ECONOMICS OF ALASKA NORTH SLOPE GAS UTILIZATION OPTIONS

1. INTRODUCTION

The recoverable conventional natural gas resources in the developed and known undeveloped fields on the Alaska North Slope (ANS) total about 38 trillion cubic feet (TCF). No significant commercial sales have been made of this large natural gas resource because there are no existing facilities in place to economically transport this gas to current markets, all of which are outside of the North Slope. In addition to the known gas resources, the U. S. Geological Survey's (USGS) most recently published estimate of technically recoverable conventional natural gas resources in undiscovered fields in Northern Alaska has a mean value of 64 TCF (USGS, 1995).

About 26 TCF of the 38 TCF recoverable natural gas are estimated to be available for sale.[a] The balance will be consumed in oil and gas production operations on the North Slope. The 26 TCF equates to over 4 billion barrels of oil equivalent (BBOE). These known gas resources coupled with the potential for large additional gas discoveries in Northern Alaska, make it important for the U.S. Department of Energy (DOE), industry, and the State of Alaska to evaluate and assess the options for development of this vast gas resource to obtain the maximum benefit for Alaska and the nation, and to determine the impact that development would have on Alaska's economy and U.S. domestic energy supply, jobs, and balance of payments.

Currently, ANS gas is not marketed off the North Slope except in the form of natural gas liquids (NGLs), which are composed chiefly of butane and higher hydrocarbons that are blended with crude oil for transport in the Trans Alaska Pipeline System (TAPS). All of the produced gas, except that used for production operations, TAPS fuel, and local sales, has been reinjected back into the reservoirs to maintain reservoir pressure and for improved oil recovery projects. It has always been the intent of the North Slope operators to sell this gas when a market develops. In the interim, the use of the gas for improved oil recovery has been very successful as demonstrated by the increase in reserves for the Prudhoe Bay Unit (PBU) from the early estimates of under 10 billion barrels oil (BBO) to the current estimate of 13 BBO (56% of the

a. Reserves and resource estimates in this report were developed by the authors using data publicly available from reports in the news media, the Alaska Department of Natural Resources, the Department of Energy, the Department of the Interior, and industry. These estimates and specific references are provided in the body of the report in **Section 2** and **Appendix A.**

original oil in place). Thus, the natural gas reinjected into the reservoirs has had significant value to the producers in improving production rates and ultimate oil recovery. However, the value of the gas for these purposes can be expected to decrease as the gas/oil ratio (GOR) continues to increase in PBU, which will require shut in of the higher GOR wells or additional investment to expand gas handling facilities beyond the current capacity of 7.5 billion cubic feet per day (BCFPD). As PBU oil production continues to decline, the value of the gas for interim use for enhancement of oil recovery at PBU will decline, making it more urgent that a means be developed to market the available ANS gas to obtain its maximum benefit.

Numerous options for use and sale of the ANS gas resources have been studied since the discovery of the Prudhoe Bay field. Two gas pipeline options that have been explored in the past are a gas pipeline from the ANS through Alaska to Canada and then to the U.S. lower 48 states for direct delivery of the ANS gas to the U.S. natural gas distribution system, and a gas pipeline through Alaska to an ice-free port for conversion to liquefied natural gas (LNG) for sale to Japan and other Asian countries. Recent advances in gas-to-liquids (GTL) conversion technology that may provide the means to economically convert natural gas to hydrocarbon liquids compatible with the ANS crude oil have raised the interest in this alternative option for ANS gas utilization. Such an option would mean that a gas pipeline would not have to be built and would provide a higher volume of hydrocarbon liquids to transport through TAPS. This added liquid volume would assist in maintaining the viability of TAPS operations and result in lower tariffs for all liquids transported in TAPS. Lower TAPS tariffs return a higher net oil price (wellhead oil price) for all fields, those currently producing as well as future developments. Given the ample gas supply potential in Canada and the U.S. that is closer to conventional Lower 48 gas markets than Alaska, only LNG and GTL options appear to be practical and merit study for ANS gas utilization at this time.

1.1 Purpose

The purposes of this study are:

(a) To provide a technical and economic evaluation of using technology for chemical conversion of natural gas-to-hydrocarbon liquids for bringing the large, remote, and currently unmarketable ANS natural gas resource to market.

(b) To examine how the gas-to-liquids (GTL) conversion option compares to the more frequently discussed option of construction of a natural gas pipeline to an all-weather Alaska port and construction of a new plant for physical conversion of gas to LNG, with subsequent tanker transport and sale of the LNG to Asian buyers.

(c) To provide a basis for discussion and evaluation of the interrelated, complex issues and concerns involved in the development and sale of the ANS gas resource.

The results of the evaluations and economic comparisons are intended to provide information to assist industry, the State of Alaska, and the federal government in making a better assessment of how to realize the maximum benefit from the ANS oil and gas resources.

1.2 Scope

First, locations of the known natural gas resources on the North Slope of Alaska are identified and recoverable natural gas volumes estimated. Next, the impact of major ANS gas sales on current and future oil production is assessed based on two potentially viable ANS gas sales scenarios, an LNG project and a GTL conversion project. The two gas sales scenarios are then technically and economically evaluated. Major components of the evaluation include an assessment of conversion and transportation options; a review of natural gas, LNG, crude oil, and products markets; and a return-on-investment economic analysis of the alternatives. The economic analysis is driven by gas and oil prices available on the world market and allows comparable examination of the two different gas sales scenarios. These components are schematically illustrated in **Figure 1.1**.

The *resource assessment* component is illustrated by the left side of **Figure 1.1** and discussed in detail in **Section 2**. In evaluating the options for utilization of ANS natural gas, it is necessary to account for the interaction of ANS gas production with ANS oil production. While some of the known gas resources on the North Slope are in gas reservoirs that have been capped waiting for commercial production opportunities, such as the Point Thomson Unit (PTU), or were discovered during oil exploration activities and were left undeveloped, most of the known gas available for potential major gas sales is *associated* gas that is co-produced along with the oil production from PBU. The current rate of gas production from PBU is about 7.5 BCFPD. Except for gas used locally on the North Slope as fuel for field and TAPS operations, this gas is now being reinjected to maintain reservoir pressure and to increase oil production. Thus, ANS natural gas has a current use and value to the producers, but the value of the gas for reinjection to increase PBU oil recovery is expected to decrease over the life cycle of oil production as the benefits of pressure

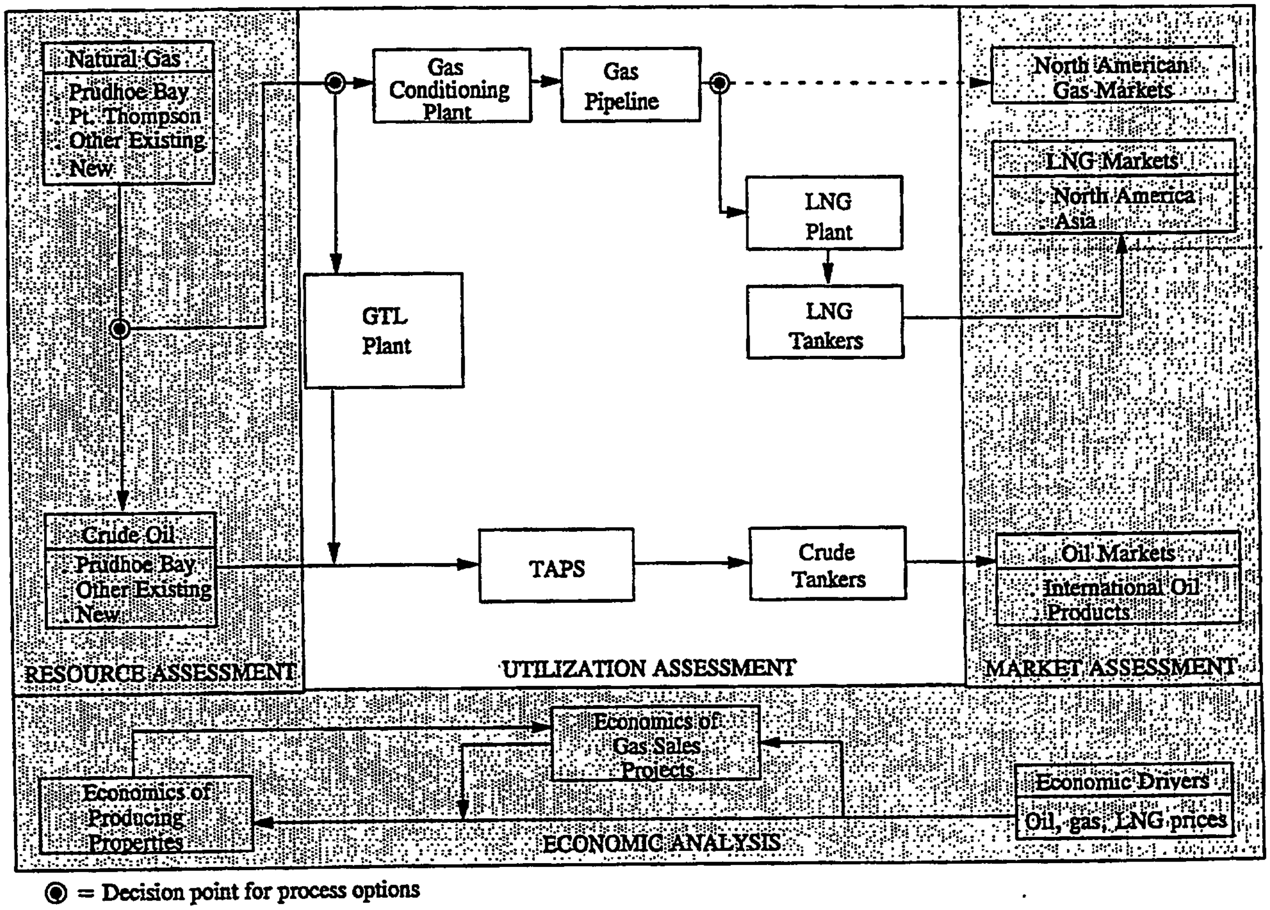

Figure 1.1. Assessing economics of future Alaska North Slope natural gas utilization.

maintenance diminish and enhanced recovery projects using natural gas and NGLs are completed. There is also an interaction between potential LNG and GTL projects on the continued economic life of the ANS oil fields. A successful LNG project may extend the economic life of oil production at PBU by increasing field overall profitability and -- provided TAPS operations remain viable -- enabling some additional oil recovery to take place that would replace some of the oil that may not be recovered due to major gas sales. Similarly, a successful GTL project would also potentially increase the profitability of PBU through sale of gas to the project. In addition, the liquid hydrocarbon product made from the gas would increase the volume of liquids being transported through TAPS, which would result in lower pipeline tariffs for crude oil and GTL liquids. The lower TAPS transportation costs would also increase the wellhead oil price for all ANS oil production and potentially extend the oil producing life of a number of ANS fields, including PBU.

The *conversion and transportation options* are represented by the middle portion of **Figure 1.1.** The three optional paths from reserves to end markets represented are (1) gas delivered via a new gas pipeline from the North Slope connecting to a gas pipeline system through Canada to U.S. markets, (2) gas delivered via a new gas pipeline to an LNG facility where it is liquefied and then transported by LNG tanker to a gas market, and (3) gas delivered to an ANS GTL conversion plant where it is converted to a liquid and then delivered to TAPS where it is blended with ANS crude oil and transported to the oil market. (An alternative that was not examined in this study would be to transport the GTL product as intermittent slugs in TAPS). The first optional path, gas transported via a new gas pipeline to an existing gas pipeline, is described briefly in **Section 3.2.1**, but is not analyzed because the economics are generally recognized to be unfavorable.

For the two options analyzed in detail, the individual component pieces are selected to make the resulting evaluations as comparable as possible. LNG technology is a mature technology and the challenges involved in making a decision to develop the LNG option are primarily economic. Major environmental concerns have not been raised at this point. In comparison, GTL conversion technology is rapidly evolving and projects with the large scale envisioned in the North Slope scenario examined in this study do not exist today. Hence, the comparisons developed in this study are based on input data for both options that have different ranges of uncertainty in cost estimates. Currently, the GTL conversion option has a broader range of uncertainty than the LNG option. The same gas sales rates and the same development schedules are assumed for both options. Also, the gas price that is paid to the gas owners (the producers) is determined by requiring that each option provide a 10% rate of return on investment to the project developers. A sensitivity analysis is performed to indicate the effects changing the variables would have on the economics of each option. Gas conversion processes and the advantages and disadvantages of each of the two transportation options are discussed in **Section 3.**

The right side of the illustration in **Figure 1.1**, represents the *market forces* that influence and drive the prices for natural gas, LNG, and oil and petroleum products. The inclusion of the GTL conversion option for use of ANS gas means that not only are gas and LNG markets important to ANS gas sales but also crude oil and product markets. Current and future prices of pipeline gas in the U.S. and gas as LNG in Asian markets are determined by different market factors. U.S. natural gas market prices are determined by the domestic supply/demand balance. The U.S. gas supply has generally been in surplus for the past 10 years and prices have fallen on a constant dollar basis. The cost of finding and developing new gas reserves is not a very significant factor in determining prices in Asian LNG markets at the present time. LNG markets typically utilize gas reserves in remote production areas where available gas reserves exceed production capability and local gas demand. In those locations, the primary market factors are the availability of LNG facilities, cost of liquefaction, and cost of LNG transportation. The economics of the GTL conversion option depends on prices in oil product markets, which are primarily dependent on the international crude market, rather than prices in gas markets. The oil and gas market assessments are described in **Section 4.**

The three assessment components of **Figure 1.1** are brought together in the economic analyses of the no-major-gas sales reference case and the comparison of an LNG option to a GTL conversion option (presented in **Section 5**). International gas and oil markets drive the prices, which influence the optimum timing for major gas sales from the fields and the viability of the gas sales options. The economic analyses of the two gas sales options also include the impact of major gas sales on future ANS oil recovery potential. **Section 5** provides comparative economics and evaluations of the sensitivity of the analyses to cost estimates for new process technologies and other cost elements. The two gas sales scenarios (LNG and GTL) are evaluated such that all project developers receive a 10% rate of return on their investments. This is accomplished by varying the price paid to the producers (North Slope unit owners) for their gas through the use of a gas product net back fraction applied to the price received for the LNG or the GTL liquid product. The North Slope gas price (derived from the gas product price times the gas product net back) is used in evaluating the effects of each gas sales option on the economics of the producing units. The actual gas prices received by the gas producers from the gas project owners would be determined by a gas sales contract and could involve sharing of facilities, risks, and other factors. The effects of major North Slope gas sales on industry, State of Alaska, and federal income are also estimated.

Detailed discussions of the status of ANS oil and gas development, including the basic data and forecasts used in the economic analyses, the description of the economic model, details of the sensitivity analyses, and the bibliography are included in **Appendices A** through **E.**

Conclusions based on the results of the analyses are presented in **Section 6.**

1.3 Methodology

Discounted cash-flow analyses are performed to determine the economic limit for the producing fields, the value of each field's resources, and the economic viability of each of the gas utilization options. The value of the projects are quantified in terms of the net present value (NPV). A project that produces a return exactly equal to the discount rate (DR) has a net present value of zero ($NPV_{DR} = 0$), indicating that the investment earns the minimum acceptable rate of return. The minimum acceptable rate of return for new projects may vary for different companies depending on their internal assessment of variables such as project risks, oil and gas price expectations, and alternative investment opportunities on a worldwide basis. All of the major developments on the North Slope, including infrastructure such as TAPS, have multiple owners with varying ownership levels and competing interests, which makes it impossible to choose a discount rate that would be representative for each company.

The gas sales options are evaluated as stand-alone projects that purchase gas from the producing units based on the gas product net back fraction. The owners of the gas utilization projects could include the unit owners, developers such as YPC, and possibly purchasers such as Japanese companies in an arrangement similar to TAPS. No attempt is made in this study to evaluate impacts of arrangements such as these.

Uncertainties in assumptions are evaluated by determining the sensitivity of project economics to changes in economic variables. The effects of changing variables such as oil price forecasts, operating costs, capital investment, process efficiencies, and federal and State taxes are evaluated.

1.4 Background

The possibility of commercializing the huge North Slope gas reserves has been the subject of numerous studies since 1970 (State of Alaska, 1996). These studies have involved evaluations of proposed projects for exporting the Alaskan gas to supply natural gas markets in the lower 48 states as well as foreign markets. One option that has been considered in the past is the Alaskan Natural Gas Transportation System (ANGTS), which would involve a gas pipeline through Alaska and Canada to markets in the lower 48 states. Another plan was proposed in the early 1980's for a Trans-Alaska Gas System (TAGS) project that has evolved into the project proposed by Yukon Pacific Corporation (YPC), a division of CSX Corporation. Under this plan a gas pipeline would be built paralleling TAPS to transport the gas to a liquefaction plant located on Prince William Sound (Valdez, AK), where it would be converted to LNG and exported to Asian LNG markets. Recently, a major feasibility study for LNG options was conducted by the three major North Slope oil and gas producers (Arco, BP, and Exxon). The study has not been released outside of the participant companies; however, it was reported in July 1995 that the major gas owners on the North Slope had concluded that a large Alaska LNG project could not compete in today's Pacific Rim markets and is at least 10 years off, probably longer (Oil Daily, 1995a; Energy Daily, 1995).

Investments in oil recovery projects have overshadowed development of natural gas resources on the ANS almost entirely because of uneconomic gas market conditions. Furthermore, existence of North Slope oil production and transportation infrastructure has caused the operators to direct their exploratory and development efforts to oil projects that utilize and prolong the effective life of these installations. Major gas sales were anticipated at the initial unitization of PBU and have been the subject of continuing studies and evaluations over the life of the field. However, the operators will continue to be unwilling to invest in exploration and production for gas until there is greater certainty in market timing and gas value.

The primary drawback to any ANS gas utilization project is the ability of the market to provide a reasonable wellhead gas price. Hence, major gas sales from PBU, developing other proven North Slope gas resources, and exploration targeted to the large potential undiscovered natural gas resource on the North Slope cannot be expected to occur until the market value of the gas is greater than its value for the production of oil on the North Slope. This study evaluates the LNG and GTL conversion options to determine if they can be expected to provide viable markets for ANS gas.

1.4.1 Key Issues Impacting ANS Gas Utilization

There are several interrelated factors, issues, and concerns that need to be considered by industry, State, and federal interests in order to properly assess ANS gas utilization. It is the need to address these issues and to determine their impact on the overall ANS resource assessment that prompted this study to be undertaken at this time. These issues are as follows:

- ANS oil production, which has accounted for almost 25% of the daily U.S. domestically produced oil since production was initiated from the Prudhoe Bay field in 1977, has been declining since its peak of over 2 million barrels of oil per day (MMBOPD) in 1987 to just over 1.5 MMBOPD in 1995. This production will continue to decline in the future as shown in **Figure 1.2.** The production forecasts shown were developed by the authors based on publicly available data and are discussed in **Section 2** and **Appendix A.** This decline is dominated by the production decline from the Prudhoe Bay field and clearly cannot be halted or reversed without major new discoveries and developments.

- TAPS has a minimum throughput at which it can be operated [U.S. Department of Energy (DOE), 1993a]. The minimum throughput will be determined by both technical constraints and operating and maintenance costs. The dashed lines and arrows at the bottom of **Figure 1.2** indicate the range of minimum TAPS throughput of 200 to 400 thousand barrels of oil per day (MBOPD) discussed in the DOE (1993a) report. With that throughput range and projected current field operations, TAPS shutdown could occur between 2009 and 2016. This range has not been firmly established and it is certain that every effort will be put forth by industry and the State of Alaska to maintain the viability of TAPS for as long as possible. Although it is a common belief by many parties in Alaska that these efforts will be successful and the lower limit will be reduced to 100 MBOPD or less, there are no known studies by Alyeska Pipeline Service Company or the major owners of TAPS to confirm this. Hence, the 200 to 400 MBOPD range is used in this study to illustrate the effects that a shutdown would have on ANS production. The end of ANS production will more likely be dictated by oil pipeline transportation costs considerations than by production costs of North Slope fields. A shutdown, mothballing, or abandonment of TAPS and consequently other existing ANS infrastructure would significantly burden the economics of future ANS exploration and development projects and discourage efforts to pursue any developments except very large, major ANS exploration prospects. Additional large volumes of liquid production from new discoveries and field developments or major new projects, such as GTL conversion, prior to TAPS shutdown would extend the operational life of TAPS and result in the recovery of significant additional oil from existing producing ANS fields, as well as production from future potential fields and projects.

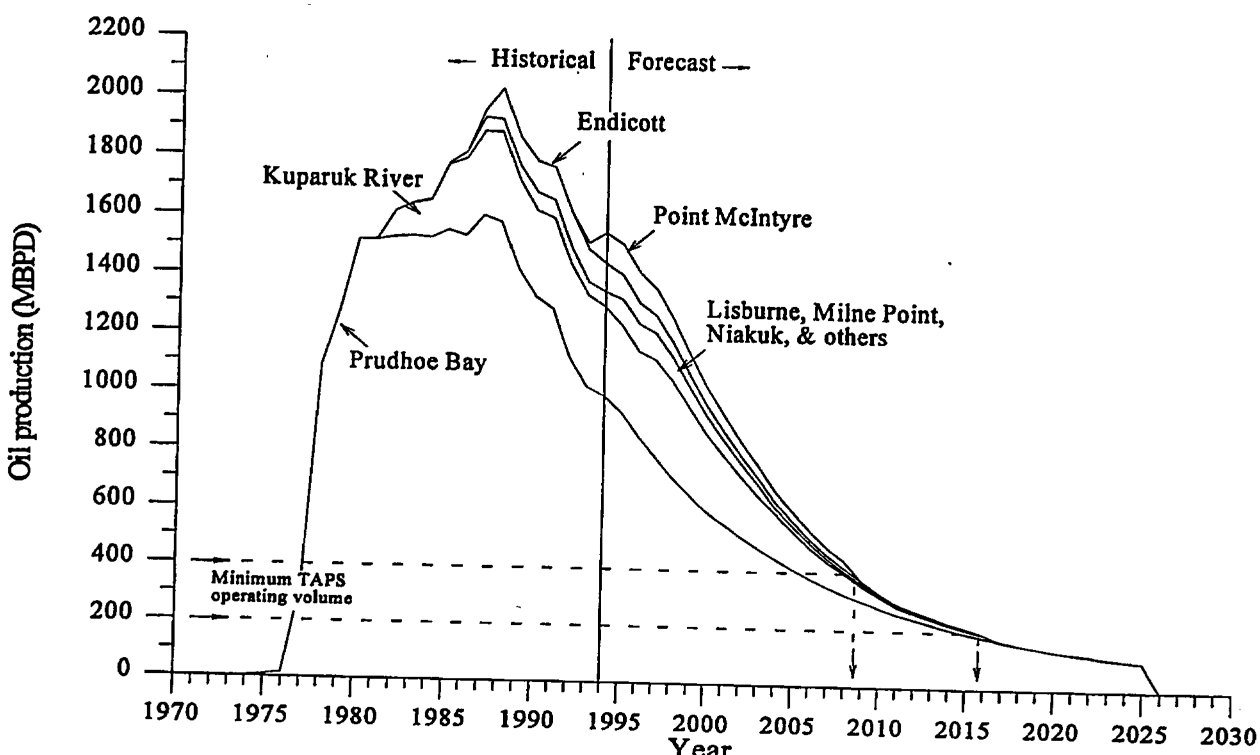

Figure 1.2. The Alaska North Slope historical production and production forecast at the Energy Information Administration (EIA) Reference Oil Price (economically recoverable oil).

- Gas pipeline and LNG plant scenarios have historically been considered as the most likely commercialization route for ANS gas. However, advances in GTL conversion technology and the development of commercial projects around the world have increased the possibility that the conversion of natural gas to high-value, environmentally desirable, hydrocarbon liquids compatible with the TAPS transportation system has become a viable option for utilizing ANS gas resources.

- Long lead times, on the order of 5 to 10 years, are required to bring major ANS development projects on production. Hence, the time for public and private policy debate attaining optimum use of the remote ANS gas before TAPS shutdown (possibly as early as 2009) is becoming relatively short.

- In addition to the impact of GTL processes on the future of the ANS gas utilization, the development of economical hydrocarbon conversion processes for production and upgrading of heavy oils and tar on the North Slope could also have a significant impact. The West Sak and Ugnu fields are estimated to contain about 35 billion barrels of original heavy oil and bitumen in place (Mahmood, 1995) (see **Figure 2.1** and **Figure 2.2**). The exploitation of these resources may depend on maintaining the viability of TAPS operations until these resources can be economically developed.

1.4.2 Other Studies

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 history of exploration and development up to early 1990 is described in that publication. The report presented an analysis of several potential scenarios concerning future production from the North Slope. Five producing oil fields, two fields nearing development, four discovered but undeveloped fields and three potential exploratory areas were analyzed for their effect on the lifetime of TAPS.

The National Energy Strategy (NES) issued in February 1991 included a call for accelerated development of five undeveloped Alaskan North Slope fields (West Sak, Point Thomson, Gwyder Bay, Seal Island/Northstar, and Sandpiper Island). The 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. A report titled "Alaska North Slope National Energy Strategy

Initiative - Analysis of Five Undeveloped Fields," was released in May 1993 (DOE, 1993). The report presented an analysis of environmental, regulatory, technical, and economic information relating to the development potential of the five fields.

These two earlier Alaska North Slope oil and gas resource studies and the study presented in this report have been performed at the DOE's Idaho National Engineering Laboratory (INEL) in Idaho Falls, Idaho. This study makes full use of INEL's previous studies of Alaska's North Slope oil outlook in 1991 and 1993, and new information gathered by the authors to update and expand upon these earlier efforts to assess the potential for development of the natural gas resource.

1.4.3 DOE Program Office

The study presented in this report was funded by the DOE Office of Fossil Energy through the Gas Processing program, a component of the Natural Gas (Supply) Research Program. It was directed and managed by DOE's Morgantown Energy Technology Center, which implements most of the Natural Gas Research Program, and by the Gas Processing program within the Office of Fossil Energy's Washington, D.C. headquarters Office of Gas and Petroleum Technology.