Table, are not considered to have the potential for significantly affecting the course of development. Obtaining these "other" permits is considered straight forward and any disagreements on specific action or technologies to be applied may be resolved easily. Costs associated with obtaining all permits are considered as part of operating costs (see **Section 3.4.5**).

Table 2-2. Federal Acts and state statues, agency responsible, permits, and purpose.

Legal Authority (Act or Statute)	Agency	Permit / Consistency Review	Purpose / Action
National Environmental Policy Act (NEPA)	Lead responsibility depends on action or location of action. May be Corps, MMS, FWS, or BLM. Co-lead or Cooperating Agency status may be designated when multiple federal actions are involved.	None	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 contained in an Environmental Assessment (EA) or EIS. An EIS is not required if the results of an EA is a "Findings of No Significant Impact (FONSI)."
Alaska National Interest Lands Conservation Act (ANILCA)	DOI	None	Designated conservation units for Federally owned land in Alaska. Prohibits oil and gas leasing and other development unless authorized by an Act of Congress ANILCA is the principal mechanism for regulating subsistence activities in Alaska.
Clean Air Act (CAA)	EPA, ADEC	NESHAP; PSD	Requires pollutant source controls to comply with the "best available control technology (BACT). Establishes National Emission Standards for Hazardous Air Pollutants (NESHAP). Required EPA to review and comment upon the environmental impacts of any proposal and refer environmentally unsatisfactory matters to the Council on Environmental Quality
Clean Water Act (CWA)			
Water Quality Certification of Federal Permit (Section 401)	ADEC	401 Water Quality Certification	Requires applicant to apply for a permit to obtain a certification from the state.
National Pollutant Discharge Elimination System (NPDES) (Section 402)	EPA	NPDES Permits	Authorizes NPDES permits for point-source discharges to waters of the United States.
Discharges of Dredge and Fill Materials into U. S. Waters (Section 404)	Corps & EPA	404 Permit	Requires that discharges of dredged or fill material into waters of the U.S. will not have unacceptable adverse environmental impacts.
Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)	EPA	None	Requires that certain releases of hazardous substances from a facility or vessel be reported to the National Response Center.

Table 2-2. Continued.

Legal Authority (Act or Statue)	Agency	Permit / Consistency Review	Purpose / Action
Endangered Species Act (ESA)	FWS & NMFS	Action agency prepares a Biological Assessment if endangered or threatened species present (this is not a permit)	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 the FWS or the NMFS. FWS or NMFS prepare a Biological Opinion
Coastal Zone Management Act (CZMA)	DGC, NSB	Coastal Zone Management Consistency Review	The CZMA provides a cooperative federal/state mechanism to protect the coastal zone and resolve conflicts among competing uses. Section 307 of the CZMA 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 the state CZMP.
Fish and Wildlife Coordination Act (FWCA)	FWS, NMFS	None	Requires other federal agencies to consult with the FWS, the NMFS, and state Fish & Wildlife agencies when any stream or other water body is to be modified. This act provides the opportunity for resource agencies to comment on permit applications, often resulting in permit stipulations.
Marine Mammal Protection Act (MMPA)	FWS & NMFS	*Incidental Take* permit requested by operator if actions are going to or have harass(ed) a marine mammal; *Scientific Research* permit required to conduct research on marine mammals.	Certain species and population stocks of marine mammals are, or may be, in danger of extinction or depletion as a result of man's activities. Therefore, the MMPA prohibits the "taking" of sea mammals, with certain exceptions.
Outer Continental Shelf Lands Act (OCSLA)	MMS	Exploration, Development, & Production Plans, Geological exploration permits, Application for Permit to Drill	The OCSLA requires the leasing be tempered to ensure protection of human, marine, and coastal environments.

Table 2-2. Continued.

Legal Authority (Act or Statute)	Agency	Permit / Consistency Review	Purpose / Action
Resource Conservation and Recovery Act (RCRA)	EPA-- Hazardous Waste Management Program ADEC-- Solid Waste Management Program	Permitting program requirement for Treatment / Storage / Disposal (TSD) facilities.	EPA provides a "cradle to grave" management of hazardous wastes. ADEC is responsible for the implementation of solid waste management programs.
River and Harbors Act (RHA)	Corps	Section 9 permit & Section 10 permit	Section 9 refers also to bridges and causeways. Section 10 prohibits the unauthorized construction or alteration of any navigable water of the U.S.
Alaska State Coastal Zone Management Act	DGC	Consistency Review	Projects are reviewed to ensure that they are consistent with the standards of the Alaska CMP prior to issuance of any state or federal permits.
Title 16, Alaska Statutes	ADFG	Title 16 permit (Fish Passage)	Requires that an applicant obtain a permit prior to installation of a structure that may interfere with fish passage
		Title 16 permit (Anadromous Fish)	Requires that an applicant obtain a permit prior to conducting work within an anadromous fish stream.
Lease Sale Agreements	ADNR	Lease Sale Agreement between industry and state of Alaska	Requires the Director of the Division of Oil & Gas, ADNR to determine whether a lease sale serves the best interest of the state. Also, state statutes require a determination that the sale is consistent with the Alaska CMP, including policies of the NSB CZMP.

An important role of federal, state, and local agencies or governments is to review and comment on the various permits. The FWCA requires that comments and suggestions from FWS, NMFS, and state fish and wildlife agencies (e.g., ADFG) be considered in the permit process. In addition, other federal or state agencies and local governments provide information through the various permit processes. For example, the EPA, BLM, and DGC provide information during the Section 404 permit process through a review. This occurs before a decision on whether to issue a permit (see **Section 2.4.2.3**).

2.4 Lease Sale And Regulatory Permit Process

A major purpose of the permit processes is to protect human and environmental health, and to develop permit stipulations that will mitigate negative effects. The framework for these evaluations is through the NEPA processes (e.g., environmental assessments [EA] and EISs). Through these assessments, federal, state and local governments, special interest groups, developers, and the public have an opportunity to comment on the proposed project, alternatives, and mitigative measures. The following discussion reviews three regulatory processes that result in permitting decisions on oil and gas exploration and development activities on the North Slope. These processes are

- State Lease Sale Approval (state land nearshore, <3 miles and onshore)
- Federal Lease Sale Approval (federal land offshore, >3 miles and federal land onshore)
- Corps Section 404 Permitting.

The MMS and ADNR conduct most lease sales for oil and gas exploration and development on the North Slope (including offshore on the OCS). Permitting processes associated with the lease sales are generally conducted by MMS (e.g., Permit to Drill), or the Corps (e.g., Section 404). The state's participation is through the consistency review of the CZMP and Section 401 of the CWA. Also, the NSB uses administrative approval and permits to regulate activities within the borough. Other federal agencies may also conduct lease sales on federal lands (e.g., BLM in the National Petroleum Reserve Alaska and Arctic National Wildlife Refuge). The Corps and EPA do not conduct lease sales, but may become involved in all the processes described below through the CWA and the NEPA.

2.4.1 State Leasing / Permit Process

ADNR has the authority to establish Lease Sale Agreements with industry on state lands, which includes the nearshore area (less than 3 miles offshore). This process begins when industry submits a nomination or ADNR solicits comments on a proposed lease sale (see **Figure 2-1**). ADNR prepares maps of the lease sale area before soliciting comments from interested parties, including federal, state, and local governments or agencies and the public. Comments must be submitted within 30 days. Following the comment period, ADNR prepares a 5-year Leasing Program for the sale area and conducts a Technical Review (e.g., land status review, analysis of geophysical and geological data). At least six months before the sale, ADNR releases the *Preliminary Findings and Proposed Coastal Zone Determination*. Following

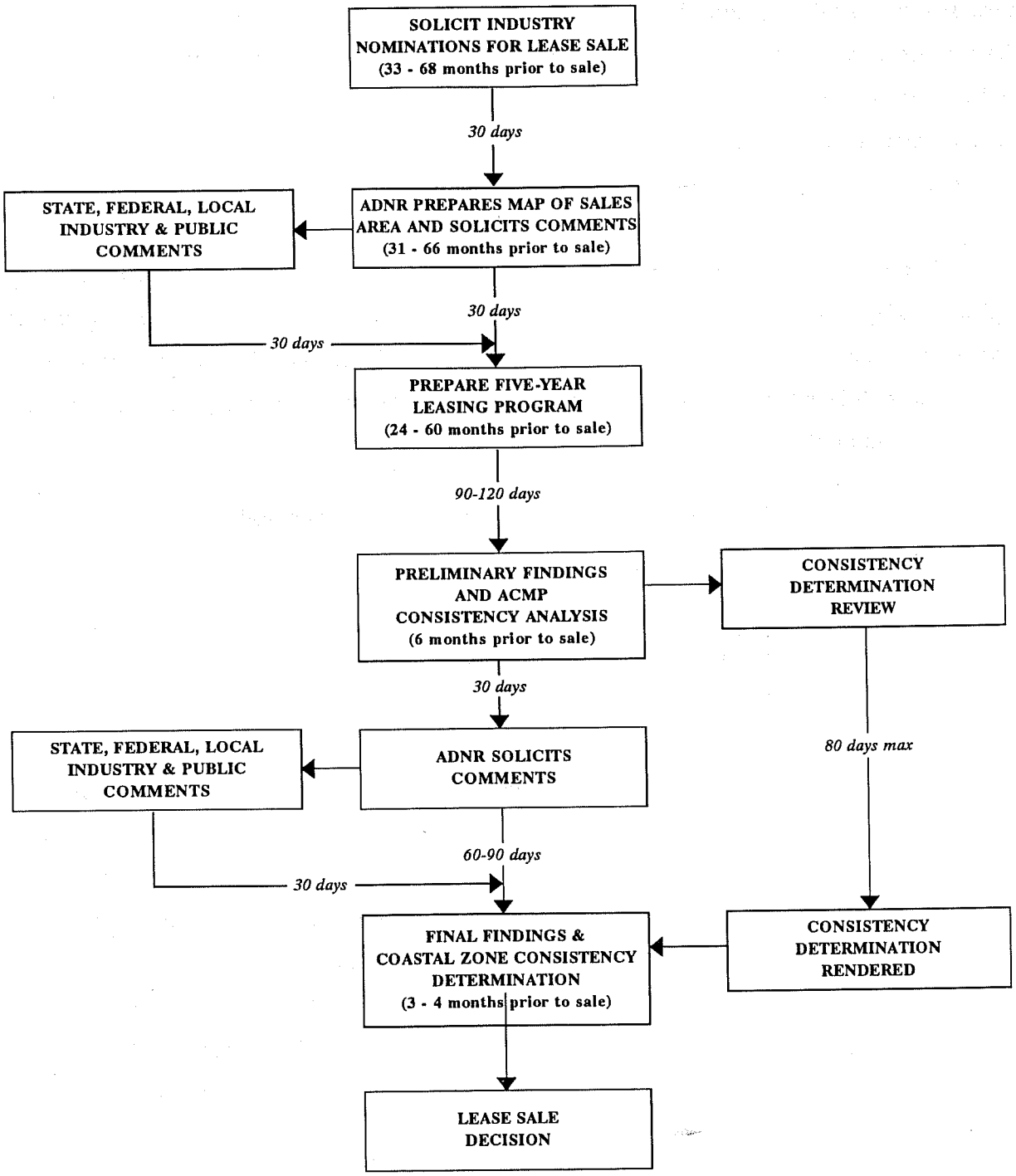

Figure 2-1. ADNR lease sale agreement process.

another 30-day public comment period, ADNR releases the *Final Findings and Coastal Zone Management Consistency Determination* three months before the sale. A lease sale does not authorize exploration or development activity. Prior to any actions on land leases, the appropriate permits must be submitted and authorization granted. If the proposed activity will not result in significant impacts, then ADNR can grant or authorize the permit. However, if the action causes significant impacts or involves other state agencies, then DGC coordinates the permit process.

The DGC acts as the coordinating agency for all state agencies and provides the mechanism by which a single response (or viewpoint) from the state may be issued. DGC coordinates the Coastal Zone Consistency Determination and 401 Certification processes (see **Figure 2-2**). DGC automatically becomes involved when federal lands are included in part of the proposed action. Project applications are reviewed and categorized by DGC as follows

Category A:	Those proposed actions for which the design has already been through the permit process and approved (e.g., navigation beacon).
Category B:	Those proposed actions for which the design has been through the permit process, is usually consistent, but may include site-specific stipulations.
Category C:	Those proposed actions that require a consistency review.

If a project needs a consistency review, the DGC is responsible for coordinating the state's response. The DGC reviews all comments from other involved state agencies and local governments. If a state agency does not agree with the determination made by DGC, an elevation process is in place within the state government to allow further consideration and dispute resolution. The Corps does not issue a Section 404 permit without the state's consistency determination.

Following receipt of comments and, if necessary, resolution of the dispute, the DGC renders a decision on coastal zone management consistency. The conclusive Consistency Determination and the 401 Certification decisions (made by ADEC) are forwarded, within 30 to 50 days, to the appropriate permitting agency (e.g., Corps, ADNR, MMS), if the review process has not been suspended for informational needs.

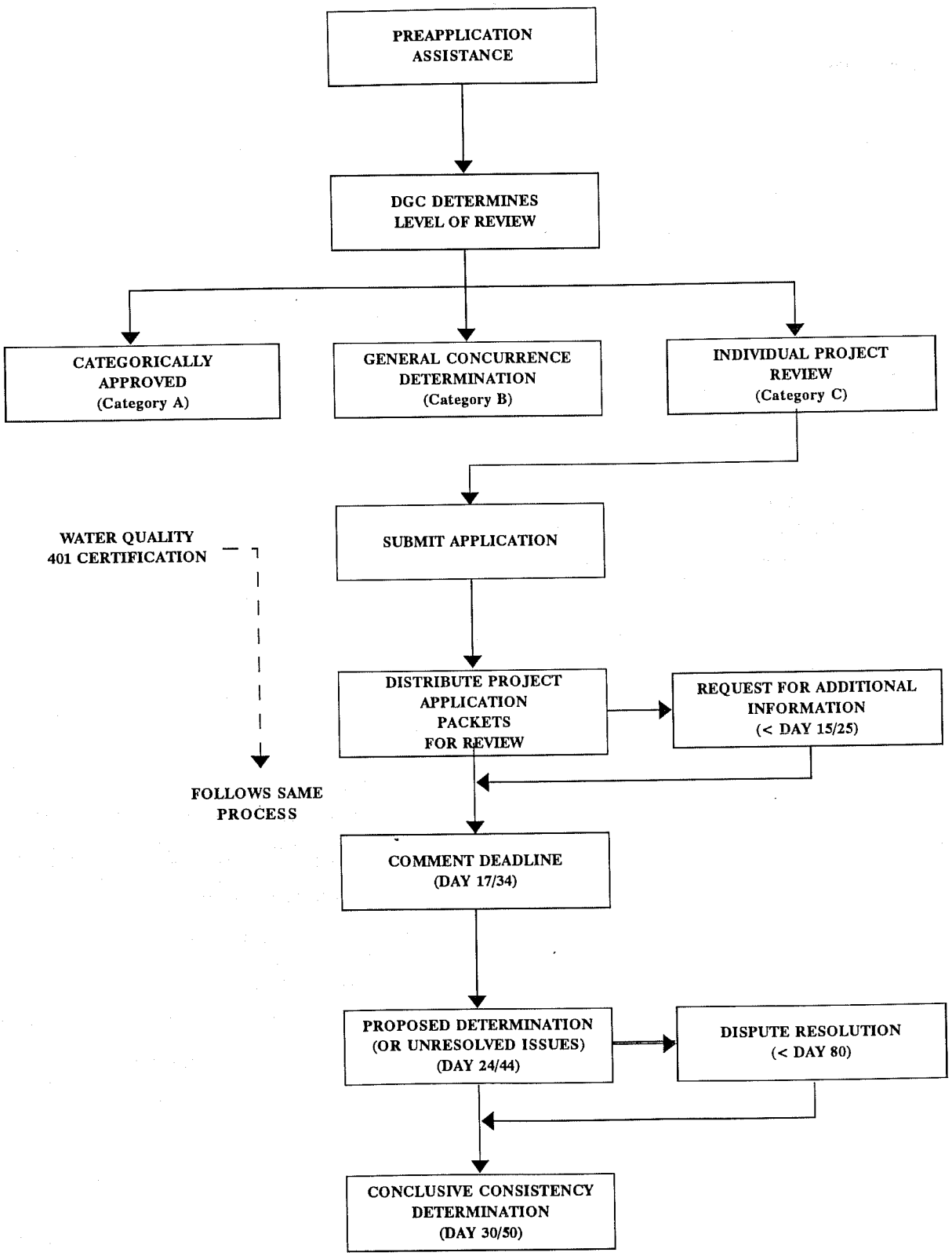

Figure 2-2. Alaska Coastal Zone Management Program Consistency Review and Section 401 Water Quality Certification Process.

2.4.2 Federal Leasing / Permit Process

The federal leasing and permit process includes offshore and onshore processes. Section 2.4.2.1 discusses offshore leasing and permitting. Section 2.4.2.2 discusses onshore leasing and permitting. The Corps' Section 404 process is outlined in Section 2.4.2.3.

2.4.2.1 Offshore, Outer Continental Shelf Leasing / Permit Process. The MMS conducts leasing procedures for the OCS. They consist of several steps (see **Figure 2.3**) including

- Area evaluation and decision process
  - Information base review and request for interest and comments
  - Call for Information and Nominations and Notice of intent to prepare an EIS
  - Consultations and scoping process
- Proposed action and alternative memorandum
- Area identification
- Public hearings to discuss draft EIS
- Comments from Governor's Office
- Preparation of final EIS and consistency determination
- Final notice of sale
- Public reading of bids
- Accept or reject bids
- Issuance of leases

The first step in the offshore leasing process is the *Area Evaluation and Decision Process* (AEDP). The AEDP involves an Information Base Review (IBR), publication in the Federal Register of a Request for Interest and Comments (RFIC), and a Call for Information and Nominations and Notice of Intent to Prepare an EIS. AEDP provides a framework for the activities that precede the decision of whether and under what conditions to hold an OCS lease sale. The goal of the IBR process is to acquire environmental, geological, and economical information used in OCS management and decision making. The RFIC obtains information to assist MMS in deciding the level of industry and public interest. If sufficient interest is shown, MMS will proceed with planning activities for the development of a leasing proposal. A Call for Information and Notice of Intent to Prepare an EIS invites comments from the oil industry, governmental agencies, environmental groups, and the public on areas of interest or special concern. A Notice of Intent serves to announce the scoping process that will be followed for the EIS. This process is a means for early identification of important issues deserving of study in the EIS. The intent of scoping is to avoid overlooking important issues that should be analyzed in the EIS. Comments are invited from all interested parties. The scoping process identifies major issues, alternatives, and

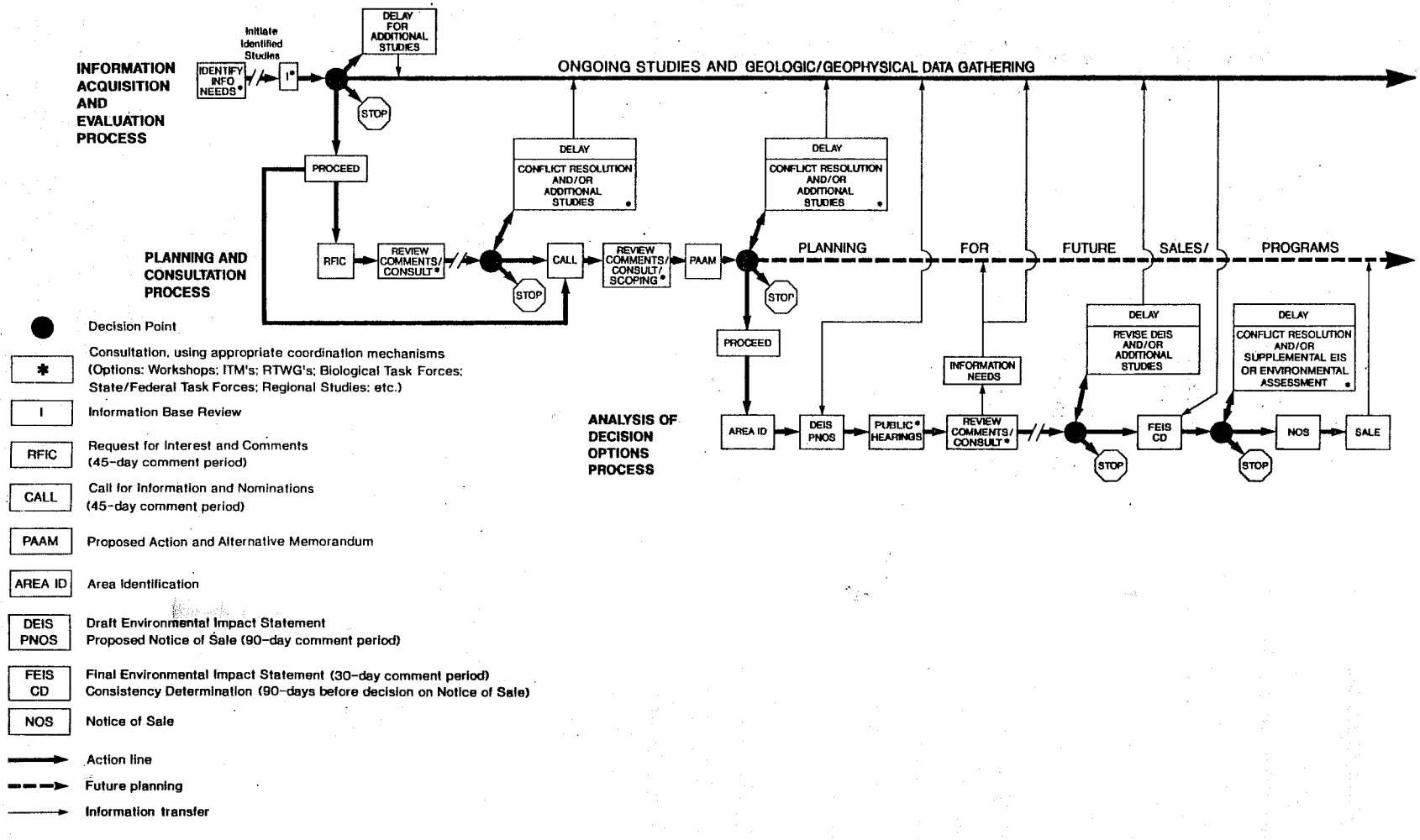

Figure 2.3. MMS Area Evaluation and Decision Process

mitigative measures for analysis in the EIS.

The purpose of the *Proposed Action and Alternatives Memorandum* (PAAM) is to decide whether to proceed with, delay, or cancel the further development and analysis of a leasing proposal. If the decision is to go on, MMS will decide and announce the scope of that review and analysis. The PAAM documents the consultation process and the information used to ensure an informed decision on the identification of the proposed action to be analyzed in the draft EIS.

During the *Area Identification* step, MMS attempts to develop proposals that include as much acreage with leasing and hydrocarbon potential as possible, balanced by the potential for causing environmental harm or conflict with other uses of the seabed. Areas with significant multiple-use conflicts and low potential for hydrocarbons are eliminated from further consideration. The final area of consideration is identified through public notice.

Following the identification of the final area, MMS prepares a draft EIS. The NEPA requires the preparation of an EIS before the conduct of any major federal action that could significantly affect the quality of the human environment (see **Section 2.3**). Draft EISs are filed with the EPA and made available to the public for review. The comment period is generally 60 days. Public hearings are held between 30 and 60 days to solicit comments on the draft EIS.

A *Proposed Notice of Sale* is a public announcement of the proposed sale. The proposed notice of sale is released at the time the draft EIS is filed with the EPA and identifies the blocks that are available, potential mitigative measures, and other pertinent information useful to the bidder. The Governor's Office receives copies of the public notice of sale, and the rationale for decisions. The Governor has 60 days to submit comments on the size, timing, and location of the proposed lease sale. A final EIS is prepared based on comments received during the public comment period and new information gathered before the final phase. At the time the final EIS is released, a Consistency Determination is also made available as required by the Coastal Zone Action Reauthorization Amendments of 1990. This document is prepared to help decide whether the proposed sale is consistent with the provisions of the State's Coastal Management Program to the maximum extent possible. A final notice of sale is released at least 30 days before the sale date and following the receipt of the Governor's comments and the decision to proceed with the sale. Following the sale, MMS can accept or reject bids.

Bids are usually based on receipt of fair-market value. A lease is awarded if the bid is accepted. The oil and gas mineral lease grants the right to explore, develop, and produce oil and gas, for a specific term and from a specific tract of submerged OCS land.

The MMS post-lease responsibilities include regulating and monitoring exploration and development activities on the OCS. Before such activities can go on, the lessee must submit the appropriate Exploration Plan (EP) or Development and Production Plan (DPP) to the MMS for approval. The EP and DPP permitting processes involve several steps, including reviews by Federal and State agencies, local governments and the public. **Figure 2-4** illustrates the EP review process.

Some preliminary activities (e.g., geological and geophysical operations, cultural, and biological surveys) can be conducted that enable the development of a comprehensive EP. The EP, submitted for a single or multiple lease, includes the type, timing, and sequence of operation. The EP also includes a description of the anticipated environmental conditions and an assessment of the expected effects resulting from the activities. Along with the EP, the lessee must submit an oil spill contingency plan that discusses the lessee's proposed response to an oil spill. Information in the EP helps determine consistency under the CZMA.

Once MMS has received a complete EP, it has 30 days to review and approve or disapprove the plan. Concurrent to MMS's review, all relevant information is sent to the state of Alaska's Division of Governmental Coordination, appropriate Federal agencies, and made available to the public for review. As required by NEPA, MMS analyzes all activities proposed in the EP. Following a technical and environmental evaluation and receipt of the comments from reviewers, MMS either approves or disapproves the EP. If disapproved, the plan is returned to the lessee.

Drilling activities described in the plan may not commence until the MMS receives and approves an Application for Permit to Drill (APD) for the well. The lessee or operator must obtain an APD before drilling each well. The APD includes the technical drilling requirements and well design, and the measures for pollution prevention and safety. Approval of the APD will be granted only after the EP is approved and is deemed consistent with the CZMP. The CZMP consistency review may take up to six months (see **Figure 2-4**).

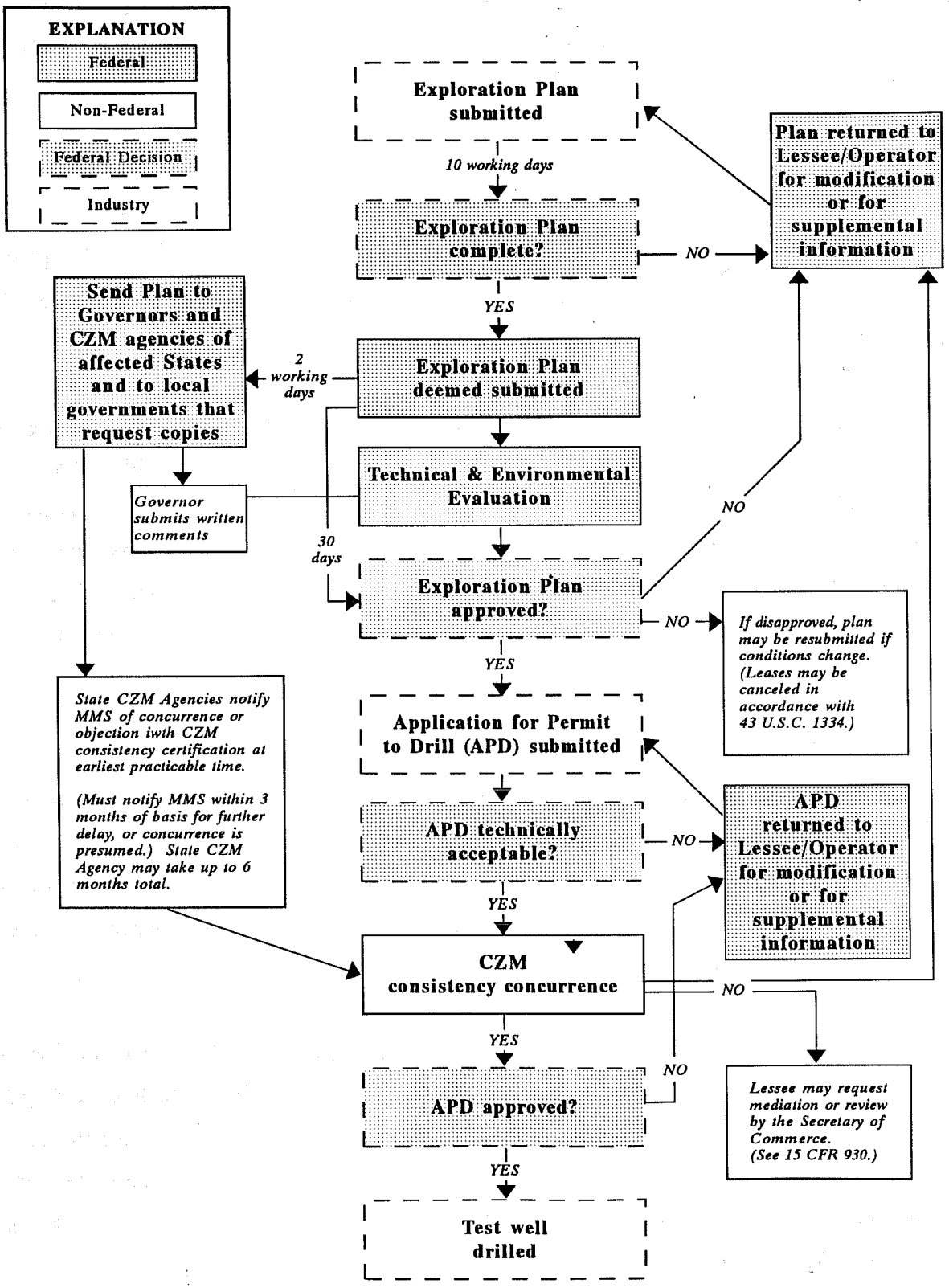

Figure 2-4. MMS exploration plan review process.

Figure 2-5 outlines the Development and Production Plan (DPP) process. The process is similar to the EP review with different times. As with the EP, an oil spill contingency plan must be included with the DPP. The MMS has 20 days to decide if the DPP is complete. If complete, copies of the plan are distributed to other federal agencies, the state, and released to the public for review.

MMS provides a technical and environmental review of the DPP and other associated materials. As part of the review, the MMS prepares either a Findings of No Significant Impact if impacts are found insignificant, or an Environmental Assessment. This review may take up to 120 days, unless the Environmental Assessment identifies the plan as a major Federal action, in which case an EIS would be necessary. If MMS decides an EIS is necessary, the 120-day mandate is suspended. At the end of 120 days or following the EIS process, MMS approves or disapproves the DPP (see **Figure 2-5**). The MMS disapproves the plan if the state of Alaska has not concurred with the CZMP consistency determination. Also, a plan is disapproved if the lessee (a) fails to show compliance with federal laws and regulation, (b) proposes activities that threaten National Security, or (c) proposes activities that cause serious harm or damage to aquatic life, property, or the environment. If disapproved, the lessee may modify the plan and resubmit. If the plan is approved, development can proceed. Any drilling under the approved DPP requires the review and approval by MMS of an APD similar to the EP phase.

2.4.2.2 Onshore Leasing / Permitting Process. Lease and permitting for onshore federal land would be under the jurisdiction of the DOI and administered by the BLM. This process is similar to that used by the MMS for offshore lease sales (see **Section 2.4.2.1**). Federal land on the North Slope includes the National Petroleum Reserve Alaska and the Arctic National Wildlife Refuge. None of the five NES fields are located on BLM or FWS lands.

2.4.2.3 Corps Section 404 Permit Process. Proposed activities that involve discharges into waters of the U.S. (e.g., wetlands - including most of the North Slope) must submit applications to the Corps. Section 404 is administered by the Corps and the EPA, the FWS and NMFS have important advisory roles through the Fish and Wildlife Coordination Act. In addition, the Department of the Interior provides comments through Section 404(m) of the CWA. The Corps has the primary responsibility for the permit program. The EPA has primary responsibility for

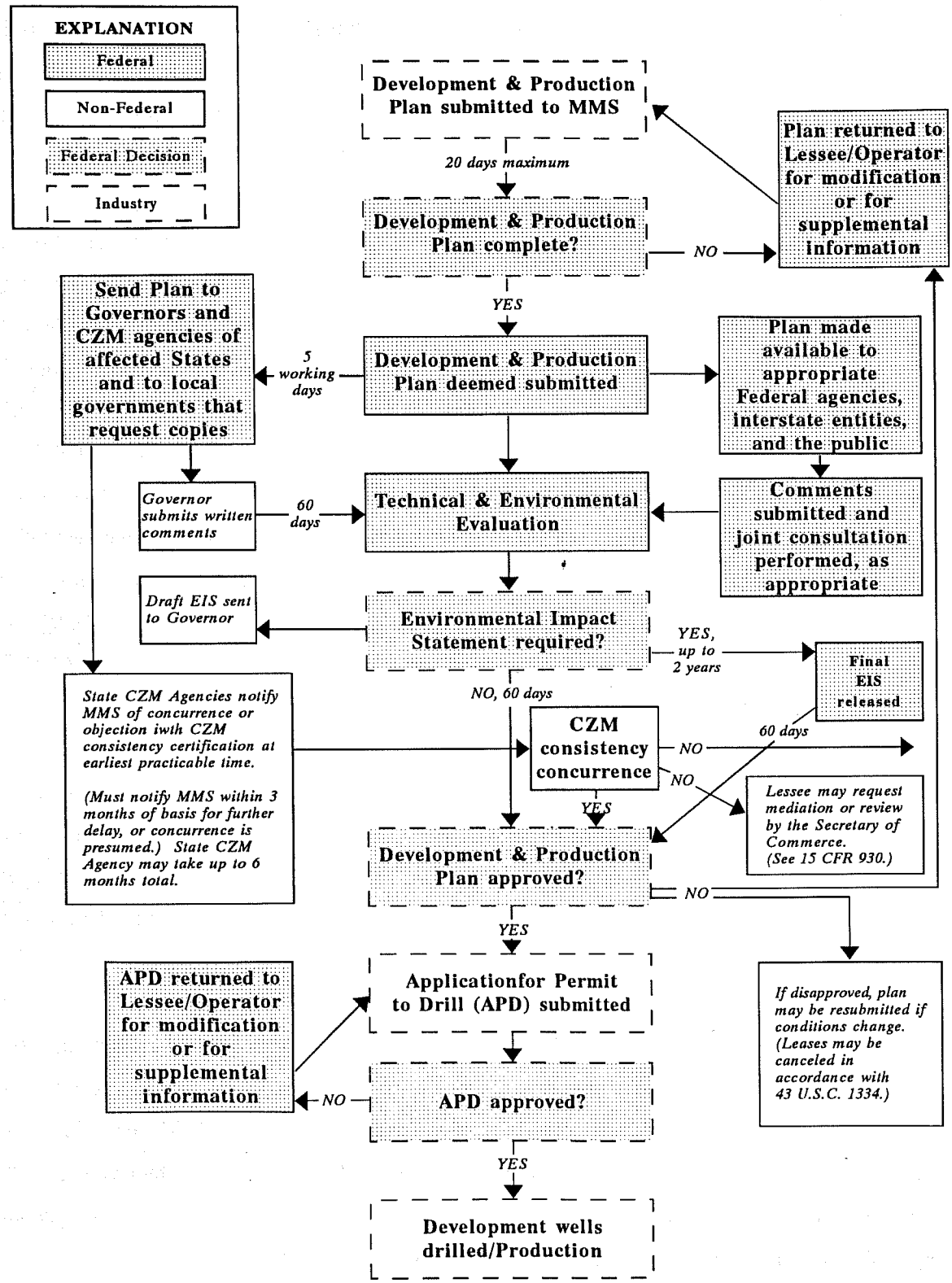

Figure 2-5. MMS development plan review process.

- development of guidelines under 404(b)(1)
- prohibition of unacceptable adverse impacts, under 404(c)
- establishment of jurisdictional scope
- interpretation of exemptions.

There are four general steps in Section 404 permitting. They include: (a) preapplication, (b) preliminary assessment, (c) project review, and (d) decision making (**Figure 2-6**). A permit application submitted to the Corps for review and authorization begins the process. Before submitting the permit application, the applicant may request a preapplication consultation meeting. The purpose of this meeting is to discuss the proposed activity with the Corps and other federal and state agencies, and help identify potential problems. Submitting the permit application to the Corps begins the review process.

Following formal submittal of a permit application the Corps conducts a *Preliminary Assessment* of the proposed action. During the preliminary assessment the appropriate authorization and the level of review needed for the proposed action is decided. The different types of authorization considered are

- Nationwide Permits issued by Washington, D.C. office for similar actions in the U.S.
- Regional Permits issued by the Alaska District for similar actions within the state or a region of the state
- Letters of Permission usually issued for Section 10 of RHA only
- Individual Permits specifically for single projects.

NEPA documentation is already prepared for the *Nationwide Permit* and *Regional Permit*. A decision and authorization are usually made within 30 days of receiving a complete application. An EA or EIS is not required for either permit. A *Letter of Permission* can be issued without a public notice, usually within 30 days. An *Individual Permit* requires a 30-day public notice and either an EA or EIS, unless the proposed actions meets the criteria for categorical exclusion. If the public review shows that an EA is an adequate level of documentation or it qualifies for categorical exclusion, the Corps usually issues a decision in 60 to 120 days. If an EIS is suggested, either during the preliminary assessment, or following public notice, the process will be lengthened considerably (2+ years).

Following the Corps preliminary decision (non-EIS route), the permitting agency issues a public notice containing the information needed to evaluate the likely impact of the proposed activity. The Corps sends the notice to all interested parties including adjacent property owners, appropriate

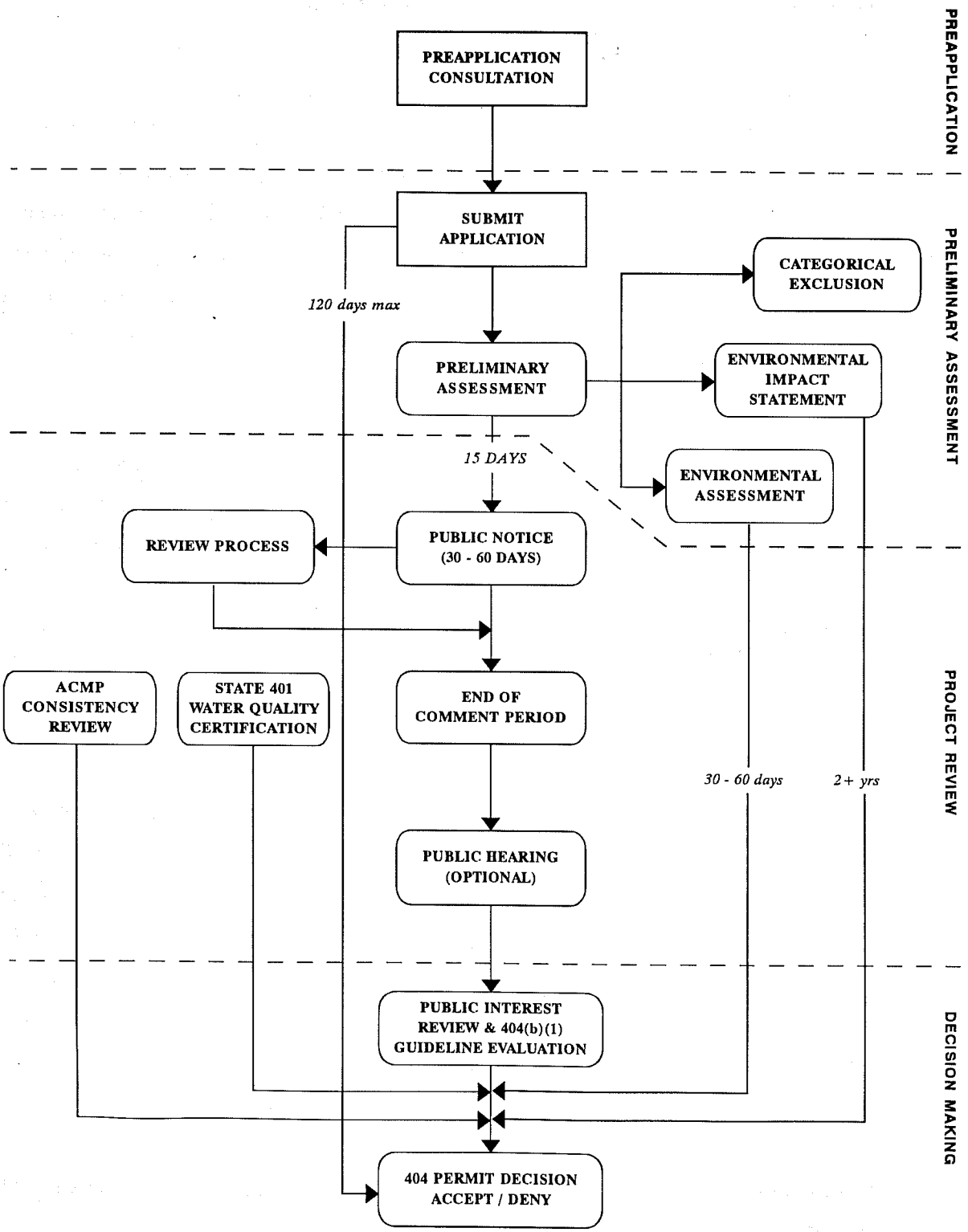

Figure 2-6. Section 404 of the CWA permit process.

government agencies at the federal, state, and local level, and others as requested. The Corps has established Memoranda of Agreements (MOA) to simplify the review of permits by the FWS, NMFS, EPA, and USCG. Public hearings may also be held, if requested by an interested party. The comment period is generally 30 days, but may be extended upon request to 60 days.

A *Guideline Evaluation* and *Public Interest Review* is conducted by the Corps following the review process and public hearing. The Corps' evaluation during this step consists of a two-part test that involves determining whether the project complies with the Section 404(b)(1) Guidelines and a public interest review. Key requirements of the Guidelines include

- No discharge may be permitted if there is a practicable alternative with less adverse impact
- No discharge may be permitted if the action would violate applicable laws, such as state water quality standards
- Discharges may only be permitted if all appropriate and practicable steps are taken to minimize the adverse impacts of the discharge.

The Corps' public interest review balances the public and private benefits of a project against its impacts to the environment. As part of this evaluation, the Corps conducts an EA under the NEPA to determine whether the project has significant environmental impacts. The permit is denied if the project fails to comply with the Guidelines or is contrary to the public interest.

Besides the 404(b)(1) Guidelines and the public interest review, the state must certify that the activity complies with water quality standards (Section 401 of the CWA). Alternatively, the state, waives its right to certify by not taking action within a specified time. The state must also conduct a coastal zone consistency review to ensure the proposed action is consistent with the CZMP. The Corps will not authorize the proposed activity without the state's water quality certification and coastal zone consistency review concurrence. The DGC coordinates the state's response (see **Section 2.2.2.1**).

2.4.3 Summary of Regulatory Permit Process

The regulatory processes governing environmental permitting for oil and gas activities on the North Slope of Alaska, from lease sales through the issuance of regulatory permits, are well defined (e.g., in terms of requirements, durations and milestones, and review and comment procedures). Congressional acts and state statues also support the regulatory process (see **Section 2.3**). However, the

process often involves unknown, overlapping, and uncertain jurisdictions. This leads to confusion and fewer definite requirements, etc. While these processes have defined time requirements, projects on the North Slope are generally large and can become controversial. This makes obtaining permits for them more likely to require additional time (ranging from completing an EIS to resolving disagreements through the elevation processes). **Section 2.5** discusses examples of project delays while controversial issues such as site-specific location and mitigative measures were addressed and resolved.

2.5 Mitigation Measures

The continued development of the North Slope of Alaska and adjacent nearshore and offshore areas for oil production requires the consideration of numerous environmental issues (e.g. impacts to wetlands, air quality, and fish and wildlife). Concerns regarding the impact of exploration and development on the environment are centered on four principal activities

1. Transportation of materials and equipment to and within the area of development
2. Construction of facilities including drilling pads, roads, and housing and support facilities
3. Disposal of various waste types generated during exploration and production
4. Removal of equipment and materials following completion of the drilling.

Many of the environmental impacts associated with exploration and development activities can be ameliorated through the application of *mitigative measures,* defined for the purpose of this document as specific stipulations placed on permits at the time of issuance by regulatory agencies of the state and federal government. The types and extent of mitigative measures placed on a permit are determined prior to the initiation of a project, and help to define how the project will be developed. The cost of mitigative measures should be factored into development decisions. However, these measures can, in effect, prevent development either by adding significant cost to the project or by making operation impractical.

An overview of potential mitigative measures that could be applied to a project on the North Slope is provided in this section. This overview draws primarily from examples of stipulations imposed on previous North Slope development permits. Mitigative measures described in this section revolve around the following issues

- Onshore Development (e.g., loss of wetland habitat)
- Nearshore and offshore development (e.g., construction of solid-fill causeways, drilling platforms)
- Air and water pollution
- Waste disposal.

Some mitigative measures are fairly simple to apply, and are relatively inexpensive. Others can be much more complex and potentially involve significant costs. Many mitigative actions are to some degree interrelated, particularly those involving onshore exploration and development activities. For offshore projects, mitigative actions are often more distinct, such as seasonal drilling restrictions to minimize impact to whale migration. Most mitigative measures are related to the specific project for which the permit is issued. On occasion, however, stipulations for restoring the impact from past actions not related to the specific project at hand have been suggested.

The following descriptions of mitigative measures are considered the most likely to potentially impact the economic viability of the five NES fields. It is not intended to be a comprehensive list. Although many other environmental issues are important and will have to be addressed during the permit process, mitigative actions related to these other issues are not considered capable of impacting the economics of a field to the extent of the issues listed above.

2.5.1 Onshore Development

2.5.1.1 Gravel Mining and Placement. Most wetlands losses on the North Slope of Alaska occur from the placement of gravel for roads and for the construction of drill pads, pump stations, solid-fill causeways, living areas, and other miscellaneous support facilities. The gravel base for these structures is typically 5-ft thick to insulate the underlying permafrost. This prevents the permafrost from melting while providing a secure foundation on which to house the infrastructure necessary. Besides the obvious direct loss of wetland habitat, the construction of gravel roads, pads, and other structures can change the nature of wetlands through long-term alteration of surface water drainage patterns. Local sources of gravel are mined to provide the material, and typically include inactive stream beds, upland sites, river terraces, lagoons, etc. The mining of these materials causes additional impacts.

The use of gravel to provide a base for protection of the permafrost is crucial to the continued development of the North Slope for oil and gas production. The current strategy preferred by industry regarding gravel mining and placement is one of minimization, supplemented on a case-by-case basis with avoidance and enhancement activities. Federal, state, and local regulatory agencies review and approve applications for gravel mining and placement. Permit stipulations typically include restrictions on mining techniques, periods of operation, and restoration of mined sites.

2.5.1.2 Wetlands. In a MOA signed in 1990, EPA and Department of the Army established criteria for evaluating compliance with the Section 404 guidelines.[a] The purpose of the memorandum was to assist field offices in evaluating proposals dealing with 404 permit applications. The MOA described three general types of mitigative actions for wetlands: avoidance, minimization, and compensation. As the terms imply, avoidance of wetlands involves siting and designing projects such that wetland areas are not affected. Minimization involves reducing impacts to wetlands to the extent practicable. An example of avoidance is the construction of facilities during the winter using ice roads to transport material across otherwise fragile wetlands. Consolidation of facilities on a smaller total area of gravel pads is an example of possible wetland mitigation by minimization. Compensatory mitigation involves the creation or restoration of wetlands to replace the functions and values of impacted wetlands.

The petroleum industry prefers using, where possible, the strategy of avoidance and minimization to mitigate impacts to wetlands habitat. In the past, Senner (1989) found that a strategy of avoidance and minimization is common to Section 404 permits. Past mitigative measures on the North Slope have been largely limited to minimization. This is due, in part, to the difficulty in avoiding impacts in areas where the great proportion of land is wetland. Also, there are technical difficulties involved in restoring or creating wetlands underlain by permafrost. In certain cases in the past, the FWS has requested compensation of wetland habitat. This has included requests by FWS to protect wetland habitat in areas of known oil reserves. The intent of FWS is to ensure that these areas of known oil reserves would be protected from future development. Post (1990) suggests that compensation (such as wetland restoration, enhancement, or creation projects) may yield similar habitats to those lost. He further states that wetland

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a. Memorandum of Agreement Between the Environmental Protection Agency and the Department of the Army Concerning the Determination of Mitigation Under the Clean Water Act Section 404(b)(1) Guidelines, January 24, 1992.

functions, other than habitat may be restored or created (e.g., flood control). However, compensatory mitigation has rarely been required in the state of Alaska.

Besides the loss of wetland habitat, state and federal resource agencies have expressed concern over other potential environmental impacts from gravel mining and placement. For example, mining of gravel on the North Slope may adversely affect water quality and fish habitat, create fugitive dust, and cause wildlife disturbance. Mitigative measures relating to gravel mining discussed in the Alaska National Wildlife Refuge (ANWR) EIS focused on avoidance, and included restrictions on mining gravel from active stream channels of major fish bearing rivers or from barrier islands (DOI 1987a).

In addition, it was recognized that mining sites where large pits are created can provide fish and wildlife habitat following abandonment (DOE 1987a). Several rehabilitated mine sites in the Prudhoe Bay and Kuparuk oilfields (with connection to adjacent rivers or streams) provide freshwater reservoirs and valuable overwintering fish habitat that are scarce on the North Slope. Gravel mining plans incorporate such features as shallow and deep mining to provide littoral and deeper water habitats, and the selective use of overburden for nutrient enrichment.

FWS maintains that the placement of gravel for roads, living quarters, drilling pads, etc. causes changes in the behavioral reactions of individual animals, and alters local habitat resulting in declines to wildlife populations, especially birds (FWS 1987). Also, the blockage of wildlife migrations may result from the placement of gravel structures on the North Slope (FWS 1987). Recent technological developments, however, have enabled reductions in the land area required to support a drilling operation. By reducing the spacing between surface locations for wells on a single pad, less surface land is disturbed. For example, the P-Pad, located in the Prudhoe Bay Unit, is the smallest pad ever proposed for the number of wells it supports. P-Pad also represents a prototype for a production pad without a reserve pit for the disposal of mud and cuttings. Additional measures aimed at mitigating gravel placement could involve actions such as the rehabilitation of roads and pads at the end of their useful period. This could include revegetation of the gravel surfaces or the complete removal of the gravel base followed by revegetation.

2.5.1.3 Pipelines. Future onshore and offshore oil and gas development in the Arctic will likely involve the construction of pipelines to connect newly-developed fields to the existing TAPS pipeline.

The construction of pipelines and associated developments (e.g., roads along corridors) are governed by federal and state regulations. Federal permitting focuses on the CWA and ESA (see **Section 2.3**).

Site-specific assessments of pipeline construction from landfall areas to the TAPS are discussed in the draft Beaufort Sea Planning Area Oil and Gas Lease Sale 124 EISs (DOI 1990, **Draft**) and the Chukchi Sea Oil and Gas Lease Sale 109 Final EIS (DOI 1987b). Several potential impacts to caribou and other wildlife resources from pipeline construction are identified in the EIS. These include (a) disturbance and displacement of caribou and other wildlife within a few miles of the pipeline, (b) local reductions in habitat use by some caribou (particularly cows and calves) and other wildlife within about 1 mi (1.6 km) of the pipeline corridor, (c) increases in hunting pressure, (d) contamination of rivers due to oil spills, and (e) reductions in water quality and fish habitat due to increases in erosion.

Several mitigative measures have been applied to the construction and operation of pipelines in the past. Most of these actions were taken to prevent or minimize the potential impacts on wildlife populations due to the pipeline, and include (a) adjusting pipeline height, (b) separating the pipeline from a busy road, (c) providing ramps for the caribou to cross, (d) routing pipelines to avoid major migration routes, and (e) construction during the winter. Robertson and Curatalo (1987) found that the best mitigative technique includes elevating the pipeline 5 ft (1.5 m) above the tundra and separating the pipeline at least 400 ft (122 m) from roads with traffic. Prevention of pipeline spills can be best obtained through routine maintenance and repair activities and other preventive actions. Spill response activities can help to minimize the impacts associated with pipeline spills.

Other mitigative measures that could influence pipeline and service road construction is the designation of special areas by the FWS. For example, designating significant portions of a river system as special habitat areas could prevent construction of a pipeline across the river. Therefore, exploration and development of areas beyond the river may not be feasible. Such action could result in the use of significantly different, more costly routes, or could prevent the construction of the pipeline. If a suitable pipeline corridor is not available, certain areas may become effectively inaccessible to oil exploration and development, due to a lack of alternative methods for transporting the oil to market.

2.5.2 Nearshore and Offshore Development

A recent mitigation issue that has developed on the North Slope involves mitigation of solid-fill gravel causeways, specifically the existing causeway servicing the Endicott field and the proposed Niakuk causeway. The Endicott causeway provides a solid-fill, elevated platform extending several miles into the Beaufort Sea, and connects the facility to the mainland. The Endicott causeway was initially constructed with two breaches. The service road and pipeline connecting the Endicott facility with the Trans-Alaska Pipeline System (TAPS) are on the top of the causeway. Shorter causeways have been constructed in two locations on the North Slope to allow for docking barges transporting large modules and other equipment to the area (East Dock and West Dock). Development of new fields may depend on the construction of some form of solid-fill causeway.

The FWCA, requires the Corps to give full consideration to comments and suggestions from FWS, NMFS, and ADFG. The Corps and resource agencies are concerned with potential environmental impacts resulting from the presence of solid-fill causeways. Therefore, the Corps recently required breaching of existing causeways extending into the Beaufort Sea. The intent of this breaching is to reduce or minimize the impact of the causeway on the flow of nearshore currents and movement of fish. Breaching existing causeways is costly, and involves dismantling part of the causeway and bridging the resulting gap. Such an action was recently negotiated for the Endicott and West Dock causeways. This settlement agreement resolved a dispute between the Corps and three development companies over the need for additional breaching of the Endicott and West Dock causeways. The dispute centers on the Corps findings that the ". . . causeways [Endicott & West Dock] produced water temperature and salinity changes which pose a threat to the fish in the nearshore environment . . ." and that ". . . unacceptable adverse impacts have been identified which allow the Corps to order additional breaching . . ." of causeways (Corps 1991).

The companies involved agreed to provide additional breaching in the causeways as stated in the permit stipulations. The Corps agreed not to require additional funding for ". . . future fisheries and oceanographic monitoring in association with the existing . . ." Endicott and West Dock permits (Corps 1991). Within the settlement agreement, the Corps stated that ". . . reasonably breached, solid-fill causeways may be one of several appropriate technologies for nearshore Beaufort Sea oil and gas

development." In addition, the Corps ". . . will consider future causeway proposals on their own merits and on a site-specific, case-by-case basis . . ." (Corps 1991).

Several alternatives exist to breached, solid-fill gravel causeways, each with their own potential set of environmental impacts (Ross 1988, Padron 1989, Sayles 1990). The petroleum industry, resource agencies, environmental consultants, and regulatory agencies disagree over the environmental impacts of the different methods. However, it appears likely that future causeways in the Beaufort Sea will require breaching.

The Niakuk offshore project was abandoned in part because of the controversy surrounding the causeway issue (see **Appendix D, Section D.2 - Comparison of Niakuk Onshore and Offshore Projects**). Continuation of the offshore project would have likely resulted in delays of several years, expensive monitoring, and the potential of retrofitting of additional breaches as occurred at Endicott. Directional drilling, however, was a practicable alternative to the Niakuk offshore project. In addition, facilities-sharing with Lisburne contributed to making the onshore proposal more economical than the offshore alternative.

Offshore drilling mitigation relates primarily to the disturbance of marine mammals, and is regulated primarily by the MMPA and the ESA. Special restrictions in offshore areas typically involve the imposition of seasonal restrictions on drilling or other operations if the permitting agencies decide that marine mammals and/or endangered species could potentially be affected by the operation (DOI 1987b). An example is the required cessation of drilling activities during whale migration periods. In addition, offshore drilling permits typically require whale monitoring programs. Monitoring programs can be required by MMS stipulations or with incidental take permits. Such restrictions can result in additional costs of operation (DOI 1987b). Offshore drilling restrictions could significantly influence future exploration of offshore lease areas such as in the Beaufort Sea. These restrictions are compounded in northern Alaska by the short annual periods of open water (DOI 1987b). The costs associated with such actions could be significant, and would be dependant primarily on the duration of the restriction period, also the volume of the field, and oil prices (DOI 1987b).

Subsistence hunting and fishing activities of indigenous peoples are also involved. Causing changes in the migration routes of marine mammals, such as whales, may affect subsistence hunting.

Native peoples have requested stipulations on drilling and other activities that may affect the species on which they depend (see **Section 2.6.2**). For example, the oil company operators have reached agreements with subsistence whalers to avoid conflicts by such measures as setting up a communication's network.

2.5.3 Air and Water Pollution

Control equipment proposed for new air pollution sources must represent the "best available control technology" (BACT). This is defined in the CAA as the "emission limitation that represents the maximum reduction achievable for each regulated air pollutant, considering energy, environmental, and economic impacts and other costs; the resulting emissions must comply with applicable emission standards." The BACT emission limit must be at least as stringent as that established under Section 111 or 112 of the CAA Standards of Performance for New Stationary Sources and the NESHAP. Interpretation of what is the "BACT" by the ADEC could result in permits being dependant on the use of new, more costly pollution control equipment.

Potentially costly mitigative measures with respect to air quality could include the retrofitting of existing pollutant sources with additional pollution-control devices. These actions could include specific requirements of individual permits or result from the BACT provision of the CAA. More stringently permitted emission levels could also result in the need for retrofitting existing facilities. The costs associated with retrofitting could be substantial. Generally, however, compliance with air pollution standards is considered part of the normal operating costs for a given development project. While not insignificant, it is not expected that the costs associated with air quality compliance would prevent the development of a particular oilfield.

The EPA, Region 10, writes the permits for point source discharges to waters covered under Section 402 of the CWA (NPDES Permits and Effluent Guidelines) (see **Section 2.3**). Recently proposed projects have eliminated the need for reserve pits, and now involve the downhole disposal of waste waters. This change in procedure has been largely driven by mitigative requirements for water quality. Water quality issues are not expected to add significant costs to the production of oil resources on the North Slope, as permit stipulations are generally well established and attainable. For example, current effluent guidelines in 40 CFR 435 establish limitations for oil and grease in five of seven waste streams identified for onshore oil and gas activities. These are based on EPA evaluation of the "best practicable

control technology" (BPT).[a] The EPA has also proposed limitations following its evaluation of the best available control technology (BACT) for offshore releases in 1985 (50 Federal Register [FR] 34592, 8/26/85). Final promulgation of the offshore guidelines is pending.[a] In the interim, EPA Region 10 is writing NPDES permits for offshore effluent based on "best professional judgement."

2.5.4 Waste Disposal

The potential impact of waste disposal policies on future North Slope development is subject to uncertainties in the regulatory framework. A change in the ADEC or EPA permitting requirements, such as the loss of the Congressional exemption from RCRA hazardous waste regulations for oil production operators, could change in the future, requiring the application of different waste disposal methods. In response to the changing policies regarding waste disposal, the use of reserve pits for disposal of drilling wastes is *currently* being phased out on the North Slope. For example, the P-Pad represents a prototype for a production pad constructed without a reserve pit for the disposal of mud and cuttings. These materials are reinjected into disposal wells. Imposition of additional treatment requirements, or the long distance transportation of drilling wastes could result in significant additional compliance costs.

Another waste disposal issue that must be considered in the future of the North Slope development involves the disposition of radioactive waste. Brine is co-produced along with the crude oil in increasing amounts over the operating lifetime of oilfields. Depending on several factors, brine may contain measurable quantities of naturally occurring radioactive materials (NORM). These materials may become incorporated into the mineral scale that accumulates on the interior of pipes, or may be concentrated in sludges or sands in various components of the production equipment (Rogers, 1989). The regulatory framework for disposing of these materials is currently changing. Oil companies have pioneered a new approach to NORM scale removal and waste handling. A new enclosed, mechanized system has been developed for cleaning pipes. Approval from the Alaska Oil and Gas Conservation has been obtained to slurry the collected NORM contaminated scale in mud and inject the waste in a Class II disposal well. The first pilot injection of NORM scale occurred on the North Slope in October 1992.

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a. Susan MacMullin, EPA, letter to Guido DeHoratiius and Don Juckett, DOE-FE, 2/1/92.

Finally, mitigation of waste disposal activities on the North Slope could include the required cleanup of past waste disposal sites, should they become classified as CERCLA sites.[a] Development companies could be largely responsible for the associated remediation costs if waste disposal sites on the North Slope are designated as CERCLA sites. Depending on the number of such sites, requirements for bonding, or the cleanup costs involved, such an action could influence future development on the North Slope.

2.5.5 Mitigation Examples

Three past examples of the avoidance, minimization, and compensatory mitigative strategy -- Endicott in the Duck Island Unit, P-Pad in the Prudhoe Bay Unit, and Drill Site 3-L in the Kuparuk River Unit -- are discussed below. These examples are not intended to be *typical* of development and permitting activities on the North Slope of Alaska. However, they do provide a *worse case* scenario of permitting delays due to controversy over sensitive environmental issues. It is likely that much of the development of new production facilities will affect sensitive environmental areas. Thus, one could expect the permit process to be lengthy, based on these examples.

2.5.5.1 Endicott. During the 1985 permitting of the Endicott development area (Duck Island Unit), FWS requested compensatory mitigation for the onshore gravel placement required for the project access road. If imposed, this would have stipulated that "areas of known development potential "be identified and set aside in perpetuity. The justification cited by FWS was that the road and pipeline corridor for the Endicott project would cause *indirect* loss of 40,000 acres of Resource Category 2 caribou insect relief habitat. Specifically, the FWS suggested that compensation for this habitat loss include the Colville River Delta. The "permittee" eventually signed to compensate for adverse impacts from the *direct* habitat loss due to gravel placement (Corps 1985). Based on this agreement, the Corps reduced the acreage requiring compensation from 40,000 to 360 acres.

In practice, the Endicott wetland mitigation plan consisted of two phases. The initial phase was a 5-year research program to investigate the feasibility of transplanting the native grass *Arctophila fulva*

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a. EPA-Office of Solid Waste, Robert Tonetti, personal communication.

in disturbed aquatic sites such as potential impoundments along the Endicott Road. The second phase involved carrying out of actual mitigative measures at Endicott.

2.5.5.2 P-Pad. In planning for minimization of the impact from a proposed production pad (P-Pad) at the Prudhoe Bay Unit, the development company performed geobotanical and hydrological surveys and a study of bird use on the site. The locations of the proposed road, pad, and pipelines were determined cooperatively with the regulatory agencies. This helped to avoid high value habitat areas (e.g., *Arctophila* areas), high density nesting areas, and less abundant habitat types. Also, impacts were minimized to the extent practicable. This represents an example of mitigation by avoidance and minimization of impacts to these areas.

During the permit process for P-Pad, the FWS requested that the Corps include a permit stipulation requiring off-site compensation, because "although (the developer's) project proposal incorporates recommendations that avoid and minimize some impacts to wildlife habitat value, unavoidable losses of high value migratory bird habitat will still occur." Specifically, FWS proposed that an abandoned exploratory pad in the area be rehabilitated as compensatory mitigation for the proposed P-Pad project. The EPA also requested off-site mitigation following their review of the P-Pad permit application, and recommended a stipulation calling for the rehabilitation of a nearby abandoned exploration pad (EPA 1988).

The developer did not feel that it was appropriate to require mitigation of a facility covered under an earlier permit as a stipulation for a permit for a separate action. After negotiations between the company and the FWS, the company agreed to conduct a pilot restoration program on the exploration pad. As a result, the FWS withdrew its request to the Corps for a stipulation mandating restoration of P-Pad. Following these negotiations, the FWS and EPA dropped their requests for off-site habitat rehabilitation.

The P-Pad study represented a major advance in pad design and reduction in tundra coverage by elimination of the reserve pit and closer well spacing. This example of "minimization" enabled a reduction of about 70% in pad size (i.e., from about 40 acres to 10 acres).

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2.5.5.3 Kuparuk Drill Site 3-L. The permitting history of the Kuparuk Drill Site 3-L (3-L site) provides an example of how controversy over mitigation techniques can result in significant delays to construction and operation. Initial permitting for the 3-L site began in October 1987 with a preapplication meeting between the developers, Corps, and other agencies. An application for the 3-L site was submitted in November 1987. Following receipt of comments from the EPA on the application, the site operator requested that the permit process be suspended in March 1988. Several revised plans were subsequently submitted to the Corps followed by consultation with the EPA between March 1988 and March 1990. In March 1990, the EPA requested elevation of the proposed decision to the Division Engineer of the Corps. When the Corps ruled against the EPA in July 1990, the EPA requested an elevation to the Assistant Secretary of the Army in August 1990. The EPA argued that (a) few environmentally damaging alternatives were available, and (b) the Corps decision regarding no need for compensatory mitigation was in error.

In October 1990, the Assistant Secretary of the Army ruled the Corps should reevaluate the habitat impact and hydrology associated with each proposed route. The Corps reevaluated the application and decided that no change was warranted. On March 11, 1991, the Corps issued a permit for the 3-L pad development. At the time the permit was issued to the applicant, 13 months had been required for the elevated review and responses.

Following the Corps issuance of the permit, the EPA using its authority given in Section 404(c) of the CWA, vetoed the permit. The EPA published its proposed determination in the Federal Register in May 1991. Throughout the Section 404(c) consultation process, the developer and EPA worked to address issues concerning wetland values of the proposed project site. Ways to reconfigure the proposed project to protect environmental values and recover the targeted petroleum reserves were investigated. Following several meetings between the developer, EPA, and the Corps, the developer and EPA reached agreement to move the 3-L pad site to an alternative location some 1,500 ft from the originally proposed site. In October 1991, EPA Region 10 recommended approving withdrawal of Section 404(c) action.

The 404 permitting of the 3-L site took approximately 3 years. Review of the application, through the elevation and Section 404(c) process, required at least 20 months of that 3-year period. A permit was eventually issued resolving environmental and developer concerns. The process, however, was time consuming, resulting in a delay in construction and production.

2.5.6 Summary of Mitigation Measures

The primary means by which environmental protection regulations are applied to petroleum exploration and development activities on the North Slope is through the permit process for each proposed activity. Permit stipulations are determined before the initiation of a project. This helps define how the project will mitigate environmental impact. Permit stipulations and mitigation requirements for a proposed project are discussed and stipulated before permit issuance. Knowledge of the environmental stipulations likely to be imposed helps determine the economic feasibility of the project. General areas in which additional costs to the economic viability of the NES fields could occur include

1. The carrying out of permit stipulations because of studies
2. Changing regulatory constraints
3. Mitigative actions applied to activities not associated with the actual permitted action.

When environmental mitigation requirements are defined in the permit before the commencement of the project, the exploration and development company can factor the costs associated with these requirements into the economic evaluation of the project. However, additional costs can result when permit stipulations (e.g., studies) suggest further mitigative actions may be necessary, after the project has been initiated and study results are available. An example of such an action was the breaching of existing causeways extending into the Beaufort Sea recently required for the Endicott and West Dock causeways, as described above.

To make viable economic evaluations regarding the five NES fields, and for development decision making for other fields on the North Slope, the industry must know what regulatory constraints will be imposed in the future. This has not always been the case as state and federal policies have changed, often significantly, over the periods required for exploration and development of North Slope oilfields. As an example, new wetland's legislation could have a significant impact on the development of future exploration and development activities in northern Alaska. Development of new areas will continue with a strategy of minimization of wetland habitat on the North Slope. If a strict policy of avoidance of all wetland areas were to be created, future development will likely be curtailed. However, it should be noted that practicable mitigative measures are pursued by the EPA. If compensation, as prohibiting future development in wetland habitat areas known to contain reserves is applied, the permitted project may not

be affected, but future development of restricted areas could be prohibited. This could ultimately affect the production from the North Slope as a whole.

To help clarify policy related to mitigative actions under the CWA Section 404(b)(1) Guidelines, the EPA and Corps signed a MOA. The Corps and the EPA must follow and carry out the Guidelines when considering mitigation requirements for standard permit applications. The Corps will use this MOA when deciding with respect to mitigation for standard permits applications. The EPA will use this MOA in developing its positions on compliance with the Guidelines for proposed discharges and will reflect this MOA when commenting on standard permit applications.

Another significant unknown is the restriction that could potentially be placed on exploration and development activities relating to the subsistence hunting and fishing issue. The costs associated with drilling restrictions for protection of species hunted and fished by native peoples could be significant, depending on the duration of the restriction period, the projected volume of the field, and oil prices (DOI 1987b). Loss of the Congressional exemption from RCRA hazardous waste regulations for oil production operators may increase the costs of exploration and development on the North Slope and elsewhere.

Permit stipulations requiring mitigative actions, represent additional project costs that must be considered. For example, if old, unlined reserve pits at previously existing facilities not related to the proposed action are required to be removed before a new permit is issued, substantial costs may be incurred. Economic evaluations of the new field must include these costs, resulting in an impact to the decision making process. These costs will depend on the number, size, and location of these existing pits, the quantity and types of the materials within the pits, and the ultimate disposition of the materials involved. Similarly, if CERCLA sites on the North Slope become the responsibility of current operators, the economic future of development in the region may be influenced.

2.6 Environmental Sensitivity

The following sections focus on the sensitivity of oil and gas exploration and development to environmental issues and policies related to: (a) NEPA documentation, (b) wetland's protection, and (c) subsistence hunting and fishing. Each issue is discussed below. Most of the regulations and laws,

environmental issues, and mitigative issues discussed in previous sections apply to all of the NES fields. Some, however, are appropriate only to specific fields (e.g., subsistence issues related to bowhead whales). **Table 2-3** summarizes regulatory activity, responsible agencies, key regulatory/environmental issues, and issues where there is uncertainty about their impact on oil and gas development for each of the five NES fields. The responsibilities for regulatory permitting and NEPA documentation are well defined for most of the five NES fields. The one exception is Seal Island/Northstar where MMS and ADNR share the responsibility for leasing and permitting. The Corps may also be involved with Seal Island/Northstar because of onshore collection and distribution facilities.

Regulatory issues, such as wetland mitigation, protection of endangered species, and subsistence hunting regulatory issues have the potential to significantly affect the development of the five NES fields. For the most part, these issues can be resolved through proper siting and mitigative actions. However, several issues cast uncertainty on development of these fields. These include: (a) drill pad spacing requirements and mitigative strategy at West Sak, (b) subsea pipeline technology and permitting at Seal Island/Northstar and Sandpiper Island, (c) pipeline construction to TAPS from Point Thomson, and (d) the management of waste.

2.6.1 NEPA Documentation

The Council on Environmental Quality's Regulations for the Implementation of the Environmental Provisions of NEPA (40 CFR 1500 - 1508) requires that federal agencies document and assess compliance with many statues, policies and executive orders to protect the environment. We list some of these laws below

- Clean Air Act
- Clean Water Act
- Marine Protection, Research, and Sanctuaries Act
- Endangered Species Act
- Noise Control Act
- Resource Conservation and Recovery Act
- Safe Drinking Water Act
- Toxic Substances Control Act
- Comprehensive Environmental Response, Compensation, and Liability Act of 1980.

Also, see **Section 2.3** and **Table 2-2** for a discussion of the above laws and others as they pertain to the North Slope.

Table 2-3. Summary of environmental issues for five NES fields.

NES FIELDS	REGULATORY ACTIVITY / RESPONSIBLE AGENCY	KEY ENVIRONMENTAL ISSUES	UNCERTAINTIES
West Sak	Leasing / ADNR State Permitting / DGC Federal Permitting / Corps NEPA / Corps	Wetland Development Protection of Coastal Habitat	Drill pad spacing requirement Waste Management
Point Thomson	Leasing / ADNR State Permitting / DGC Federal Permitting / Corps NEPA / Corps	Wetlands Development Protection of Coastal Habitat Subsistence Hunting & Fishing	Waste Management Pipeline construction to TAPS
Gwydyr Bay	Leasing / ADNR State Permitting / ADNR Federal Permitting / Corps NEPA / Corps	Wetlands Development Protection of Coastal Habitat	Waste Management
Seal Island/Northstar	Leasing / MMS & ADNR State Permitting / DGC Federal Permitting / MMS & Corps NEPA / MMS & Corps	Subsistence Hunting & Fishing Protection of Endangered Species & Marine Mammals Protection of Coastal Habitat	Subsea pipeline technology and permitting Waste Management
Sandpiper Island	Leasing / MMS State Permitting / None Federal Permitting / MMS NEPA / Corps	Subsistence Hunting & Fishing Protection of Endangered Species & Marine Mammals Protection of Coastal Habitat	Subsea pipeline technology and permitting Waste Management

NEPA analysis will likely be required for all major federal actions on the North Slope. The federal agency with control and responsibility for the proposed action assumes the lead role for conducting an EA or EIS. Control and responsibility depend on the permit or project scope, project location, and jurisdictional boundaries. On the North Slope, the Corps, FWS, BLM, and MMS are the federal agencies that could assume the lead role responsibility, depending on the location of the field (**Table 2-2**).

Projects with only small impacts on the environment are generally not recommended for EAs or EISs. These projects are usually categorically excluded from further NEPA documentation. Categorical Exclusions must be published and made available for comment, in the Federal Register (40 CFR 1507.3(b)). These projects are typically small or involve emergencies. Section 404 General Permits may cover these actions, thus minimizing the duration of the permit process.

An EA that results in a FONSI, may take 30 to 60 days. A determination to conduct an EIS may lengthen the process as much as 2 years. On the North Slope it is likely that exploration or development of an oil and gas field will require an EIS. A time saving approach, used in the NEPA process, would be to prepare a *program, plan, or policy* EIS that could cover several projects or actions (e.g., Legislative or Programmatic EIS). Subsequent projects or actions could incorporate information from this Programmatic EIS by reference, thus saving time and effort. This approach is called *Tiering*. Tiering may be defined as a method for reducing paperwork and labor by judicious use of already published EISs of broader scope. This can be done by incorporating the published EIS by reference (Murphy 1988) or by adopting the previously published EIS. Examples of tiering include

- Preparation of a supplemental EIS to an existing EIS
- Preparation of site-specific EAs or EISs from a program, plan, or policy EIS (e.g., Legislative EIS).

There are opportunities on the North Slope for the lead federal agency to conduct a *Programmatic* EIS, followed by EAs or site-specific EISs. Another example of using the tiered approach on the North Slope would be incorporating, by reference, the *Existing Environment* Sections from the Chukchi and Beaufort seas EISs into a more site-specific offshore EIS.

2.6.2 Wetlands

The environmental issues related to wetlands have received substantial attention from the Administration, federal and state resource and regulatory agencies, industry, special interest groups and the public. The high interest over wetlands stems from the amount of wetland habitat lost nationwide over the past 200 years. At the time of Colonial America, the area that now forms the 50 United States contained an estimated 392 million acres of wetlands (Dahl, 1990). Over a period of 200 years, the Lower 48 states lost an estimated 53 percent of their original wetlands. However, Alaska, which had 170

million acres, has only lost a fraction of 1 percent. This section discusses the potential effects on wetland regulation in Alaska resulting from

- The Comprehensive Wetlands Plan proposed by the Administration
- Wetland's regulation
- Wetland's mitigation
- New proposed legislation regarding wetlands.

2.6.2.1 Wetlands Regulation. The individual permit process under Section 404 can be an intensive, time consuming and controversial case-by-case evaluation process. Proper initial planning and coordination can reduce both time and the controversial nature of the permit. The 404(b)(1) Guidelines provides for a planning process that can result in a more predictable decision making process. Industry and the public uses information developed in this planning process, known as Advanced Identification (ADID). Such information can include general locations and values of waters of the U.S. and potential threats and impacts to those values. This process usually results in maps that provide information on where discharges to waters of the U.S., including wetlands, may be generally suitable or unsuitable. However, these results are informational only, and are not binding regulatory decisions. In Alaska, ADID process would be conducted by the EPA and the Corps. The products that result from the ADID process include, designation of areas as generally suitable or unsuitable for use as discharge site. This could be used by the Corps to issue general permits for some activities in portions of the area designated as suitable for disposal.

Streamlining the regulatory process (e.g., eliminating steps or time between steps) would reduce the time involved to authorize noncontroversial proposed actions. It is likely that large projects will still require a more in-depth review and NEPA analysis (e.g., EISs). Currently, the federal and state agencies work together to coordinate reviews (e.g., DGC's review process, MOA between federal agencies). Several things can be done to simplify the regulatory permit process

- Advanced identification of disposal sites
- Pre-application consultation
- General permitting (e.g., nationwide permits, abbreviated permits)
- Special Area Management Plans
- Cooperating agencies in EISs.
- Timely Consistency Determination and Water Quality Certification

These measures could help to streamline the regulatory processes, thus reducing operating costs. Components that affect operating costs are discussed in **Section 3.4.6.**

More effective use of the *Pre-Application Consultation* could result in less controversial projects. Pre-Application Consultation could identify potential impacts and problems early in the process. This would reduce the amount of time taken during the review process for each of the permit processes. The use of general permits, or abbreviated permits, for noncontroversial projects would reduce the total time needed to grant or deny a permit.

2.6.2.2 Comprehensive Wetlands Plan (CWP). In August 1991, the Administration announced a comprehensive plan for improving the protection of the nation's wetlands including measures to improve the Section 404 regulatory program. The President's plan consists of three goals

1. Strengthen wetland habitat acquisition programs and other efforts to protect wetlands
2. Revision of the interagency manual defining wetland habitat to ensure that it is workable
3. Improve and streamline the current regulatory system.

Strengthening of wetland habitat acquisition and revising the wetlands delineation manual will have *little* affect on the development of wetland habitat on the North Slope of Alaska. Increasing funding for wetland acquisition programs will mostly benefit the wetland habitat in the Lower 48 states. While some programs (e.g., expanding existing satellite monitoring and research) may provide funds for North Slope wetlands, most programs (e.g., wetlands reserve, wetland's restoration and creation) are designed specifically for the Lower 48 states.

Revision of the 1989 "Federal Manual for Identifying and Delineating Jurisdictional Wetlands" (EPA 1991), while a controversial issue, will likely *not affect* the identification and delineation of wetlands on the North Slope of Alaska. Federal agencies (e.g., Corps, FWS) are currently using the Corps' 1987 regulations to delineate wetland habitat. Most low lying lands on the coastal plain of the North Slope would be delineated as wetland habitat, whether using the Corps' 1987 regulations, 1989 Manual, or the August 1991 proposed revisions to the 1989 Manual. Permafrost conditions on the North Slope result in water always being close to, if not on top of the surface. Therefore, the soil is always saturated. Also, during the summer growing period, surface water and hydrophytic vegetation is present most, if not all, the time. These characteristics satisfy the current criteria for wetland habitat.

Third, the improvement and streamlining of the current regulatory process and added flexibility could greatly affect wetlands permitting on the North Slope of Alaska. The plan proposes the following actions to improve the 404 regulatory program

- Streamline the permitting process
- Define wetland's categories
- Develop a mitigation banking system based on wetlands categories
- Develop permit conditions for different valued wetlands
- Increase the State's role in the permitting process
- Modify the coverage of the 404 program.

Practicable mitigation on the North Slope has generally resulted in the minimization of adverse impacts. Frequently, avoidance and compensation (at least on-site) of impact to wetlands on the North Slope are not practicable. However, industry does routinely avoid "higher value" wetland habitat. In addition, compensatory mitigation is practicable for some projects where abandoned gravel pads and/or roads are near the proposed project.

The Plan states that "States with less than a 1 percent historic rate of wetlands development would be able to satisfy permit requirements through minimization." This provision applies directly to Alaska where historically there were approximately 170 million acres of wetlands in 1867, but where developments of all types have resulted in the loss of approximately 200,000 acres (< 1% disturbed or lost) (Dahl 1990; BP Exploration 1989). On November 4, 1992, the EPA proposed a rule in the Federal Register in accordance with the President's CWP. Should the rule be finalized as proposed, it would eliminate the requirement to avoid impacts to wetlands or compensate for wetlands losses in Alaska. However, the existing provisions of the Guidelines and the MOA already provide that the proportion of wetland habitat in an area is an important factor in determining whether, and to what extent, mitigation steps (i.e., avoidance, minimization, and compensation) are practicable in a particular case.

The CWP proposes changes to help ensure more timely decisions and effective coordination among agencies. Those that will affect permitting on the North Slope include: (a) single agency coordination, (b) reemphasis on preapplication meeting, (c) permit decisions within 6 months, and (d) the use of general permits. The Plan establishes an interagency technical committee to define several wetland categories based on function, value, and their relative scarcity or abundance. This process will help

categorize important wetlands on the North Slope and assist the oil and gas industry when planning and siting exploratory and production activities.

2.6.2.3 Wetlands Mitigation. Mitigation of impacts to wetlands is regulated under Section 404 of the CWA (see **Section 2.4.2.3**). In addition, the Corps and EPA have signed a MOA concerning mitigation under the CWA. Corps and EPA personnel use the MOA when carrying considering mitigation requirements for standard permit applications. The Corps uses this MOA when deciding whether mitigation for standard permit applications meets the Guidelines. The EPA uses this MOA in developing its positions on compliance with the Guidelines for proposed discharges.

In administering these provisions, the Corps strives to avoid adverse impacts and offset unavoidable adverse impacts to existing aquatic resources when permitting actions. For wetlands, it will strive to achieve a goal of no overall net loss of values and functions. Under the present Guidelines, the Corps is required to seek appropriate and practicable mitigation (e.g., *avoiding*, *minimizing*, or *compensating)* for unavoidable adverse impacts. In determining "appropriate and practicable," the Corps should consider the scope and degree of those impacts, and the cost of existing technology and logistics in light of overall project purposes. The level of mitigation determined to be appropriate and practicable may lead to individual permit decisions that do not fully meet the goal of no net loss. Therefore, the goal of no net loss of wetlands functions and values may not be achieved in every permit action.

2.6.2.4 Proposed Legislation. New legislation introduced into Congress could revise the current delineation, identification, and permitting processes associated with wetland habitat. The effects of these legislative bills range from strengthening the concept of no net loss of wetlands to replacing the entire Section 404 Permitting Process (see **Table 2-4**).

The impact on the North Slope permitting process would vary depending on which, if any, piece of legislation is enacted. All of the bills contain provisions to define and classify wetland habitats, streamline the permit process, mitigate adverse impacts, and transfer authority to the states. The major difference between the bills occurs in their incorporation of the no net loss concept, mitigation strategies, coverage or permit conditions, and jurisdictional authority. Many concepts included in these legislative bills incorporate ideas proposed in the President's CWP. Additional legislation could also be introduced

Table 2-4. Examples of bills introduced in the Senate and House of Representatives related to the protection of wetlands.[a]

No.	Title
Bills in the Senate	
S. 1463	Comprehensive Wetlands Conservation and Management Act
S. 2018	Wetlands Simplification Act
Bills in the House of Representatives	
H.R. 251	Wetlands No Net Loss Act of 1991
H.R. 404	Wetlands Protection and Regulatory Reform Act of 1991
H.R. 1010	To Prohibit Federal Agencies from Implementing the Federal Manual for Identifying and Delineating Jurisdictional Wetlands
H.R. 1330	Comprehensive Wetlands Conservation and Management Act of 1991
H.R. 2185	Just Compensation Act of 1991
H.R. 2400	Wetlands Stewardship Act of 1991
H.R. 2564	Agricultural Wetlands Exemption Act
H.R. 2594	Wetlands Stewardship Trusts Act of 1991
H.R. 3492	Wetlands Improvement Act of 1991
H.R. 3523	Wetlands Disposition and Protection Act of 1991
H.R. 3578	Study of the Environmental Research Basis of Wetlands Delineation Provision
H.R. 4093	Wetlands Simplification Act
H.R. 4255	Wetlands Reform Act of 1992
H.R. 4486	The Wetlands Preservation Act
H.R. 4840	Wetlands Delineation Fairness Act
H.R. 5422	Preservation of Wetlands and Historic Sties in Florida, Authorization, Amendment
H.R. 5585	Establishment of United States Policy regarding Wetlands, and for other purposes
H.R. 5874	Wetlands Center, Brownsville, TX, Establishment
H.R. 352	Year of the Wetlands, Designation

a. Modified from "Wetlands Protection Hotline, Legislative Update", September 1992. These bills are not in the current Congress, but are examples of the types of legislative actions introduced to the Senate and House related to wetland habitats.

regarding wetlands protection. Until new legislation is enacted, wetland's regulation continues under the current implementing statute.

2.6.3 Subsistence

Subsistence uses are defined as "the customary and traditional uses by rural Alaska residents of wild, renewable resources for direct personal or family consumption as food, shelter, fuel, clothing, tools, or transportation; for the making and selling of handcraft articles out of nonedible byproducts of fish and wildlife resources taken for personal or family consumption; and for customary trade" (DOI 1987a). The Alaska CMP recognizes the need to protect the opportunity for subsistence usage in the coastal areas (Alaska Administrative Code [AAC] 80.120) and requires the designation of areas where subsistence is the priority use. In these areas, permits would likely restrict transportation, construction, and operational activities during certain times of the year. These restrictions would be in the interest of sustaining population levels of mammals and fish. Subsistence hunting and fishing resources are also protected by the NSB Land Management Regulations and the Coastal Zone Programs. NSB regulates development in zoning districts through the Administrative Approval, Use Permits, and Conditional Permits (e.g., Conservation Districts, Resource Districts, Transportation Corridor Districts). In addition, Section VIII of the Alaska National Interest Land Conservation Act is the principal mechanism for the regulation of subsistence activities in Alaska. Inherent to granting approval or permits for development is the protection of subsistence hunting and fishing resources.

Several existing units are included in the NSB Resource Development District, including the Prudhoe Bay, Milne Point, Duck Island, and Kuparuk River Units. The NSB Land Management Regulations specifically point out that Gwydyr Bay and Point Thomson do not have master plans, and therefore do not have administrative approval for uses or development in these areas (NSBMC Title 19.40.080 [E]).

The NSB is particularly concerned with the effect offshore oil and gas exploration and development could have on subsistence hunting and fishing. A major concern of the NSB regarding offshore oil development is the potential impact of oil spills on subsistence hunting and fishing resources

and opportunities. The position of the NSB is that offshore development should not occur without assurances that oil spill cleanup can occur in all types of weather conditions.[a]

Location of potential oil and gas fields in areas of high subsistence use may require mitigative measures such as seasonal restrictions on drilling, transportation, and production operations. As the number of fields increases on the North Slope, the issue of subsistence will likely become more important. Cumulative effects from oil and gas fields on hunting and fishing resources and opportunities may require additional and more stringent regulations to prevent impacts to subsistence living.

2.7 References

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3. TECHNICAL AND ECONOMIC ANALYSIS

3.1 Overview

This section includes a discussion of the technical and economic evaluation for each of the five NES Fields. These five undeveloped fields are diverse in terms of geographic location, size of resources, areal extent, depth of producing horizon, type and quality of hydrocarbons, and type of reservoir rock. The evaluations are designed to facilitate the understanding of the development decision-making process for each of the fields. The environmental and regulatory issues are addressed through their impacts on operating and investment costs. The economic results are determined using four oil price forecasts. Following the individual field evaluations, sensitivity analyses are performed to evaluate effects of changing various parameters that control the economic viability of the potential developments. Sensitivity analyses provide a measure of the effects that potential cooperative efforts by state and federal agencies and industry can have on the development of the five NES fields. The relative effects of (a) increased oil price, (b) increased accumulation size and production rate, (c) reduced environmental and regulatory costs, (d) reduced federal and state revenue needs, and (e) investment and operating cost reduction measures instituted by the industry are illustrated by the analysis.

3.2 Economic Parameters - Definitions and Assumptions

The economic parameters involved in the evaluation of the five NES fields are defined and discussed in this section; the financial model is described in Appendix D.

3.2.1 Oil and Gas Prices

The price forecasts used and the methods of determining price schedules are discussed in this Section.

3.2.1.1 Oil Prices. One NES oil price case and three Energy Information Administration (EIA) oil price cases are included in the economic analyses. The NES Low price case is discussed in the *National Energy Strategy Annex 2*, (NES 1991a). The EIA oil price cases, High, Mid-Level scenario, and Low, are discussed in *Assumptions for the Annual Energy Outlook 1992*, (EIA 1992). The Mid-Level

Table 3.2. North Slope gas sale prices (1/1/92$ /MCF).

Oil price	2008 Asian NGL $/MCF prices	2008 Gas prices at various net-back factors ($/MCF)				
		5%	10%	15%	20%	25%
EIA Low	4.29	0.22	0.43	0.64	0.86	1.07
NES Low	5.31	0.27	0.53	0.80	1.06	1.33
EIA Mid-Level	6.42	0.32	0.64	0.96	1.28	1.61
EIA High	7.79	0.39	0.78	1.17	1.56	1.95

North Slope gas at the inlet of the purchasers facilities.

3.2.1.3 Wellhead price. The following definitions are used to calculate wellhead price:

- Wellhead Oil Price = World Oil Price - Oil Net Back
- Oil Net Back = Marine Tariff + Taps Tariff + Gravity Adjustment + Field Tariff
- Wellhead Gas Price = Price at the inlet to the purchasers facilities less any field transportation and compression costs
- Producer Gas Net Back = North Slope producers share of the price LNG is sold for in Asian markets.

The individual components to the oil net back and field gas costs are discussed in the following sections.

3.2.1.3.1 Marine Tariffs. The crude oil, condensate, and natural gas liquids (NGLs) mixture is shipped from Valdez to West Coast and Gulf of Mexico delivery points. Estimates of future marine transportation costs include consideration of:

- Double-hull requirements
- The age of the fleet transporting Alaska crude
- The change in the West Coast demand for Alaskan crude
- The declining volume of Alaskan crude to be shipped.

The Alaska Department of Revenue (ADR) recently completed an in-depth study of tanker rates for North Slope crude (ADR 1991a). The state of Alaska's mid-range marine tariff schedule in constant 1/1/92 dollars is used. The schedule is shown in **Table 3.3** (ADR 1991b).

Table 3.3. Marine transportation costs, Valdez to Lower 48 ($/BBL).[a]

Fiscal Year	As Spent	Constant 1/1/92$[b]
1992	1.52	1.4902
1993	1.59	1.4989
1995	1.55	1.3509
2000	1.69	1.2107
2005	2.16	1.2718

a. Average cost of West Coast/Gulf Coast Delivery mix.
b. Deflated at 4% per year.

The yearly schedule of marine tariffs is developed as follows:

- Interpolated data points are calculated between 1993 and 2005.
- Data points are obtained after 2005 by using a straight line extrapolation; the tariff in 2025 is $1.49/BBL (1/1/92$).

3.2.1.3.2 TAPS Tariffs. TAPS tariffs are determined individually by owner companies according to a 1985 settlement agreement between the owners and the state. A brief discussion of the method used to estimate TAPs tariffs follows. A more complete discussion on TAPS tariffs can be found in Section 3.2.5.1 of the previous DOE publication (1991). Simplifying assumptions are:

- Single ownership of pipelines
- Total throughput goes to Valdez
- Minor investments after 1/1/92
- Operating expenses adjusted to current level; currently about $700 MM/yr (Platts 1992)
- Operating expenses are cut by 1/3 by 12/31/96[a]
- Simplified depreciation
- Net carry-overs are zero
- State and federal income taxes to remain unchanged
- Field production volumes reduced by a 0.957 factor to account for fuel usage and losses.

The method results in an estimated annual total revenue requirement (ATRR) necessary for the TAPS owners to receive the allowed return on their investment. As a starting point, the ATRR is calculated for 1991 using the average 1991 tariff (ADR 1991b) and the 1991 North Slope total field production. The resulting ATRR is compared to an ATRR calculated from information in the previous

a. Alyeska Pipeline Service Co., "Facing The Future, Commitment, Challenge, Change," Remarks by James B. Hermiller, January 6, 1992.

DOE publication (1991). The results are about 10% apart. Because of this difference and the projected reduction in operating costs, a new TAPS tariff schedule was prepared using the updated information including the current production forecasts of North Slope field rates of active fields, fields under development, and potential field developments. The new TAPS tariff schedule in 1/1/92$ is given in **Table 3.4**.

Table 3.4 TAPs tariff schedule (1/1/92$).

Year	$/BBL	Year	$/BBL	Year	$/BBL	Year	$/BBL	Year	$/BBL
1992	3.52	1999	2.17	2006	2.69	2013	5.15	2020	12.48
1993	3.29	2000	2.31	2007	2.87	2014	6.95	2021	13.64
1994	3.04	2001	2.29	2008	2.99	2015	7.52	2022	14.59
1995	2.73	2002	2.40	2009	3.28	2016	7.86	2023	16.02
1996	2.46	2003	2.52	2010	3.68	2017	8.97	2024	16.75
1997	2.19	2004	2.53	2011	4.15	2018	10.00		
1998	2.08	2005	2.60	2012	4.91	2019	10.87		

The ADR published TAPS tariff schedules for three production case scenarios from 1991 through 2015 (ADR 1991b). Comparing the schedule in **Table 3.4** to ADR's mid-scenario (in constant 1992 dollars) showed less than 4% difference in the first 14 years and about 10% difference in the last 10 years. The greater difference in the last 10 years is due to differences in the production rate forecasts.

3.2.1.3.3 Field Tariffs. TAPS pump station (PS) No. 1 is located near the center of Prudhoe Bay Unit (PBU) (see **Figure 3.2**). The producers deliver crude oil (can be a mixture of oil, condensate, and NGL) to PS No. 1 for shipment to Valdez, Alaska. Four smaller pipelines that deliver crude to PS No. 1 are shown on **Figure 3.2**. These are the Endicott, Kuparuk, Milne Point, and Lisburne pipelines. As a simplification in the evaluation of the fields under development and the five NES fields, the cost of the pipeline to deliver crude to an existing field pipeline is included in the project investment. When any producer transports crude through a field pipeline to PS No. 1, a field tariff is charged. If the field tariff is known, it is used in the economic evaluation.

A field pipeline tariff is estimated, as follows, for each field where the tariff is unknown.[a]

a. Alaska Department of Natural Resources, personal communication, May 1990.

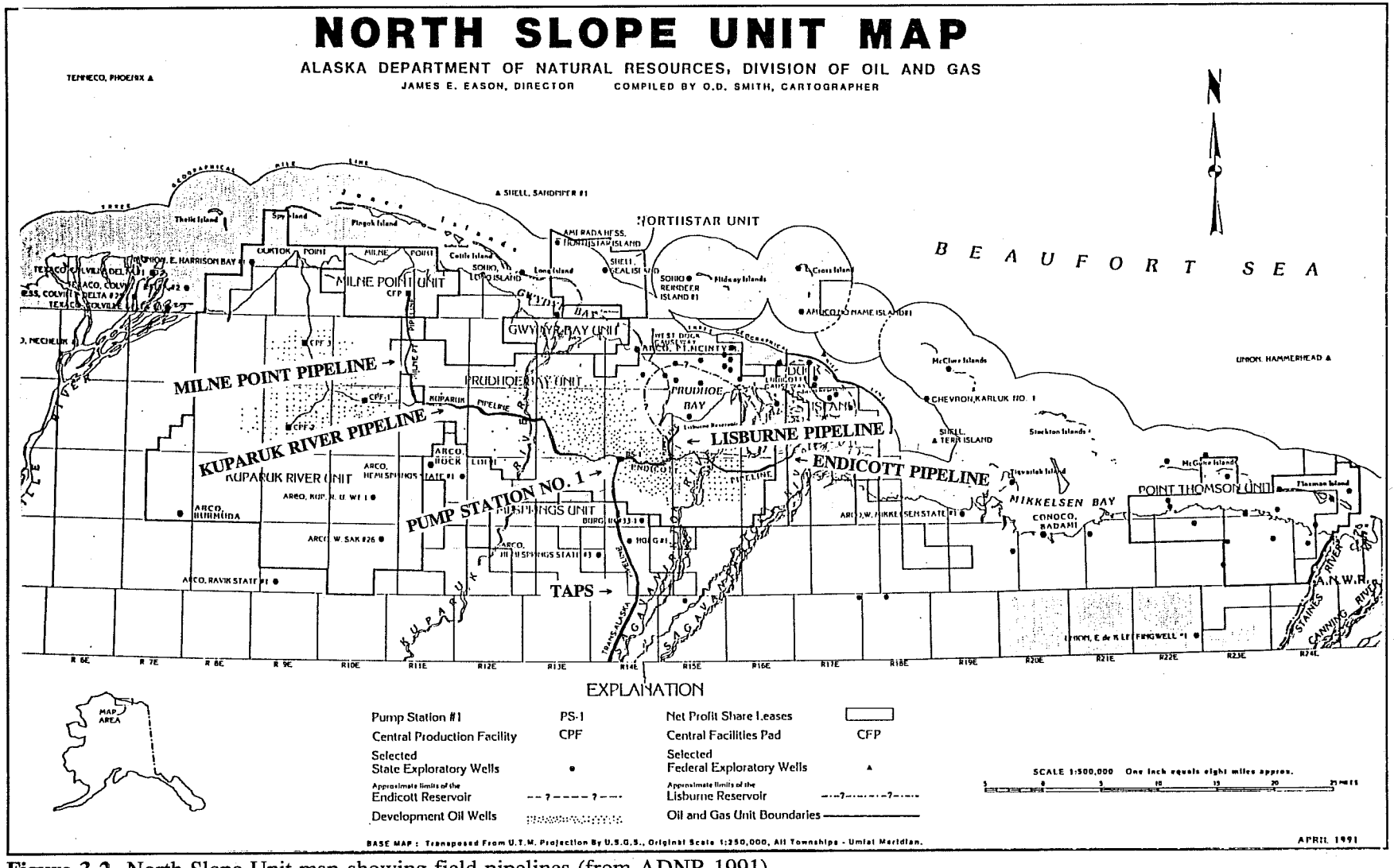

Figure 3.2 North Slope Unit map showing field pipelines (from ADNR 1991).

$$\text{Tariff} = \frac{\text{Cost of pipelines, haul road, and pump stations (1/1/92\$)}}{\text{Total volume to be transported (BBL)}} \times 3.35 = \text{\$/BBL (1/1/92\$)} \quad (3.3)$$

Pipeline construction costs presented by Young (1986) and the National Petroleum Council (1981) are used for each field pipeline situation.

3.2.1.3.4 Gravity Adjustment. Crude oil purchasers post a price for a crude stream (mixture of various hydrocarbons) in a certain geographic area and at a specified API gravity. Variations from the specified API gravity result in a positive price adjustment for crudes with a higher API gravity or a negative price adjustment for crudes with lower API gravities. Postings for North Slope crudes are based on an API gravity of 28°API. Variations from the base gravity are adjusted ±$0.29/°API/BBL.[a]

3.2.2 Discount Rate

The following assumptions are used:

- Base year for discussing constant dollars is 1/1/92.
- Inflation rate = 3.5%.
- Nominal discount rates used are 10 and 15% (see **Appendix D.1.1.10**, page D-11 for definition of real and nominal discount rate).

Individual companies evaluate the economic viability of future potential field developments by determining if their internal oil price forecast and discount rate (hurdle rate) will result in a present worth (PW) = 0 or better as discussed in **Section 1.2.3**. Current hurdle rates and price forecasts for individual companies are unknown. Hurdle rates will vary from company to company and from time to time based on economic conditions. There is some evidence that the cost-of-capital for major/integrated companies is about 15% (Miller 1992); therefore, the hurdle rate may be greater than 15%. However, for the purposes of this study, rates of 10 and 15% are assumed to bracket individual company hurdle rates.

3.2.3 Operating Costs

Operating costs include the operating and maintenance costs of (a) facilities, (b) wells (including workovers), (c) roads, (d) pipelines, (e) drillsites, (f) solvent, (g) fuel, (h) overhead costs, (i) shared

a. Alaska Department of Revenue, personal communication.

facilities charge (infrastructure use, processed water, and compression costs), and (j) estimated purchase cost of miscible injectant (MI). Operating costs also include the non-capital costs of environmental and regulatory compliance.

3.2.4 Facility Cost Factor

Although there were other sources of data for estimating facility investments (NPC 1984; MMS 1985), a method was developed in the previous DOE publications (1991) that was based on data from developed North Slope fields. Data were tabulated on a field by field basis that included historical investment data and estimates of future investments. The future investments were based on public information. These investment totals excluded all drilling costs. Investments for individual fields were related to the peak oil production rate of the field to result in investment per barrel of peak production rate.

A facility cost factor was determined for PBU, Kuparuk River Unit (KRU), Milne Point Unit (MPU), Duck Island Unit (DIU) (Endicott), and Lisburne Participating Area (LPA). The PBU facilities cost factor was excluded when determining the average factor because PBU was responsible for setting up the core infrastructure and, in addition, the other four fields benefitted from technology improvements, joint use of facilities, reduced costs due to design modification, and use of the in-place infrastructure. The average of the remaining facility cost factors is $15,200/BBL of peak production rate (1/1/92$) and is used in potential field analyses. This factor may be increased by 10 to 20% for projects with potential development difficulties, such as offshore projects, heavy oil fields, or fields located outside the PBU/KRU area.

3.2.5 Future Producing Well Determination.

The number of future active wells on an annual basis is required in severance tax calculations. A method was developed in the previous DOE publication (1991) to project the future active producers. PBU and KRU were used as guides in this method. Historical active well data were used where available. Schedules of future active wells that would be required in each units recovery plan were developed using industry experience and engineering judgement. Two sets of equations were developed to determine the future active producers in two different project sizes. The first set, for projects similar to PBU, is:

Set A - For the production period between 80 and 98% of ultimate recovery the current number of active producers is:

- Producers = {[181.1011 - 1.0112 (% of ultimate recovery)] x maximum active producers} ÷ 100.

For the production period after 98% of ultimate recover, the current number of active producers is:

- Producers = [1845.3988 - 17.9939 (% of ultimate recovery)] x maximum active producers ÷ 100.

The second set, for projects closer in size or smaller than KRU, is:

Set B - For the production period between 60 and 95% of ultimate recovery, the current number of active producers is:

- Producers = {[124.5528 - 0.4065 (% ultimate recovery)] x maximum active producers} ÷ 100.

For the production period after 95% of ultimate recovery, the current number of active producers is:

- Producers = {[458.3330 - 4.3330 (% of ultimate recovery)] x maximum active producers} ÷ 100.

Maximum active producers is assumed as the total cumulative producers drilled with no allowance for shutdown wells unless complete segments of the project are abandoned.

3.2.6 Production Forecast Parameters

Before well test data are available for use in estimating individual well and total field producing rates, empirical methods are used. Such methods are presented by Young (USDI 1986) and NPC (1981). After the total recoverable reserve volume is determined, the annual peak production rate is set as a percentage of the ultimate recovery. The producing rates for the early years are increased until the peak

rate is achieved. The peak rate is held constant for a number of years, then the peak production rate is declined. The decline rate used is usually between 12 and 15% per year. For smaller projects the life is about 15 years, but the life of larger projects may exceed 25 years. These factors are used as guides to prepare the production forecasts and may be modified using engineering judgement. These factors are listed in **Table 3.5**.

Table 3.5. Production forecast parameters.

Field Size (MMBO)	Peak % of Ultimate Recovery	Yearly % of Ultimate Recovery				Years at Peak Rate	Decline (%)
		1	2	3	4		
300[a]	7	3	5	-	-	4	15
50 to 300	10	3	7	-	-	3	12
300 to 725	10	3	7	-	-	4	15
725 to 1350	10	3	5	7	-	4	15
1350 to 3000	7	3	4	5	-	7	12
3000 to 7250	6	1	3	4	5	8	12

a. Limestone reservoir like Lisburne.

3.2.7 Water-cut Data

Forecasts of operating costs are prepared, for most of the projects in this study, using a relationship between percent water cut and percent of ultimate recovery. The previous DOE publication (1991) developed this relationship for PBU and KRU using available historical data and future data based on industry experience and patterned after Milne Point Kuparuk and Endicott model results. Model results were available at both MPU and Endicott for direct use. More water-cut data are available for KRU now than were available for the 1991 study and that relationship has been revised. The water-cut relationships for KRU, MPU, and Endicott are used in the evaluations of the five NES fields. Production data from ARCO's West Sak hot waterflood pilot were considered but, because they come from a very small area ($\approx$40 acres) and may not be representative of the field, they are not used.

3.2.8 Facilities Sharing Fee

The determination of fees for the use of shared facilities is assumed to be similar to the

determination of pipeline tariffs. Therefore, the tariff formula (3.3) in **Section 3.2.1.3** is adapted for these calculations as follows:

$$\text{Facilities sharing fee} = \frac{\text{Facilities cost savings (1/1/92\$)}}{\text{Estimated volume total fluid processed water processed for sharing project}} \times 3.35 = \text{\$/BBL (1/1/92\$)} \qquad (3.4)$$

3.2.9 Definitions

The definitions of the economic variables, tax rates, royalty rates, tariffs, etc. are included in **Appendix C.**

3.2.10 Financial Model

The financial model used was described in Section 3.7 of the previous DOE publication (1991). The model, which has been changed in several areas since 1991, is described in **Appendix D.**

3.3 Technical and Economic Analysis

The development plans and economic parameters for each of the five NES fields are described in this section and summary economics presented for each field.

3.3.1 West Sak

As described in the detailed history of the West Sak field contained in **Appendix B.1**, the West Sak sands, which are encompassed by the KRU, MPU, and a small part of PBU, contain oil at depths from 2000 to 4500 ft in the MPU and KRU, with the deepest portion to the northeast in the MPU. Oil production from the Schrader Bluff oil pool in the MPU operated by Conoco started in March 1991. The "O" sands of the Schrader Bluff sands are equivalent to the West Sak sands in the KRU but the "N" sands are more equivalent to the lower Ugnu sands (see **Appendix B.1.1**). Hence, direct comparisons of Schrader Bluff with the balance of the West Sak area should be approached with caution. A discussion of Schrader Bluff is contained in **Appendix A.2.2**.

In the KRU area, West Sak wells produce very little by primary methods (ARCO 1989); therefore, some form of enhancement will be required. KPA processing facilities are not expected to have spare capacity but can be expanded to handle the entire West Sak production stream as discussed in **Appendix A.1.2.2.3** (ARCO 1989).

3.3.1.1 Evaluation Data. Evaluation data are based on published documents and on some field production history (hot-water pilot). To estimate recovery from the West Sak sands it is necessary to determine the recovery method to employ, the plan of development, the reservoir intervals to be included, and the area for development.

3.3.1.1.1 Recovery Processes--Various potential enhanced oil recovery (EOR) processes are reviewed briefly in the following paragraphs. These include hot waterflooding, CO_2 water-alternating-gas (WAG), steam flooding, and hydrocarbon miscible WAG. In addition to the high variability and low quality of the oil in West Sak, the reservoir is highly stratified with numerous shale streaks and the lower sand member consists of thin-bedded sands interbedded with siltstone and mudstone. These characteristics affect all potential recovery processes.

1. **Hot waterflood.** ARCO initiated a 40-acre hot waterflood pilot using 5-acre well spacing and a nine-spot pattern in November 1983. The pilot project was shutdown in December 1986 after recovering 720,392 BBL of oil. ARCO has indicated the project was not an economic success.[a]

   However, the project was a technical success in that water was injected at significant rates and oil was moved to the producing wells. The December 1986 production volumes were 22,302 BBL of oil and 9,288 BBL of water giving a water cut of about 30%. Industry experience shows that most successful waterfloods (with good quality sands and hydrocarbons) would have recovered less than 50% of ultimate recovery at that water cut. Even with expected lower performance at West Sak, the pilot could have recovered significant additional volumes of oil if operations had continued. Conservatively, with projected abandonment at a water/oil ratio (WOR) between 55 and 70%, potential additional oil recovery is estimated at between 220,000 and 315,000 BBL.

a. ARCO Alaska, Inc., personal communication, October 22, 1991.

These volumes give estimated total recoveries of 12.9 to 14.1% of original oil in place (OOIP).

It is assumed the hot waterflood pilot would have recovered 13.5% of OOIP had it been operated to a water cut of about 60%.

2. **CO_2 WAG**. Although a potential source of CO_2 exists in the PBU gas cap (12% by volume or in excess of 3 TCF), the use of CO_2 in a West Sak development scenario poses several problems.

a) CO_2 was shown to be immiscible with two West Sak crude oil samples at reservoir pressures up to 2,000 psia. Although CO_2 had a very positive effect on oil viscosity, it was due to solubility only (DeRuiter 1990).

b) With early breakthrough of CO_2 gas, the laboratory recovery of 48% is about one-half that of hydrocarbon-gas injectants (DeRuiter 1990). Therefore, much of the CO_2 would likely channel to producers increasing handling costs while providing little benefit to recovery.

c) The use of CO_2 would result in contamination of the KPA shared facilities and hydrocarbons produced from KPA and West Sak with CO_2.

3. **Steamflooding**. West Sak does not appear to be a very good prospect for steamflooding. According to the screening criteria set forth by the National Petroleum Council (NPC) in their 1984 report on enhanced oil recovery (NPC 1984), the majority of the West Sak reservoir is unsuitable or only marginally suitable for steamflooding. Two important screening criteria for the West Sak reservoir are depth of the reservoir and thickness of the sands. The NPC suggests that heat loss to the overburden and underburden for sands thinner than 20 ft would be too high for an economical steamflood. Heat loss in shallow arctic reservoirs such as West Sak may dictate that the minimum sand thickness be somewhat more than 20 ft because of the close proximity of the permafrost. Most of the reservoir does not satisfy a minimum requirement of 20 ft for sand members. The reservoir is highly stratified with numerous shale streaks. The lower sand member

consists of thin-bedded sands interbedded with siltstone and mudstone. Individual sand beds in the lower sand member range from 0.2 to 5 ft thick with a few up to 10 ft in thickness. The upper sand member consists of two sand packages. Each package consists of individual beds 0.5 to 10 ft thick. The two packages in the upper sand member reach thicknesses of 25 to 40 ft in a few areas of the reservoir (Werner 1986). This is discussed in more detail in **Section 3.3.1.1.3**.

Much of the West Sak formation discussed in this study lies below 3000 ft subsea as shown on **Figure 3.3**. The NPC screening criteria indicate that at depths below 3000 ft, heat losses during injection would probably result in nearly total condensation of the steam in the injection tubulars. Hot waterfloods, although they do produce oil, have been shown to be uneconomical in the West Sak reservoir.[a] Screening West Sak for sand thickness and depth leaves a relatively small portion of the reservoir that may be amenable to steamflooding.

4. **Hydrocarbon miscible WAG**. Laboratory experiments show that some hydrocarbon gases or gas mixtures are miscible with West Sak crude oils at pressures as low as 1000 psia. This is well below the reservoir pressure of about 1600 psia (DeRuiter 1990).

   Review of the results of laboratory experiments indicate an enriched hydrocarbon gas mixture may be best suited for the West Sak reservoir. The laboratory tests results show late breakthrough of the MI and recoveries of greater than 95%. These slim tube miscibility tests are not directly related to field recoveries, but do show proof of concept.

It is concluded that miscible WAG is the best process to be used in any West Sak development scenario. It is important to recognize that West Sak is at least third on the list of fields that are using or may use the limited supply of MI currently available on the North Slope.[a] Because of the high investment and operating costs that will be experienced in West Sak and the lower wellhead price for West Sak crude, it is anticipated that this project will not justify the use of MI until after both PBU and KRU demands are satisfied.

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a. ARCO Alaska, Inc., personal communication, October 22, 1991.

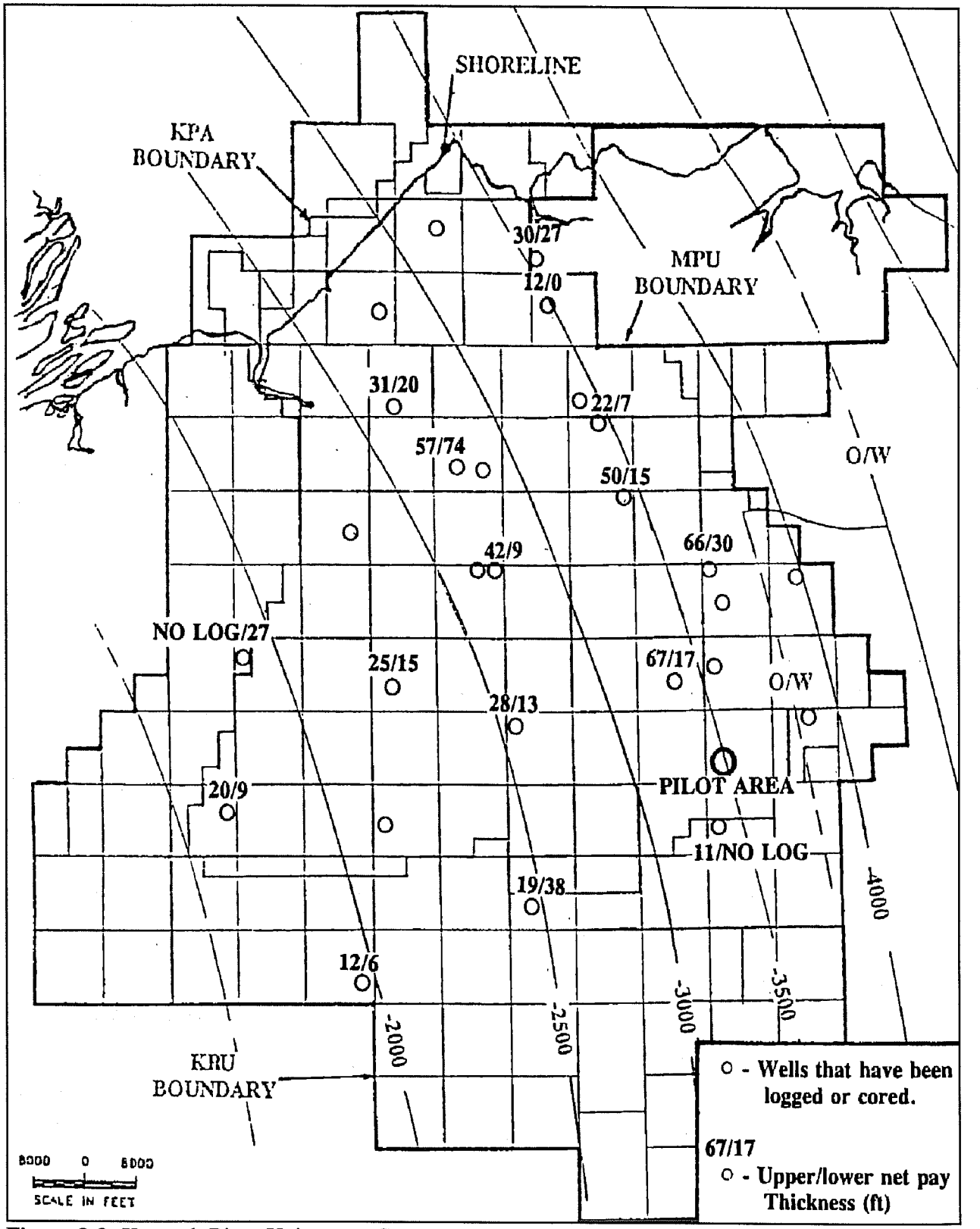

Figure 3.3 Kuparuk River Unit area. Contours on top of the West Sak sands (contour intervals estimated from Werner 1986, top of West Sak structure map). Upper and lower West Sak sand thicknesses (DOE 1990).

3.3.1.1.2 Development Plan. The development schedule for West Sak must consider the availability of MI, economics of expansion of KPA processing facilities, and phased development to recover reserves before possible shutdown of TAPS (see **Section 1.1**).

Current plans call for 20-acre spacing with about 25 wells being drilled from each well pad.[a] This results in development of about 500 acres/pad, or slightly more than one pad per section. The use of a nine-spot waterflood pattern, as was used in the hot waterflood pilot, would result in about a 26.7-acre drainage area/producer. A nine-spot pattern is adopted for this study. Any development scenario may require modification to minimize environmental impacts because of ponds, lakes, streams, and wildlife habitat (AeroMap 1988). During actual development, pad locations will be adjusted to fit the complex faulting pattern. Assumptions are incorporated in the recoverable oil evaluation in **Section 3.3.1.1.5** for such possibilities. The use of any existing KPA pads (or enlargements) would be considered during actual field development. Based on available information, it appears that six and possibly seven KPA pads are located so they may be enlarged for West Sak development.

3.3.1.1.3 Reservoir Intervals and Zones to be Developed--Reproductions of a number of well logs covering the West Sak sand intervals are available (Werner 1986; AOGCC 1990; DOE 1990; Jamison 1980).[a] Petrophysical properties are also available on 13 wells (DOE 1990). See **Figure B.1** (**Appendix B**) for a type log from the West Sak River State No. 1.

Examination of petrophysical data calculated from 12 wells by the University of Alaska Fairbanks (DOE 1990) shows a wide variation in net sand thickness of from 1 to 37 ft in the upper two West Sak sands. Visual examination of four additional well logs shows a similar variation from 0 to 34 ft. In these 16 wells there are only 16 net sand intervals in excess of 15 ft. These sand interval thicknesses are listed in **Table 3.6**. Net sand intervals for the five lower West Sak sands in 17 wells are also listed in **Table 3.6**. These lower sand intervals vary from 0 to 37 ft in thickness; however, only eight intervals exceed 10 ft in thickness. There is more uncertainty on the performance of thin sand intervals and they may be poor candidates for development except in conjunction with the development of the upper sands. The sands must be continuous between wells to be effectively flooded.

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a. ARCO Alaska Inc., February 13 and 14, 1992; response to data request for copies of downhole logs on West Sak wells, No. 13, 14, 15, and 23.

Table 3.6. West Sak formation sand thickness.[a]

	Upper Sands			Lower Sands					
Well Name	**No. 1**	**No. 2**	**Total**	**No. 1**	**No. 2**	**No. 3**	**No. 4**	**No. 5**	**Total**
West Sak No. 1	32	34	66	11	9	6	4	0	30
West Sak No. 2	30	37	67	5	4	4	4	0	17
West Sak No. 3	18	10	28	0	4	1	8	0	13
West Sak No. 5	10	1	11	No Log Data Available					--
West Sak No. 9	33	9	42	6	2	1	0	0	9
West Sak No. B-10	7	12	19	3	20	11	4	0	38
West Sak No. 11	17	9	26	0	0	2	0	0	2
West Sak No. 17	4	8	12	0	0	0	0	0	0
West Sak No. 18	No Log Data Available			4	3	6	0	0	13
East Ugnu No. 1	8	14	22	5	2	0	0	0	7
Kuparuk No. 1G-7	23	27	50	2	5	8	0	0	15
Kuparuk No. 3B-14	21	36	57	37	29	2	0	6	74
Milne Pt. No. N-1B	10	20	30	4	12	11	0	0	27
Per Well Avg.	17.75	17.33	35.08	6.42	7.50	4.33	1.67	0.5	20.42
West Sak No. 13	0	12	12	2	4	0	0	0	6
West Sak No. 14	18	7	25	1	10	1	3	0	15
West Sak No. 15	8	12	20	4	3	2	0	0	9
West Sak No. 23	16	15	31	8	4	2	6	0	20
Per Well Avg.	11.5	11.5	23.0	3.75	5.25	1.25	2.25	0	12.50
Average All Data	16.19	15.87	32.06	5.75	6.94	3.56	1.82	0.37	18.44

a. The data on the first 13 wells is taken from UAF report (DOE 1990). The data on the last four wells from visual examination of logs.

The hundreds of wells drilled to develop the deeper KRU provide limited information on the West Sak reservoir. The KRU wells are drilled as straight holes from the surface through the permafrost before being deviated to the bottom hole location in the Kuparuk reservoir. Thus, the KRU wells are very closely spaced below the widely spaced pads as they penetrate the West Sak interval and do not provide as extensive information as might be expected.

It is assumed that any area considered for development must have a minimum combined net pay thickness of 40 ft in the upper two sand zones to provide adequate production rates for a successful recovery project. Based on the assumption that the lower intervals are continuous over the area, the lower

sand pays are included in the evaluation. These pay intervals increase the recoverable reserves and the average production rate. The wells that meet these criteria are shown in **Table 3.7** with their net pay footage.

Table 3.7. West Sak wells with net pay footage greater than 40 ft.

	Net Pay - ft		
Well Name	**Upper Sands**	**Lower Sands**	**Total**
West Sak No. 1	66	30	96
West Sak No. 2	67	17	84
Kuparuk No. 1G-7	50	15	65
West Sak No. 9	42	9	51
Kuparuk No 3B-14	57	74 (40)	131 (97)

The lower sand thickness of 74 ft in Kuparuk 3B-14 appears to be an anomaly and is not used in determining Area B average thickness. Examination of the log on this well indicates the possibility of a total lower sand thickness of between 35 and 45 ft. An average lower sand interval of 40 ft is assumed for Well 3B-14 and results in a total thickness of 97 ft.

3.3.1.1.4 Area to be Developed--Criteria used to determine areas of potential development are:

1. Pay thickness of more than 40 ft in upper two sands (**Table 3.7**)
2. Reservoir temperature and crude oil viscosity
3. Structure map on top of West Sak (**Figure 3.3**)

Variations in West Sak oil gravities and viscosities are reported but the areal extent and distribution is not publicly available. An approximate reservoir temperature of 70°F is reported at a depth of 3,000 ft (Werner 1986; AOGCC 1990). Based on reported viscosities for one West Sak crude oil of about 10,000 cp at 60°F (DeRuiter 1990), an upper limit of 2,500 ft (top West Sak) is assumed for reservoir development. **Figure 3.4** shows the thicknesses of the upper and lower West Sak sands for the wells listed in **Table 3.6**. Using the sand interval thicknesses from **Table 3.7** and the 2,500 ft upper limit, two areas of potential development are defined. These areas are designated "A" and "B" and are

shown on **Figure 3.4**. The average pay thicknesses for Area A and Area B are estimated at about 82 and 74 ft, respectively.

Using the development outlines on **Figure 3.4**, the size of Areas A and B are estimated as 22,500 and 7,000 acres, respectively. These areas are used in reserve calculations and in determining the number of drilling pads required.

Based on the development plan discussed in **Section 3.3.1.1.2**, one possible scenario for well pads required to develop Areas A and B is shown in **Figure 3.5**. These locations are premised on a continuous reservoir body and no surface restrictions imposed by environmental or wildlife issues. In this scenario there are 45 pads with 1,125 total wells in Area A and 14 pads with 350 wells in Area B.

3.3.1.1.5 Recoverable Oil Calculations--No specific recovery factors (percent of OOIP) are available for a West Sak miscible WAG development. The following information provides guidelines for determining estimated recovery factors for Areas A and B.

- Estimated hot waterflood pilot recovery of about 13.5%.
- Conoco's Schrader Bluff estimates of primary recovery of 12% and waterflood recovery of 9% using laboratory tests and reservoir modeling.[a]
- James Eason's U.S. Federal Energy Regulatory Commission testimony giving recovery from the West Sak reservoir of between 5 and 15% of 15 to 20 BBOIP.[b] This general range of recoveries applies to the entire accumulation and not to smaller areas of better reservoir development.

Little or no primary recovery is expected from most of the West Sak reservoir.[c] Therefore, the estimated recovery of 13.5% from the hot waterflood pilot is assumed to be representative of primary, secondary (waterflood), and some tertiary recovery (hot waterflood). Based on the effectiveness of the slim-tube miscibility tests (DeRuiter 1990), it is assumed that a 50% increase in recovery efficiency would be possible. This results in an estimated recovery of about 20% of OOIP.

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a. Conoco, Inc., personal communication, October 21, 1991.

b. James E. Eason, Director of the Division of Oil and Gas, Alaska Department of Natural Resources; Testimony before U.S. Federal Energy Regulatory Commission on behalf of the state of Alaska, June 12, 1992.

c. ARCO Alaska, Inc, personal communication, October 22, 1991.

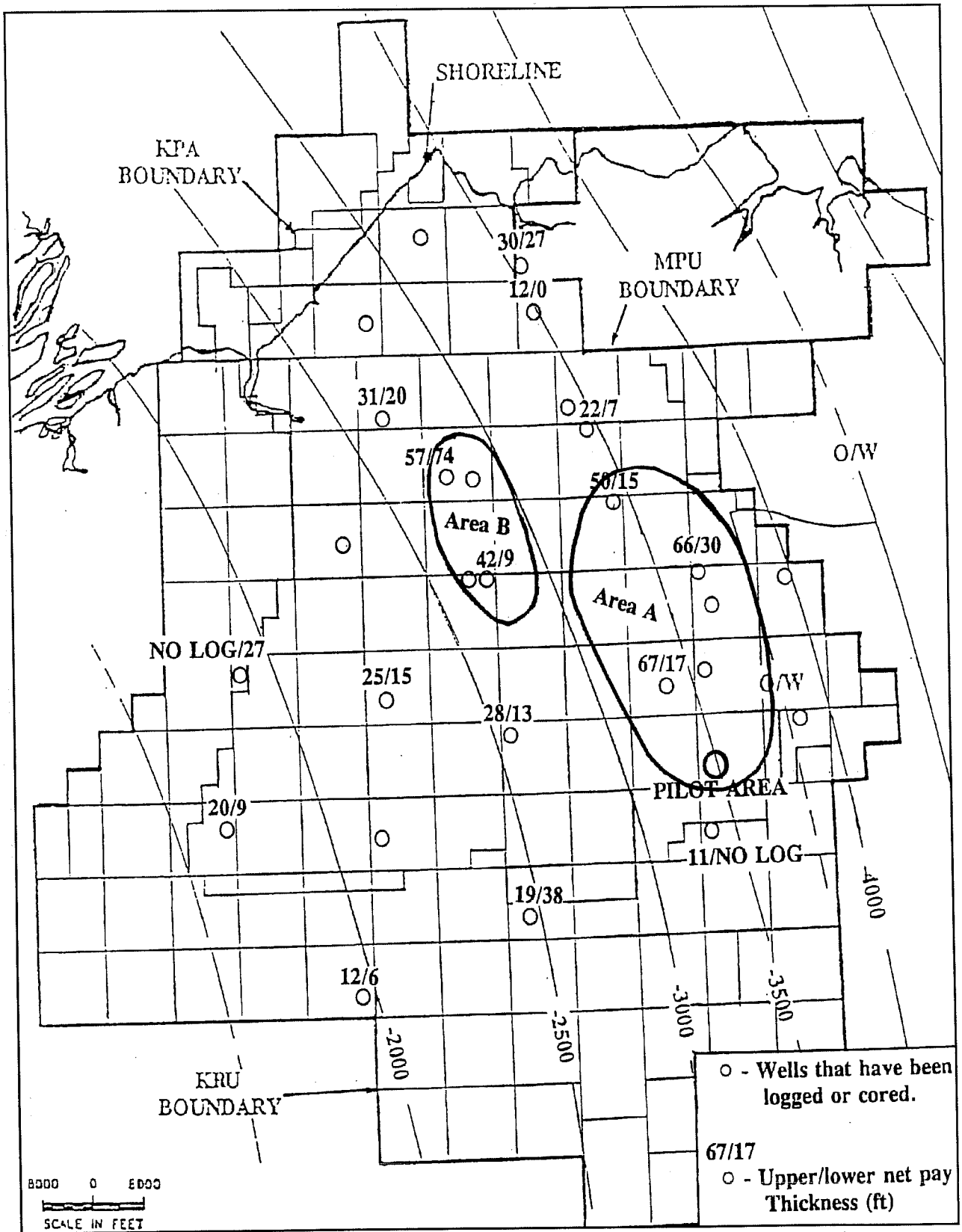

Figure 3.4 Potential West Sak development areas. Contours on top of the West Sak sands (contour intervals estimated from Werner 1986, top of West Sak structure map). Upper and lower West Sak sand thicknesses (DOE 1990).

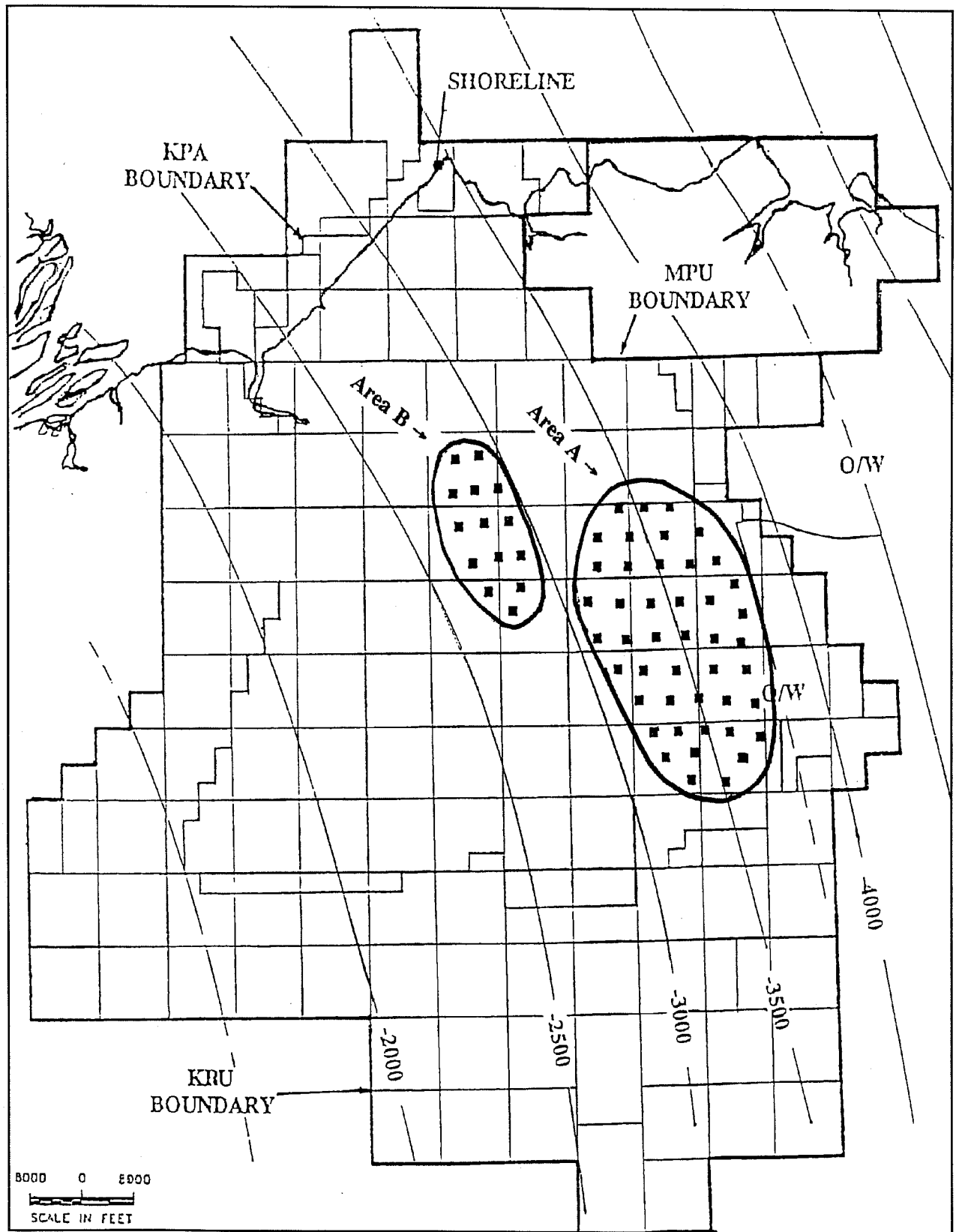

Figure 3.5 Potential West Sak drilling pad locations. Contours on top of the West Sak sands (contour intervals estimated from Werner 1986, top of West Sak structure map).

Because Area B is shallower, with the top of West Sak at about 2,500 ft, a lower recovery of about 15% is assumed due to the higher in-situ oil viscosity; i.e., a more unfavorable mobility ratio. Given the heterogeneity of the formation as demonstrated by the logs, the variation in pay intervals, the variations in oil gravities, and the reported faulting that is illustrated by the faulting in the Schrader Bluff area as shown in **Figure B.18 (Appendix B)**, the estimated recoveries are further reduced to compensate for these factors. In addition, the probability exists that all drilling pads cannot be placed at the desired surface locations because of wetlands or wildlife considerations, thus reducing the areal sweep efficiency. Therefore, a reduction of 20% in the recovery factors is assumed for both Area A and Area B; i.e., a process efficiency (PE) of 80%. Thus, OOIP is calculated as follows:

$$OOIP = [7{,}758 \text{ BBL/acre-ft} \times A \times \phi \times (1-S_w) \times h]/FVF \quad (3.5)$$

where

A	=	area (acres)
ϕ	=	porosity
S_w	=	water saturation
h	=	average pay thickness (ft)
FVF	=	formation volume factor (RB/STB).

Remaining recoverable reserves are calculated as follows:

$$\text{Recoverable reserves} = OOIP \times PE \times RF \quad (3.6)$$

where

OOIP	=	original oil in place
PE	=	process efficiency (fluid and reservoir variations and sweep efficiency)
RF	=	recovery factor.

Area A. The recoverable reserves calculated for Area A include the cumulative 720 MBO production (AOGCC 1992) from the hot waterflood pilot area (**Figure 3.4**). The parameters for calculating the remaining recoverable reserves are as follows:

A	=	22,500 acres (assumed pilot acreage included)

ϕ	=	33% (assumed)
S_w	=	30% (assumed)
h	=	82 ft (average of 3 wells)
FVF	=	1.053 RB/STB (DeRuiter 1990)
PE	=	80%
RF	=	20%.

Using Equations (3.5) and (3.6), the OOIP and recoverable reserves are:

OOIP	=	3,140 MMBO
Recoverable reserves	=	3,140 MMBO x 0.80 x 0.20 - 0.720 MMBO = 502 MMBO.

Area B. The parameters for calculating the recoverable reserves are as follows:

A	=	7000 acres developed
ϕ	=	33% (assumed)
S_w	=	30% (assumed)
h	=	74 ft (average of 2 wells)
FVF	=	1.53 RB/STB (DeRuiter 1990)
PE	=	80%
RF	=	15%.

Using Equations (3.5) and (3.6), the OOIP and recoverable reserves are:

OOIP	= 881.6 MMBO
Recoverable Reserves	= 105.8 MMBO (use 106 MMBO).

3.3.1.2 Production Forecasts. The production forecasts developed for Areas A and B are assumed to utilize only processing capacity provided by expansion of the KPA facilities. The KPA facilities capacity is discussed in **Appendix A.1.2.2.3**. The production forecasts consider (a) availability of MI, (b) economics of expanding KPA processing facilities, and (c) development timing and rate designed to recover reserves before possible shutdown of TAPS. Initial MI availability is assumed to occur in 2001 with volumes increasing over the next 3 years. **Section 3.3.1.3** discusses this in more

detail. It is assumed that expansion of the KPA processing facilities will be justified by the facilities sharing fee discussed in **Section 3.3.1.4**. It is further assumed that sufficient facilities capacity (oil, gas, and water) will be included in the expansion to increase oil throughput by about 50% or by about 185 MBOPD and that the expansion will occur in stages, resulting in the peak rate being available in 2005. If the development of any of West Sak is delayed much past the year 2000, the shutdown of TAPS (see **Section 1.1**) due to minimum through-put limitations could prevent recovery of part or all of the projected production. Production forecasts are developed that recover the estimated potential reserves by the year 2013. Production from Area B does not commence until 2008 when MI is assumed to become available. All of the potential reserves from Area B will be lost if TAPS is shut down in 2008.

The production history of the hot waterflood pilot indicates the maximum productivity of the West Sak sands may be greater than the 250 BOPD/well used in the previous DOE publication (1991). The miscible WAG project should increase well productivity; therefore, oil rates may exceed the rates obtained in the pilot waterflood. A peak average oil rate of 300 BOPD is used for Area A and 260 BOPD for Area B. Total fluid rates in later life are expected to exceed either of these rates.

3.3.1.2.1 Area A Forecast--A production forecast is developed using a single producer forecast designed to recover the reserves using a 20-acre well spacing and nine-spot patterns. The schedule is discussed in the following subsections. It is assumed that first production will be in 2001.

(a) **Individual Well Schedule.** An average producer recovers 594.8 MBBLS of oil (502 MMBO divided by 844 producers). A 1-year period is used to reach peak production of 300 BOPD and is held for 2 years and then declined at about 15%/yr to an abandonment producing rate of about 150 BOPD. This results in slightly more reserves than the average well. Adjustment is made in the final year of production so ultimate recovery equals predicted recovery resulting in a single well forecast as follows:

Year	BOPD
1	225
2	300
3	300
4	255
5	215
6	185
7	150

(b) **Production Forecast.** Total area production forecast begins in 2001 and gradually increases to a peak rate of 168 MBOPD in 2006 and 2007. The production rates in the final year are adjusted to recover the total reserves by the 13th year. This step is reasonable because the best parts of the reservoir will be developed first and would have more per well reserves than an average well. This forecast is shown in **Table 3.8**. Also shown in **Table 3.8** are the total producing wells required each year to obtain the forecasted annual production volume.

Table 3.8. Production forecast and number of producers required for West Sak Area A.

Year	No. Prod Req.	Area A Yearly Production - MBOPD												
		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
2001	172	39	52	52	44	38	33	26	0					
2002	98	0	22	29	30	25	21	18	14	0				
2003	123	0	0	28	37	37	32	26	23	18	0			
2004	148	0	0	0	33	44	45	37	33	28	22	0		
2005	53	0	0	0	0	12	16	16	14	11	10	9	0	
2006	95	0	0	0	0	0	21	28	29	24	20	17	14	0
2007	74	0	0	0	0	0	0	17	22	22	19	16	15	14
2008	81	0	0	0	0	0	0	0	18	24	24	21	19	18
Tot.	844	39	74	109	144	156	168	168	153	127	95	63	48	32

3.3.1.2.2 Area B Forecast--A production forecast and a well drilling schedule for Area B are developed using the same method as for Area A. A decline rate of about 20%/yr is used in this forecast to reflect the lower recovery efficiency. Per well reserves in Area B are only about 70% of those in Area A. Therefore, a shorter well life is used in Area B, 5 years as compared to 7 years in Area A. Development is over a 3-year period. The average per well recovery is 403 MBO (106 MMBBLS divided by 263 wells). Initial production in 2008 is assumed. The individual well production forecast schedule for Area B is as follows:

Year	BOPD	Year	BOPD
1	200	4	215
2	260	5	170
3	260		

The production forecast and the total yearly producing wells required to obtain the forecasted annual production volumes are shown in **Table 3.9**.

Table 3.9. Production forecast and number of producers required for West Sak Area B.

Year	Producers Drilled	Area B Yearly Production - MBOPD					
		2008	2009	2010	2011	2012	2013
2008	100	20	26	26	22	18	
2009	130	0	26	34	34	29	23
2010	33	0	0	7	9	9	8
Total	263	20	52	67	65	56	31

3.3.1.3 Investments. The scenario being considered for the development utilizes expanded KPA processing facilities for all the produced fluids and for supply of the pressured injection fluids (ARCO 1989). A facilities sharing agreement will be required between the KPA and a West Sak participating area. For this scenario the state must approve a plan for the allocation of production between the two participating areas (ARCO 1989).

There are indications that savings to a West Sak participating area by sharing in the KPA fluid treating facilities (including injection), as compared to a stand-alone project, would be about $550 MM (1/1/92$) (ARCO 1989). The cost of this field development is estimated at $3.1 billion (1/1/92$) using the method discussed in **Section 3.2.4**. After deducting the shared facilities savings of $550 MM (1/1/92$), investments totalling $2,520 MM (1/1/92$) for well and pad facilities, roads, pipelines, and fluid handling facilities is still required. Some of the existing roads and pipelines can be used, but most of the drilling pads will be new. An additional 10% of the total facilities investment is assumed to be saved by utilizing the KPA infrastructure. The total shared facilities savings is $857 MM (1/1/92$). The facilities investment after reduction for facilities sharing is $2,213 MM (1/1/92$). The $2,213 MM (1/1/92$) investment is allocated between Areas A and B on the basis of percent of total wells in both areas. The investment schedules for Areas A and B are shown in **Table 3.10**.

Based on current information (ADNR 1989),[a] the drilling and completion cost of $850 M/well (1/1/90$) used in the previous DOE publication (1991) is low. Conoco advised their cost to drill and

a. Conoco, Inc., personal communication, October 21, 1991.

Table 3.10. West Sak Area A and B drilling and investment schedules.

West Sak Area A							
Year		Development Wells			Investments - $MM (1/1/92$)		
No.	Date	Producers	Injectors	Total	Wells	Facilities	Total
-2	1999	100	33	133	266	0	266
-1	2000	72	24	96	192	416	608
1	2001	98	33	131	262	233	495
2	2002	123	41	164	328	294	622
3	2003	148	49	197	394	354	748
4	2004	53	18	71	142	126	268
5	2005	95	32	127	254	228	482
6	2006	74	25	99	198	117	315
7	2007	81	26	107	214	60	274
Total		844	281	1125	2250	1828	4078
West Sak Area B							
Year		Development Wells			Investments - $MM (1/1/92$)		
No.	Date	Producers	Injectors	Total	Wells	Facilities	Total
-1	2007	100	33	133	266	152	418
1	2008	130	43	173	346	233	579
2	2009	33	11	44	88	0	88
Total		263	87	350	700	385	1085

complete a producer is currently about $2 MM. This is a reasonable cost for wells and some pad facilities. Completion practices are very complex and usually include a stimulation treatment of at least one zone. The current cost to drill and complete a producer is assumed to be $2.0 MM/well (1/1/92$). Even though injectors should cost less than a producer, the same cost is used for both type wells.

The development pattern scenario for West Sak has one injector for each three producers. **Table 3.10** shows the development drilling schedules for producers and injectors that are required to meet the production forecasts for Areas A and B shown on **Table 3.8** and **3.9**, respectively.

It is assumed that West Sak development depends on availability of MI. Therefore, initial development is delayed until sufficient MI volumes are available. PBU owners are studying plans to expand the PBU EOR area, which could tie up large volumes of injectant for years (AOGCC 1992a). KRU is also conducting a small EOR pilot to determine MI applicability to that reservoir. The timing of these projects is not firm. However, due to the possibility that insufficient volumes will be produced from North Slope fields to keep TAPS operating beyond the 2010 to 2015 period, West Sak development must occur as early as possible.

It is assumed that initial Area A production will commence in 2001 and occur in stages where production gradually increases to about 168 MBOPD by the year 2006, which allows more time for MI to become available from PBU and KPA or from some other source. The cost of MI to West Sak is estimated at about $1 billion (ARCO 1991a). The MI cost determined in **Section 3.3.1.4** is allocated to Areas A and B, and scheduled over the first 8 and 4 years, respectively, of project life. If Area B production is initiated in 2008, the peak rate from West Sak would be 170 MBOPD in 2008. The production profiles for these development scenarios are shown on **Figure 3.6**, superimposed on the KPA production forecast that is shown on **Figure A.4**.

3.3.1.4 Operating Costs. The various operating cost variables are listed in **Section 3.2.3**. The estimated operating cost variables used in the previous DOE publication (1991) are:

- Fixed costs - $50 MM/yr (unescalated)
- Well workovers - $3.00/BBL oil (escalated)
- Shared facilities - $1.34/BBL total fluid (unescalated).

This resulted in cumulative inflated operating costs of about $6.655 billion. This total appears reasonable.

The premises used for this analysis are:

(a) Well workover cost of $3.00/BBL is estimated using oil and is related to total fluid using on estimated 1,890 MM BTF from preliminary evaluation runs (see **Section 3.3.1.5**).

Well workover costs = [($3.00/BBL)(502 MMBO + 106 MMBO)]/1890 MM BTF
Well workover costs = $0.97/BTF (1/1/92$).

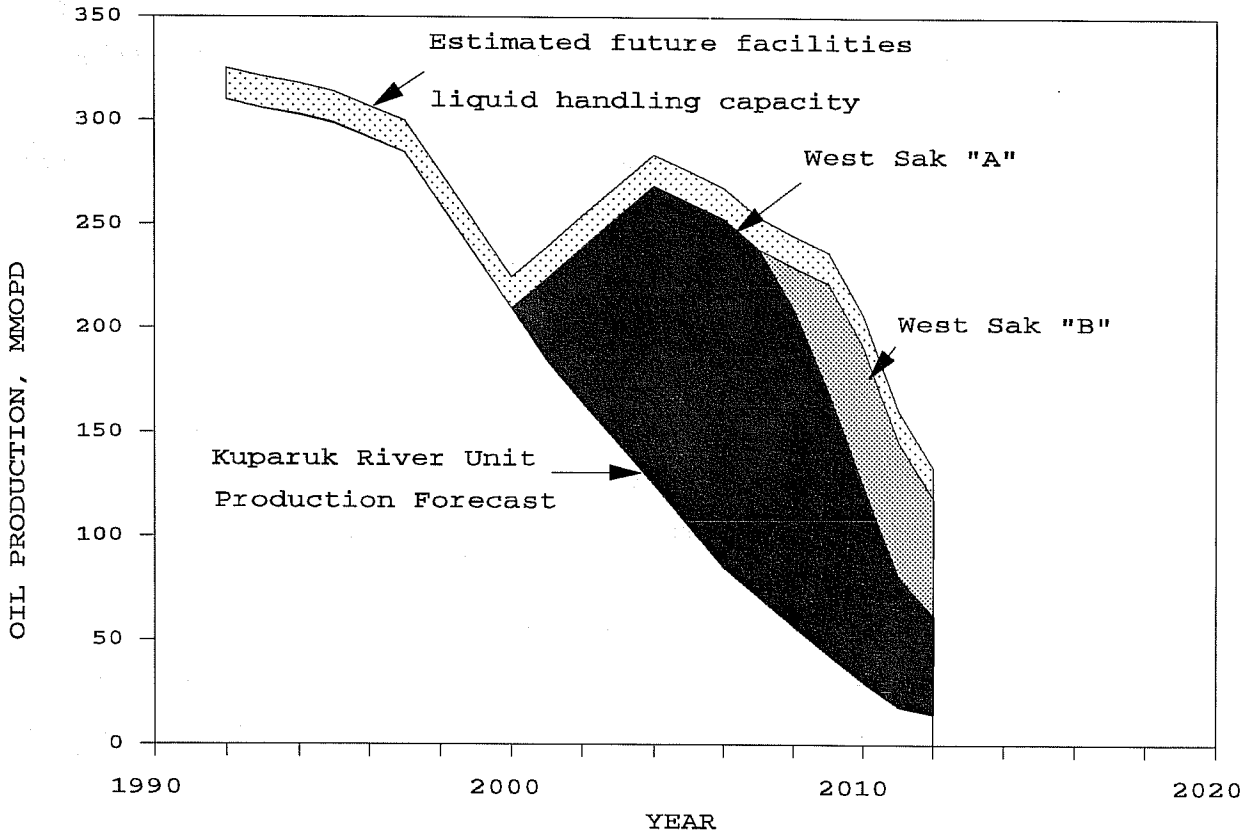

Figure 3.6 Possible future KPA facilities liquid capacity showing KPA production profile with production from West Sak development Areas A and B superimposed.

(b) As discussed in **Section 3.3.1.3**, the estimated facilities investment savings is $857 MM (1/1/92$). A shared facilities charge is calculated using Equation (3.4) as follows:

Facilities charge = ($857 MM/1,890 MM BTF) x 3.35 = $1.52/BTF (1/1/92$).

(c) It is assumed that a West Sak Participating area will purchase water from the KPA at $0.15/BBL. The volume purchased is assumed to be 200% of the total fluid production or 3.78 billion barrels of water. The source water cost is $0.30/BTF (1/1/92$) produced.

(d) With a miscible WAG recovery process assumed, a much larger volume of gas would be processed and compressed by the KPA facilities than would be required under primary or waterflood operations. For simplification, it is assumed that the overall project GOR will be 2,500 ft^3/BBL. This also accounts for the gas used in gas lift operations. These

assumptions facilitate the calculation of a charge to be added to other operating cost. It is assumed the cost to compress gas is $0.15/MCF (1/1/92$). The gas operating cost is $0.12/BTF (1/1/92$).

(e) The upper limit of MI requirement is estimated at 1 TCF. Because some of the MI (gas plus liquid hydrocarbons) will be recovered and recycled, the purchased volume of MI will be less than the total volume required. It is assumed that between 1000 and 1500 ft^3 of MI is dissolved in each barrel of crude oil recovered. Because the MI recovered can be reused, the estimated volume of MI required is reduced to between 0.6 and 0.9 TCF. The actual volume required could be higher as all oil with dissolved MI probably will not be recovered. If 15% loss is assumed, the MI requirement is increased to about 0.7 TCF as a minimum and to 1 TCF as the upper limit. As stated above, MI will be processed and recycled. There are only a few projects using enriched gas for recovery and no reference was located giving the percent of total MI requirement that is cycled. In miscible CO_2 projects, the expected recycled volume is between 30 and 50% (NPC 1984). As enriched gas and CO_2 are similar processes, it is assumed the recycled volume of injectants is similar. A recycled MI volume of 40% is assumed. Therefore, the purchased MI volume is between 420 BCF and 600 BCF. The average of 510 BCF is used. The cost of the upside MI volume was estimated at $1 billion (1/1/92$) (ARCO 1991a). Assuming this relates to the upside MI volume of 600 BCF above, the cost of MI is $1.67/MCF resulting in a total cost for MI of about $850 MM (1/1/92$). This cost is divided between Areas A and B based on the predicted ultimate recovery for each area.

It is assumed that MI is used over the first 8 years of production in Area A and the first 4 years in Area B. The MI cost is allocated over those time periods in proportion to the annual production volumes. The MI purchase cost for Area A is $700 MM and for Area B is $150 MM. Some percentage of the purchased MI probably would be capitalized for income tax purpose, and the remainder would be expensed. As a simplifying assumption, all of the MI is expensed. The MI costs per year for Areas A and B are given in **Table 3.11.**

(f) The remaining operating cost components are assumed to be $20 MM/yr and are inflated annually.

Table 3.11. MI costs per year for West Sak Areas A and B.

MI - $MM (1/1/92$)		
Year	**Area A**	**Area B**
2001	25	0
2002	50	0
2003	75	0
2004	100	0
2005	110	0
2006	120	0
2007	120	0
2008	100	14
2009	0	41
2010	0	50
2011	0	45
Total	700	150

A summary of the operating cost components (1/1/92$) for West Sak are:

(a) Well workovers - $0.97/BTF
(b) Shared facilities - $1.52/BTF
(c) Injection water - $0.30/BTF
(d) Gas handling - $0.12/BTF
(e) MI - See **Table 3.10**
(f) Other costs - $20 MM/yr.

Total operating costs for Area A and B using these operating cost components are $4,985 MM and $1,153 MM, respectively, (1/1/92$) over the forecasted life.

3.3.1.5 Total Fluid Determination. A method is required to estimate total annual fluid production as certain operating costs are based on total oil and water production. No computer model results of the West Sak are available for use. The water-cut data from producing wells in ARCO's hot waterflood pilot area are not useable because the producing life of the project was too short for the results

to be valid for use in determining water production from the West Sak formation. The updated curve for the KRU Kuparuk formation is used in this evaluation (see **Figure A.5, Appendix A**).

3.3.1.6 Future Producers. Based on the assumed production profile and individual well forecast for Areas A and B contained in **Section 3.3.1.2**, the future active well count is listed in **Table 3.12**.

Table 3.12. West Sak Areas A and B future active producers.

Year	Area A Producers	Area B Producers
2001	172	0
2002	270	0
2003	393	0
2004	541	0
2005	594	0
2006	689	0
2007	762	0
2008	672	100
2009	574	230
2010	451	263
2011	303	263
2012	250	263
2013	155	163
2014	81	33

3.3.1.7 Field Pipeline Tariff. It was assumed that the Kuparuk River Pipeline tariff used for the KPA will be applicable to production from the West Sak. In 1990, the tariff was $0.61/BBL. On February 13, 1992, the Alaska Department of Revenue (ADR) advised that the tariff was $0.21/BBL. This tariff is used in the West Sak evaluation.

3.3.1.8 Technical Summary. West Sak contains the largest resource volume of the five NES fields, with estimates of up to 20 BBOIP. West Sak crude properties and reservoir conditions present formidable challenges to economic development. Low gravity, high viscosity oil in a shallow, thin bedded, low temperature reservoir that is highly faulted presents a number of problems to be resolved before any development can take place. With production coming from unconsolidated beds, completion techniques must be developed or existing techniques adopted to the West Sak conditions. Laboratory

testing and a hot waterflood pilot indicate that a miscible WAG process, using close well spacing is the most likely recovery process. Further work may be required before final selection of a process is made. Because of the shallow depth of the reservoir, drilling pads will be required on every section developed and could lead to pattern changes to reduce surface environmental concerns.

Although considerable study has apparently been conducted by the operator, little of this proprietary information is public. Based on available data, is it estimated that between 500 and 600 MMBO can be recovered from better quality reservoir on about 30,000 acres. The timing of the development of these potential reserves is dependent on having an adequate oil price (as discussed later in this section) and an economical source of MI. The volume of MI on the North Slope is limited at present and will be used in the most economical projects first. This places West Sak at least third behind PBU and KRU. The timing of obtaining MI for West Sak is critical when considering the time frame of TAPS shutdown. MI must be available by 2001 for Area A to be considered for development. If TAPS shuts down before 2014, it is unlikely that sufficient MI will be available early enough for the development of Area B to be considered unless a source of MI, other than PBU is developed. About 239 MMBO would be unrecovered under these development scenarios, if TAPs shuts down at year-end 2008.

3.3.1.9 Economic Evaluation. The results of the economic evaluation of West Sak Areas A and B, using the four oil price scenarios (**Section 3.2.1**), are shown in **Tables 3.13** and **3.14**. These economic results clearly indicate that these projects are marginal prospects for development. Sensitivity analyses for West Sak are presented in **Section 3.4**.

Table 3.13. West Sak Area A economics of development - $MM (1/1/92$).

Economic Factor	Oil Price Forecasts			
	EIA High	EIA Mid-Level	NES Low	EIA Low
Project Life - yrs	13	13	12	10
Reserves - MMBO	502.2	502.2	490.5	450.0
Investments	4,077	4,077	4,077	4,077
Operating Costs	4,985	4,985	4,724	4,115
Cash Flow - PW_{10}	1,113	259	(444)	(1295)
State Revenue - PW_{10}	1,151	923	735	562
Federal Revenue - PW_{10}	769	344	32	0

Table 3.14. West Sak Area B economics of development - $MM (1/1/92$).

Economic Factor	Oil Price Forecasts			
	EIA High	EIA Mid-Level	NES Low	EIA Low
Project Life - yrs	6	6	5	5
Reserves - MMBO	106.2	106.2	94.9	94.9
Investments	1,085	1,085	1,085	1,085
Operating Costs	1,153	1,153	892	892
Cash Flow - PW_{10}	206	2	(128)	(273)
State Revenue - PW_{10}	203	150	119	97
Federal Revenue - PW_{10}	153	57	5	0

3.3.2 Point Thomson

The Point Thomson Unit (PTU) covers a gas condensate field about 50 mi east of TAPS PS No. 1. The unit contains about 83,800 acres, much of which is offshore (**Figure 1.3**). (A detailed description of the Point Thomson field is contained in **Appendix B.3**.) The current reserve estimates for the PTU carried by the ADNR (1991) are 5 TCF gas and 300 MMBBLS of oil and condensate. The ADR does not include major North Slope gas sales in their Fall 1991 forecast of revenue (ADR 1991b). The possibility of a reduced reservoir size is mentioned in a letter from the unit operator to the ADNR (1991b). A reduction in reservoir size is considered for comparison purposes.

3.3.2.1 Date of Initial Production. The date of initial production is unknown. A number of articles have been published that discuss sale of North Slope gas with possible dates of first gas sales varying from 1997, at the earliest, to beyond 2010 at the latest (Anch 1991a; Anch 1991b; Anch 1991c; Platts 1991; ADN 1992a; ADN 1992b). The date of first gas sales from PTU is dependent on gas sales from PBU or some large undiscovered gas field with PBU-size reserves to justify the construction of a gas sales line. Construction of the line is dependent on an end-point market willing to pay a price to justify the total project. The following assumptions are made.

1. A gas sales system is completed by 2005 (ADN 1992a; ADN 1992b).
2. PBU gas becomes available during the year 2005. A ramp-up of 4 years is used for gas sales to reach 2 BCF/d.
3. PTU development begins in 2002 with first production about 2008.

3.3.2.2 Evaluation Data. Publicly available data are used where available; otherwise, best judgement estimates are made. Well and test information are used extensively. The data used for two possible reservoir volumes are discussed.

3.3.2.3 Base Reservoir Volume. The reserves carried by the ADNR (1991a) are used as a guide in developing the base case.

3.3.2.3.1 Reservoir Area--To obtain an independent estimate of field reserves an approximate field size is required and used to determine the number of wells for field development. Information obtained from the exploratory wells in the Point Thomson area is used to estimate an outer reservoir limit boundary. This limit is shown by the solid line on **Figure 3.7** and contains 36,600 acres. (Note: The dashed line area is discussed in **Section 3.3.2.4.1**).

3.3.2.3.2. Development Plan. One possible gas sales development scenario is based on the original reservoir area of 36,000 acres. This scenario includes 37 wells drilled from onshore pads and five wells drilled from Challenge Island and connected to shore by a subsea pipeline. The six onshore drillsites plus the one offshore are connected to a central processing center **(Figure 3.8).** Two pipelines are required, one for liquid sales to TAPS PS No. 1, and the other to a gas sales line in the Prudhoe Bay field area. **Figure 3.9** shows a possible sales pipeline and main road corridor. **Figure 3.9** also shows the five major river crossings that the pipelines and road would encounter.

3.3.2.3.3 Reservoir Parameters--The following reservoir parameters are used to determine gas volumes (ADNR 1988; USGS 1987).

- S_w = 35% (Assumed)
- h = 110 ft (The Pt. Thomson sand is up to 300 ft thick as shown on **Figure B.9, Appendix B.** Two hundred feet is assumed as the average thickness. The Flaxman sand is 70 ft thick in one well (**Figure B.12**), but is limited to the northern area. In determining net pay, 70 ft is assigned to 1/4 of the productive area. Pre-Mississippian sand is present in two wells; therefore, 5 ft is assigned to 1/20 of productive area. A net-to-gross ratio of 0.50 is assumed, resulting in an average pay thickness of about 110 ft.)
- ϕ = 20% (Varies by zone: Pt. Thomson - 5 to 25%, Flaxman >20%, Pre-Mississippian - No record. An average of 20% is assumed for all zones.)
- A = 36,600 acres

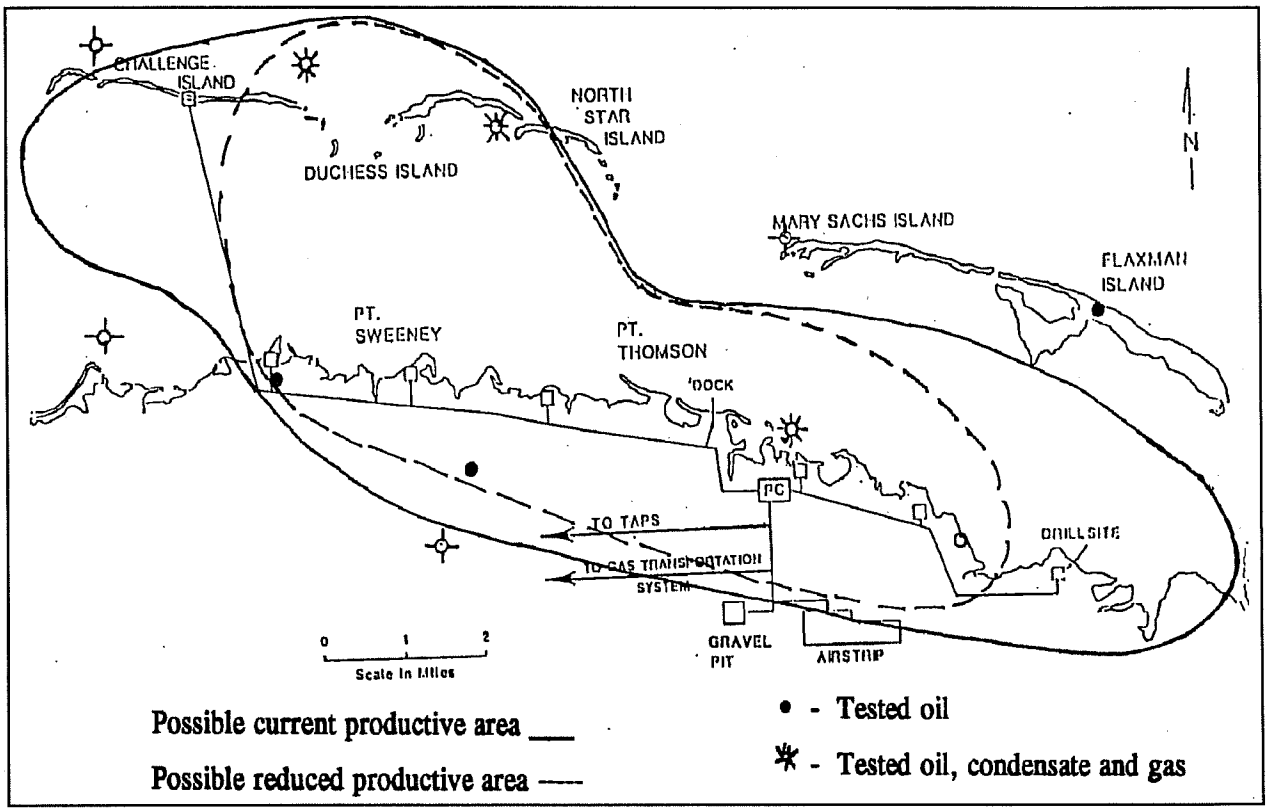

Figure 3.7. PTU possible reservoir limits.

- Reservoir temperature (T_r) = 238°F or 698°R
- Reservoir pressure (P_r) = 10154.7 PSIA
- Gas gravity = 0.8 (Assumed)
- Gas compressibility at surface (Z_s) = 1.0
- Gas compressibility at reservoir conditions (Z_r) = 1.45
- Surface pressure (P_s) = 14.7 PSIA
- Surface temperature (T_s) = 60°F or 520°R
- RF = 70%.

3.3.2.3.4 Recoverable Gas--The volume of the reservoir occupied by gas, the volume of that gas at surface conditions, and the estimated recoverable hydrocarbon gas volume using the 36,600-acre reservoir are determined as follows:

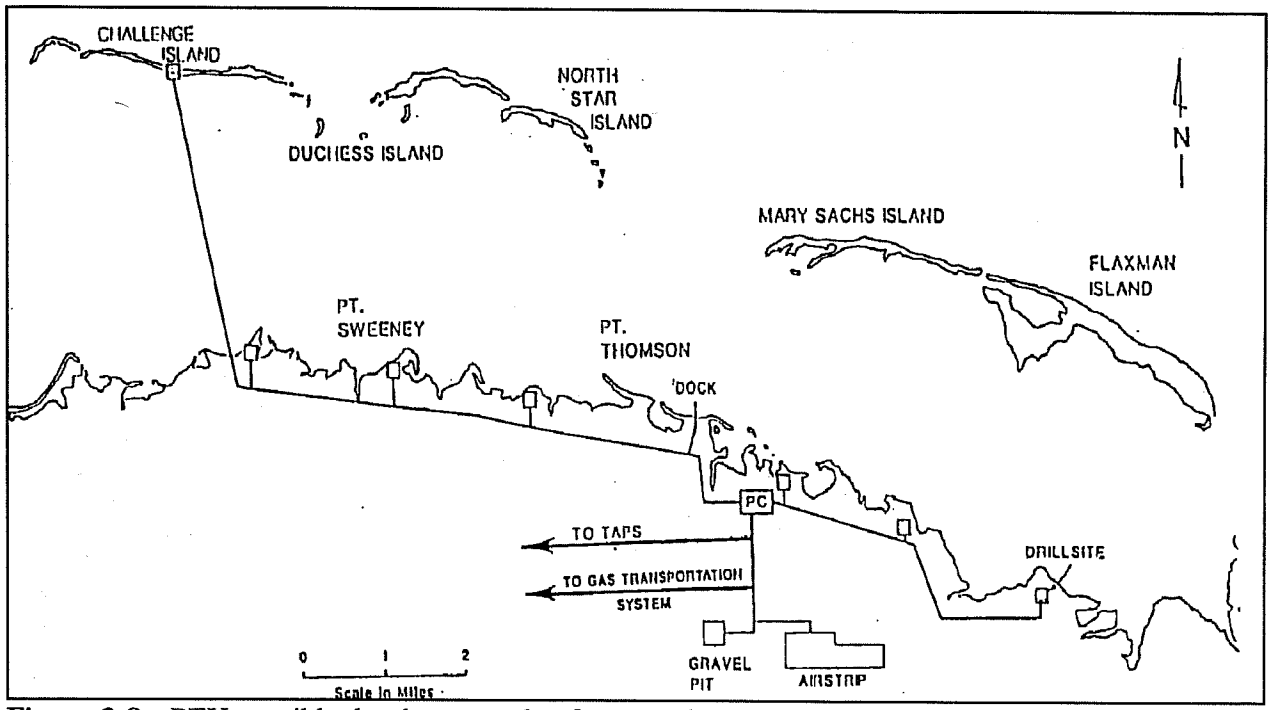

Figure 3.8. PTU possible development plan for gas sales.

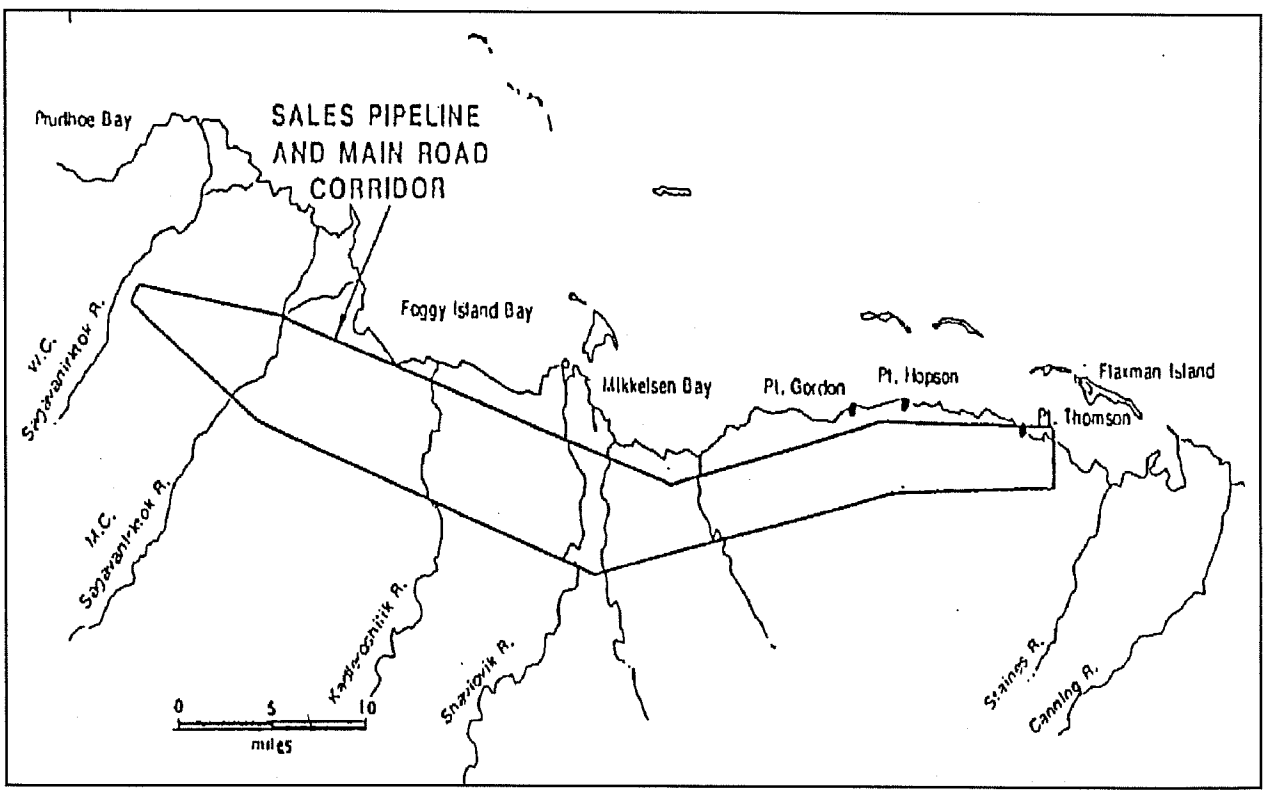

Figure 3.9. PTU possible sales pipelines and main road corridor.

(1) Reservoir volume of gas (G_r) is

$$G_r = 43{,}560\ ft^3/acre\text{-}ft \times h(ft) \times \phi \times (1\text{-}S_w) \times A = 22.798 \times 10^9\ ft^3. \quad (3.6)$$

(2) Gas volume at surface conditions (G_s) is

$$G_s = (P_r \times G_r \times Z_s \times T_s)/(P_s \times Z_r \times T_r) = 8.09\ TCF. \quad (3.7)$$

(3) Recoverable gas (G_p), including CO_2 and liquids, is

$$G_p = G_s \times RF = 5.664\ TCF. \quad (3.8)$$

Point Thomson contains about 4% CO_2;[a] therefore, the recoverable wet hydrocarbon gas volume is

(4) $G_p = 5.437$ TCF (w/o CO_2).

3.3.2.3.5 Recoverable Hydrocarbons--The volumes estimated in **Section 3.3.2.3.4** are wet gas, which must be reduced for shrinkage from condensate removal and to account for the reservoir volume occupied by the oil column. It is assumed that, with these additional adjustments, the estimated recovery volume will be in close agreement with the reserves carried by the state of Alaska. Therefore, a recoverable gas volume of 5 TCF and 300 MMBBLS (oil and condensate) are used to determine the base case.

3.3.2.3.6 Production Forecasts--A possible gas sales scenario is for a maximum production rate of 500 MMCFPD of wet gas. It is assumed that 60 MMCFPD accounts for fuel, liquid shrinkage, and CO_2 removal. The CO_2 volume is 20 MMCFPD, using a 4% CO_2 concentration. At 440 MMCFPD, gas sales total about 4.5 TCF through 2035.

The average oil rate for five drillstem tests (DSTs) is about 650 BOPD (ADNR 1988; USGS 1987). It is assumed that oil production averages 400 BOPD/well for the first year and goes on decline at about 20%/yr. The last year of oil recovery will be 2013. This results in oil recovery of 13 MMBO. Twenty wells are used to recover oil-rim reserves.

Information on liquid recovery is very limited. Both oil and condensate are produced with the gas. It is assumed that the 40°API condensate and oil mixture can be stabilized to meet TAPS specifications. Based on DST results, the condensate yield could be between 40 and 80 BBL/MMCF

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a. Exxon Company U.S.A., personal communication, September 12, 1991.

(ADNR 1988, USGS 1987). An initial condensate ratio of 70 BBLS/MMCF of wet gas is assumed in forecasting condensate rates. The estimated condensate production profile follows curve C of Figure 41 from Standing (1977) (**Figure 3.10).** A peak condensate ratio of about 80 BBLS/MMCF is reached in years 5 and 6 before declining to about 18.6 BBLS/MMCF in 2035. This rate forecast results in recovery of 284 MMB of condensate over the 28 year life.

Based on the assumption that TAPS may not operate at rates lower than 400 to 200 MBPD, it is assumed that the condensate liquids from PTU will not be sold after 2014 (see **Section 1.1**).

The oil, condensate, and the gas sales forecasts are given in **Tables 3.15** and **3.16**. **Table 3.15** represents a scenario where all liquids are sold throughout the project life. **Table 3.16** represents the scenario that assumes TAPS does not operate at lower than 200 MBPD throughput. This results in sales of 112 MMB (oil plus condensate) through 2014, and is used in the PTU base case evaluation.

3.3.2.3.7 Investments--Facilities investments are estimated using a facility cost factor of $15,200/BBL (1/1/92$) of peak rate of production as discussed in **Section 3.2.4**. The peak rate is determined by converting the produced gas volume to equivalent barrels using an assumed relative value factor of 11.1:1. The facilities investment estimated by this approach is $675.7 MM (1/1/92$).

The estimated cost to construct the gas and oil pipelines to the Prudhoe Bay area is determined using data from Han-Padron (MMS 1985). Assumptions used in this estimate are:

- 75% of the lines are below ground.
- One haul road is constructed.
- A reduction of 25% is realized in the investment for the smaller line when two lines are constructed simultaneously.
- The liquid line connects to the Endicott pipeline at the closest point.
- The gas sales line is south of the PBU central gas facility.

The estimated cost to construct the two pipelines and the haul road is $193.0 MM (1/1/92$).

The estimated cost to drill development wells is based on the Han-Padron study (MMS 1985). Because these wells will be drilled and completed in an overpressured reservoir, the cost was increased by an assumed 1.25 factor. The estimated cost to drill the average well, after adjustment, is about $16.9 MM (1/1/92$). The total number of wells is estimated using the area within the solid line on **Figure 3.7**.

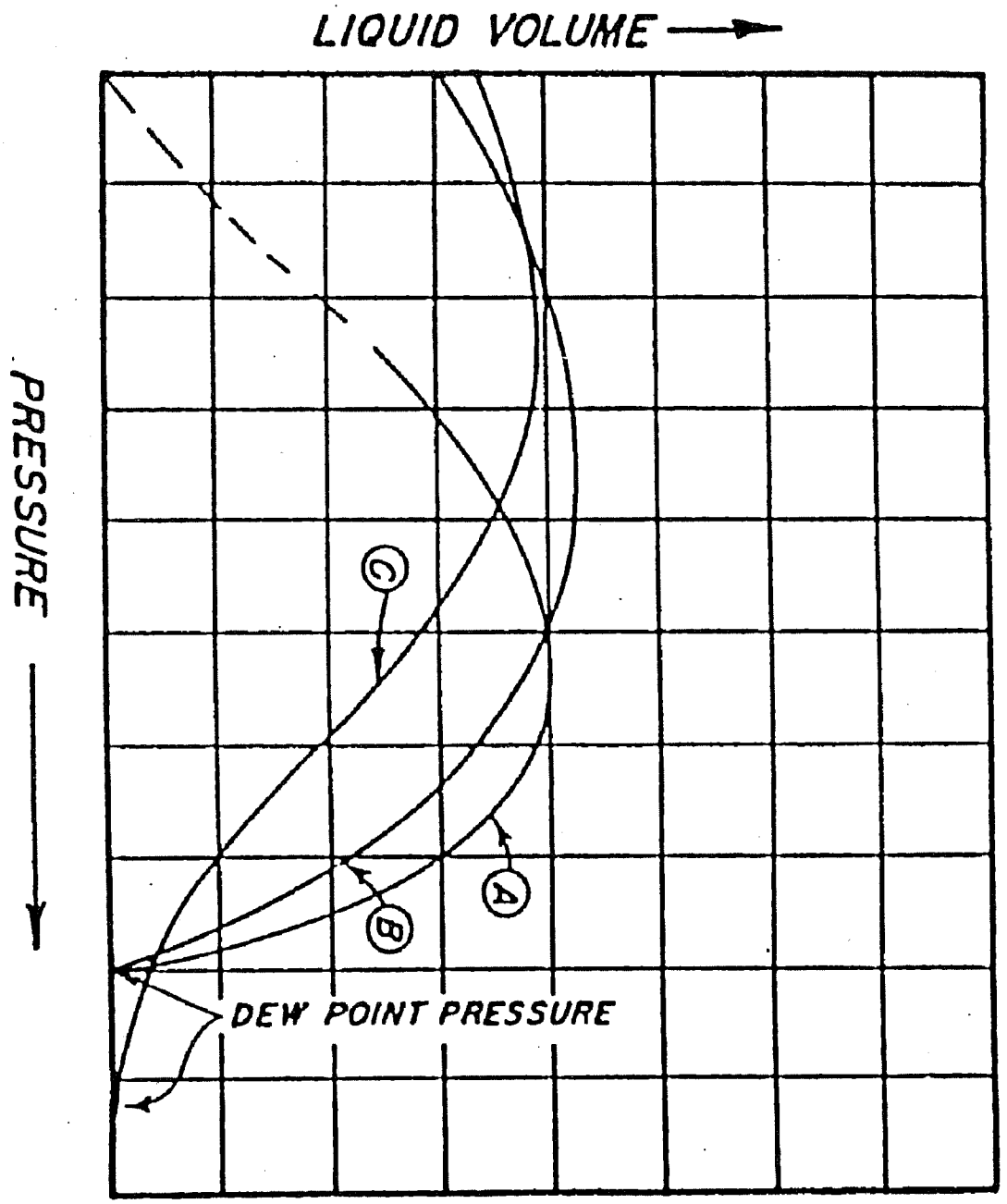

Figure 3.10 Curves illustrating several types of liquid behavior of condensate systems (Standing 1977).

Table 3-15. Production forecast - 5 TCF case, liquid sales, not pipeline limited.

Year	Condensate		Oil (MBPD)	Sales Liquids (MBPD)	Gas Production	
	Ratio (BBLS/MMCF)	Recoverable (MBPD)			Wet Gas (MMCFPD)	Sales Gas (MMCFPD)
2008	71.1	35.53	9	44.53	500	440
2009	74.2	37.12	8	45.12	500	440
2010	77.6	38.79	6	44.79	500	440
2011	79.0	39.50	5	44.5	500	440
2012	80.0	40.00	4	44.00	500	440
2013	80.0	40.00	3	43.00	500	440
2014	79.9	39.99	0	39.99	500	440
2015	79.9	39.98	0	39.98	500	440
2016	78.1	39.03	0	39.03	500	440
2017	76.6	38.32	0	38.32	500	440
2018	74.2	37.12	0	37.12	500	440
2019	70.9	35.45	0	35.45	500	440
2020	68.5	34.27	0	34.27	500	440
2021	64.7	32.36	0	32.36	500	440
2022	59.0	29.51	0	29.51	500	440
2023	54.3	27.13	0	27.13	500	440
2024	50.5	25.23	0	25.23	500	440
2025	46.2	23.08	0	23.08	500	440
2026	44.3	22.14	0	22.14	500	440
2027	38.6	19.28	0	19.28	500	440
2028	35.2	17.61	0	17.61	500	440
2029	32.4	16.18	0	16.18	500	440
2030	29.5	14.75	0	14.75	500	440
2031	26.7	13.33	0	13.33	500	440
2032	24.7	12.37	0	12.37	500	440
2033	22.8	11.42	0	11.42	500	440
2034	20.9	10.47	0	10.47	500	440
2035	18.6	6.79	0	6.79	200	176

Table 3.16. PTU production forecast - 5 TCF case, liquid sales limited by TAPS throughput minimum.

Year	Condensate		Oil (MBPD)	Sales Liquids (MBPD)	Gas Production	
	Ratio (BBLS/MMCF)	Sales (MBPD)			Wet Gas (MMCFPD)	Gas Sales (MMCFPD)
2008	71.1	35.53	9	44.53	500	440
2009	74.2	37.12	8	45.12	500	440
2010	77.6	38.79	6	44.79	500	440
2011	79.0	39.50	5	44.5	500	440
2012	80.0	40.00	4	44.00	500	440
2013	80.0	40.00	3	43.00	500	440
2014	79.9	39.99	0	39.99	500	440
2015	79.9	0[a]	0	0	500	440
2016	78.1	0	0	0	500	440
2017	76.6	0	0	0	500	440
2018	74.2	0	0	0	500	440
2019	70.9	0	0	0	500	440
2020	68.5	0	0	0	500	440
2021	64.7	0	0	0	500	440
2022	59.0	0	0	0	500	440
2023	54.3	0	0	0	500	440
2024	50.5	0	0	0	500	440
2025	46.2	0	0	0	500	440
2026	44.3	0	0	0	500	440
2027	38.6	0	0	0	500	440
2028	35.2	0	0	0	500	440
2029	32.4	0	0	0	500	440
2030	29.5	0	0	0	500	440
2031	26.7	0	0	0	500	440
2032	24.7	0	0	0	500	440
2033	22.8	0	0	0	500	440
2034	20.9	0	0	0	500	440
2035	18.6	0	0	0	200	176

a. Starting in 2015, none of the condensate is sold.

Spacing of 870 acres/well is assumed. This results in 42 wells for this scenario. Of these 42 wells, five are drilled from Challenge Island to better develop that part of the reservoir.

The facilities investment includes onshore pads, the Challenge Island pad, and an undersea pipeline to shore, field roads and pipelines, causeway to a dock, airstrip, separation and treatment facilities, and compression (as needed for sales and for CO_2 disposal). The assumed investment schedule spans 6 to 7 years of which about 2 years are for EIS preparation ($2.65 MM in 1/1/92$) and approval followed by 4 to 5 years for design, construction, shipping, installing facilities and pipelines, and for drilling wells. Thirty producing wells are drilled and completed by the date of initial sales with the remaining 12 wells drilled over the next 2 years.

The resulting investment schedule is shown in **Table 3.17**.

Table 3.17. PTU 5 TCF case investment schedule.

Year	Wells	Investments - $MM (1/1/92$)		
	No.	Wells	Facilities	Total
2002	0	0	2.7	2.7
2003	0	0	0	0
2004	0	0	16.0	16.0
2005	10	169.2	250.0	419.2
2006	10	169.2	300.0	469.2
2007	10	169.2	300.0	469.2
2008	6	101.5	0	101.5
2009	6	101.5	0	101.5
Totals	42	710.6	868.7	1,579.3

3.3.2.3.8 Operating Costs--There are no published estimates of operating costs for PTU. The method using a cost per barrel of total fluid and water-cut percentages related to ultimate recovery are not applicable at PTU because it is primarily a depleting gas condensate reservoir. An empirical method used by industry for large projects, such as offshore U.S. and Europe, uses the cumulative inflated investment and a certain percentage factor to determine annual operating costs. This factor

varies, but most commonly is between 5 and 7%.[a] A 5% factor at PTU is considered a reasonable estimate. After all investments are complete, the operating costs are inflated annually thereafter. Because all wells are required for deliverability throughout the project life, operating costs are not reduced in late project years. The total operating cost over the 28 year life is $2,206 MM (1/1/92$).

3.3.2.3.9 Field Pipeline Tariff--The development scenario for PTU includes investment and operating costs for a gas pipeline to a Prudhoe Bay area sales line, therefore there is no tariff charge. However, it is assumed the liquids line is connected to the Endicott Pipeline, and a tariff is estimated. Using the Endicott pipeline tariff of $0.71/BBL for a throughput of 393 MMBO (**Appendix A.2.1**) the adjusted tariff, after adding the PTU liquids volume of 214 MMBBLS, is $0.46/BBL.

3.3.2.3.10 Gas Sales Price--The gas sales price is determined by the method discussed in **Section 3.2.1.2**.

3.3.2.3.11 Royalty Rate--The majority of tracts carry 12.5% royalty, six tracts carry high NPIs or sliding scale royalty (see **Appendix B.3.2**). As average royalty of 14.25% is assumed.

3.3.2.4. Revised Reservoir Volume. There is a limited amount of control on both the east and west flanks of the Point Thomson area. Thus, it is likely that the reservoir is smaller than previously estimated. The possibility of a reduced reservoir size is mentioned in a letter from the unit operator to the ADNR (1991b).

3.3.2.4.1 Reservoir Area--A revised reservoir limit excludes areas with limited well control. This smaller area is shown by the dashed line on **Figure 3.7**. The area inside the dashed line is about 23,800 acres.

3.2.2.4.2 Development Plan--For the development scenario based on the reduced reservoir area shown in **Figure 3.7** it is assumed that the area can be drained by 32 wells. This development scenario does not require any wells on Challenge Island and only requires five drilling pads onshore. The resulting drainage area is about 700 acres/well. The processing facilities and pipelines are about the same as required for the original reservoir area as discussed in **Section 3.3.2.3.1**.

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a. Personal knowledge, Allaire, R. B. and Doughty, T. C.

3.3.2.4.3 Reservoir Parameters--Except for reservoir size, the parameters listed in **Section 3.3.2.3.3** are used for this evaluation.

3.3.2.4.4 Recoverable Gas-- Using Equations (3.6), (3.7), and (3.8), the reservoir volume occupied by gas, volume of that gas at surface conditions, and the estimated volume of recoverable hydrocarbon gas using the revised development assumptions are as follows:

(1) Reservoir gas volume, $G_r = 14.825 \times 10^9$ ft^3

(2) Gas volume at surface conditions, $G_s = 5.2613$ TCF

(3) Recoverable gas (including CO_2 + liquids), $G_p = 3.683$ TCF

(4) $G_p = 3.536$ TCF w/o CO_2 (at 4%).

3.3.2.4.5 Recoverable Hydrocarbons--The volumes estimated in **Section 3.3.2.4.4** are wet gas. The wet gas is reduced for shrinkage from condensate removal and by adjusting for the reservoir occupied by the oil column. With this reduction, the revised gas reserve is 2/3 of the state's reserve estimate of 5 TCF, or about 3.4 TCF.

Recoverable condensate is reduced in proportion to the reduced gas reserves, from 287 MMB (300 MMB - 13 MMBO) to 191 MMB (see **Section 3.3.2.3.5, and Section 3.3.2.3.6**). As no reduction in oil volume is assumed, the liquids total for this case is 204 MMB (191 + 13 MMB). This volume is further reduced as a result of an assumed TAPS throughput limit of 200 MBPD as discussed in **Section 3.3.2.3.6**.

3.3.2.4.6 Production Forecasts--It is assumed that the reduced reservoir size does not affect the forecasted oil rate. The rate forecast developed in **Section 3.3.2.3.6** is adopted.

It is assumed that reducing the reservoir size does not affect the field deliverability rate of 500 MMCF/gas used in the 5 TCF case. Even so, the well spacing is reduced to about 700 acres, as a conservative assumption. This reduces the life from 28 years to 19 years.

The schedule of condensate recovery (BBLS/MMCF) in **Section 3.3.2.3.6** is modified for the reduced recovery of 191 MMBBLS of condensate. This modification gives approximately the same yield at the same stage of reservoir depletion as in the 5 TCF case. The revised production forecasts for

condensate, oil, wet gas, and the sales gas streams are shown in **Tables 3.18** and **3.19**. **Table 3.18** represents a scenario where all liquids are sold throughout the project life. **Table 3.19** represents the scenario that assumes TAPS does not operate at lower than 200 MBPD. The liquid sales volume is reduced to 99 MMB.

Table 3.18. PTU 3.4 TCF case, liquid sales not pipeline limited.

Year	Condensate		Oil (MBPD)	Sales Liquids (MBPD)	Gas	
	Ratio (BBLS/MMCF)	Recoverable (MBPD)			Wet Gas (MMCFPD)	Gas Sales (MMCFPD)
2008	71.1	35.53	9	44.53	500	440
2009	77.6	38.80	8	46.80	500	440
2010	79.5	39.75	6	45.75	500	440
2011	80.0	40.00	5	45.00	500	440
2012	79.9	39.95	4	43.95	500	440
2013	78.2	39.10	3	42.10	500	440
2014	75.8	37.90	0	37.90	500	440
2015	72.0	36.00	0	36.00	500	440
2016	67.5	33.75	0	33.75	500	440
2017	61.9	30.95	0	30.95	500	440
2018	54.2	27.10	0	27.10	500	440
2019	48.2	24.10	0	24.10	500	440
2020	41.5	20.75	0	20.75	500	440
2021	36.7	18.35	0	18.35	500	440
2022	30.9	15.45	0	15.45	500	440
2023	28.1	14.05	0	14.05	500	440
2024	24.7	12.35	0	12.35	500	440
2025	21.8	10.90	0	10.90	500	440
2026	18.6	5.60	0	5.60	300	265

Table 3.19. PTU 3.4 TCF case, liquid sales limited by TAPS throughput minimum.

Year	Condensate		Oil (MBPD)	Sales Liquids (MBPD)	Gas	
	Ratio (BBLS/MMCF)	Sales (MBPD)			Wet Gas (MMCFPD)	Gas Sales (MMCFPD)
2008	71.1	35.53	9	44.53	500	440
2009	77.6	38.80	8	46.80	500	440
2010	79.5	39.75	6	45.75	500	440
2011	80.0	40.00	5	45.00	500	440
2012	79.9	39.95	4	43.95	500	440
2013	78.2	39.10	3	42.10	500	440
2014	75.8	37.90	0	37.90	500	440
2015	72.0	0[a]	0	0	500	440
2016	67.5	0	0	0	500	440
2017	61.9	0	0	0	500	440
2018	54.2	0	0	0	500	440
2019	48.2	0	0	0	500	440
2020	41.5	0	0	0	500	440
2021	36.7	0	0	0	500	440
2022	30.9	0	0	0	500	440
2023	28.1	0	0	0	500	440
2024	24.7	0	0	0	500	440
2025	21.8	0	0	0	500	440
2026	18.6	0	0	0	300	265

a. Starting in 2015 none of the condensate is sold.

3.3.2.4.7 Investments--The investments for the reduced reservoir size are obtained by adjusting investments in **Section 3.3.2.3.7**. Primarily this is for the reduced number of wells. The reduced reservoir shown on **Figure 3.7** can be effectively drained by 32 onshore wells. It is assumed that field deliverability is 500 MMCF/day, the same as used in the 5 TCF case, and that no additional facilities (compression) are required. Even though reductions in facility investments may not occur, a 5% decrease in investments for pads, roads, and onshore and offshore pipelines is assumed along with the 10-well reduction. The revised investments used for this reduced reservoir case are shown in **Table 3.20**.

3.3.2.4.8 Operating Costs--Operating costs are determined by the method in **Section 3.3.2.3.8.** The total operating cost over the 19 year life of this reduced reserve project is $1,298 MM (1/1/92$).

Table 3.20. PTU revised investments for 3.4 TCF case.

Year	No. Wells	Investments - $MM (1/1/92$)		
		Well	Facilities	Total
2002	0	0	2.7	2.7
2003	0	0	0.0	0.0
2004	0	0	16.0	16.0
2005	10	169.2	237.2	406.4
2006	10	169.2	284.7	453.9
2007	10	169.3	284.6	453.9
2008	2	33.8	0	33.8
Total	32	541.5	825.2	1,366.7

3.3.2.4.9 Field Pipeline Tariff--The field pipeline tariff determined in **Section 3.3.2.3.9**, is revised to reflect the reduced rate from PTU. The field tariff for the scenario used in this reduced recovery case is $0.51/BBL.

3.3.2.4.10 Gas Sales Price--The gas sales price is determined by the method discussed in **Section 3.2.1.2**.

3.3.2.4.11 Royalty Rate--An average royalty rate of 14.25% is assumed (see **Appendix B.3.2**).

3.3.2.5 Summary. The Point Thomson field contains the only non-oil reservoirs in the five NES fields. The main resource is gas condensate from a deep overpressured reservoir that is located mostly offshore. In addition, it is the only one of the five NES fields that is not located within or close to the PBU/KRU infrastructure. It does not appear that development of Point Thomson for sales of liquids alone is economically feasible. With no major gas purchase line on the North Slope, and none anticipated in the foreseeable future, the date that Point Thomson might be developed is unknown. In addition to the technical problems associated with developing a deep overpressured offshore field using highly deviated wells, the size of the resource is still questionable. Preliminary recoverable gas reserves of 5 TCF may be reduced by as much as one-third based on a recent 3-D seismic study.

By itself, the resulting Point Thomson reserve volume will not justify sale of gas from the North Slope. Sales from the much larger PBU gas cap, or a similar size gas reserve, will be required to justify any sales scenario. The earliest this might occur from PBU is about 2005 (**Section 3.3.2.1**). However, before any gas sales can occur from the North Slope, a gas market must be available that will provide a purchase price for the gas that can justify development of the gas resources and the required infrastructure and facilities. In addition, the Point Thomson project faces the construction of field delivery lines to the Prudhoe Bay area that will encounter five major river crossings and be in the coastal plain. The impact of these conditions will not be determined until environmental assessments are conducted.

The economics of developing PTU for gas sales under the base case and reduced reserves case assumptions are summarized in **Tables 3.21** and **3.22** for four oil and gas price forecasts. Provided a gas sales line is available as assumed for the analysis, these economics indicate that either of these scenarios could provide a 10% rate of return except for the EIA Low price case.

Table 3.21. PTU 5 TCF case economics - $MM(1/1/92$).

Economic Factor	Oil Price Forecasts			
	EIA High	EIA Mid-Level	NES Low	EIA Low
1/1/2008 North Slope Gas Price ($/MCF)[a]	1.17	0.96	0.80	0.64
Project Life - yrs	28	27	27	27
Reserves - MMB[b] - TCF (Sales)	111.7 4.4	111.7 4.4	111.7 4.4	111.7 4.4
Investments	1,579	1,579	1,579	1,579
Operating Costs	2,206	2,127	2,127	2,127
Cash Flow - PW_{10}	494	287	63	(74)
State Revenue - PW_{10}	527	452	373	326
Federal Revenue - PW_{10}	347	242	131	66

a. See **Table 3.2**.
b. Liquid reserves limited by TAPS shutdown at 200 MBOPD

Table 3.22. PTU 3.4 TCF case economics - $MM(1/1/92$).

Economic Factor	Oil Price Forecasts			
	EIA High	EIA Mid-Level	NES Low	EIA Low
1/1/2008 North Slope Gas Price ($/MCF)[a]	1.17	0.96	0.80	0.64
Project Life - yrs	19	19	19	18
Reserves - MMB[b] - TCF (Sales)	98.9 3.0	98.9 3.0	98.9 3.0	98.9 3.0
Investments	1,367	1,367	1,367	1,367
Operating Costs	1,298	1,298	1,298	1,230
Cash Flow - PW_{10}	530	331	135	(4)
State Revenue - PW_{10}	472	401	331	284
Federal Revenue - PW_{10}	360	258	158	90

a. See **Table 3.2.**
b. Liquid reserves limited by TAPS shutdown at 200 MBOPD.

3.3.3 Gwydyr Bay

The Gwydyr Bay Unit (GBU) is located north of the PBU in the delta of the Kuparuk River (**Figure 1.3**). As discussed in **Appendix A.3.1**, the oil accumulation in the Kuparuk formation in the eastern part of this unit will probably be included in the Point McIntyre development area, therefore, it is not included in this evaluation. This evaluation includes the Sadlerochit and Kuparuk accumulations in the western part of GBU (**Figure B.15**, **Appendix B**). The accumulations are not defined, as only one well out of six exploratory wells in this area has tested hydrocarbons (**Figure B.16** and **B.18**). Additional delineation wells are needed before the potential of the area is proven. It is possible that one delineation well will be drilled in 1993 (**Section B.5.2**).

3.3.3.1 Evaluation Data. The greatest uncertainty is the size of the accumulation. Publicly available information is limited to well logs and production test data as described in **Appendix B.5**. The approximate areal extent is shown on **Figures B.16** and **B.18**. Reliance is placed on empirical relationships with other fields, primarily on the North Slope. The development scenario includes the drilling of 17 wells from a single pad, which also serves as the site of all other facilities, and a pipeline to deliver crude to the Kuparuk pipeline. The maximum reach of wells is 10,600 ft.

3.3.3.1.1 Recoverable Oil--Recoverable oil volumes are estimated for the three indicated oil accumulations using "rule-of-thumb" recovery factors as shown in **Table 3.23**.

Table 3.23. Gwydyr Bay recoverable oil volumes.

Area	Acres	Estimated Factors		Recovery (MMBO)
		Column (ft)	Recovery (BPAF)	
Proved Ivishak (Sadlerochit)	140	56	400	3
Potential Ivishak				
High	476	200	400	38
Low	476	200	300	29
Potential Kuparuk				
High	1432	75	300	32
Low	1432	75	200	21

Assuming these accumulations are proven as shown on **Figures B.16** and **B.18**, the size, location, and configuration of the Ivishak areas would restrict well placement; therefore, the above listed recoveries are reduced by 30%. This restricted development pattern precludes the use of recovery enhancement methods. The Kuparuk area is small and, with only nine wells on about 160-acre spacing, a 15% reduction in recovery is assumed. Total estimates of recoverable oil are 56 MMBO for the high reserves case and 40 MMBO for the low reserves case. The average of 48 MMBO is used.

3.3.3.1.2 Production Forecast--There are no well test data available, therefore the empirical method discussed in **Section 3.2** is used. The estimating factors for a field size below 300 MMBO are used except that a decline rate of 11% is used. The production forecast is shown in **Table 3.24**.

3.3.3.1.3 Investments--As noted in **Section 3.3.3**, the accumulations in this part of the GBU are not delineated. Before any development can be considered it is assumed that a minimum of four delineation wells are required. It is assumed that one well will be drilled in 1993, one well in 1994, and two wells in 1995 at a cost of $6.5 MM/well (1/1/92$). The development scenario is included in **Figure 3.11**. This scenario involves drilling three wells with deviations of greater than 9,200 ft. The remaining 14 wells have deviations of about 7,900 ft or less. Of these wells, 12 are producers and the remaining

Table 3.24. GBU production forecast.

Year	Production (MBOPD)	Year	Production (MBOPD)
1999	4.0	2007	8.3
2000	9.3	2008	7.4
2001	13.3	2009	6.6
2002	13.3	2010	5.9
2003	13.3	2011	5.5
2004	11.8	2012	5.1
2005	10.5	2013	4.7
2006	9.3	2014	4.3

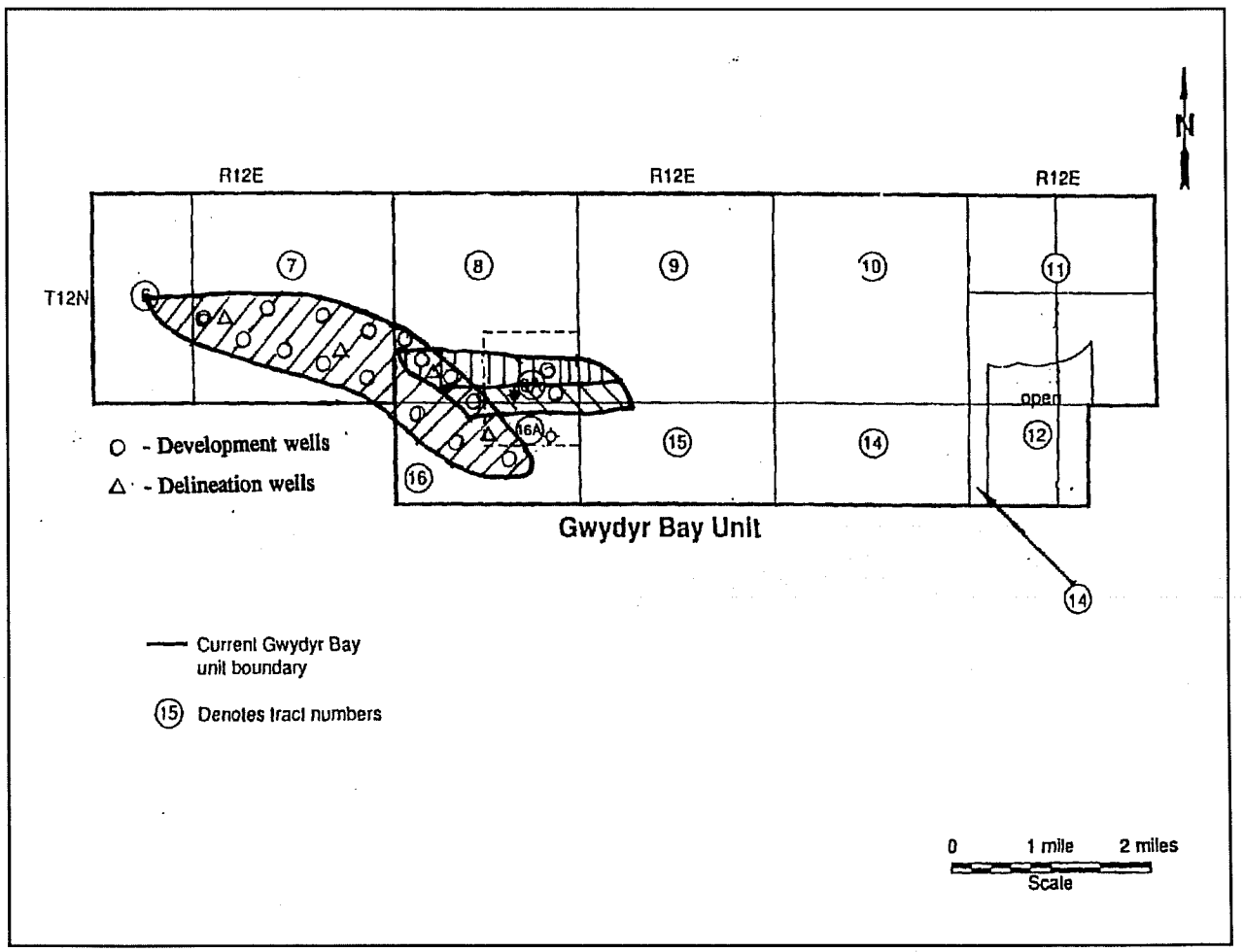

Figure 3.11 GBU development scenario.

six wells are used as service wells; one for gas injection, four for water injection, and one for water supply. Drilling costs of $6.1 MM/well used for Niakuk wells (**Appendix A.3.2**) are used for the three wells with the higher deviations. Drilling cost of $3.2 MM/well estimated for Point McIntyre wells (**Appendix A.3.1**) is used for the remaining 15 wells. Initial investment is assumed to occur in 1997, with first development wells drilled in 1998. Production is assumed to commence in 1999. Facilities investment is based on the method discussed in **Section 3.2.4**. The total facilities investment is $222.5 MM (1/1/92$) at $15,200/BBL of daily peak production rate plus 10% for location in the Kuparuk River Delta. A field pipeline is constructed to deliver crude oil to the Kuparuk pipeline, which is the nearest field pipeline on the west side of the Kuparuk river. The estimated cost to build a 7½ mi pipeline and access road is $25 MM (1/1/92 $) (MMS 1985). The investment schedule using these guidelines is shown in **Table 3.25**.

3.3.3.1.4 Operating Costs--Basic operating costs are estimated using a cost per barrel of total fluid produced. Niakuk is similar in size to GBU and operating costs are assumed to be similar. The $1.35/BTF (1/1/92$) operating cost determined for Niakuk as a stand alone project (no facilities sharing) is adopted for GBU. Total fluid is determined using the Milne Point smoothed model water-cut data in **Figure A.15**.

The estimated cost of performing 68 workovers over the project life is added to the basic operating cost. At $500 M/workover, the total cost is $34 MM (1/1/92$). As a simplification, the cost

Table 3.25. Gwydyr Bay investment schedule.

Year	Wells	Investments - $MM (1/1/92$)		
	No.	Wells	Facilities	Total
1993	1	6.5	0	6.5
1994	1	6.5	0	6.5
1995	2	13.0	0	13.0
1996	0	0	0	0
1997	0	0	122.0	122.0
1998	6	22.1	110.0	132.1
1999	6	22.1	10.0	32.1
2000	6	22.1	5.5	27.6
Total	22	92.3	247.5	339.8

is allocated over the project life on the basis of total fluid produced using an ultimate WOR of 2:1. The cost factor for workovers is $0.23/ BTF.

Because the cost of building the field pipeline is included in the investments for this project, an operating cost adjustment is made. It is assumed that about 70% of a pipeline tariff is for operating costs (**Appendix A.2.2**). The tariff for such a pipeline is $1.73 BBL, as determined by the method discussed in **Section 3.2.1.4**, resulting in a pipeline operating cost of $1.21/BBL oil. Related to total fluid, this cost is $0.39/ BTF.

Therefore, the total estimated operating cost factor for GBU is $1.97/BTF. Using this factor, the total operating cost over the 16 year life is $266 MM in 1/1/92$.

3.3.3.1.5 Field Pipeline Tariff--The pipeline tariff for the Kuparuk pipeline of $0.21/BBL is adopted for GBU.[a]

3.3.3.1.6 Active Producers--Future active producing wells are listed in **Table 3.26**.

Table 3.26. GBU Active Producers.

Year	No.	Year	No.
1999	4	2007	12
2000	8	2008	11
2001	12	2009	10
2002	12	2010	9
2003	12	2011	8
2004	12	2012	7
2005	12	2013	7
2006	12	2014	6

3.3.3.2 Summary. Gwydyr Bay Unit (GBU) is located north of the PBU and contains hydrocarbon accumulations in its eastern and western tracts. As noted in **Appendix A.3.1.1**, the eastern accumulation will be included in the Point McIntyre development. The western accumulations are not

a.. Alaska Department of Revenue, personal communication.

well defined; therefore, experience factors are used to estimate potential reserves of from 40 to 56 MMBO with 48 MMBO used for analysis. The joint use of existing facilities does not appear feasible for GBU due to its isolated location. Independent development is assumed except that a portion of the Kuparuk pipeline is used to deliver crude to PS No. 1. Because additional delineation is necessary, initial production is assumed for early 1999. Recovery is expected to last 16 years or through 2014. If development of this small project is economical, about 11.5 MMBO recoverable oil would be lost if TAPS is shutdown at year-end 2008.

The economics of developing GBU under the scenario described in this section are summarized in **Table 3.27** for four oil price forecasts.

Table 3.27. GBU development economics, $MM (1/1/92$).

Economic Factor	Oil Price Forecasts			
	EIA High	EIA Mid-Level	NES Low	EIA Low
Project Life - yrs	16	16	16	14
Reserves - MMBO	48	48	48	45
Investments	340	340	340	340
Operating Costs	266	266	266	207
Cash Flow - PW_{10}	178	88	14	(41)
State Revenue - PW_{10}	136	112	92	75
Federal Revenue - PW_{10}	118	73	37	13

3.3.4 Offshore Fields

In this section the design, construction, and cost criteria for development in a Beaufort Sea environment in the area of the Seal Island/Northstar and Sandpiper Island discoveries are discussed.

3.3.4.1 General. Design of offshore production platforms and subsea pipelines for a Beaufort Sea environment in the area of the Seal Island/Northstar Unit and the Sandpiper discovery must include considerations for the predominant ice, wave, current, water depth, soil and geotechnical conditions (MMS 1985).

The Lease Planning and Research Committee (LPRC) of the Alaska Oil and Gas Association (AOGA) is a special committee of AOGA with a mission to conduct research required for exploration

and production of oil and gas in lease sale areas in Alaska. Since 1970, the LPRC has coordinated over 385 studies that member oil companies have funded at a cost of $330 MM. Most of the studies have a period of confidentiality, usually 5 years past the final report date. The reports that were available and applicable to this study were reviewed. Information available through the Alaska Environment and Natural Resources Institute of the University of Alaska [formerly the Alaska Environment Information Data Center (AEIDC)], Cold Regions Research Environmental Laboratories, The Arctic Institute of North America at the University of Calgary, and various publications and technical conference data were reviewed.

The Minerals Management Service (MMS), Alaska Outer Continental Shelf Region study, "Beaufort Sea Petroleum Technology Assessment" by Han-Padron Associates, March 1985 (MMS 1985), is used as a source of consolidated capital investment and operating cost data for offshore oil production platform and subsea pipelines in the Beaufort Sea. The capital investment allowances used for the base case for Sandpiper and Seal Island/Northstar do not include any abnormal cost or schedule impact from the permitting process or regulatory issues. Impacts of these issues are addressed in the sensitivity analyses.

The MMS study uses two generic production alternatives for cost analysis that are (a) caisson retained gravel island and (b) a prefabricated bottom-founded conical production structure. Conceptual representation of a caisson-retained gravel island and a prefabricated bottom-founded conical structure are shown in **Figure 3-12**. The cost allowance for the generic prefabricated bottom-founded conical production structure presented in the MMS study (1985) is used as the basis of the capital allowance. However, because of the existence of gravel islands currently on site for both the Sandpiper discovery and Northstar Unit (NU), the caisson-retained island may be a viable alternative in both cases. The estimated investment for a conical production structure may be 20 to 50% greater than the caisson-retained island depending on the water depth and the availability and location of suitable gravel for the caisson-retained island alternative. Investment alternatives are included in the economic sensitivity discussion.

Drilling costs presented in the MMS study (1985) indicated a cost of over $12 MM per offshore development well drilled to a total depth of 12,000 ft TVD (MMS 1985). Recent drilling cost experience on the North Slope indicates that the 1985 drilling cost estimate contained in the MMS study may be high for the Prudhoe Bay Area. The estimated cost of a Niakuk offshore development well was $4 MM and

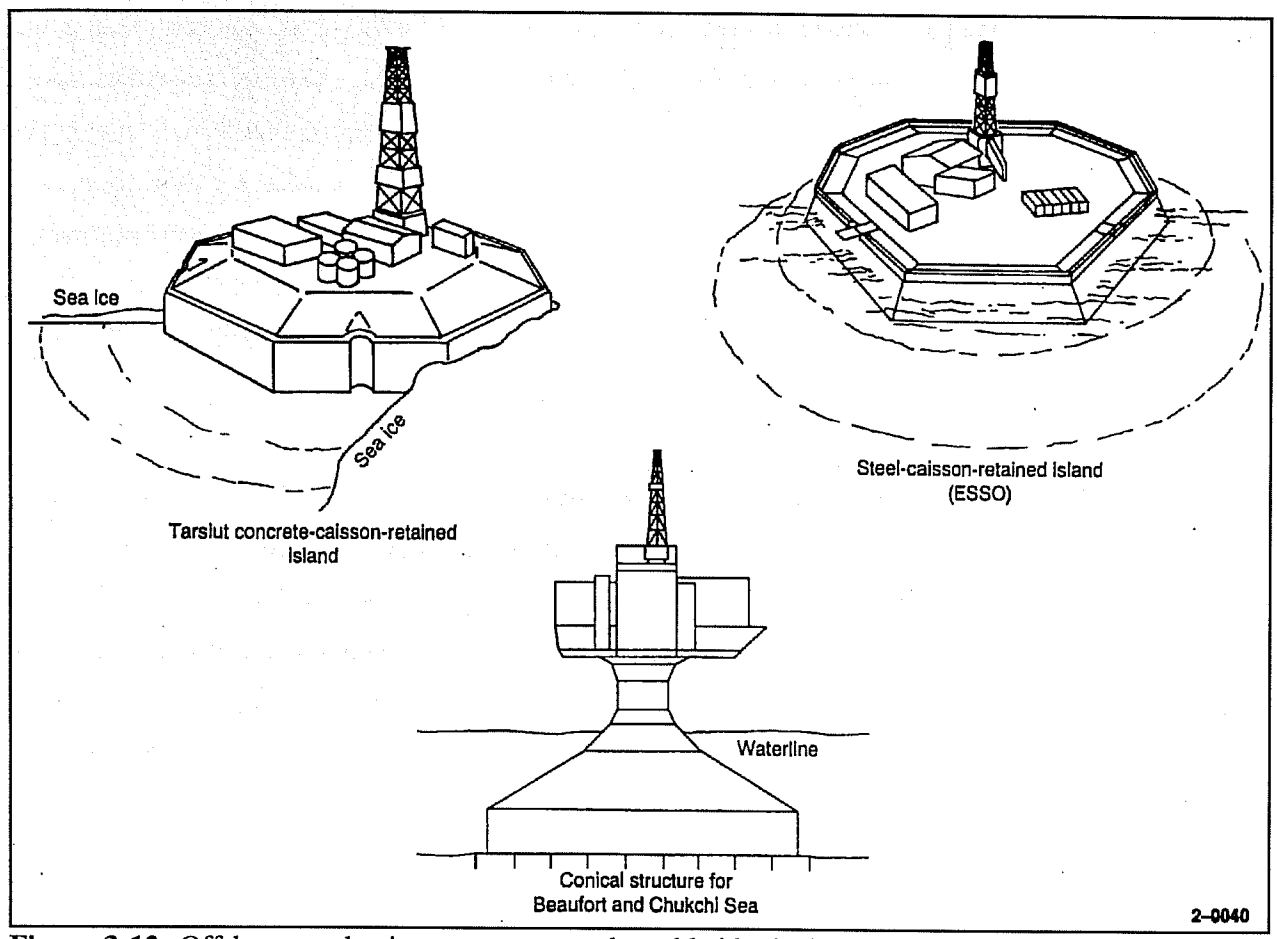

Figure 3.12 Offshore production structures used worldwide, including offshore Alaska (Alaskan Update 1987; Alaskan Update 1986).

$3 MM for the Endicott development. Based on this experience, an allowance of $5 MM per development well (1/1/92$) is used. Higher well cost is accounted for in the economic sensitivity discussion.

Actual design of arctic subsea pipelines and offshore production facilities must be tailored to conditions of a specific site. As a result, the estimated cost of a site-specific subsea pipeline and offshore production platform may vary considerably from the generic case used for conceptual estimating purposes. The economic sensitivity discussion provides the opportunity to analyze investment alternatives.

3.3.4.2 Seal Island/Northstar (Northstar Unit). NU is located about 6 mi offshore in the Beaufort Sea, and about 15 mi northwest of Prudhoe Bay (**Figure 1.3**). Two exploratory wells recovered oil from the Sadlerochit and were certified as producers; one additional well encountered hydrocarbons.

The area was unitized in 1989, however, the owners have not announced any plans for development. It is assumed that steps will be taken to evaluate this discovery's potential to permit a 1/1/98 start up. A detailed history of the prospect is contained in **Appendix B.7**.

3.3.4.2.1 Evaluation Data--Very little information is available on this discovery. Some test rates are available but the size of the accumulation is unknown. Without seismic data, the areal extent is estimated by using the bottomhole location and results of the exploratory wells. Producing rates are empirically estimated. Investment and operating costs are based on the 1985 Beaufort Sea study (MMS 1985).

1. **Recoverable oil**. As discussed in **Appendix B.2.7.1,** reserve estimates range from 150 to 300 MMBO. Reserves of 200 MMBO are used.

2. **Production forecast**. A production schedule is developed to recover the 200 MMBO volume within a reasonable time using the empirical method discussed in **Section 3.2** is used. The second set of factors is used with the following modifications: (a) the first and second years production rates are 40 and 75% of the peak production rate, and (b) the peak rate period is extended 2 years and then declined at 15%/yr. The production forecast is shown in **Table 3.28**.

Table 3.28. NU production forecast.

Year	Production (MBOPD)	Year	Production (MBOPD)
1998	22	2005	47
1999	38	2006	40
2000	55	2007	33
2001	55	2008	29
2002	55	2009	24
2003	55	2010	21
2004	55	2011	17

3. **Royalty interest**. The unit has a combination of state and federal tracts. The two federal tracts have a 16 2/3% royalty. Four of the state tracts have a basic 20% royalty plus NPIs of 85.26% to 93.2%. The other state tract has a 12.5% basic royalty plus a 40% NPI. However,

based on available data, it is assumed this tract does not contain hydrocarbons. The average NU basic royalty is estimated at 19%. The NPI on a unit wide basis is estimated at 68%.

4. **Future Producers**. The future producing wells as determined by using the Set B equations in **Section 3.2.5**.

5. **Investment and operating costs**. Investment and operating costs for NU are based on the following assumptions:

- 55 MBOPD peak rate
- 50 wells (38 producers)
- Cost per well of $5 MM (1/1/92$)
- Well depth of 12,000 ft (TVD)
- Thirty-six wells drilled in first 3 years with all wells drilled by eighth year.
- Water depth of 50 ft
- Two bottom founded conical structures
- Complete oil, water, and gas separation, processing, and handling facilities
- 8 mi, 16 in. diameter subsea pipeline to shore
- Buried (trenched) sub-sea pipeline to mitigate ice pounding, gouging, and scouring
- Subsea permafrost mitigation included
- 16 mi, 16 in. diameter onshore pipeline w/haul road
- Complete onshore support facility
- First year of production is fourth year
- Peak production in sixth year.

Table 3.29 summarizies the investment estimate and **Table 3.30** lists operating cost estimates for major cost categories during peak production years for NU.

The operating costs during the first and second years of operation are $41 and $72 MM (1/1/92$), respectively. Total operating costs of $113 MM (1/1/92$) (at peak production rate) are held constant until cumulative production reaches about 80% of estimated ultimate recovery. At that time, operating costs are held constant in as-spent dollars till abandonment. The total operating cost over the life of this project is $1,506 MM in constant 1/1/92$.

3.3.4.2.2 Summary. NU, located about 6 mi offshore, has been partially delineated by the drilling of six exploratory wells. Other than test rates and bottomhole well locations, little information is available on the size of the accumulation. Recoverable oil estimates range from 150 to

Table 3.29. NU investment schedule - $MM (1/1/92$).

Year	Pipeline	Platform Facilities	Development Drilling	Base Camp	Total
1995	40	320	0	25	385
1996	40	320	0	25	385
1997	40	320	60	25	445
1998	0	0	60	0	60
1999	0	0	60	0	60
2000	0	0	30	0	30
2001	0	0	30	0	30
2002	0	0	10	0	10
Total	120	960	250	75	1,405

Table 3.30. NU operating cost projection at peak rate - $MM (1/1/92$)

Pipelines	Production Platform Facilities	Base Camp	Yearly Total
3	85	25	113

300 MMBO, and a reserve volume of 200 MMBO is used for evaluation. The development scenario, including production/drilling structures and subsea pipelines, is based on arctic studies because there is no offshore arctic Alaska developments that can be used as a guideline. The analysis assumes current technology can be adopted or will be developed as required. A major deterrent to the development of this field is the high NPIs applicable to five state tracts as discussed in **Section 3.4** and shown in **Table 3.31**. Using an assumed start-up of 1/1/98, recovery of oil would extend into 2011. Shutdown of TAPS in 2008 would result in an estimated loss of about 23 MMBO should development occur as assumed.

3.3.4.3 Sandpiper Discovery. The Sandpiper discovery is located about 9 mi offshore in the Beaufort Sea and about 25 mi northwest of Prudhoe Bay (**Figure 1.3**). Two exploratory wells were drilled and only one tested hydrocarbons (see discussion in **Appendix B.9**). No further drilling activity has occurred. However, in November 1992, a Sandpiper Unit was approved by the MMS. Five leases are included in the Unit (**Figure B.20**) and a 5-Year Unit Plan of Operation similar to that underway at the Northstar Unit will be conducted by Murphy Oil USA, Inc.[a]

a. Minerals Management Service, "Review of Draft Report," January 12, 1993.

Table 3.31. NU development economics - $MM(1/1/92$)

Economic Factor	EIA High		EIA Mid-Level		NES Low		EIA Low	
	w/NPI	w/o NPI	w/NPI	w/o NPI	w/NPI	w/o NPI	w/NPI	w/o NPI
Project Life - yrs	14	14	14	14	13	13	12	12
Reserves - MMBO	200	200	200	200	194	194	187	187
Investments	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405
Operating Costs	1,506	1,506	1,506	1,506	1,414	1,414	1,319	1,319
Cash Flow - PW_{10}	(492)	325	(648)	(11)	(796)	(332)	(894)	(591)
State Revenue - PW_{10}	2,023	867	1,532	713	1,078	572	772	480
Federal Revenue - PW_{10}	6	344	0	183	0	53	0	0

3.3.4.3.1 Evaluation Data--Information on this discovery is limited primarily to state well completion reports and electric log sections. Empirical methods are used for this evaluation. Investments and operating costs were based on a 1985 Beaufort Sea study (MMS 1985).

1. **Recoverable oil**. Using a rudimentary approach, potential reserves are estimated. The assumptions used in this approach are as follows:

- A domal accumulation is present.
- The No. 1 well is at the apex of the dome.
- The radius of the reservoir extends 6,000 ft (or 400 ft less than the distance to the No. 2 wellbore intersection with the top of the zone).
- A 90-ft average pay thickness is present.
- No gas cap is present.
- The recovery factor is 400 BBLS/acre-ft.

Potential reserves of approximately 93 MMBO are calculated using the above assumptions. Subsequent to this determination, a representative from Amoco stated that their potential reserve estimate is 86.7 MMB of liquid (to distinguish the high gravity test recoveries in the discovery well). The 86.7 MMB volume is adopted for evaluation.

2. **Production Forecast**. An empirical method of developing a production forecast is used. The factors in **Table 3.4** for a field size less than 300 MMBO are used as a guide. The first and second year production rates are 40 to 70% of the peak production rate, respectively. The peak

yearly rate is set at 11% of ultimate recovery and is held for 4 years. The production rate is declined at 14%/yr resulting in a 13-year life. The production forecast is shown in **Table 3.32**.

Table 3.32. Sandpiper production forecast.

Year	Production (MBOPD)	Year	Production (MBOPD)
2000	10.4	2007	19.3
2001	18.3	2008	16.6
2002	26.1	2009	14.3
2003	26.1	2010	12.3
2004	26.1	2011	10.6
2005	26.1	2012	9.1
2006	22.4		

3. **Royalty interest**. The two exploratory wells are on federal tracts; therefore, a royalty of 16 2/3% is used.

4. **Investment and operating costs**. Investment and operating costs are estimated for the Sandpiper discovery based on the following assumptions:

- 26 MBD peak rate
- 16 wells
- Well depth of 12,000 ft (TVD)
- Four wells drilled per year for 3 years; two wells per year for 2 years
- Water depth of 50 ft
- One bottom founded conical production structure
- Complete oil, water, and gas separation, processing, and handling facilities included
- 10 in. diameter subsea pipeline 8 mi in length to the NU platform
- Buried (trenched) sub-sea pipeline to mitigate ice pounding, gouging, and scouring
- Subsea permafrost mitigation included
- Complete onshore support facility
- First year of production is fourth year (2000)
- Peak production in sixth year and held for 4 years.

Table 3.33 summarizes the investment estimate for the Sandpiper discovery based on these assumptions.

Table 3.33. Sandpiper discovery investment schedule - $MM (1/1/92$).

Year	Pipeline	Production Platform Facilities	Development Drilling	Base Camp	Total
1997	15	220	0	25	260
1998	15	220	0	25	260
1999	15	220	20	25	280
2000	0	0	20	0	20
2001	0	0	20	0	20
2002	0	0	20	0	20
Total	45	660	80	75	860

Table 3.34 summarizes the operating cost estimate. The operating costs during the first and second years of operation are $28 and $48 MM (1/1/92$), respectively. Total operating costs of $76 MM (1/1/92$) (at peak production rate) are held constant until cumulative production reaches about 80% of estimate ultimate recovery. At that time, operating costs are held constant in as-spent dollars till abandonment. The total operating cost over the life of this project is $875 MM in constant 1/1/92$.

Table 3.34. Sandpiper discovery operating cost estimate at peak rate - $MM (1/1/92$).

Pipelines	Production Platform Facilities	Base Camp	Yearly Total
1	50	25	76

3.3.4.3.2 Summary. The Sandpiper discovery, located 9 mi offshore and about 10 mi west of NU, has been explored by only two wells. Approval of the Sandpiper Unit by the MMS in November 1992 may indicate that future exploration efforts are planned. Based on the very limited information available, potential reserves of 93 MMBO were estimated. An operator's estimate of potential reserves of about 87 MMBO is used. The development scenario is based on arctic studies, and, as with the NU evaluation, it is assumed existing technology can be adapted or will be developed as required. Using an assumed start-up date of 2000, the life of the project would extend through 2012. Shutdown of TAPS in 2008 would result in an estimated loss of about 19 MMBO should development occur as assumed. Economics of development of this discovery under the scenario decribed in this section are summarized in **Table 3.35** for four oil price forecasts.

3.3.4.4 Technical Summary. Sea ice is a primary design consideration for petroleum production facilities in the Beaufort Sea. The oil industry has jointly spent over $60 MM conducting

Table 3.35. Sandpiper development economics - $MM(1/1/92$).

Economic Factor	Oil Price Forecasts			
	EIA High	EIA Mid-Level	NES Low	EIA Low
Project Life - yrs	13	13	12	9
Reserves - MMBO	86.7	86.7	83.4	69.8
Investments	860	860	860	860
Operating Costs	875	875	811	605
Cash Flow - PW_{10}	(49)	(192)	(357)	(496)
State Revenue - PW_{10}	282	232	188	142
Federal Revenue - PW_{10}	80	20	0	0

research on the behavior, location, mechanical properties, and movements of sea ice in the Beaufort Sea by way of oil industry sponsored studies through the LPRC of AOGA (Alaskan Update 1991). An estimate of the amount of money spent by the oil industry on individual industry proprietary research in this area is not available.

Offshore production structure design for the Beaufort Sea has focused on two major categories, artificial (man-made) islands and bottom-founded structures. The alternative selected for a particular site will be based on specific site evaluation including (a) water depth; (b) distance to shore; (c) type of soil on the seafloor; (d) oceanographic, ice, and weather conditions; (e) the number of years the structure will be used; (f) logistics of construction and supply; (g) government regulations; and (h) costs (Alaskan Update 1991). The only offshore production structure in operation in the Beaufort Sea is the Endicott development, which includes two gravel islands in about 4 ft of water 2 mi from shore. Several exploration gravel islands have been constructed in the Alaskan Beaufort Sea at Sandpiper, Seal Island, and Northstar Island in less than 50 ft of water. Several bottom-founded exploration structures shown in **Figure 3.13** have been used in the Beaufort Sea.

Man-made island and bottom-founded structure alternatives for offshore oil production will be larger (and cost more) than those designed only for exploration drilling because of the requirements to design for continuous occupancy by personnel, to remain in place for the economic life of the project, and to serve as a full-time platform for production and drilling equipment. Based on the research in the MMS study, the technology for either alternative is available. Site specific data and analyses of the nature of the ice and structure interaction will determine the structural configuration to be considered

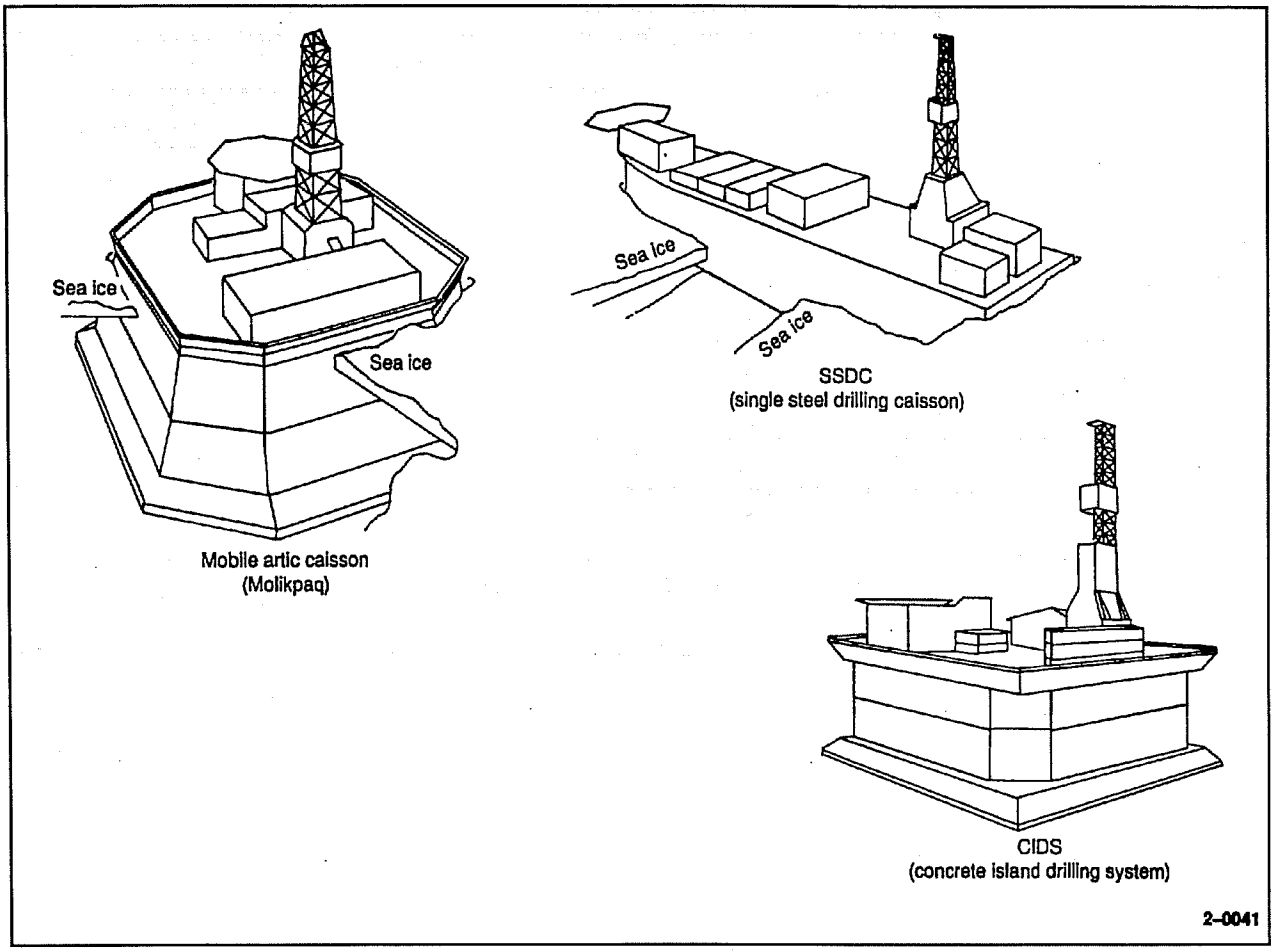

Figure 3.13. Offshore exploratory drilling structures used in Alaska and the arctic (Alaska Update 1986).

(MMS 1985). Considerations of risk and economics will be key factors in the selection.

There are no existing subsea pipelines in the Beaufort Sea; however, there is no doubt that their construction is technically feasible. Subsea pipeline design and construction will need to account for several unique aspects of operating in the Beaufort Sea. Included in these considerations are ice and weather effects on construction equipment and the effective length of the construction season, the nature of the seabed soil, seabed ice gouging, and the prevention of permafrost degradation in the permafrost zones (MMS 1985).

Open water construction periods will vary based on the seasonal ice retreat rate. Trenching will be necessary to lower the pipe below ice-gouge hazards. Trenching depths will be evaluated and determined based on acceptable risk, which requires gathering and evaluating data on the frequency, depth, and location of seabed gouges, and a determination of the recurrence interval for various gouge

depths along the proposed pipeline route. Several proprietary studies have been or are being conducted to obtain these data. Ice gouging to depths of 20 ft have been documented in the area of interest for this study in the Beaufort Sea. The impact of strudel scour (seafloor depressions created by fresh river water draining through cracks in the sea ice at breakup) will need to be evaluated in the proposed location of subsea pipelines. Strudel scour holes of 10 to 26 ft below seabed have been observed in the Beaufort Sea in water depths of 7.5 and 6.5 ft, respectively (Barry 1989). If a strudel scour condition occurs in a subsea pipeline location, the pipeline may become exposed to overstress conditions. Pipeline and trenching design will need to recognize the subsea permafrost location and prevent permafrost degradation, which could cause pipeline subsidence leading to pipeline overstress and potential failure. Even with a subsea pipeline installed well above the permafrost, a small amount of settlement (less than 1.5 ft) can overstress the pipe (Barry 1989). Trenching techniques may require that trench fill be made up of thaw-stable gravel in order to prevent pipeline subsidence. Trench design may also include the need for bedding material to avoid excessive settlement.

An additional aspect of subsea pipeline design and operation should include the ability to pinpoint leaks and provide for all weather pipeline repair. Oil spill contingency plans will need to address methods of year-round oil spill detection, pipeline repair, and cleanup.

Although the oil industry continues to conduct research and evaluate offshore production platform and subsea pipeline design alternatives, recent world oil price trends have resulted in a slower pace to these R&D expenditures. This is confirmed by **Figure 3.14** that shows the annual AOGA (LPRC) research expenditures related to annual crude oil prices. These research funds exclude expenditures for drilling seven stratigraphic wells and a study on using tankers to transport North Slope oil.

The uncertainty and risk associated with the construction and operation of offshore production facilities and subsea pipelines will require the appropriate combination of reserves and design of specific offshore production facility alternatives and subsea pipelines.

3.3.5 Summary of Five NES Fields

The five NES fields are diverse in terms of geographic location, size of resources, areal extent, depth of producing horizon, type and quality of hydrocarbons, and type of reservoir rock. All are currently in a non-producing status and most will require further exploration/delineation before

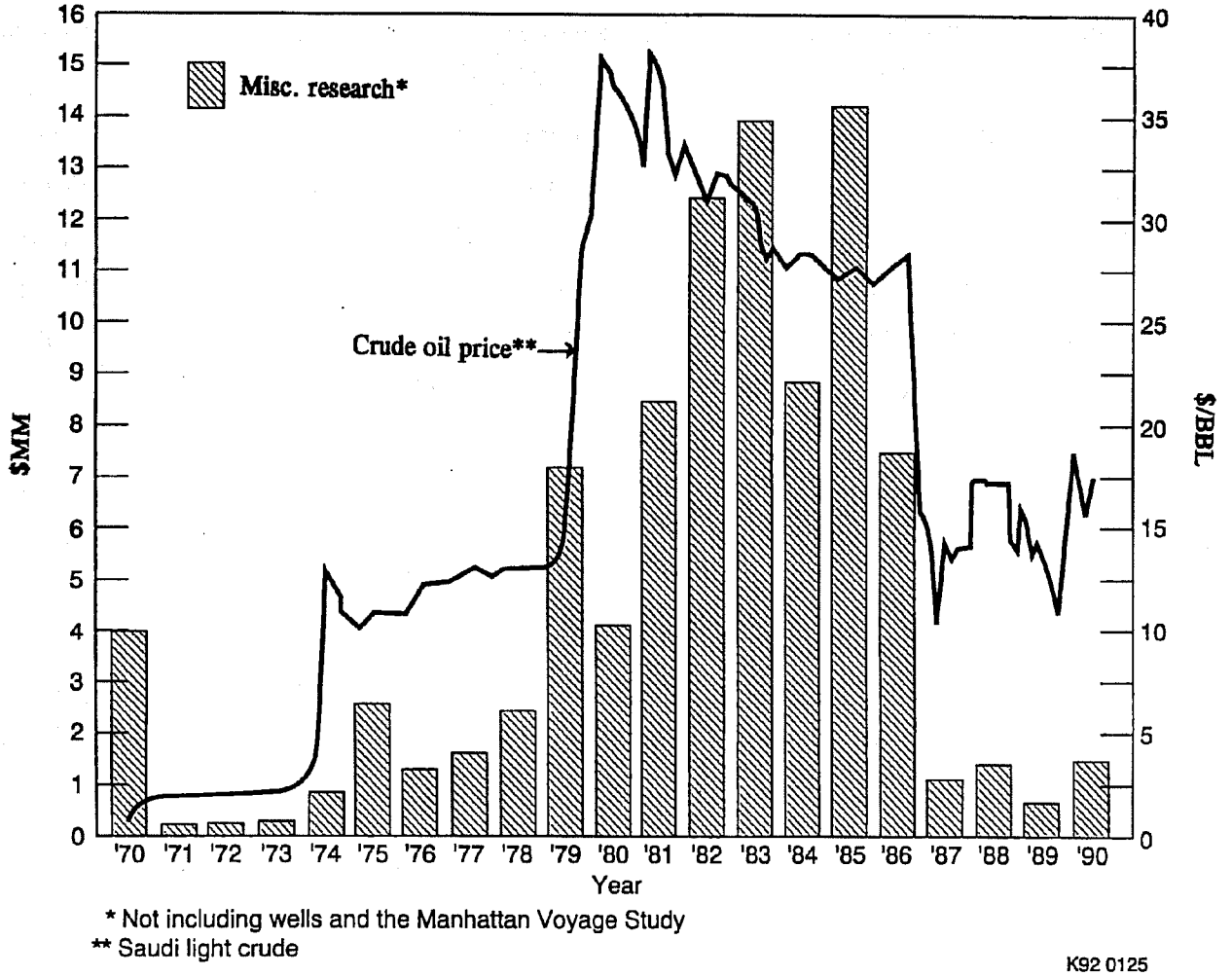

Figure 3.14. Summary of annual research expenditures and crude oil prices (Alaska Update 1991).

development decisions can be made. One result of this is that public information is limited on all five fields.

Consequently, where data are missing, comparisons to producing North Slope fields, empirical relationships developed by industry, and personal knowledge were used in forecasting rates, reserves, operating costs, and development investments. In some instances, it was assumed that existing technology could be adapted to the arctic North Slope developments or that technology can be developed to meet the particular conditions that would be encountered. For example, technology will have to be proven for the development of Northstar and Sandpiper that are about 9 mi offshore in 50 ft of water, and Point Thomson where highly deviated wells will encounter an overpressured reservoir. In addition, it appears that added study would be helpful in determining the best recovery and completion methods for West Sak.

Even the smallest of the five NES fields would be a major economic discovery in the Lower 48. However, the high investment and operating costs on the North Slope and technical constraints such as lack of availability of MI and a gas sales pipeline make development of any of the fields questionable at this time. Even though a large gas reserve exists at Point Thomson, it is not large enough by itself to justify a gas sales line for North Slope gas. A gas cycling project for liquid recovery at Point Thomson was not analyzed, but development on this basis could become feasible if additional large discoveries are made and developed that would support the development of a pipeline and related infrastructure.

Investments are forecasted taking into consideration each fields particular circumstances, such as location, size of accumulation, possibility of facilities sharing, estimated maximum recovery rate, and timing of development. Recoverable hydrocarbons and total investments estimated for development of each field are shown in **Table 3.36**. Investment saving where facilities sharing is assumed is also included in the table.

Table 3.36. Forecasts of recoverable hydrocarbons and investments for the five NES fields.

Field	Liquids (MMB)	Gas (TCF)	Investments - $MM (1/1/92$)		1st Yr of Prod.	Forecast Life
			Development	Facilities Sharing Savings		
West Sak A	502	(a)	4,078	857	2001	2013
West Sak B	106	(a)	1,085	(c)	2008	2013
Point Thomson - 5 TCF[b]	112	4.4	1,579	--	2008	2035
Point Thomson - 3.4 TCF[b]	99	3.0	1,367	--	2008	2026
Gwydyr Bay	48	(a)	340	--	1999	2014
Northstar	200	(a)	1,405	--	1998	2012
Sandpiper	87	(a)	860	36 to 120[d]	2000	2012

a. No estimate made - gas used in field operations only.
b. Condensate and NGL reserves limited by TAPS shutdown at 200 MBPD (2014) and gas sales less CO_2 and NGL.
c. Maximum savings is facilities is realized even if Area B is not developed.
d. Oil is assumed to be shipped through the NU field pipelines that have an estimated cost of $120 MM. This is the maximum savings to Sandpiper. Based on percent of oil shipped, the minimum saved is about $36 MM, if Sandpiper joined in constructing the lines.

3.4 Economic Sensitivity Analysis

3.4.1 Overview

The economic analyses of the five NES fields utilizes the investment decision-making process discussed in **Section 1.3.** The analysis includes:

1. Basic technical assumptions used for the analyses.
2. Economic results for each field development using the four oil price cases discussed in **Section 3.3.1.**
3. Flat oil price (FOP) in 1/1/92$ required for each field development to provide industry a present worth (PW) of zero at different discount rates.
4. The share of benefits from the development of the five NES fields that industry, state government, and federal government would receive.
5. The sensitivity of the results of the economic evaluation to changes in the selected components.
6. Summary observations.

3.4.2 Technical Assumptions

The basic assumptions used in the analysis of each of the five NES fields are listed in **Table 3.37**. Assumptions other than those listed for each field development would require additional analysis and would provide different specific results. The use of the higher price forecasts may give results that are not directly comparable to the two lower price forecasts; i.e., where the cumulative cash flow is very low or negative. Under the low price scenarios, the project would either not be considered or the scope of the project would be revised and reevaluated (e.g., the project would be revised using reduced investments, operating costs, and area being developed) to determine if any size project would be economical. The effects of changes in specific components such as investments, operating costs, volume, and tax and royalty rates are included in the sensitivity analysis discussed in **Section 3.4.6.** The economic effects that could be expected from improved technology and more cost efficient regulatory systems are illustrated by the sensitivity analysis.

Table 3.37. Basic field assumptions for the five NES fields, $MM (1/1/92$).

	West Sak		Point Thomson		Gwydyr Bay	Seal Island/ Northstar	Sandpiper
	A	B	5 TCF	3.4 TCF			
INVESTMENT							
No. of Wells	1,125	350	42	32	22	50	16
Total Well Investment ($MM)	2,250	700	711	542	92.3	250	80
No. of Producers	844	263	42	32	12	38	12
Total Facility Investment ($MM)	1,828	385	869	825	248	1,155	780
Total Investment ($MM)	4,077	1,085	1,579	1,367	340	1,405	860
Total Investment ($/BBL)	8.12	10.23	5.72[a]	6.12[a]	7.08	7.03	9.90
OPERATING COST							
Total Operating Costs	4,985	1,153	2,206	1,298	266	1,506	875
$/BBL Oil	9.93	10.88	8.60[a]	6.17[a]	5.54	7.53	10.06
VOLUME							
Peak Field Rate (MBPD) (MMCFD)[d]	168 -	67 -	45[b] 440	47[b] 440	13	55	26
Total Recovery (MMBO) (TCF)[d]	502 -	106 -	112[c] 4.4	112[c] 3.0	48	200	87
1st Year Production	2001	2008	2008	2008	1999	1998	2000
Forecast Life	2013	2013	2035	2026	2014	2012	2012

a. Equivalent oil basis on North Slope value (30.5 MCF/BBL).
b. Condensate plus oil.
c. Liquid sales (2008 to 2014).
d. Gas sales volumes.

3.4.3 Economic Results

The present worth values at two discount rates (10 and 15%) are provided for each of the five NES fields in **Table 3.38**. The four oil prices used are shown in **Figure 3.1** and **Table 3.1**. The possible development of these fields is directly related to the oil price scenario that is believed by industry to be representative of future rates. Industry evaluates the economic viability of a future potential field development to determine if any of various oil price scenarios will result in PW = 0 at a chosen discount rate (hurdle rate). Current hurdle rates for individual companies are unknown and, in addition, hurdle rates will vary over time based on economic conditions. A range of 10 to 15% is assumed to bracket current industry discount rates. The price scenarios that provide a 15% rate of return are highlighted in the table. For example, the West Sak Area A development attains a positive PW at the EIA Mid-level

price case at discount rates slightly below 15% (the calculated value is 14%) over a 13-year life (2001 to 2013). At the NES Low oil price case, a discount rate of only 1.5% gives a PW = 0, which is well below the range that industry can accept. The NES Low oil price case is used as the reference or target price case for comparative purposes. Summary level financial results are shown in **Appendix D** for the development scenarios of the five NES fields at the NES Low price case.

Table 3-38. Five NES fields, industry PW results for four price cases, $MM (1/1/92$).

Oil Price Case		West Sak[b]		Point Thomson[b]		Gwydyr Bay[b]	Seal Island/ Northstar[c]	Sandpiper
		A	B	5 TCF	3.4 TCF			
EIA High	PW_{10}	1113	206	494	958	178	-492	-42
	PW_{15}	420	68	128	286	66	----	----
EIA Mid-level	PW_{10}	259	2	287	331	88	-648	-192
	PW_{15}	-23	-19	44	76	17	----	----
NES Low	PW_{10}	-454	-128	60	135	14	-796	-356
	PW_{15}	----	----	-39	-2	-26	----	----
EIA Low	PW_{10}	-1323	-273	-75	-4	-43	-897	-509
	PW_{15}	-----	----	----	----	----	----	----

a. PW_{10} is present worth at a 10% discount rate; PW_{15} is present worth at 15% discount rate.
b. Shaded blocks indicate cases with positive PW at indicated discount rates.
c. With net-profit interest (NPI).

To show the relationship of the four oil price cases to the FOP required for PW_{10} and PW_{15} = 0, an equivalent flat oil price (EFOP) is calculated for each price case for each project. The EFOP is calculated by determining the value of the hydrocarbons sold in 1/1/92$ and dividing this value by the total recovery. Gas is converted to the equivalent oil value for Point Thomson. These EFOP values are project specific because of the differences in development timing, investments, and production profiles for each project. The EFOP values for the projects and the FOP for PW_{10} and PW_{15} = 0 are given in **Figures 3.15** to **3.19**. The FOP for PW_{10} = 0 is highlighted by the horizontal line in each figure to provide a datum for comparison with the EFOP for the NES Low oil price case.

3.4.4 Flat Oil Price (FOP)

The economic viability of the future field developments is evaluated using a flat oil price (FOP); i.e., a price forecast that does not include any real growth. A FOP (1/1/92$) is determined that allows

the field developments to provide a PW = 0 at discount rates of 10 and 15%. This FOP concept is used in the sensitivity analyses to illustrate the effects that individual or combined changes in operating costs, investment costs, reserves, and tax and royalty rates have on reducing the FOP to a targeted reference oil price forecast.

As shown in **Figure 3.15** for West Sak Area A, the FOP for PW_{10} = 0 is $30.83/BBL compared to an EFOP for the NES Low oil price case of $27.47/BBL. For Area B, the FOP for PW_{10} = 0 is $35.83/BBL compared to an EFOP for the NES Low oil price of $29.52/BBL. Data are presented in the figures for Point Thomson 3.4 and 5 TCF cases, Seal Island/Northstar with and without NPI applied, and Sandpiper. The Point Thomson 3.4 TCF case as developed gives slightly better economic results than the 5 TCF case because the gas sales rate is assumed to be the same for both cases. It is clear from **Figure 3.18** that the NPI on Northstar is the most detrimental factor for the development scenario.

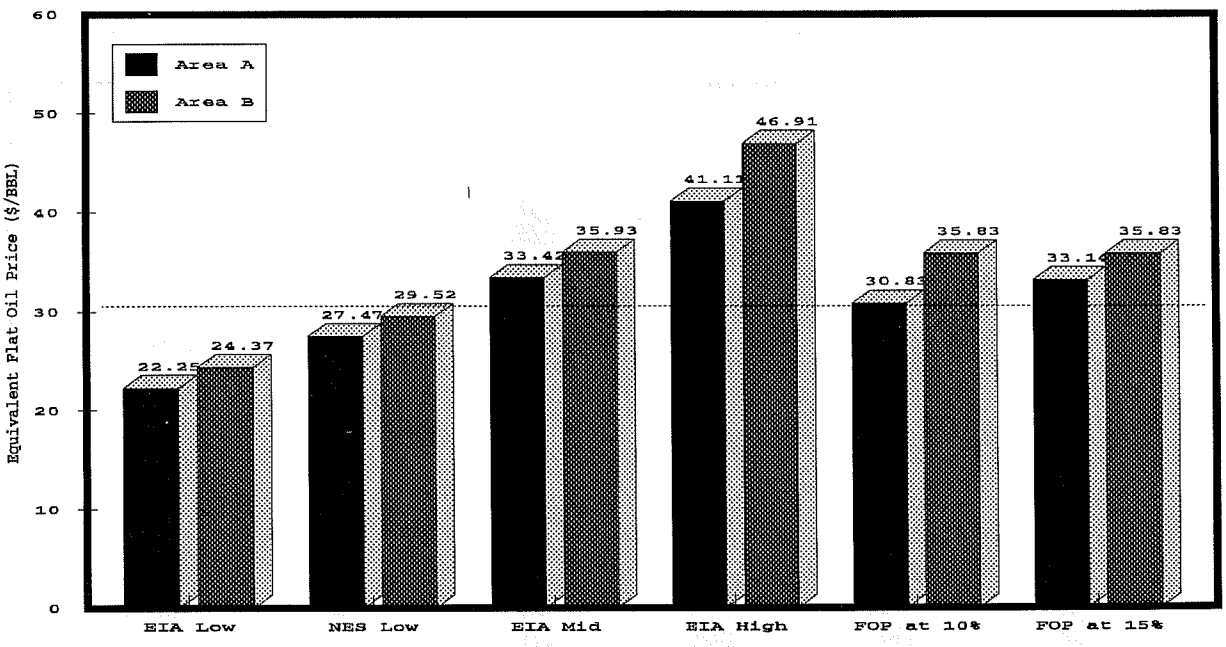

Figure 3.15. West Sak Areas A and B - comparison of EFOP for the four oil price cases with FOP required for PW_{10} and PW_{15} = 0.

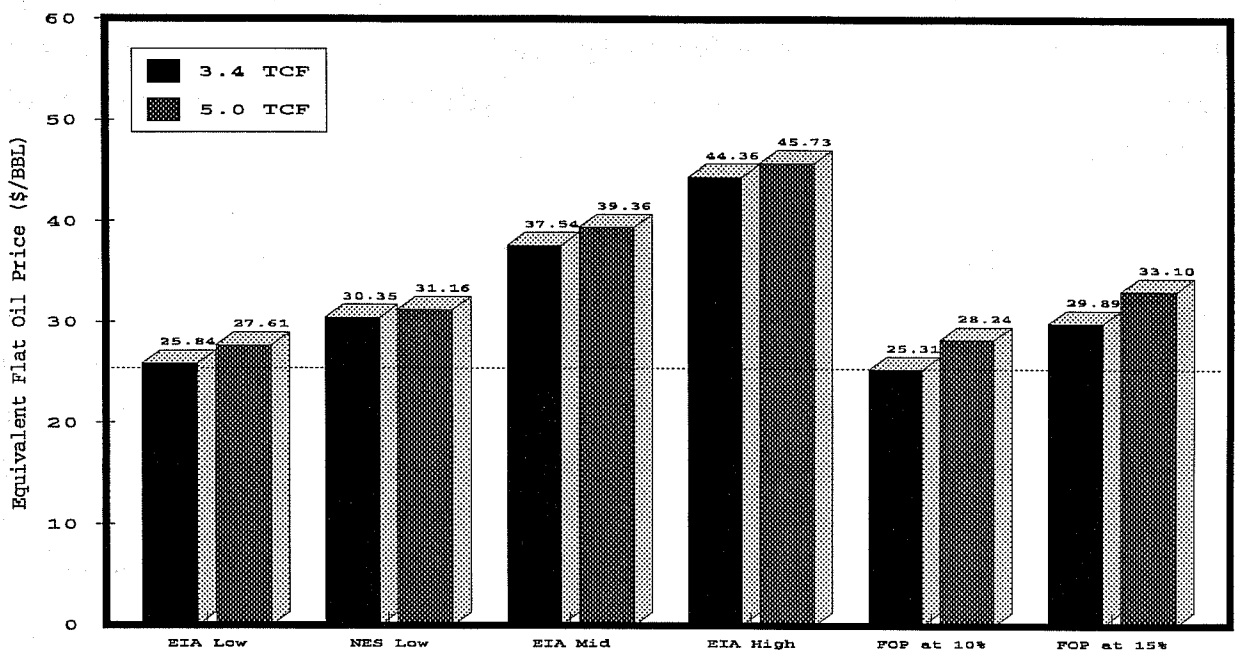

Figure 3.16. Point Thomson - comparison of EFOP for 3.4 and 5 TCF cases for the four oil price cases with FOP required for PW_{10} and $PW_{15} = 0$.

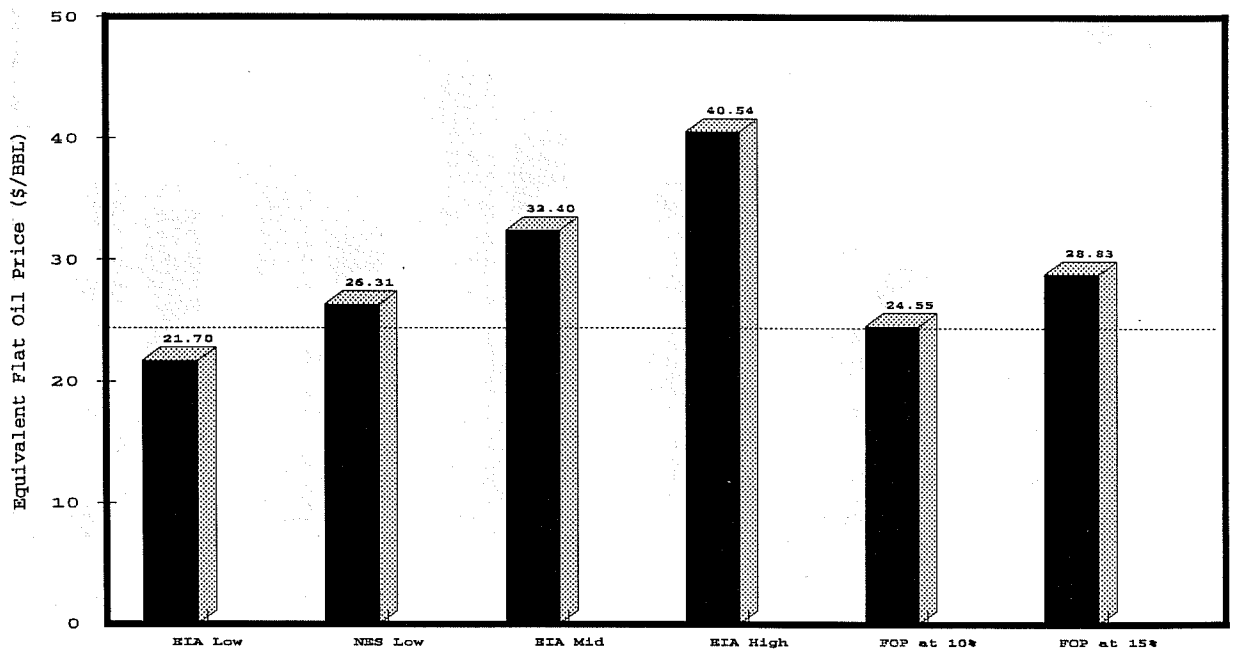

Figure 3.17. Gwydyr Bay - comparison of EFOP for the four price cases with FOP required for PW_{10} and $PW_{15} = 0$.

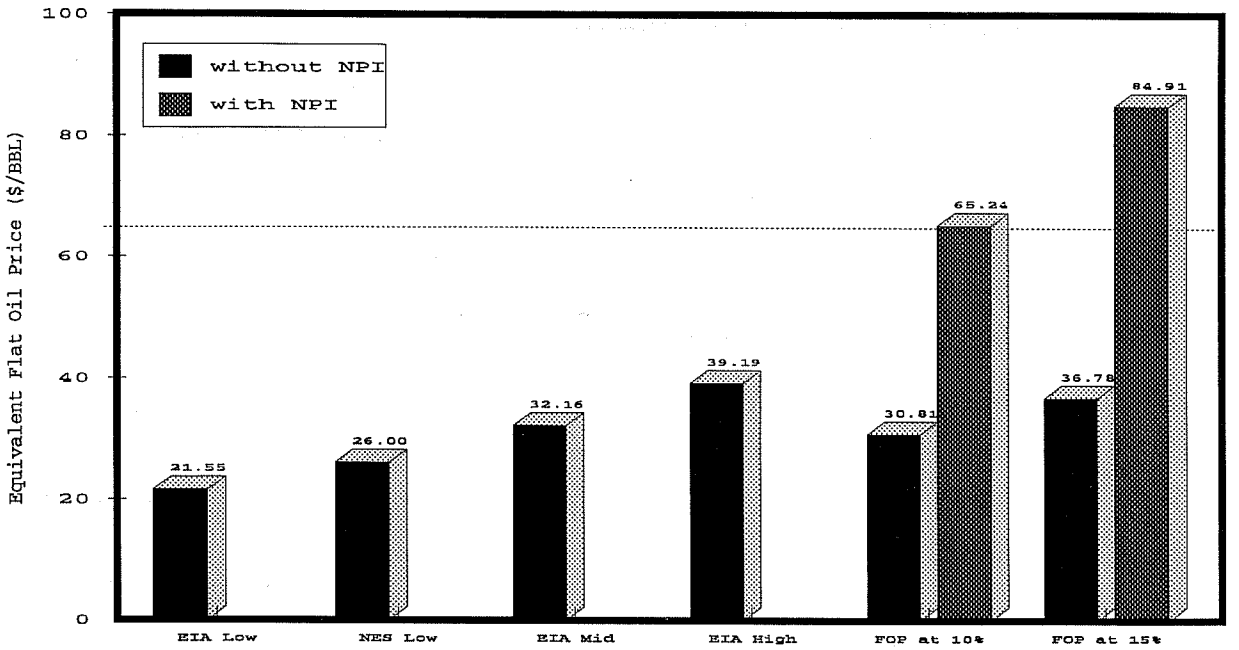

Figure 3.18. Seal Island/Northstar - comparison of EFOP for the four oil price cases with FOP required for PW_{10} and PW_{15} = 0 with and without NPI.

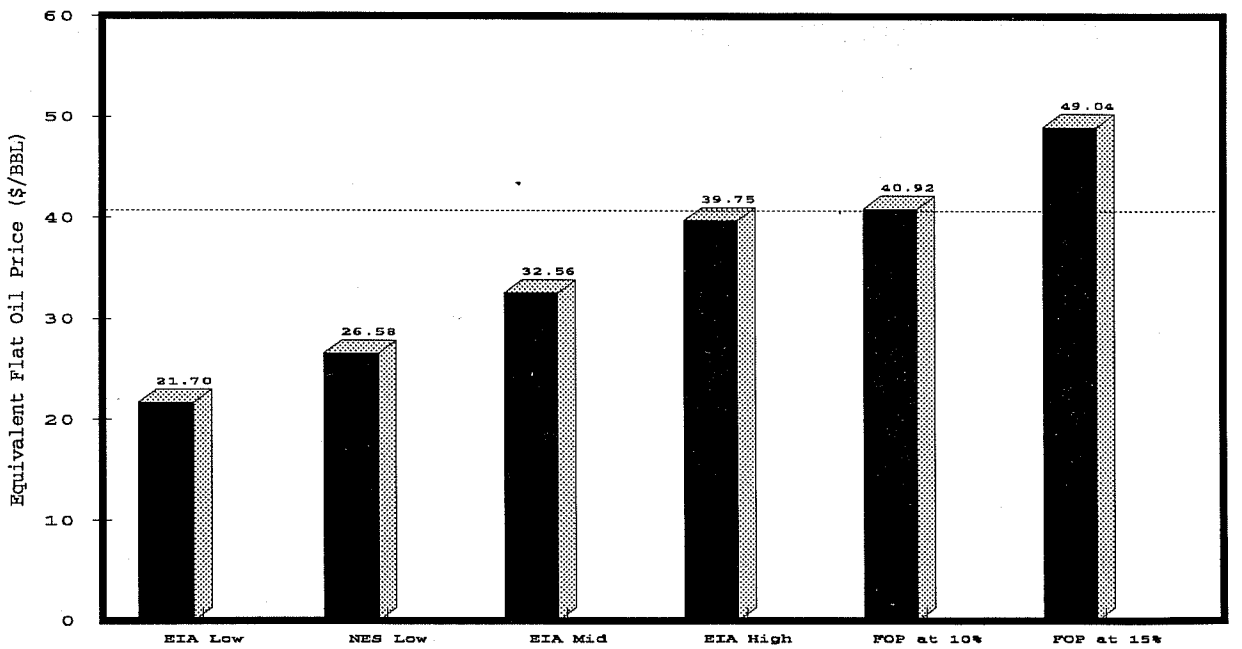

Figure 3.19. Sandpiper - comparison of EFOP for the four oil price cases with FOP required for PW_{10} and PW_{15} = 0.

3.4.5 Industry, State, and Federal Share of Benefits

The financial benefits to the state of Alaska include the revenues from royalties, severance tax, ad valorem tax, conservation tax, conservation surtax, and state income tax. The federal share is from federal income tax and royalties on federal leases.

3.4.5.1 Five NES Fields. The estimated state and federal shares of revenue (cumulative PW at 10% discount rate) for each of the five NES fields are summarized in **Table 3.39**. These revenue streams to the state of Alaska and the federal government are significant even if minimum industry economic hurdle rates are not met (**Table 3.38**). The value of the development of the five NES fields is greater to the state and federal government than to industry at all oil price levels. This situation may present opportunities for share re-distribution among the state of Alaska, the federal government, and industry that would provide the necessary value to industry to encourage development at oil prices at or near the NES Low oil price forecast (see **Section 3.4.6**). .

3.4.5.2 Currently Producing Fields. As shown in **Table 1.1** the start up dates for the producing fields were: (a) Prudhoe Bay, July 1977; (b) Kuparuk River, December 1981; (c) Lisburne PA, March 1985; (d) Endicott, October 1987; and (e) Milne Point, November 1985. A decision to develop on the North Slope must be made a minimum of 2 years before startup because of the requirement for design and construction in the Lower 48 and sea-lift to the North Slope during open water in the summer. Thus, a comparison of these start-up dates with the historical world oil prices as shown in **Figure 3.20** shows that the decisions to develop all these fields (with the exception of Prudhoe Bay) were made during the period of time between 1975 and 1986 when world oil prices were about $30/BBL or above.

Using the publicly available information, the historical value of the currently producing fields measured in after-tax cash flow (1992 as base year) is estimated for each field on a stand-alone basis. As shown in **Table 3.40**, Prudhoe Bay is the only field that has provided its investors with a positive value at a 10% discount basis by 1/1/92. Kuparuk has provided significant value to the state of Alaska but has not yet met a 10% hurdle rate (in 1/1/92$). Lisburne, Endicott, and Milne Point also have not provided their investors with a positive 10% discounted cumulative cash flow through 1991. The future cumulative cash flows to industry, discounted at 10%, for the EIA Mid-Level and the NES Low oil price cases for each of these fields is shown in **Table 3.41**.

Table 3.39. Total state, federal, and industry revenue shares ($MM) for each oil price at 10% discount rate.

NES Fields		Oil Price Scenario			
		EIA Low	NES Low	EIA Mid-Level	EIA High
West Sak Area A	State	605	745	925	1150
	Federal	0	30	345	770
	Industry	-1325	-455	260	1115
West Sak Area B	State	95	120	150	205
	Federal	0	5	55	155
	Industry	-275	125	5	205
Pt. Thomson - 5 TCF	State	325	375	455	530
	Federal	65	130	240	345
	Industry	-75	65	285	495
Pt. Thomson - 3.4 TCF	State	285	330	400	655
	Federal	90	160	260	580
	Industry	-5	135	330	960
Gwydyr Bay	State	75	90	110	135
	Federal	15	35	75	120
	Industry	-45	15	90	180
Northstar (W/NPI)	State	785	1090	1530	2025
	Federal	0	0	0	6
	Industry	-895	-795	-650	-490
Northstar (W/O NPI)	State	480	570	715	865
	Federal	0	55	185	345
	Industry	-590	-330	-10	325
Sandpiper	State	160	190	230	285
	Federal	0	0	20	85
	Industry	-510	-355	-190	-40

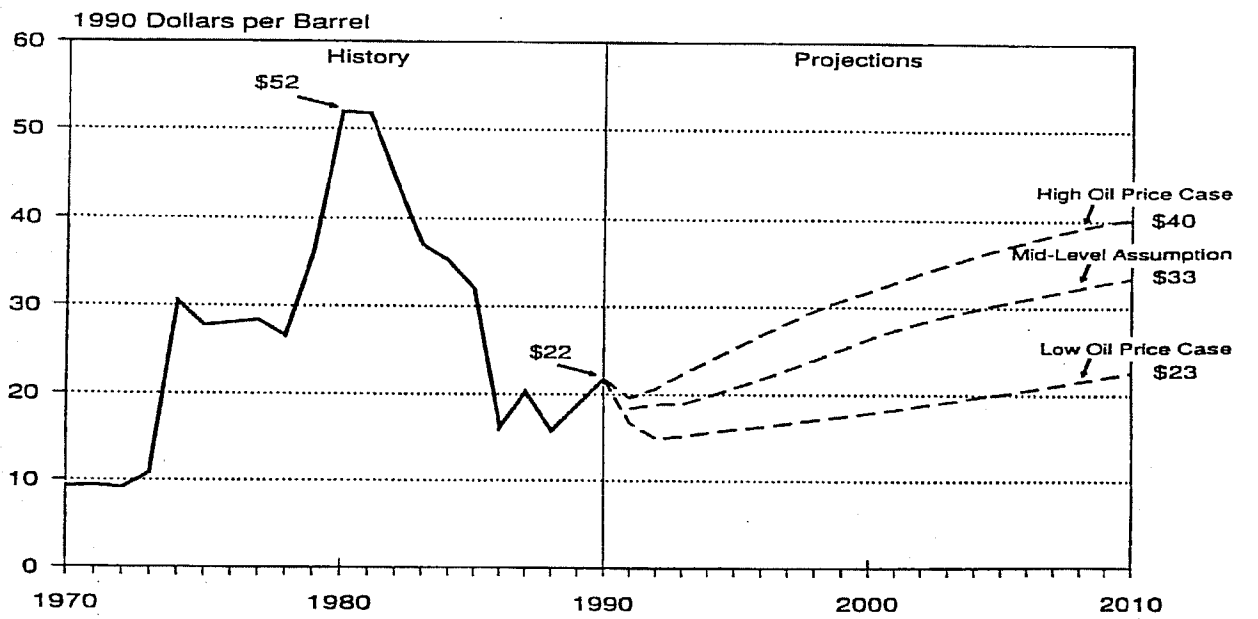

Figure 3.20. Historical world oil prices and world oil price assumptions (EIA 1992a).

Table 3.40. Existing fields past share estimates at 10% discount rate - ($MM, 1/1/92$).

North Slope producing fields	Cumulative historical discounted cash flow (1992 base year)		
	Industry	Federal	State
Prudhoe Bay	40,000	40,000	65,000
Kuparuk	-2,000	200	3,600
Lisburne	-800	0	300
Endicott	-1,300	0	600
Milne Point[a]	-800	0	100

a. Includes production volume from Schrader Bluff.

Table 3.41. Producing fields future 10% discounted cash flows for the EIA Mid-Level and NES Low oil price cases ($MM, 1/1/92$).

	Prudhoe Bay	Kuparuk	Lisburne	Endicott	Milne Point
EIA Mid-Level	24,200	3,700	800	700	360
NES Low Case	16,900	1,500	500	400	-120

a. Includes Schrader Bluff.

The estimates presented in these tables indicate that if the decisions were being made in 1992 and a hurdle rate of PW = 0 at a 10% discount rate was used, Kuparuk, Lisburne, Endicott, and Milne Point probably would not be developed. These results illustrate the significant uncertainty and risk involved in decision making given the volatility of world oil prices.

3.4.6. Sensitivity Analysis

The components of an economic evaluation are (a) revenue, (b) operating costs, (c) investment, and (c) taxes and royalties. These components are driven by (a) oil and gas prices, (b) technical aspects of the accumulation, (c) environmental and regulatory issues, (d) federal and state revenue needs, (e) cost reduction measures used by the industry, and (f) technical advances as illustrated in **Table 3.42**. For example, the environmental/regulatory requirements as discussed in **Section 2** can affect both operating costs and investments. Operating costs are affected through such things as the labor costs to perform environmental assessments, permitting activities, increased fluid handling costs, waste management, and mitigation requirements. Investments, and sometimes reserves, have been affected by causeway breaches

and alternate or less optimum pad locations; e.g., events at Endicott, Point McIntyre, and Niakuk provide examples of effects of the causeway issues and Kuparuk Drillsite 3-L illustrates effects that can result from pad location issues (see **Section 2.5**). The comparison of the Niakuk onshore project with the offshore Niakuk project, described in **Appendix D.2**, illustrates the effects environmental requirements can have on reserves and economics. The proven and potential reserves for the onshore project are estimated to be 70.4 MMBO compared 99.0 MMBO for the original offshore project resulting in a potential loss of reserves of 29 MMBO. The cash flow to industry and revenue to the state of Alaska and federal government are reduced by a total of $135 MM (1/1/92$) using the NES Low oil price scenario. These results provide a quantifiable estimate of the impact that environmental requirements have had on a North Slope project. Project delays causing increases in time between investments and production also affects the economics of projects.

Table 3.42. Driving forces that impact economic evaluation.

Driving Forces	Economic Component			
	Revenue	Operating Costs	Investment	Taxes and Royalties
Oil and Gas Prices	X			
Technical				
Size		X	X	
Rate		X	X	
Location		X	X	
Recovery		X	X	
Wells		X	X	
Environmental/Regulatory				
Wetlands		X	X	
Subsistence		X	X	
Permitting		X	X	
Waste management		X	X	
Federal & State Revenue Needs				
Income tax rates				X
Production tax rate				X
Other tax rates				X
Royalty rates				X
Cost Reduction Measures & Technical Advances		X	X	

Decreases in operating costs and investments and increases in reserves can be achieved through improved technology for drilling, facility design, production technology, streamlining of environmental permitting, reduced cost of environmental compliance, and improved recovery processes.

The magnitude of the impact on project economics by changes in selected factors and combinations of factors for the five NES fields are shown in **Figures 3.21** to **3.27**. Also shown for comparison purposes are the project specific EFOP for the NES Low oil price forecast. The detailed results are presented in **Appendix D, Tables D.5** to **D.11**.

For West Sak Area A (**Figure 3.21**), these results indicate that a 15% reduction each in operating cost and investment reduce the FOP for $PW_{10} = 0$ to \$27.18/BBL, slightly below the EFOP of \$27.47/BBL for the NES low oil price case. A reduction in operating cost and investment of 10% each and an increase in reserves of 10% provides a similar reduction in the FOP for $PW_{10} = 0$. A 50% reduction in royalty and tax rates (conservation and conservation surtax rates are not changed in the calculation) reduce the FOP for $PW_{10} = 0$ to \$27.94/BBL. The final comparison shown is for the combination of a 50% reduction in royalty and tax rates, 10% reduction in operating cost and investments, and a 10% increase in reserves. This combination results in a FOP at $PW_{15} = 0$ lower than the EFOP for the NES low oil price.

With the NPI in place the development of the Northstar Unit would appear to be out of the range of possibility as illustrated in **Figure 3.26**. The major requirement for Sandpiper development is the confirmation of larger reserves.

3.4.7. Summary Observations

(1) Under the assumptions used, the economic results for three of the five NES fields (West Sak, Point Thomson, and Gwydyr Bay) indicate that only price forecasts with significant real growth can provide industry with a positive PW at a discount rate of 10% (see **Table 3-38**). The two offshore fields (Seal Island/Northstar and Sandpiper) do not provide a positive PW at a 10% discount rate for any of the price scenarios.

(2) Results of the economic sensitivity analyses presented in **Figures 3.21** to **3.27** show that combinations of reduced operating costs, investments, tax and royalty rates, NPI, and increased

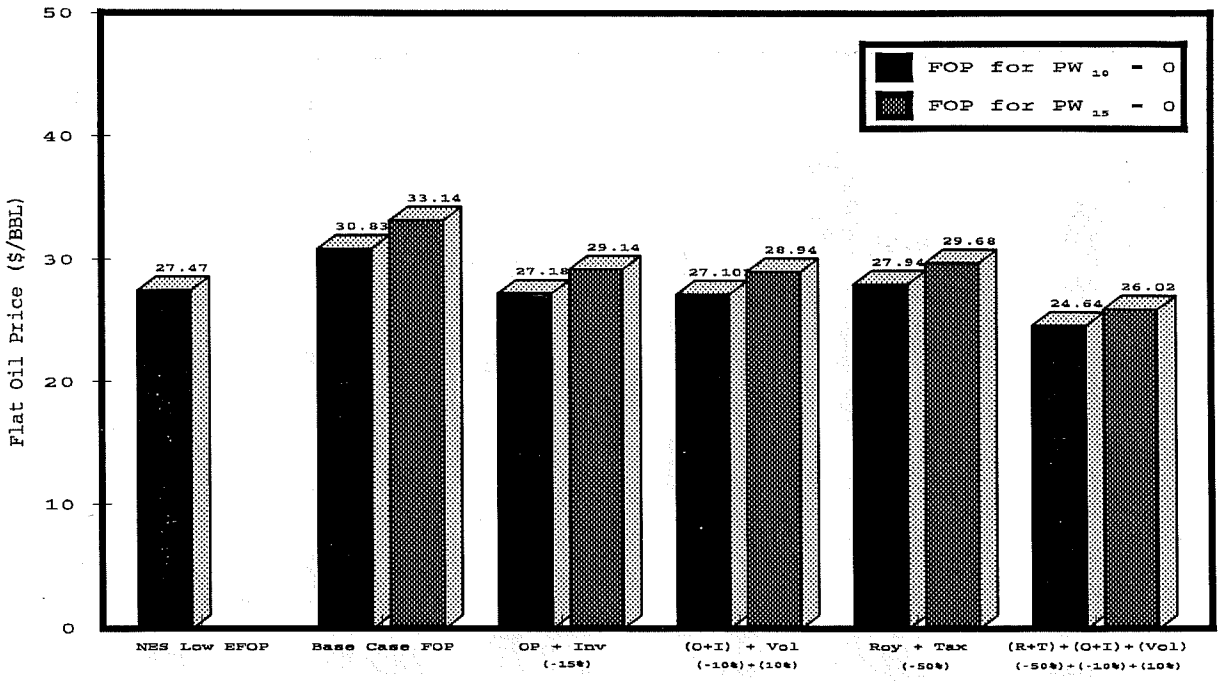

Figure 3.21. West Sak Area A economic sensitivity analysis.

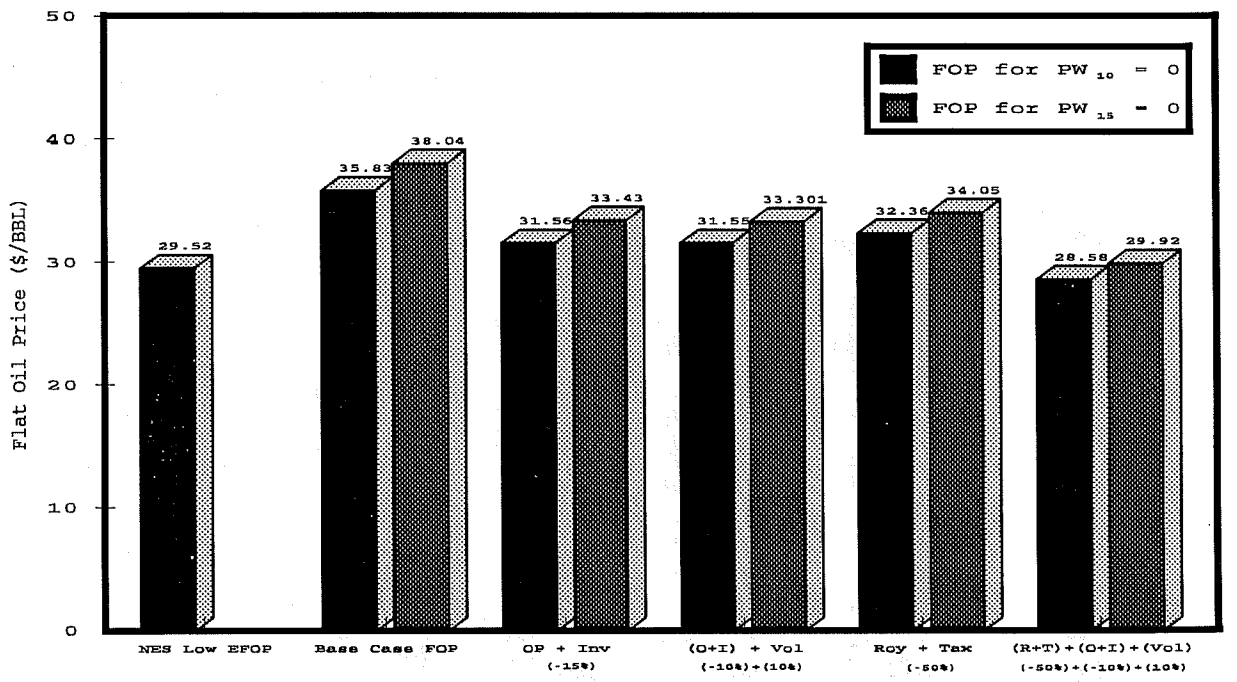

Figure 3.22. West Sak Area B economic sensitivity analysis.

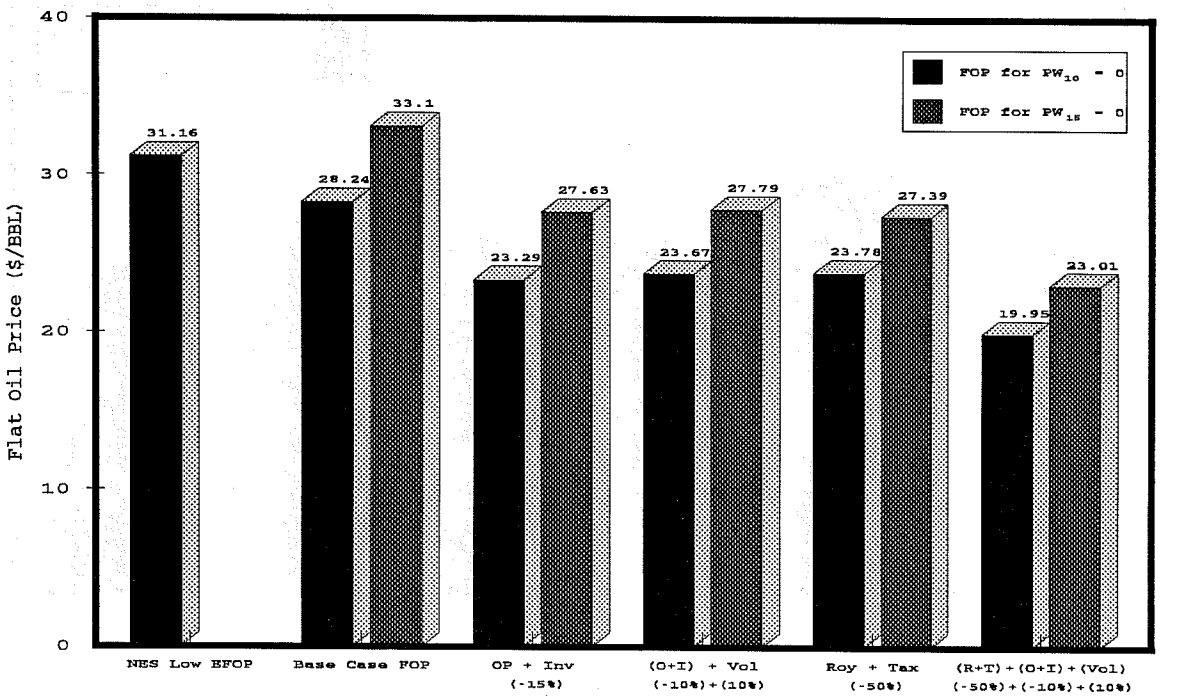

Figure 3.23. Point Thomson 5 TCF case economic sensitivity analysis.

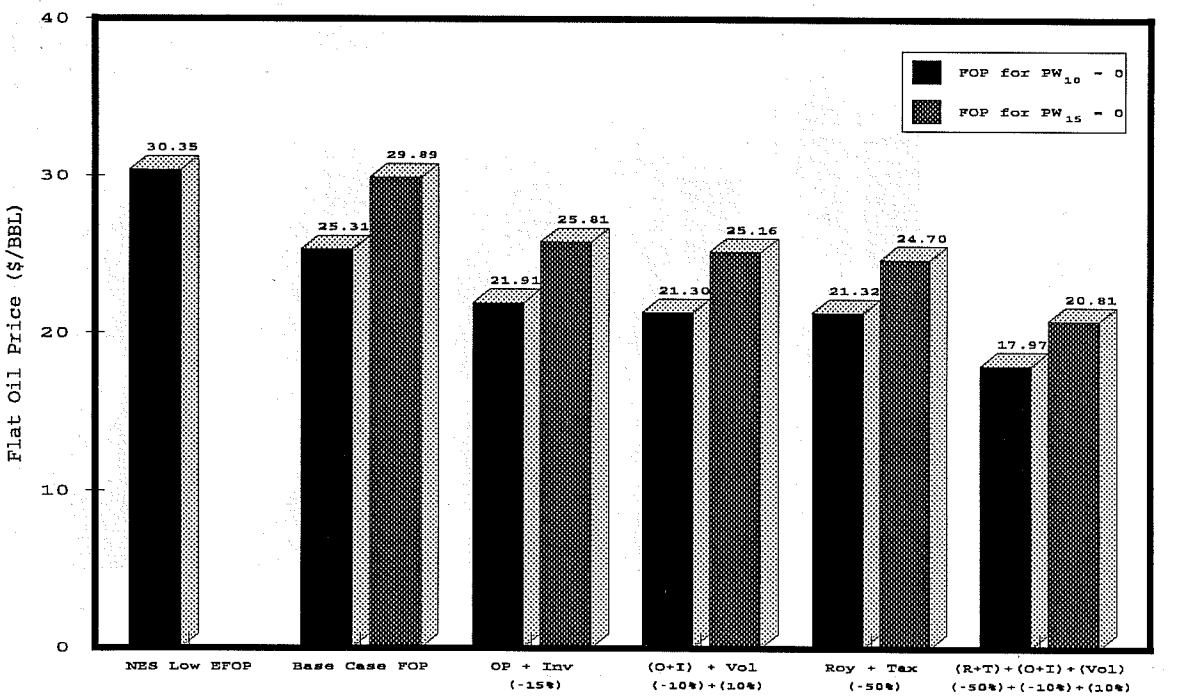

Figure 3.24. Point Thomson 3.4 TCF case economic sensitivity analysis.

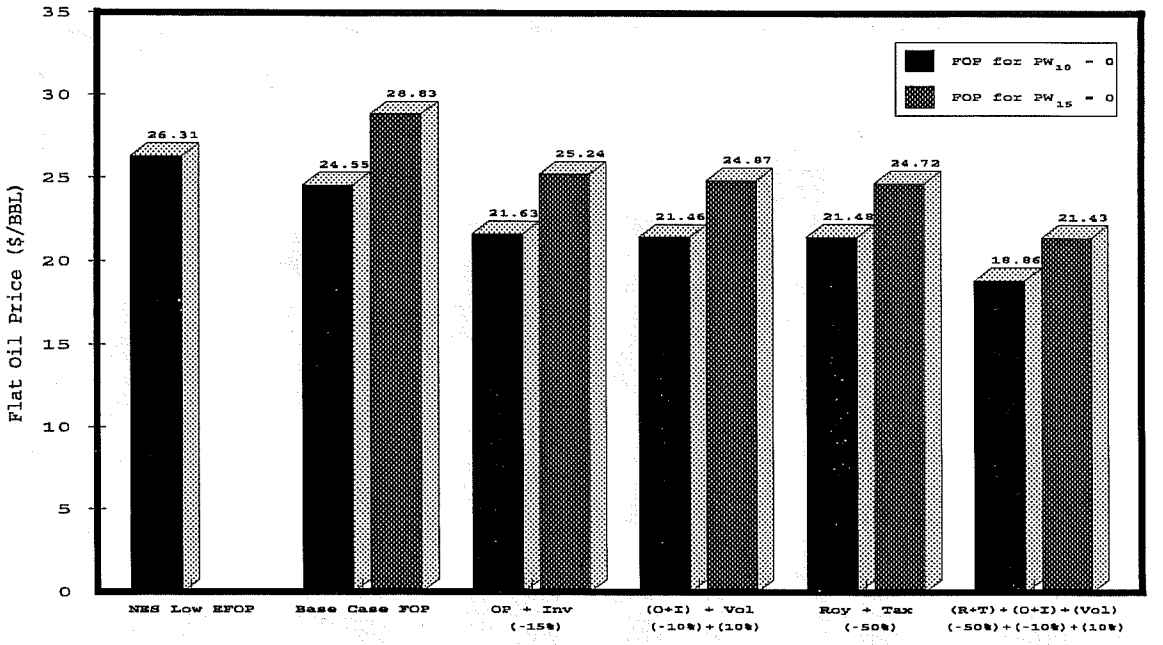

Figure 3.25. Gwydyr Bay economic sensitivity analysis.

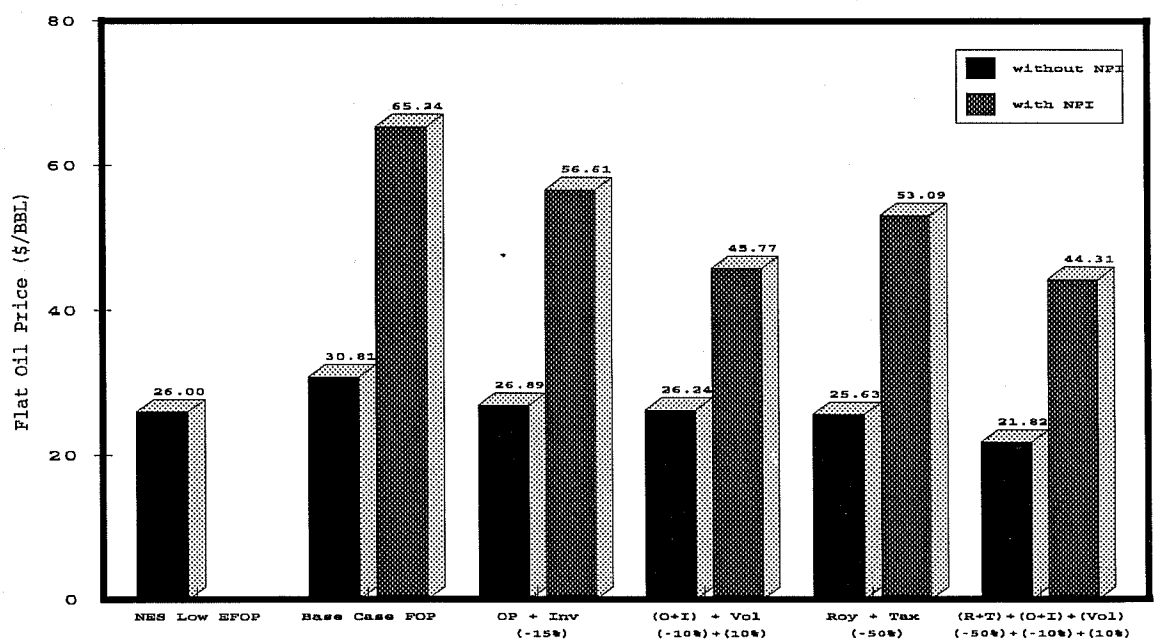

Figure 3.26. Northstar Unit economic sensitivity analysis for discount rate of 10%, with and without NPI.

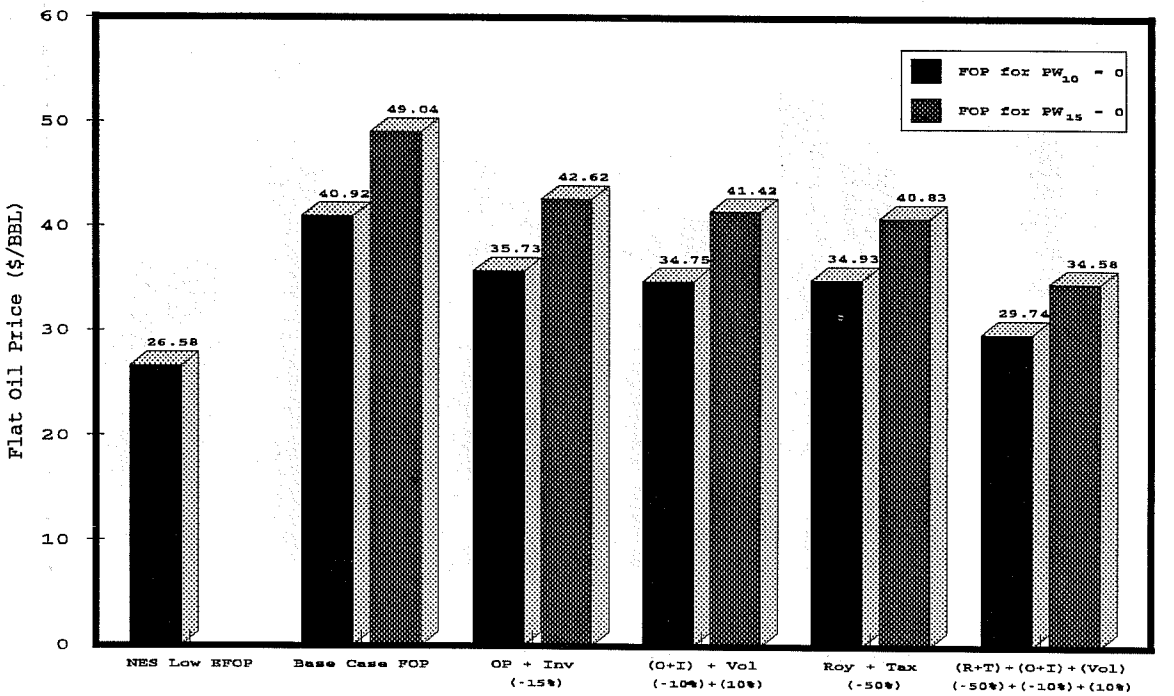

Figure 3.27. Sandpiper Field economic sensitivity analysis.

reserves could make development of these five fields potentially economic provided the following requirements are met:

- MI is available for use in West Sak, which will be at least third after PBU and KRU.
- A gas sales line is developed for PBU gas before Point Thomson can be developed.
- The potential reserves at Gwydyr Bay must be proven and the uncertainty of costs related to development in the Kuparuk River Delta resolved.
- The Northstar Unit does not appear feasible without removal of the NPI burden.
- Larger reserves at Sandpiper must be confirmed.

(3) The Alaska North Slope production profile (**Figure 3.28**) is based on the EIA Mid-level price in **Table 3.1**. At these prices and using a 10% discount rate, West Sak Area A and B, Point Thomson, and Gwydyr Bay provide a positive PW and are included in the production profile. Seal Island/Northstar and Sandpiper do not meet this economic hurdle rate and are not included. Point Thomson and Gwydyr Bay provide a 10% rate of return at the NES low oil price. At the EIA Low oil price case none of the five NES fields provide a positive PW at a 10% discount and result in an Alaska North Slope production profile as shown in **Figure 3.29**.

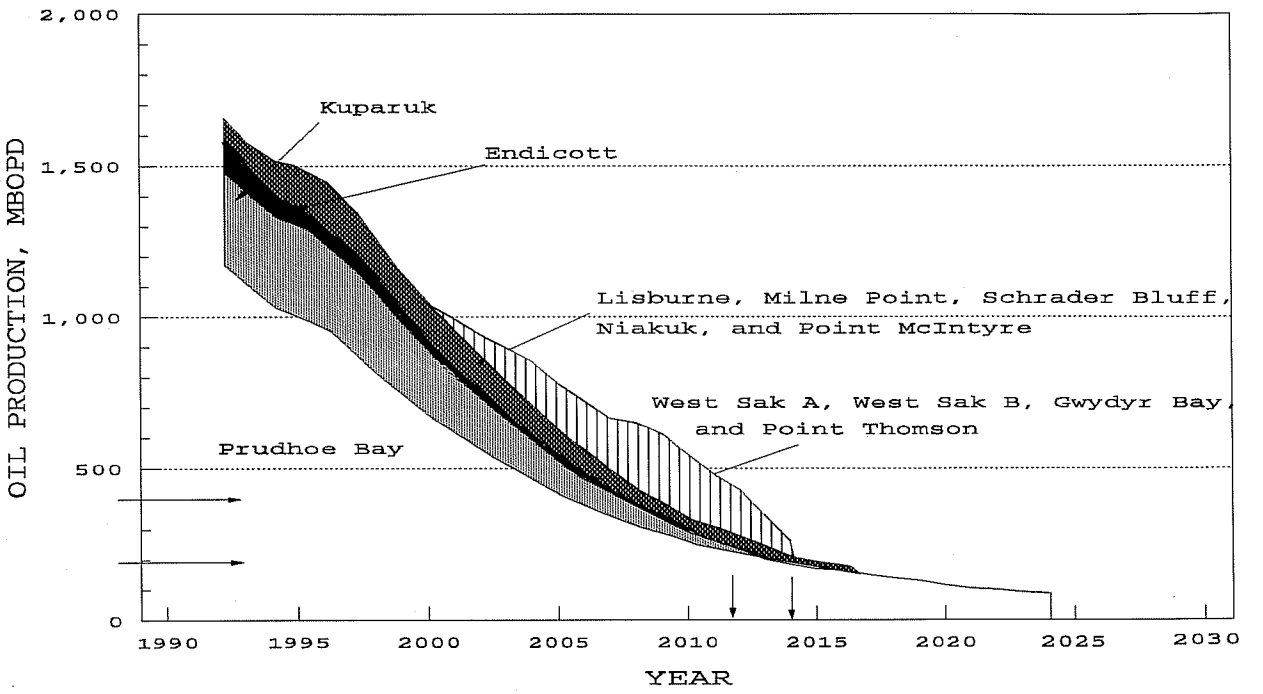

Figure 3.28 The Alaska North Slope composite production forecast including West Sak, Point Thomson, and Gwydyr Bay (arrows indicate the potential range of TAPS shutdown).

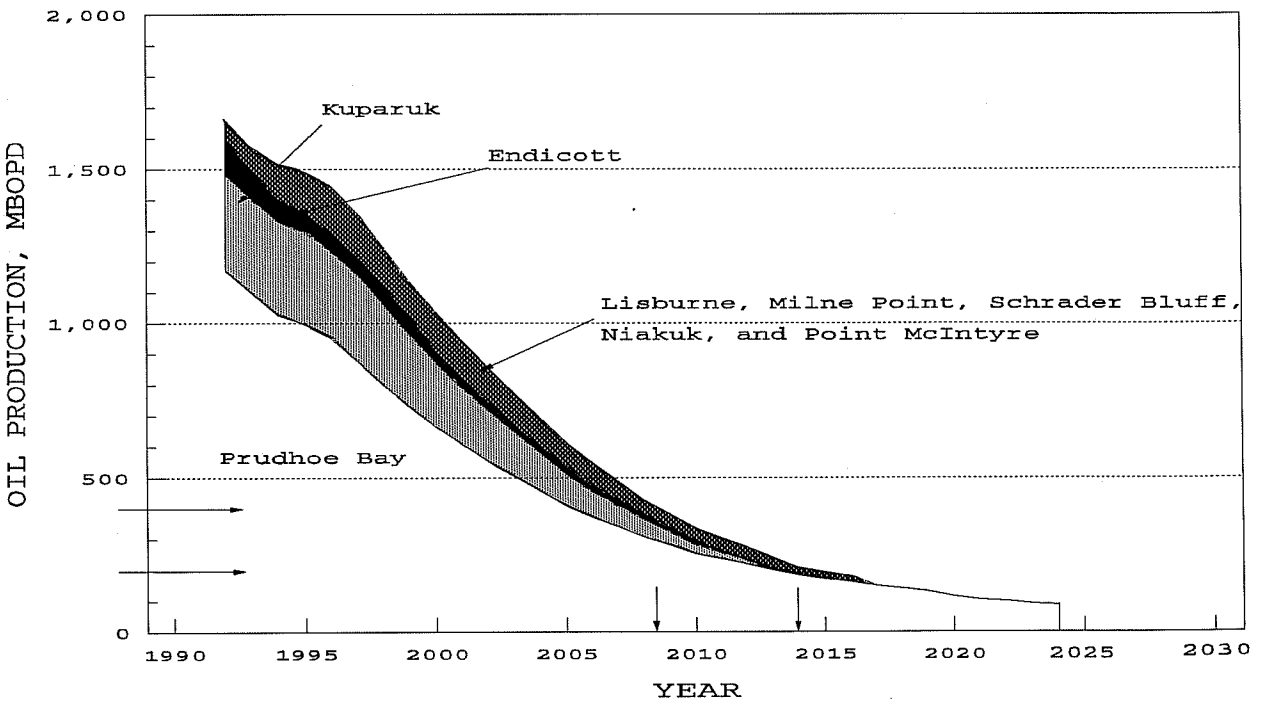

Figure 3.29 The Alaska North Slope production rate forecast at the EIA Low oil price; economically recoverable oil (arrows indicate the potential range of TAPS shutdown).

(4) Alternate investment opportunities would be expected to seriously compete with the investment capital for the five NES fields at any oil price that provides industry with only a $PW_{10} = 0$.

(5) State benefits from the development of each of the five NES fields are significant. Federal benefits, although limited at the two lowest oil price cases, are significant at the higher oil price cases. State and federal benefits and those for industry are shown in **Table 3.39**. These data demonstrate the different levels of benefit that accrue to industry and to state and federal governments with the current royalty and tax rates and illustrate the possibility for share redistribution to encourage development.

(6) State and federal benefits from the currently producing fields are significant. Prudhoe Bay has been beneficial to all parties (industry and state and federal governments). The other four producing fields have provided value to the state and to industry. The federal government has benefitted to a lesser degree. However, these four fields, on a stand-alone basis, have not provided a positive cumulative discounted (10%) after-tax cash flow to the industry (1992 base year) and may not unless oil prices increase to levels at or above the EIA Mid-Level oil price scenario (**Tables 3.40** and **3.41**).

(7) Stable world oil prices, high enough to provide adequate rates of return to offset the financial risks involved in development in the harsh environmental conditions of the North Slope, would be the most sure guarantee of development of the five NES fields and other similar fields on the North Slope. However, the sensitivity analyses indicate that reductions in operating costs and investments and increases in recovery volume through combinations of improved technology and streamlined processes for environmental and regulatory requirements or both can feasibly move some of these fields to development. Reductions in tax and royalty rates would provide additional incentive.

3.5 Conclusions

(1) It appears that all of the five NES fields will remain economically marginal developments unless world oil prices improve.

(2) The sensitivity analysis results indicate that improved technology and reduced costs through the combined cooperative efforts of industry and government could make it economically feasible to develop some of these fields.

(3) Data are not available to accurately quantify the costs of regulatory compliance, mitigation, and costs to reduce or maintain environmental impacts to acceptable levels. However, it is clear that efforts to reduce costs associated with regulatory and environmentally required activities would be beneficial to the potential development of the resources in the five NES fields and other potential discoveries on the North Slope.

(4) As shown in **Figure 3.28**, the development of three of the NES fields would have an impact on North Slope production over the period from about 2000 to 2014 but cannot replace the decline in PBU production or maintain the operation of TAPS beyond about 2014.

(5) Economically recoverable reserves "left in the ground" in existing fields would range from 0.5 to 1.0 BBO over the time period from 2008 to 2014 corresponding to TAPS shutdown rate of 400 to 200 MBPD.

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APPENDIX A

STATUS OF NORTH SLOPE DEVELOPMENT AND PRODUCTION

The purpose of this section is to provide an update of the status of development and production on the North Slope of Alaska since the writing of the previous report, "Alaska Oil and Gas - Energy Wealth or Vanishing Opportunity?" (DOE 1991). Production forecasts and economics have been updated to January 1, 1992 using the actual 1990 and 1991 production. This section also includes a more detailed discussion of recently developed fields (Endicott, Milne Point, and Lisburne) and fields with development potential that are expected to soon be in production (Point McIntyre and Niakuk).

A.1 Major Fields

The major fields include the Prudhoe Bay and Kuparuk River fields.

A.1.1 Prudhoe Bay

The Prudhoe Bay field is the largest oil field in North America and is located adjacent to the Beaufort Sea coastline about 200 mi east of Point Barrow (see **Figure 1.2 and 1.3**)

The field was discovered in 1968 when oil and gas were tested in the Prudhoe Bay State No. 1. Hydrocarbons are present in three Permo-Triassic sand intervals, the Ivishak sandstone of the Sadlerochit Group, Sag River, and Shublik, with the Ivishak being the most prolific. Estimated original oil-in-place (OOIP) is about 23 billion barrels of oil (BBO).

The Prudhoe Bay field was unitized in 1977 and placed on production in June 1977. Total liquids recovery [oil, condensate, and natural gas liquids (NGLs)] from the Permo-Triassic participating area is 7.581 BBO through December 1991. Production has been declining since its peak average rate of about 1,600 thousand barrels of oil per day (MBOPD) during 1987. In December 1991, production averaged about 1,266 MBOPD.

Total recovery estimates range from 12 to about 12.9 BBO, which is between 52% and 56% of OOIP, (ADNR 1991; AOGCC 1992; DOE 1991).

A.1.1.1 Development Plan. Current development plans (AOGCC 1992) are directed towards enhancing ultimate recovery through infill drilling and enlarging the Prudhoe Bay miscible gas project (PBMGP) that could extend the life of the PBMGP to about 2010. These planned actions include:

- Completion of the installation of the second gas handling expansion of GHX-2 bringing the capacity to 7.5 BCFD. The miscible injectant (MI) manufacturing capacity will be increased from 450 MMCFD to 700 MMCFD.
- Expansion of the PBMGP to cover nearly the entire area under waterflood including the reservoir between the 0 and 100 ft light oil contour.
- Expansion of the PBMGP will include 100 new infill wells and water injection facilities for 30 new water injection (WI) wells.
- Addition of new produced water treatment and processing facilities, upgrading the existing MI distribution lines, new MI lines, and conversion of up to 90 additional wells to water-alternating-gas (WAG) injection service.
- In the North West Fault Block (NWFB), development will include drilling of up to 20 wells for production and conversion of 10 wells to injection, which will reduce the effective well spacing from over 70 to 5 acres per well; installation of associated production; WAG injection; and MI distribution systems. At full infill, the number of miscible injectors may increase from 18 to 32.

A.1.1.2 Input Data. Most of the input data are based on published information and field production history. The recent hearing before the AOGCC (1992) and published industry information (ARCO 1990; ARCO 1991a) contribute to an understanding of unit plans, the potential benefits, and the potential costs of these plans.

A.1.1.2.1 Recoverable Oil--The ultimate recoverable reserves forecast in the previous DOE publication (1991) was about 12.9 BBO. Recent public records (ADNR 1991; AOGCC 1992) list ultimate reserve volumes ranging from 12 to 12.6 BBO. Any of these reserves volumes appear reasonable. The ultimate reserve volume from the previous DOE publication (1991) is adopted. Remaining reserves at 1/1/92 are about 5.3 BBO (oil, condensate, and NGLs) with cumulative recovery of about 7.6 BBO as of 1/1/92 (AOGCC 1991).

Prudhoe Bay Unit (PBU) production is declining but the actual rate of decline is not clearly established. Given the extensive efforts throughout the life of the Prudhoe Bay field to increase recovery, future actions can only be expected to have a mild mitigating effect on the decline rate.

The expansion of existing facilities and future new projects and their impact on production rate are considered in determining the decline profile needed to recover the forecast recoverable oil. Average daily production in 1991 was about the same as in 1990 but producing rates in late 1991 indicate that production is declining. The production forecast is patterned after the most likely case in the previous DOE publication (1991). Some modifications were made in the years 1992 through 1997 to reflect current production levels and anticipated results of current unit plans. Production rates after 2010 were modified to reflect results of increased gas cap cycling with the installation of additional facilities that increased gas handling capacity to 7.5 BCFD. The revised forecast is shown in **Table A.1**.

Table A.1. PBU production forecast.

Year	MBOPD	Year	MBOPD	Year	MBOPD
1992	1170	2003	507	2014	184
1993	1100	2004	460	2015	170
1994	1025	2005	408	2016	164
1995	995	2006	372	2017	155
1996	950	2007	341	2018	145
1997	880	2008	309	2019	135
1998	803	2009	282	2020	125
1999	732	2010	258	2021	115
2000	666	2011	239	2022	105
2001	608	2012	220	2023	95
2002	553	2013	200	2024	53.4

A.1.1.2.2 Investments--Estimates of future investments are based on the most current unit plans and published industry estimates of future investments (ARCO 1990; ARCO 1991a; AOGCC 1992). Review of the future investments estimated for the most likely case in the previous DOE publication (1991) indicated that the previously forecast investments after 1/1/92 provided funds for all of the major projects included in the current plans. That investment schedule, after adjusting for inflation, is adopted for PBU evaluations and is shown in **Table A.2**.

Table A.2. PBU drilling and investment schedule.

Year	Drilling	Investments- $MM (1/1/92$)		
	No. Wells	Wells	Facilities	Total
1992	50	103.1	798.1	901.2
1993	50	103.1	751.0	854.1
1994	50	103.1	569.4	672.5
1995	50	103.1	380.8	483.9
1996	30	61.8	139.9	201.7
1997	30	61.8	38.8	100.6
1998	20	41.2	59.4	100.6
1999	20	41.2	59.4	100.6
Total	300	618.4	2796.8	3415.2

A.1.1.2.3 Operating Costs--Operating costs are estimated by using a cost per barrel of total fluid (BTF) produced. The water cut versus percent recovery data used in the previous DOE publication (1991) is still valid for estimating operating costs. These data are shown in graphical form in **Figure A.1**. No public data were found concerning operating costs for PBU. The operating cost factor in 1/1/90 dollars was $1.00/BTF in the previous DOE publication (1991). A review of industry information shows that the cost factor remained essentially constant in 1990 and 1991 at the $1.00/BTF. That cost factor, $1.03/BTF in 1/1/92 dollars, is used in PBU evaluations.

A.1.1.2.4 Future Producers--The number of future active producing wells is required for annual severance tax calculations. The Set A equations listed in **Section 3.2.5** are used to project the decline of future active producing wells for PBU. See also Table 3.29 of the previous DOE publication (1991).

A.1.1.3 Summary. The PBU Permo-Triassic oil pool, the largest in the United States, has been on decline since a peak of about 1.6 MMBOPD during 1987. No development or production enhancement projects remain that will arrest the decline in production that had reached about 1.3 MMBOPD in December 1991. Even so, the oil pool is expected to recover more than 50% of OOIP. The estimate of future recoverable liquids as of 1/1/92 is 5,300 MMB (oil, condensate, and NGLs). Analysis, using the NES Low oil price (see **Table 3.1, Section 3.2)**, shows that all of those liquids can be economically recovered resulting in an ultimate reserve estimate of 12,00 MMB that is recovered

through 2024. If TAPS shuts down as early as 2008 (400 MBPD) (**Section 1.1**), unrecovered economical reserves of 966 MMB may be lost. If conditions allow TAPS to operate through 2014 (200 MBPD), then lost reserves may be 461 MMB. As a result of TAPS shutdown, PBU ultimate reserves would be reduced to between 11,800 MMB and 12,400 MMB.

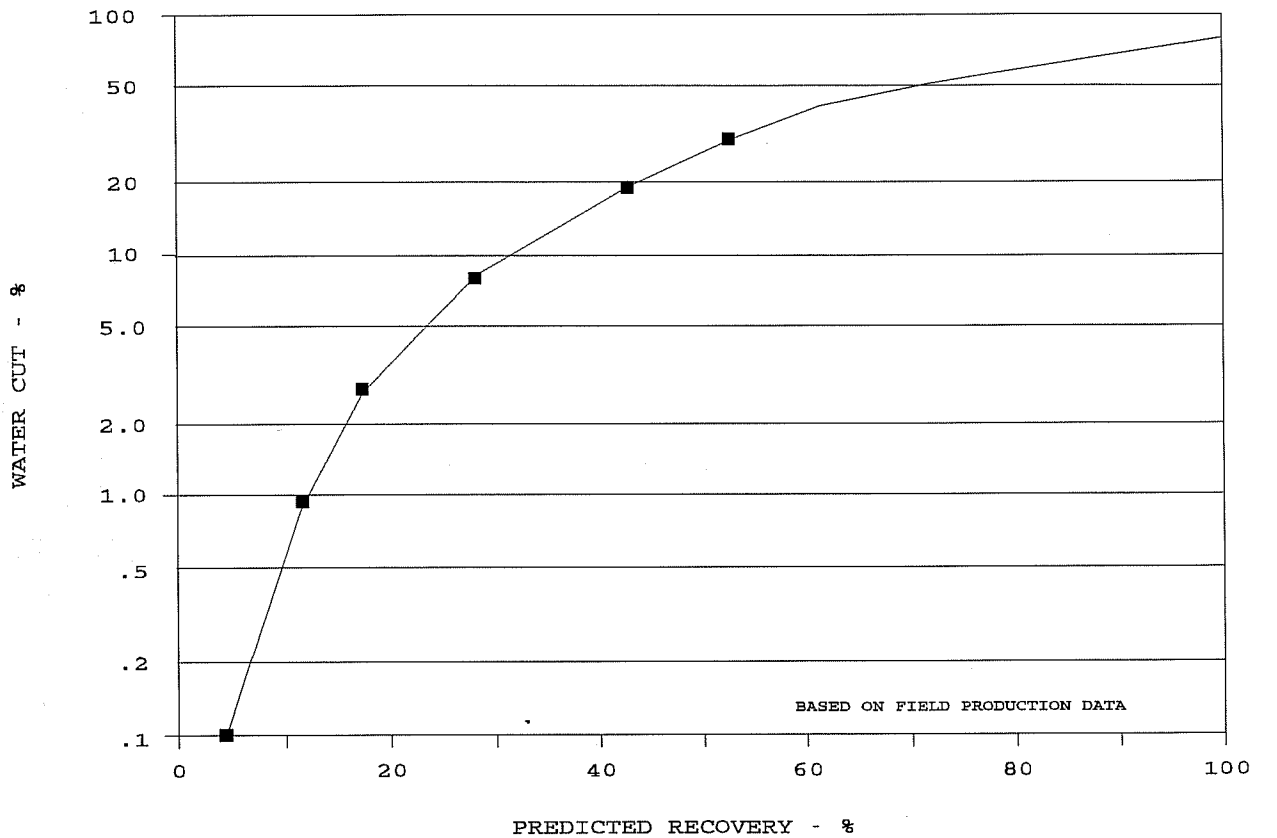

Figure A.1. PBU Permo-Triassic watercut curve - percent watercut versus percent recovery.

A.1.2 Kuparuk River Unit

The Kuparuk River field is located about 30 mi west of PBU (**Figure 1.3**). It was discovered by Sinclair and BP in 1969 in the Ugnu State No. 1 well, which tested at a rate of 1,056 BOPD from the interval 6,158 to 6,175 ft. Sinclair and ARCO merged that same year and ARCO Alaska, Inc. ultimately became operator of the Kuparuk River Unit (KRU), which was formed in 1981.

Production has been established from sandstones within two members of the Kuparuk River formation of Lower Cretaceous Age. The two members were both deposited in marine environments and

are separated by an unconformity. Sands in the lower member average 23% porosity and 100 md permeability. Upper members sandstones average 23% and 130 md (Masterson 1987).

Oil is trapped on a southeast plunging anticline by truncation of the lower member sands by the unconformity and by pinchout of upper member sands to the west (**Figure A.2**) (Masterson 1987). Sands of both members pinchout or grade into mudstones on the south flank. The northeast field limits are formed by oil-water contacts varying from 6,350 to 6,650 ft subsea. The northeast flank of the field is cut by a complex pattern of normal faults with northwest to northeast trends and varying amounts of throw up to 300 ft. Faulting has a significant effect in displacing the reservoir sands that range up to 90 ft of net pay (Masterson 1987).

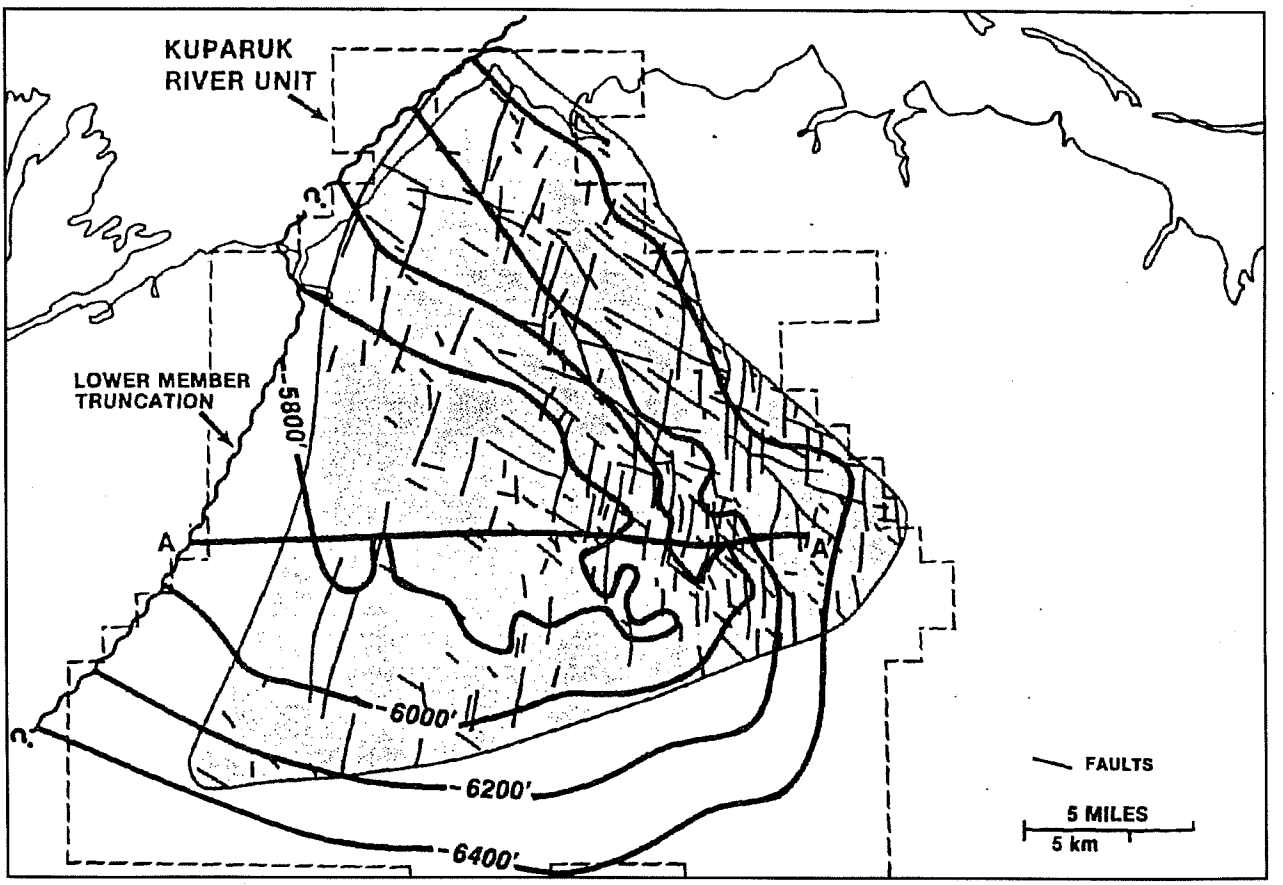

Figure A.2 Structure map on top of the Kuparuk River formation. Faults are mapped from seismic data (Masterson 1987).

Oil gravity ranges from 15° to 26° but averages about 24°API (Carman 1982) and is similar to Prudhoe Bay crude. Early estimates of volumes showed 4 BBO in place with anticipated recovery of 1 to 1.5 BBO, making the Kuparuk River field one of the largest ever found in the U.S.

The KRU was formed in 1981 with ARCO as unit operator. BP holds a major interest in the unit along with ARCO. Minor participating interests are currently held by Amoco, Chevron, Exxon, Mobil, and Unocal (ADNR 1990a). The unit covers about 200 square miles. Leases carry a 12.5% royalty and five leases along the northern border also carry net-profit share burdens. The KRU and the Kuparuk Participating Area (KPA) are shown on **Figure A.3**. Production began in December 1981 and by mid-1991 there were about 640 total wells including 360 producers. Production averaged about 311 MBOPD during 1991. Cumulative production to 1/1/92 was 836.2 MMBO.

A.1.2.1 Development Plan. The KRU development plan (ADNR 1991m) is used as a guide in estimating future recoverable oil and developing the production forecast. Details of the plan include:

- Drilling in the peripheral area and infill drilling opportunities will be a major focus to 7/31/92 and beyond.
- Nine new pads will be added to complete 160 acre development. Significant delays have been experienced in obtaining permits.
- The 160-acre waterflood is limited by the highly faulted heterogeneous nature of the Kuparuk. Implementation of an 80-acre infill program is expected to improve performance. Infill drilling will proceed on a phased, drillsite by drillsite basis. To date 20 infill wells have been drilled.
- Immiscible WAG is in progress at 12 drillsites. Two drillsites, and possibly a third, will be added.
- Evaluation of expanding the miscible WAG process is underway. Conceptual planning includes flooding 15 drillsites from 1994 through 2005. Hydrocarbon injectant must be brought in from an outside source, such as PBU (ARCO 1991a).
- Facilities will be revised to improve liquids handling efficiencies for both production and injection.
- Environmental issues continue to have a major impact on the Field Development Plan. In particular, the issue of wetlands compliance continues to adversely affect the ability to obtain Section 404 permits for development projects.

A.1.2.2 Input Data. Evaluation input data are developed using history, current development plans, published information, and personal communication.

A.1.2.2.1 Recoverable Oil--The previous DOE publication (1991) carried KPA recoverable reserves of 1,514 MMBO as of 12/31/89. Combined with the cumulative recovery of 616

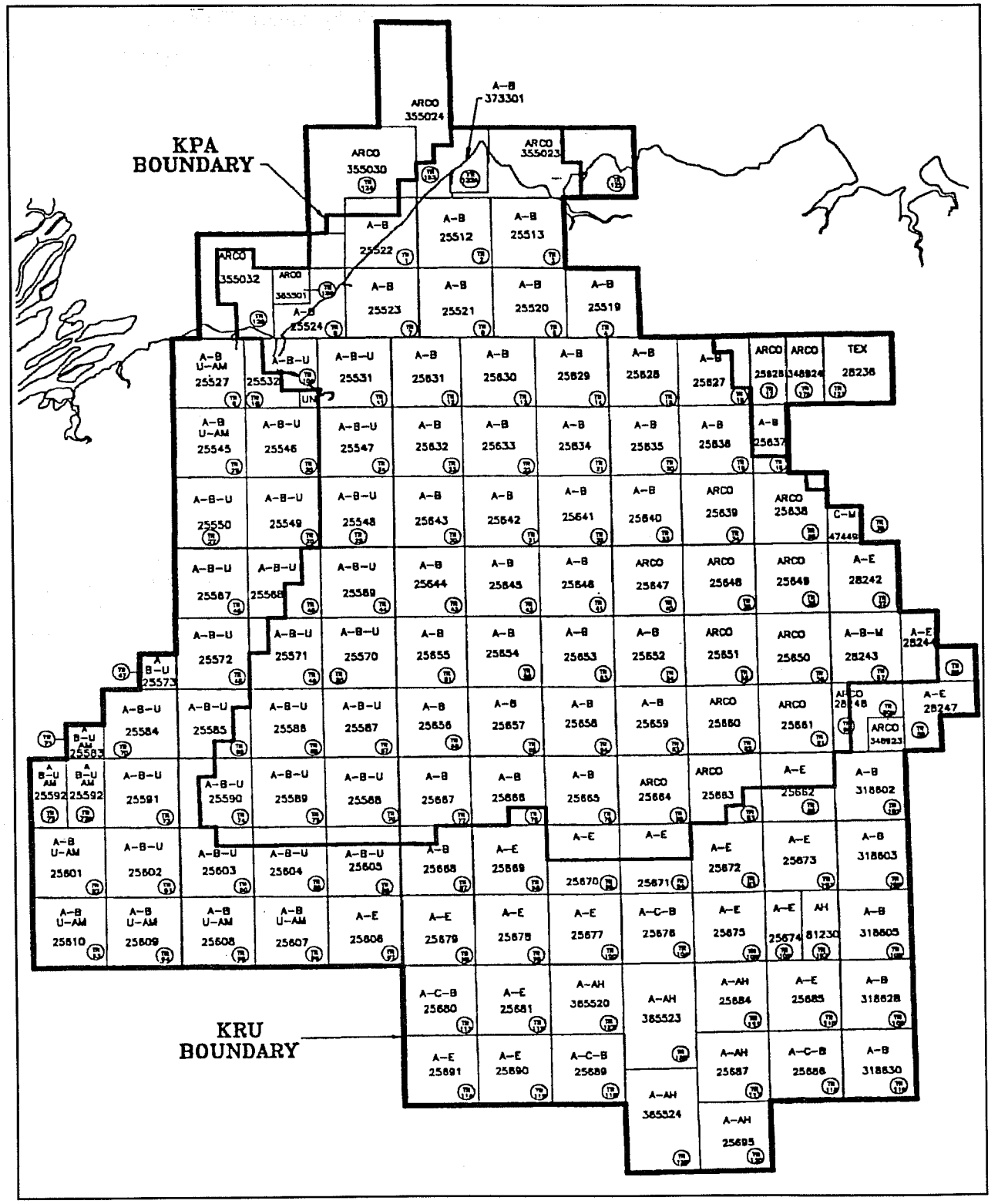

Figure A.3 KRU and KPA outline.[a]

a. Alaska Department of Natural Resources, personal communication, December 1992.

MMBO to the same date, the ultimate project recovery was 2,130 MMBO. The Alaska Department of Natural Resources (ADNR) has estimated an ultimate Kuparuk recovery of 1,894 MMBO (ADNR 1991). From previous discussions with ADNR representatives, and from written statements (ADNR 1991), state estimates of future reserves include only amounts that can be recovered under existing economic and operating conditions. From this, it is probable that the state would consider a part of the future reserves of the KPA as unproven. Based on the reserves in the previous DOE publication (1991), the Kuparuk remaining reserves at 1/1/92 are 1,293 MMBO.

From additional information (ADNR 1991; ARCO 1991a), Kuparuk reserves are estimated as 1,196 MMBO as of 1/1/92. This confirms that reserves of 1,293 MMBO are reasonable. If part of the West Sak accumulation is developed, the economic life of the KPA could be extended, and the reserve volumes increased accordingly. For example, a 1-year extension would be at an estimated rate of 32 MBOPD and increase KPA reserves by 11.7 MMBO. This is an increase in future reserves of less than 1%. Extension of KPA production for 3 to 5 years would have a minor impact on this analysis.

A.1.2.2.2 Production Forecast--The future production forecast in the previous DOE publication (1991) is used as the base forecast for preliminary consideration.

The recent production history for Kuparuk was reviewed to determine that the 1990 forecast is still valid (ADNR 1991; AOGCC 1991). The Kuparuk formation produced a total of 113.5 MMBO during 1991, or an average of 311 MBOPD. The operator expected production to average about 305 MBOPD from 1991 through 1995 (ADNR 1991m). The operator now projects KPA production to be fairly level over the next 4 to 5 years.[a] The ADNR has projected average production of 300 MBOPD from 1991 through 1994 with 1995 averaging 280 MBOPD (ADNR 1991; ADNR 1991a). Based on the current production level and the planned projects listed by the operator, it is possible that rates exceeding those published can be reached over the 1992 to 1995 period. For this forecast, production is held at 310 MBOPD for 1 year and then declined at about 1.5% through 1997. After that date, the decline is increased to about 11% for 6 years; the decline averaged about 17% thereafter. The revised forecast results in remaining recoverable oil of 1,293 MMBO as of 1/1/92. The forecast rates are shown in **Table A.3.**

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a. ARCO Alaska, Inc., personal communication, March 9, 1992.

Table A.3. KPA production forecast.

Year	MBOPD	Year	MBOPD	Year	MBOPD
1992	310	1999	235	2006	85
1993	306	2000	210	2007	71
1994	303	2001	185	2008	57
1995	299	2002	165	2009	43
1996	292	2003	145	2010	30
1997	285	2004	125	2011	18
1998	260	2005	105	2012	14.6

A.1.2.2.3 Facilities Capacity--The KPA processing center has the following design capacities:[a]

- Name plate oil handling - 335 MBOPD
- Approximate gas handling - 450 to 500 MMCFPD
- Approximate water handling - 1 MM BWPD

The maximum oil handling capacity is at low gas rates. The 1991 gas-constrained oil capacity is about 310 MBOPD with gas rates of about 335 MMCFD.[b] Produced gas volume has been relatively constant over the past 4 years averaging about 320 MMCFD. During that same period the fieldwide gas/oil ratio (GOR) has varied from 982 to 1,087 ft^3/BBL with an average of 1,059 ft^3/BBL. Higher gas volumes are expected to occur with the expansion and maturing of the current WAG process and as production occurs in or near the gas storage area. As water production increases, greater amounts of gas lift gas will be required. The continued increase in offtake gas (production plus gas lift) will most likely result in gas-constrained oil production for many years.[a] In the absence of data for a detailed study, it is assumed that KPA processing facilities will not have any significant surplus capacity at any time in the future. **Figure A.4** shows future daily average facilities capacity about 15 MBOPD greater than estimated average daily production. This is an arbitrary assumption taking into account the probable daily variation in produced volumes. If oil other than from the KPA (e.g., West Sak) is processed through this plant, the gas handling facility (and probably the water handling facility) must be expanded.

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a. ARCO Alaska, Inc., personal communication, March 9, 1992.

b. ARCO Alaska, Inc., personal communication, February 22, 1992.

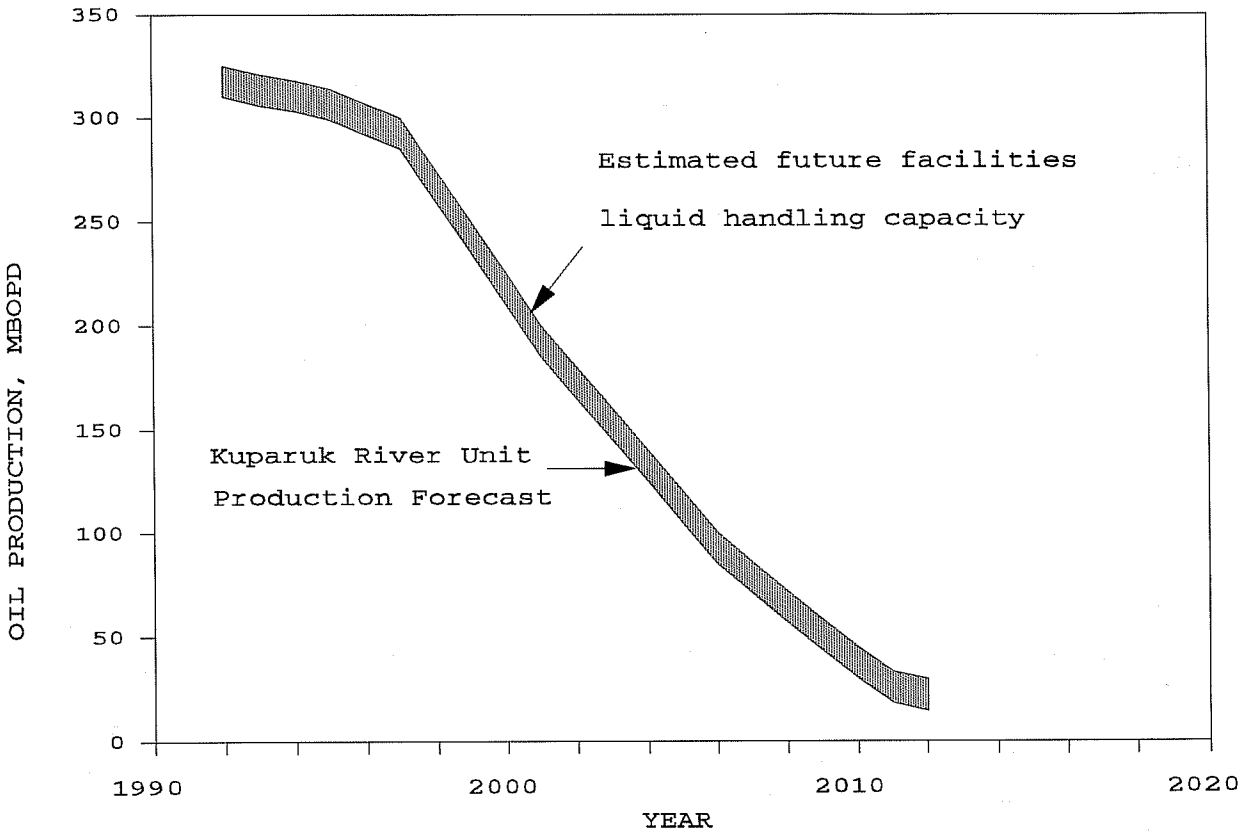

Figure A.4 Kuparuk Participating Area processing facilities capacity.

A.1.2.2.4 Investments--Total capital investment from 1991 through 2000 is estimated at $2.2 billion for the KPA (ARCO 1991a). This is assumed to be in mid-1991 dollars. This estimated total, without 1991 expenditures, is $2,096 MM (1/1/92$).

Projects that are planned for this time period include:

- Drill remaining development wells
- Drill infill wells
- Facility expansions
- Expansion of EOR project.

The development of the 15 drill sites for the EOR expansion is currently planned to start in 1992 and continue through 2005.

The number of future wells to be drilled is estimated at 316. The $2.1 MM/well estimate (1/1/90$) for KPA wells from the previous DOE publication (1991) will be used ($2.2 MM in 1/1/92$). Based on available information (ARCO 1991a; ADNR 1991m), drilling and facilities investment schedules are shown in **Table A.4.**

Table A.4. KPA drilling and investment schedules.

Year	Drilling	Investment - $MM (1/1/92$)		
	No. Wells	Wells	Facilities	Total
1992	52	115.3	215.4	330.7
1993	54	119.8	246.5	366.3
1994	56	124.2	333.7	457.9
1995	54	119.8	205.8	325.6
1996	54	119.8	205.8	325.6
1997	46	102.0	126.9	228.9
1998	0	0	20.4	20.4
1999	0	0	20.4	20.4
2000	0	0	20.4	20.4
Total	316	700.9	1395.3	2096.2

A.1.2.2.5 Operating Costs - In the previous DOE publication (1991), operating costs were determined using a cost per BTF. Total fluid production was based on a relationship between water cut and percent of ultimate recovery using past history. The water cut versus cumulative recovery relationship has been updated using oil and water production volumes through December 1991. The future extrapolation after 38.9% oil recovery, was based on industry experience and patterned after the Milne Point and Endicott model results. The revised relationship is shown in graphical form on **Figure A.5.**

The cost per barrel factor used in the previous DOE publication (1991) was $1.19/BTF. No public data were available concerning operating costs for KRU; therefore, $1.27/BTF (1/1/92$) is used.

Unit plans discussed in **Section A.1.2.1** include the expansion of the miscible WAG project area. KPA does not have sufficient volumes of NGLs and gas to manufacture the miscible injectant (MI) required. The most likely source is the PBU; however, no surplus MI is available at PBU and none is

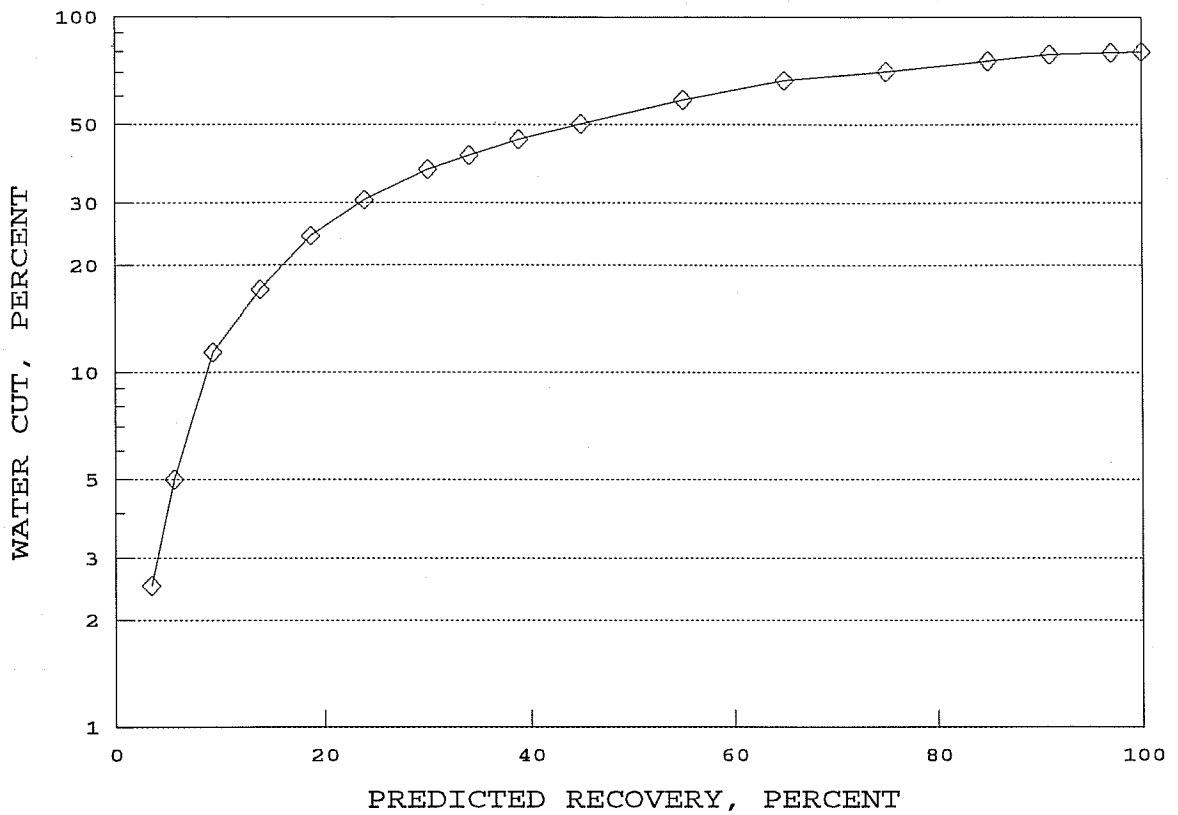

Figure A.5. KRU water cut versus cumulative production as percent of ultimate production.

expected for several years. When there are excess volumes of MI available at PBU, it is expected that they will be utilized at KPA. The indicated cost of MI to KPA could be up to $1 billion (ARCO 1991a). To simplify use in the evaluation, this cost is allocated on a produced barrel-of-oil basis from 1995 through 2005.

A.1.2.2.6 Kuparuk Pipeline Tariff--The pipeline tariff listed in the previous DOE publication (1991) is $0.61/BBL. In February 1992, the Alaska Department of Revenue (ADR) stated that the current tariff is $0.21/BBL. The $0.21/BBL tariff is used for this evaluation.

A.1.2.2.7 Future Producers--The number of future active producing wells is required for annual severance tax calculations. The Set B equations listed in **Section 3.2.5** are adopted for this evaluation.

A.1.2.3 Summary. The KRU Kuparuk oil pool has been on production since December 1981. However, due to staged development, the entire resource base is not expected to be fully developed until about 1997. The staged development is probably designed to keep the KPA processing facilities loaded at peak oil handling volume. This staged development and probable use of miscible WAG process later will result in little or no future excess in liquid handling capacity.

Assuming development is completed and a miscible WAG process is applied, as discussed in this section, a future recoverable oil volume of 1,293 MMBO is estimated. Analysis, using the NES Base oil price, shows that all oil can be economically recovered resulting in an ultimate reserve volume of 2,129.6 MMBO. If TAPS shuts down in 2008 (400 MBPD), about 39 MMBO of economically recoverable oil will be lost. If conditions allow TAPS to operate through 2,014 (200 MBPD), then no reserves will be lost. Shutdown of TAPS as noted would result in ultimate reserves of between 2,091 MMBO and 2,129.6 MMBO.

A.1.3 Major Fields Summary

Prudhoe Bay and Kuparuk fields are the No. 1 and No. 2 producing rate fields in the U.S. As such, they produce about 18% of the nation's daily output of crude and NGLs production or about 1.6 MMB of the total 8.9 MMB. Prudhoe Bay production is declining; Kuparuk production is expected to remain fairly steady for several more years before a significant decline begins.

Remaining reserves are estimated at 5,300 MMB for Prudhoe Bay and 1,300 MMB for Kuparuk. It is these two fields with their reserves and rate of production that dominate predictions for the duration of economic oil production on the North Slope of Alaska.

The previous DOE publication (1991) presented a most likely case of minimum TAPS throughput rate of 300 MBPD with pipeline shutdown occurring at year-end 2009. This case resulted in about 1 BBO of otherwise recoverable oil being "lost" (see DOE 1991, pp. 3-35 to 3-38). Using a TAPS shutdown ranging from year-end 2008 (400 MBPD) to year-end 2014 (200 MBPD), the possible "lost" liquids from these two fields would be about 1 BBO to 0.5 BBO, respectively.

The impact of the Prudhoe Bay field discovery, development, and creation of infrastructure, including TAPS, can be appreciated in total only by realizing that all of the other producing fields and

all of the potentially productive fields are dependent upon the existing infrastructure. If TAPS does, in fact, shut down by year-end 2008, then the timeline for bringing discovered fields on production is rapidly approaching criticality because of the lengthy period between decision to develop and first production. The time factor is even more critical for potential undiscovered fields, such as in ANWR or offshore, because the time from lease sale to first production is greater than 10 years (DOE 1991). More specifically, in the previous DOE publication (1991), the ANWR assumption was 12 years and the Chukchi Sea assumption was 14 years.

Thus, it is evident that the declines of Prudhoe Bay and Kuparuk fields impose the dominant time constraint on future North Slope production and exploration.

A.2 Recently Developed Fields

The recently developed fields, Endicott, Milne Point (including Schrader Bluff), and Lisburne, provide examples of fields that have been developed with the benefit of the infrastructure and TAPS that are in place as a result of the discovery and development of the super-giant Prudhoe Bay field. These fields illustrate the advancement of arctic technology that has reduced the size of the footprint required in the arctic since the Prudhoe Bay development. Factors influencing these technological advances are low oil prices, environmental and regulatory concerns, and relatively small reserves.

A.2.1 Endicott

The world's first arctic offshore commercial oil field was discovered in 1978 by the Sohio (BP) Sag Delta No. 4 well that tested 2,473 BOPD from the Kekiktuk formation of Mississippian age **(Figure 1.3)**. Later in the same year ARCO and Exxon drilled the Duck Island No. 1 well, which extended the field to the southeast, testing 2,651 and 1,979 BOPD from two separate zones (Woidneck 1987). A total of seven delineation wells were drilled and a 3-D seismic survey was shot in the winter of 1982/1983 to define the field limits (**Figure A.6**). The field is located about 20 mi east of Prudhoe Bay in offshore waters of the delta of the Sagavanirktok River in depths ranging from 2 to 14 ft.

Production was initiated in October 1987 with development from two man-made gravel islands linked to the mainland by a breached gravel causeway. Production during 1991 averaged 110 MBPD (oil + NGLs) and production totaled 160.5 MMB (oil + NGLs) through 1991 (AOGCC 1991).

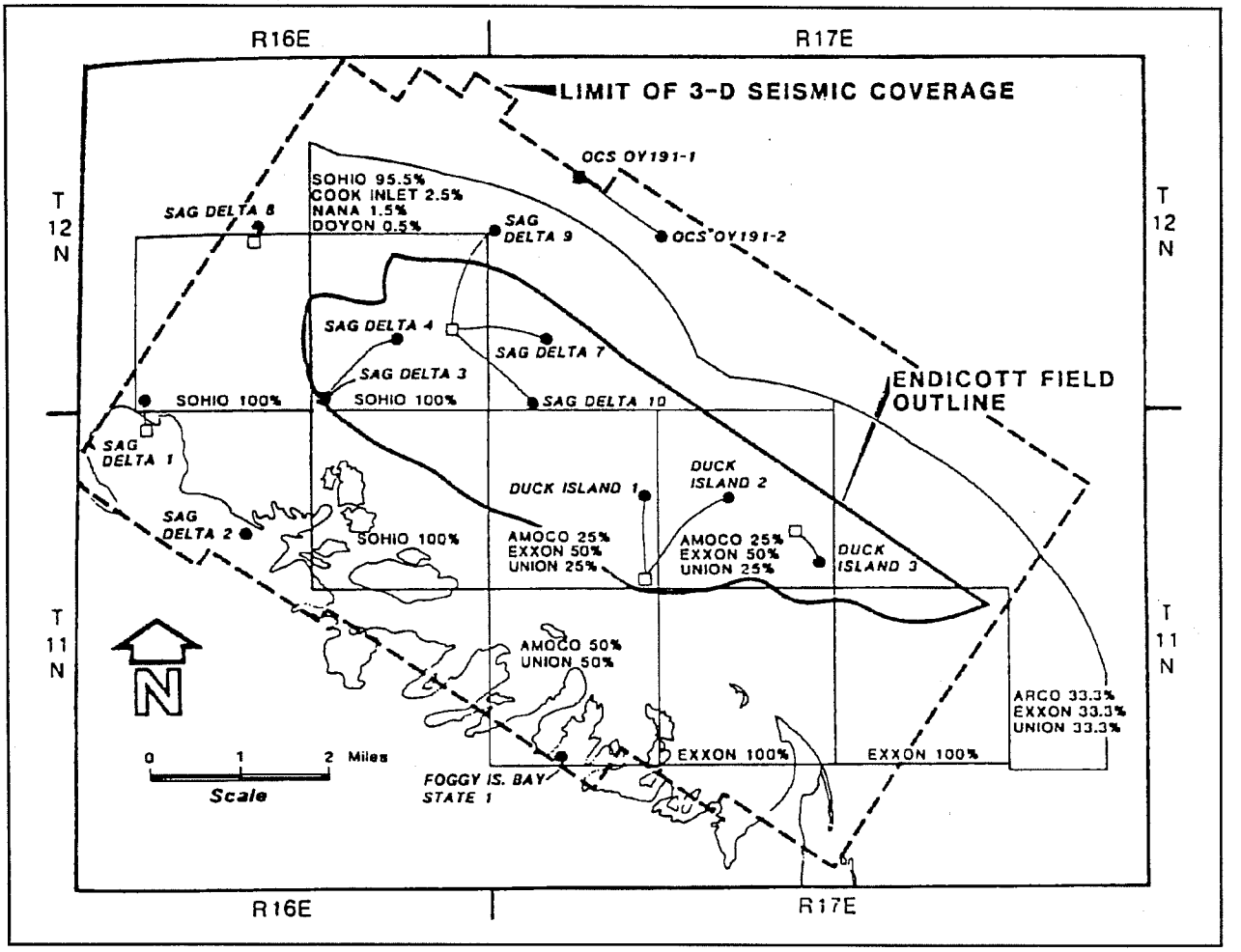

Figure A.6. Endicott field limits (Woidneck 1987).

The Endicott reservoir is the productive zone of the Endicott Participating Area of the Duck Island Unit (DIU) (see **Figure A.7**). In 1984, ARCO sold its working interest to Exxon. BP (Sohio) is the unit operator and the other working interest owners are Amoco, Exxon, and Union. Minor interests are held by ARCO and three Alaska native regional corporations, Cook Inlet, Doyon, and NANA (Woidneck 1987; AOGCC 1986). Within the participating area, eight tracts carry a 12.5% royalty interest (RI) and two tracts carry 20% RI, one of which has a net-profits interest (NPI) of about 49% and the other one a NPI of about 80%.

Reservoir rocks are fluvial sandstones of the Upper Mississippian Kekiktuk formation, which is the oldest of three formations comprising the Endicott Group (**Figure A.8**). The Kekiktuk has been subdivided into three zones in the field (**Figure A.9**) with the majority of the oil in place occurring in zone 2 (60%) and zone 3 (40%). Zone 2 average porosity is 22% and average permeability is 800 md. Zone 3 average porosity is 19% and average permeability is 300 md (AOGCC 1989a). The Kekiktuk

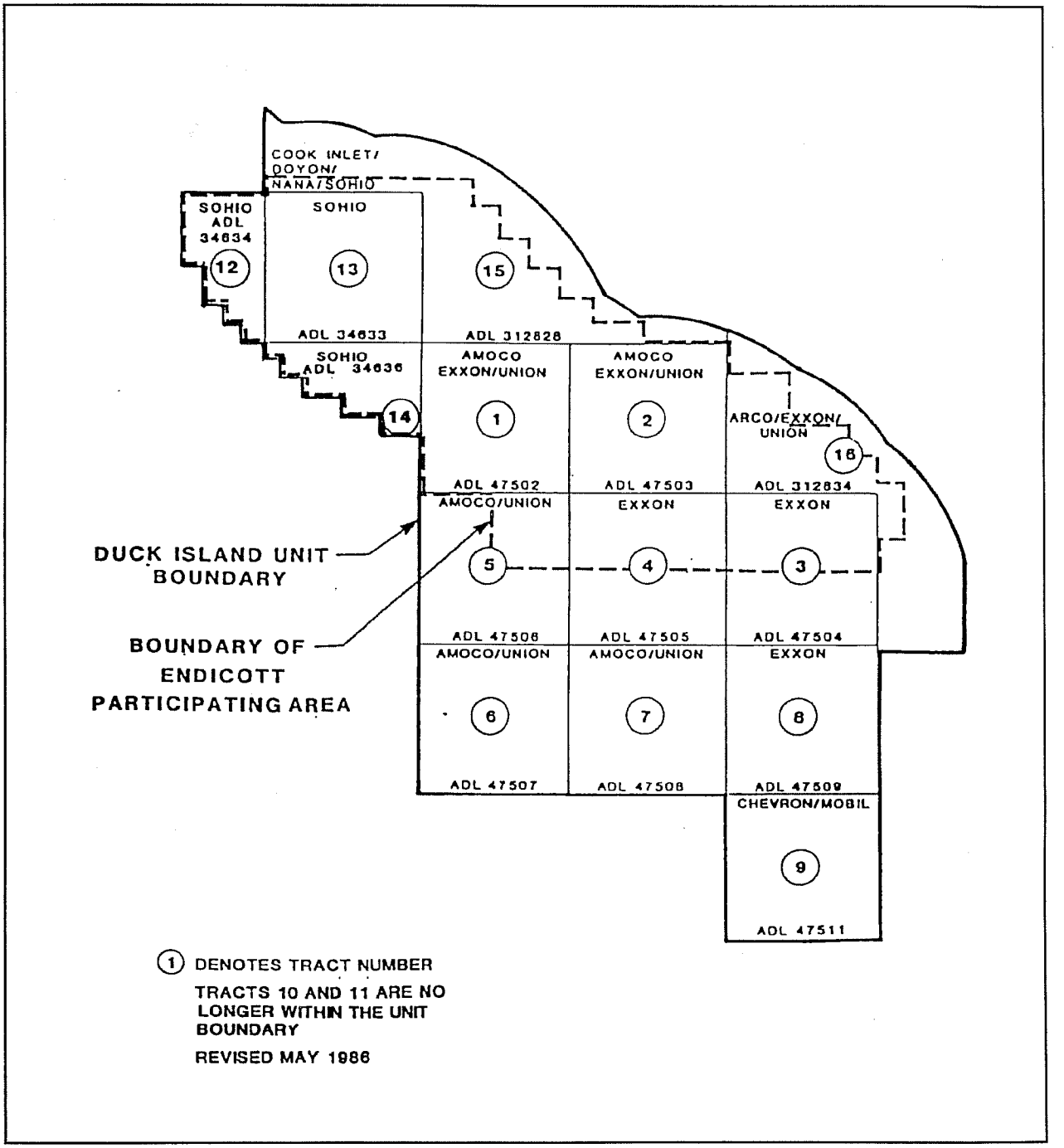

Figure A.7. Endicott Participating Area of the Duck Island Unit (AOGCC 1986).

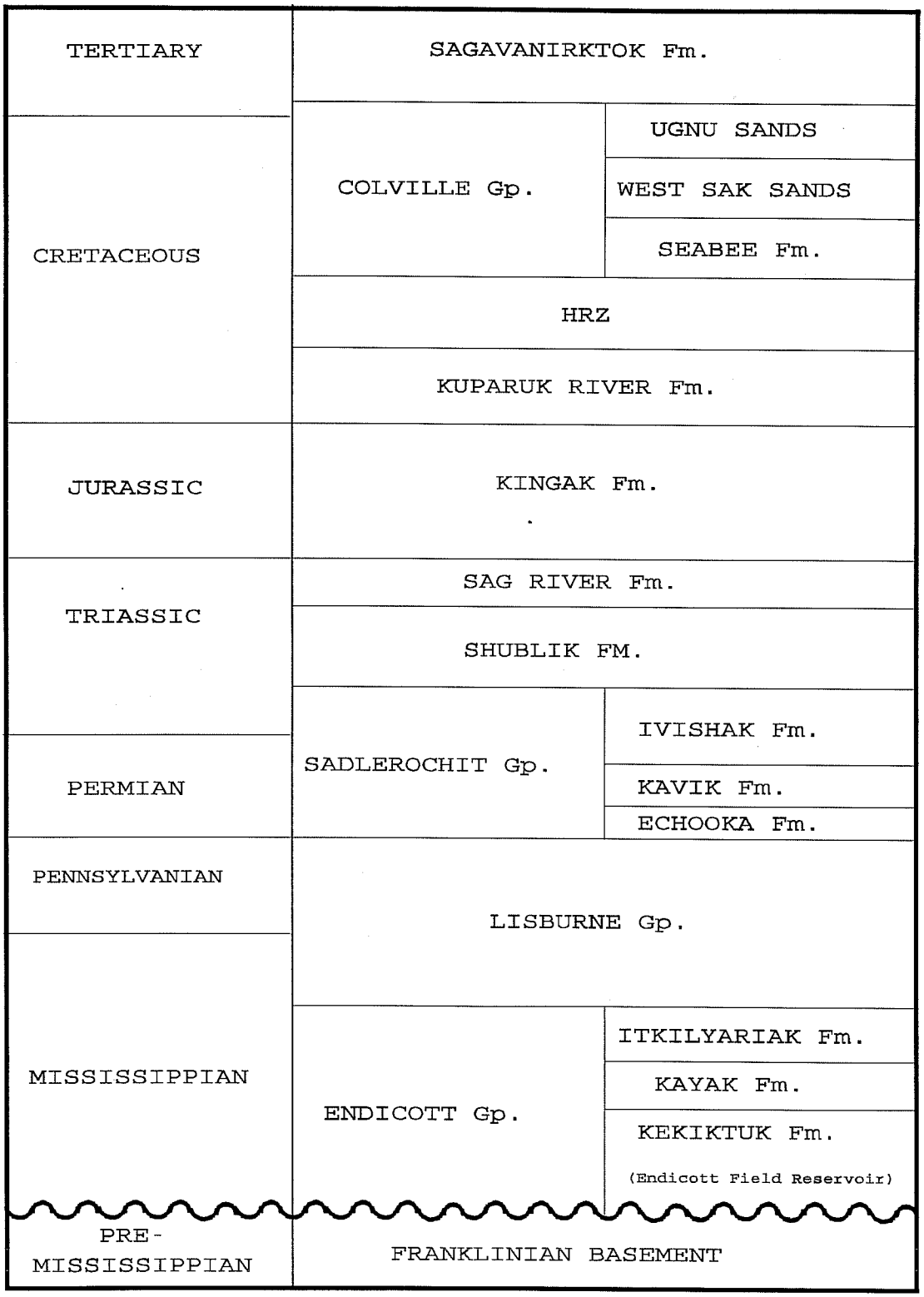

Figure A.8 General Stratigraphy underlying the Central North Slope, Alaska (Woidneck 1987).

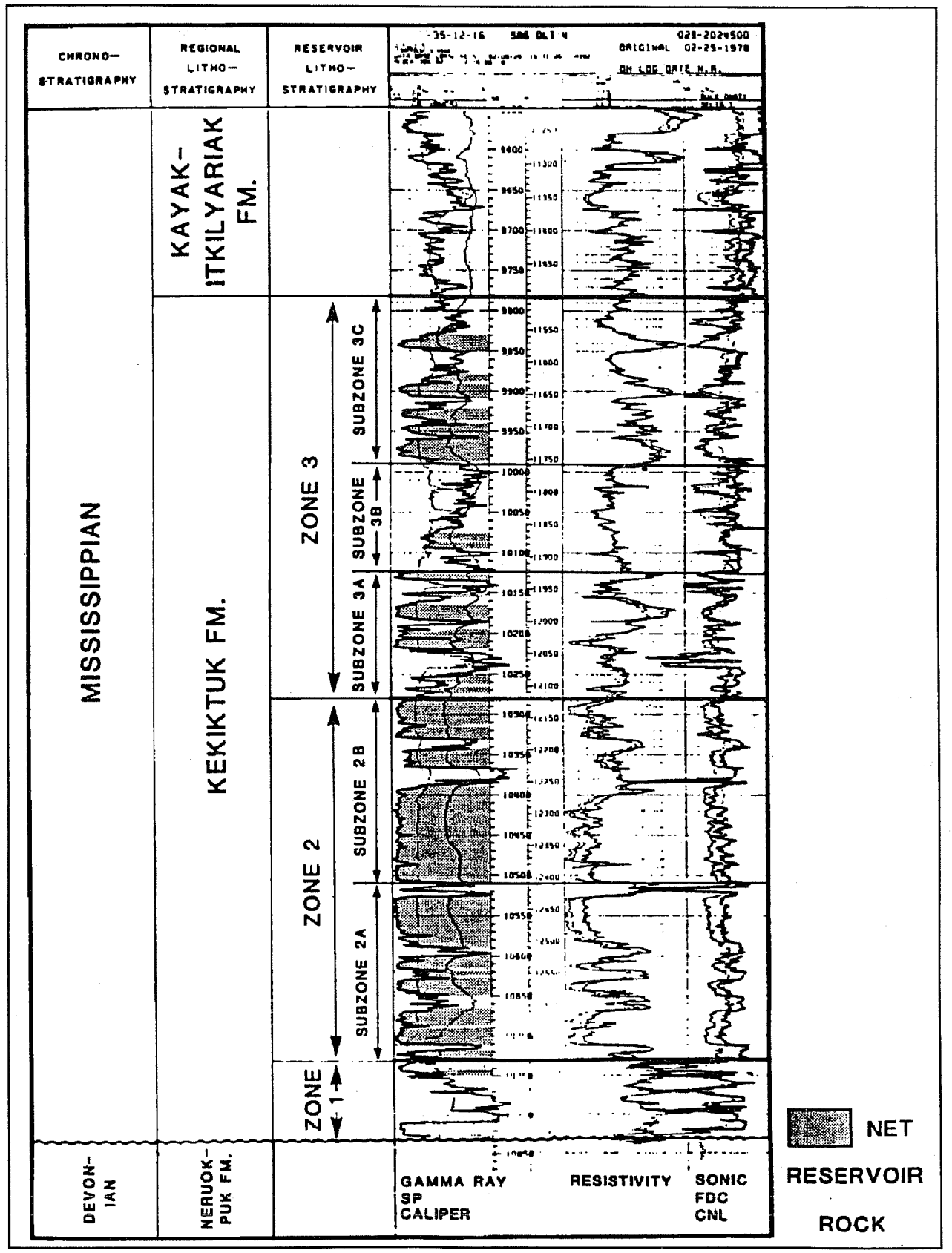

Figure A.9. Sag Delta 4 log with Kekiktuk Formation zones (AOGCC 1984).

consists of fluvial sandstones and interbedded shales deposited in southerly flowing channel systems. The sands are stacked and discontinuous with a low net-to-gross ratio (AAPG 1990).

As shown in **Figure A.10**, the structure on top of the Kekiktuk is a southwest plunging anticlinal nose bounded by faults on the north, northeast, and southwest. The top of the zone is truncated by the Lower Cretaceous Unconformity. Smaller intra-formational faults have been identified but are not shown in **Figure A.10** (AOGCC 1989a). The productive area is about 8,600 acres.

A gas cap is present and the gas/oil contact (GOC) is at 9,855 ft subsea; the oil/water contact (OWC) occurs approximately at 10,192 ft subsea. A 365 ft gas column and a 340 ft oil column result in a total productive column maximum of about 700 ft. Average oil gravity is 23°API. Original in-place hydrocarbon volumes are estimated at 1 BSTB, 365 BCF of gas-cap gas, and 750 BCF of solution gas (AAPG 1990). Ultimate recovery estimates have increased from 350 to 393 MMBO (Platts 1990; AAPG 1990; DOE 1991).

During 1989, BP Exploration tested the Sag Delta No. 9 well as the start of a 2-year program to evaluate development of the Sag Delta North accumulation. The well was originally drilled as a wildcat from Endeavor Island, a gravel-filled drilling island connected by a bridge to the main production island. Production testing began in July 1989 and by December was averaging 3,550 BOPD.[a] In 1991, BP applied to the state to develop the Alapah (Mississippian carbonate) and Ivishak (Permo-Triassic sandstone) reservoirs that lie in a separate fault block north of the main-field Kekiktuk reservoir. In various applications the company requested a new participating area of the DIU, (see **Figure A.11**) downhole commingling of production from the two zones, and equipment sharing of Endicott facilities (ADNR 1991h; AOGCC 1991b). By year end 1991, the Ivishak had recovered 4.2 MMBO. Production during 1991 averaged 6,326 BOPD.

A.2.1.1 Development Plans. The Plan of Development (POD) for the Sag Delta North included producing through the Endicott Participating Area facilities and downhole commingling of the unitized substances from the Ivishak (Sadlerochit) and Alapah (Lisburne) oil pools. Development plans included about six total wells (including the discovery well, Sag Delta 9) to develop these accumulations on 40-acre spacing (AOGCC 1991b). Indications are that the Ivishak will be waterflooded. Production from

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a. Alaska Oil and Gas Conservation Commission, 1990, Computer print-out of production and injection statistics by month for State of Alaska.

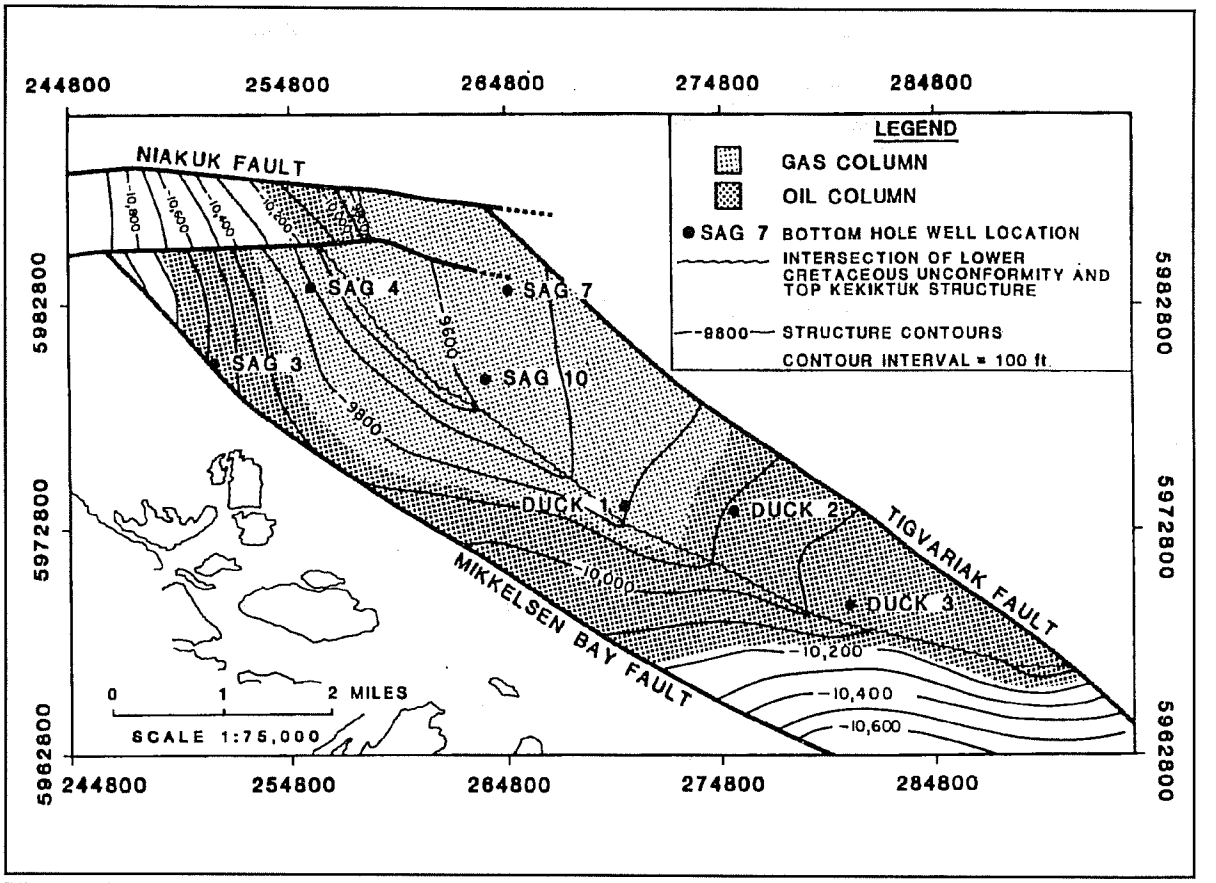

Figure A.10 DIU, structure on top of the Kekiktuk formation, Endicott Group (AOGCC 1984).

the Alapah will be by primary recovery and will be commingled downhole with the Ivishak.

BP Exploration reported that the Endicott owners have reached tentative agreement with the Corps of Engineers regarding an additional 650 ft breach near the existing 200 ft breach in the causeway (ADNR 1991i). Early estimated cost of retrofitting the causeway was ~ $45 MM (1/1/92$) (OGJ 1989). A more recent estimate of the cost is $56 MM (1/1/92$).[a]

A.2.1.2 Input Data. Input data are developed using history, current development plans, published information, and personal communications.

A.2.1.2.1 Recoverable Oil--Initial Endicott reserve estimates were 350 MMB of liquids (oil, condensate, NGLs) (OGJ 1987; BP 1988, Woidneck 1987). By May 1990, the estimate of recoverable liquids was increased to 393 MMBO because of improved reservoir performance (Platts

b. BP Exploration (Alaska) Inc., personal communication, October 23, 1991.

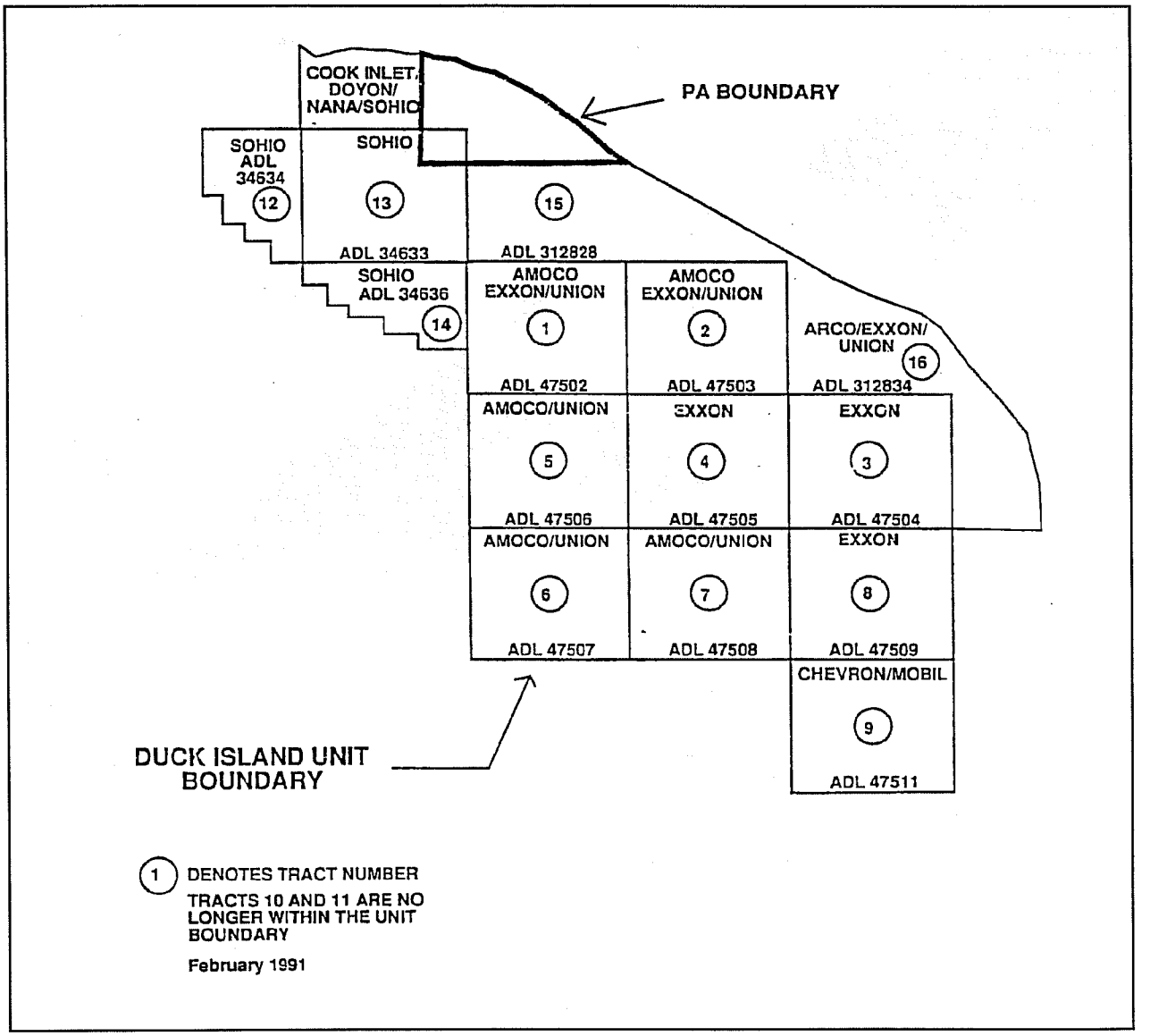

Figure A.11. Sag Delta North Participating Area (AOGCC 1991a).

1990). The ADNR forecasted future recovery of 296.4 MMB of liquid (oil, condensate, NGLs) from the Endicott and Sag Delta North as of 12/31/90. With cumulative recovery of 122.3 MMB through 12/31/90, ADNR estimated ultimate recovery would be 418.7 MMB (ADNR 1991).

Review of the Endicott production history shows that published reserves of 393 MMB (Platts 1990) are reasonable. Based on the forecasting parameters in Table 3-15 of the previous DOE publication (1991) for field size of 300 to 725 MMBO as a guide, one additional year at the current rate is possible before decline begins. This would bring the number of years at peak rate to five, the same as was presented during the field rules hearing in 1984 (AOGCC 1984).

Assuming Endicott production (oil plus NGLs) continues at the 1991 average rate through 1992, drops to 85 MBPD in 1993, and then declines at 15% beginning on 1/1/94, the remaining reserves at 1/1/92 are 235.6 MMB. Added to cumulative recovery of 160.5 MMB as of 12/31/91, total recovery is 396.1 MMB. With good waterflood response and gas cap expansion, recovery of about 39.6% of OOIP could be low as the current water cut is only 30%. Review of historical water-cut data indicates a 5% upward revision may be possible. This would increase Endicott reserves to about 416 MMB or about the same volume carried by the Division of Oil and Gas (DOG) (ADNR 1991). Additional production history is needed before further revision is considered.

In November 1991, the water cut for Sag Delta North production was about 54%. Industry experience shows most projects would have recovered over 50% of ultimate reserves when the water cut is from 50 to 60%. Total recoverable reserves for Sag Delta North would be 7.7 MMBO by assuming recovery is 55% as of 11/30/91.

Production history is limited and is only used to test the reasonableness of the above estimate. An ultimate reserve estimate of 7 MMB is determined using production history. This is reasonably close to the previous estimate. Future reserves for Sag Delta North, as of 1/1/92, are about 3.5 MMB. Therefore, ultimate reserves for the DIU at 1/1/92 are: (a) Endicott - 396.1 MMB, (b) Sag Delta North - 7.7, for a total of 403.8 MMB.

A.2.1.2.2. Production Forecasts--The estimated forecasts are combined for economic evaluations.

Endicott. The Endicott forecast is developed using the assumptions in **Section A.2.1.2.1** for estimating future recoverable oil. The peak oil rate plateau has continued through 1992 at a rate of 110 MBOPD. A 15% annual decline rate is used for 1994 and later years. The resulting production forecast for Endicott is shown in **Table A.5**.

Sag Delta North. Given a limited production history, a decline rate is selected that allows for the recovery of the estimated future reserves of 3.5 MMB determined for this accumulation. The forecast shown in **Table A.5** uses about a 40%/yr decline.

Table A.5. Endicott and Sag Delta North production forecast.

Year	Endicott (MBOPD)	Sag Delta North (MBOPD)	Year	Endicott (MBOPD)
1992	110.1	4.1	2002	20.0
1993	85.0	2.5	2003	17.0
1994	71.9	1.5	2004	14.0
1995	61.0	0.9	2005	12.0
1996	52.0		2006	10.0
1997	44.0		2007	9.0
1998	38.0		2008	7.5
1999	32.0		2009	6.5
2000	27.0		2010	5.3
2001	23.0			

A.2.1.2.3 Investments--Endicott has been on production since 1987 and it is assumed the majority of investments have already been made. Known future investments include the drilling of 10 additional wells and the additional 650 ft breach to the causeway. The cost to add the breach is estimated at $56 MM.[a] It is assumed that no other major facility investments will be required to recover the future reserves.

Based on the production performance of the Sag Delta North wells, no additional investments will be required to deplete the reservoir.

The investment schedule is developed using the following assumptions:

- Endicott development wells are drilled over the next 5 years.
- The cost to drill at Endicott estimated in the previous DOE publication (1991) is valid and is $3 MM/well (1/1/92$).
- The most recent cost of $56 MM (1/1/92$) to retrofit the causeway is used.
- The causeway breach is installed during 1992.
- Miscellaneous investments of $5 MM are carried for years 1993 through 1996.

The drilling and investment schedules are shown in **Table A.6**.

a. BP Exploration (Alaska) Inc., personal communication, October 23, 1991.

Table A.6. Endicott drilling and investment schedules.

Year	Drilling	Investment - $MM (1/1/92$)		
	No. Wells	Well	Facilities	Total
1992	2	6	56.0	62.0
1993	2	6	5.0	11.0
1994	2	6	5.0	11.0
1995	2	6	5.0	11.0
1996	2	6	5.0	11.0
Total	10	30	76.0	106.0

A.2.1.2.4 Operating Costs--Operating costs are based on a cost factor per BTF. An Endicott water cut versus percent cumulative recovery relationship is used to determine total fluid produced. The Endicott production performance to date was examined and a current relationship developed using the new ultimate reserves determined. The new water-cut relationship is shown **Figure A.12.**

The cost per barrel factor used in the previous DOE publication (1991) was $1.40/BTF (1/1/90$). In the absence of new information, the 1990 cost factor is used. Adjusted for inflation this factor is $1.50/BTF (1/1/92$).

A.2.1.2.5 Future Producers--The number of future active producing wells is determined using the Set B equations **Section 3.2.5**.

A.2.1.2.6 Field Pipeline Tariff--Endicott liquids are delivered to TAPS PS No. 1 through a separate 26-mi field pipeline. The tariff calculated for the DIU in the previous DOE publication (1991) was $0.71/BBL (1/1/90$). The pipeline throughput used to calculate that tariff is within 3% of the current estimated throughput. Thus, the same, tariff is used. After adjustment for inflation, the rate is $0.76/BBL (1/1/92$).

A.2.1.2.7 Net Profits Interest--Two leases have NPIs in addition to 20% royalty. An estimate of the NPI share is made to better reflect the state of Alaska and industry share of revenue. Based on historical evaluation, it is believed that the NPI would not have been previously active due to

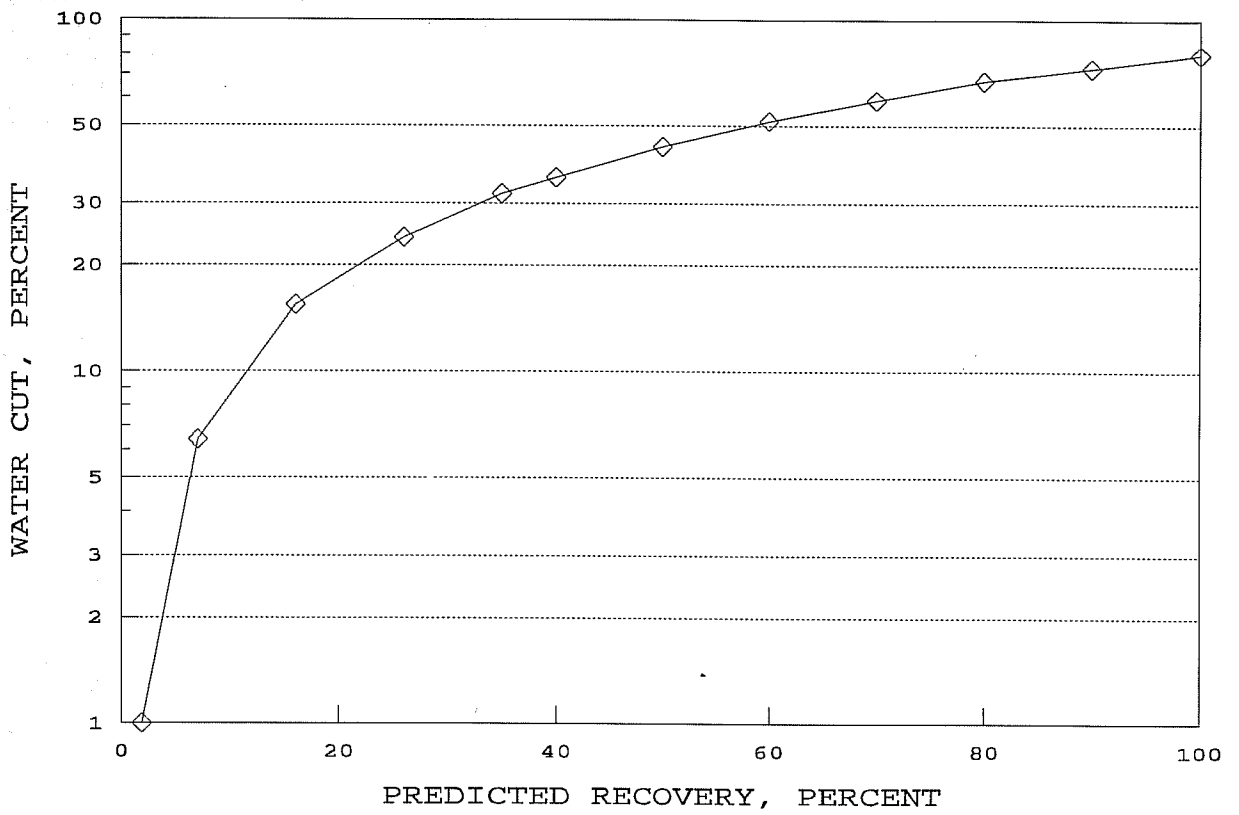

Figure A.12. Endicott formation - percent water cut versus percent recovery.

the high level of investments. The NPI share is estimated to be 18% of income before federal income tax. That percentage factor, for simplicity, is used over the remaining project life.

A.2.1.3. Summary. Endicott (DIU), the world's first commercial arctic offshore oil field, began producing in October 1987. Development is complete except in two minor reservoirs. The peak unit production rate of just over 100 MBPD is expected to continue through 1992. Assuming a decline rate of about 15%/yr after 1993, future estimated recoverable liquids (oil + NGLs) are 235.6 MMB from the Endicott (at 1/1/92). Future estimated recoverable oil from the minor reservoirs totals 3.5 MMBO (at 1/1/92) for a total future unit recoverable liquid volume of 239.1 MMB. Analysis, using the NES Low oil price, shows that all of these liquids can be economically recovered giving ultimate reserves of 403.8 MMB. Recovery of future reserves from DIU is expected to last through 2010; therefore, shutdown of TAPS will have only a minimal effect on ultimate recovery. Shutdown of TAPS at year-end 2008 will reduce recovery by an estimated 4 MMB.

A.2.2 Milne Point

The Milne Point Unit (MPU) lies 30 mi northwest of PBU and was unitized in 1979 with a total area of 35,744 acres (see **Figure 1.3**). MPU has production established from two zones, the Kuparuk sandstone of Lower Cretaceous age and the Schrader Bluff sands of Upper Cretaceous age. The Kuparuk zone was discovered in 1969 by the Sinclair East Ugnu No. 1 drilled 5 mi to the southwest, and the Schrader Bluff, also known as the Ugnu and West Sak sands, was first encountered in the Ugnu well and in Chevron's Kavearak Point well the same year (see **Figure A.13**). This well was located in the area later unitized.

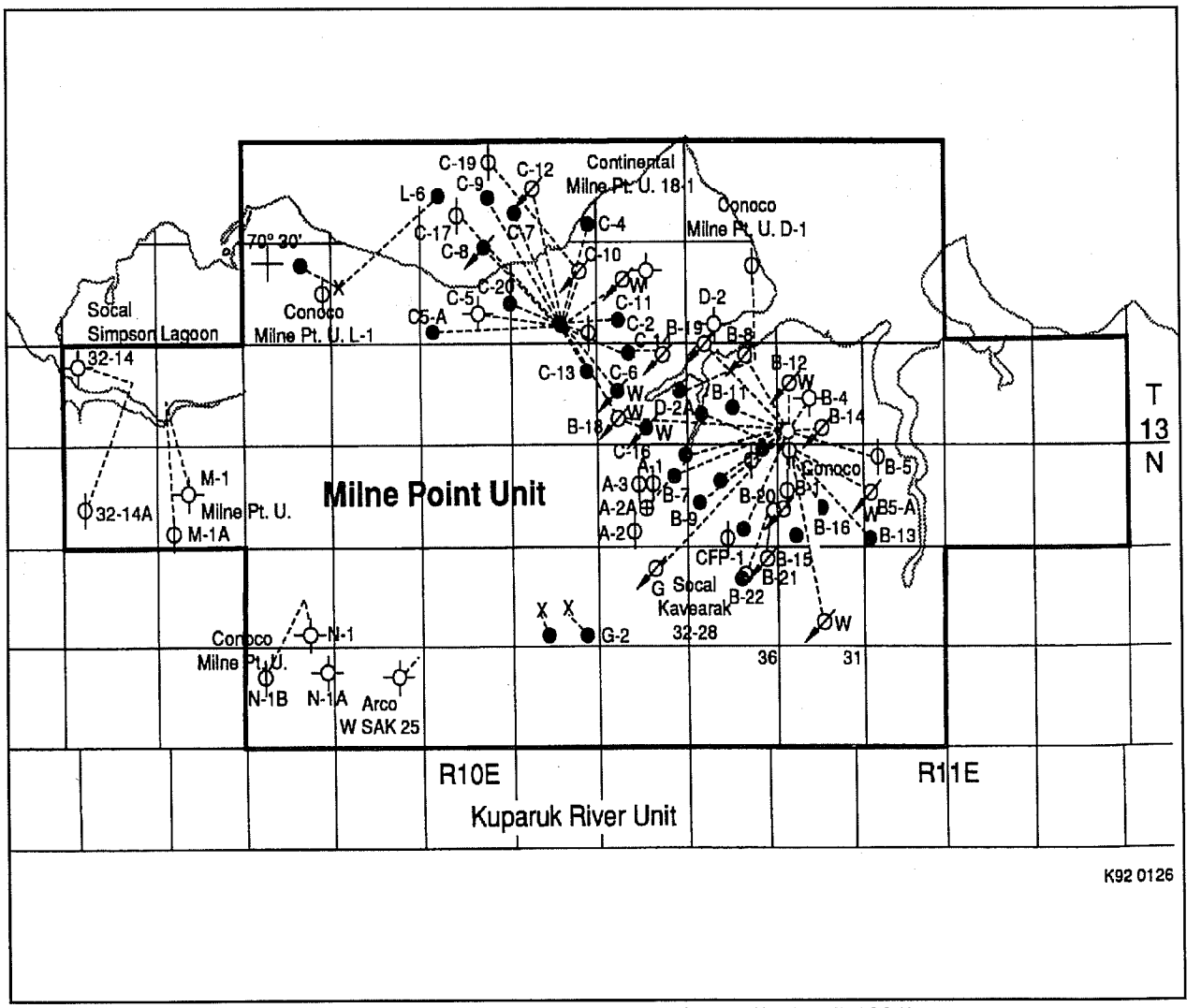

Figure A.13. MPU area showing Chevron's Kavearak Point well (AMS 1991).

Original reserves were estimated at 100 MMBO but were later reduced to 62.5 MMBO for the Kuparuk only. Production began in November 1985 from the Milne Point Kuparuk Participating Area (MPKPA), was shut-in in January 1987, and restarted in April 1989. The MPKPA covers 13,362.5 acres. Conoco is Unit Operator and is one of only three working interest owners, the others are Chevron and Occidental (see **Figure A.14**). Production from MPKPA averaged 18.4 MBPD during 1991. Cumulative oil production through 1991 was 22.5 MMBO.

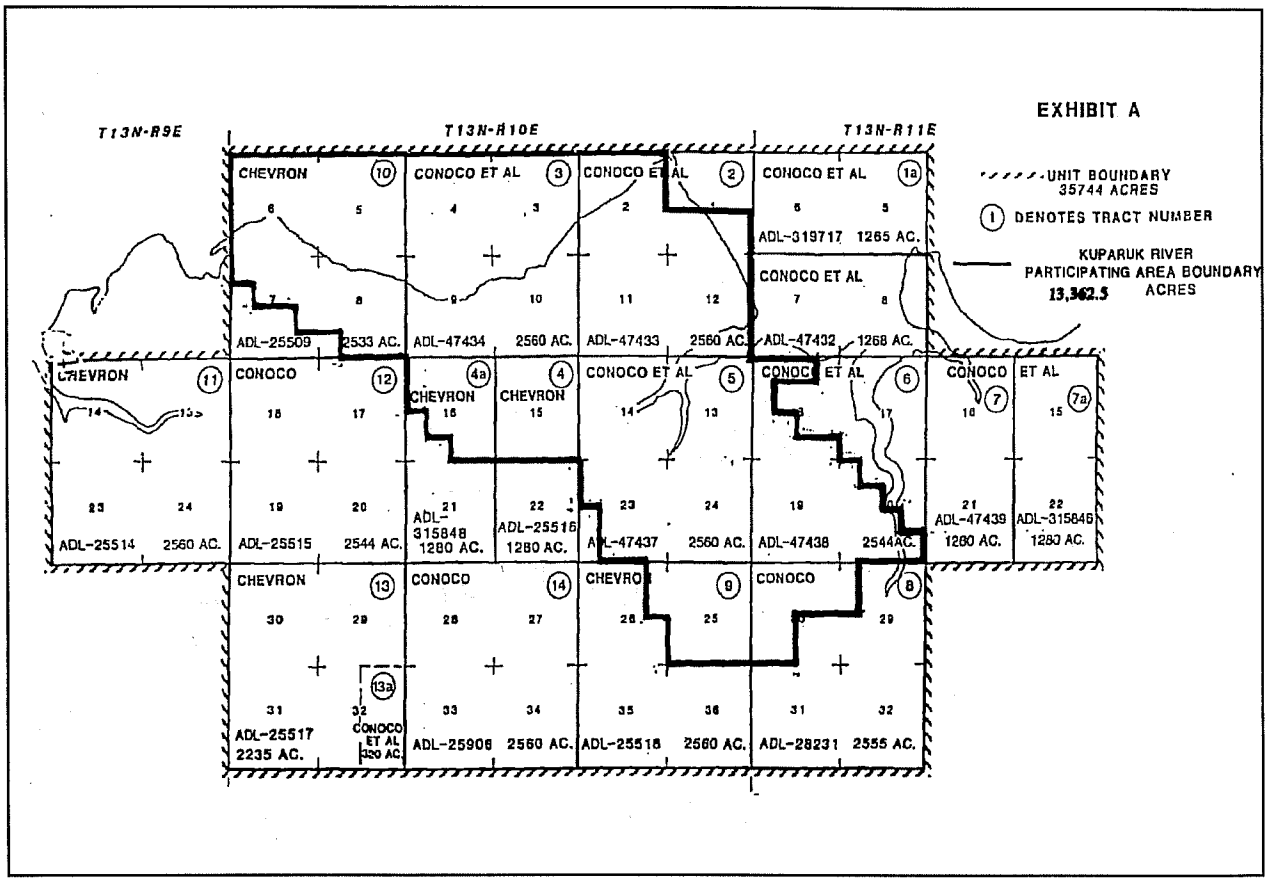

Figure A.14 MPKPA (AOGCC 1989).

A.2.2.1. Development Plans. Current plans include installation of test facilities for wells drilled in 1990 and 1991. In addition, a gas injection well is planned. Further development drilling will be based on a 3-D seismic program. At present no further drilling is proposed and the expansion of central facilities capacity from 40 to 60 MBOPD was postponed indefinitely.

A.2.2.2. Input Data. Input data are developed using history, current development plans, published information, and personal communications. Effects of a 1992 enlargement of the MPU are not included in this report. See **Appendix E** for details.

A.2.2.2.1 Recoverable Oil--The reserve volumes carried by the ADR (1991), the ADNR (1991), and in the previous DOE publication (1991) are used in conjunction with recent production history (AOGCC 1991a) and unit plans to estimate future recoverable oil.

The newly completed wells and continued waterflood operations are assumed to bring production to an average of about 18.5 MBOPD during 1992 to 1994 before production goes on decline. It is assumed that Kuparuk production will decline at about 12% per year to an average daily production rate of 11.0 MBOPD by 1999. This results in future recovery of 40 MMBO as of 1/1/92.

A.2.2.2.2 Production Forecast--Based on the assumptions used to determine recoverable oil, the future production schedule developed for this project is shown in **Table A.7**.

Table A.7. MPKPA production forecast.

Year	MBOPD
1992	18.5
1993	18.5
1994	18.5
1995	16.2
1996	14.3
1997	12.6
1998	11.0

A.2.2.2.3 Investments--Based on the future plans (Conoco 1991; ADNR 1991b)[a] the only investments forecast are those associated with drilling 12 wells to complete development of the current operating area. Expansion of the developed area is not foreseen. The cost to drill wells in the previous DOE publication (1991) of $2.1 MM/well (1/1/92$) is used. The cost of associated well and pad facilities is assumed to be between $5.0 MM and $10.0 MM per pad. It is assumed that the pads on which the new development wells are located will require about $1.0 MM per well for additional facilities. The resulting drilling and investment schedules are shown in **Table A.8.**

a. Conoco, Inc., personal communication, October 21, 1991.

Table A.8. MPKPA Drilling and investment schedules.

Year	Drilling	Investment - $MM (1/1/92$)		
	No. Wells	Well	Facilities	Total
1992	4	12.6	9.0	21.6
1993	4	12.6	3.0	15.6

A.2.2.2.4 Operating Costs--The operating costs factor used in the previous DOE publication (1991) was $1.49/BTF (1/1/90$). In review, that cost did not include future well workover costs that are estimated as high as $0.97/BTF (1/1/92$) in other projects. Similar costs are assumed to apply in MPKPA. The revised total operating cost used is $2.50/BTF (1/1/92$).

Estimates of total fluid volumes are determined using a relationship of water cut versus percent of ultimate recovery that uses Milne Point Kuparuk waterflood model results. The model study was premised on enhancing recovery by water injection in a Kuparuk formation. Insufficient production data are available to modify the model results, as KPA it is still in the process of being delineated, and a portion of the developed area is under enhanced recovery. **Figure A.15** shows the model results. A best fit curve through the data points is used.

The MPKPA (**Figure A.14**) processing facilities and some infrastructure components will be used by the Milne Point Schrader Bluff Participating Area. The estimated incremental cost to operate these facilities is added to the MPKPA operating cost. Examination of North Slope projects suggests a ratio of $2.33 of operating costs to $1.00 of total investments. This is assumed to be a reasonable split of the cost sharing fee the MPKPA receives from the Milne Point Schrader Bluff Participating Area. The economic evaluation includes 70% of that fee as added operating costs to the MPKPA.

A.2.2.2.5 Field Pipeline Tariff--The tariff used in the previous DOE publication (1991) was $2.02/BBL (1/1/90$). A review of industry and published data indicates the total field tariff is $2.00/BBL (ADR 1991). The total pipeline tariff from the previous DOE publication (1991) is adopted, $2.16/BBL (1/1/92$).

A.2.2.2.6 Facilities Sharing--The cost sharing fee paid by the Milne Point Schrader Bluff Participating Area is included as income to MPKPA and is not subject to royalty and state production taxes. The income is subject to state and federal income tax.

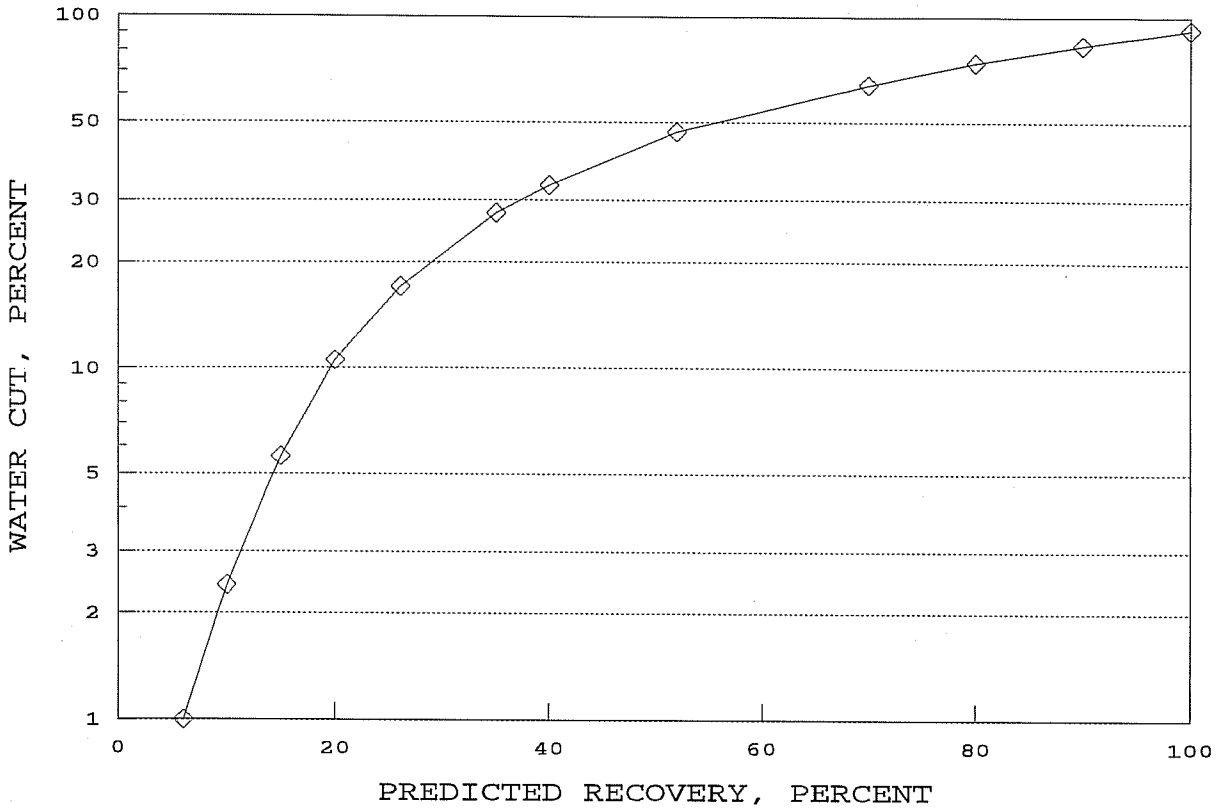

Figure A.15. MPU - model data of percent water cut versus percent of ultimate recovery.

A.2.2.2.7 Future Producers--The Set B equations in **Section 3.2.5** are used.

A.2.2.3 Summary. Production began in November 1985 from the MPKPA, was shut-in in January 1987, and restarted in April 1989. Production averaged about 18 MBPD during 1991. Current plans do not include expansion of the area under development; however, a few in-fill wells are included to complete the current producing area. The current producing rate, about 18.5 MBOPD, is expected to continue through 1994 before production begins to decline. Future recoverable oil is estimated at 40 MMBO as of 1/1/92. Analysis, using the NES Low oil price, shows that all the oil can be economically recovered resulting in ultimate reserves of 62.5 MMBO. With a production life projected only through 1999, MPU reserves are not affected by the life of TAPS.

A.2.3 Schrader Bluff

In 1990, Conoco applied to the state to establish pool rules for Schrader Bluff development. Schrader Bluff was defined by the section encountered in the Conoco Milne Point A-1 well in the interval

4,174 to 4,800 ft and correlated with other formations as shown in **Figure A.16**. The productive intervals of the Schrader Bluff are locally named the "N" and "O" sands. The N is equivalent to the basal shale and mudstone of the lower Ugnu in the KRU to the southwest. The sandstones of the O are equivalent to the West Sak sands of the KRU. The unconformity above the N sands is an important geological hiatus that marks a significant change in oil gravity. Above the unconformity, sands contain thick, viscous oil ranging in gravity from 10 to 13°API. Below the unconformity, gravities range from 14 to 19.5°API (AOGCC 1990a).

The Schrader Bluff dips 1 to 2° to the east-northeast forming a regional homocline extending from southwest of the Kuparuk River field to beyond the offshore barrier islands (see **Figure A.17**) (AOGCC 1990a).

The N sands are generally thin, ranging from 5 to 20 ft thick with a maximum of 33 ft. They are friable, fine-grained sands deposited in the marginal or distal areas of a large delta in shallow marine conditions. The O sands were deposited in a similar paleoenvironment but are thicker, more massive, and have a high degree of lateral continuity. Sands range from 20 to 50 ft in thickness (AOGCC 1990a).

Oil is trapped in the shallower, less continuous N sands by updip pinchouts to the southwest and by faulting. The oil in the O sands is trapped by faults updip to the southwest. As shown in **Figure A.18**, fault zones (rather than individual faults) create impermeable barriers to oil migration and have formed five separate accumulations with different OWCs in the six large mapped fault blocks. The overall density of faulting is much greater than shown on the map, which adds to complexity and heterogeneity of the reservoir.

The state approved the pool rules for Schrader Bluff on July 2, 1990, providing for an area encompassing the entire MPU. Among other items covered, the rules provide for nominal 10-acre spacing for wells and allow surface commingling of production between Schrader Bluff and Kuparuk River oil pools (AOGCC 1990a).

The Milne Point Schrader Bluff Participating Area covers 21,640 acres (**Figure A.19**). Working interest owners are Conoco, Occidental, and Chevron. Five of the 13 tracts in the Participating Area carry 20% royalty, and the rest carry 12.5%.

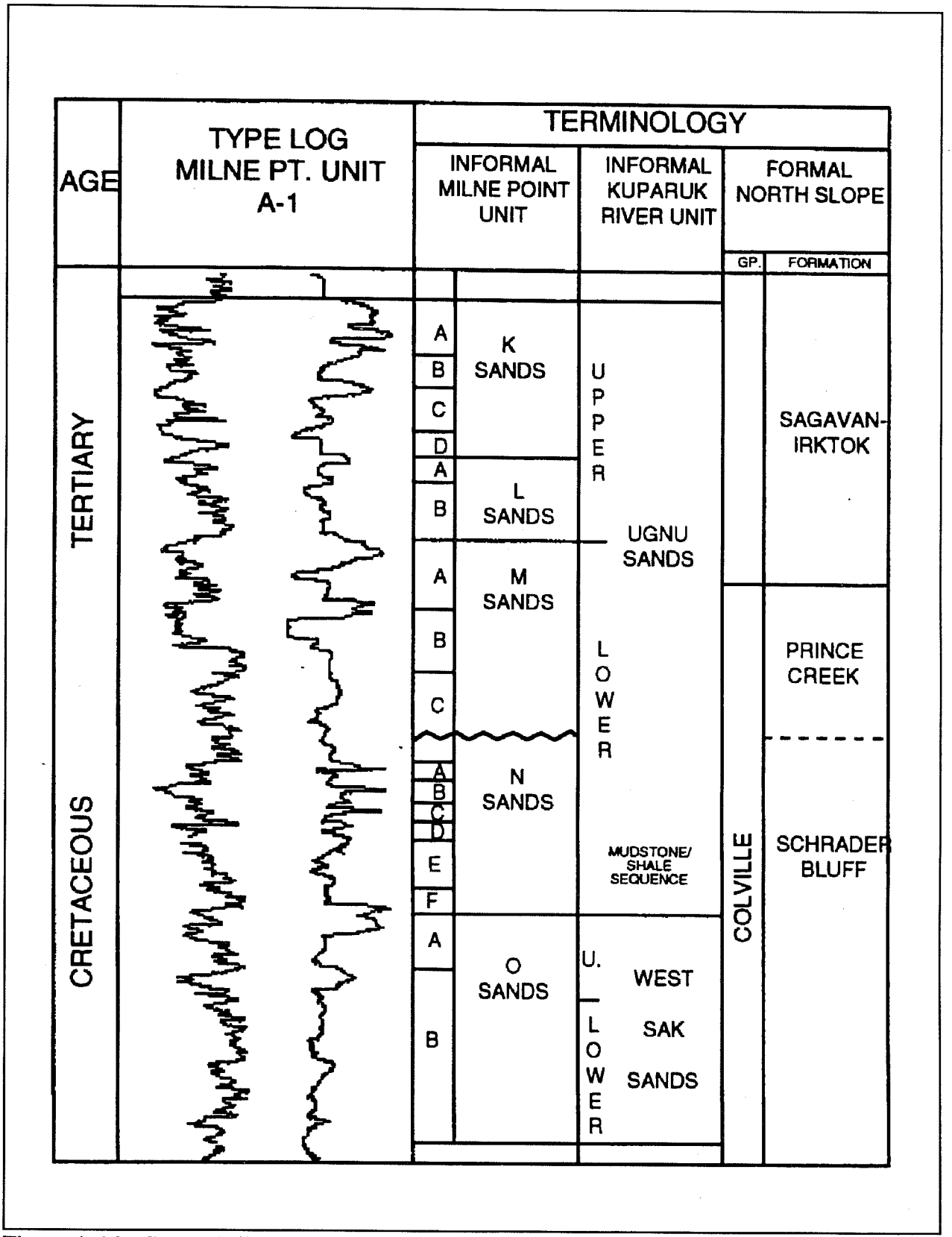

Figure A.16. Conoco Milne Point A-1 well (Werner 1986).

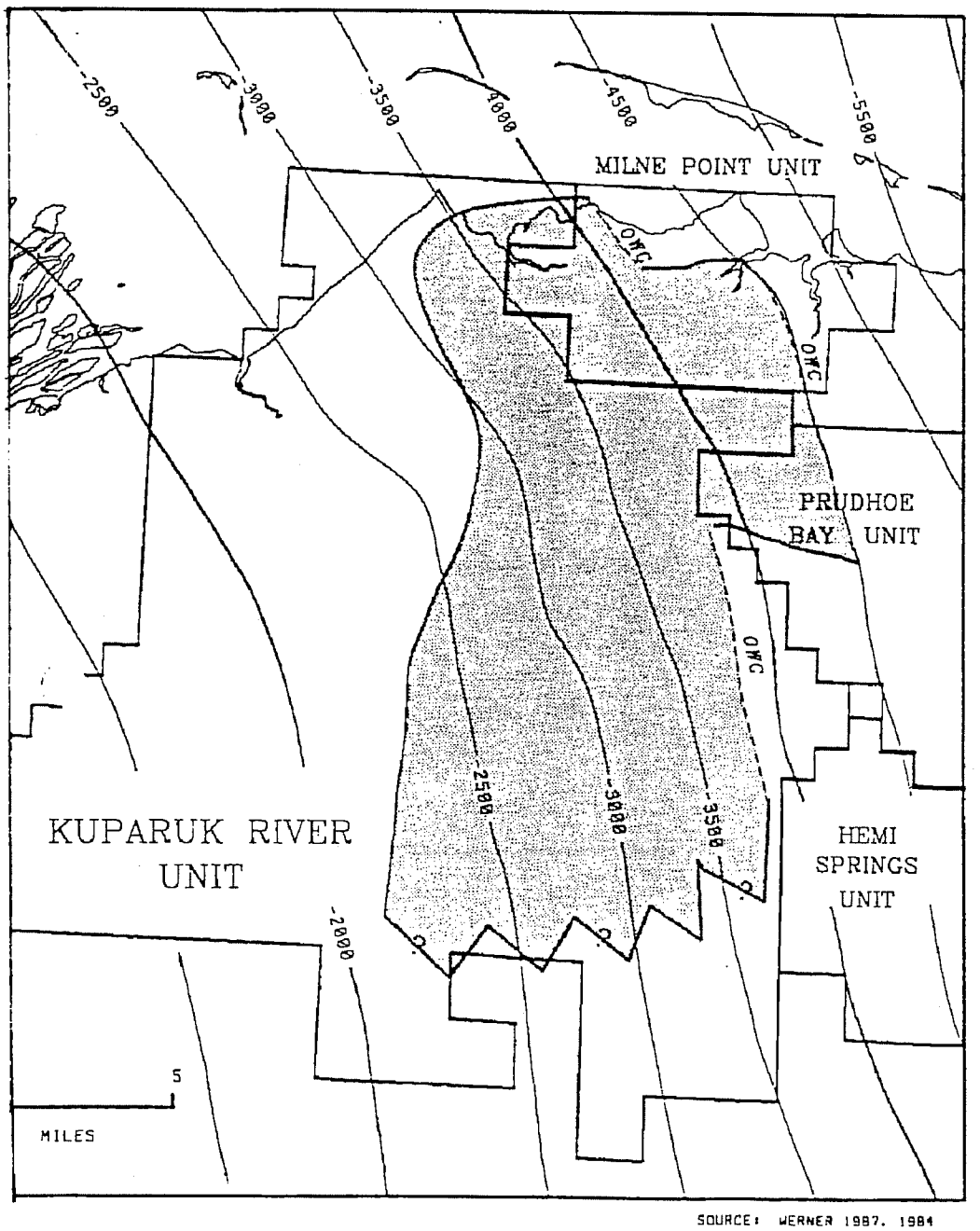

Figure A.17 Schrader Bluff structure (AOGCC 1990a).

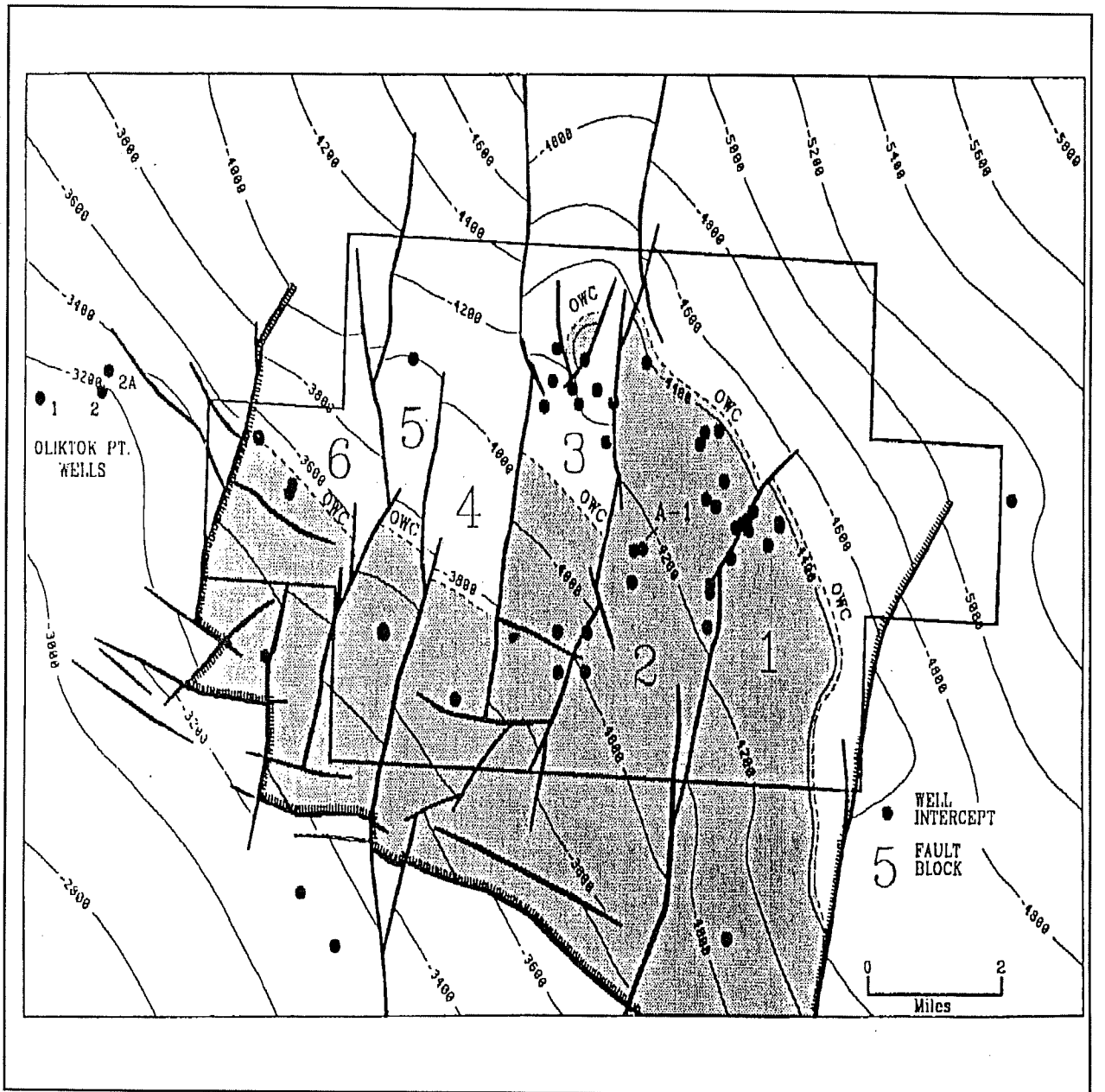

Figure A.18 Schrader Bluff faulting (AOGCC 1990a).

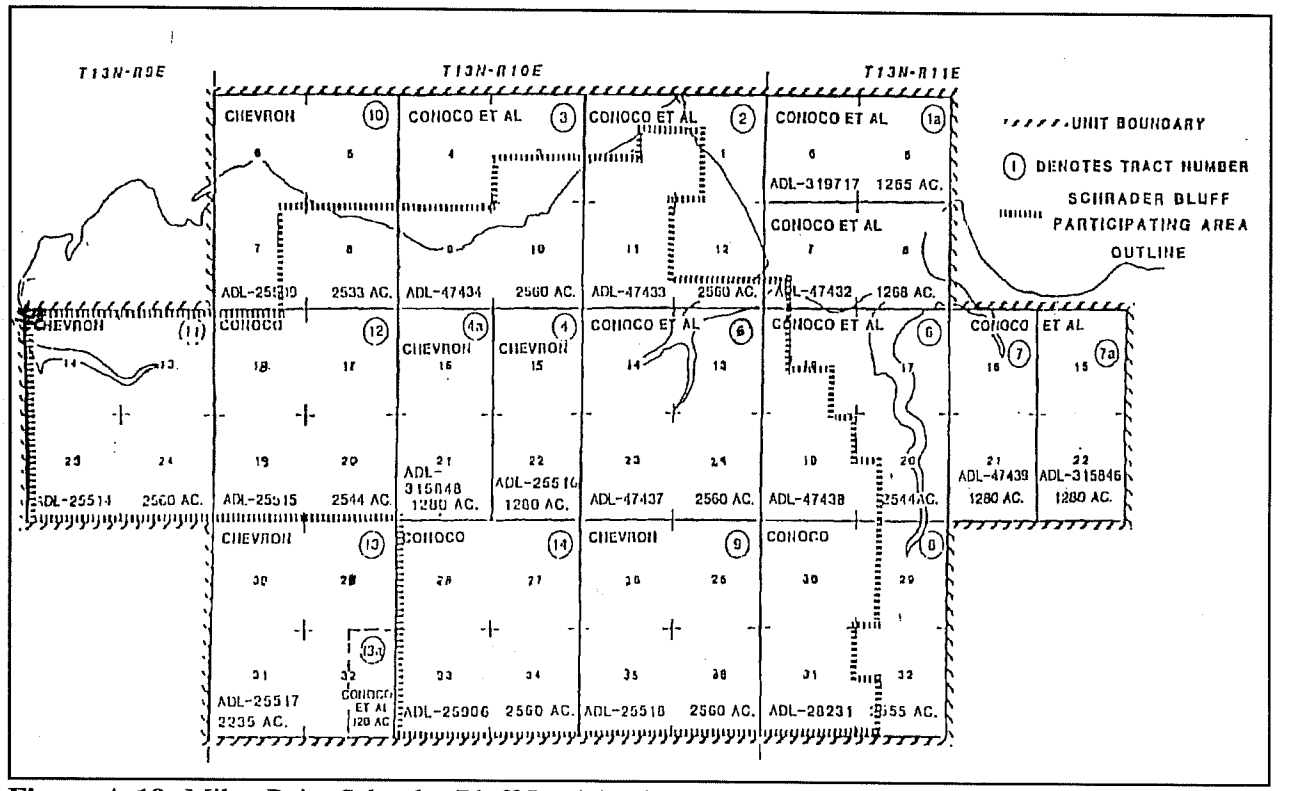

Figure A.19 Milne Point Schrader Bluff Participating Area (AOGCC 1989).

Production from Schrader Bluff began in March 1991. The December 1991 production rate was 3,062 BOPD and the total production through 12/31/91 was 760.1 MBO (AOGCC 1991a).

A.2.3.1 Development Plan. Development drilling has taken place on four drilling pads on Tract 14 (**Figure A.20**). By late 1991, 20 wells were completed as producers. Some will be converted to injectors in the future. The most recent plan of development indicates a slow down of development by the postponement of wells on three new pads (Wash 1991, Conoco 1991). Long range plans call for development of about 16,800 acres (AOGCC 1990a).

A.2.3.2. Input Data. Input data are developed using history, current development plans, published information, and personal communications.

A.2.3.2.1 Recoverable Oil--Reserves have been estimated by the ADR (1991) and the ADNR (1991). The ADNR does not list a separate reserve estimate for the Schrader Bluff formation. However, the ADR estimates 107 MMBO reserves as of 1/1/92. A maximum reserve potential of 270

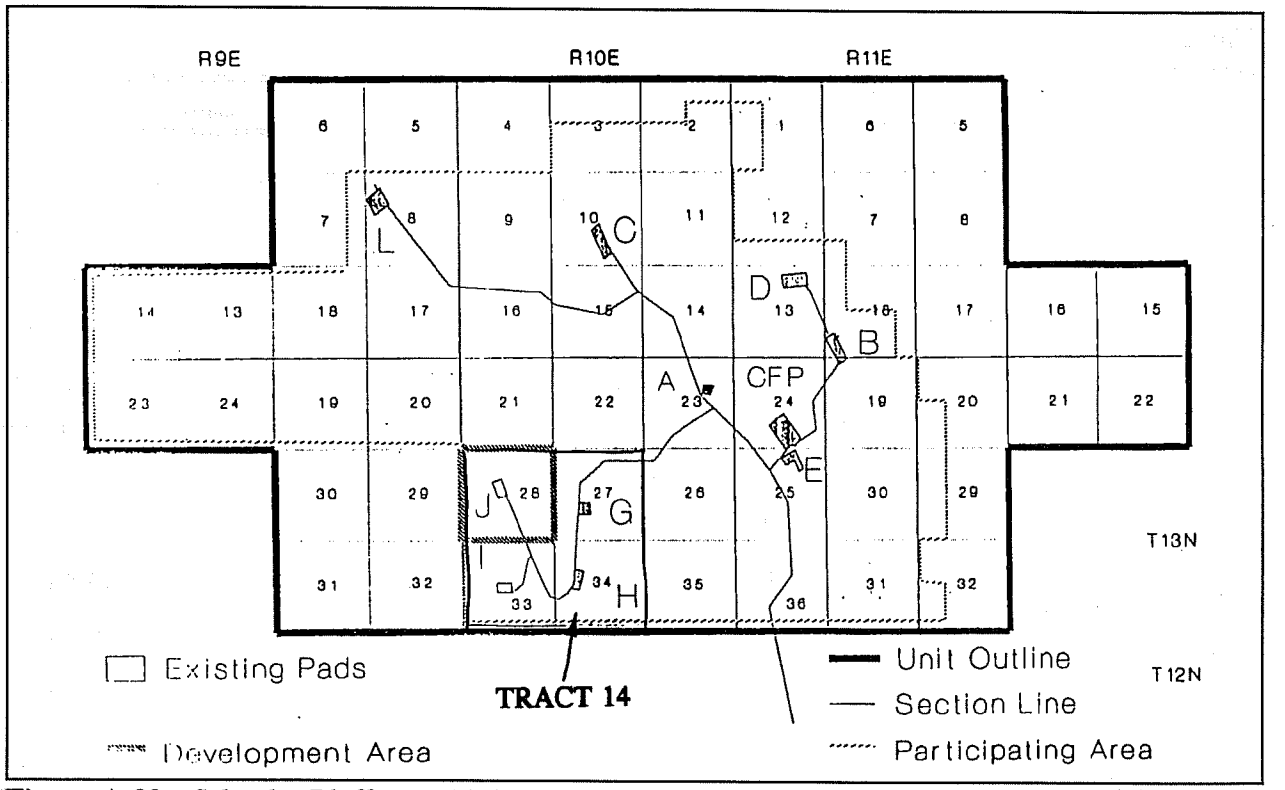

Figure A.20. Schrader Bluff tract 14 development area.[a]

a. Conoco Inc. Schrader Bluff presentation to EG&G Idaho, Inc., 10/21/91.

MMBO for Schrader Bluff was furnished by Conoco.[a]

Figure A.18 is a structure map of one Schrader Bluff interval that shows the varying OWCs in different fault blocks within the unit boundary. The area above the OWCs of about 16,800 acres is the assumed potential development area. Recoverable reserves are calculated for Schrader Bluff using 16,800 acres as the overall area to be developed and applying the parameters given in **Table A.9.**

Ultimate recoverable oil using these values is 209.5 MMBO. Future recoverable oil as of 1/1/92 is 208.8 MMBO.

A.2.3.2.2 Rate Forecast--Wells are produced with electrical submersible pumps. Problems have been encountered which have resulted in frequent failures.[b] It is assumed that these

a. Conoco, Inc., personal communication, December 28, 1992.

b. Conoco, Inc., personal communication, October 21, 1991.

Table A.9. Schrader Bluff reserves parameters.

Parameter		Value	Source
Area	- Acres	16,800	AOGCC 1990a
Thickness	- ft	50	Average assumed
Porosity	- %	27.5	AOGCC 1990a (estimated from Figure 5)
Water saturation	- %	41	Average assumed
FVF	- BBL/BBL	1.06	AOGCC 1990a
Recovery	- %	21	Personal communication

problems will be solved by year-end 1992 or early 1993 and that the mechanical problems will not further delay development beyond late 1993. The well rates in this project may average as high as 400 BOPD.[b] However, the average well rate during 1991 was 340 BOPD and is used to develop the forecast. Assuming the mechanical problems are solved by early 1993, the forecast of rates is prepared using a phased development schedule.[b] The Schrader Bluff development is planned to utilize spare capacity. Current facilities capacity is 30 MBOPD. The volume above projected MPKPA production levels is used as a guide. For simplification, it is assumed that the staged development occurs at 2-year intervals. The last drilling pads to be developed will be those nearest to the OWCs. Because of the reservoir configuration, it is assumed that development will require 20 additional pads plus enlargements to three existing MPKPA Pads (ADNR 1990). Three individual well production schedules are developed to represent recoveries at high mid and low structural positions. The assumptions are:

- Initial rate - 270 BOPD
- Peak rate - 340 BOPD
- Duration of peak rate
  - High wells - 3 years
  - Mid wells - 2 years
  - Low wells - 1 year
- Decline from peak rate - 15%.

The forecast is shown in the **Table A.10.**

A.2.3.2.3 Investments--Total facility investment is expected to be in a ratio of about $1 for every $2 of well costs and the non-drilling investments are estimated to range from $5 to $10 MM

Table A.10. Schrader Bluff production forecast.

Year	MBOPD	Year	MBOPD	Year	MBOPD
1992	4.1	2000	29.0	2008	28.0
1993	9.0	2001	30.0	2009	29.0
1994	10.5	2002	29.0	2010	25.5
1995	13.5	2003	30.0	2011	26.5
1996	15.5	2004	29.0	2012	25.0
1997	17.0	2005	30.0	2013	24.0
1998	19.0	2006	29.0	2014	22.5
1999	28.0	2007	30.0	2015	21.5
				2016	17.4

per drilling pad (1/1/92$).[a] Using $8 MM for new and $6.75 MM for enlarged pads, the facilities investment is $180.3 MM (1/1/92$). Initial drilling on 80-acre spacing requires 196 wells from new pads or enlarged MPKPA pads at a cost of $411.6 MM (1/1/92$). It is assumed that well spacing on better quality reservoirs will take place before proceeding with lower structure wells. One hundred additional wells will be required to reduce well spacing to 40 acres on 8,000 acres at a cost of $210.0 MM (1/1/92$) to bring the total drilling costs to $621.6 MM (1/1/92$). At the 2 to 1 ratio, estimated facilities investment is $310.8 MM. The average of these two estimates, $245.6 MM (1/1/92$), is used.

Because early development requires constructing more roads and pipelines and in-fill wells require additional pad facilities, $15 MM/pad is allocated in the first three phases, $6 MM/pad in the next two phases, and the balance is allocated to the final phase.

The drilling and investment schedules are shown in the **Table A.11.**

A.2.3.2.4 Operating Costs--Operating costs for Schrader Bluff consists of three factors: A basic operating cost, well workover costs, and a facilities sharing fee. A basic operating cost of $2.50/BTF (1/1/92$) is used.[b] Schrader Bluff is paying the facilities sharing fee; therefore, this basic operating cost is reduced by an assumed 30%.

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a. Conoco, Inc., personal communication, December 12, 1991.

b. Conoco, Inc., personal communication, December 12, 1991.

Table A-11. Milne Point Schrader Bluff drilling and investment schedules.

Year[a]	Drilling	Investments-$MM (1/1/92$)		
	No. Wells	Wells	Facilities	Total
1993	12	25.2	0	25.2
1994	32	67.2	40	107.2
1996	22	46.2	40	86.2
1998	36	75.6	60	135.6
2000	34	71.4	20	91.4
2002	36	75.6	20	95.6
2004	28	58.8	24	82.8
2006	24	50.4	24	74.4
2008	24	50.4	6	56.4
2010	24	50.4	6	56.4
2012	24	50.4	5.6	56.0
Total	296.0	621.6	245.6	867.2

a. Odd years (1995 through 2011) have no wells or investments.

To determine well workover costs, it is assumed that each producing well requires two workovers and each injector requires one workover. At $500 M (1/1/92$) per workover, the total cost of workovers is $189 MM. Using a total produced fluid estimate of 362 MMB, the cost is $0.52/BTF.

The facilities cost savings to the Schrader Bluff by utilizing MPKPA facilities spare capacity is unknown. Using the Niakuk development as a reference, the savings for this project are estimated at $135 MM (1/1/92$). Using the facilities sharing fee formula in **Section 3.2.8.**, a cost sharing fee of $1.24/BTF is estimated.

To determine total fluid production, a water cut versus percent cumulative recovery relationship is used. Lacking any other basis, it is assumed that the Milne Point waterflood model results are acceptable for calculating total fluid volumes for determining the operating costs for this project (see **Figure A.15**).

A.2.3.2.5 Field Pipeline Tariff--As discussed in **Section A.2.2.2.5**, a tariff of $2.16/BBL (1/1/92$) is used .

A.2.3.2.6 Future Producers--The Set B equations in **Section 3.2.5** are used to estimate future annual producing wells.

A.2.3.3. Summary. The Schrader Bluff pool, which is a combination of lower Ugnu sands, and upper West Sak sands, began producing in March 1991. December 1991 production averaged 3,062 BOPD. The most recent plan of development indicates a cautious approach to further expansion of the developed area; however, long range plans call for the development of about 16,800 acres. Assuming this area will ultimately be developed, estimated future recoverable oil is 208.8 MMBO. Analysis, using the EIA Mid-level and the NES Low oil price, indicates that all of this oil can be economically recovered from Schrader Bluff, resulting in an ultimate reserve volume of 209.5 MMBO. The NES Low oil price case results in a PW = 0 at about 3% discount rate for the scenario examined. With future production projected through 2016, shutdown of TAPS will reduce Schrader Bluff recovery by 70 MMBO if shutdown occurs in 2008 and by 14 MMBO for shutdown in 2014.

A.2.4 Lisburne

The Lisburne reservoir (or pool) was discovered in 1968 by the ARCO/Humble (Exxon) Prudhoe Bay State No. 1 well, the discovery well for the super-giant Prudhoe Bay field (**Figure 1.3**). Test rates ranged from 434 to 1,152 BOPD and 1.3 to 22 MMCFPD from carbonates of the Mississippian-Pennsylvanian Lisburne group (Jamison 1980). Because of the much larger reserves and much greater productivity of the shallower Ivishak sandstone, the main reservoir of the Prudhoe Bay field, recognition of the Lisburne potential and eventual development was delayed for a number of years.

In 1986, the Lisburne Participating Area (LPA) of PBU was approved by the state (see (**Figure A.21**). As shown on the map, the reservoir outlined by the LPA lies both onshore from the Sagavanirktok delta on the east, around Prudhoe Bay on the south and west, and offshore across Prudhoe Bay itself. The LPA is comprised of 41 tracts, 38 leases, and covers 80,039 acres. All leases carry a 12.5% royalty. ARCO was designated operator for the LPA. Working interest owners are ARCO (40%), Exxon (40%), and BP (Standard Alaska Production Co.) (20%). The initial POD covered the 5-year period to December 1, 1991 (ADNR 1986a).

The Lisburne group is composed dominantly of shallow-marine carbonate sandstones and dolomites with minor interbeds of clastics and cherts and occasional thin evaporites. The group is

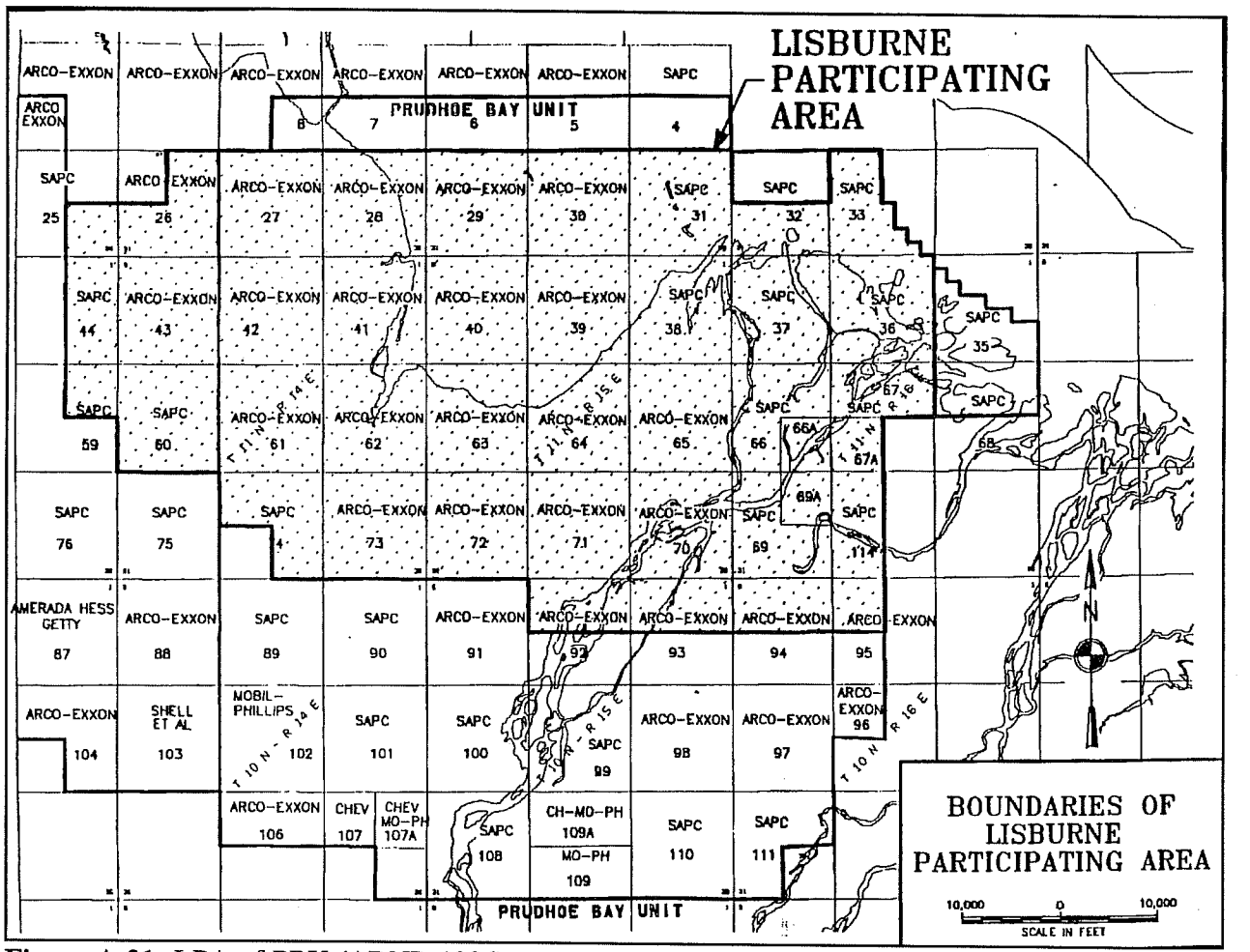

Figure A.21 LPA of PBU (ADNR 1986).

subdivided into two formations, the Alapah of Mississippian age and the overlying Wahoo of Pennsylvanian age (Jamison 1980; ADNR 1986). The Lisburne averages about 1,800 ft thick in the Prudhoe Bay area except where it is truncated by erosion (Jamison 1980). In the discovery well, the top of the Lisburne occurs at 8,790 ft measured depth (MD), the Wahoo-Alapah contact at 9,500 ft MD and the base of the Alapah at 10,440 ft MD as shown on **Figure A.22** (ADNR 1986).

Although porosity averages about 10% in the productive intervals, permeability averages only 1 md. Porosity is predominantly secondary, involving facies distribution, leaching, and dolomitization. Occasional vuggy porosity occurs with intercrystalline porosity in dolomites with values up to 20%. The Lisburne is commonly fractured with most fractures vertical and partially or entirely cemented with calcite. Fractures are believed to add significantly to the producing rates (Jamison 1980; ADNR 1986).

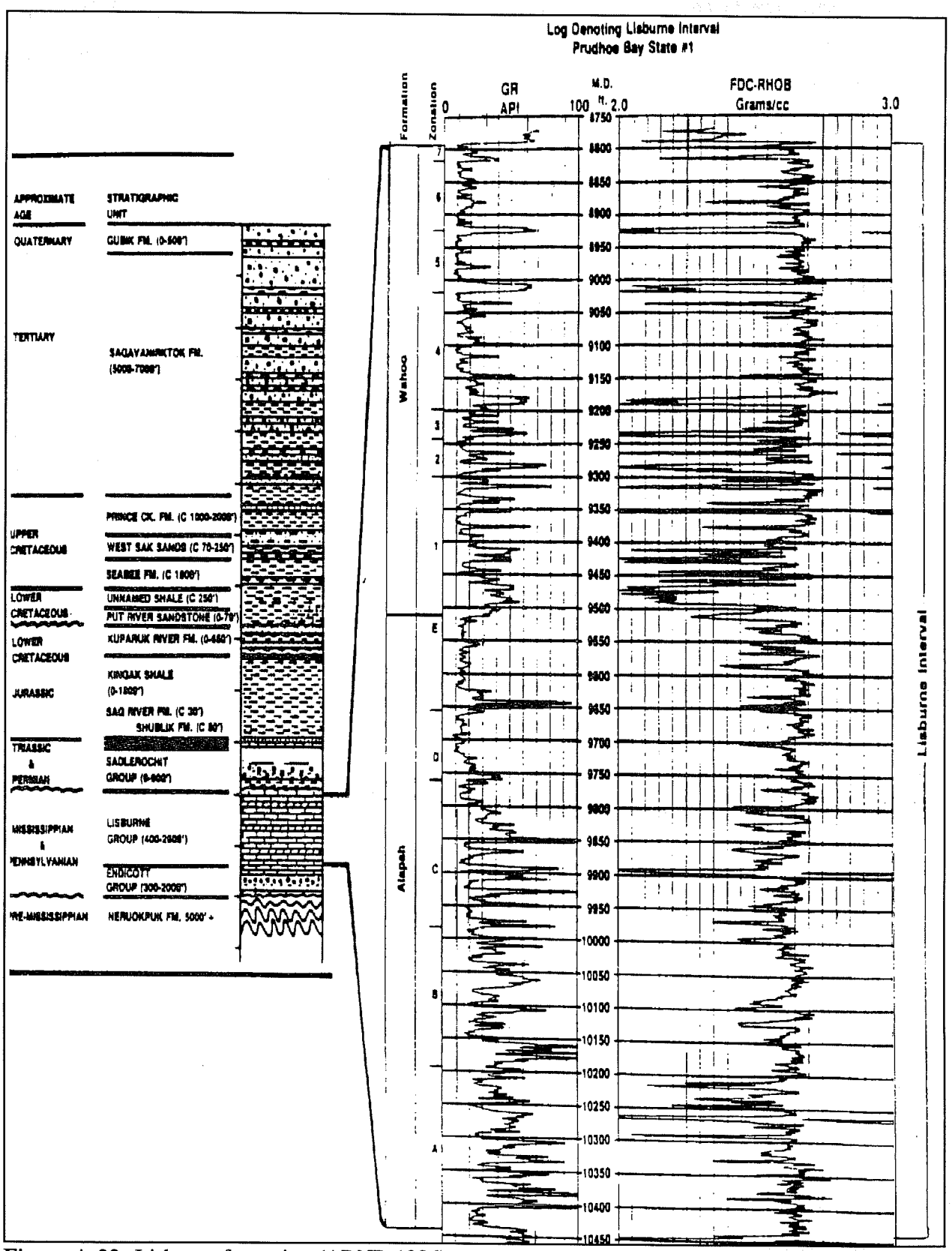

Figure A.22 Lisburne formation (ADNR 1986).

The structure on the top of the Wahoo as shown in **Figure A.23** is a gentle south flank of an east-west trending anticline, faulted on the north, and truncated on the east and southeast by the Lower Cretaceous Unconformity.

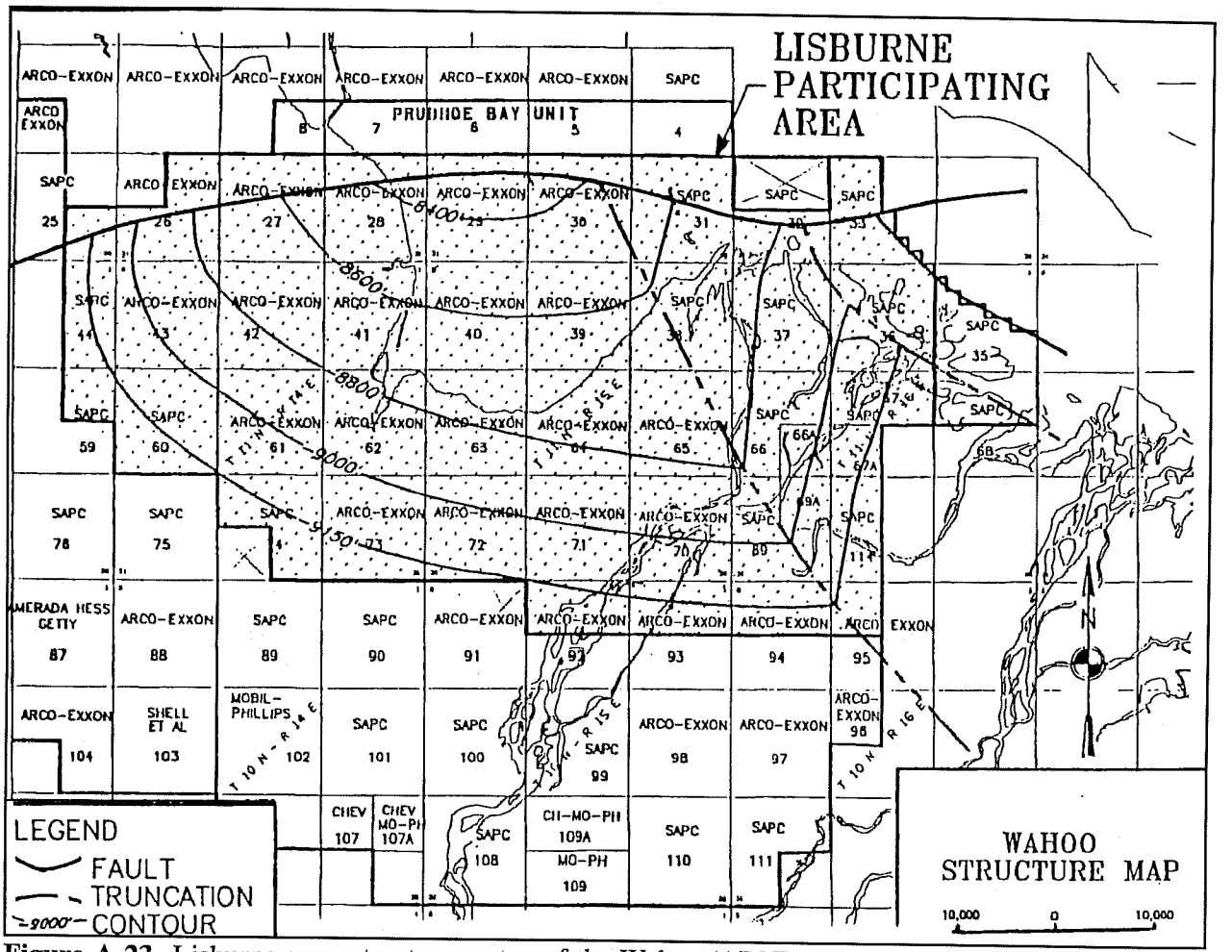

Figure A.23 Lisburne area, structure on top of the Wahoo (ADNR 1986).

A gas cap is present with the GOC at 8,600 ft subsea. The oil column extends to about 9300 ft subsea where low oil saturation establishes downdip limits, even though oil-staining occurs below this depth (ADNR 1986).

Original oil in place (OOIP) was estimated to be 3 BBO with 500 BCF of free gas in place (ADNR 1986). Gravity of Lisburne oil is 27°API. Original recoverable reserves were thought to total about 400 MMBO (1991), but, after some production history, were revised downward to 171 MMBBLS (oil + NGLs) (ADNR 1991). The previous DOE publication (1991) details an increase in estimated reserves to 206 MMBBLS. The reserves estimated in this study show another upward revision to 237

MMBO. Development began in 1984 with initial production in December 1986. The 1991 production averaged 40.1 MBOPD and total production through 1991 was 82.2 MMBO.

A.2.4.1 Development Plan. At the time of approval of the first POD, the state requested that the Lisburne Working Interest Owners provide a subsequent plan to develop the eastern and western sectors of the LPA (ADNR 1986a). Some of the owners' concerns with the eastern sector involved the Alapah. The Alapah, as mapped in the 1986 submission is shown in **Figure A.24**. As part of the second POD, submitted in August 1991, the 5-year plan incorporates delineation drilling in the eastern and western Wahoo and a specific well for the eastern Alapah in 1993 (ADNR 1991g).

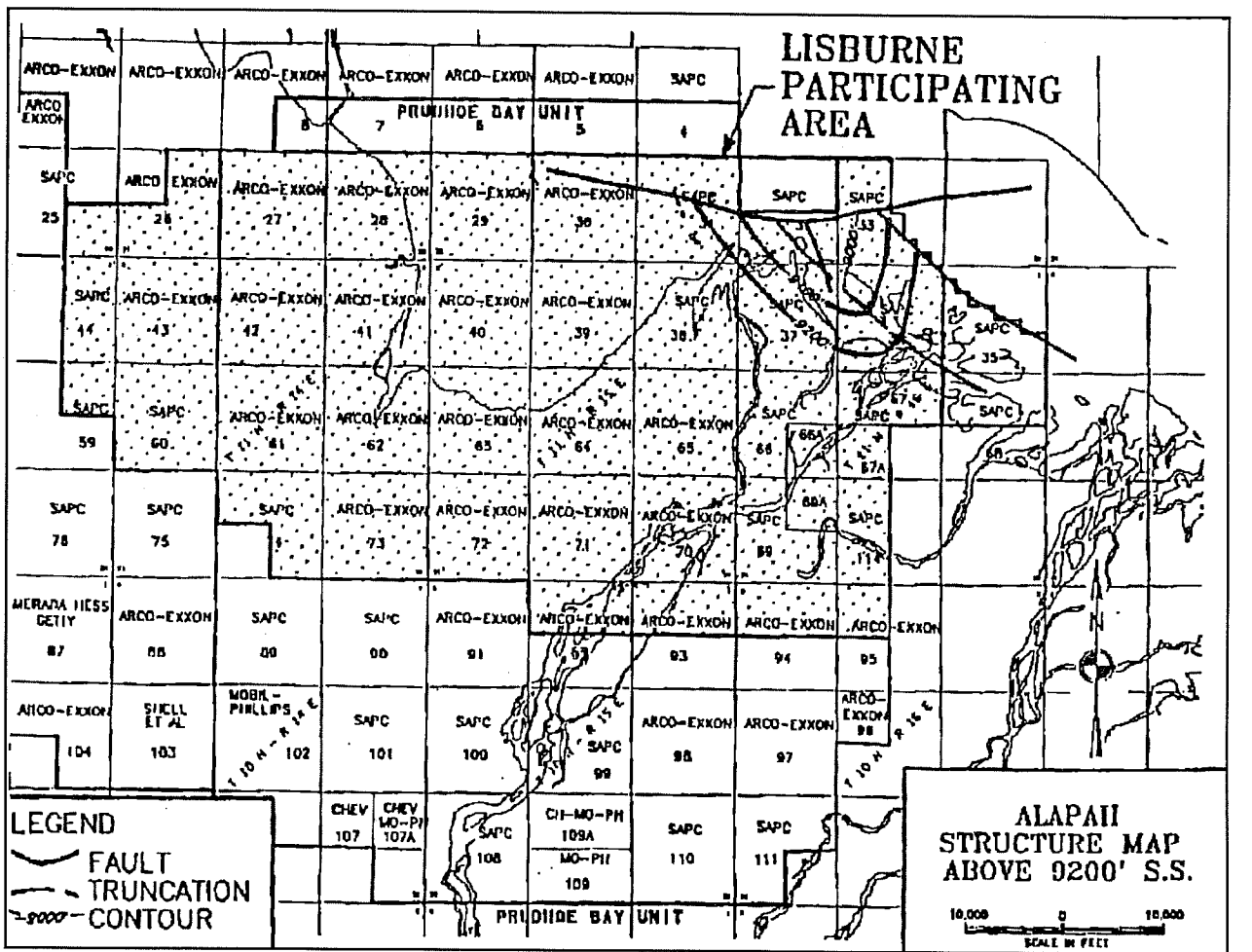

Figure A.24 Lisburne area, structure on top of the Alapah (ADNR 1986).

Some of the planning for Lisburne development involved shared wells for evaluation purposes with the initial participating area of the PBU. Also, production facilities sharing of the Lisburne

Production Center (LPC) with the Niakuk and Point McIntyre reservoirs is in the negotiation process. Indications are that both these fields will share Lisburne facilities. This will reduce the environmental impacts and costs of these developments (ADNR 1991g). These two fields will be discussed in **Section A.3**.

A.2.4.2 Input Data. The input data are developed using available public information, history, development plans, production rates, reserves, and costs.

A.2.4.2.1 Recoverable Oil--The published recoverable reserves (at 1/1/92) for the LPA vary from about 89 MMBO (ADNR 1991) to a high of 143 MMBO (ADR 1991). The reserves from the previous DOE publication (1991) are 128.6 MMBO (at 1/1/92). Production history indicates that additional wells must be drilled to maintain production at or near present levels through mid-1994. It is assumed that production from the new wells holds the decline to between 10 and 15% per year. This performance results in recoverable oil ranging from 110 to 150 MMBO. The recoverable oil from the previous DOE publication (1991) of 128.6 MMBO (1/1/92) is a reasonable estimate for the LPA and is adopted.

Information is not available on the expected recovery from the Alapah (east) and the Wahoo (eastand west) areas of possible field extension. Limits of the accumulation have not been established. These areas are on the outer edge; therefore, it is assumed the per well recovery is lower than the average well recovery in the primary development area. Examination of a map with existing wells spotted (**Figure A.25**) shows that about 27 wells are needed to complete the 160-acre spacing pattern. Using the reserves of 128.6 MMBO, the cumulative recovery of 82.2 MMBO as of 1/1/92, and the projected 73 producing wells in the development area, the average ultimate recovery is 2.9 MMBO/well. It is assumed that the successful Alapah and Wahoo wells will be 60% of this well recovery, or 1.75 MMBO/well. It is assumed that delineation drilling proves at least 2,400 acres in these formations. Using 160-acre well spacing, 15 wells are required for development. Using recovery of 1.75 MMBO/well the estimate of recoverable oil is 26.3 MMBO (1/1/92). Total future recoverable oil for the LPA is 154.9 MMBO (1/1/92).

A.2.4.2.2. Investments--The most current estimate of future Lisburne investments is combined with the Pt. McIntyre estimated investments for a total of about $980 MM over a 10-year period (1/1/92$) (ARCO 1991a). Estimated total investment for Pt. McIntyre is $727 MM (1/1/91$) or

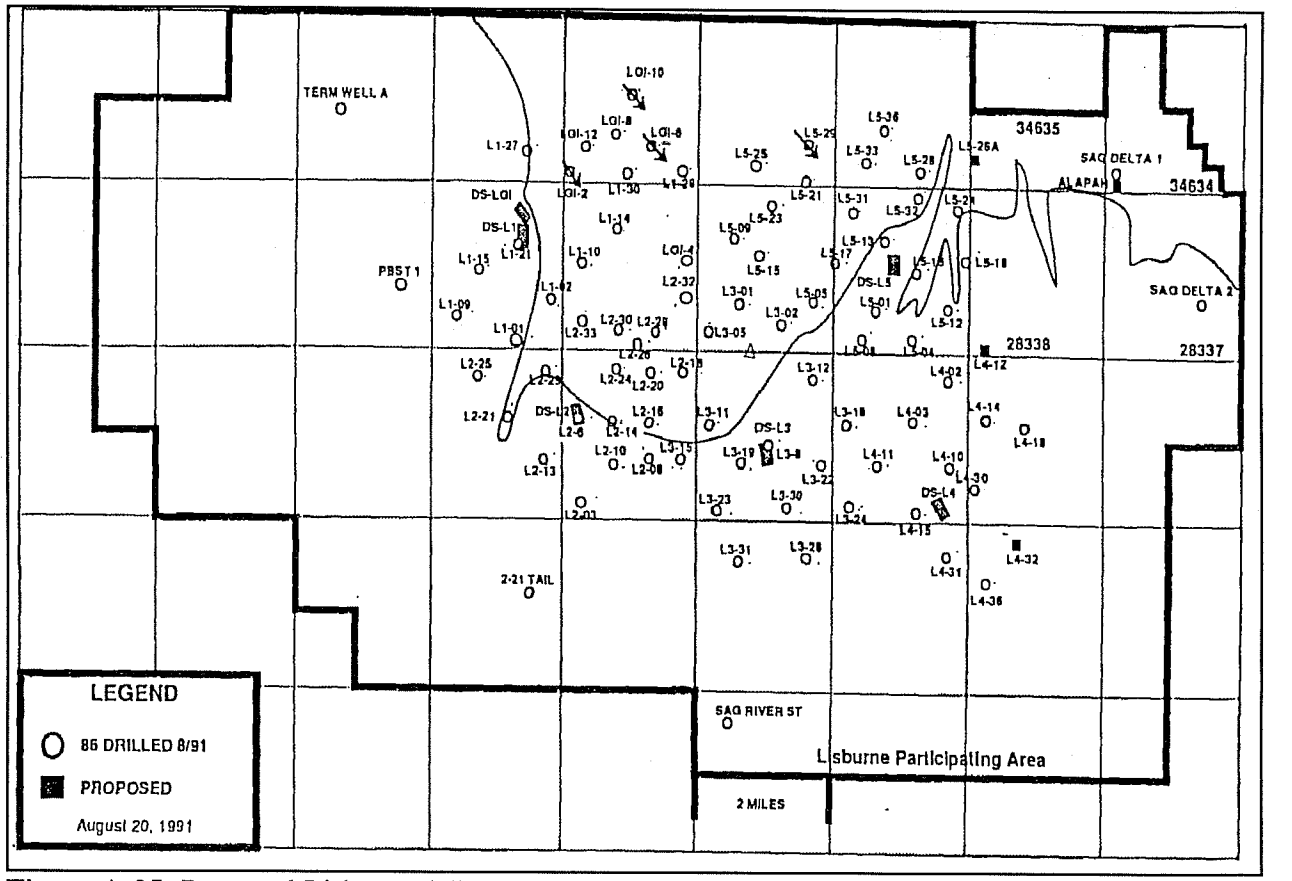

Figure A.25 Proposed Lisburne delineation well locations (ADNR 1991g).

$755 MM (1/1/92$) (PIC 1991). The difference between these two investment figures of $225 MM is assumed for future Lisburne investments.

A large portion of the $225 MM capital investment is drilling costs. The cost to drill a Lisburne well in the previous DOE publication (1991) was $3.05 MM/well (1/1/90$). This cost, $3.27 MM/well (1/1/92$), is used. Using the 1991 plan of development (ADNR 1991g) as a guide, the assumed Lisburne drilling schedule is: 1992 - 9 wells, 1993 - 8 wells, 1994 - 7 wells, and 1995 - 3 wells.

The first Alapah well is to be completed in 1994 (ADNR 1991g). The drilling schedule for the remaining wells is assumed to be: 1995 - 4 wells, 1996 - 5 wells, 1997 - 4 wells, and 1998 - 2 wells.

The estimated drilling investment is $137.3 MM (1/1/92$) leaving a balance of $87.7 MM for facilities costs. The facilities investment includes test separation equipment and the expansion of processing facilities for pads, roads, and lines for the Alapah and Wahoo developments.

The drilling and investment schedules for the LPA are shown in **Table A.12.**

Table A.12. LPA drilling and investment schedules.

Year	Drilling	Investments - $MM(1/1/92$)		
	No. Wells	Wells	Facilities	Total
1992	9	29.4	0	29.4
1993	8	26.2	50.7	76.9
1994	7	22.9	10.0	32.9
1995	7	22.9	10.0	32.9
1996	5	16.3	5.7	22.0
1997	4	13.1	5.7	18.8
1998	2	6.5	5.6	12.1
Totals	42	137.3	87.7	225.0

A.2.4.2.3 Production Forecast--The Lisburne production forecast used in the previous DOE publication (1991) was updated with 1990 and 1991 production data to determine if modifications are necessary. The peak rate is now predicted to last through mid-1994 before production declines. With excess produced gas being reinjected and with new wells being brought on production through 1998, a decline of 12% is assumed. The production schedule for the 15 wells Alapah and Wahoo wells is developed using the drilling schedule in **Section A.2.4.2.2** and these assumptions:

- Year one equals 10% of ultimate recovery
- Peak rate reached at start of second year
- Peak rate equals 15% of ultimate recovery
- Peak rate is sustained for one year.
- At end of second year production declines at 12% per year.

The production schedules for the LPA and the Alapah/Wahoo development are shown **Table A.13.**

A.2.4.2.4 Operating Costs--No published data are available that discuss Lisburne operating costs. In the previous DOE publication (1991) operating costs were based on a BTF cost factor. A water-cut relationship for the LPA was used to determine total fluid produced. The relationship was premised on enhancing recovery by water injection. Although waterflooding has been terminated in the LPA, that empirical method resulted in a reasonable estimate of operating costs and it is used. The operating costs for years late in the project life are tempered to reflect some leveling of the costs. The

Table A.13. LPA production forecast (MBOPD).

Year	Lisburne[a]	Alapah Wahoo	Total
1992	40	0	40
1993	40	0	40
1994	37	0.5	37.5
1995	35	2.2	37.2
1996	31	5.2	36.2
1997	27	8.0	35.0
1998	24	9.2	33.2
1999	21	8.6	29.6
2000	18	7.6	25.6
2001	16	6.7	22.7
2002	14	5.9	19.9
2003	12	5.2	17.2
2004	11	4.6	15.6
2005	9.6	3.8	13.4
2006	8	2.7	10.7
2007	7	1.7	8.7

a. Recovery from 1/1/92 through 2007 is 127.97 MMBO.

cost-per-barrel factor ($1.50/BTF in 1/1/92) in the previous DOE publication (1991) is used.

A.2.4.2.5 Future Producers--The Set B equations in **Section 5.2.5** are used to estimate future active producing wells.

A.2.4.2.6 Lisburne Production Center--The nominal design rates for the LPC are 100 MBPD of oil, 10 MBPD of water, and 600 MMCFPD (AOGCC 1985). A detailed engineering study is ongoing to expand the water handling capacity of the LPC (ADNR 1991g). Based on potential rates and timing, it appears that expansion of the LPC oil handling capacity must be completed before total combined projected production from Lisburne, Point McIntyre, and Niakuk can be processed.

A.2.4.3. Summary. Although discovered in 1968, the Lisburne pool was not developed until 1984, with initial production occurring in December 1986. Production during 1991 averaged about 40 MBOPD. A waterflood program has been shutdown after results were very discouraging. Future

operating plans currently include only primary depletion. Development plans include infill drilling in the current producing area and the delineation and development of two separate small areas of indicated accumulation to the northeast and northwest of the main area. Assuming the two small accumulations will be proven and infill drilling will proceed, future recoverable oil is estimated at about 155 MMBO. Analysis, using the NES Low oil price forecast, shows that all of this oil can be economically recovered resulting in ultimate reserves to the LPA of about 237 MMBO. The estimated future reserves are predicted to be recovered by year-end 2007 and will not be impacted by the earliest indicated TAPS shut-down date.

A.2.5 Recently Developed Fields Summary

Although sizable by Lower 48 standards, Endicott, Milne Point, and Lisburne fields are not major factors on the North Slope in terms of reserves or production rate. Nevertheless, these three fields are more typical of the five NES fields. Their history provides a comparison for evaluation of factors affecting future development.

As discussed in **Section 1.3.1**, long delays ensured between discovery and production of the recently developed fields: Endicott - 9 years; Milne Point - 16 years; Lisburne - 18 years. A similar pattern can be assumed for other relatively small North Slope fields, discovered or undiscovered.

These three fields combine to total 592 MMBO of remaining reserves and begin to decline in 1993 (Endicott), 1994 (Lisburne), and 2008 (Milne Point/Kuparuk and Schrader Bluff). Production limits are reached in 2010, 2007 and 2016, respectively, for the three fields. Except for a minor amount from Schrader Bluff, they have no effect on extending TAPS beyond 2010.

The major lessons to be learned from the fields are the economic and environmental benefits derived from careful engineering design for facilities down-sized for lower reserves and rates than those of the Prudhoe Bay field. As discussed in **Section A.1.3**, another major factor in viability of these fields is the use of, and integration into, the Prudhoe Bay infrastructure.

From an industry perspective, the additional 650 ft breach in the Endicott causeway adds a $56 MM burden to capital investment totalling $106 MM over the remaining productive life of the 240 MMBO reserve. At an ultimate reserve total of 404 MMBO, Endicott ranks third among North Slope

fields. Smaller fields, or large ones with lesser remaining reserves, may be unable to achieve or continue economic recovery under similar circumstances. Cost-benefit analysis, utilizing actual risk estimates, may be an additional factor that could assist decision-making in future regulatory evaluation.

A.3 Fields with Development Potential

This section provides the lease status and history for the Point McIntyre and Niakuk fields. The development of both of these fields has been impacted by the causeway issues discussed in **Section 2** and facility sharing with Lisburne.

A.3.1 Point McIntyre

In February 1989, one of the largest oil field discoveries in the United States during the decade of the 1980's was announced by ARCO, Exxon, and BP. ARCO/Exxon Point McIntyre No. 3 well tested at a rate of almost 2,500 BOPD (OGJ 1989a). The first delineation well was announced in June 1989 as a success, testing at rates up to 5,350 BOPD. With the testing of the second delineation well, ARCO announced flow rates up to 5,400 BOPD and estimated the field could recover approximately 300 MMBO (WSJ 1989; ARCO 1989).

The area of accumulation lies mostly offshore in Prudhoe Bay, centered about 5 mi north of the original discovery well, Prudhoe Bay State No. 1 (see **Figure 1.3**). The Point McIntyre No. 3 well tested oil from two zones. The shallower K-10 or Cretaceous Seabee formation flowed 1,016 BOPD of 28°API gravity oil and 772 MCFPD from 8,840 to 8,890 ft measured depth. The deeper lower Cretaceous Kuparuk River Sand flowed 2,442 BOPD of 28°API gravity oil and 1.917 MMCFPD from the perforated interval 9,230 to 9,240 ft measured depth (see **Figure A.26**). The Kuparuk is the main productive horizon that was evaluated by the two delineation wells drilled by ARCO/Exxon during the spring of 1989 (PIC 1991a).

The Point McIntyre No. 4 tested three intervals in the Kuparuk for rates between 4,750 and 5,408 BOPD with average rates of 5,349 BOPD and 1.22 MMCFPD. True vertical depths ranged from 8,805 to 8,963 ft with the lowest 70 ft of perforations contributing 86% of the production. The Point McIntyre No. 5 well flowed 5,415 BOPD and 3.28 MMCFPD from two perforated zones at 8,929 to 8,989 ft TVD in the Kuparuk. See **Figure A.27** for bottom hole locations of the three wells.

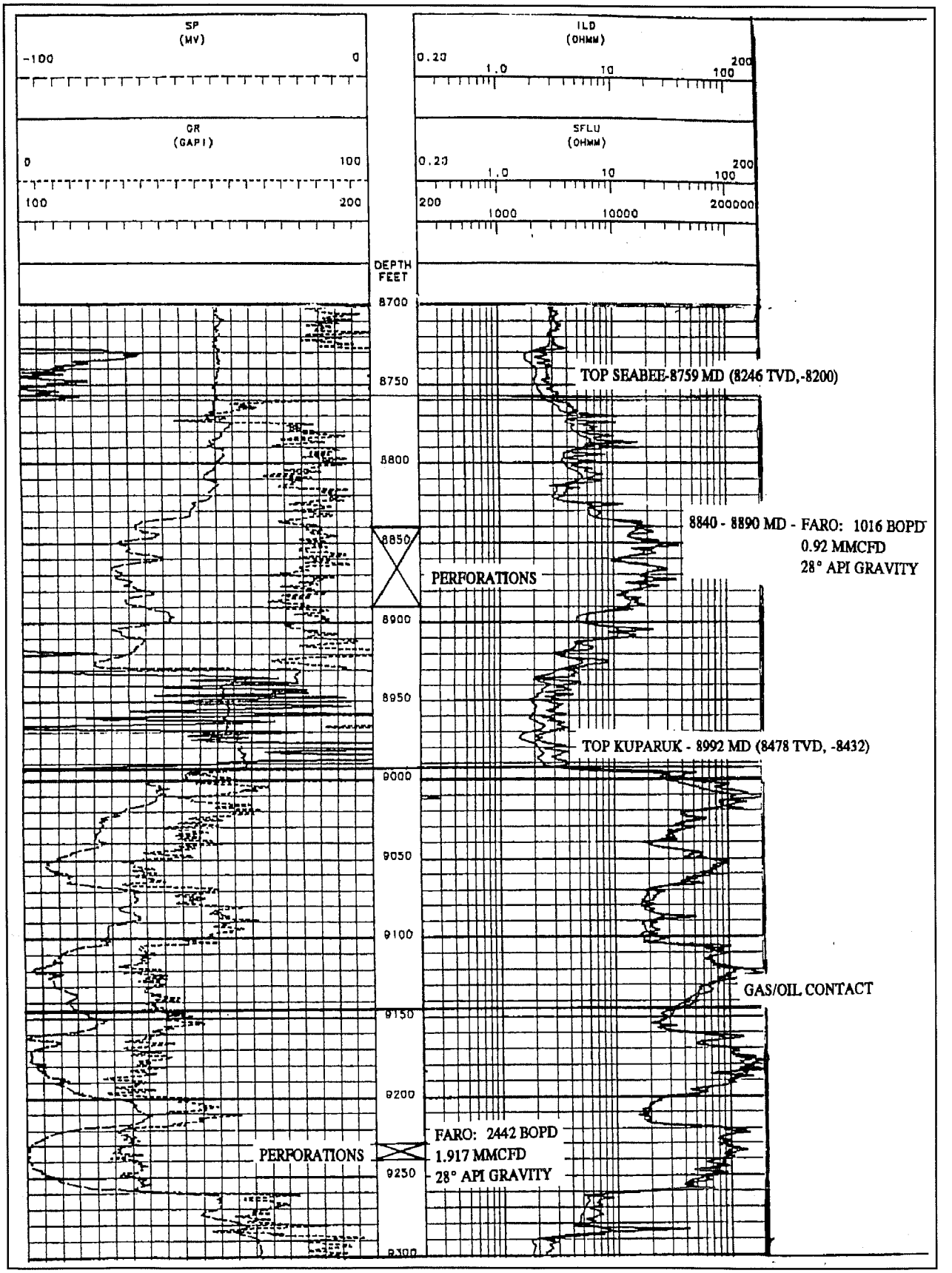

Figure A.26 Point McIntyre State No. 3 - well log (ADNR 1991e)

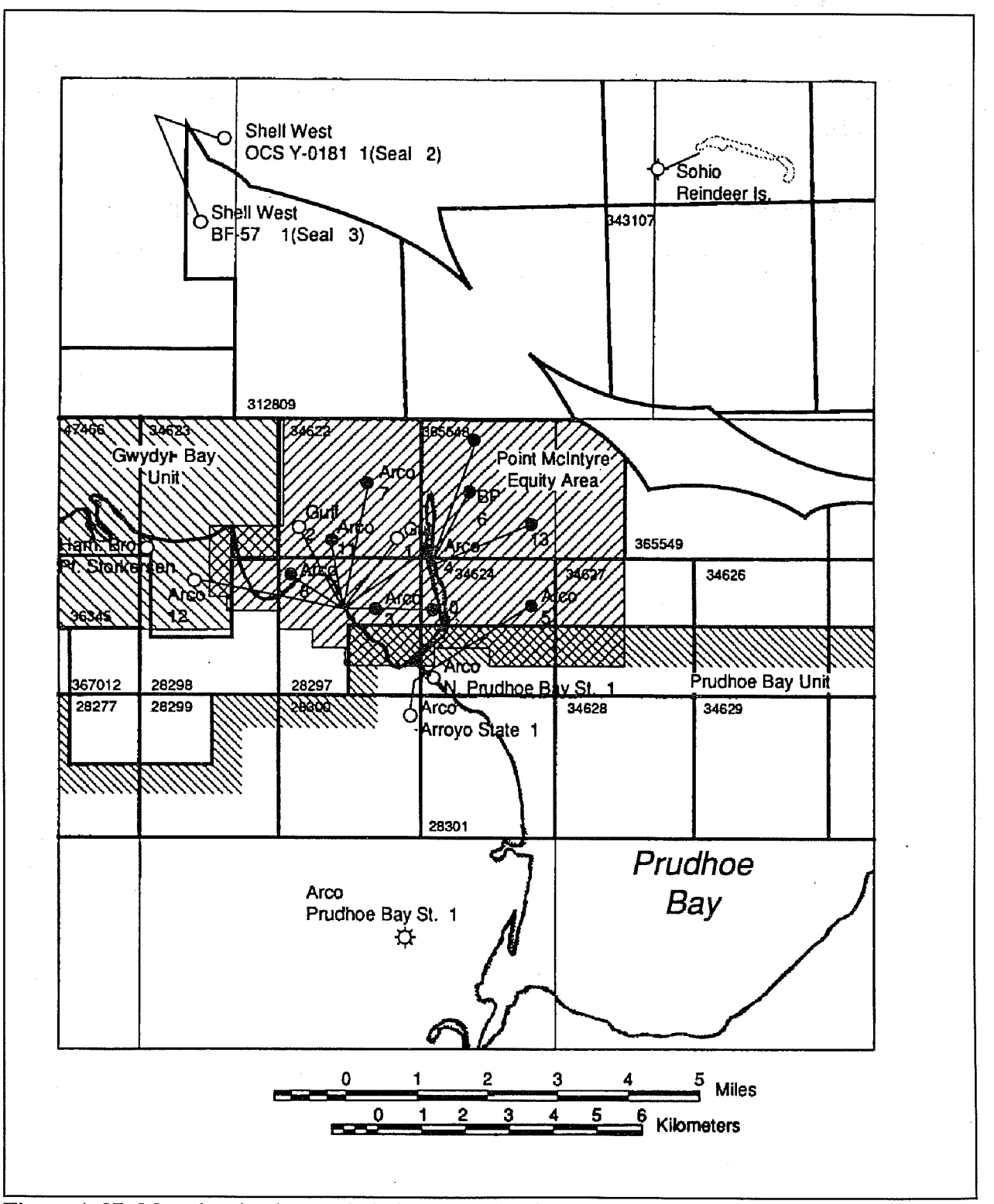

Figure A.27 Map showing bottom hole locations of Point McIntyre Wells (ADNR 1991f).

BP participated in the delineation program, drilling three wells, Point McIntyre Nos. 6, 9, and 13 into the northeastern area of the accumulation (BP 1990). ARCO/Exxon drilled the Nos. 7, 8, 10, and 11 wells to define the offshore area and one well was drilled as a westerly step-out into the onshore Gwydyr Bay Unit. The No. 12 well was cased but not tested (see the discussion of the Gwydyr Bay area in **Appendix B**).

Although working interest owners completed a 3-D seismic survey in 1990 (BP 1990), data revealing the subsurface structure of the field have not been released. Similarly, details of the lithology of the Kuparuk zone have not been released. However, some generalized information has been released indicating an average of 130 ft net pay with average porosity of 21%. The average water saturation is 30% and primary plus waterflood recovery is estimated at 42%. The areal extent of the reservoir is 6,700 acres.[a]

A.3.1.1 Current Status. Negotiations are currently underway to determine equities for the field. The initial outline of the equity area is shown in **Figure A.28**.[a] From this outline and lease record data (ADNR 1991c), an approximate area of 11,320 acres is estimated. Plans are underway to simultaneously contract the Gwydyr Bay Unit and expand the Prudhoe Bay Unit to include the Point McIntyre field in a new participating area. Current negotiations are also underway to combine Niakuk, Point McIntyre, and Lisburne production through the LPC. (See **Section A.3.2**).

A.3.1.2 Input Data. Evaluation input data are developed using published information, personal comunications and empirical relationships.

A.3.1.2.1 Recoverable Oil--Estimated recovery volumes for Point McIntyre vary from a low of 282 MMBO (ADR 1991) to a high of 314 MMBO (ADNR 1991). A number of publications have placed the recoverable oil at 300 MMBO (ARCO 1990; Oil 1989; Anch 1990; WSJ 1990). Using the reservoir parameters in **Section A.3.1**, with recovery factors of 35% and 45%, the estimated recoverable oil volumes are 250 MMBO and 320 MMBO, respectively. A recovery of 300 MMBO is assumed for Point McIntyre.

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a. Arco Alaska, Inc., personal communication, January 29, 1992.

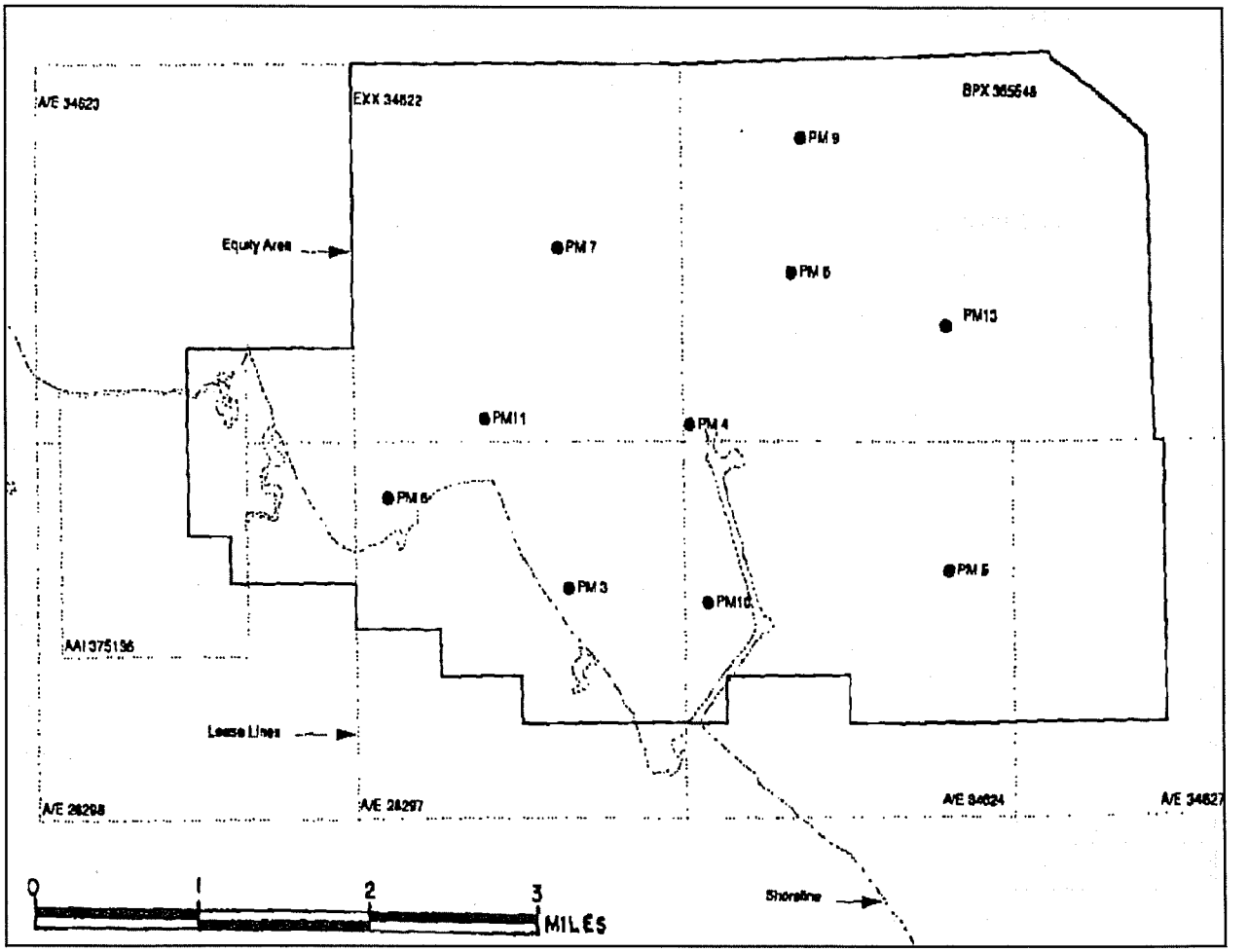

Figure A.28 Point McIntyre equity area, with existing wells (ARCO 1992).

A.3.1.2.2 Investments--In 1990, the estimated investments were about $315 MM (1/1/90$) or $402 MM (1/1/92$), to develop Point McIntyre if Lisburne facilities were shared (ARCO 1990). A cost savings of about $268 MM (1/1/92$) was estimated by facilities sharing. A stand-alone cost is assumed to be the total of these estimates or $670 MM (1/1/92$). Adding the estimated $53 MM (1/1/92$) (WSJ 1990, OGJ 1990b) cost to add a breach to the Westdock causeway, the total stand-alone project cost would be $723 MM (1/1/92$). A more recent estimated development cost of about $752 MM (1/1/92$) is used for this report (PIC 1991). The percentage of investment savings reported in 1990 (ARCO 1990), as a result of facilities sharing, is applied to the total project estimate to arrive at an investment of $490 MM (1/1/92$).

Using 80-acre spacing requires 84 wells to develop the 6,700 acres of Kuparuk formation from three well pads. Enhanced recovery by waterflooding is also assumed with a producer/injector ratio of 1.7:1. Two additional wells are required for water disposal. The cost to drill Point McIntyre wells in

the previous DOE publication (1991) was $2.85 MM (1/1/90 $)/well. No new information has been received that would justify revision. A per well drilling cost of $3.05 MM (1/1/92$) is used for all type wells.

The drilling and investment schedules for Point McIntyre are given in **Table A.14.**

Table A.14. Point McIntyre drilling and investment schedules.

Year	Drilling	Investments-$MM (1/1/92$)		
	No. Wells	Wells[a]	Facilities	Total
1993	20	61.0	137.2	198.2
1994	18	54.9	40.0	94.9
1995	15	45.7	20.0	65.7
1996	12	36.6	14.6	51.2
1997	8	24.4	5.0	29.4
1998	6	18.3	5.0	23.3
1999	4	12.2	5.0	17.2
2000	3	9.2	0	9.2
Total	86	262.3	262.3	489.1

a. The ratio of producers to total service wells is 1.7/1.

A.3.1.2.3 Production Forecast--The Point McIntyre production forecast is based on the following guidelines:

- Initial production could occur in 1993 (ARCO 1991a); however, it is assumed to commence on 1/1/94
- Initial Point McIntyre production plus Lisburne production was estimated at 82 MBOPD with 100 MBOPD as a peak (PIC 1991)
- A production profile for Lisburne/Point McIntyre was presented by ARCO (ARCO 1991a)
- A preliminary Point McIntyre production profile is obtained by subtracting out the previously determined Lisburne forecast from the volumes estimated from those extracted from Figure 17, page 8 of ARCO (1991a).

A peak rate of 60 MBOPD is assumed for Point McIntyre. This assumed peak rate is less than the volume estimated using the factors listed in **Table 3.4**. The peak rate plateau is extended until the cumulative recovery (at the end of peak rate) reaches about 50% of ultimate recovery as determined by

the above referenced table. For this study, Point McIntyre's peak rate is extended to the end of the eighth year of production. Although this results in slightly greater recovery (54%) at the end of peak production than shown in the reference table, it is not a significant difference. To recover the reserve volume set for this project a decline rate of about 12% is required. This is the decline percentage shown in **Table 3.4** for fields with 300 MMBO reserves.

Even though start-up or first production during 1993 has been indicated (ARCO 1991a), to be conservative it is assumed that initial production will occur on 1/1/94. The average daily production forecast for Point McIntyre given in **Table A.15.**

Table A.15. Point McIntyre production forecast.

Year	MBOPD	Year	MBOPD
1994	40.0	2005	36.0
1995	50.0	2006	32.0
1996	60.0	2007	28.0
1997	60.0	2008	25.0
1998	60.0	2009	22.0
1999	60.0	2010	20.0
2000	60.0	2011	18.0
2001	60.0	2012	16.0
2002	53.0	2013	14.0
2003	47.0	2014	13.0
2004	41.0		

A.3.1.2.4 Operating Costs--Operating costs are based on a BTF cost factor and a water-cut relationship to determine total fluid produced. The smoothed MPU model results (**Figure A.15**) are used for the water-cut relationship for Point McIntyre. The cost per barrel factor used in the previous DOE publication (1991) was about $1.40/BTF (1990$). No published data have been found which would cause a revision of those costs. Because the project is not fully developed at first production, the production is increased to the peak rate after the first 2 years. The cost-per-barrel factor is adjusted the first year to result in a minimum yearly operating cost of about $20 million. This is assumed to be reasonable considering the size and location of the project. The adjusted factor for 1994 is $1.53/BTF (1/1/92$). For the remainder of the years, an operating cost factor of $1.50/BTF (1/1/92$) is used.

Because Point McIntyre will be paying a facilities sharing charge to LPA, which includes operations and maintenance costs, the cost-per-barrel factor is reduced. No information is available on the operating cost savings, a 20% reduction in the cost-per-barrel factor is assumed. The adjusted operating cost factor (1/1/92$) is $1.22/BTF for 1994 and $1.20/BTF, thereafter.

A.3.1.2.5 Future Producers--The Set B equations in **Section 3.2.5** is used to estimate future annual producers.

A.3.1.2.6 Point McIntyre Facilities Sharing Fee--As discussed **Section A.3.1.2.2**, joint use of facilities is expected to save about $262 MM (1/1/92 $). It is assumed that this includes the cost of a field pipeline from the processing center to PS No. 1. Calculation of a facilities sharing fee is made using the facilities sharing formula in **Section 3.2.8**. For this calculation, total fluid production of 900 MMBBLS is used. The facility sharing cost to Point McIntyre is shown as income to the Lisburne PA. The estimated facilities sharing fee is $0.98/BTF (1/1/92$).

A.3.1.3 Summary. The Point McIntyre field was discovered in 1989 followed by 10 delineation wells being drilled into 1990. Initial development will not occur until in-progress unitization matters are resolved. Conservatively, the Point McIntyre field is expected to be placed on production in early 1994. The development of the field is made more attractive by the plan to utilize excess LPA processing capacity. An estimated $260 MM (1/1/92$) investment is saved by facilities sharing. Using generalized reservoir data, recoverable oil is estimated at 300 MMBO. All reserves are economically recoverable through the year 2014, using the EIA Mid-level oil price. The NES Low oil price case results in the loss of the last year of production. With TAPS shut-down expected between 2008 and 2014, lost reserves vary from about 38 MMBO to zero, respectively.

A.3.2 Niakuk

In early 1985, BP drilled the Niakuk No. 5 discovery well for this new field from the Niakuk No. 4 gravel island in state offshore waters (**Figure 1.3**). The well flowed at an average rate of 4,521 BOPD of 25.3°API gravity oil through perforations from 10,016 to 10,038 ft measured depth. Production was from the Kuparuk River formation sand and was first announced by the company in 1987 (PIC 1991b). In 1986, BP drilled the Niakuk No. 6 confirmation well from the island. The Kuparuk

sand in this well produced at an average rate of 4,737 BOPD of 26°API gravity oil and 3.12 MMCFPD at a subsea depth of approximately 9,500 ft (PIC 1991b) (see **Figure A.29**).

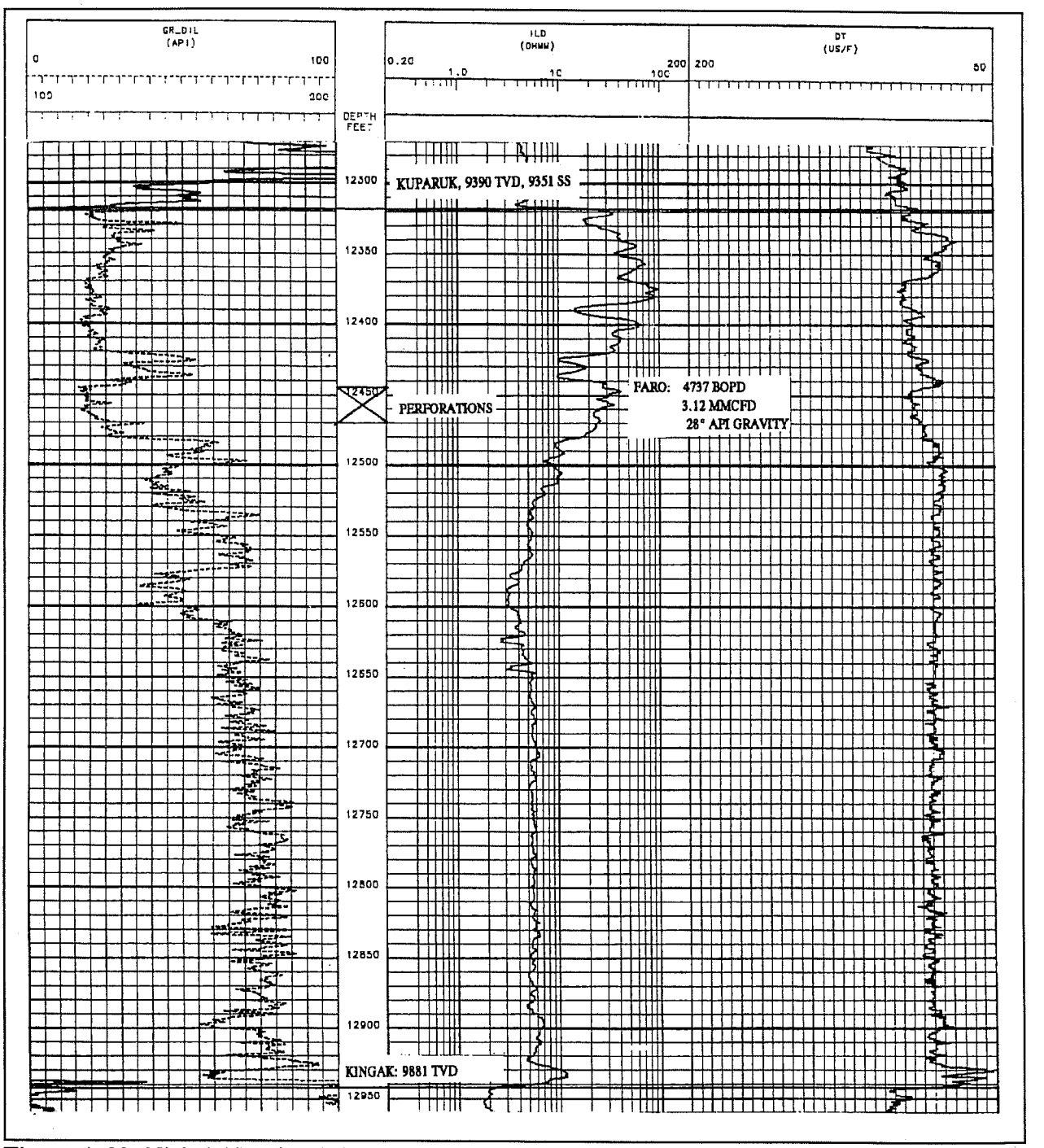

Figure A.29 Niakuk No. 6 well log (ADNR 1991j).

The field is located adjacent to production in the Prudhoe Bay field to the west and southwest and adjacent to production from the Endicott field to the east. Niakuk lies off the mouth of the Sagavanirktok River delta in water depths averaging about 4.5 ft (see **Figure A.30**).

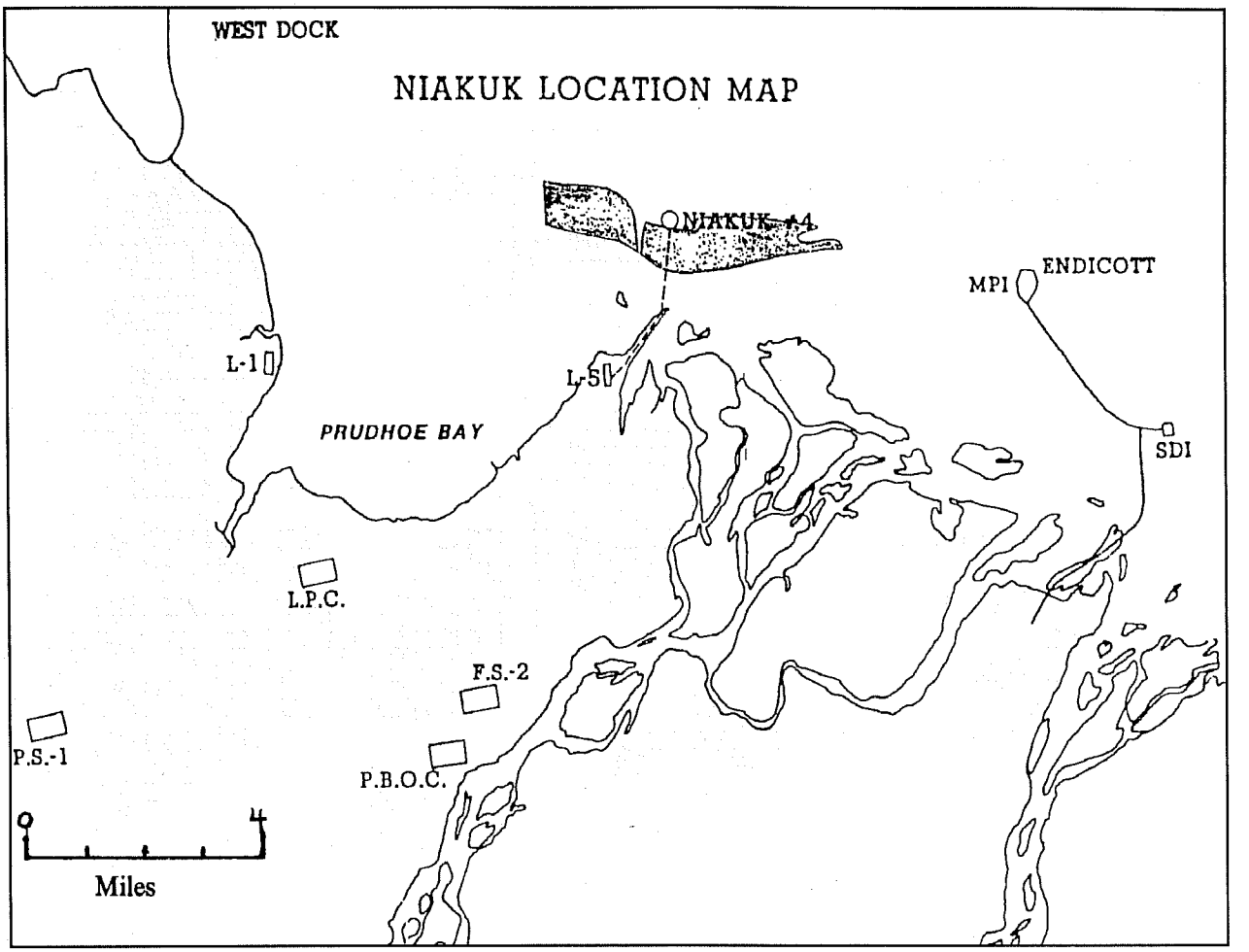

Figure A.30 Niakuk Location Map (SAPC 1988).

In 1977, an earlier test in the area, the Niakuk No. 2-A, flowed 674 BOPD of 42.7°API gravity oil from the Triassic/Jurassic Sag River formation sandstone at a drilled depth below 12,200 ft (OGJ 1981). The Niakuk No. 5 also tested the Sag River at low oil rates (42 BOPD) at drilled depths below 10,600 ft (PIC 1991b).

In 1988, BP began permitting efforts to expand the Niakuk No. 4 gravel island and to build a gravel causeway to Heald Point to develop the field. Reserves were estimated at 58 MMBO and 30 BCF. Plans were to begin drilling in early 1991 with a total of 14 producers and injectors (OGJ 1988). A 300

ft breach in the 6,600 ft causeway was incorporated in the design. Production was expected to begin in late 1991 and reach 20 MBOPD and 12 MMCFPD (STD 1988; OGJ 1988).

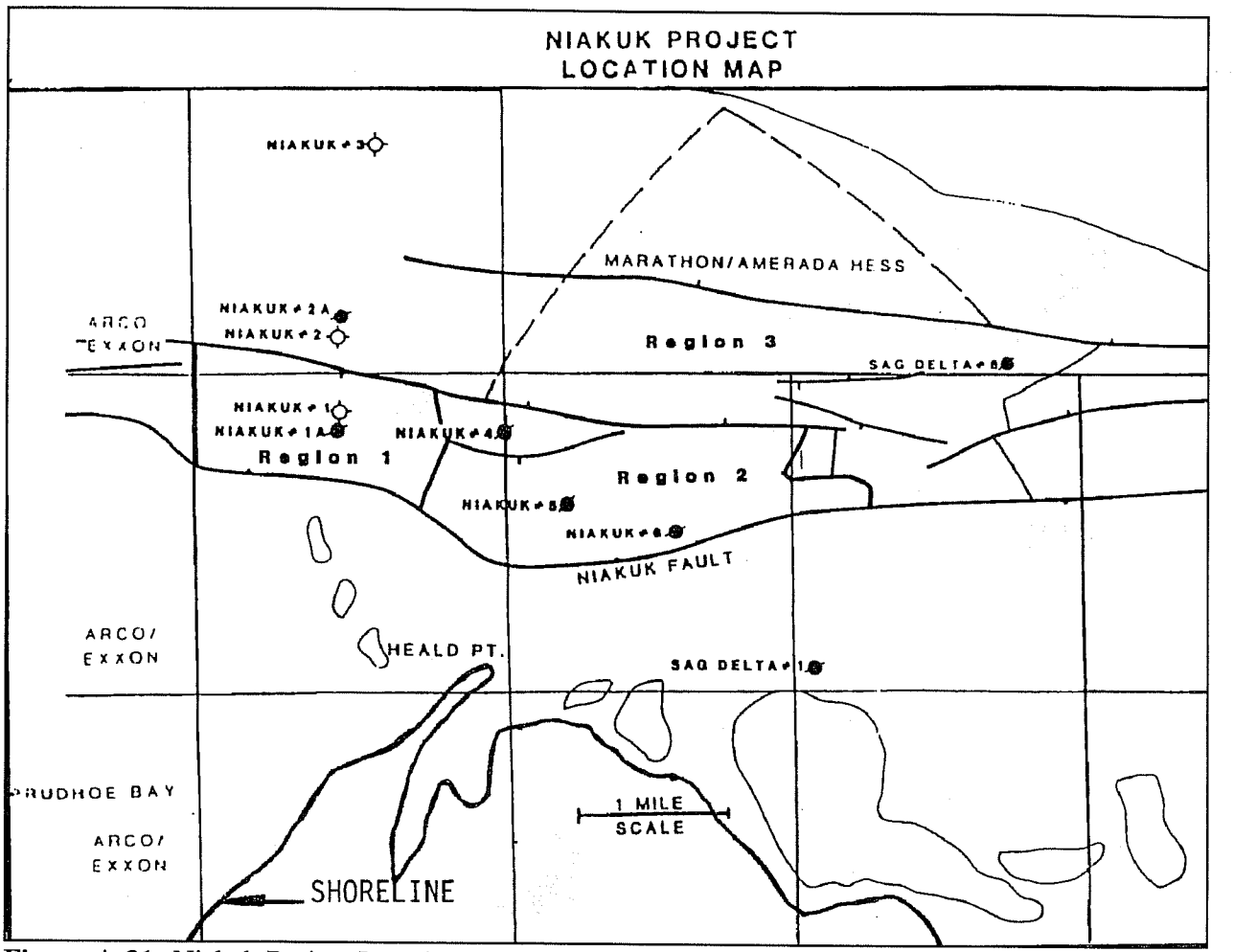

Figure A.31 Niakuk Project Location Map-Development Regions (SAPC 1988).

In July 1991, BP announced that it would forego continuing the controversial permitting process that had developed in regard to all causeways in the region. The company stated a study would be undertaken to develop the field by directional drilling from a pad on Heald Point to reach the various areas in the accumulation (**Figures A.31** and **A.32**).

A 3-D seismic survey was conducted in 1985 (OGJ 1988) but, other than the maps shown in **Figure A.31** and **A.32**, no structural or reservoir area maps are available. The reservoir area has been characterized as approximately 5,000 acres (STD 1988).

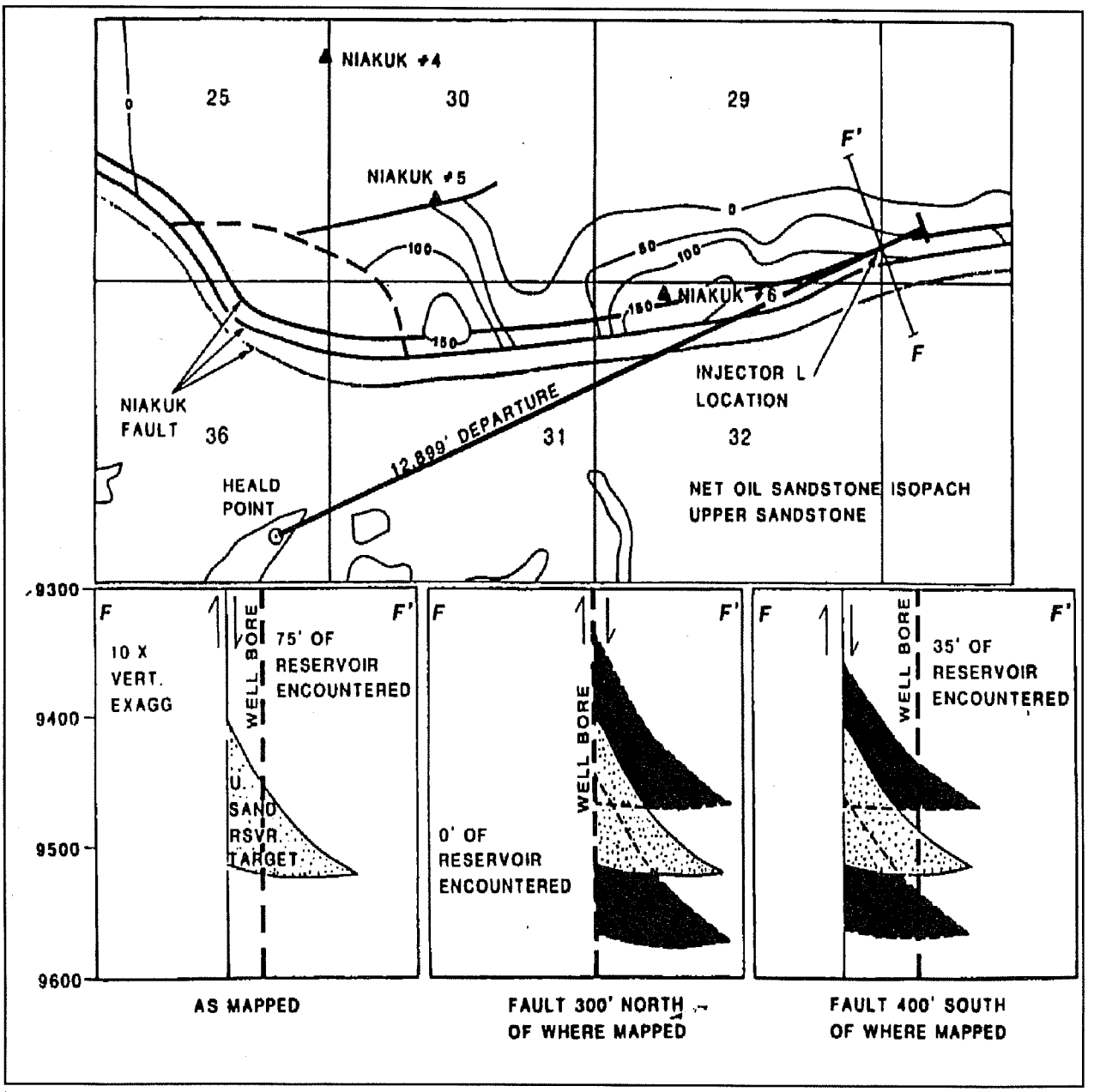

Figure A.32 Niakuk Isopach Map of Kuparuk River Formation (SAPC 1988).

Leases in the area were acquired in State Sale No. 18 in 1967 and carry a 12.5% royalty. One lease which may or may not be in the primary area of Kuparuk development, ADL 312827, carries a 20% RI and a 74.83% NPI share (**Figure A.33**). The Sag Delta No. 8 well on this lease has been certified by the state as capable of producing in paying quantities. Also, ADL 34635 carries a 5% royalty discovery bonus through March 31, 1995 (ADNR 1991k).

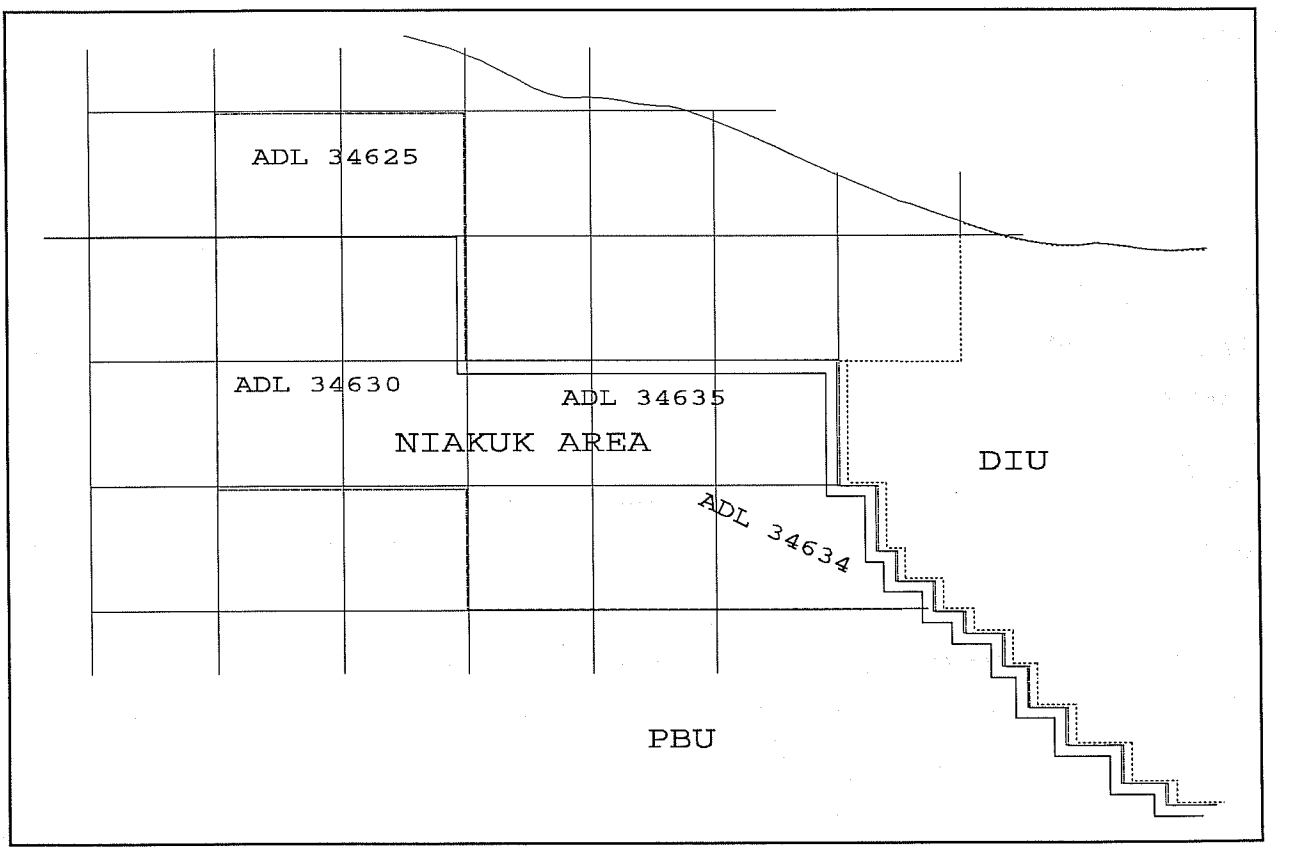

Figure A.33 Niakuk Area Lease Map (AMS 1991).

A.3.2.1 Development Plan. In addition to the main Kuparuk development, two smaller accumulations are under study. The first is the Kuparuk formation area further offshore, which may be delayed while drilling technology is established for deviated wells to reach 13,000 ft and beyond. The second is a small accumulation in the Alapah formation of the Lisburne Group that could also be developed as part of the Niakuk development (Lisburne discussion, **Section A.2.3**). This might be carried out as a joint development by Niakuk and the LPA.

Indications in earlier published materials are that the same number of wells will be drilled in the onshore development (AK 1988). Plans now include joint use of the LPC.

A.3.2.2. Input Data. The evaluation input data are developed using past history, current development plans, and published information on production rates and reserves.

A.3.2.2.1 Recoverable Oil--The original estimates of proven Kuparuk recoverable reserves (OGJ 1987a; STD 1988; PIC 1991b; PIC 1991c; OGJ 1988) ranged from 51 to 58 MMBO. Development from a pad on Heald Point will recover less reserves than the offshore option. The proven reserves are located in Region 1 and Region 2 shown on **Figure A.31.** In addition, the operator has identified potential reserves in Region 3 of about 34 MMBO. Because a reach of greater than about 11,000 ft has not yet been proven on the North Slope (STD 1988), only 80% of the 58 MMBO proven reserves can be developed from Heald Point (STD 1988; PIC 1991c). As the potential reserves are located further offshore, it is estimated that only 50% can be developed with current technology. These lower recoverable reserve estimates of 46.4 MMBO (proven) and 17 MMBO (potential) are used. The estimated recoverable reserves (proven plus potential) from an onshore development scenario are about 29 MMBO less than are estimated for an offshore island development scenario.

It is assumed that the Niakuk acreage will support four Alapah wells. Using a recovery of 1.75 MMBO/well, recoverable reserves are estimated at 7.0 MMBO.

A.3.2.3 Investments. Estimated investments for development of Niakuk using an island and causeway to shore are well documented (ACE 1990; STD 1988; STD 1988a; AK 1988; OGJ 1990). Details of the development from Heald Point are lacking. The 1991 estimated total development costs were about $250 MM (1991$) for a stand-alone project with no facilities sharing with LPA (STD 1988; ADN 1991; STD 1988a).

The estimated investment for the onshore case is $250 MM (mid-1991$) and is shown in **Table A.16.**

The following assumptions are made to adjust investment costs to reflect facilities sharing with the LPA:

- 40% of plant investment is required for well testing, compression for gas reinjection, and for water injection capacity.
- 75% of civil investment required for installation of drilling pads, pipelines, and roads.
- The drilling investment includes only development wells for proven Kuparuk reserves.

Table A.16. Niakuk project investments for onshore development without facilities sharing.

Investment Type	Onshore development investment categories (stand alone)	
	$MM (Mid-1991$)	$MM (1/1/92$)
Miscellaneous	10.5	10.7
Pipelines	27.7[a]	28.2
Drilling	84.3[b]	85.8
Plant Facilities	104.5	106.3
Facilities Sharing	6.4[c]	6.5
Civil	16.6[d]	16.9
Totals	250.0	254.4

a. Pipelines are revised; however, no data available. Assume no cost change.
b. Assume this cost includes abandonment of three wells on island.
c. Assume this is for buying into the LPA oil sales line.
d. An adjustment is made in civil cost to keep the total project cost at $250 MM.

These estimated investments are shown in **Table A.17.**

Table A.17. Niakuk project investments for onshore development with facilities sharing.

Investment Type	No facilities sharing $MM (1/1/92$)	Facilities sharing $MM (1/1/92$)[a]
Miscellaneous	10.7	10.7
Pipelines	28.2	28.2
Drilling	85.8[b]	85.8[b]
Plant Facilities	106.3	42.5
Facilities Sharing	6.5	6.5
Civil	16.9	12.7
Totals	254.4	186.4

a. Breakdown of investment is assumed.
b. Includes wells for development of proven reserves only.

Initial startup was planned for 1993 (ACE 1990). Due to delays encountered, a startup of 1/1/94 is used. First investments are assumed in 1992 for facility design and fabrication, with delivery in the summer of 1993 and initial drilling in mid-1993. All wells developing the Kuparuk proven reserves are completed by the end of 1994. This results in peak production in 1995 that continues through 1997.

Drilling of the wells to develop the minor accumulations will be accomplished after 1995 and increase the investments by $67.5 MM (1/1/92$) for a total of $253.9 MM (1/1/92$).

Based on the previous assumptions the investment and drilling schedules are shown in **Table A.18.**

Table A.18. Niakuk drilling and investment schedules.

Year	Wells		Investment - $MM (1/1/92$)			
	No.[a]	No. (Alapah)	Wells	Facilities	Pipelines	Annual total cost
1992	0	0	0	5.0	4.0	9.0
1993	4	0	24.5	58.0	33.6	116.1
1994	10	0	61.3	0	0	61.3
1995	0	3	18.4	0	0	18.4
1996	3[b]	1	24.5	0	0	24.5
1997	2[b]	0	12.3	0	0	12.3
1998	2[b]	0	12.3	0	0	12.3
Totals	21	4	153.3	63.0	37.6	253.9

a. Proven and potential Kuparuk wells.
b. Seven potential Kuparuk wells.

A.3.2.4 Production Forecasts A production forecast was included in updated cost information provided to the Corps of Engineers in March 1990 (ACE 1990). This supplemented the information contained in the 1988 project Environmental Assessment and Project Description (EAPD) (STD 1988). It is assumed that the onshore Niakuk development schedule results in a production forecast that reflects the referenced forecast. The production rate forecast for the Alapah is patterned after the forecast developed for the Lisburne Alapah (**Section A.2.4.2.3**). The rate forecast for potential Kuparuk reserves is developed using the following factors:

Year	Factor (% of ultimate recovery)
1	3.0
2	12.0
3	12.0
4	12.0
5 and later	Decline peak rate at 12%/year.

The individual production forecasts and the total project production forecast developed are listed in **Table A.19.**

Table A.19. Niakuk production forecast (MBOPD).

Year	Kuparuk	Alapah	Kuparuk Potential	Project Total
1994	5.1	0	0	5.1
1995	15.2	1.4	0	16.6
1996	15.2	2.6	2.4	20.2
1997	15.2	2.6	6.0	23.8
1998	13.4	2.3	6.0	21.7
1999	11.8	2.0	6.0	19.8
2000	10.4	1.8	5.3	17.5
2001	9.1	1.6	4.6	15.3
2002	8.0	1.4	4.1	13.5
2003	7.0	1.2	3.6	11.8
2004	6.2	1.1	3.2	10.5
2005	5.5	0.9	2.8	9.2
2006	5.0	0.3	2.6	7.9

A.3.2.5 Operating Costs. In the previous DOE publication (1991), operating costs were based on a BTF cost factor of $1.19/BTF (1/1/90$). No data are available to revise that value. Therefore, $1.27/BTF (1/1/92$) is used in determining the basic operating cost. The Milne Point water cut relationship is used to determine total fluid produced (**Figure A.15**).

As shown in the EAPD (STD 1988), operating costs will be greater for the more highly deviated wells from shore because the well workover costs are substantially higher. The range of these increased costs is from $5 to $26 MM (1/1/88$) or from $5.7 to $29.3 MM (1/1/92$). The average, $17.5 MM (1/1/92$), is used to develop a $0.06/BTF factor using an estimated project total fluid (oil and water) volume of 300 MMB resulting in a cost factor of $1.33/BTF(1/1/92$). This cost factor would be applicable if Niakuk were installing all development facilities. However, Niakuk will pay a facilities sharing charge to the LPA, which includes operations and maintenance costs. Therefore, the cost-per-barrel factor is reduced. An estimated 20% reduction in the cost-per-barrel factor is used, resulting in an adjusted operating cost factor of $1.06/BTF (1/1/92$).

A.3.2.6 Future Producers. Curve B in Table 3-9 in the previous DOE publication (1991) is used.

A.3.2.7 Facilities Sharing Fee. Based on the facilities investment study in **Section A.3.2.3.**, the use of the LPC will reduce Niakuk investments by an estimated $68.5 MM (1/1/92$). A facilities sharing fee is calculated by the facilities sharing formula in **Section 3.2.8**. For this calculation, total fluid production of about 300 MMB is used. The estimated facilities sharing fee is $0.76/BTF (1/1/92$). The facilities sharing cost to Niakuk is an operating cost to Niakuk and revenue to the LPA.

A.3.2.8 Field Pipeline Tariff. The estimated capital investment in **Section A.3.2.3** includes a $6.5 MM facilities sharing cost. It is assumed that this is for a buy-in share of the sales line from LPC to PS No. 1. There is no field pipeline tariff charge.

A.3.2.9. Summary. The Niakuk Kuparuk field was discovered in 1985, followed by two confirmation wells. The initial plan provided for development from an enlarged offshore island connected to shore by a causeway. Plans to develop from the offshore island were abandoned in 1991 and a study of development from shore was undertaken. Onshore development includes facilities sharing with the LPA and reduces the investment required by about $70 MM (1/1/92$). A loss of 29 MMBO of recoverable oil (proven plus potential) is expected from onshore development because the reservoir that can be reached from shore is limited by current directional well drilling technology. The estimated recoverable oil volume (proven plus potential) is about 70 MMBO. Analysis, using the NES Low oil price forecast, shows the entire volume can be economically recovered through the year 2006 and will not be impacted by the earliest assumed TAPS shut-down date.

A.3.3 Summary Fields with Development Potential

Contrary to the normal long delays between discovery and production, Point McIntyre field should set a record of only 6 years from the 1988 discovery to the 1994 beginning of production. Located adjacent to Prudhoe Bay and Lisburne fields, Point McIntyre benefits from proximity to existing infrastructure to a remarkable degree. In addition, it benefits (as does Niakuk) from the pending agreement to share in the LPA production facilities. Investment savings to Point McIntyre total about $262 MM, indicating the substantial positive impact facilities sharing can have on prospects on the North Slope. Facilities sharing also has a positive environmental impact through "footprint" reduction.

Reserves are estimated at 300 MMBO for Point McIntyre and 70.4 MMBO (53.4 MMBO proven) for Niakuk. Production will begin in 1994 from both fields. Point McIntyre will begin to decline in 2002 and could produce through 2014. Niakuk begins to decline in 1998 and maintains production through 2006. Thus, the later production from these fields helps to offset the earlier declines of production from the bigger fields. Nevertheless, the impact is insufficient to alter the overall North Slope production decline to an extent that would prolong the life of TAPS. Many more Point McIntyre size fields or one or more super-giant field discoveries are necessary to significantly prolong the life of TAPS.

A.4 Summary

With the EIA Mid-level oil price case, all the oil forecast for these seven fields is economically recoverable. One year of forecast production from Schrader Bluff and Point McIntyre would be cut off using the NES Low oil price case. The future lives of the five producing fields and the two fields with development potential range from about 16 years in the LPA to about 33 years for Prudhoe Bay. The composite production curve, at the EIA Mid-level oil price, is shown on **Figure A.34**.

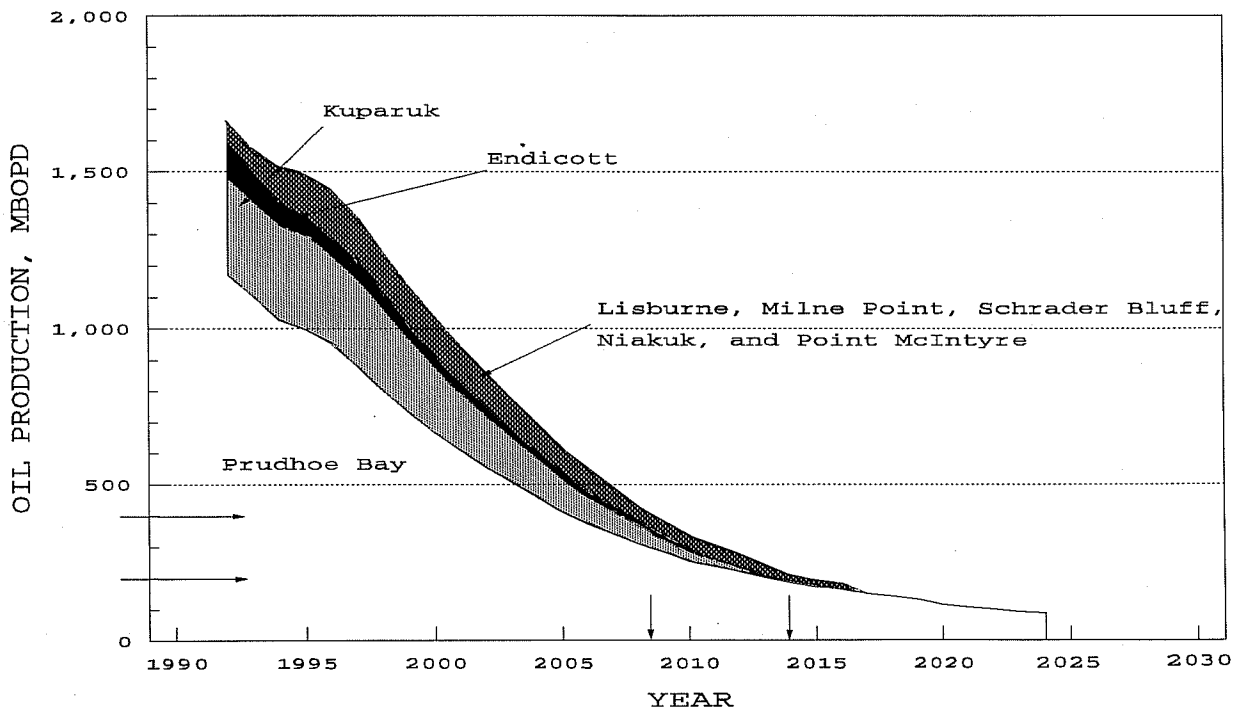

Figure A.34. Composite North Slope production including Point McIntyre and Niakuk.

In the 2008 to 2014 time frame five fields included in the above forecast are still recovering economical oil volumes, Prudhoe Bay (Permo-Triassic), Kuparuk River Unit, Endicott, Point McIntyre, and Schrader Bluff. Under the TAPS shutdown assumptions discussed in **Section 1.1**, the economically recoverable reserves "left in the ground" in existing fields would range from 1 to 0.5 BBO over the above time period. This points out the need to develop known fields and discover and develop new fields on the North Slope of Alaska if the pipeline is to remain operational for a longer period of time.

As evident in the discussion of these fields, all are dependent upon the Prudhoe Bay infrastructure, which includes TAPS. Also, the two fields soon to be developed depend to a large extent on facilities sharing in the LPC to be economically viable. Because of the causeway issue, Niakuk is being developed from shore resulting in the loss of 29 MMB of potential oil reserves. The five NES fields, or future discoveries, may not meet economic criteria for development if such fortuitous timing and proximity factors do not exist for them. As illustrated by the Niakuk analysis, regulatory decisions can result in increased investments, timing delays, and increased operating costs and could result in more marginally economic fields not being developed.

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APPENDIX B: HISTORICAL REVIEW

In this section, field histories and issues related to the potential development of the five NES fields are discussed.

B.1 West Sak Field History

Heavy oil was first encountered in shallow Upper Cretaceous and Tertiary sands in the Kuparuk River area of the North Slope in Chevron's Kavearak Point well in 1969. Following the discovery of Prudhoe Bay in 1968, a number of wells were drilled in the general Kuparuk River area with the Ivishak member of the Sadlerochit group as the primary target. The West Sak sands were first tested in 1971 in the ARCO West Sak No. 1 well about 24 mi west of the Prudhoe Bay State No. 1 discovery well. Type log shown in **Figure B.1.** Drill stem tests of the zone recovered oil at rates ranging from 112 to 192 BOPD. Gravities ranged from 17 to 23° API (Jamison 1980).

Between 1969 and 1978, a total of 23 wells drilled in the area penetrated West Sak sands, but only five acquired core or test data (Werner 1986). In the period from 1979 to 1981, delineation and development drilling in the Kuparuk River field helped to establish the wide extent of the low gravity oil sands of Upper Cretaceous and Tertiary age, the West Sak and Ugnu sands. During 1981 and 1982, ARCO Alaska, Inc. demonstrated that individual accumulations extended over an area of 200 square miles and estimated the total in-place volumes for both zones at 18 to 40 BBO (Werner 1986).

West Sak sands underlie three producing units, the Prudhoe Bay Unit (PBU) established in 1977, the Milne Point Unit (MPU) established in 1979, and the Kuparuk River Unit (KRU) established in 1981. Because these units were formed to develop deeper horizons, specific plans to test or develop the shallower West Sak sands must be designed to operate within the framework established in each separate unit agreement by the state of Alaska and the unit working interest owners. West Sak sands containing oil occur mostly in the MPU and KRU. Pilot tests and development activity have therefore occurred in these two units (Werner 1986). (See **Figure 1.3**.)

A comprehensive program to acquire data in the shallow, heavy oil sands began in the KRU in 1982 as a part of the normal development drilling program in the deeper Kuparuk formation. In 1983, ARCO, the unit operator, applied to the state of Alaska to conduct a pilot project for a hot waterflood.

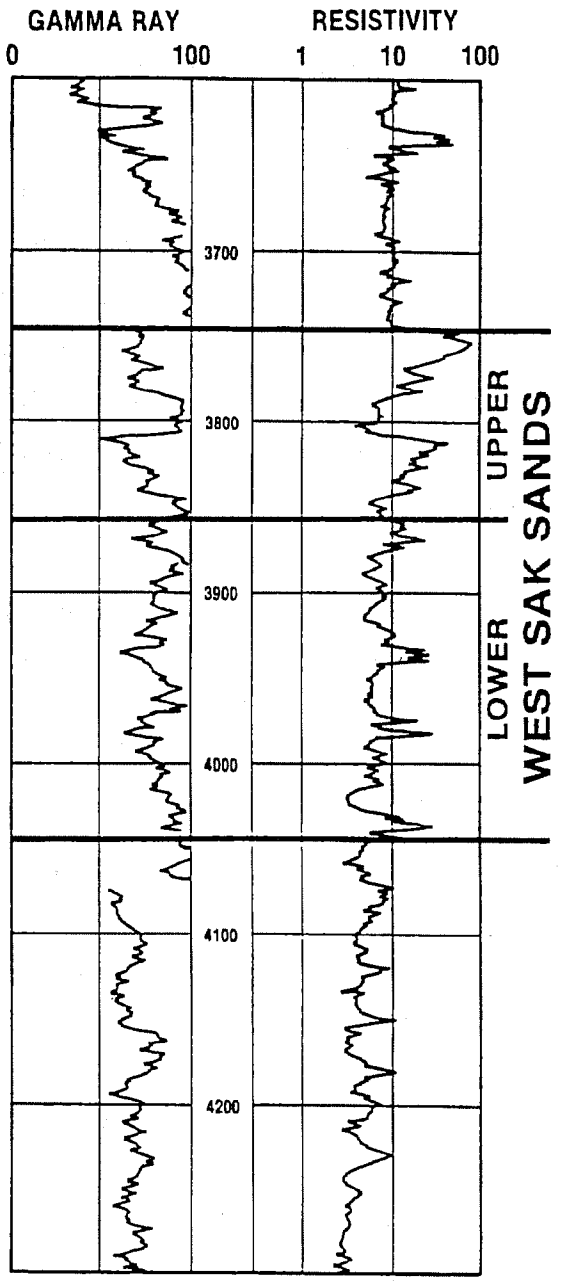

Figure 3. Type log of the West Sak sands. The first successful test of the West Sak was conducted in this well in 1971. The well produced 17-22° API oil from intervals between 3,745 and 4,000 feet (1,141 and 1,219 m) at rates of 90 to 100 barrels per day.

Figure B.1 Type log for West Sak sands, West Sak River St. #1 (Werner 1986).

The pilot commenced in 1984 and was completed in 1986.

In July 1990, the state of Alaska approved pool rules for production from the Schrader Bluff oil pool in the MPU operated by Conoco. The Schrader Bluff productive zones are the "N" and "O" intervals which correlate, respectively, with the lower Ugnu and West Sak sands of the KRU as shown on **Figure B.2**. Conoco began producing Schrader Bluff on March 21, 1991 (ADNR 1991a). Conoco stated a production goal of 6,000 to 8,000 BOPD by the end of 1991, which would bring total Milne Point production to facility capacity of 32,000 BOPD (Anch 1990; ADN 1991). Schrader Bluff production averaged 3,447 BOPD during December 1991 (AOGCC 1991a).

B.1.1 Data Summary

The West Sak sands were named for their occurrence in the ARCO West Sak No. 1 well in the interval 3,745 to 4,000 ft as shown in **Figure B.1** (Werner 1986). Some discrepancies in published correlations are apparent, but generally the West Sak sands are equivalent to the lower portion of the Schrader Bluff formation as shown on **Figure B.2** (AOGCC 1990a, Werner 1986). The "O" sands of the Schrader Bluff are equivalent to the West Sak sands in the KRU but the "N" sands of the Schrader Bluff are more properly equivalent to the lower Ugnu sands.

In the KRU, the West Sak stratigraphic interval averages 300 ft in thickness, thinning from 450 ft in the southwest to 200 ft in the northeast. An upper and lower member are recognized in the unit area. The lower member consists of interbedded thin sands, siltstone, and mudstone with individual sand beds ranging from 0.2 to 5 ft in thickness and laterally continuous for 3 to 5 mi. The upper member contains two sands ranging from 25 to 40 ft in gross thickness with individual beds 0.5 to 10 ft thick. The sands exhibit a transition from inner shelf to shallow marine or delta front depositional environments from the lower through the upper members as shown in **Figure B.3** (Werner 1986). Core data in the KRU area indicate a 25 to 35% range in porosity and a 10 to 800 md range in permeability (Werner 1986). Data from the "O" sand in the MPU show a permeability range of 21.2 to 143 md (AOGCC 1990a). ARCO recently stated average well permeability ranges of 50 to 200 md in the KRU area.[a]

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a. ARCO Alaska, Inc., West Sak presentation to EG&G Idaho, Inc., October 22, 1991.

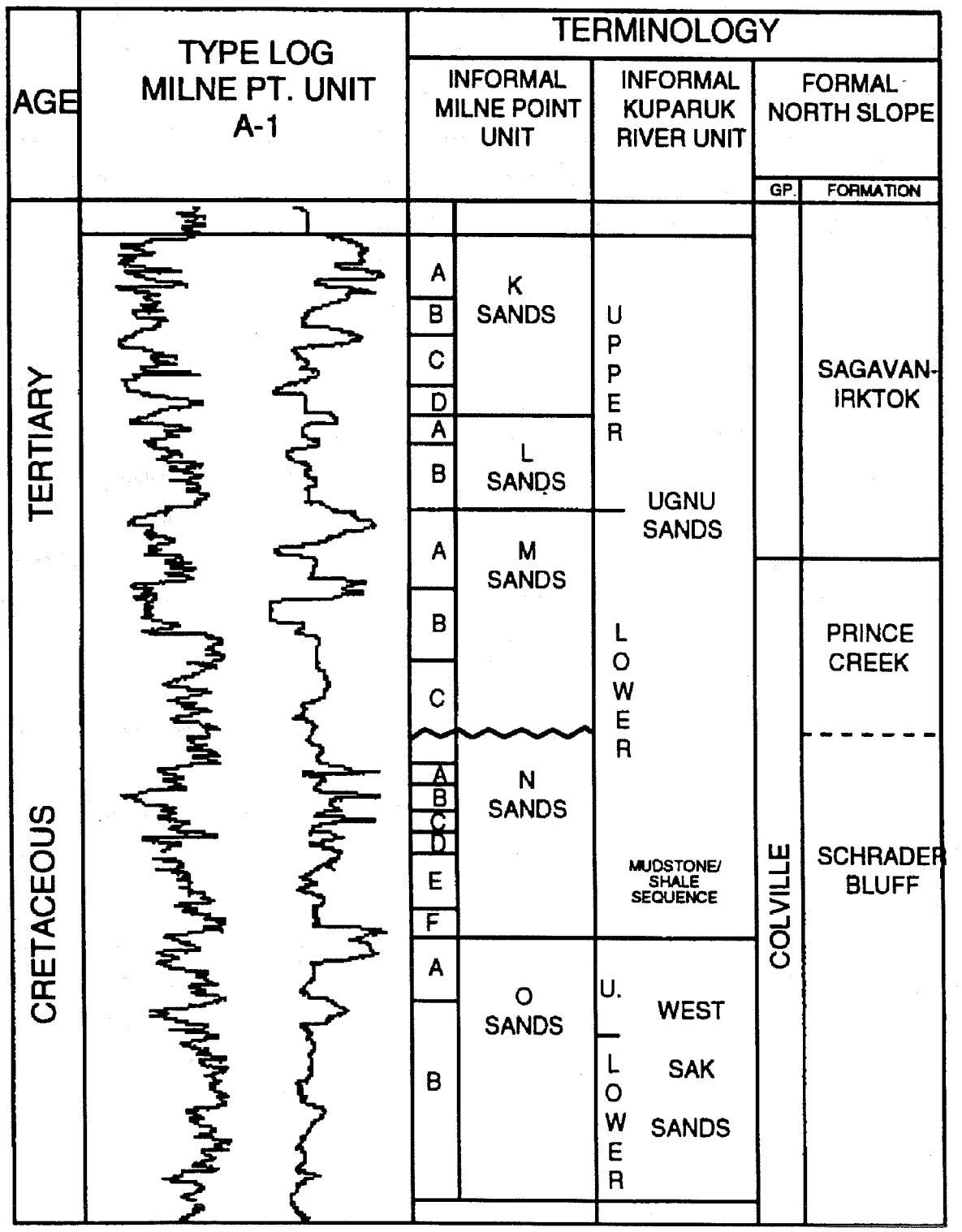

Figure B.2 Type log for Milne Pt. Unit A-1 and generalized stratigraphic column for the Kuparuk River area of the North Slope (AOGCC 1990a).

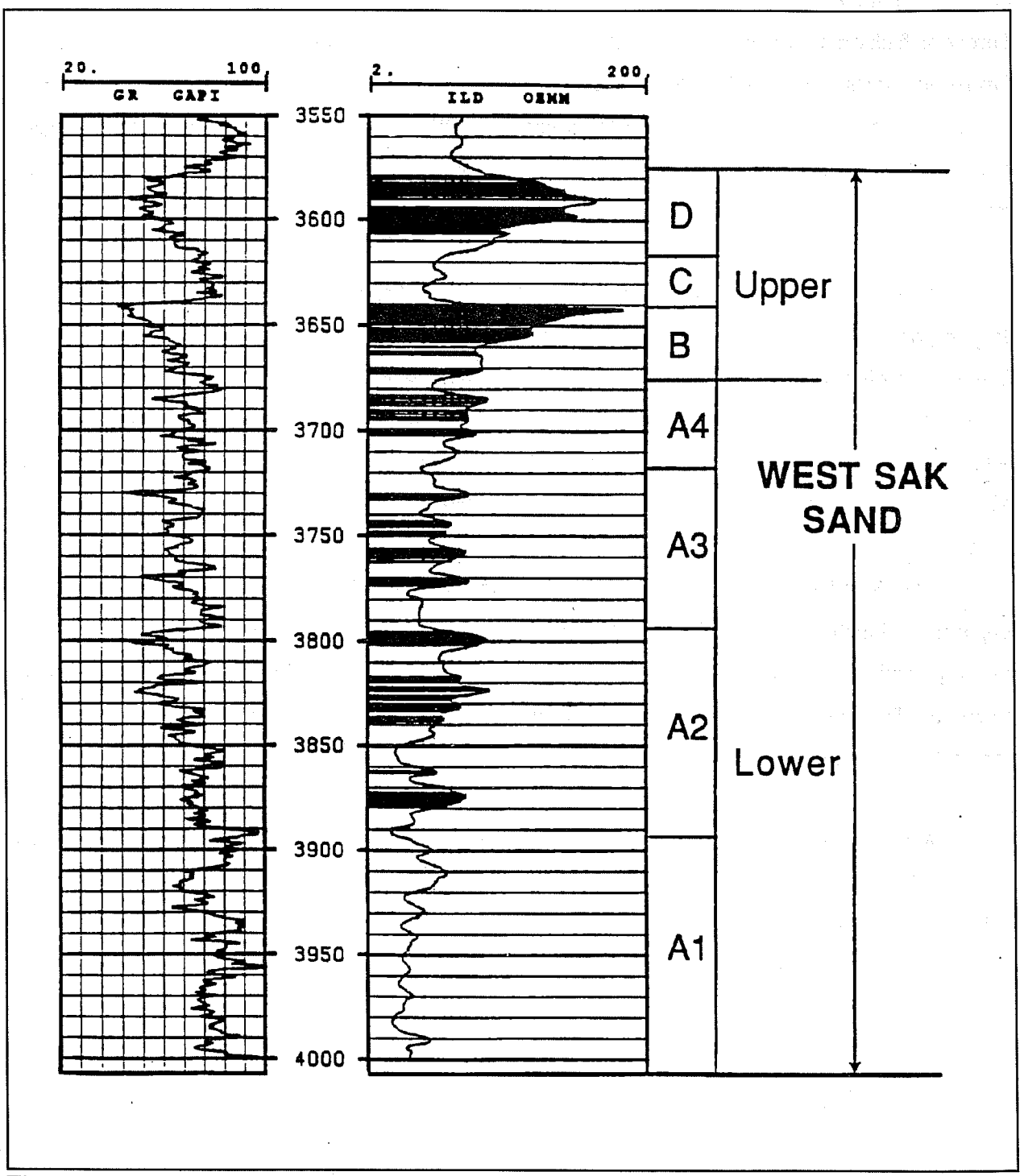

Figure B.3 West Sak log for well WS1-01 showing oil saturated sand beds.[a]

a. ARCO Alaska, Inc. West Sak presentation to EG&G Idaho, Inc., October 22, 1991.

Regional structure on the sands is a homocline exhibiting gentle (1 to 2°) dip to the northeast (see **Figures B.4** and **B.5**). Faulting is common in the area with north striking faults downthrown to the east. Throw of faults ranges from 50 to 200 ft (Werner 1986). "In the Milne Point Unit the Schrader Bluff formation is densely faulted " (AOGCC 1990a). In the July 1990 Conservation Order No. 255 (AOGCC 1990a), it is stated that five separate oil water contacts (OWCs) have been documented in a continuous sand member of the Schrader Bluff, which indicates fault compartments with different pressures and reservoirs.

West Sak sands contain oil at depths from 2,000 to 4,500 ft in the MPU and the KRU, with the deepest portion to the northeast in the MPU. Average depth of permafrost in the area is less than 1,500 ft and reservoir temperatures range from 45 to 100°F with Schrader Bluff averaging 90°F at 4,000 ft subsea (Werner 1986, AOGCC 1990a). West Sak oil ranges from 16 to 22°API gravity, whereas Schrader Bluff gravities range from 14 to 19.5°API, averaging 17°API (Werner 1986, AOGCC 1990a). ARCO reports gravities from 10 to 22° API (ADNR 1989a).[a]

The West Sak sands are believed to extend over more than 200,000 acres and cover most of the Kuparuk field in the KRU and MPU (see **Figure 1.3**). Currently ARCO estimates 13 BBOIP as "known" with a potential of an additional 7 BBOIP. Temperatures range from 50 to 80°F in the highly faulted reservoir. The upper sands are less consolidated than those in the lower member. Oil gravities vary both vertically and laterally with a decrease in oil quality updip to the southwest (ADNR 1989a).[a]

Although general agreement exists that 25 to 44 BBOIP occurs in the West Sak and Ugnu sands, major differences of opinion are apparent in terms of potential reserves. The state of Alaska has estimated technical recovery of 0.5 to 1 BBO while ARCO has indicated a 5% recovery of 10 BBOIP or 500 MMB of recoverable oil (Sullivan 1991). Ultimately, technical, environmental, and economic factors will all play major parts in the determination of rates and volumes.

B.1.2 Lease Summary

Primary interest in West Sak and Schrader Bluff sands is focused in the KRU and MPU, both of which were unitized to produce from the deeper Kuparuk sands. Therefore, all operations involving other zones are subject to the unit agreement and the unit operating agreement of those units. Agreement by the working interest owners of all units involved and the state is required to conduct operations.

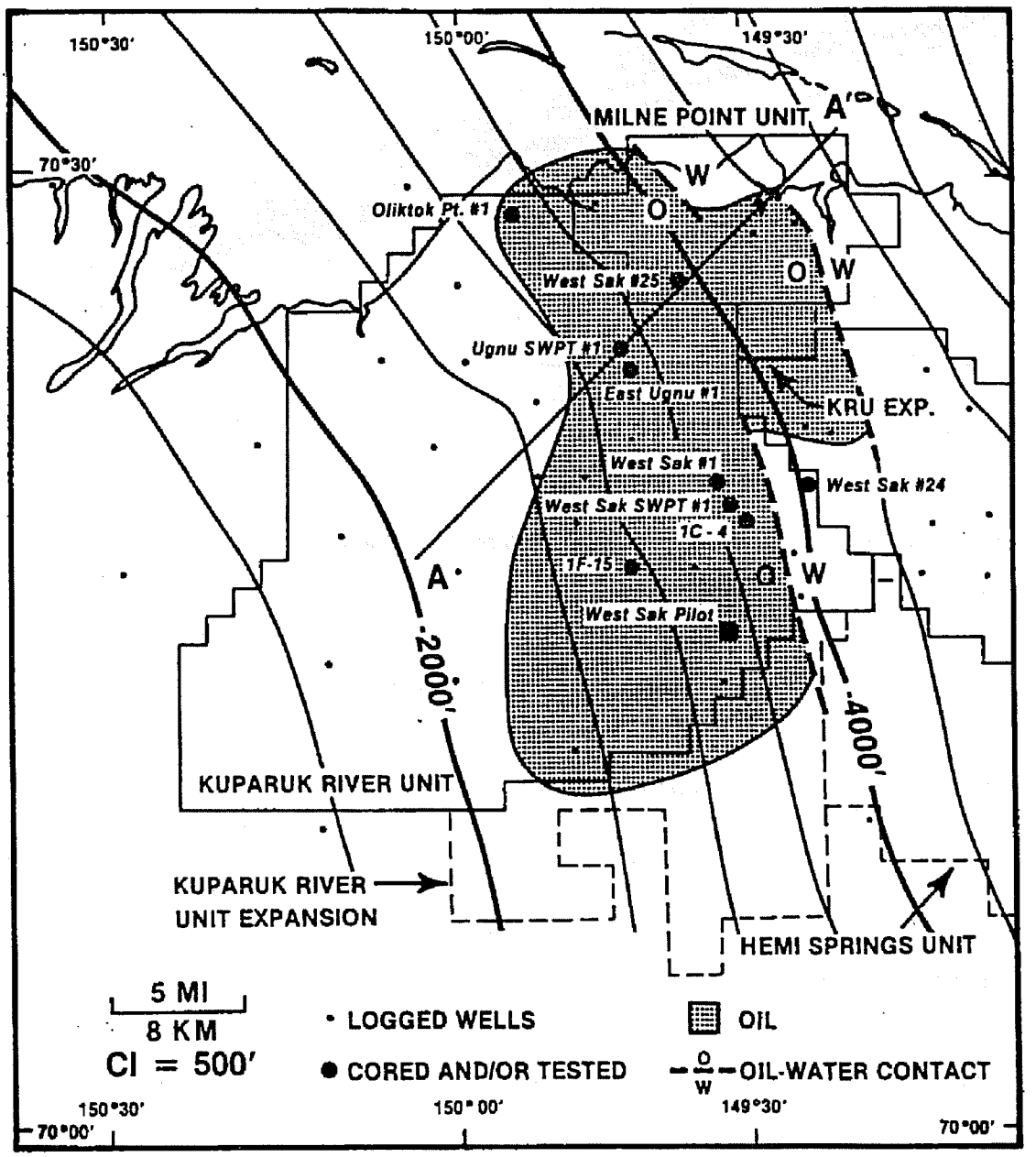

Figure B.4 Structure of on top of the West Sak sands (Werner 1986).

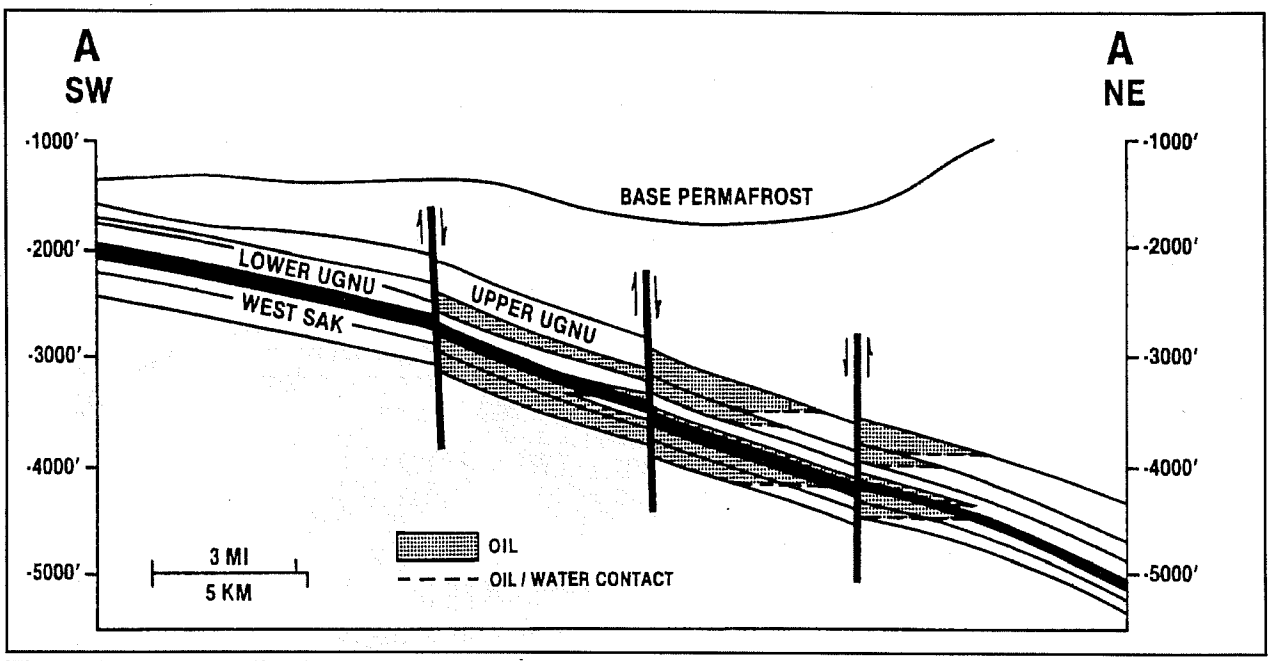

Figure B.5 Generalized structure section for the West Sak and Ugnu sands in the northern KPU (Werner 1986).

Applicable state laws and regulations govern development. The current KRU and KPA are shown in **Figure A.1**. The Milne Point field and Unit are described in **Appendix A.2.2.**

B.2 West Sak Issues

Important issues confront operators attempting to evaluate the potential development of the West Sak sands. The occurrence of billions of barrels of oil in place is well documented. Technical questions revolve around the problems of recovery techniques in producing from shallow, unconsolidated sand reservoirs in proximity to permafrost with cold temperatures in the objective horizons. Oil quality is another serious concern because low gravity and high viscosity compound the difficulties of development. Variability of oil quality, both vertically and laterally, and heterogeneity of reservoirs make the use of conventional secondary recovery flooding techniques much more complex.

Economics of North Slope production play a primary role in the development decision-making process, particularly affecting high cost operations to recover low-value West Sak oil. Unstable world oil price, uncertain expectations of future oil prices, and technical difficulties are the driving forces in the economic evaluations of West Sak development. As in other fields in the region, cost reduction through sharing of facilities will have a positive effect on economics. With the KRU production facilities

currently operating at full capacity, West Sak potential production must compete on an economic basis with already established, higher value Kuparuk production for production capacity and development capital.

The development of West Sak, which will require close well spacing (20-acre) compared to the current 160-acre spacing for most Kuparuk development, will increase the pad, road, and density of facilities several fold. More numerous and concentrated surface impacts on the environment will result; thus, making compliance with the various federal, state, and local laws and regulations much more onerous (see **Section 2.6**).

B.3 Point Thomson History

Point Thomson lies about 50 mi southeast of Prudhoe Bay along the Beaufort Sea coast. Leases were first acquired in the area in State Sale No. 14 in 1965. At that time Exxon and Mobil successfully bid on three tracts each. In 1969, in State Sale No. 23, a number of companies acquired leases in the area, including Exxon, Mobil, Pennzoil, and Chevron.

In 1975, the discovery well in the area, the Exxon Alaska State A-1, tested 23°API gravity oil at a rate of 2,507 BOPD, 2.2 MMCFPD, GOR 864, from the Lower Tertiary (Canning formation) Flaxman Sand from 12,565 to 12,635 ft (ADNR 1988; USGS 1987). Following the discovery, unitization efforts were initiated resulting in formation of the Point Thomson Unit (PTU) effective August 1, 1977. The PTU included 18 leases covering 40,768 acres of state land with 12 working interest owners. Exxon was designated Unit Operator (AOGCC 1984).

In December 1977, the first well in the new unit was flow tested from a different zone, the Thomson Sand. The PTU No. 1 well flowed 18° API gravity oil at a rate of 2,283 BOPD, GOR 5,829, from the zone 12,963 to 13,050 ft. At 12,834 to 12,874 ft the well tested at a rate of 3,860 MMCFPD, 170 BPD condensate, 45°API gravity (USGS 1987). This Lower Cretaceous (Neocomian) sand was the major reservoir to be discovered in the area and led to the early estimate of potential recoverable reserves in the "field" of 5 TCF and 350 MMB condensate (OGJ 1984). PTU was extended beyond the initial 5-year period by the discovery.

Over the next 7 years, six additional wells were drilled to delineate the extent of the two discoveries and in the process discovered two other hydrocarbon reservoirs. In 1978, the PTU No. 2 tested 21° API gravity oil at a rate of 248 BOPD, 124 MCFPD, GOR 500, from the "Staines River Sand", a local sand in the Tertiary Canning formation at a depth of 11,580 to 11,678 ft (USGS 1987). In 1982, the Exxon Alaska State F-1 well tested the Thomson sand at a rate of 4.235 MMCFPD. It also tested the Devonian (which had flowed 4,220 BPD of salt water from an open hole drillstem test (DST) in the initial A-1 discovery) and flowed at a rate of 2.975 MMCFPD from 13,940 to 14,316 ft with 152 BOPD of 35° API gravity oil and a GOR of 19,572 (USGS 1987). This well defined the third potentially productive zone of the PTU, the pre-late Devonian metasedimentary sequence or "Pre-Miss" of later usage.

During this period, leases were acquired in State Sale No. 30 in December 1979 and State Sale No. 36 in May 1982. On March 26, 1984, the state approved the expansion of the PTU to the north and to the south with the addition of all or portions of 25 leases covering 94,152 acres, bringing the PTU total to 134,920 acres (see **Figure B.6**). Ten wells, six in the north and four in the south, were drilled in the expansion area. As a condition of unit expansion approval, the state required an additional well by March 31, 1985 to hold leases in the south and another well in the north by February 1, 1990 to hold 10 leases (AOGCC 1984).

In April 1985, two leases were lost when the PTU was contracted because of failure to drill the southern obligation well. In October 1988, the eighth plan of development (POD) was submitted to the state and proposed the PTU No. 5 well, which would hold the 10 northern leases, as well as a 3-D seismic program and construction of consensus maps of critical horizons in the PTU (ADNR 1988). The seismic program was completed May 15, 1989 (ADNR 1991g).

The February 1, 1990 obligation date for the northern well was not met and the PTU was again contracted. Nine of the ten northern leases were lost (ADL 312682 was held by certification of the State F-1 well as capable of production).

The PTU at this time covered 83,825 acres including 32 leases. Some of the leases contracted out of the Unit were reacquired in State Sale No. 65 in June 1991. These leases are not included in the current unit outline (see **Figure B.7**).

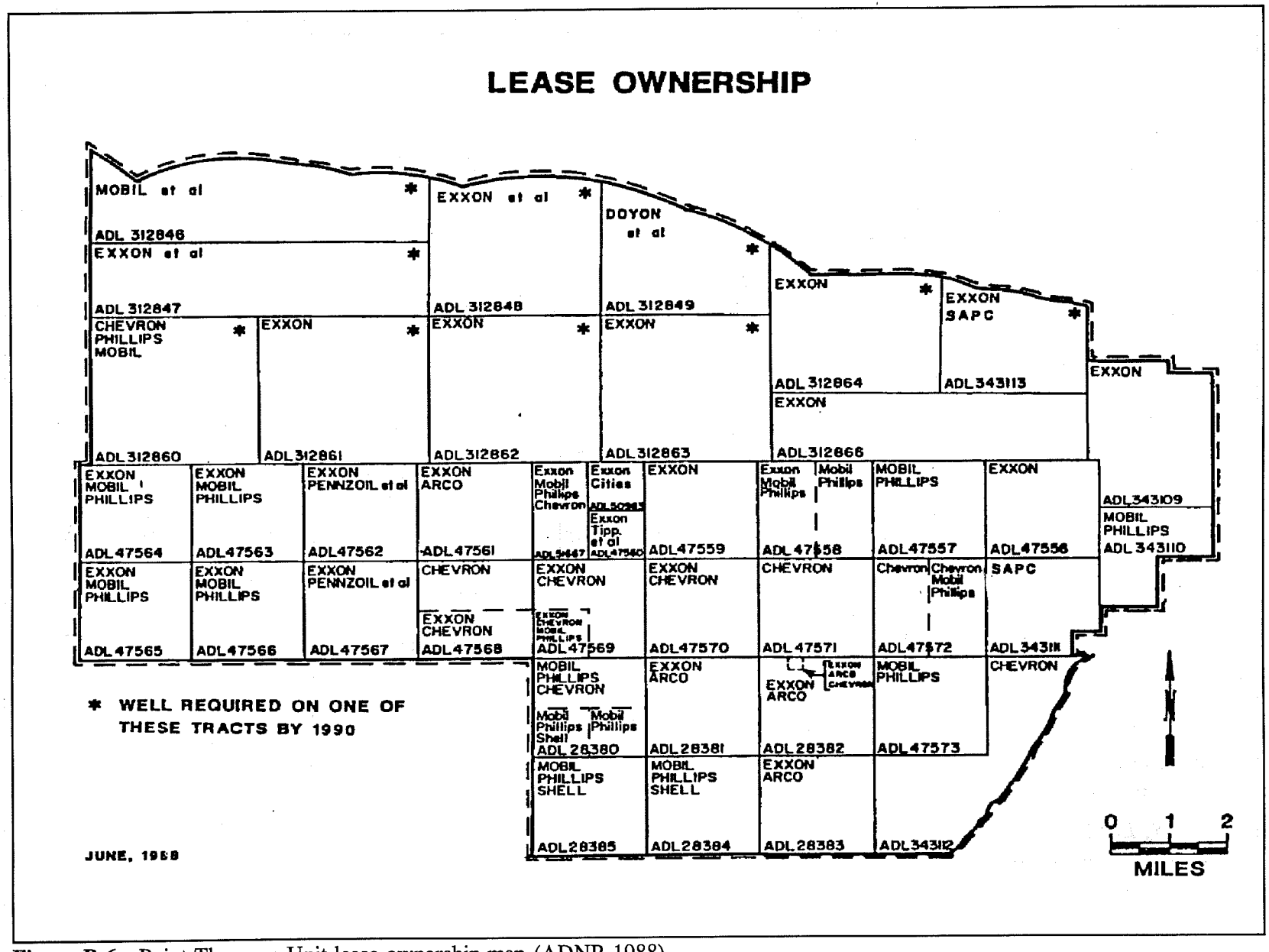

Figure B.6. Point Thomson Unit lease ownership map (ADNR 1988)

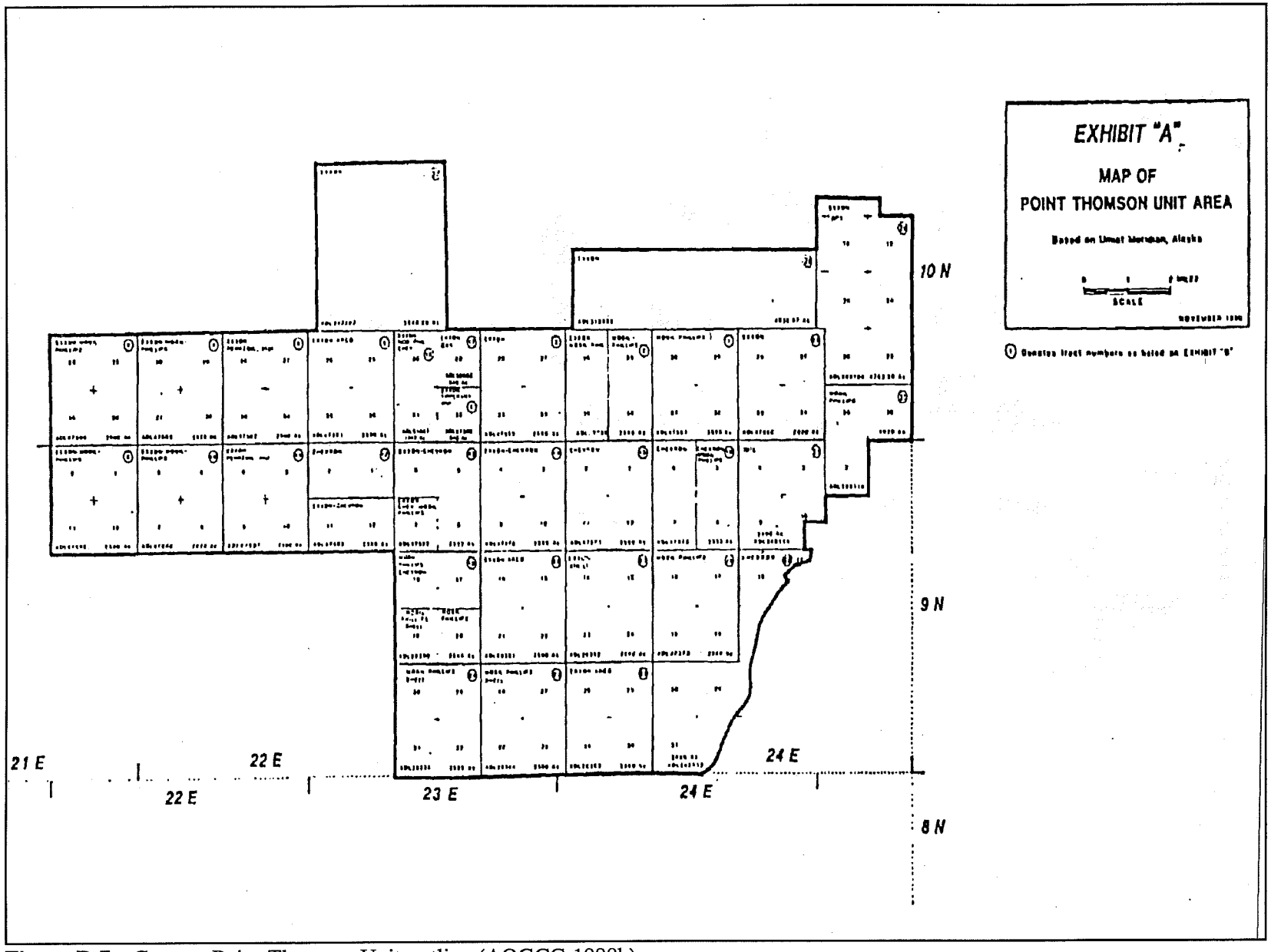

Figure B.7. Current Point Thomson Unit outline (AOGCC 1990b).

The ninth POD submitted by the unit working interest owners on September 25, 1991 requested a 4-year period ending in 1995 to complete work on consensus structural maps, define major uncertainties, and develop options to pursue for future development (ADNR 1991g). The ADNR on January 3, 1992 approved the ninth POD but only allowed a 1-year period to complete the consensus mapping efforts and stated that this would allow the Division of Oil and Gas to "better maintain its ability to understand the circumstances and conditions under which the Point Thomson area reservoir(s) can be developed." It was also stated, "At the conclusion of the Ninth Plan period, Exxon should be prepared to convene a joint meeting of the working interest owners and the Division of Oil and Gas to discuss progress under the Ninth Plan and the potential development options and schedules." (ADNR 1992b).

B.3.1 Data Summary

Within or closely adjacent to the PTU, a total of 15 wells have been drilled. The well data together with the recent 3-D seismic survey should give the unit owners excellent detailed control with which to map the productive zones in the overall accumulation. As stated in the previous section, consensus structural mapping of the three productive zones is underway and will provide a basis for future development decisions. The state of Alaska reports estimated potential reserves of 300 MMB condensate and 5 TCF (ADNR 1991a). In the letter transmitting the ninth POD to ADNR, Exxon indicated that preliminary work suggested that reserves may be up to one-third less than the nominal 5 TCF assigned to the field (ADNR 1991g).

The "Pre-Miss" reservoir was tested in two wells in the northern part of the Unit. The mud log from the Challenge Island well (well was lost before it could be tested) shows indications of "Pre-Miss" carbonates (see **Figure B.8**). The carbonate rocks penetrated in the northern area, as opposed to the tight argillites and phyllites to the south, tested water at high rates and tested gas at reasonably high levels (ADNR 1988; USGS 1987). The carbonates may be equivalent to the Precambrian Katakturuk dolomite which crops out in the mountains to the southeast. In the outcrop, vuggy dolomites with high porosity and permeability are present. However, measured samples from both wells and outcrops in the "Pre-Miss" or "basement complex," average less than 5% porosity, with a range of 1 to 25%, and average less than 1 md permeability, with a range of <0.1 to 1 md (USGS 1987).

The early Cretaceous Thomson sand extends over an area of 5 by 12 mi and is the primary reservoir of the PTU. It is a fine grained, dolomitic sand which coarsens northward and becomes

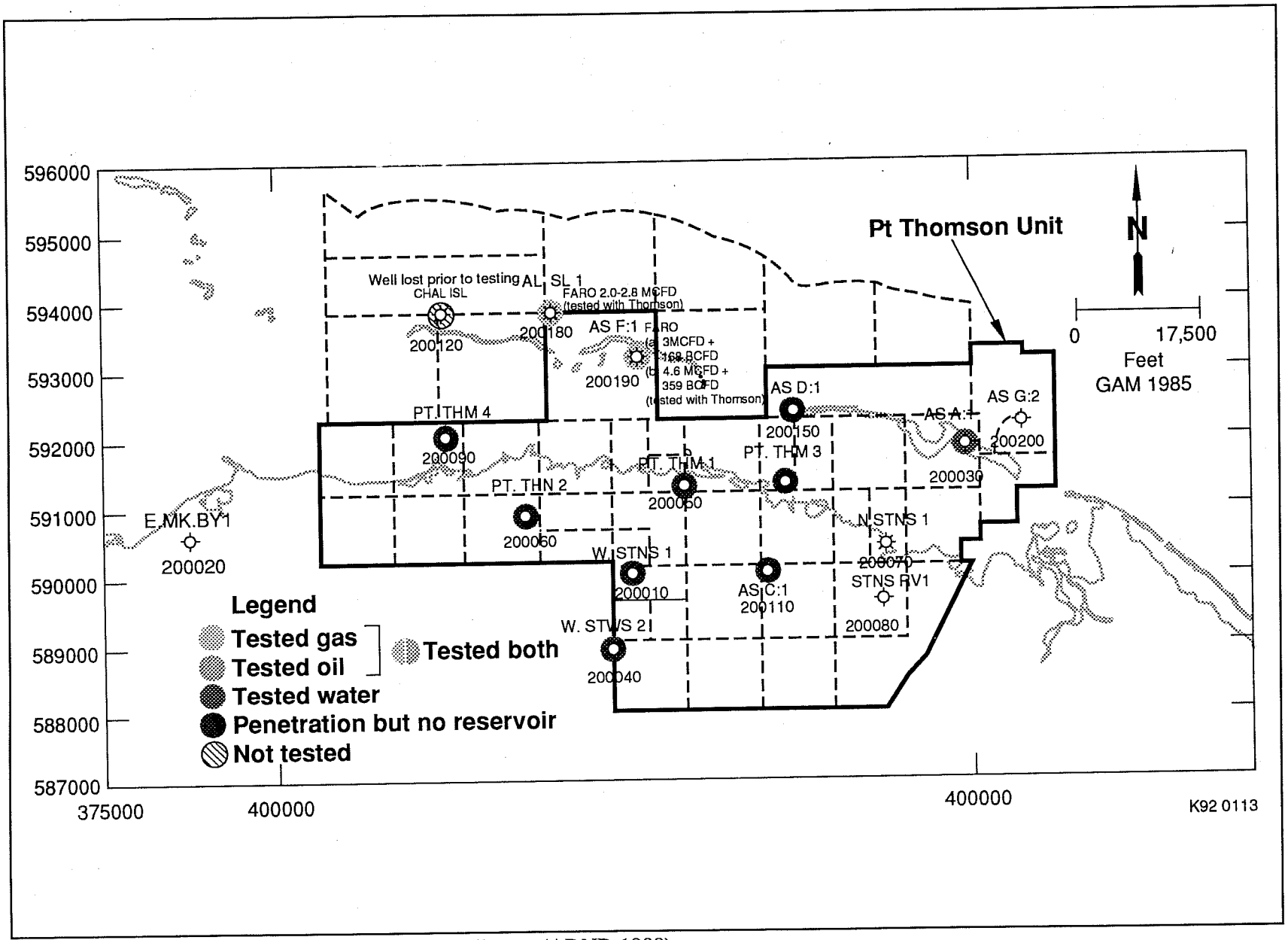

Figure B.8. Point Thomson Area, "Pre-Miss" well tests (ADNR 1988).

conglomeratic. Porosity ranges from 11 to 25% with a 16% average and permeabilities range from 10 to over 1,000 md. Reservoir depth averages about 13,000 ft subsea. The sand is overpressured. It ranges in thickness from 0 to 332 ft (USGS 1987) (see **Figure B.9**). Its distribution by wells in the unit area is shown in **Figure B.10**.

The upper reservoirs in the Point Thomson area consist of turbidite sands of the Tertiary Canning formation such as the "Staines River Sand" of the PTU No. 2 and the "Flaxman Sand" of the State A-1 (see **Figure B.11**). Distribution of the Lower Tertiary Sandstone reservoir by wells is shown in **Figure B.12**. These sands are also overpressured with gradients up to 0.84 psi/ft. They are mostly fine-grained sandstones with porosity averaging at least 20% (USGS 1987).

B.3.2 Lease Summary

The PTU currently includes an area of 83,825.03 acres. A total of 32 state of Alaska tracts are held by 25 owners, although 93% of the acreage is held by only five companies, Exxon, Chevron, Mobil, Phillips, and Shell (ADNR 1991c). Four tracts are held by shut-in production and the rest are held by the Unit.

The majority of tracts (26) carry a 12.5% royalty. One tract has a 20 to 65% sliding scale royalty. One has a 20% royalty and a 52.352% net profits interests (NPI) share and four have a 12.5% royalty and a 40% NPI share.

B.4 Point Thomson Issues

The state of Alaska's approval of the ninth POD for 1 year only to complete structural mapping was imposed because of, "...its desire for the working interest owners to take advantage of any and all windows of opportunity that may have an impact on the Point Thomson area." Following this effort, the technical aspects of potential development schemes, timing, and economics will be discussed (ADNR 1992b).

Questions remaining deal with uncertainties associated with reservoir size and configuration, highly deviated wells in an abnormally pressured reservoir, reservoir performance during sales with gas and condensate production, availability of transportation systems, possible co-development with other

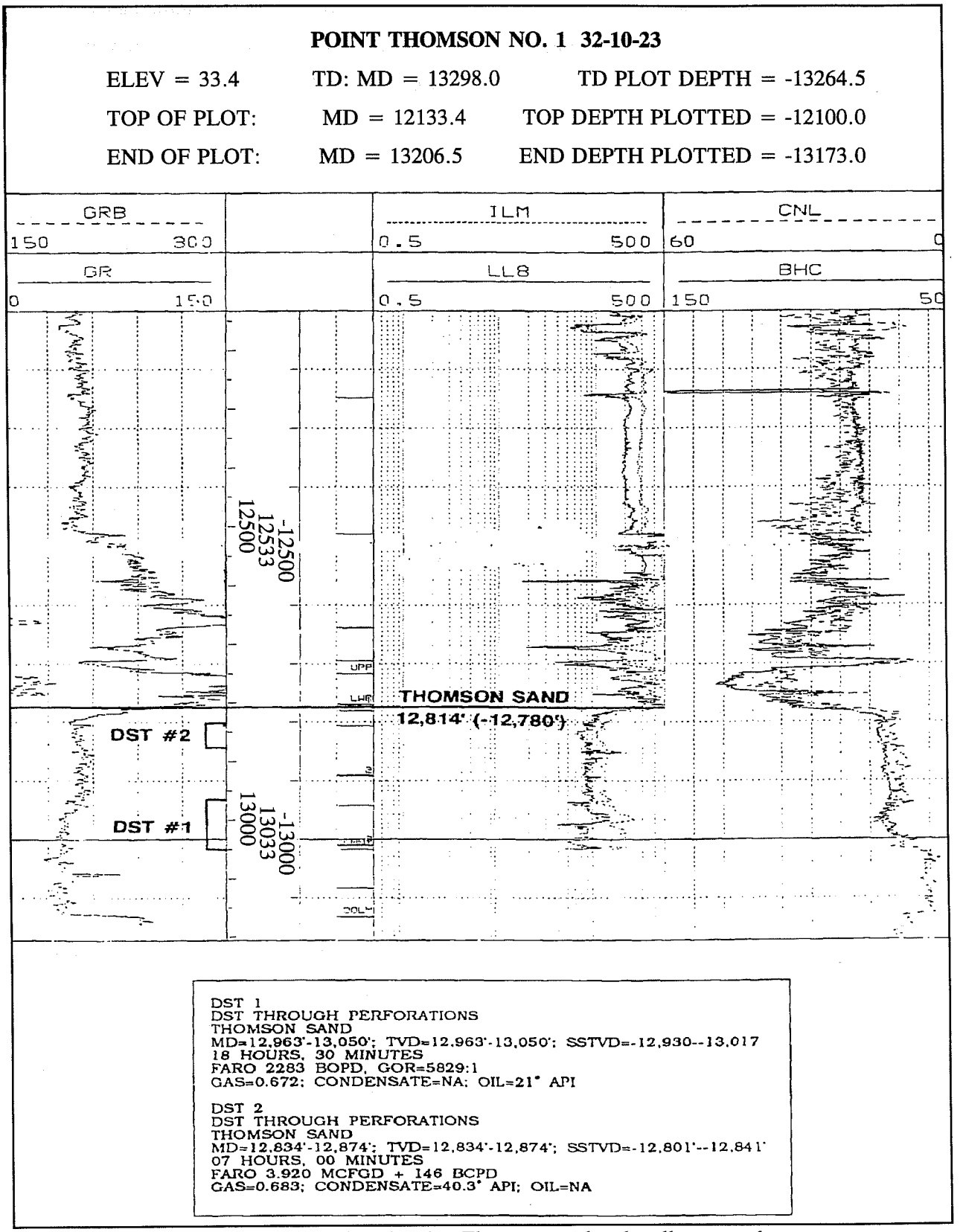

Figure B.9. Point Thomson No. 1 log showing Thomson sand and well test results.

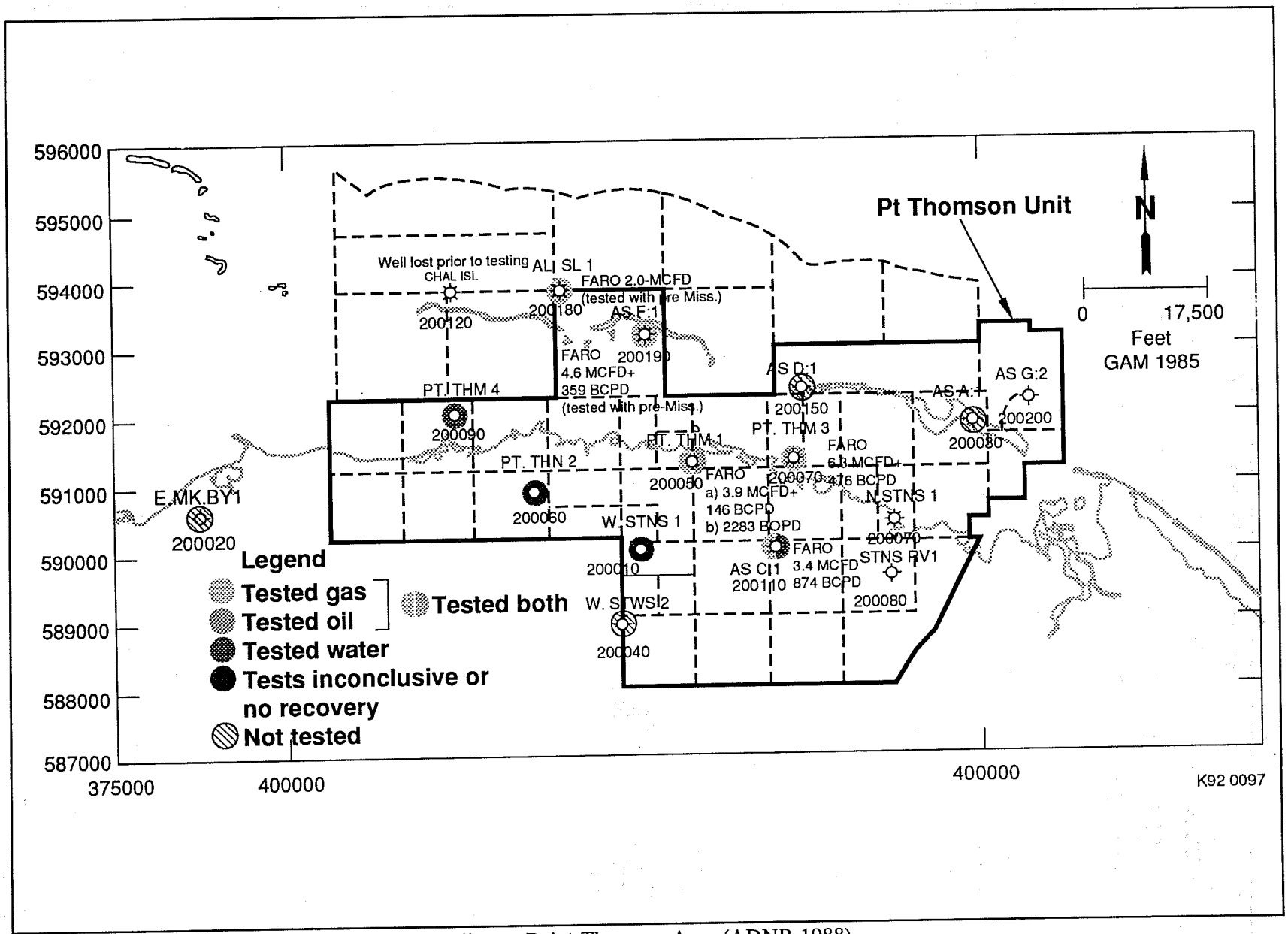

Figure B.10. Thomson sand distribution and well test, Point Thomson Area (ADNR 1988).

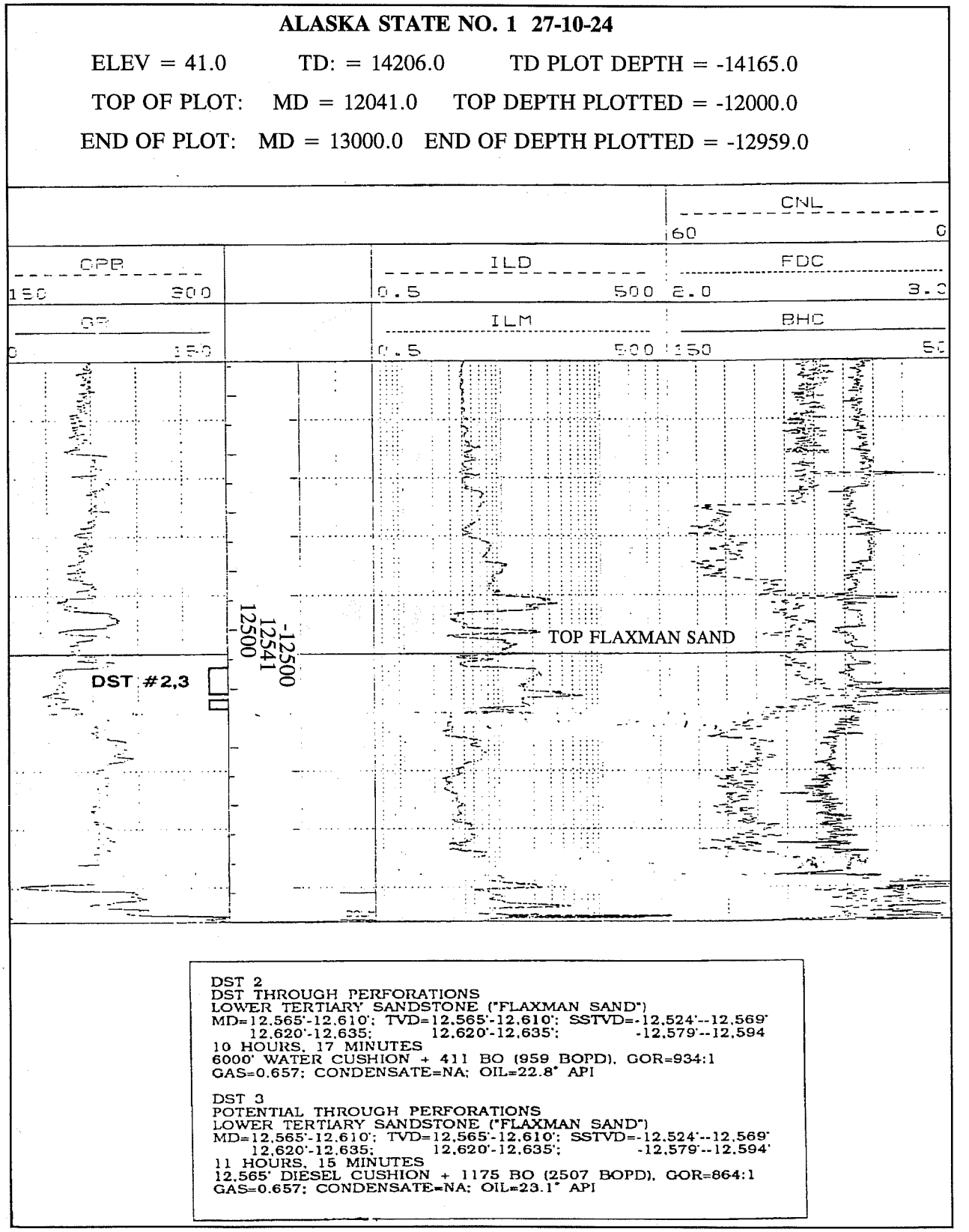

Figure B.11. Alaska State No. 1 well log showing "Flaxman Sand" and well tests results.

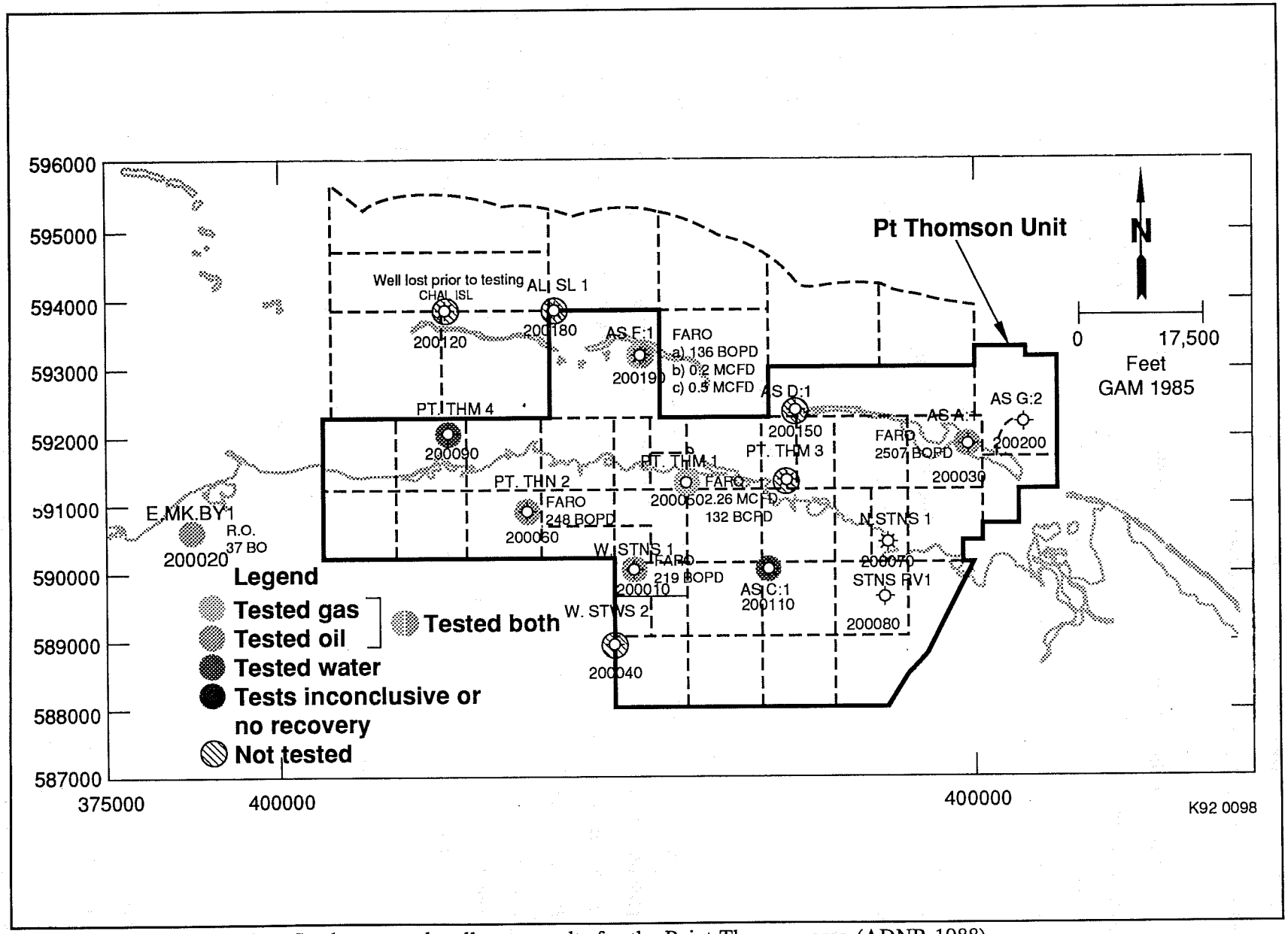

Figure B.12. Lower Tertiary Sandstones and well tests results for the Point Thomson area (ADNR 1988).

fields, investment levels, timing, gas cycling, price structure and forecast for both condensate and gas, and the overall effects on economics of development.

The previous DOE publication (1991) described in detail the natural gas reserves and potential resource on the North Slope and the lack of a market price in the foreseeable future that would make construction of a gas pipeline economically feasible. The reserve base of more than 30 TCF (DOE 1991) is an attractive target for future marketing and the Point Thompson contribution would be significant.

Potential production of Point Thomson condensate or gas, or both, might be greatly enhanced by exploration and development of the Arctic National Wildlife Refuge (ANWR), which lies adjacent to the east. A significant discovery and resulting development in the offshore eastern Beaufort Sea could also have a positive impact by providing a transportation infrastructure.

B.5 Gwydyr Bay History

Leases were first acquired in the Gwydyr Bay area in Alaska State Sale 14 in 1965. Further acquisitions occurred in Sale 18 in 1967 and Sale 23 in 1969. The first "discovery" well was the Hamilton Brothers Point Storkerson No. 1, which tested 5.5 MMCFPD and 381 BOPD from the Sadlerochit in 1969. Four more wells were drilled in the area prior to unitization in September 1979. The Mobil Gwydyr Bay South No. 1 well was certified by the state as producing in paying quantities on March 19, 1976. The well tested 34.6°API gravity oil Sadlerochit at a rate of 2,263 BOPD, GOR 574. Another Hamilton Brothers well, the Kup Delta No. 51 No. 1, tested 32.8° API gravity oil 2,200 BOPD, GOR 350, from a 40 ft Cretaceous sand, 1,600 ft above the Kuparuk. A follow-up well, the Kup Delta 51 No. 2, did not encounter the shallow sand zone of the 51 No. 1 but tested 695 BOPD, 1,000 BWPD, GOR 700, 38°API gravity oil from the Sadlerochit and 384 BOPD, GOR 108, 26.7°API gravity oil from the Kuparuk. The fifth well was a dry hole and the block around the Cities Service Gwydyr Bay State No. A-1 well was excluded from the subsequent unit (AOGCC 1982; ADNR 1987).

The Gwydyr Bay Unit (GBU) was approved by the state on September 28, 1979 with 15 state leases and one parcel of federal land, PLO 1571, included in the total area of approximately 27,160 acres with 18,380 acres committed to the GBU (see **Figure B.13**). Conoco was appointed Unit Operator with 14 of 18 interest holders committed to the GBU and a total of 15 working interest owners. On September 24, 1982, the GBU was automatically extended with a "valuable discovery of hydrocarbons" following

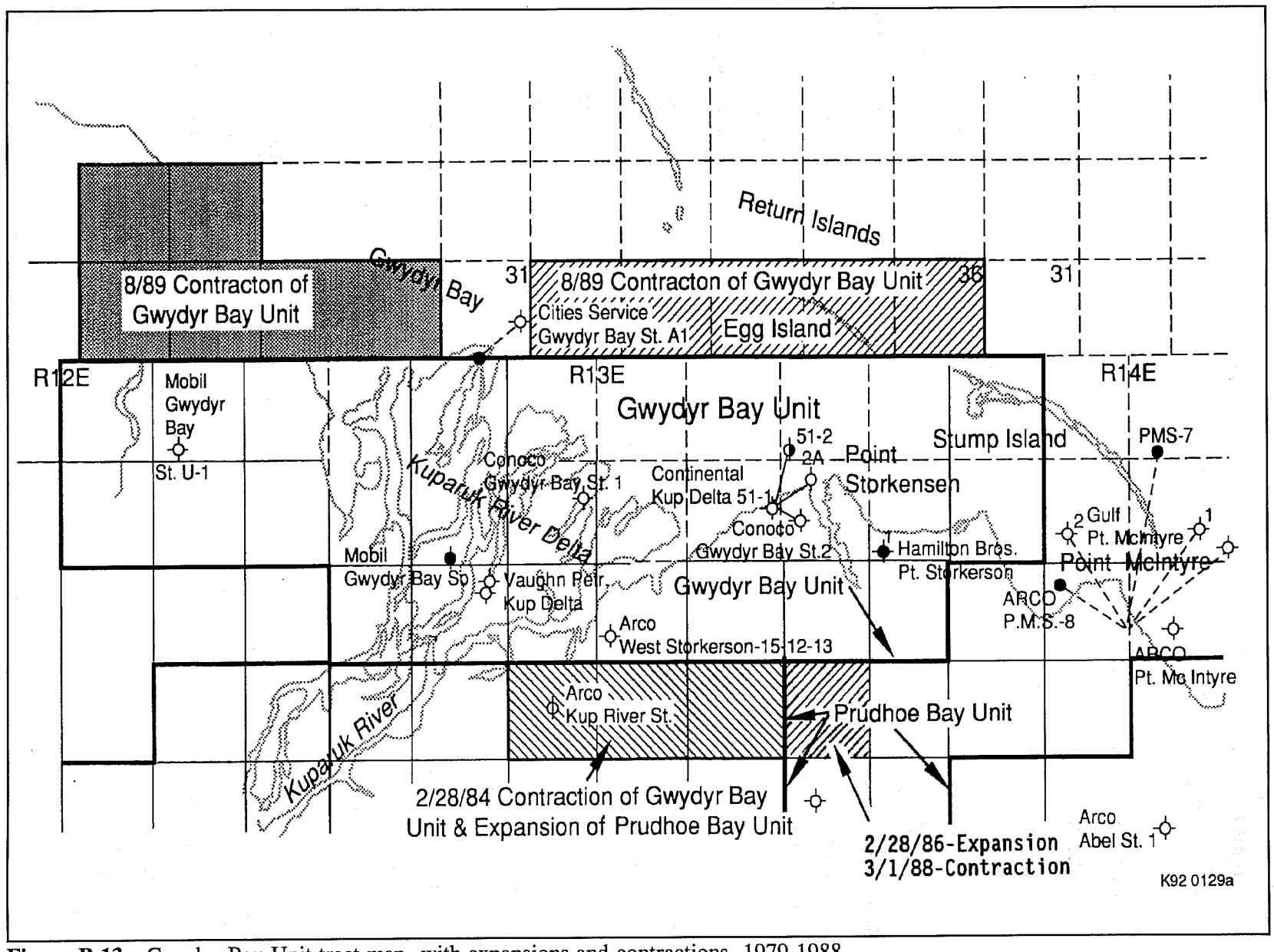

Figure B.13. Gwydyr Bay Unit tract map, with expansions and contractions, 1979-1988.

certification of the Conoco Gwydyr Bay State No. 2A well. It was tested in the Sadlerochit at 3,000 BOPD, 170 BWPD, GOR 900, 37°API gravity oil and in the Kuparuk at 740 BOPD, GOR 410, 19°API oil gravity (ADNR 1986; AOGCC 1982; ADNR 1987).

On March 1, 1984, the GBU was contracted by 1,920 acres. Concurrently the Prudhoe Bay Unit was expanded to include portions of two leases (see **Figure B.13**). The GBU then included 15 state leases and one federal lease for a total area of 25,240 acres (ADNR 1986).

On February 28, 1986, the GBU was expanded by 640 acres with the inclusion of a portion of lease ADL 28276 contingent upon the proposed drilling of three exploratory wells, one each in 1987, 1988, and 1990, respectively (see **Figure B.13**). One well, the CM/Vaughn Kup Delta No. 1, was drilled, sidetracked, and abandoned as a dry hole in 1987. No subsequent wells were drilled under the terms of the expansion (ADNR 1986).

In 1988, ARCO replaced Conoco as Unit Operator and submitted a revised ownership and unit outline to the state of Alaska (see **Figure B.14**) (ADNR 1989). The unit contraction resulted in a total area of 18,173 acres, effective August 1, 1988. The ninth POD was submitted to the state on September 30, 1991.

B.5.1 Data Summary

As stated in the previous section, five wells were drilled prior to unitization, all but one testing hydrocarbons in one or more zones. Subsequent to unitization a total of five more wells have been drilled with only the Conoco Gwydyr Bay State No. 2A well finding hydrocarbons.

With the 1989 discovery of the Point McIntyre field and the delineation of the extent of the Kuparuk River formation accumulation, ARCO Alaska Inc. and Exxon Corporation drilled three wells adjacent to the GBU in 1990 and 1991. "All three wells have been completed and temporarily abandoned until a participating area is approved and facilities are installed" (ADNR 1991b). The 10th well in the GBU, the ARCO Point McIntyre No. 12, was not flow tested prior to spring break-up in 1991. The hole was cased and suspended to preserve the option of testing and further evaluation.

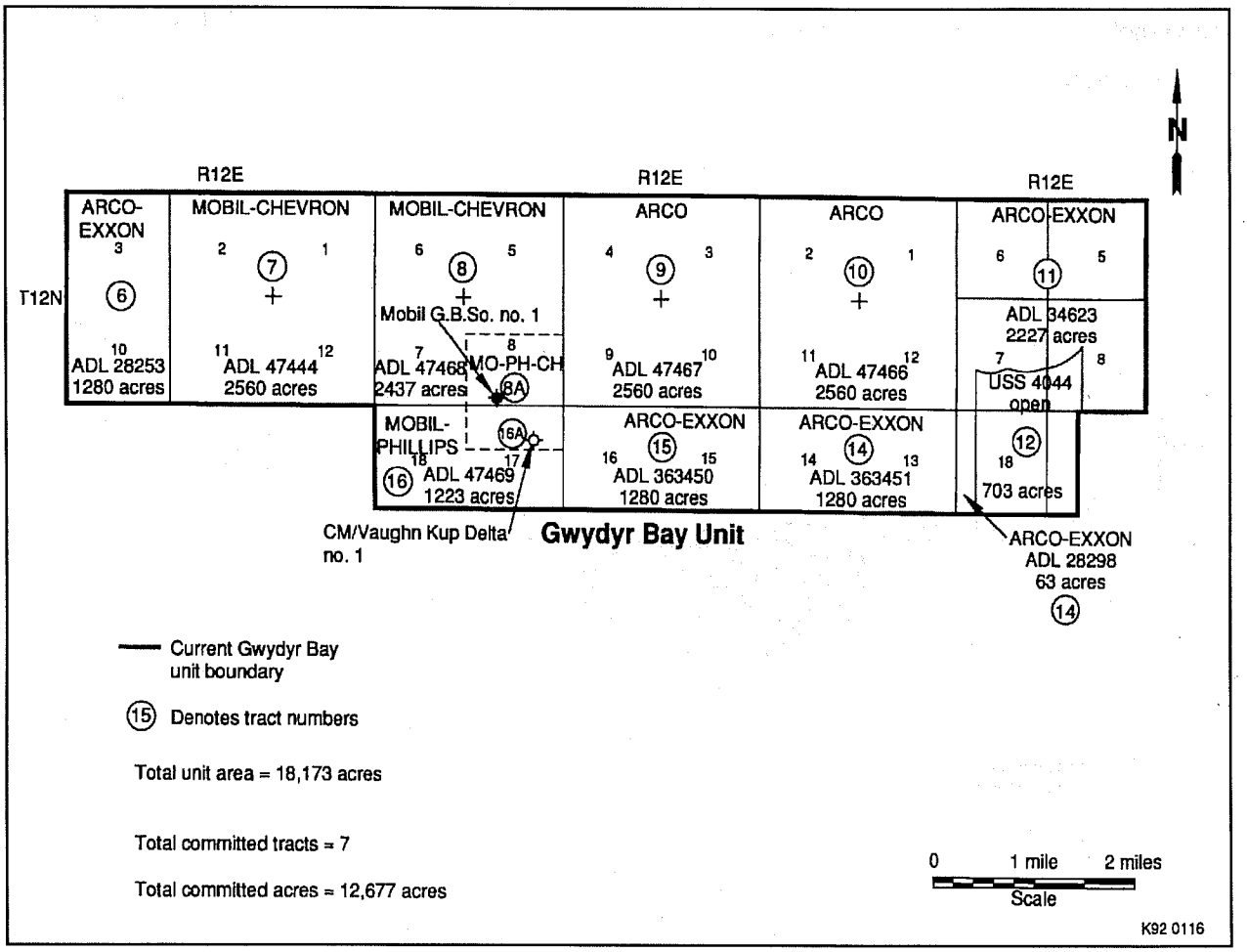

Figure B.14. Gwydyr Bay Unit area as contracted on August 1, 1988 (ADNR 1989).

During 1990, a 3D-seismic program was conducted in the eastern unit area. During 1991, data processing was completed and interpretation began. A portion of the Point McIntyre Kuparuk reservoir extends onto acreage within the GBU. Plans are to include that acreage in a PBU participating area by an expansion of PBU and a concurrent contraction of the GBU (ADNR 1991b). Thus, future focus of potential resource discovery and development will be in the western area of the present unit. ARCO is planning to conduct a 2D-seismic program in that area during the 1991/1992 winter season and to complete processing and interpretation in 1992.

Total expenditures in the GBU through 1991 exceeded $44 million.

Based upon interpretation of well data in the GBU western area, it is assumed that two accumulations are present. A small proved 3 MMB recoverable oil accumulation occurs in a fault block penetrated by the Mobil Gwydyr Bay South No. 1 well. A northerly postulated 30 to 40 MMB

recoverable oil accumulation is a potential extension of the Ivishak (Sadlerochit) discovery (see **Figures B.15 and B.16**).

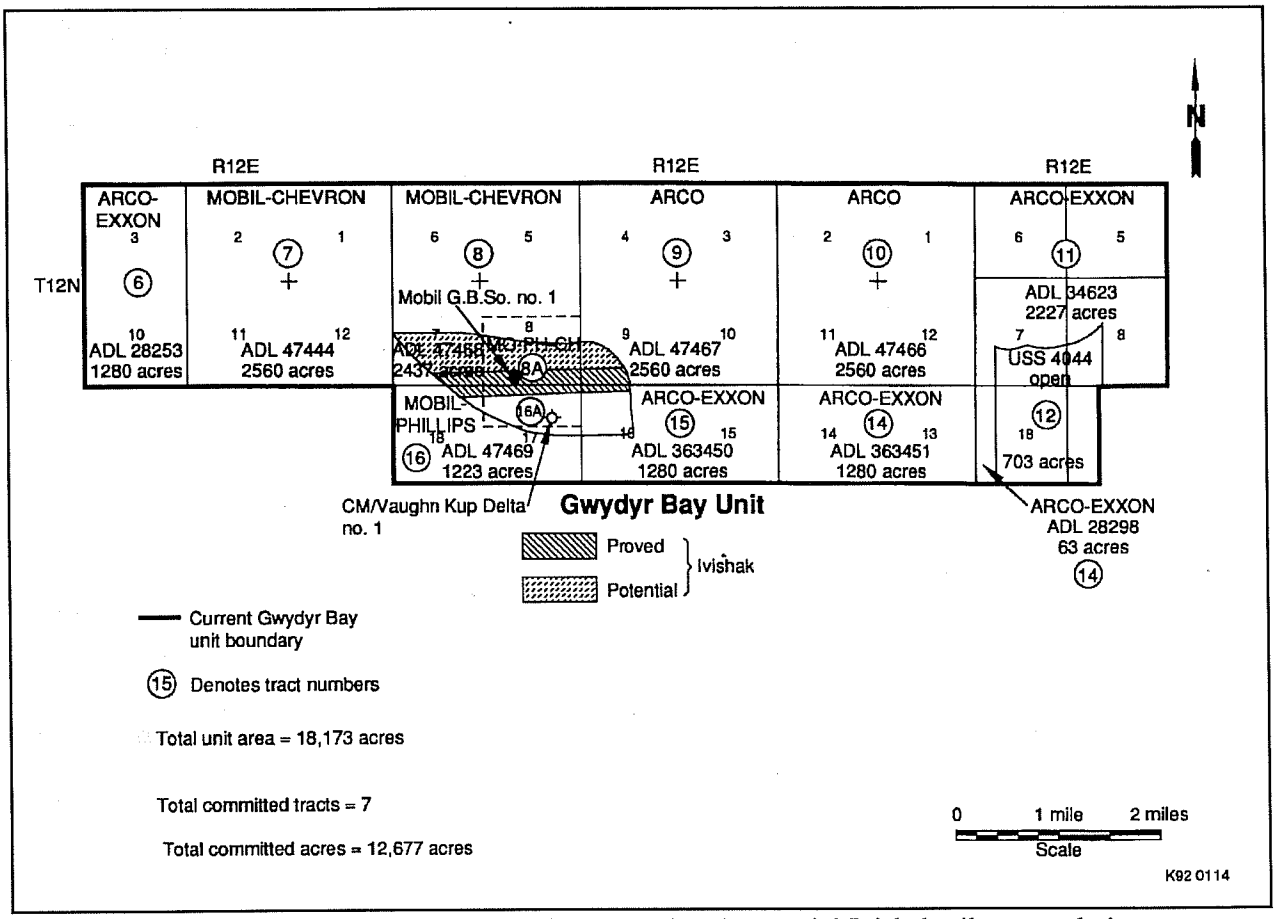

Figure B.15. Gwydyr Bay Unit map showing proved and potential Ivishak oil accumulations.

A potential Kuparuk accumulation lies updip from the Mobil well and from the CM/Vaughn Kup Delta No. 1 well (**Figure B.15**). It is estimated that this possible accumulation ranges from 15 to 30 MMB of recoverable oil (see **Figure B.17**). Therefore, a total of 48 to 73 MMB of recoverable oil potential may lie under the western GBU area.

B.5.2. Lease Summary

The current unit outline (see **Figure B.14**) includes 18,173 acres with seven tracts comprising 12,677 acres committed to the GBU, and 5,496 acres not committed.

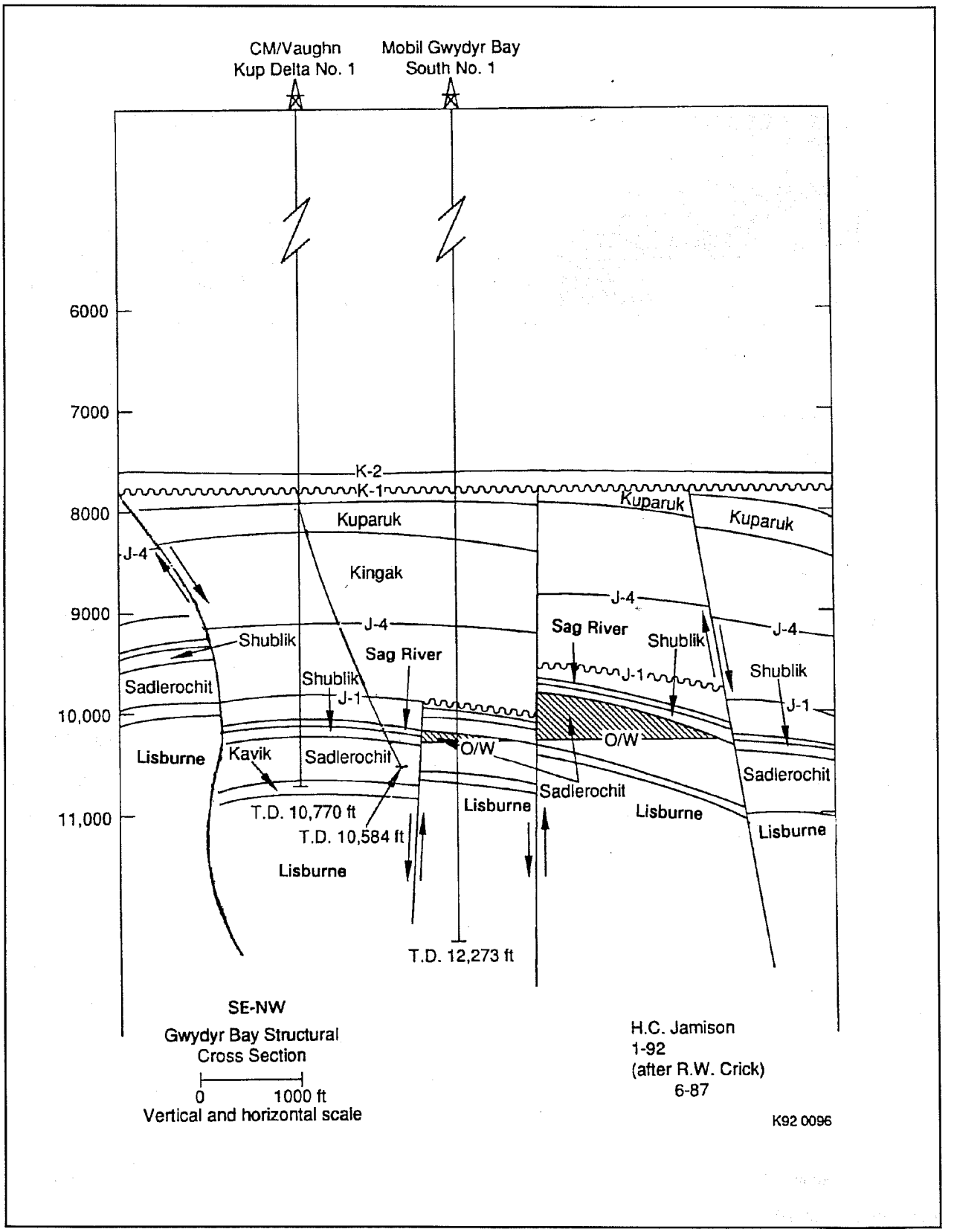

Figure B.16. Gwydyr Bay structural cross section.

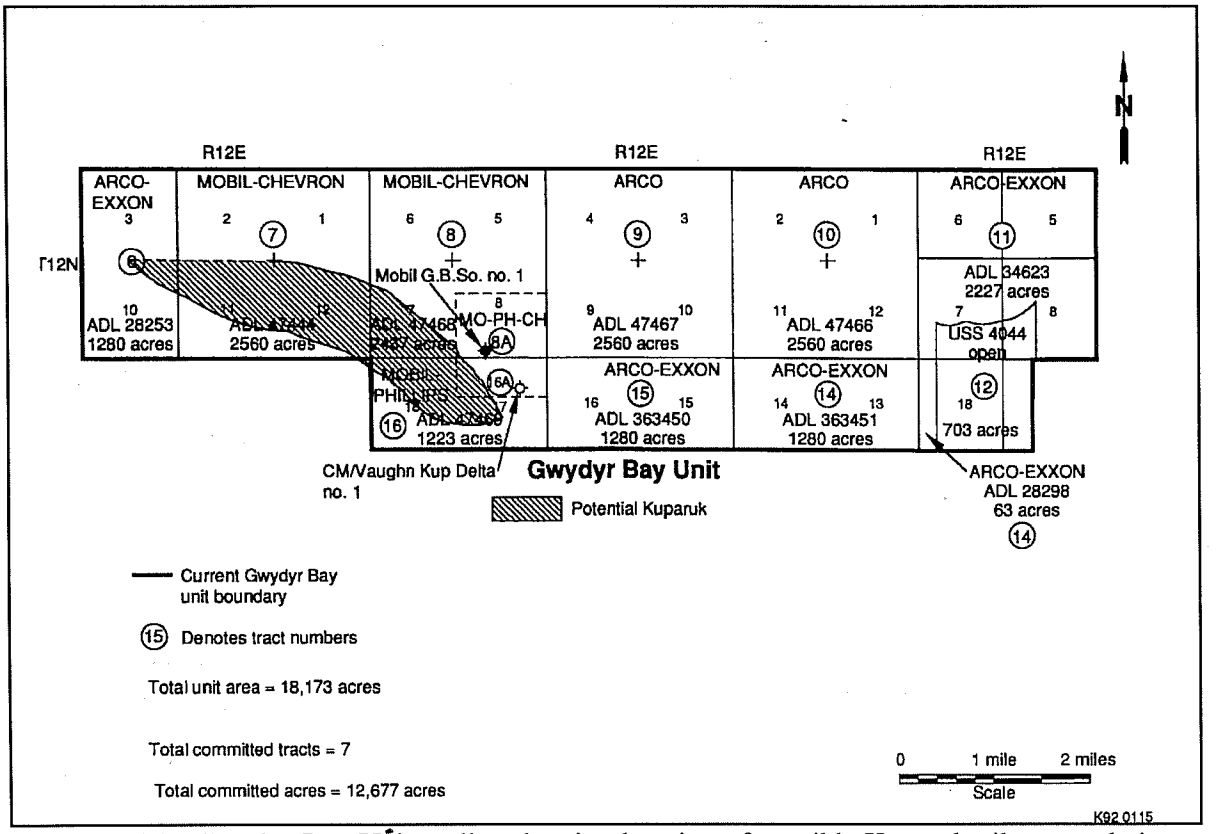

Figure B.17. Gwydyr Bay Unit outline showing location of possible Kuparuk oil accumulation.

One tract, number 12, remains unleased and is held under Public Land Order (PLO) 1571 by the federal government. All other tracts are state leases held by the current working interest owners ARCO, Exxon, Mobil, Phillips, and Chevron. Royalty on all leases is 12.5%. Certain tracts are subject to litigation settlements, farmout agreements, or overrides convertible to working interests at payout (ADNR 1989).

The ninth POD, as submitted in October 1991, requested a term through December 31, 1994. The western area 2D-seismic program and an option to drill on Mobil/Phillips/ Chevron acreage in 1993 comprise the work program proposed by ARCO with Exxon to be solicited as a partner (ADNR 1991b).

B.6 Gwydyr Bay Issues

Because of the historical contraction of the GBU and the anticipated further contraction (presumably in 1992), potential development will hinge on further exploration activity and drilling in the western area. Target sizes of potential accumulations appear small and development would be difficult

and costly because of locations in the Kuparuk River delta. Proximity to the producing infrastructure of Milne Point, Kuparuk, and Prudhoe Bay fields will improve economics. However without a dramatic, and unexpected, increase in the oil exploration potential in Gwydyr Bay area, it appears that the likelihood of significant production is low.

B.7 Seal Island/Northstar History

In 1979, a joint lease sale was conducted by the state of Alaska and the U.S. Mineral Management Service (MMS) in the offshore waters of the Beaufort Sea. One group of successful bidders, with Shell as initial operator, formed a joint effort to explore their state/federal leases centered about 15 miles northwest of Prudhoe Bay. Shell completed the construction of Seal Island in 1982. The first well, BF-47 No. 1, resulted in a discovery testing 4,750 BOPD from the Ivishak formation of the Sadlerochit group, the main producing interval in the Prudhoe Bay field.

Ultimately, four wells were drilled from Seal Island resulting in two certified producers, another that encountered hydrocarbons, and one dry hole (MMS 1989a). In 1985, Amerada Hess constructed Northstar Island about 4½ mi northwest of Seal Island and drilled a successful confirmation well, the BF 46 No. 1 in 1986. This well tested at rates of up to 3,500 BOPD from the Ivishak with oil gravity "similar to that in the Seal Island wells, in the 40°s." A subsequent well, deviated to the southeast, encountered mechanical problems and was abandoned without reaching the Ivishak. Shell estimated the structure held more than 300 MMBO total (OGJ 1986).

B.7.1 Data Summary

In 1989, the working interest owners (Amerada Hess Corporation, Murphy Oil USA, Inc., Shell Western E&P, Inc., and Enterprise Oil Ex Co. Inc.), formed the Northstar Unit (NU) (**Figure B.18**) with Amerada Hess as operator and submitted a POD to the MMS and ADNR. This plan called for a total expenditure of $21 MM during the 1990 to 1994 period. The plan included island maintenance, a petrophysical/petrographic study, production facility design, about 250 mi of 2-D seismic, seismic analysis and interpretation, reservoir engineering studies, extension fee payments (in lieu of drilling) that will escalate from $1 MM to $4 MM over the 5-year period, and a unit area reevaluation to be conducted in 1993 (MMS 1989a). In 1991, a $1 MM payment to the state was made in lieu of drilling. The petrophysical/petrographic study and conceptual production facilities design were initiated. Island

maintenance was done in July to August 1991 and the 1991 summer seismic program acquired 210 line miles of data (ADNR 1991d; ADNR 1991e).

During 1991, the petrophysical/petrographic program was completed by Neil Barry and Associates and Core Lab, Inc. The conceptual facilities design was also completed by R.M. Parsons Company. A modification of the seismic plan proposes additional coverage during the 1992 winter season, which will exceed that of the original plan. Because a delineation well was not drilled during 1991, Amerada Hess paid $2 MM to the state in January 1992 (ADNR 1992a).

At the time NU was formed, an estimated total of $280 MM had been expended on lease acquisition, island construction, and exploratory drilling. If all estimated expenditures for the POD are spent, the total cost prior to initial development or an eventual decision to cancel the project will exceed $300 MM.

Limited public technical data, consisting only of well logs and histories, preclude a reliable independent assessment of potential reserve volume. Published data specific to Seal Island/Northstar indicate a range of potential reserves from 150 to 300 MMBO (OGJ 1986; ADNR 1991a). However, data representing undeveloped reserves for the Beaufort Sea published by the state of Alaska in June 1991, indicate a range of 180 to 225 MMBO (mid to high). It is assumed that those reserve estimates apply specifically to Seal Island/Northstar (ADNR 1991). Using the available data, a conservative estimate of 200 MMBO as a potentially recoverable resource is made and used for evaluation purposes (see **Figure B.18**).

B.7.2 Lease Summary

Leases were acquired at Seal Island/Northstar from both the state of Alaska and the federal government in sale BF-79. Federal leases carried a 10-year primary term with expiration on July 31, 1990 with a 1/6 royalty. State tracts were also for a 10-year primary term expiring January 31, 1990, with four leases carrying a 20% royalty and one carrying a 12.5% royalty. All the state leases also include a net profit share percentage, ranging from 40% to 93.2% (see **Figure B.19**) (MMS 1989; ADNR 1991f).

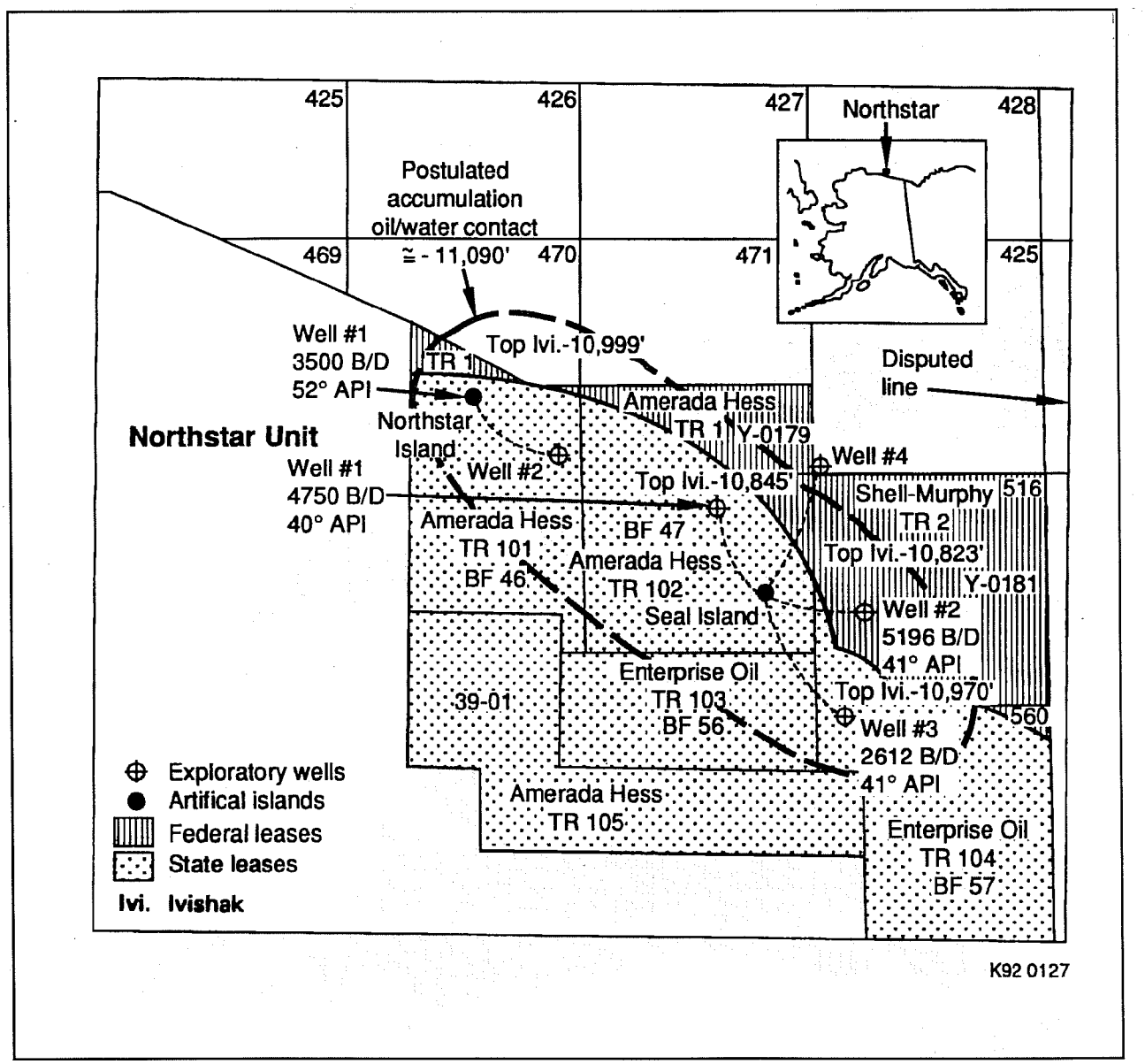

Figure B.18. NU map and postulated outline of the accumulation.

Current status of ownership provides that costs will be shared (unless otherwise stated in the Unit Operating Agreement) as follows (ADNR 1991f):

- Amerada Hess (operator) 80.85%
- Murphy Oil USA, Inc. 1.92%
- Shell Western E&P, Inc. 17.23%

Total NU area is 30,837.99 acres comprised of 7,494.50 acres of federal land and 23,343.49 acres of state land (see **Figure B.19**).

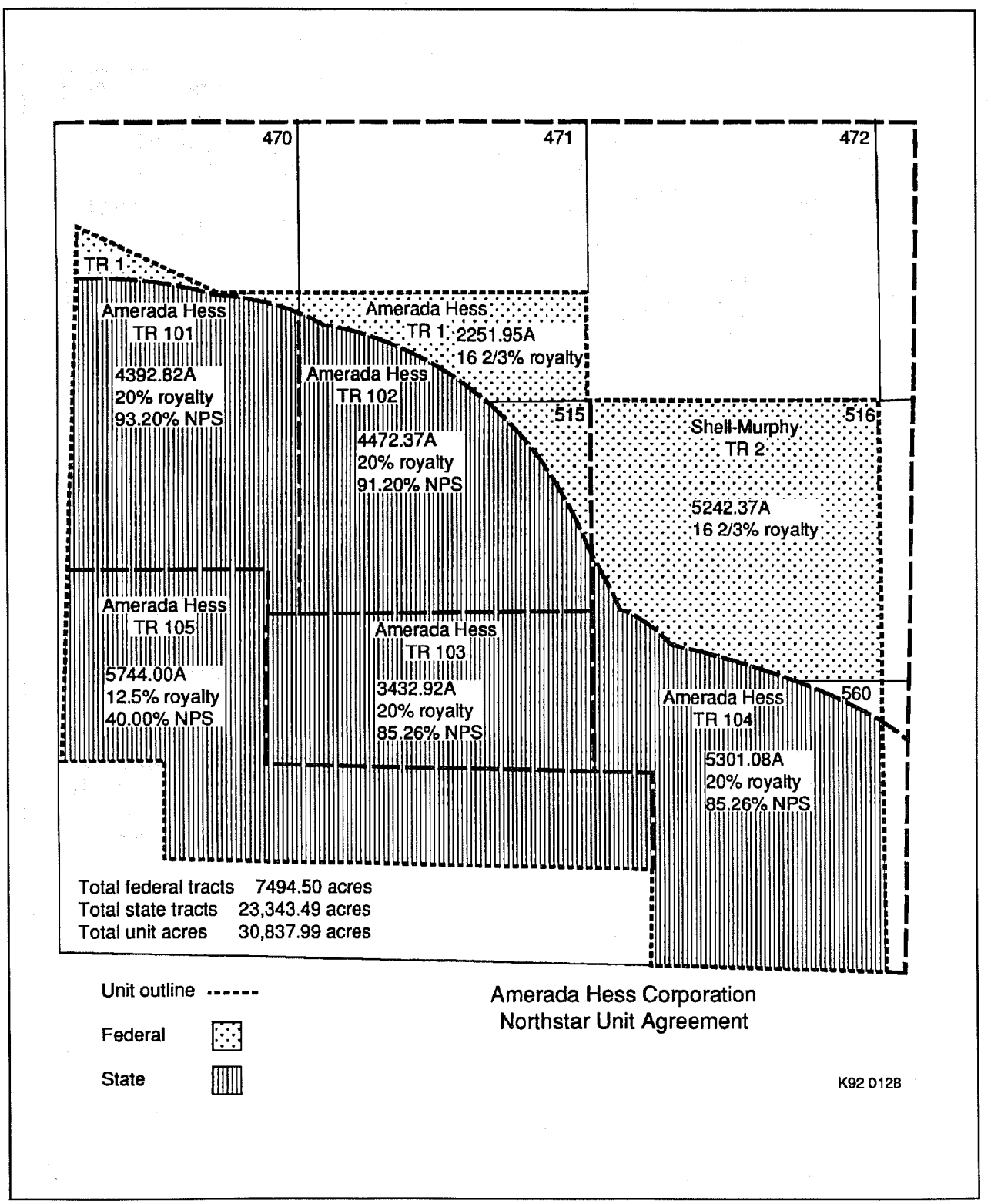

Figure B.19. NU royalties, net-profit share percentages, and ownership (MMS 1989).

B.8 Seal Island/Northstar Issues

As the NU evaluation process continues during the current POD covering the period from 1990 to 1994, the primary technical issues are the size of the accumulation, development costs, and the field production rate.

It appears the NU owners currently think the accumulation is too small to be economically developed. The high test rates in the exploration wells indicate good reservoir rocks in the Sadlerochit and the high gravity reported indicates good quality crude. The economics of construction of development and production facilities, including ice-resistant platforms and subsea pipelines in 50 ft water depths 15 mi offshore, present formidable challenges. For comparison, Endicott field, lies 2 mi offshore in about 4 ft water depths, produces from a gravel island, and is connected to shore by a gravel causeway. Total, ultimate reserves for Endicott are 403.8 MMBO.

Ultimately, the working interest owners will have to decide whether the accumulation is economic to produce. The net profit share provisions of the state leases add a very significant burden to the economic viability of NU.

B.9 Sandpiper Island History

Leases were first acquired in what would eventually be called the Sandpiper Island area in OCS Lease Sale 71 in 1982. It is located approximately 25 mi northwest of Prudhoe Bay. Six leases in the immediate area totaled $73,731,567 in successful high bids at the federal sale. Shell Western E&P Inc. became the operator for a group consisting of Shell, Amoco Production Co., Murphy Oil USA, Petrofina Delaware Inc., and Koch Industries Inc.

By 1986, Shell had constructed Sandpiper Island to drill the first well on the group's Harvard prospect. The gravel island was built for an estimated cost of $29 MM (OGJ 1986a). That year Shell drilled the OCSY-370 No. 1 (Sandpiper No. 1) to a total depth of 12,575 ft. During tests of the Sadlerochit, the well flowed at a rate of 2,419 BOPD, 275 BWPD, 3613 GOR, 41.2°API gravity from a lower zone and 409 to 2,325 BPD condensate, 2.9 to 18.6 MCFPD, 49 to 51°API gravity from an upper zone (AOGCC 1986). The well bottomed approximately 3,300 ft north of the island.

Immediately following the discovery, a second well was drilled for Amoco, Murphy, and Petrofina, the OCS Y-371 No. 1 (Sandpiper No. 2) to a target approximately 7,900 ft northeast of the island, or about 6,400 ft southeast of the bottom hole location of the first well. The Sandpiper (OCS Y-370) No. 2, well encountered the Sadlerochit low and wet and was not tested (AOGCC 1986). Both wells were plugged and abandoned and no further exploration activity has occurred. State and federal representatives advise that the island is now below sea level and natural erosion has resulted in a submerged mound.

In November 1992, a Sandpiper Unit consisting of five leases associated with the Sandpiper accumulation, as shown in **Figure B.20,** was approved by the MMS with Murphy Oil USA, Inc. as the unit operator. A 5-Year Plan of Operation will involve reservoir engineering studies, petrophysical/petrographic studies, and geological/geophysical mapping to be conducted by Murphy.

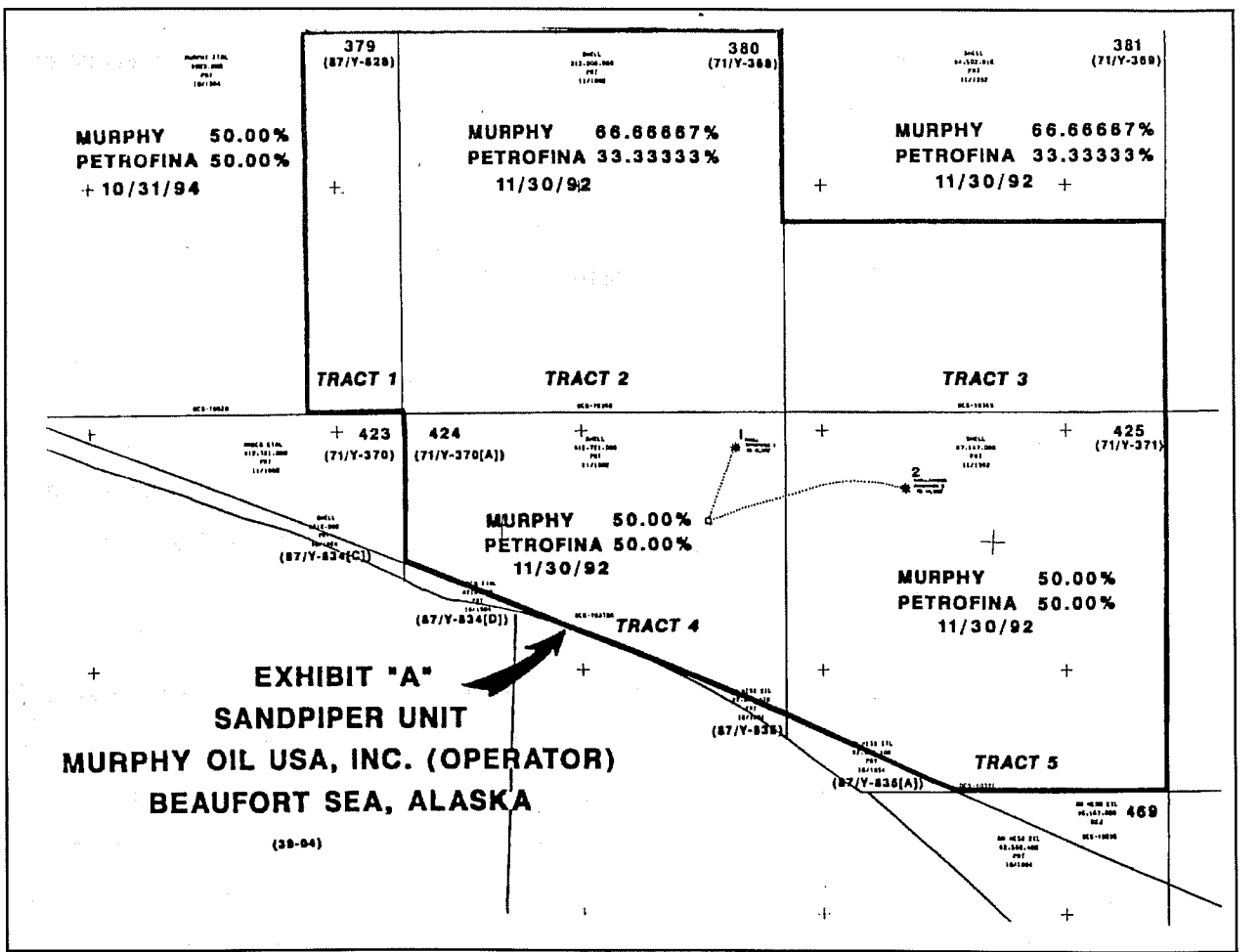

Figure B.20. Map of Sandpiper Unit, Murphy Oil USA, Inc.

B.9.1 Data Summary

No volumes have been published or released concerning potential reserves at Sandpiper Island. No seismic data are available to indicate the possible size of the structural closure or potential reservoir limit. Therefore, a rudimentary approach is used to determine a postulated reservoir volume. The TVD of the top of the zone in the No. 1 well was 11,117 ft subsea. The top of the zone in the No. 2 well was 11,301 ft subsea and presumably wet. The OWC in the No. 1 well occurs at 11,332 ft subsea, thus indicating a slightly tilted OWC between the No. 1 and No. 2 wells, or a partially oil saturated zone at the top of the No. 2 well, or a possible separation between the wells such as a fault (see **Figures B.21 and B.22**). A potential recoverable resource of approximately 93 MMBO is estimated by this method (see **Section 3.2.4.3.1.**).

B.9.2 Lease Summary

The unit formed in November 1992 and the ownership is shown in **Figure B.20**.

B.10 Sandpiper Island Issues

Many of the issues that apply to the NU are identical to those at Sandpiper Island with the added problems of a location 10 mi further offshore and an apparent recoverable oil volume about one-half the size of NU. Oil quality and reservoir quality appear similar. The working interest owners have demonstrated little interest in continuing operations, in contrast to the efforts in the NU, until the Sandpiper Unit was formed in November 1992. More definitive results should be forthcoming with the formation of the unit and the 5-year Plan of Operation.

B.11 Summary of History and Issues of Five NES Fields

The five NES fields are characterized by their dissimilarity. West Sak is by far the largest, but is plagued by poor oil quality, high oil viscosity, shallow depth, low reservoir temperatures, and low producing rates. Gwydyr Bay is the smallest of the fields and potential producing areas are fragmented on the surface by channels of the Kuparuk River Delta. Point Thomson is respectably large, but its reserves are comprised of gas and condensate, and currently there is no gas market or gas pipeline. Also the condensate will require stabilization before it can be transported in TAPS. The two offshore fields

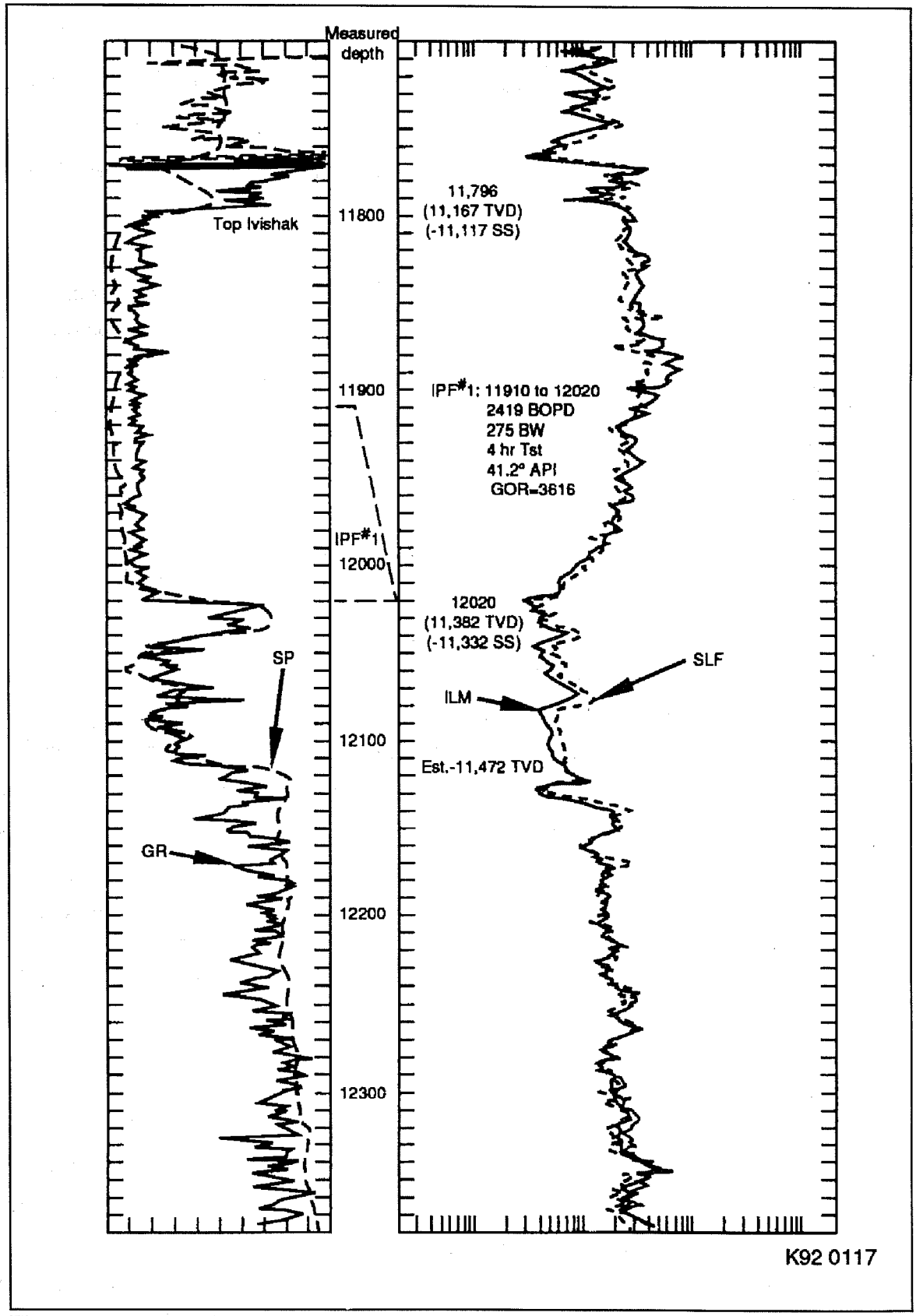

Figure B.21. Sandpiper No. 1 well log (AOGCC 1986).

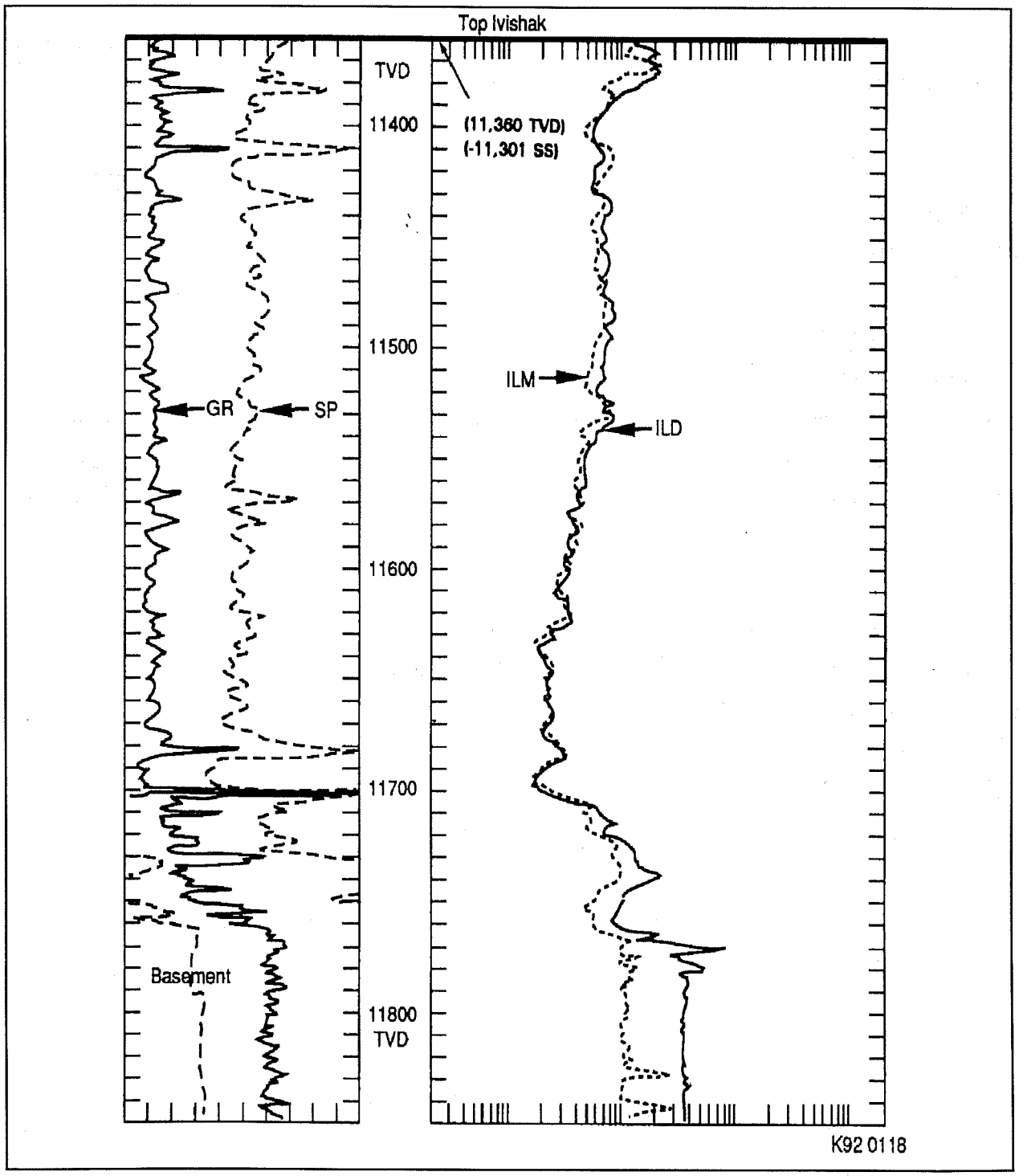

Figure B.22. Sandpiper No. 2 well log (AOGCC 1986a).

share more similarities in oil and reservoir quality, but appear to suffer the consequences of threshold reserve volume.

The dominant shared characteristic is the fact that none of the fields is on production (although nominal production occurs from the West Sak interval in the MPU Schrader Bluff).

As stated in **Section 1**, volume and rate are the two primary factors that control the decision-making process. Two NES fields, Gwydyr Bay and Sandpiper Island, have small unproven reserves and both are in areas of difficult operating and environmental conditions.

Northstar Unit, however, is an accumulation that appears to be a borderline case in terms of size. The uncertainty in the precise reserve volume (in published data) and in the project economics, may be resolved by the owners by 1994, the end of the current POD. Evaluation efforts by the owners indicate continued interest in possible development. It is possible that federal and state agencies, in cooperation with each other, and with the owners, may have an opportunity to apply innovative forms of regulatory or tax relief that could bring NU closer to the threshold of economic viability.

Point Thomson, with its unique mix of condensate and gas in a large onshore North Slope accumulation appears to be a likely candidate for liquids production if treatment and transportation technology can assist in lowering overall production and delivery costs. Regulatory aspects affecting pipeline construction and operation could assist bringing this field to producing status. Shared transportation facilities, if a major discovery occurred in ANWR or the eastern Beaufort Sea, could also be a major factor for Point Thomson production.

West Sak probably holds the greatest promise for relatively early and eventual substantial production that could have an impact on total North Slope production rate and TAPS throughput. Even this large accumulation of oil in place would require improvements or breakthroughs in technology to make such an impact. Current estimates of reserves will not achieve a level of production to begin to replace the decline of Prudhoe Bay and Kuparuk fields. Nevertheless, the 500 MMBO to 1 BBO reserve attributed to West Sak is the equivalent of the discovery of a new super giant oil field. With an estimated 13 to 20 BBOIP, every potential advance in drilling and production technology that would apply to this field is worthy of support and advocacy. Heavy oil production research; horizontal drilling techniques;

reservoir deposition, characterization, and prediction studies; and enhanced oil recovery methods all have a worthwhile target in West Sak.

Additionally, being located in the area of the existing Kuparuk field, with the knowledge base of operating field conditions gathered over 10 years of producing history, it would seem that regulatory practices at both federal and state level could offer opportunities for streamlining operations. To contribute to the reserve base on the North Slope within the time frame of practicality and in significant volume, West Sak offers the best opportunity currently identified, but requires equally practical and significant assistance.

The circumstances of utilizing the existing infrastructure of Kuparuk and Prudhoe Bay fields as their production declines may well be the key to West Sak development. Facilities sharing, using the giants to assist the average and small fields, offers the best hope for economically marginal accumulations. An investment and regulatory climate to assist such transitions is an absolute necessity.

B.12 References

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APPENDIX C

DEFINITION OF TAX AND ROYALTY RATE AND ECONOMIC VARIABLES

The tax and royalty rates and economic variables are defined as follows:

(1) **Base year** for discussing constant dollars is as of January 1, 1992.

(2) **Inflation rate** used is a constant 3.5%.

(3) **Royalty interest rate** - The Alaska royalty rate ranges from 12.5% to 20% depending on the lease terms of field. The state royalty rate, if unknown, is considered to be one-eighth or 12.5%.

(4) **Royalty oil processing fee** is the price per barrel that the state is charged by the producer for processing of the state's royalty oil. Some of the established field oil processing fees are as follows:

Field	$/BBL
Prudhoe Bay	0.73
Kuparuk	0.345
Lisburne	0.73
Milne Point	0
Endicott	0.47

The assumption for the royalty oil processing fee for the five NES Fields is zero.

(5) **Ad Valorem tax** is a state of Alaska property tax and the rate is 2% of the current year property tax base.

(6) **Severance tax rate**:

Oil- The Alaska severance tax for oil is 12.25% for the first 5 years of field production and 15% thereafter multiplied by the economic limit factor (ELF) with a minimum tax of $0.80 (un-escalated) applied to each barrel of field production less the state royalty share.

Gas - The Alaska severance tax for gas is 10% multiplied by the gas economic limit factor (ELF) with a minimum tax of $0.064/MCF.

(7) **Economic Limit Factor (ELF):** The economic limit factor (ELF) is defined as follows:

Oil ELF = [1 - 300/Daily Average Well Rate] **{150,000/Average Daily Field Rate}**1.5333

GAS ELF = 1 - (3000 MCF / Daily Average Gas Rate)

(8) **The Alaska conservation tax** is $0.004/bbl of production less the state royalty share. The conservation surtax is a state tax of $0.05/bbl of production less the state royalty share.

(9) **Alaska income tax rate** - The Alaska state income tax rate is calculated as follows:

Rate = 9.4% * 1/3 [Alaska Sales/Worldwide Sales
+ Alaska Production/Worldwide Production + Alaska Assets/Worldwide Assets]

Because it is very difficult to determine any company's worldwide sales, production, and assets, a nominal effective **state income tax rate of 3%** is used.

(10) **Federal tax rate** is assumed to be 34%.

(11) **TAPS blended API gravity** - The average TAPS gravity is assumed to be 28°API.

(12) **Gravity differential** = $0.29/°API.

(13) **Gross Revenue** = Field Production Volume of Oil and Gas x Well Head Price.

(14) **Royalty** = [Royalty Interest Rate x Gross Revenue] - [Oil Processing Fee x Field Production Volume x Royalty Interest Rate].

(15) **Net Revenue** = Gross revenue - Royalty.

(16) **Oil Severance Tax** is the greater of:

(a) Current year Severance Tax Rate x ELF x Well Head Price x Field Production Volume x (1 - State Royalty Interest Rate), or

(b) $0.80 x ELF x Field Production Volume x (1 - Royalty Interest Rate).

(17) **Gas Severance Tax** is the greater of:

(a) $0.10 x ELF x Well Head Price x Field Production Volume x (1 - Royalty Interest Rate), or

(b) $0.064 x ELF x Well Head Price x Field Production Volume x (1 - State Royalty Interest Rate).

(18) **Ad Valorem Tax** = Ad Valorem Property Tax Base x Ad Valorem Property Tax Rate.

(19) **Ad Valorem Property Tax Base** = [Previous Year Ad Valorem Property Tax Base - (Previous Year Ad Valorem Property Tax Base/Remaining Project Life)] x (Inflation Rate) + Previous Year Tangible Investment.

(20) **Conservation Tax** = (Conservation Tax Rate + Conservation Surtax Rate) x Field Production Volume x (1 - Royalty Interest Rate).

(21) **Income Before State and Federal Taxes** = Gross Revenue - Operating Costs - Royalty - Severance Tax - Ad Valorem Tax - Conservation Tax.

(22) **State Income Tax** = (Income Before State and Federal Taxes - State Income Tax Depreciation) x State Income Tax Rate.

(23) **State Income Tax Depreciation (Straight Line Basis)** = Cumulative Total Capital/Project Life.

(24) **State Income Tax Depreciation (Units of Production Basis)** = State Income Tax Depreciation Factor x State Income Tax Depreciation Basis.

(25) **State Income Tax Depreciation Factor** = Current Year Total Field Production/Current Year End Remaining Reserves.

(26) **State Depreciation Basis** = Previous Year State Depreciation Basis + Current Year Total Capital - Previous Year State Income Tax Depreciation.

(27) **Federal Income Tax** = (Income Before State and Federal Taxes - Federal Income Tax Deduction - State Income Tax) x Federal Income Tax Rate.

(28) **Federal Income Tax Deduction** = Federal Income Tax Depreciation + Amortized intangible drilling cost (IDC) + Expensed IDC.

(29) **Federal Income Tax Depreciation** = 1.5 x [(Current Year Tangible Capital + Previous Year Book Value) Depreciated on a 7-year 150% continuous declining balance basis].

(30) **Book Value** = Cumulative Tangible Investment - Cumulative Tax Depreciation.

(31) **Tangible Capital** = Plant Capital + 0.30 x Drilling Capital.

(32) **Intangible Capital** = 0.70 x Drilling Capital.

(33) **Expensed IDC** = 0.70 x Intangible Drilling Capital.

(34) **Amortized IDC** = (Current Year Unexpensed Drilling Capital + Previous Year Unamortized IDC); amortized on a 5-year straight line basis.

(35) **Total Capital** = Plant capital + Drilling Capital.

(36) **Plant Capital** = 100% Tangible.

(37) **Drilling Capital** = 30% Tangible + 70% Intangible.

(38) **Operating Cash Flow** = Income Before State and Federal Income Taxes - Federal Income Tax - State Income Tax.

(39) **Industry Cash Flow** = Income Before State and Federal Income Tax - Federal Income Tax - State Income Tax - Total Capital.

(40) **State Revenue** = Royalty + Severance Tax + Ad Valorem Tax + Conservation Tax + State Income Tax.

(41) **Federal Revenue** = Federal Income Tax.

APPENDIX D

Appendix D contains the following:

1. Economic model description.
2. Comparison of Niakuk onshore versus offshore development.
3. **Tables D.5 to D.7**, production forecasts.
3. **Tables D.8** to **D.14** containing sensitivity analysis results.
4. Financial summaries for each of the five NES fields at the NES Low oil price (1/1/92$).

D.1 Economic Model

A commercially available financial software package[a] is used to develop the Alaska economic model. This software allows the easy creation of a financial model, has extensive features for querying the model, construction of "what if" scenarios, and goal-seeking features. The economic model was previously described in *Alaska Oil and Gas: Energy Wealth or Vanishing Opportunity?* (DOE 1991). The previous model is refined and modified for the current study.

D.1.1 Model Description

A discounted cash flow petroleum accounting model is used to evaluate the historical and projected economics of arctic Alaska oil resources. The model is constructed so the appropriate level of detail for the currently producing and known undeveloped fields can be used depending on the available information. Producing fields and known undeveloped fields are analyzed using historical and projected production and investment schedules reflecting the information known about these fields.

Geologic, geophysical, and lease acquisition costs are assumed to be sunk costs, and are excluded from economic calculations. All costs, oil prices, inflation, and discounting are calculated at the mid-year. Project capital is assumed to be 100% equity with no debt financing or leverage considered.

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a. Interactive Financial Planning System, (IFPS). *The use of a commercial product neither implies endorsement or recommendation.*

D.1.1.1 Resource Parameters. The original oil in place (OOIP) and ultimate hydrocarbon recovery factors are primary inputs. Production from this resource base is accomplished in several ways:

- Historical and projected production schedules are directly entered into the model.
- Undiscovered resource production schedules are extrapolated from a peak production rate followed by a specified exponential decline.
- The build-up to peak production rate and the length of time of peak production are variables in the model.

A percent water cut versus percent predicted ultimate recovery relationship is used to calculate water production. The water and oil production are summed to give total fluid production. This feature is used to calculate production operating costs on a per barrel of fluid lifted basis.

The number of development wells drilled is calculated using the development drilling investment schedule and the cost per development well. Development well cost is determined by average well-depth look-up table. Development wells are either producing wells or injection wells. The number of producing wells is determined as a percentage of total development wells. As a field nears depletion, the number of active producers is reduced as a specified function of ultimate recovery. This procedure simulates the late-life operations of a producing field, as individual uneconomic wells are shut-in. The average well production rate is calculated by dividing the total field production rate by the number of active producers. This allows calculation of production based severance tax, as discussed below. Field oil production terminates when the specified reserves are depleted.

D.1.1.2 Capital Investments. Project investments include exploration, delineation, and development well costs and production facilities. All investment costs are input as 1/1/92 dollars and inflated to mid-year then current dollars using the applicable inflation category:

- Historical and projected well costs, counts, and timing are directly entered for the producing and known undeveloped fields.
- Well costs for undiscovered resources are related to a series of cost versus depth curves for the exploration and development wells. Delineation wells are assumed to cost the same as development wells. Development well costs are reduced with time to approximate the experience gained and the optimization of drilling practices during field development.
- Historical and projected facilities cost are directly entered.
- Offshore production platforms are directly entered for all cases.

D.1.1.2.1 Costs--Project costs are either tangible or intangible and treated differently for tax purposes. Tangible costs are assumed to be 100% of production facilities, 30% of development well costs, and 10% of exploration and delineation well costs. The balance is considered to be intangible.

D.1.1.2.2 Timing--The scheduling of the exploration, delineation, and development drilling programs is estimated and directly entered into the model. The actual project timing is determined by institutional, regulatory, economic, and environmental factors.

D.1.1.3 Operating Costs. Total field operating costs are calculated using a combination of cost components based on total fluid lifted, well workover cost, facilities cost-sharing fee, and miscible injectant (MI). For each case studied, the actual cost components used varied. **Table D.1** shows which cost components are used for each field.

Table D.1. Cost components used for each field.

Field	Total Fluid Lifted	Well Workover	Facilities Cost Sharing	Miscible Injectant
Prudhoe Bay	Yes	No	No	No
Kuparuk River	Yes	No	No	No
Lisburne	Yes	No	No	No
Endicott	Yes	No	No	No
Milne Point	Yes	No	No	No
Point McIntyre	Yes	Yes	Yes	No
Niakuk Onshore	Yes	No	Yes	No
West Sak "A"	No	Yes	Yes	Yes
West Sak "B"	No	Yes	Yes	Yes
Schrader Bluff	Yes	Yes	Yes	No
Gwydyr Bay	Yes	Yes	No	No
Seal Island/Northstar	No	No	No	No
Sandpiper	No	No	No	No

Operating costs for Seal Island/NorthStar and Sandpiper are given a direct cost and escalated at the general inflation rate. The historical total operating cost for the developed fields is expressed as a function of total fluid production.

A percent water cut versus percent of ultimate predicted recovery relationship is used to estimate water production. Historical reservoir water-cut performance is extrapolated for the projected cases using the actual reported production history, while the known undeveloped cases use an analogous water-cut curve based on the estimated size of the resource and producing formation. Where pilot test or reservoir study data is available, this information is used. The oil production rate and recovery at any point in time is used to calculate the water production. The oil production rate and water production rate are summed for total fluid production rate. This approach incorporates historical and expected reservoir performance in the determination of operating cost based on total fluid production.

D.1.1.4 Oil Price. The base oil prices used are the EIA High, Mid-Level, and Low and NES Low as described in **Section 3.2**, expressed in 1/1/92 dollars. The base oil price is inflated at the general inflation rate to calculate the mid-year base oil price for the current year. Additional adjustments to the base oil price are made for marine tanker transportation charges, TAPS tariff, field tariff, and API gravity price adjustments. The net result is a wellhead price per barrel in then current year dollars. No attempt is made to adjust the oil prices for crude quality. The world oil price is referenced for a basket of crude oils with an unknown average crude quality. The initial marine tanker transportation cost and field tariff are entered in 1/1/92 dollars and adjusted by transportation inflation. The TAPS tariff schedule is calculated independent of the economic model to reflect the projected TAPS throughput rate for the various scenarios studied. It is entered on a yearly basis in 1/1/92 dollars and adjusted by transportation inflation.

D.1.1.5 Inflation Adjustment. All costs are inflated to then current dollars from a 1/1/92 base using a mid-year inflation. Four types of inflation can be used:

- General inflation - assumed to be related to the Gross National Product implicit price deflator
- A transportation inflation factor
- A drilling inflation factor
- An oil inflation factor that consists of general inflation plus real oil price growth.

A future inflation rate of 3.5% for general, transportation, and drilling inflation factors and zero for real oil price inflation are assumed. The historical annual percent change in the GNP price deflator is presented in **Figure D.1**. The average for the years 1983 to 1989 is 3.36%.

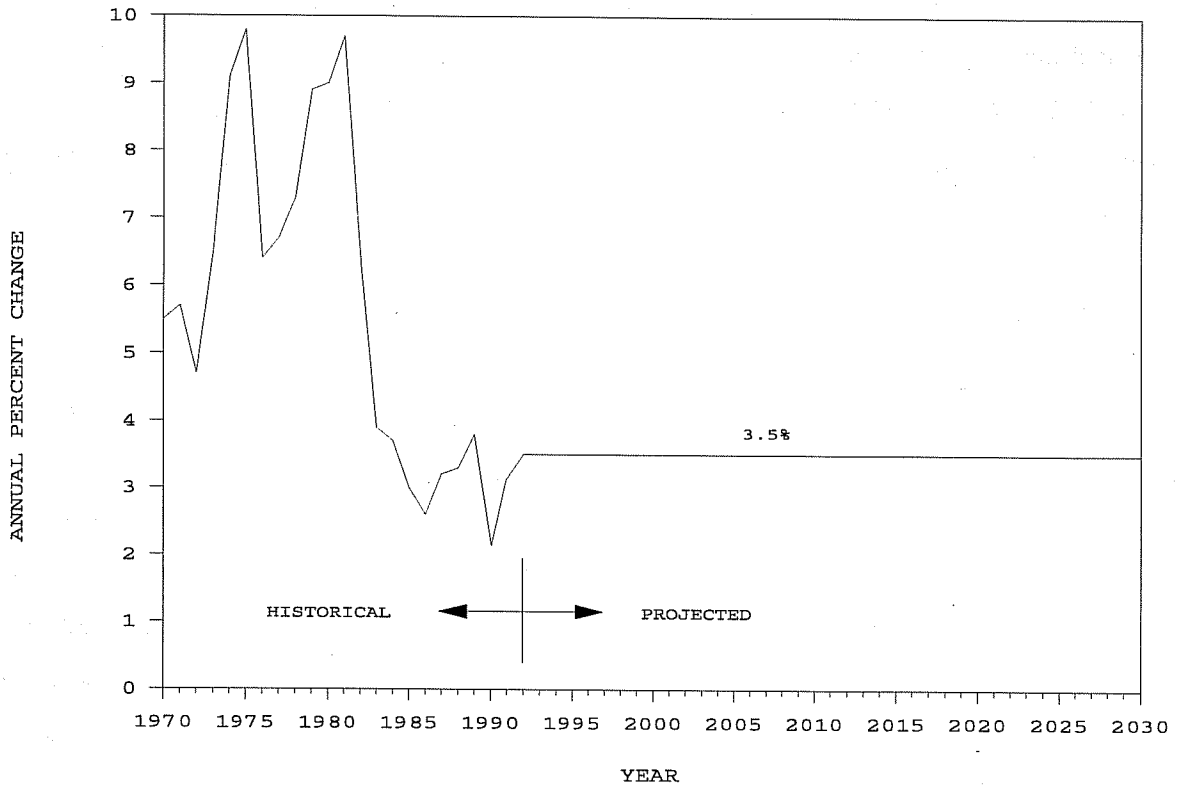

Figure D.1 Historical annual percent change in the Gross National Product price deflator.

D.1.1.6 Royalty. Royalty is calculated by multiplying the royalty rate for a specific field by the gross wellhead revenue. The royalty rate ranges from 12.5 to 18.0%, depending on the field. Royalty oil processing fees are paid by the state to the Unit Owners for treating the state's royalty oil to meet pipeline specifications. The processing fee is deducted from the royalty. Lease terms for Seal Island/Northstar specify a net profits interest (NPI) calculation in addition to a conventional royalty. The NPI is 68.21% of the revenue before income tax, calculated as net revenue less the sum of total operating cost, severance tax, conservation tax, conservation surtax, and ad valorem tax. State tax calculations then follow this calculation.

D.1.1.7 Tax Calculations The determination of the undepreciated state and federal balances and property tax base is required to estimate future income for the currently producing fields. Historical cases are run for Prudhoe Bay, Kuparuk River, Lisburne, Endicott, and Milne Point using the best available information for historical and announced oil prices, production rates, and investment schedules and categories. The historical runs are made to year-end 1993 to provide an overlap for the forecast models. Year-end 1991 federal undepreciated balances, as calculated in the historical runs, are added

to the depreciation for new investments starting in 1992. The year-end 1991 undepreciated balance depreciated for various time lengths to provide the best match of the 1992 to 1993 historical overlap time periods. While not exactly matching the historical depreciation schedule, the total values are in very good agreement. There is a minor affect for the first 3 to 4 years of the forecast economic runs. Unamortized intangible drilling cost (IDC) balances are treated in a similar fashion.

D.1.1.8 State of Alaska Taxes. A major improvement in this model relative to the previous study is the incorporation of Alaska tax law for the treatment of state depreciation, property tax, severance tax with an economic limit factor (ELF) for both oil and gas, conservation tax and surtax, royalty processing fees, and state income tax. State taxes are calculated before federal income tax and are a deduction in determining federal taxable income. One major change from the previous study was the incorporation of a state income tax loss carry-forward provision. No state income taxes are paid until all previous state income tax losses had been offset. This study focuses on project specific economics and does not attempt to take into account individual companies tax position. Two different approaches can be used, tax loss to offset other company income or to treat a tax loss as zero taxes with no offsetting effect. The tax loss carry-forward approach is essentially intermediate to the other two options.

D.1.1.8.1 Depreciation--The state of Alaska calculates depreciation on a units-of-production basis on the total investment (tangible and intangible) once the asset has been placed in service. A units-of-production depreciation factor is calculated using the yearly production divided by the year-end remaining reserves. The depreciable basis is the cumulative total investment less cumulative depreciation. The state depreciation is the product of the state depreciation factor and the depreciation basis. This amount is deducted as a non-cash expense.

D.1.1.8.2 Property Tax--The state property tax base is calculated using the inflation adjusted cumulative tangible investment, less the previous year's property tax base divided by the remaining project life. This value is adjusted by the general inflation rate plus previous year tangible investment. The property tax (or ad valorem tax) is 2% of the current year property tax base.

D.1.1.8.3 Severance Tax--The state oil severance tax is calculated at 12.25% of the net wellhead value (i.e., less royalty oil) for the first 5 years of production and 15% thereafter, multiplied by the oil economic limit factor (OELF) with a minimum tax of $0.80 (unescalated) per net barrel of

production. Net production is defined as oil production less royalty. The OELF calculation used is the post-1989 formula, which is:

$$OELF = [1 - 300/\text{Daily Average Well Rate (BOPD)}]^{x}$$

where

$$x = [150{,}000/\text{Average Daily Field Rate (BOPD)}]^{1.5333}.$$

Similarly, the state gas severance tax is calculated at 10.0% of the net wellhead value, multiplied by the gas economic limit factor (GELF), with a minimum tax of $0.064 per thousand standard cubic feet of gas (MCF). The GELF calculation is:

$$GELF = [1 - 3{,}000/\text{Daily Average Well Rate, (MCF/day)}]$$

D.1.1.8.4 Conservation Tax--The conservation tax rate is $0.004/BBL of net production and the conservation surtax is $0.05/BBL of net production.

D.1.1.8.5 Income Tax Calculation--The state income tax rate is calculated as follows:

$$9.4\% * 1/3 * \left[\frac{\text{Alaska Sales}}{\text{Worldwide Sales}} + \frac{\text{Alaska Production}}{\text{Worldwide Production}} + \frac{\text{Alaska Assets}}{\text{Worldwide Assets}}\right]$$

Because it is difficult to independently determine any company's worldwide sales, production, and assets, a nominal effective state tax rate of 3% is used. This value compares favorably with the implicit effective rate from Deakin (1989). An effective rate of 1.5 to 3% is used by the Department of Revenue for revenue forecasting.[a]

The state income tax is calculated as follows:

- Net Revenue = Gross Revenue - (Royalty - Processing Fee)
- Net Before State Income Tax = Net Revenue - Total Operating Cost - Severance Tax - Conservation Tax - Conservation Surtax - State Property Tax - State Depreciation

a. Alaska Department of Revenue, personal communication, May 1990.

- Net After State Income Tax = Net Before State Income Tax - State Income Tax + State Depreciation.

The state depreciation is added back for the calculation of federal taxes.

D.1.1.9 Federal Taxes. Federal income taxes are calculated after the state of Alaska tax calculations, with state taxes treated as a deduction from federal income. The federal income calculations involve the treatment of IDCs, depreciation, and federal income tax. One major change from the previous study is the incorporation of a federal income tax loss carry-forward provision. No federal income taxes are paid until all previous federal income tax losses have been offset. This study focuses on project specific economics and does not take into individual companies tax position. Two different approaches could be used, tax loss to offset other company income or to treat a tax loss as zero taxes with no offsetting effect. The tax loss carry-forward approach is essentially intermediate to the other two options.

D.1.1.9.1 Federal Amortization of IDCs--Federal tax law allows IDCs to be expensed and amortized and permits a more favorable treatment of depreciation. Current tax law permits 70% of the IDCs to be expensed in the year incurred and the balance amortized over 60 months. The model assumes that IDCs are 90% of exploration and delineation well costs and 70% of development well costs.

D.1.1.9.2 Federal Depreciation--Federal depreciation is calculated using a 7-year, 150% declining balance of the tangible investment with no switchover. This method is consistent with the approach used by the Alaska Department of Revenue. The tangible assets are assumed to have no salvage value at the end of the project. Federal law allows the choice of depreciation methods such as Accelerated Cost Recovery System (ACRS), straight line, declining balance, units of production, and sum-of-the-years digits with a switchover before the end of the depreciation life. No depletion allowance is used for the recovery of exploration and lease acquisition costs; these costs are assumed to be sunk costs.

D.1.1.9.2.1 Federal Income Tax Calculation--The federal income tax rate is 34% of the federal taxable income. Non-cash deductions are added back to net income for the determination of cash flow.

The federal income tax, net income, and operating and total cash flows are calculated as follows:

- Net Income Before Federal Income Tax = Net After State Income Tax - Expensed IDC - Amortized IDC - Federal Depreciation
- Net Income = Net Income Before Federal Income Tax - Federal Income Tax
- Operating Cash Flow = Net Income + Federal Depreciation + Amortized IDC + Expensed Intangible Investment
- Total Cash Flow = Operating Cash Flow - Total Investment.

D.1.1.10 Economic Determination. The yearly total cash flow is discounted to determine the present worth of the future total cash flow. The economic limit is defined as the year operating cash flow is negative (after payout of the project). Nominal discount rates of 10%, and 15% are used. The real discount rate is related to the nominal discount rate by the following equation from Stermole (1982).

$$[1/(1+i_n)]^n = [1/(1+f)]^n \times [1/(1+i_r)]^n$$

where

n = time periods

i_n = nominal discount rate

f = inflation rate

i_r = real discount rate.

With an inflation rate of 3.5% and a 30 year time period, the real discount rate for a nominal discount rate of 10 and 15% is 6.28 and 11.1%, respectively. The actual real discount rate for any specific project depends on the project life.

The yearly present values are summed to determine the cumulative net present value of each case considered. The model does not directly calculate the internal rate of return (IRR), but the IRR can be determined by solving for the nominal discount rate that results in a cumulative net present value of zero at the end of the project.

D.1.1.11 Model Validation. The economic model was previously validated (DOE 1991) by comparison with the Young (1986) and the Deakin (1989) studies. For a discussion of the model validation see the above referenced study.

D.1.2 References

Deakin, E. B., 1989, "Oil Industry Profitability in Alaska - 1969 through 1987," Alaska Department of Revenue, March 15, 1989.

U.S. Department of Energy (DOE), 1991, *Alaska Oil and Gas - Energy Wealth of Vanishing Opportunity?*, DOE/ID/01570-H1, January 1991.

Young, Y. S., W. S. Hauser, 1986, "Economics of Oil and Gas Production from ANWR for the Determination of Minimum Economic Field Size," Bureau of Land Management, Alaska State Office, Division of Mineral Resources.

Stermole, F. J., 1982, *Economic Evaluation and Investment Decision Methods*, Fourth Edition, pp. 169-177.

D.2 Comparison of Niakuk Onshore and Offshore Projects

BP announced in July 1991 that if would forego the controversial offshore Niakuk permitting process that had developed because of the causeway breaching issue in favor of development for Heald Point (see **Section A.3.2**). Development by directional drilling from a pad located on Heald Point was determined to be technically feasible in 1991 because advances in directional drilling technology made a 200 ft bottomhole location resolution possible compared to the 400 ft resolution that was possible in 1988 when the original offshore project was initiated.[a] The economics of the original offshore project are developed to provide an estimate of the costs and effects that environmental requirements can have on projects.

It is assumed that 100% of the proven and potential Kuparuk zone would be developed by the offshore project compared to the 80% of the 58 MMBO proven reserves and 50% of the 34 MMBO potential reserves in Region 3 assumed for the onshore development. This results in a total from the Kuparuk zones of 92 MMBO. The Alapah recoverable reserves are 7.0 MMBO, the same as before (see **Section A.3.2**), for a total of 99 MMBO.

It is estimated that 11 new wells are needed to develop the proven Kuparuk reserves at $3.4 MM/well plus costs to recomplete the 3 exploratory wells at 50% of the cost of new wells. It is assumed that 14 wells will be needed to develop 100% of the potential Kuparuk reserves and 4 wells, as before, to develop the Alapah. Facilities and pipelines, including $31.5 MM for a 1000 ft breach, are estimated to be $220.1 (1/1/92$) by comparison to the data discussed in **Section A.3.2**. The investment and drilling schedule are shown in **Table D.2**.

The production forecast is developed as discussed in **Section A.3.2.4** for the increased reserves of 99 MMBO. The forecast is given in **Table D.3**.

Operating costs are assumed to be 30% greater than for the onshore project; i.e., 1.3 x $1.27/BTF = $1.68/BTF (1/1/92$). The Milne Point water-cut relationship is used to determine total fluid produced (**Figure A.15**). Future producers are determined from the Set B curve (see **Section 3.2.5**). No facilities sharing fee is used. The field pipeline tariff is estimated to be $0.53/BBL using the

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a. BP Exploration (Alaska) Inc., personal communication, August 1992.

Table D.2. Niakuk offshore development case.

Year	Wells		Investments - $MM (1/1/92$)		
	No.[a]	No. (Alapah)	Wells	Facilities (Inc'l pipelines)	Annual Total Cost
1992	0	0	0	25.1	25.1
1993	4	0	17.2	98.0	115.2
1994	7	0	30.1	97.0	127.1
1995	3.5[b]	3	28.0	0	28.0
1996	4[c]	1	21.5	0	21.5
1997	4[c]	0	17.2	0	17.2
1998	4[c]	0	17.2	0	17.2
Totals	26.5	4	131.2	220.1	351.3

a. Kuparuk wells for development of proven and potential reserves.
b. Recompletion of 3 exploratory wells at 50% of normal cost plus 2 Kuparuk wells for potential reserves.
c. Kuparuk wells for potential reserves, total 14.

Table D.3. Niakuk offshore case production forecast.

Year	Kuparuk	Alapah	Kuparuk Potential	Project Total
1994	4.8	0	0	4.8
1995	19.0	1.4	2.8	23.2
1996	19.0	2.6	11.2	32.8
1997	19.0	2.6	11.2	32.8
1998	16.7	2.3	11.2	30.2
1999	14.5	2.0	10.0	26.5
2000	12.7	1.8	8.8	23.3
2001	11.0	1.6	7.8	20.4
2002	9.6	1.4	6.8	17.8
2003	8.4	1.2	6.0	15.6
2004	7.3	1.1	5.3	13.7
2005	6.4	0.9	4.7	12.0
2006	5.5	0.3	4.1	9.9
2007	5.0	0.0	3.4	8.4

procedures discussed in **Section 3.2.1.3.3**.

The economic results for the onshore versus the offshore cases are shown in **Table D.4**. The discount rate for PW = 0 for the offshore case is about 20% and for the onshore case it is about 19%. Although the rate of return for each project is similar, the cash flow to industry and revenue to the state and federal governments are reduced by a total of $135 MM in constant 1/1/92$. More importantly, the reserves are potentially reduced by 29 MMBO for the onshore case with current drilling technology.

Table D.4. Niakuk onshore development economics compared to offshore development economics using NES Low oil price case - $MM(1/1/92$).

Economic Factor	Onshore	Offshore
	NES Low oil price	NES Low oil price
Project Life - yrs	13	14
Reserves - MMBO	70.4	99.0
Investments	253.9	322.8
Operating Costs	379.1	495.0
Cash Flow - PW_{10}	86	133
State Revenue - PW_{10}	137	192
Federal Revenue - PW_{10}	70	103

D.3 PRODUCTION FORECASTS

Table D.5. Production forecasts for Prudhoe Bay, Kuparuk, Endicott, Lisburne, Milne Point, Schrader Bluff, Niakuk, and Point McIntyre (MBOPD).

YEAR	PBU	KRU	ENDICOTT	LISBURNE	MILNE PT	SCHRADER BLUFF	NIAKUK	PT. McINTYRE	COMPOSITE PRODUCTION
1992	1170	310	114.2	40	18.5	4.1	0	0	1,656.80
1993	1100	306	87.5	40	18.5	9	0	0	1,561.00
1994	1025	303	73.4	37.5	18.5	10.5	5.1	40	1,513.00
1995	995	299	61.9	37.2	16.2	13.5	16.6	50	1,489.40
1996	950	292	52.0	36.2	14.3	15.5	20.2	60	1,440.20
1997	880	285	44	35	12.6	17	23.8	60	1,357.40
1998	803	260	38	33.2	11	19	21.7	60	1,245.90
1999	732	235	32	29.6		28	19.8	60	1,136.40
2000	666	210	27	25.6		29	17.5	60	1,035.10
2001	608	185	23	22.7		30	15.3	60	944.00
2002	553	165	20	19.9		29	13.5	53	853.40
2003	507	145	17	17.2		30	11.8	47	775.00
2004	460	125	14	15.6		29	10.5	41	695.10
2005	408	105	12	13.4		30	9.2	36	613.60
2006	372	85	10	10.7		29	7.9	32.9	547.50
2007	341	71	9	8.7		30		28	487.70
2008	309	57	7.5	0		28		25	426.50
2009	282	43	6.5	0		29		22	382.50
2010	252	30	5.3	0		25.5		20	332.80
2011	239	18		0		26.5		18	301.50
2012	220	14.6		0		25		16	275.60
2013	200	0		0		24		14	238.00
2014	184			0		22.5		13	219.50
2015	170			0		21.5			191.50
2016	164			0		17.4			181.40
2017	155								155.00
2018	145								145.00
2019	135								135.00
2020	125								125.00
2021	115								115.00
2022	105								105.00
2023	90								90.00
2024	53.4								53.40

Table D.6. Production forecasts for the five NES Fields (MBOPD).

YEAR	WEST SAK A	WEST SAK B	GWYDYR BAY	POINT THOMSON (5 TCF CASE)	SEAL ISLAND/ NORTHSTAR	SANDPIPER ISLAND	TOTAL
1992	0	0	0	0			0.00
1993	0	0	0	0			0.00
1994	0	0	0	0			0.00
1995	0	0	0	0			0.00
1996	0	0	0	0			0.00
1997	0	0	0	0			0.00
1998	0	0	0	0		22	22.00
1999	0	0	4	0		38	42.00
2000	0	0	9.3	0	10.4	55	74.70
2001	39	0	13.3	0	18.3	55	125.60
2002	74	0	13.3	0	26.1	55	168.40
2003	109	0	13.3	0	26.1	55	203.40
2004	144	0	11.8	0	26.1	55	236.90
2005	156	0	10.5	0	26.1	47	239.60
2006	168	0	9.3	0	22.4	40	239.70
2007	168	0	8.3	0	19.3	33	228.60
2008	153	20	7.4	44.53	16	29	269.93
2009	127	52	6.6	45.12	14.3	24	269.02
2010	95	67	5.9	44.79	12.3	21	245.99
2011	63	65	5.5	44.5	10.6	17	205.60
2012	48	56	5.1	44	9.1		162.20
2013	32	31	4.7	43			110.70
2014			4.3	39.99			44.29
2015							0.00
2016							0.00
2017							0.00
2018							0.00
2019							0.00
2020							0.00
2021							0.00
2022							0.00
2023							0.00
2024							0.00

Table D.7 Composite Production Forecasts for **Figures 3.28 and 3.29**, and total including Five NES Fields (MBOPD).

YEAR	COMPOSITE PRODUCTION[a] (Figure 3.28)	COMPOSITE PRODUCTION[b] (Figure 3.29)	TOTAL (including Five NES Fields)
1992	1,656.80	1,656.80	1,656.80
1993	1,561.00	1,561.00	1,561.00
1994	1.513.00	1,513.00	1,513.00
1995	1,489.00	1,489.40	1,489.00
1996	1,440.20	1,440.20	1,440.20
1997	1,357.40	1,357.40	1,357.40
1998	1,245.90	1,245.90	1,267.90
1999	1,140.40	1,136.40	1,174.40
2000	1,044.40	1,035.10	1,100.40
2001	996.30	944.00	1,056.30
2002	940.70	853.40	1,008.50
2003	897.30	775.00	965.10
2004	850.90	695.10	920.20
2005	780.10	613.60	842.70
2006	724.80	547.50	777.90
2007	664.00	487.70	708.00
2008	651.43	426.50	644.50
2009	613.22	382.50	599.80
2010	545.49	332.80	528.10
2011	479.50	301.50	457.10
2012	428.70	275.60	388.70
2013	348.70	238.00	301.00
2014	263.79	219.50	219.50
2015	191.50	191.50	191.50
2016	181.40	181.40	181.40
2017	155.00	155.00	155.00
2018	145.00	145.00	145.00
2019	135.00	135.00	135.00
2020	125.00	125.00	125.00
2021	115.00	115.00	115.00
2022	105.00	105.00	105.00
2023	90.00	90.00	90.00
2024	53.40	53.40	53.40

a. Forecast includes PBU, KRU, Endicott, Lisburne, Milne Point, Schrader Bluff, Niakuk, Point McIntyre plus West Sak A, West Sak B, Gwydyr Bay, and Point Thomson.
b. Forecast includes PBU, KRU, Endicott, Lisburne, Milne Point, Schrader Bluff, Niakuk, Point McIntyre

D.4 SENSITIVITY ANALYSIS RESULTS

Table D.8. Effects on FOP ($/BBL) for PW_{10} and PW_{15} = 0 for changes in economic factors (Δ%) for West Sak Area A.

FOP $PW_{10} = 0$	FOP $PW_{15} = 0$	Op. Cost	Inv.	O+I[a]	Vol.	O+I[a] +V	Roy Rate	Tax Rate	R+T Rate[b]	R+T + O+I[c]	R+T +O+I +V[c]
30.83	33.14	0	0	0	0	0	0	0	0	0	0
29.75	32.12	-10									
28.67	31.10	-20									
26.55	29.06	-40									
32.98	35.20	+20									
29.47	31.50		-10								
28.12	29.86		-20								
25.46	26.59		-40								
33.53	36.44		+20								
28.39	30.48			-10							
27.18	29.14			-15							
25.96	27.81			-20							
21.10	22.47			-40							
35.69	38.48			+20							
32.59	35.24				-10						
29.38	31.44				+10						
28.19	30.01				+20						
27.10	28.94					-10+10					
24.81	26.44					-20+10					
26.02	27.66					-10+20					
23.85	25.30					-20+20					
30.15	32.40						-20				
29.20	31.37						-50				
28.47	30.56						-75				
32.70	35.20						+50				
30.12	32.19							-25			
29.49	31.36							-50			
28.93	30.63							-75			
32.66	35.69							+50			
29.30	31.30								-25		
27.94	29.68								-50		
26.72	28.25								-75		
34.65	37.92								+50		
27.01	28.80									-25-10	
25.77	27.34									-50-10	
23.61	24.99									-50-20	
21.44	22.64									-50-30	
24.64	26.02										-50-10+10
22.60	23.82										-50-20+10

a. Operating costs and investments decreased by equal amounts; volume change positive as shown.
b. Royalty and tax rates changed equally (conservation taxes are not changed).
c. Each set of factors are changed equally as shown.

Table D.9. Effects on FOP ($/BBL) for PW_{10} and PW_{15} = 0 for changes in economic factors (Δ%) for West Sak Area B.

FOP $PW_{10} = 0$	FOP $PW_{15} = 0$	Op. Cost	Inv.	O+I[a]	Vol.	O+I[a] +V	Roy Rate	Tax Rate	R+T Rate[b]	R+T + O+I[c]	R+T +O+I +V[c]
35.83	38.04	0	0	0	0	0	0	0	0	0	0
34.57	36.81	-10									
33.30	35.58	-20									
30.78	33.20	-40									
38.37	40.56	+20									
34.25	36.20		-10								
32.68	34.36		-20								
29.52	30.69		-40								
39.00	41.72		+20								
32.99	34.94			-10							
31.56	33.43			-15							
30.14	31.90			-20							
24.45	25.75			-40							
41.52	44.18			+20							
37.79	40.30				-10						
34.23	36.19				+10						
32.90	34.65				+20						
31.55	33.30					-10+10					
28.86	30.41					-20+10					
30.35	31.92					-10+20					
27.80	29.18					-20+20					
35.04	37.19						-20				
33.93	35.99						-50				
38.08	35.07						-75				
38.02	40.40						+50				
34.93	36.93							-25			
34.16	35.91							-50			
33.48	35.14							-75			
38.20	40.99							+50			
33.98	35.90								-25		
32.36	34.05								-50		
30.92	32.42								-75		
40.55	43.56								+50		
31.31	33.03									-25-10	
29.84	64.36									-50-10	
27.32	28.66									-50-20	
24.80	25.97									-50-30	
28.58	29.92										-50-10+10
26.19	27.39										-50-20+10

a. Operating costs and investments decreased by equal amounts; volume change positive as shown.
b. Royalty and tax rates changed equally (conservation taxes are not changed).
c. Each set of factors are changed equally as shown.

Table D.10. Effects of FOP ($/BBL) for PW_{10} and PW_{15} = 0 for changes in economic factors (Δ%) for Point Thomson 5 TCF case.

FOP PW_{10} = 0	FOP PW_{15} = 0	Op. Cost	Inv.	O+I[a]	Vol.	O+I[a] +V	Roy Rate	Tax Rate	R+T Rate[b]	R+T + O+I[c]	R+T +O+I +V[c]
28.24	33.10	0	0	0	0	0	0	0	0	0	0
27.39	32.40	-10									
26.55	31.69	-20									
24.86	30.28	-40									
29.96	34.52	+20									
25.66	30.05		-10								
23.07	27.00		-20								
17.91	20.91		-40								
33.40	39.21		+20								
24.90	29.42			-10							
23.29	27.63			-15							
21.72	25.87			-20							
15.90	19.21			-40							
35.48	40.91			+20							
29.85	35.24				-10						
26.82	31.24				+10						
25.58	29.60				+20						
23.67	27.79					-10+10					
20.68	24.47					-20+10					
22.58	26.35					-10+20					
19.76	23.23					-20+20					
27.41	32.12						-20				
26.26	30.76						-50				
25.38	29.72						-75				
30.58	35.87						+50				
26.82	31.15							-25			
25.57	29.47							-50			
24.44	28.00							-75			
31.86	38.40							+50			
25.85	30.00								-25		
23.78	27.39								-50		
21.98	25.16								-75		
34.52	41.64								+50		
22.77	26.65									-25-10	
20.94	24.32									-50-10	
18.52	21.37									-50-20	
15.73	18.55									-50-30	
19.95	23.01										-50-10+10
17.42	20.25										-50-20+10

a. Operating costs and investments decreased by equal amounts; volume change positive as shown.
b. Royalty and tax rates changed equally (conservation taxes are not changed).
c. Each set of factors are changed equally as shown.

Table D.11. Effects of FOP ($/BBL) for PW_{10} and PW_{15} = 0 for changes in economic factors (Δ%) for Point Thomson 3.4 TCF case.

FOP $PW_{10} = 0$	FOP $PW_{15} = 0$	Op. Cost	Inv.	O+I[a]	Vol.	O+I[a] +V	Roy Rate	Tax Rate	R+T Rate[b]	R+T + O+I[c]	R+T +O+I +V[c]
25.31	29.89	0	0	0	0	0	0	0	0	0	0
24.65	29.31	-10									
23.99	28.73	-20									
22.68	27.58	-40									
26.63	31.06	+20									
23.04	27.17		-10								
20.77	24.43		-20								
16.23	19.01		-40								
29.85	35.34		+20								
22.45	26.65			-10							
21.91	25.81			-15							
19.71	23.53			-20							
14.66	17.62			-40							
31.44	36.74			+20							
26.83	31.86				-10						
23.98	28.19				+10						
22.81	26.69				+20						
21.30	25.16					-10+10					
18.73	22.23					-20+10					
20.28	23.85					-10+20					
17.87	21.10					-20+20					
24.58	29.02						-20				
23.57	27.81						-50				
22.79	26.88						-75				
27.37	32.36						+50				
24.02	28.08							-25			
22.89	26.54							-50			
21.88	25.19							-75			
28.69	34.85							+50			
23.16	27.06								-25		
21.32	24.70								-50		
19.72	22.67								-75		
31.04	37.75								+50		
20.53	24.12									-25-10	
18.90	22.00									-50-10	
16.59	19.42									-50-20	
14.41	16.94									-50-30	
17.97	20.81										-50-10+10
15.80	18.39										-50-20+10

a. Operating costs and investments decreased by equal amounts; volume change positive as shown.
b. Royalty and tax rates changed equally (conservation taxes are not changed).
c. Each set of factors are changed equally as shown.

Table D.12. Effects of FOP ($/BBL) for PW_{10} and PW_{15} = 0 for changes in economic factors (Δ%) for Gwydyr Bay.

FOP PW_{10} = 0	FOP PW_{15} = 0	Op. Cost	Inv.	O+I[a]	Vol.	O+I[a] +V	Roy Rate	Tax Rate	R+T Rate[b]	R+T + O+I[c]	R+T +O+I +V[c]
24.55	28.83	0	0	0	0	0	0	0	0	0	0
24.00	28.36	-10									
23.56	27.90	-20									
22.40	26.99	-40									
25.65	29.78	+20									
23.15	26.91		-10								
21.77	25.01		-20								
19.02	21.21		-40								
27.35	32.68		+20								
22.60	26.44			-10							
21.63	25.24			-15							
20.66	24.05			-20							
16.76	19.27			-40							
28.45	33.61			+20							
26.11	30.97				-10						
23.28	27.09				+10						
22.23	25.64				+20						
21.46	24.87					-10+10					
19.64	22.66					-20+10					
20.52	23.57					-10+20					
18.80	21.50					-20+20					
24.01	28.16						-20				
23.25	27.24						-50				
22.67	26.52						-75				
26.05	30.67						+50				
23.56	27.39							-25			
22.67	26.15							-50			
21.86	25.04							-75			
27.03	32.66							+50			
22.92	26.61								-25		
21.48	24.72								-50		
20.19	23.06								-75		
28.70	34.77								+50		
21.12	24.43									-25-10	
19.81	22.71									-50-10	
18.14	20.71									-50-20	
16.47	18.70									-50-30	
18.86	21.43										-50-10+10
17.30	19.57										-50-20+10

a. Operating costs and investments decreased by equal amounts; volume change positive as shown.
b. Royalty and tax rates changed equally (conservation taxes are not changed).
c. Each set of factors are changed equally as shown.

Table D.13. Effects of FOP ($/BBL) for PW_{10} and PW_{15} = 0 for changes in economic factors (Δ%) for Northstar with and without NPI.

FOP_{10} w/ NPI	FOP_{15} w/ NPI	FOP_{10} w/o NPI	FOP_{15} w/o NPI	Op. Cost	Inv.	O+I[a]	Vol.	O+I[a] +V	R+T Rate[b]	R+T + O+I[c]	R+T +O+I +V[c]
65.24	84.91	30.81	36.78	0	0	0	0	0	0	0	0
64.38 63.52 61.80 66.96				-10 -20 -40 +20							
60.03 54.82 44.41 75.65					-10 -20 -40 +20						
59.17 56.61 53.10 40.97 77.37		26.89				-10 -15 -20 -40 +20					
71.33 60.25 56.07							-10 +10 +20				
54.68 49.11 50.92 45.77		26.24						-10+10 -20+10 -10+20 -20+20			
53.36		25.55							-50		
53.09 48.09 43.25 38.41	67.99 60.84 54.57 48.31	25.63 23.47 21.37 19.27	30.10 27.27 24.74 22.21							-25-10 -50-10 -50-20 -50-30	
44.31 39.89	55.96 50.24	21.82 19.90	25.29 22.98								-50-10+10 -50-20+10

a. Operating costs and investments decreased by equal amounts; volume change positive as shown.
b. Royalty and tax rates changed equally (conservation taxes are not changed).
c. Each set of factors are changed equally as shown.

Table D.14. Effects of FOP ($/BBL) for PW_{10} and PW_{15} = 0 for changes in economic factors (Δ%) for Sandpiper.

FOP $PW_{10} = 0$	FOP $PW_{10} = 0$	Op. Cost	Inv.	O+I[a]	Vol.	O+I[a] +V	Roy Rate	Tax Rate	R+T Rate[b]	R+T + O+I[c]	R+T +O+I +V[c]
40.92	49.04	0	0	0	0	0	0	0	0	0	0
39.77	47.94	-10									
38.63	46.83	-20									
36.34	44.61	-40									
43.21	51.26	+20									
38.60	45.87		-10								
36.29	42.69		-20								
31.68	36.34		-40								
45.56	55.40		+20								
37.46	44.76			-10							
35.73	42.62			-15							
34.01	40.48			-20							
27.12	31.94			-40							
47.85	57.62			+20							
44.68	53.65				-10						
37.92	45.34				+10						
35.43	42.30				+20						
34.75	41.42					-10+10					
31.58	37.51					-20+10					
32.51	38.68					-10+20					
29.59	35.06					-20+20					
39.59	47.40						-20				
37.77	45.15						-50				
36.41	43.45						-75				
44.77	53.81						+50				
39.25	46.47							-25			
37.81	44.31							-50			
36.54	42.44							-75			
45.43	56.21							+50			
37.68	44.55								-25		
34.93	40.83								-50		
32.57	37.69								-75		
49.77	61.76								+50		
34.54	40.71									-25-10	
32.06	37.36									-50-10	
29.19	33.89									-50-20	
26.32	30.42									-50-30	
29.74	34.58										-50-10+10
27.12	31.41										-50-20+10

a. Operating costs and investments decreased by equal amounts; volume change positive as shown.
b. Royalty and tax rates changed equally (conservation taxes are not changed).
c. Each set of factors are changed equally as shown.

D.5 FINANCIAL SUMMARIES FOR THE FIVE NES FIELDS AT THE NES LOW OIL PRICE

WEST SAK A, PAGE 1
NES LOW OIL PRICE
MILLIONS OF THEN CURRENT $
****

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
OIL PRODUCTION RATE, MBBL/day	0.00	0.00	0.00	39.00	74.00	109.00	144.00	156.00	168.00	168.00	153.00	127.00
OIL PRICE	$24.45	$26.90	$29.49	$31.91	$34.46	$37.17	$40.01	$43.01	$45.31	$47.73	$50.27	$52.92
WELLHEAD OIL PRICE	17.38	19.60	21.89	24.13	26.33	28.65	31.25	33.91	35.81	37.66	39.72	41.54
GROSS REVENUE	$0	$0	$0	$344	$711	$1,140	$1,643	$1,931	$2,196	$2,310	$2,218	$1,926
TOTAL OPERATING COST	0	0	0	121	225	358	538	682	876	1,089	1,163	997
COST SHARING FEE	0	0	0	39	83	145	236	317	430	567	634	640
OPERATING COST IN CONSTANT $	0	0	0	87	157	241	350	429	532	639	659	546
CUM OP COST IN CONST $	0	0	0	87	244	485	836	1,264	1,796	2,435	3,094	3,640
ROYALTY	0	0	0	43	89	142	205	241	275	289	277	241
SEVERANCE TAX	0	0	0	10	19	28	37	40	43	43	39	32
AD VALOREM	0	0	0	15	23	32	44	46	51	53	48	40
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	0	0	0	1	1	2	2	2	3	3	2	2
STATE INCOME TAX	0	0	0	3	6	7	9	6	0	0	0	0
TOTAL STATE	0	0	0	71	138	212	297	336	372	388	367	315
FEDERAL INCOME TAX	0	0	0	0	0	0	0	0	0	0	0	85
OPERATING CASH FLOW	0	0	-0	151	348	570	807	913	948	833	688	529
TOTAL INVESTMENT	0	344	815	686	893	1,111	412	767	616	365	0	0
CUM INVESTMENT IN CONST $	0	266	874	1,369	1,991	2,739	3,007	3,489	3,863	4,077	4,077	4,077
TOTAL CASH FLOW	$0	$-344	$-815	$-535	$-544	$-541	$395	$146	$332	$468	$688	$529

NOMINAL DISCOUNT RATE IS 10%
****

CUM PW TOTAL CASH FLOW	$0	$-168	$-530	$-746	$-946	$-1,127	$-1,007	$-967	$-884	$-777	$-634	$-535
CUM PW STATE REVENUE	0	0	0	29	79	150	240	333	426	515	591	650
CUM PW FEDERAL REVENUE	0	0	0	0	0	0	0	0	0	0	0	16

	2010	2011	2012	2013	2014
OIL PRODUCTION RATE, MBBL/day	95.00	63.00	48.00	32.00	0.00
OIL PRICE	$55.70	$58.08	$60.58	$63.18	$65.89
WELLHEAD OIL PRICE	43.24	44.33	44.88	46.51	44.80
GROSS REVENUE	$1,499	$1,019	$786	$543	$0
TOTAL OPERATING COST	897	663	547	547	0
COST SHARING FEE	573	416	338	237	0
OPERATING COST IN CONSTANT $	475	339	270	261	0
CUM OP COST IN CONST $	4,115	4,454	4,724	4,985	4,985
ROYALTY	187	127	98	68	0
SEVERANCE TAX	24	16	12	8	0
AD VALOREM	31	21	11	0	0
CONSERVATION TAX	0	0	0	0	0
CONSERVATION SURTAX	2	1	1	1	0
STATE INCOME TAX	0	1	2	0	0
TOTAL STATE	244	167	125	77	0
FEDERAL INCOME TAX	61	19	19	0	0
OPERATING CASH FLOW	297	170	96	-80	0
TOTAL INVESTMENT	0	0	0	0	0
CUM INVESTMENT IN CONST $	4,077	4,077	4,077	4,077	4,077
TOTAL CASH FLOW	$297	$170	$96	$-80	$0

NOMINAL DISCOUNT RATE IS 10%
****

CUM PW TOTAL CASH FLOW	$-484	$-457	$-444	$-454	$-454
CUM PW STATE REVENUE	692	718	735	745	745
CUM PW FEDERAL REVENUE	26	29	32	32	32

WEST SAK B, PAGE 1
NES LOW OIL PRICE
MILLIONS OF THEN CURRENT $
****

	2006	2007	2008	2009	2010	2011	2012	2013	2014
OIL PRODUCTION RATE, MBBL/day	0.00	0.00	20.00	52.00	67.00	65.00	56.00	31.00	0.00
OIL PRICE	$45.31	$47.73	$50.27	$52.92	$55.70	$58.08	$60.58	$63.18	$65.89
WELLHEAD OIL PRICE	35.81	37.66	39.72	41.54	43.24	44.33	44.88	46.51	44.80
GROSS REVENUE	$0	$0	$290	$788	$1,057	$1,052	$917	$526	$0
TOTAL OPERATING COST	0	0	119	245	375	435	546	546	0
COST SHARING FEE	0	0	27	98	189	285	360	230	0
OPERATING COST IN CONSTANT $	0	0	67	134	198	222	270	261	0
CUM OP COST IN CONST $	0	0	67	202	400	622	892	1,153	1,153
ROYALTY	0	0	36	99	132	131	115	66	0
SEVERANCE TAX	0	0	5	13	17	17	14	8	0
AD VALOREM	0	0	8	19	16	13	9	5	0
CONSERVATION TAX	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	0	0	0	1	1	1	1	0	0
STATE INCOME TAX	0	0	0	0	0	0	0	0	0
TOTAL STATE	0	0	50	131	167	162	139	79	0
FEDERAL INCOME TAX	0	0	0	0	0	11	25	0	0
OPERATING CASH FLOW	0	0	121	412	516	444	207	-99	0
TOTAL INVESTMENT	0	713	1,022	161	0	0	0	0	0
CUM INVESTMENT IN CONST $	0	418	997	1,085	1,085	1,085	1,085	1,085	1,085
TOTAL CASH FLOW	$0	$-713	$-900	$251	$516	$444	$207	$-99	$0

NOMINAL DISCOUNT RATE IS 10%
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CUM PW TOTAL CASH FLOW	$0	$-162	$-349	$-302	$-213	$-144	$-115	$-128	$-128
CUM PW STATE REVENUE	0	0	10	35	64	89	108	119	119
CUM PW FEDERAL REVENUE	0	0	0	0	0	2	5	5	5

POINT THOMSON, 5.0 TCF CASE, PAGE 1
NES LOW OIL PRICE
MILLIONS OF THEN CURRENT $
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	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
OIL PRODUCTION RATE, MBBL/day	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.53	45.12	44.79	44.50	44.00
GAS SALES RATE, MM SCF/day	0.00	0.00	0.00	0.00	0.00	0.00	0.00	440.00	440.00	440.00	440.00	440.00
OIL PRICE	$31.91	$34.46	$37.17	$40.01	$43.01	$45.31	$47.73	$50.27	$52.92	$55.70	$58.08	$60.58
WELLHEAD OIL PRICE	31.33	33.51	35.81	38.41	41.05	42.94	44.78	46.82	48.62	50.31	51.38	51.91
GAS PRICE	0.89	0.96	1.04	1.12	1.20	1.27	1.33	1.41	1.48	1.56	1.62	1.69
OIL REVENUE	$0	$0	$0	$0	$0	$0	$0	$761	$801	$822	$834	$834
GAS REVENUE	0	0	0	0	0	0	0	226	238	250	261	272
GROSS REVENUE	0	0	0	0	0	0	0	987	1,038	1,073	1,095	1,106
TOTAL OPERATING COST	0	0	0	0	0	0	0	130	144	149	154	160
OPERATING COST IN CONSTANT $	0	0	0	0	0	0	0	74	79	79	79	79
CUM OP COST IN CONST $	0	0	0	0	0	0	0	74	153	232	311	390
ROYALTY	0	0	0	0	0	0	0	141	148	153	156	158
SEVERANCE TAX	0	0	0	0	0	0	0	26	26	27	27	28
AD VALOREM	0	0	0	0	0	0	0	34	35	36	36	36
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	0	0	0	0	0	0	0	1	1	1	1	1
STATE INCOME TAX	0	0	0	0	0	0	0	17	18	18	19	19
TOTAL STATE	0	0	0	0	0	0	0	218	227	234	238	240
FEDERAL INCOME TAX	0	0	0	0	0	0	0	0	0	98	155	161
OPERATING CASH FLOW	0	0	0	0	0	-0	0	638	667	591	547	545
TOTAL INVESTMENT	0	4	0	25	667	773	800	179	185	0	0	0
CUM INVESTMENT IN CONST $	0	3	3	19	438	907	1,376	1,478	1,579	1,579	1,579	1,579
TOTAL CASH FLOW	0	-4	0	-25	-667	-773	-800	459	482	591	547	545

NOMINAL DISCOUNT RATE IS 10%
****

CUM PW TOTAL CASH FLOW	$0	$-1	$-1	$-9	$-193	$-387	$-569	$-474	$-383	$-282	$-197	$-120
CUM PW STATE REVENUE	0	0	0	0	0	0	0	45	88	128	165	199
CUM PW FEDERAL REVENUE	0	0	0	0	0	0	0	0	0	17	41	64

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	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
OIL PRODUCTION RATE, MBBL/day	43.00	39.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GAS SALES RATE, MM SCF/day	440.00	440.00	440.00	440.00	440.00	440.00	440.00	440.00	440.00	440.00	440.00	440.00
OIL PRICE	$63.18	$65.89	$68.71	$72.00	$75.43	$79.02	$82.74	$86.65	$90.62	$94.76	$99.08	$103.59
WELLHEAD OIL PRICE	53.52	51.80	52.65	54.38	54.34	54.41	54.83	53.26	52.66	52.56	50.97	51.35
GAS PRICE	1.77	1.84	1.92	2.01	2.11	2.21	2.31	2.42	2.53	2.65	2.77	2.90
OIL REVENUE	$840	$756	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GAS REVENUE	284	296	309	323	339	355	372	389	407	426	445	465
GROSS REVENUE	1,124	1,052	309	323	339	355	372	389	407	426	445	465
TOTAL OPERATING COST	165	171	177	183	190	197	203	211	218	226	233	242
OPERATING COST IN CONSTANT $	79	79	79	79	79	79	79	79	79	79	79	79
CUM OP COST IN CONST $	469	548	627	706	785	864	943	1,022	1,100	1,179	1,258	1,337
ROYALTY	160	150	44	46	48	51	53	55	58	61	63	66
SEVERANCE TAX	28	28	19	20	21	22	23	24	25	26	27	28
AD VALOREM	35	35	35	34	33	33	32	31	30	29	28	27
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	1	1	0	0	0	0	0	0	0	0	0	0
STATE INCOME TAX	19	17	0	0	0	0	0	0	0	0	0	0
TOTAL STATE	243	231	97	100	103	105	108	111	113	116	119	122
FEDERAL INCOME TAX	167	147	9	14	16	18	21	23	26	29	32	35
OPERATING CASH FLOW	548	503	25	26	31	35	40	45	50	55	61	67
TOTAL INVESTMENT	0	0	0	0	0	0	0	0	0	0	0	0
CUM INVESTMENT IN CONST $	1,579	1,579	1,579	1,579	1,579	1,579	1,579	1,579	1,579	1,579	1,579	1,579
TOTAL CASH FLOW	$548	$503	$25	$26	$31	$35	$40	$45	$50	$55	$61	$67

NOMINAL DISCOUNT RATE IS 10%
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CUM PW TOTAL CASH FLOW	$-49	$10	$12	$15	$18	$20	$23	$26	$29	$32	$35	$38
CUM PW STATE REVENUE	231	258	268	278	287	295	303	310	317	323	329	335
CUM PW FEDERAL REVENUE	85	102	103	105	106	108	109	111	112	114	115	117

POINT THOMSON, 5.0 TCF CASE, PAGE 3
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	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
OIL PRODUCTION RATE, MBBL/day	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GAS SALES RATE, MM SCF/day	440.00	440.00	440.00	440.00	440.00	440.00	440.00	440.00	440.00	440.00	176.00	0.00
OIL PRICE	$108.29	$112.67	$117.23	$121.99	$126.92	$132.04	$137.34	$142.86	$148.60	$154.57	$160.78	$167.24
WELLHEAD OIL PRICE	54.01	56.28	58.65	61.16	63.74	66.43	69.21	72.13	75.17	78.34	81.65	85.11
GAS PRICE	3.03	3.15	3.28	3.41	3.55	3.69	3.84	4.00	4.16	4.32	4.50	4.68
OIL REVENUE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GAS REVENUE	486	506	526	548	570	593	617	642	667	694	289	0
GROSS REVENUE	486	506	526	548	570	593	617	642	667	694	289	0
TOTAL OPERATING COST	250	259	268	277	287	297	307	318	329	341	353	0
OPERATING COST IN CONSTANT $	79	79	79	79	79	79	79	79	79	79	79	0
CUM OP COST IN CONST $	1,416	1,495	1,574	1,653	1,732	1,811	1,890	1,969	2,048	2,127	2,206	2,206
ROYALTY	69	72	75	78	81	85	88	91	95	99	41	0
SEVERANCE TAX	30	31	32	34	35	36	38	39	41	42	7	0
AD VALOREM	26	24	22	21	19	17	14	12	9	6	3	0
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	0	0	0	0	0	0	0	0	0	0	0	0
STATE INCOME TAX	0	1	1	1	1	2	2	2	3	5	0	0
TOTAL STATE	125	128	130	133	136	139	142	145	148	153	51	0
FEDERAL INCOME TAX	38	41	44	47	50	53	57	61	65	68	0	0
OPERATING CASH FLOW	74	79	85	91	97	104	111	118	126	132	-115	0
TOTAL INVESTMENT	0	0	0	0	0	0	0	0	0	0	0	0
CUM INVESTMENT IN CONST $	1,579	1,579	1,579	1,579	1,579	1,579	1,579	1,579	1,579	1,579	1,579	1,579
TOTAL CASH FLOW	$74	$79	$85	$91	$97	$104	$111	$118	$126	$132	$-115	$0

NOMINAL DISCOUNT RATE IS 10%
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CUM PW TOTAL CASH FLOW	$41	$44	$47	$50	$53	$55	$58	$60	$63	$65	$63	$63
CUM PW STATE REVENUE	340	345	349	353	357	360	364	367	370	372	373	373
CUM PW FEDERAL REVENUE	118	120	121	123	124	126	127	128	129	131	131	131

POINT THOMSON, 3.4 TCF CASE, PAGE 1
NES LOW OIL PRICE
MILLIONS OF THEN CURRENT $
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	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
OIL PRODUCTION RATE, MBBL/day	0.00	0.00	0.00	0.00	0.00	0.00	44.53	46.80	45.75	45.00	43.95	42.10
GAS SALES RATE, MM SCF/day	0.00	0.00	0.00	0.00	0.00	0.00	440.00	440.00	440.00	440.00	440.00	440.00
OIL PRICE	$34.46	$37.17	$40.01	$43.01	$45.31	$47.73	$50.27	$52.92	$55.70	$58.08	$60.58	$63.18
WELLHEAD OIL PRICE	33.44	35.74	38.33	40.98	42.86	44.69	46.73	48.53	50.22	51.28	51.81	53.42
GAS PRICE	0.96	1.04	1.12	1.20	1.27	1.33	1.41	1.48	1.56	1.62	1.69	1.77
OIL REVENUE	$0	$0	$0	$0	$0	$0	$760	$829	$839	$842	$831	$821
GAS REVENUE	0	0	0	0	0	0	226	238	250	261	272	284
GROSS REVENUE	0	0	0	0	0	0	985	1,067	1,089	1,103	1,103	1,105
TOTAL OPERATING COST	0	0	0	0	0	0	121	125	129	134	138	143
OPERATING COST IN CONSTANT $	0	0	0	0	0	0	68	68	68	68	68	68
CUM OP COST IN CONST $	0	0	0	0	0	0	68	137	205	273	342	410
ROYALTY	0	0	0	0	0	0	140	152	155	157	157	157
SEVERANCE TAX	0	0	0	0	0	0	26	28	28	29	29	30
AD VALOREM	0	0	0	0	0	0	32	32	31	30	30	29
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	0	0	0	0	0	0	1	1	1	1	1	1
STATE INCOME TAX	0	0	0	0	0	0	16	18	18	19	19	19
TOTAL STATE	0	0	0	0	0	0	216	230	234	236	235	235
FEDERAL INCOME TAX	0	0	0	0	0	0	0	52	165	177	180	180
OPERATING CASH FLOW	0	0	0	0	-0	0	649	659	561	556	550	547
TOTAL INVESTMENT	4	0	25	647	748	774	60	0	0	0	0	0
CUM INVESTMENT IN CONST $	3	3	19	425	879	1,333	1,367	1,367	1,367	1,367	1,367	1,367
TOTAL CASH FLOW	-4	0	-25	-647	-748	-774	589	659	561	556	550	547

NOMINAL DISCOUNT RATE IS 10%
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CUM PW TOTAL CASH FLOW	$-1	$-1	$-9	$-187	$-375	$-551	$-429	$-305	$-209	$-122	$-44	$26
CUM PW STATE REVENUE	0	0	0	0	0	0	45	88	128	165	198	228
CUM PW FEDERAL REVENUE	0	0	0	0	0	0	0	10	38	66	91	114

POINT THOMSON, 3.4 TCF CASE, PAGE 2
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	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
OIL PRODUCTION RATE, MBBL/day	37.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GAS SALES RATE, MM SCF/day	440.00	440.00	440.00	440.00	440.00	440.00	440.00	440.00	440.00	440.00	440.00	440.00	265.00
OIL PRICE	$65.89	$68.71	$72.00	$75.43	$79.02	$82.74	$86.65	$90.62	$94.76	$99.08	$103.59	$108.29	$112.67
WELLHEAD OIL PRICE	51.69	52.54	54.27	54.22	54.29	54.70	53.12	52.52	52.41	50.82	51.20	53.86	56.12
GAS PRICE	1.84	1.92	2.01	2.11	2.21	2.31	2.42	2.53	2.65	2.77	2.90	3.03	3.15
OIL REVENUE	$715	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
GAS REVENUE	296	309	323	339	355	372	389	407	426	445	465	486	305
GROSS REVENUE	1,011	309	323	339	355	372	389	407	426	445	465	486	305
TOTAL OPERATING COST	148	153	159	164	170	176	182	189	195	202	209	216	224
OPERATING COST IN CONSTANT $	68	68	68	68	68	68	68	68	68	68	68	68	68
CUM OP COST IN CONST $	478	547	615	683	752	820	888	957	1,025	1,093	1,162	1,230	1,298
ROYALTY	144	44	46	48	51	53	55	58	61	63	66	69	43
SEVERANCE TAX	29	21	22	23	24	25	26	27	29	30	31	33	17
AD VALOREM	27	26	25	23	22	20	18	16	14	11	9	6	3
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	1	0	0	0	0	0	0	0	0	0	0	0	0
STATE INCOME TAX	16	0	0	0	0	0	0	0	0	0	1	3	1
TOTAL STATE	217	91	93	94	96	98	100	101	103	105	107	111	64
FEDERAL INCOME TAX	152	22	24	27	30	33	36	40	43	47	51	54	6
OPERATING CASH FLOW	493	42	48	53	59	64	71	77	84	91	98	105	11
TOTAL INVESTMENT	0	0	0	0	0	0	0	0	0	0	0	0	0
CUM INVESTMENT IN CONST $	1,367	1,367	1,367	1,367	1,367	1,367	1,367	1,367	1,367	1,367	1,367	1,367	1,367
TOTAL CASH FLOW	$493	$42	$48	$53	$59	$64	$71	$77	$84	$91	$98	$105	$11

NOMINAL DISCOUNT RATE IS 10%
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CUM PW TOTAL CASH FLOW	$84	$88	$93	$98	$102	$107	$112	$116	$121	$125	$130	$134	$134
CUM PW STATE REVENUE	254	264	273	281	288	296	302	308	314	319	324	328	331
CUM PW FEDERAL REVENUE	132	134	137	139	142	144	146	149	151	153	156	158	158

GWYDYR BAY UNIT, PAGE 1
NES LOW OIL PRICE
MILLIONS OF THEN CURRENT $
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	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
OIL PRODUCTION RATE, Mbbl/day	0.00	0.00	4.00	9.30	13.30	13.30	13.30	11.80	10.50	9.30	8.30	7.40
OIL PRICE	$22.14	$24.45	$26.90	$29.49	$31.91	$34.46	$37.17	$40.01	$43.01	$45.31	$47.73	$50.27
WELLHEAD OIL PRICE	17.37	19.70	21.92	24.21	26.45	28.65	30.97	33.57	36.23	38.13	39.98	42.04
GROSS REVENUE	$0	$0	$32	$82	$128	$139	$150	$145	$139	$129	$121	$114
TOTAL OPERATING COST	0	0	4	9	14	17	20	22	24	25	27	30
OPERATING COST IN CONSTANT $	0	0	3	7	10	12	14	14	15	15	16	17
CUM OP COST IN CONST $	0	0	3	9	20	31	45	60	75	90	106	123
ROYALTY	0	0	4	10	16	17	19	18	17	16	15	14
SEVERANCE TAX	0	0	1	2	3	3	3	3	3	2	2	2
AD VALOREM	0	0	6	6	6	6	6	5	5	5	4	4
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	0	0	0	0	0	0	0	0	0	0	0	0
STATE INCOME TAX	0	0	0	1	1	2	2	2	2	2	1	1
TOTAL STATE	0	0	11	20	27	29	30	28	27	25	23	21
FEDERAL INCOME TAX	0	0	0	0	0	0	5	18	16	26	24	21
OPERATING CASH FLOW	0	0	17	54	87	94	95	76	72	53	47	41
TOTAL INVESTMENT	147	165	42	37	0	0	0	0	0	0	0	0
CUM INVESTMENT IN CONST $	122	254	286	314	314	314	314	314	314	314	314	314
TOTAL CASH FLOW	$-147	$-165	$-24	$17	$87	$94	$95	$76	$72	$53	$47	$41

NOMINAL DISCOUNT RATE IS 10%
****

CUM PW TOTAL CASH FLOW	$-87	$-176	$-188	$-180	$-145	$-111	$-79	$-56	$-37	$-23	$-13	$-4
CUM PW STATE REVENUE	0	0	5	14	25	36	46	54	62	68	73	78
CUM PW FEDERAL REVENUE	0	0	0	0	0	0	2	7	12	18	24	28

	2009	2010	2011	2012	2013	2014	2015
OIL PRODUCTION RATE, Mbbl/day	6.60	5.90	5.50	5.10	4.70	4.30	0.00
OIL PRICE	$52.92	$55.70	$58.08	$60.58	$63.18	$65.89	$68.71
WELLHEAD OIL PRICE	43.86	45.56	46.65	47.20	48.83	47.12	47.99
GROSS REVENUE	$106	$98	$94	$88	$84	$74	$0
TOTAL OPERATING COST	33	36	42	51	63	63	0
OPERATING COST IN CONSTANT $	18	19	22	25	30	29	0
CUM OP COST IN CONST $	141	161	182	207	237	266	266
ROYALTY	13	12	12	11	10	9	0
SEVERANCE TAX	2	2	1	1	1	1	0
AD VALOREM	4	3	3	2	1	1	0
CONSERVATION TAX	0	0	0	0	0	0	0
CONSERVATION SURTAX	0	0	0	0	0	0	0
STATE INCOME TAX	1	1	1	0	0	0	0
TOTAL STATE	20	18	16	15	13	11	0
FEDERAL INCOME TAX	18	15	12	8	3	0	0
OPERATING CASH FLOW	35	29	23	15	5	0	0
TOTAL INVESTMENT	0	0	0	0	0	0	0
CUM INVESTMENT IN CONST $	314	314	314	314	314	314	314
TOTAL CASH FLOW	$35	$29	$23	$15	$5	$0	$0

NOMINAL DISCOUNT RATE IS 10%
****

CUM PW TOTAL CASH FLOW	$2	$7	$11	$13	$14	$14	$14
CUM PW STATE REVENUE	81	84	87	89	91	92	92
CUM PW FEDERAL REVENUE	31	34	36	37	37	37	37

SEAL ISLAND / NORTHSTAR, WITH NET PROFITS INTEREST - PAGE 1
NES LOW OIL PRICE
MILLIONS OF THEN CURRENT $
****

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
OIL PRODUCTION RATE, Mbbl/day	0.00	0.00	0.00	0.00	21.92	41.10	54.80	54.80	54.80	54.80	54.80	46.58
OIL PRICE	$18.94	$17.89	$19.95	$22.14	$24.45	$26.90	$29.49	$31.91	$34.46	$37.17	$40.01	$43.01
WELLHEAD OIL PRICE	13.22	12.42	14.66	17.05	19.38	21.61	23.91	26.16	28.37	30.70	33.32	35.99
GROSS REVENUE	$0	$0	$0	$0	$155	$324	$478	$523	$567	$614	$666	$612
TOTAL OPERATING COST	0	0	0	0	51	93	151	157	162	168	174	180
COST SHARING FEE	0	0	0	0	0	0	0	0	0	0	0	0
OPERATING COST IN CONSTANT $	0	0	0	0	41	72	113	113	113	113	113	113
CUM OP COST IN CONST $	0	0	0	0	41	113	226	339	452	565	678	791
ROYALTY	0	0	0	0	30	62	92	100	109	118	128	117
SEVERANCE TAX	0	0	0	0	5	10	19	18	19	25	27	15
AD VALOREM	0	0	0	0	28	28	28	28	28	28	27	27
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	0	0	0	0	0	1	1	1	1	1	1	1
STATE NET PROFIT INTEREST	0	0	0	0	28	89	127	149	170	187	211	186
STATE INCOME TAX	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL STATE	0	0	0	0	91	190	267	297	326	359	394	345
FEDERAL INCOME TAX	0	0	0	0	0	0	0	0	0	0	0	0
OPERATING CASH FLOW	0	0	0	0	13	42	59	70	79	87	98	87
TOTAL INVESTMENT	0	434	450	538	75	78	40	42	14	0	0	0
CUM INVESTMENT IN CONST $	0	385	770	1,215	1,275	1,335	1,365	1,395	1,405	1,405	1,405	1,405
TOTAL CASH FLOW	$0	$-434	$-450	$-538	$-62	$-36	$19	$28	$65	$87	$98	$87

NOMINAL DISCOUNT RATE IS 10%
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CUM PW TOTAL CASH FLOW	$0	$-311	$-603	$-921	$-955	$-972	$-964	$-952	$-929	$-899	$-870	$-846
CUM PW STATE REVENUE	0	0	0	0	49	141	260	380	500	620	739	835
CUM PW FEDERAL REVENUE	0	0	0	0	0	0	0	0	0	0	0	0

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
OIL PRODUCTION RATE, Mbbl/day	39.59	33.65	28.60	24.31	20.67	17.57	14.93	0.00	0.00	0.00
OIL PRICE	$45.31	$47.73	$50.27	$52.92	$55.70	$58.08	$60.58	$63.18	$65.89	$68.71
WELLHEAD OIL PRICE	37.90	39.76	41.83	43.66	45.38	46.48	47.05	48.69	46.99	47.88
GROSS REVENUE	$548	$488	$437	$387	$342	$298	$256	$0	$0	$0
TOTAL OPERATING COST	186	186	186	186	186	186	186	0	0	0
COST SHARING FEE	0	0	0	0	0	0	0	0	0	0
OPERATING COST IN CONSTANT $	113	109	105	102	98	95	92	0	0	0
CUM OP COST IN CONST $	904	1,013	1,119	1,221	1,319	1,414	1,506	1,506	1,506	1,506
ROYALTY	105	94	84	74	66	57	49	0	0	0
SEVERANCE TAX	9	8	7	6	5	4	4	0	0	0
AD VALOREM	26	25	25	24	23	22	21	0	0	0
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	1	0	0	0	0	0	0	0	0	0
STATE NET PROFIT INTEREST	150	119	92	66	43	19	-2	0	0	0
STATE INCOME TAX	0	0	0	0	0	0	0	0	0	0
TOTAL STATE	291	247	208	170	136	103	71	0	0	0
FEDERAL INCOME TAX	0	0	0	0	0	0	0	0	0	0
OPERATING CASH FLOW	70	56	43	31	20	9	-1	0	0	0
TOTAL INVESTMENT	0	0	0	0	0	0	0	0	0	0
CUM INVESTMENT IN CONST $	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405	1,405
TOTAL CASH FLOW	$70	$56	$43	$31	$20	$9	$-1	$0	$0	$0
					NOMINAL DISCOUNT RATE IS 10%					
					**********					
CUM PW TOTAL CASH FLOW	$-828	$-815	$-807	$-801	$-797	$-796	$-796	$-796	$-796	$-796
CUM PW STATE REVENUE	908	964	1,007	1,039	1,062	1,078	1,089	1,089	1,089	1,089
CUM PW FEDERAL REVENUE	0	0	0	0	0	0	0	0	0	0

SANDPIPER DISCOVERY - PAGE 1
NES LOW OIL PRICE
MILLIONS OF THEN CURRENT $
****

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
OIL PRODUCTION RATE, Mbbl/day	0.00	0.00	0.00	0.00	10.45	18.29	26.13	26.13	26.13	26.13	22.47
OIL PRICE	$19.95	$22.14	$24.45	$26.90	$29.49	$31.91	$34.46	$37.17	$40.01	$43.01	$45.31
WELLHEAD OIL PRICE	13.03	15.35	17.63	19.80	22.03	24.22	26.36	28.62	31.16	33.76	35.59
GROSS REVENUE	$0	$0	$0	$0	$84	$162	$251	$273	$297	$322	$292
TOTAL OPERATING COST	0	0	0	0	38	67	109	113	117	121	125
COST SHARING FEE	0	0	0	0	0	0	0	0	0	0	0
OPERATING COST IN CONSTANT $	0	0	0	0	28	48	76	76	76	76	76
CUM OP COST IN CONST $	0	0	0	0	28	76	152	228	304	380	456
ROYALTY	0	0	0	0	14	27	42	45	50	54	49
SEVERANCE TAX	0	0	0	0	3	4	6	6	6	6	5
AD VALOREM	0	0	0	0	19	19	18	17	15	14	12
CONSERVATION TAX	0	0	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	0	0	0	0	0	0	0	0	0	0	0
STATE INCOME TAX	0	0	0	0	0	0	0	0	0	0	0
TOTAL STATE	0	0	0	0	36	50	67	69	72	74	67
FEDERAL INCOME TAX	0	0	0	0	0	0	0	0	0	0	0
OPERATING CASH FLOW	0	0	0	0	10	45	76	91	109	127	100
TOTAL INVESTMENT	0	314	325	362	27	28	29	0	0	0	0
CUM INVESTMENT IN CONST $	0	260	520	800	820	840	860	860	860	860	860
TOTAL CASH FLOW	$0	$-314	$-325	$-362	$-16	$17	$47	$91	$109	$127	$100

NOMINAL DISCOUNT RATE IS 10%
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CUM PW TOTAL CASH FLOW	$0	$-186	$-361	$-538	$-545	$-538	$-521	$-491	$-458	$-423	$-397
CUM PW STATE REVENUE	0	0	0	0	16	36	61	84	106	126	143
CUM PW FEDERAL REVENUE	0	0	0	0	0	0	0	0	0	0	0

SANDPIPER DISCOVERY, PAGE 2
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	2007	2008	2009	2010	2011	2012	2013	2014	2015
OIL PRODUCTION RATE, Mbbl/day	19.32	16.62	14.29	12.29	10.57	9.09	0.00	0.00	0.00
OIL PRICE	$47.73	$50.27	$52.92	$55.70	$58.08	$60.58	$63.18	$65.89	$68.71
WELLHEAD OIL PRICE	37.38	39.36	41.11	42.73	43.74	44.21	45.75	43.96	44.74
GROSS REVENUE	$264	$239	$214	$192	$169	$147	$0	$0	$0
TOTAL OPERATING COST	130	130	130	130	130	130	0	0	0
COST SHARING FEE	0	0	0	0	0	0	0	0	0
OPERATING COST IN CONSTANT $	76	73	71	69	66	64	0	0	0
CUM OP COST IN CONST $	532	605	676	745	811	875	875	875	875
ROYALTY	44	40	36	32	28	24	0	0	0
SEVERANCE TAX	5	4	3	3	3	2	0	0	0
AD VALOREM	10	9	7	5	2	0	0	0	0
CONSERVATION TAX	0	0	0	0	0	0	0	0	0
CONSERVATION SURTAX	0	0	0	0	0	0	0	0	0
STATE INCOME TAX	0	0	0	0	0	0	0	0	0
TOTAL STATE	59	53	46	40	33	27	0	0	0
FEDERAL INCOME TAX	0	0	0	0	0	0	0	0	0
OPERATING CASH FLOW	75	56	39	22	6	-10	0	0	0
TOTAL INVESTMENT	0	0	0	0	0	0	0	0	0
CUM INVESTMENT IN CONST $	860	860	860	860	860	860	860	860	860
TOTAL CASH FLOW	$75	$56	$39	$22	$6	$-10	$0	$0	$0

NOMINAL DISCOUNT RATE IS 10%
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CUM PW TOTAL CASH FLOW	$-380	$-369	$-361	$-358	$-357	$-358	$-358	$-358	$-358
CUM PW STATE REVENUE	156	167	176	183	188	192	192	192	192
CUM PW FEDERAL REVENUE	0	0	0	0	0	0	0	0	0

APPENDIX E
REVISED MILNE POINT UNIT PARTICIPATING AREA BOUNDARY

The Milne Point Unit (MPU) was enlarged in 1992 to about twice its original size.[a] The 71,151 acre unit now includes offshore leases as shown in Figure E.1. Exploratory drilling yielded encouraging results and may show the existence of a Kuparuk reservoir extension. If proven, the producing life of the Milne Point Kuparuk Participating Area (MPKPA) would be extended well beyond 1998 as projected in **Section A.2.2**. Discovery of additional reserves and the possible increase in productive capacity would require enlargement of the MPKPA processing facilities for the handling of both Kuparuk and Schrader Bluff produced fluids. In addition, if the accumulation cannot be developed from shore sites, the MPKPA owners will be faced with causeway issues, or if development is from a barrier island, the use of unproven technology for construction of Arctic subsea pipelines would be required (See **Section 3.3.4**). Although the potential Kuparuk extension may be highly significant to MPKPA owners, the potential accumulation will have to be of major size (1 BBO or greater) before the effect on the life of TAPS would be significant.

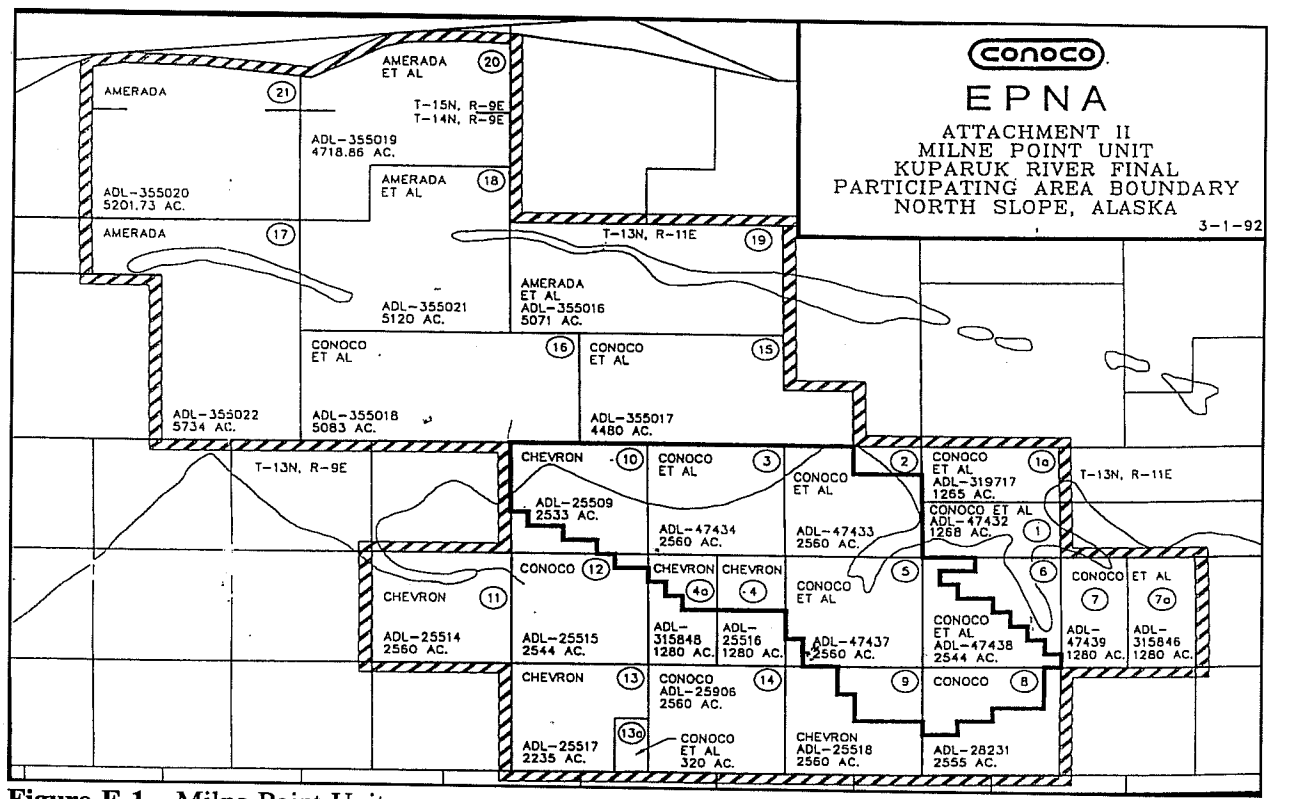

Figure E.1. Milne Point Unit.

a. Conoco, Inc., personal communication, December 28, 1992.