Economics of Alaska North Slope Gas Utilization Options

Eric P. Robertson (epr@inel.gov; 208-526-7456)
Idaho National Engineering and Environmental Laboratory
P.O. Box 1625
Idaho Falls, ID 83415-2213

Charles P. Thomas (cpt@baervan.nmt.edu; 505-835-5408)
Petroleum Recovery Research Center - New Mexico Tech
801 Leroy Place
Socorro, NM 87801

Abstract

About 26 of the 38 Tcf technically recoverable, conventional natural gas located in developed and known undeveloped fields on the Alaskan North Slope is available for sale; the remainder will be consumed in oil and gas operations on the North Slope. No significant commercial use has yet been made of this large natural gas resource because the economics have not yet been favorable to support development of a gas transportation system.

Two gas utilization and transportation options were evaluated that could be used to exploit the vast arctic gas resource: 1) a gas-to-liquids (GTL) option that converts the gas to a stable liquid on the North Slope using Fischer-Tropsch technology and then transporting the resulting liquid along with produced crude through the Trans-Alaska Pipeline System (TAPS), and then to conventional refineries via tankers; 2) a liquified natural gas (LNG) option that involves constructing a gas pipeline from the North Slope to an LNG plant located in Valdez, AK, and then to Asian LNG markets via LNG tankers.

The options were evaluated using discounted cash flow analysis on an after-tax basis. Results indicate that both options are profitable when evaluated using the Energy Information Administration's 1995 Reference Oil Price forecast, which assumes real growth in oil prices. The LNG option has a slight economic advantage under the conditions assumed in the analysis, but the uncertainty associated with the input parameters leads to the conclusion that neither option holds a significant quantifiable economic advantage over the other.

The current TAPS tariff charged to transport liquid product to market is about $3.00/bbl. As North Slope crude oil production continues to decline, the tariff per barrel will increase. The GTL option would provide a significant amount of liquids to be transported through TAPS; thus reducing the per barrel tariff and effectively increasing crude oil revenues for all North Slope fields. Both options would promote continued gas exploration on the North Slope. However, only the GTL option would extend oil production from currently producing fields by reducing transportation tariffs and possibly extending the life of TAPS; thus, allowing the future exploration for and production of both oil and natural gas.

Research sponsored by the U.S. Department of Energy's Federal Energy Technology Center, under contract DE-AC07-94ID13223.

Introduction

The technically recoverable conventional natural gas resources in the developed and known undeveloped oil and gas fields on the Alaska North Slope (ANS) total about 38 Tcf. In addition to these known gas resources, the U.S. Geological Survey estimates that the recoverable gas resource in undiscovered fields in Arctic Alaska is 64 Tcf.[1] Natural gas proved reserves in the entire U.S. totaled 173 Tcf at the end of 1995.[2]

About 26 Tcf of the known recoverable gas in Arctic Alaska is estimated to be available for sale; the balance will be consumed in oil and gas production operations on the North Slope. Currently, ANS gas is not marketed off the North Slope except for natural gas liquids (NGL), which are blended with crude oil for transport in the Trans-Alaska Pipeline System (TAPS), because the economics of developing a gas transportation system have not yet been favorable. All of the produced gas, except that used for production operations and local sales, has been reinjected back into the reservoirs to maintain reservoir pressure and for improved oil recovery projects.

ANS gas has significant value in oil recovery operations on the North Slope. The use of gas for improved oil recovery has been very successful as demonstrated by the increase in reserves for the Prudhoe Bay Unit (PBU). Early estimates for total recovery were under 10 billion barrels of oil but have been raised to the current estimate of 13 billion barrels (56% OOIP) mostly due to the prudent use of the co-produced gas. As ANS oil production continues to decline, the value of the gas for improved oil recovery also diminishes; making the time ripe for development of this large gas resource.

North Slope oil production has been declining since its peak in 1987 of over 2 million BOPD to just over 1.5 million BOPD in 1995. **Figure 1** shows the historical and forecasted production from currently producing North Slope fields. The looming potential of a shutdown of TAPS because of ANS production dropping to a minimum throughput rate for the pipeline of 200 to 400 MBPD[3] in the 2009 to 2016 time frame would result in a significant loss in economically producible ANS reserves. The ANS oil production trend and the pipeline minimum throughput range, coupled with the long lead time of 5 to 10 years required to bring major ANS development projects on line, make clear the urgency of weighing technical options that could influence the future of ANS oil production, as well as gas production.

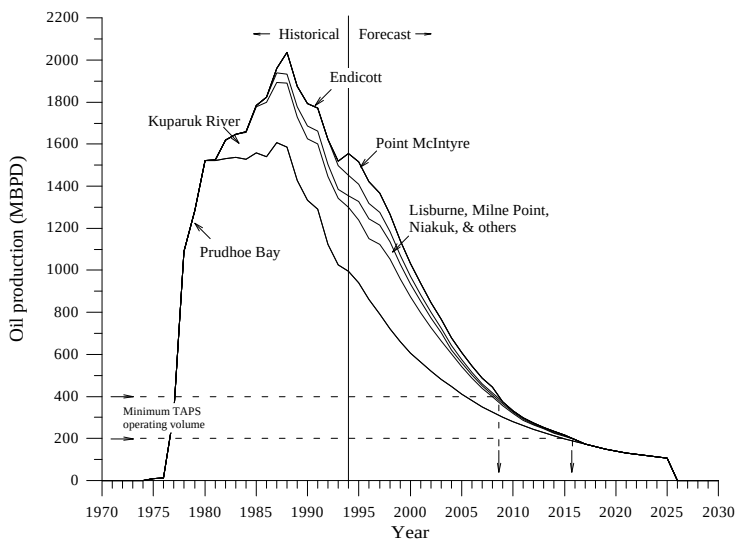

Figure 1. The Alaska North Slope historical production and production forecast.

Recent advances in gas-to-liquids (GTL) technology that may provide the means to

economically convert natural gas to hydrocarbon liquids compatible with the ANS crude oil have raised interest in GTL technology as an option for gas sales. Liquified natural gas (LNG) has also been proposed as an option for ANS gas sales.

The 26 Tcf of gas available for sale from known fields on the North Slope coupled with the potential for large additional gas discoveries make it important for all interested parties (including industry, U.S. Department of Energy, and the State of Alaska) to evaluate and assess the options for development of this vast gas resource. By understanding the available options for gas sales and how they will impact future oil production, as well as gas production, it is more likely that industry, the State of Alaska, and the nation will obtain the maximum benefit from the ANS gas resource.

This paper is a result of a study funded by the U.S. Department of Energy at the Idaho National Engineering and Environmental Laboratory and highlights the major points of a much larger and detailed report by Thomas et al.[4]

Objectives

The primary purpose of this study was to provide a technical and economic evaluation of the feasibility of using chemical conversion of natural gas to liquid hydrocarbons technology for bringing the large, remote, and currently unmarketable ANS natural gas resource to market. However, because of the long-standing interest and high visibility of the LNG option, it was apparent that an examination of how the GTL conversion option compares to the LNG option was necessary. The objective of these comparisons was 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.

Accordingly, this paper explores and compares two options, an LNG option and a GTL option, for marketing Arctic Alaska's gas. The LNG option involves constructing a gas pipeline through Alaska to an ice-free port at Valdez, constructing an LNG plant for converting the gas to LNG, and then tankering the LNG to Japan and other Asian countries for sale. Recent technological advances have raised the interest in the other option for marketing ANS gas - GTL conversion. The GTL option involves constructing a GTL plant on the North Slope where the produced gas would be converted to liquid using Fischer-Tropsch technology and transported to Valdez through TAPS along with the produced crude, eliminating the need for a separate gas pipeline. The mixture of crude oil and GTL liquids would then be transported to U.S. refineries in the Lower-48 states by conventional tankers.

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.

Approach

The first step in the evaluation was to identify the locations of the known natural gas resources on the North Slope of Alaska and estimate the known technically recoverable gas volumes.

The Prudhoe Bay Unit (PBU) and the Point Thomson Unit (PTU) were identified as the most likely sources of gas on the North Slope. Although other fields produce gas the volumes were small in comparison to PBU and PTU.

The impact of major ANS gas sales on current and future oil production was then assessed based on the two ANS gas sales scenarios. Because major gas sales from PBU would take gas presently used for oil recovery operations, oil production could be stunted depending on the start-up timing of the gas sale. Also, hydrocarbon liquids produced from the GTL plant would be transported through TAPS - lowering tariffs for crude oil shipments; effectively increasing the wellhead oil price and allowing more oil to be economically produced.

The LNG gas sales option and the GTL gas sale option were then technically and economically evaluated. The LNG option was modeled after the proposed Trans-Alaska Gas System (TAGS) project.[5] The GTL technology used in this assessment assumes the technology used in Shell's Middle Distillate Synthesis Plant that has been operating in Malaysia since 1993.[6]

Method of Evaluation

Three scenarios were evaluated and compared from the perspective of the field operators: 1) continue current mode of operation with no major gas sales; 2) The LNG gas sales option; and 3) the GTL gas sales option. If both the LNG and the GTL projects receive a 10% rate of return (ROR), the most economically attractive scenario is that which gives the field operators the highest net present value (NPV) for the oil and gas sold. It is important to include the revenue from oil sales as well as gas because the oil revenues are different for each of the three options. The option which gives the operators the highest NPV would be the highest rated option; however, this conclusion should be tempered by uncertainties in input parameters and, to some extent, the risk associated with each option.

We introduce the concept of a "gas product net back," which is simply the fraction of the final gas product price paid to the gas producing units to purchase the gas for each project. In the LNG option, the gas product net back is the fraction of the price received for the LNG sold in Japan. For the GTL option, the gas product net back is the fraction of the price received for the converted GTL liquids at West Coast refineries. The two gas sales projects were evaluated separately from field operations and were each forced to a 10% ROR by varying the gas product net back.

Alaska North Slope Oil and Gas Reserves

The remaining recoverable ANS oil and gas reserves without major gas sales and the remaining potential gross gas production (including CO_2 and other impurities) are estimated to be 6.3 billion barrels of oil and 37.6 Tcf of gas, respectively. About 26 Tcf of hydrocarbon gas will be available for major gas sales after carbon dioxide (CO_2) removal, lease usage, local sales, NGL removal, and losses. Projected net major gas sales volumes available for sale are 21.8 Tcf from Prudhoe Bay, 3.2 Tcf from Point Thomson, and 1.0 Tcf from other smaller fields. ANS fields had produced 10.5 billion barrels of oil by the end of 1994 (84% from the Prudhoe Bay field, 11% from the Kuparuk River field, and 4% from the other oil pools). Undiscovered, technically recoverable,

conventional natural gas resources in Northern Alaska are estimated by the USGS to be between 23 Tcf (95% probability) and 124 Tcf (5% probability), with a mean value of 64 Tcf.[1] As shown in **Figure 2**, there have been numerous small gas fields discovered in the search for oil across the ANS. This figure also shows the importance of facility cost-sharing to other fields, made possible by the development of infrastructure around the super giant Prudhoe Bay field.

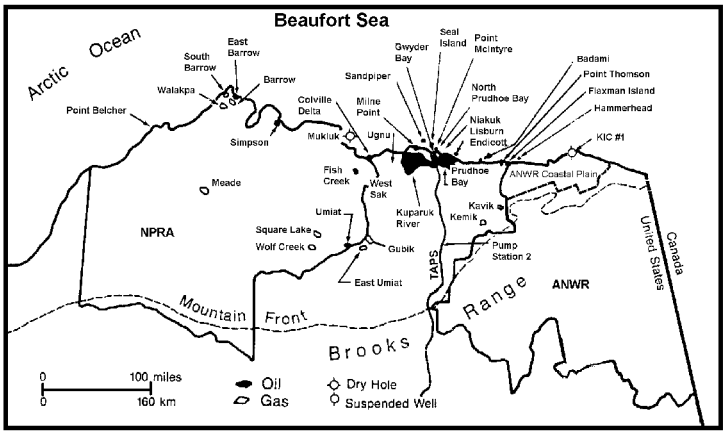

Figure 2. Known oil and gas accumulations, selected dry holes, and suspended wells.

Remaining oil reserves from PBU as of 1/1/95 are about 4.2 billion barrels of oil (crude oil, condensate, and NGLs), with ultimate cumulative recovery of about 13.0 billion barrels. The production forecasts represent estimated volumes being delivered to Pump Station No. 1 (PS No. 1) and take into account the impact on production of the planned expansion of existing facilities, future drilling, and redrilling and workover of wells.

The Point Thomson Unit, discovered in 1977, covers a gas condensate field about 50 mi east of TAPS PS No. 1. PTU's 83,000 acres covers a deep, overpressured reservoir that is mostly offshore. Estimated reserves for PTU are 12.8 million barrels of oil (crude oil, condensate, and NGLs) and 3.2 Tcf of hydrocarbon gas.

Impact of Gas Sales Options on Oil Recovery

Oil production forecasts for all currently producing oil fields were first developed assuming no major gas sales, then modified, where necessary, to take into account the impact of major gas sales. The composite oil production forecast for the ANS producing fields without major commercial gas sales is shown in **Figure 3**. Estimates for the minimum throughput volume necessary to keep TAPS operational, range from 200 to 400 MBPD[3,7] and is shown graphically in this figure by the dashed lines.

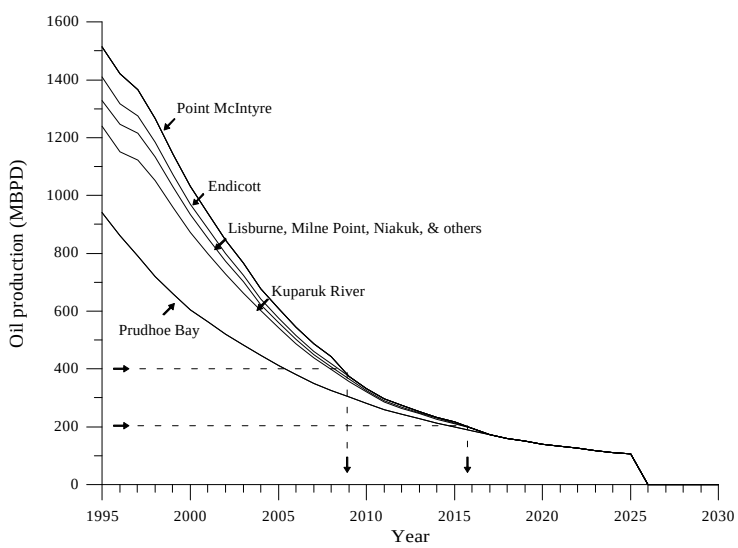

Figure 3. Composite North Slope oil and gas production forecast - no major gas sales.

A 1995 study by the North Slope operators concluded that the most likely

timing for ANS major gas sales from Prudhoe Bay field will occur after 2005 because of LNG market forces.[8,9] A gas production rate from the North Slope of about 2.05 Bcf/D [748 Bcf/yr] would be required to support delivery of the 682 Bcf/yr [14 million metric tonnes per annum (MMTPA)] of LNG to Pacific Rim countries planned for the TAGS/LNG project. The field gas production rates in this study include a maximum rate of 2.05 Bcf/D from PBU, and 0.44 Bcf/D from PTU. This provides a maximum delivery rate of 2.49 Bcf/D to the LNG project and would result in an 829 Bcf/yr [17 MMTPA] LNG project. The maximum production rate would be reached after a 5-year ramp-up as shown in **Figure 4**. It has been estimated that major gas sales from PBU starting in 2005 and ramping up to 2 Bcf/D in 5 years would reduce PBU oil recovery by 400 MMBO.[10] The oil forecasts in **Figure 4** include the loss of 400 million barrels of oil from PBU and the addition of 181 million barrels of condensate from PTU.

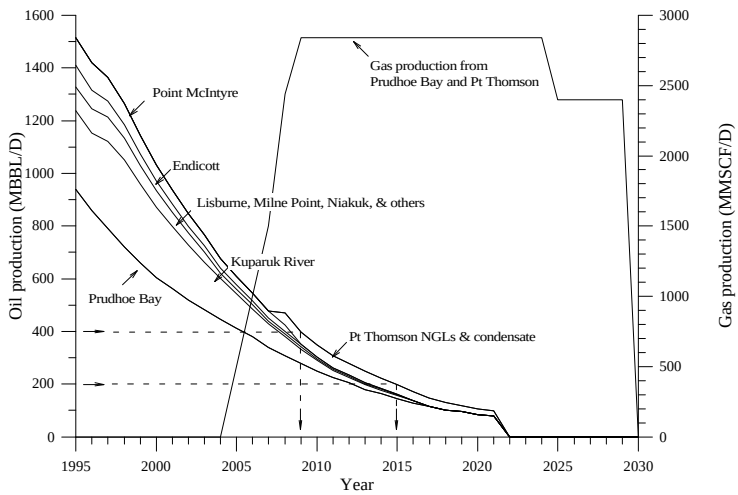

Figure 4 Composite North Slope oil and gas production forecast with major gas sales from PBU and PTU.

The same field production rates and schedules are assumed for the GTL option as those outlined for the LNG option. Using current Fischer-Tropsch technology and a conversion efficiency of 60%, the proposed GTL conversion option would convert the 2.49 Bcf/D purchased from PBU and PTU into about 300 MBPD of gasoline-type hydrocarbon liquids that can be blended with the produced crude oil being delivered to TAPS and transported to existing oil product markets as shown in **Figure 5**. This additional liquid volume would extend the operational life of TAPS to 2035 and would also result in reduced TAPS tariffs for all liquid throughput volumes from other fields.

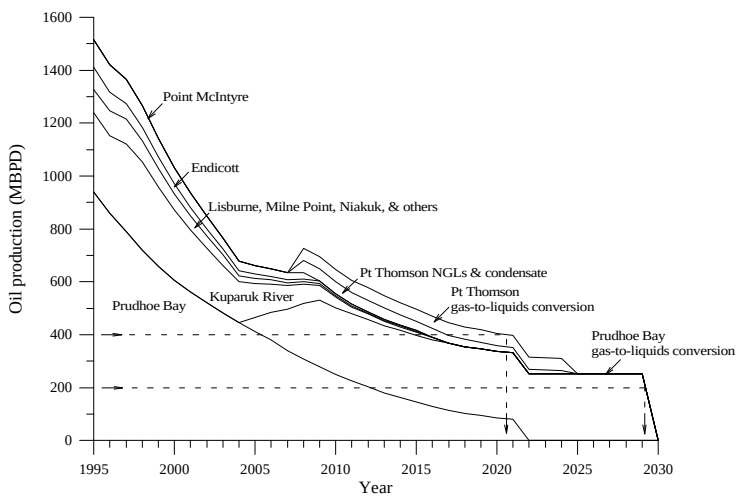

Figure 5. Composite North Slope production forecast with GTL conversion from PBU and PTU.

The TAPS tariff is based on total liquid throughput and operational costs. Generally, as total throughput declines, the cost per barrel to transport liquids through the pipeline increases. **Figure 6** shows the projected tariffs for each of the three scenarios evaluated in this paper. The tariff is highest for the LNG option because liquid throughput is reduced as a result of the 400 million barrels of lost recovery from PBU. The GTL option has a significantly lower projected tariff because the added

GTL liquids more than offset the reduction in recovery from PBU. The effect of tariff changes on other North Slope oil fields (besides PBU and PTU) is expected to have a significant impact on field economics but was not considered in this paper.

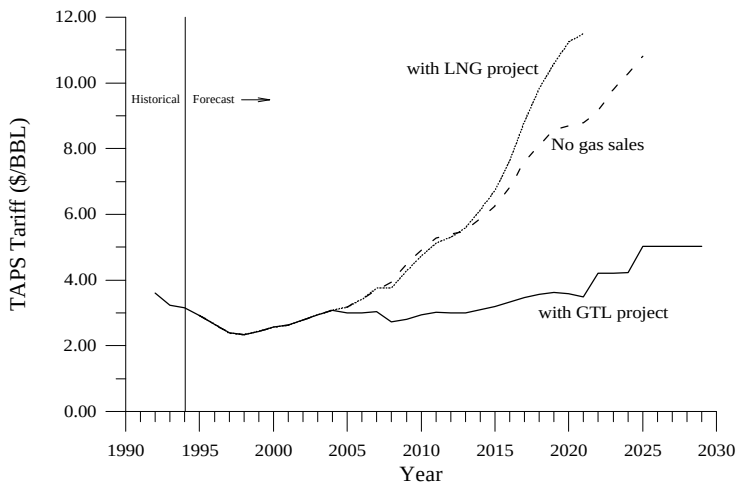

Figure 6. TAPS tariffs for three North Slope production scenarios (1995$).

Evaluation of Gas Sales Options

The utilization of the ANS natural gas resource requires the transportation of gas from the North Slope to existing markets in the Lower-48 states or to overseas markets. The TAGS/LNG project would require a gas pipeline paralleling TAPS followed by conversion of the natural gas to a cryogenic liquid in a refrigeration cycle for sea transport under low pressure in LNG tankers. The GTL project would convert natural gas on the North Slope to stable hydrocarbon liquids through one or more conversion processes, followed by shipment of the liquids to market using the existing TAPS and oil tanker system.

Of the various types of GTL conversion processes, the Fischer-Tropsch process is presently the most practical existing process although conversion costs are high.[11] The Fischer-Tropsch process first produces a synthesis gas through steam reforming and partial oxidation of methane. This step is followed by a catalytic process to convert the synthesis gas to liquid hydrocarbons that can be upgraded by conventional refining processes to diesel fuel, gasoline, etc. Reactor and other process improvements, prospects for the use of ceramic membrane oxygen production in place of expensive cryogenic oxygen, and other direct conversion options are expected to yield significant GTL conversion cost reductions and efficiency increases in the near future.

Investment Breakdown

The components of the TAGS/LNG project include a gas conditioning plant on the North Slope; the 800-mile gas pipeline from the North Slope to Valdez, AK; facilities at Valdez including an LNG plant, storage tanks, and marine terminal; and 19 LNG tankers to transport the 17 MMTPA to Asian Pacific Rim countries. Public information available on the total cost for the 14 MMTPA TAGS project is $14 billion.[5] (All dollar values in this paper are reported in 1995$). The LNG project analyzed in this study has a capacity of 17 MMTPA to handle 14 MMTPA from PBU and 3 MMTPA from PTU, and increase in capacity of 21.4%. Based on the additional equipment needed to reach this capacity, the capital costs are increased from $14 billion to $16 billion, an increase of 14.3%. The $16 billion investment is scheduled over a 9-year period. The investment breakdown for the TAGS/LNG project is listed in **Table 1**.

GTL capital costs for a North Slope installation (including any necessary gas conditioning) are estimated based on a recent report by Hackworth et al.[11] In this report, two estimates were given

for a 14,500 bbl/D GTL plant located at PBU. A much larger plant (300,000 bbl/D) is required to accept the gas produced from PBU and PTU. The study indicated that by quadrupling the plant size to 58,000 bbl/D a 33% savings in capital could be realized. The report also shows an additional savings of 25% is possible by building successive plants patterned on a first-of-kind process plant. Based on these projected savings, the range of capital required for a 300,000 bbl/D plant located on the North Slope near PBU is between $27,000 to $39,900 per daily barrel (DBL). For an unproven plant installation on the North Slope, the upper end of this investment range, or $40,000/DBL, is assumed for this evaluation. The total investment of $12 billion is scheduled over a 7-year period.

Table 1. LNG project investment breakdown.

Segment	Cost (billions $)
Conditioning plant	1.7
Pipeline	6.6
LNG plant, storage, and terminal	3.0
LNG tankers (19)	4.7
Total	16.0

Process Efficiencies

For the LNG option, gas losses include gas used as fuel or other losses in the gas conditioning plant, gas pipeline, LNG conversion plant, and LNG tankers. The TAGS/LNG project assumes a daily gas input rate to the gas pipeline of 2.49 Bcf/D and delivers 2.27 Bcf/D (17 MMTPA) to Pacific Rim countries, resulting in an overall thermal efficiency of 91%. The overall thermal efficiency of 60% percent is used in the GTL evaluation. This is three percentage points lower than the 63% design efficiency reported for Shell's Malaysia plant.[12] The 60% efficiency assumption may be conservative, but is used because actual data from Shell's plant is not publicly available.

Operating and Maintenance Costs

Operating and maintenance (O&M) costs may include operation and maintenance of facilities, overhead costs, environmental compliance, payroll, etc; but do not include the gas feed cost. Direct O&M costs are not available for the entire TAGS/LNG project nor for the separate segments of the project. TAGS/LNG economics are determined on a total project basis; therefore, O&M costs are estimated using an empirical method. For large projects, such as offshore U.S. and Europe, industry typically uses 5 to 7% of the cumulative inflated investment to estimate annual operating costs. A 5% factor is used in this paper to estimate O&M costs for the TAGS/LNG project. For the GTL project, $6.00/DBL is used to estimate the O&M costs.

LNG Market and Value

The LNG trade has been built primarily around two geographical pairings: the North Africa to Europe trade and the Australia/Asia trade to Japan. The Australia/Asia trade has experienced the most robust growth, an average of 7% per year between 1984 and 1995. North African export has grown at 4% per year during the same period. Japan is the largest LNG market, representing 65% of the world demand in 1994. LNG demand in Japan has grown at a rather steady 5% per year over

the past decade. Worldwide LNG consumption has increased 6.2% per year between 1984 and 1994.

Published analyses indicate that new competitively priced LNG supply for Japan would first come from expansion in Austrailian and Indonesian operations, then from grass roots projects in southeast Asia, with ANS gas potentially the least cost competitive.[13,14] The major reason for this conclusion is that an LNG project for North Slope gas must support a $6.6 billion gas pipeline that other operations do not require. Nevertheless, for the sake of this technical and economic study, it is assumed that there will be a market for the ANS LNG regardless of whether the market will exist or not.

Historically, the delivered price of LNG has been strongly influenced by the price of crude oil as shown in **Figure 7**.[15] Because gas is a cleaner burning fuel, LNG has, at times, received a bonus in Japan over crude oil on a BTU basis. It is assumed that the bonus is 10% greater than the world crude oil price. The crude oil price forecast used in this study is the Energy Information Administration's Annual Energy Outlook 1995 reference forecast and is shown in **Figure 8**. Assuming 5.9 MMBTU/bbl of crude oil and 1.15 MMBTU/Mcf of North Slope gas, the LNG/crude-oil conversion is calculated to be 5.13 Mcf/bbl. The LNG price in Asia is based on the following equation:

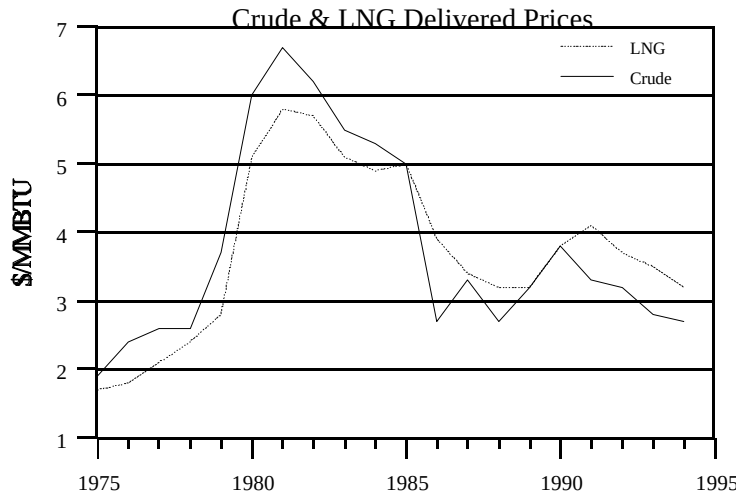

Figure 7. Historical prices for LNG and crude oil.

$$LNG\ price\ in\ Asia\left(\frac{\$}{Mcf}\right) = \frac{World\ oil\ price \times 1.1}{BTU\ conversion\ for\ LNG}. \qquad (1)$$

Therefore, for $20/bbl crude oil, LNG would sell for $4.29/Mcf in Japan.

GTL Product Market and Value

The U.S. West Coast is a major market for oil products. In 1994, the refineries in the region produced about 2.8 million bbl/D of refined products to meet a demand of 2.7 million bbl/D in the region. Gasoline was 49.5% and distillate was 29.0% of the total refined products demand.[16] In assessing the value of a GTL product as a feedstock to a refinery, the primary variable is the average crude price. The value of a feedstock, such as GTL products, can be estimated from the average crude price and is based on the relative processing costs and value of the refined products.

Over the last 15 years, wholesale gasoline prices averaged $8/bbl higher than crude oil and No. 2 fuel oil prices averaged $6/bbl higher than crude oil. In addition, the products made in Shell's Malaysia GTL plant and the Exxon AGC-21 pilot project are higher value fuel products than those

made from crude oil because of the zero sulfur, nitrogen, and aromatic content, which makes them ideal for meeting the low-emission regulations for diesel. The high-quality distillates made in the Shell Malaysia plant have been commanding premiums of $8 to $10/bbl over crude oil-derived distillate in the California market, which equates to a premium of about $15/bbl over crude oil.

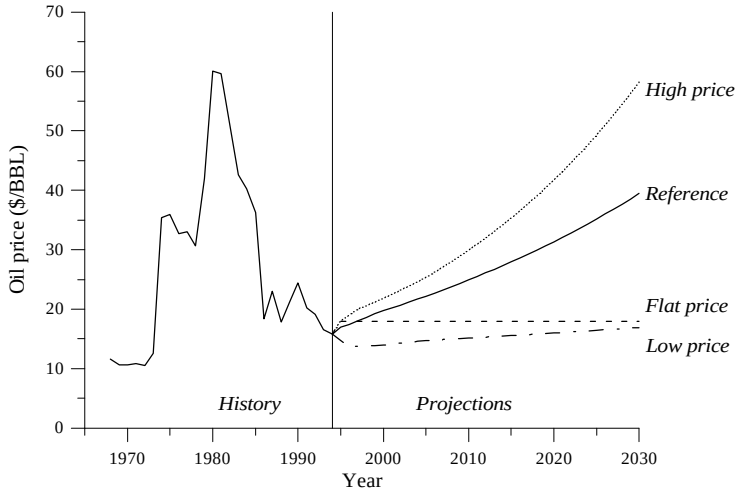

Figure 8. Historical world oil prices and world oil price forecasts.

Because the GTL product would arrive at the West Coast refineries mixed with Alaskan crude oil, the GTL product is given a conservative $5/bbl premium over the world crude oil price. The Lower-48 ANS oil price is roughly one dollar below average world crude oil price. A weighted average method is used to calculate the value of the mixed pipeline product. For example, if the world crude oil price were $20/bbl, the GTL product would be valued at $25/bbl and ANS crude price would be $19/bbl. The price of a 60/40 mixture of ANS crude and GTL product on the U.S. west coast would be calculated as follows: 0.6($19/bbl) + 0.4($25/bbl) = $21.40/bbl. The value of both the crude oil and the GTL product on the North Slope is the Lower-48 price less marine and pipeline tariffs.

Economic Analysis of Gas Sales Options

The two gas sales options were compared from the perspective of the PBU and PTU field operators. Comparison of the economic benefit of each project requires a common economic basis. By adjusting the gas purchase price at the project inlet gate, both the TAGS/LNG project and the GTL project were forced to receive an equal 10% rate of return. The options were then compared

Table 2. Economic comparison of TAGS/LNG project and GTL project.

Economic Factor	TAGS/LNG project	GTL project
Project life, years	32	32
Investment, $ billions[a]	16.0	12.0
Total operating costs,[b] $ billions	64.8	46.1
After-tax cash flow, $ billions	31.5	20.9
Rate of return, %	10.0	10.0

a. all values in 1995$
b. operating costs include O&M and gas purchase cost

by calculating the net present value of the producing units (PBU and PTU) when selling the same amount of gas to each project. **Table 2** compares the economic results of the two gas sales projects on an equal 10% ROR basis.

Scenario One: No Major Gas Sales

The first scenario evaluated from the perspective of the field operators was to continue the current mode of operation with no major gas sales. In this alternative, the Point Thomson Unit is not developed; only oil from the Prudhoe Bay Unit is sold and the produced gas is reinjected and used to enhanced oil recovery.

Estimates of future investments for PBU are based on the most current unit plans[17,18] and total $1.79 billion through 2005. Operating costs were estimated based on produced water cut and total produced fluid as described by Thomas et al.[3] For Prudhoe Bay, the wellhead oil price is simply the world oil price less the marine transportation tariff, TAPS tariff, and $1/bbl Alaskan price differential. Oil is projected to be produced through 2025, recovering an additional 4.2 billion barrels.

Scenario Two: Gas Sales to the TAGS/LNG Project

Prudhoe Bay Unit - Both PBU and PTU will be developed for gas and oil production under this scenario. Because so many facilities are already in place for the recycling of the produced gas at PBU, no additional investments will be required for major gas sales to either option; the gas conditioning plant investment is included in the gas sales projects. Investments at PBU will total $1.79 billion as in the no major gas sales scenario.

Operating costs for PBU are modified during major gas sales to reflect a gradual change from oil production costs based on water cut and fluid production to gas field operations.[4]

The loss of 400 million barrels of oil recovery as a result of major gas sales in 2005 is assumed to commence in 2007 at low volumes and increase over time; resulting in a shortening of the oil recovery period by four years and a corresponding loss in oil revenue. Wellhead oil price is affected by the loss in oil production because the TAPS tariff is based on total liquid throughput (see **Figure 6**).

Wellhead gas price for PBU is set by the economics of the TAGS/LNG project and is the LNG price in Asia multiplied by the gas product net back. The gas product net back is a constant value and is the fraction of the LNG Asian price that forces the TAGS/LNG project to earn a 10% ROR. The gas product net back for the TAGS/LNG option is 28.1% which results in a wellhead gas price of $1.21/Mcf assuming a $20/bbl world oil price.

Point Thomson Unit - Point Thomson development requires investments for wells and facilities (including onshore facilities, pads, field roads and pipelines, separation facilities, airstrip, causeway to a dock, and compression). The facilities investment is estimated to be $720 million.[4] At a spacing of 740 acres/well, 32 well are needed to develop the field; resulting in an investment of $155 million.

A maximum sustainable dry gas sales rate of 0.44 Bcf/D is assumed to begin in 2008 and continued until 3.18 Tcf is produced; a 20-yr life. It is also assumed that oil production begins in 2008 and ends by 2014, totalling 12.8 million barrels. Condensate recovery is expected to stop along with the cessation of PBU liquids after 2021 and total 169 million barrels.

This scenario requires both a gas and liquids line to transport the produced PTU fluids to the Prudhoe Bay area 50 miles to the west. To simplify the evaluation, it is assumed that an outside interest will build and operate both lines and tariffs will be charged. The estimated cost to construct the liquids line is $130 million and the gas line is estimated to cost $155 million. The tariff for transporting PTU liquids to the PBU area under the TAGS/LNG scenario is $2.64/bbl; while the gas line tariff is $0.16/Mcf. These pipeline tariffs are deducted from their respective North Slope product prices to arrive at the wellhead price for liquids and gas. The North Slope price of oil and gas are equal to the price at the Prudhoe Bay area previously discussed.

Scenario Three: Gas Sales to the GTL Project

Prudhoe Bay Unit - Prudhoe Bay investments, total oil and gas recovery, and production and rates are the same under the GTL scenario as in the TAGS/LNG scenario. The only changes are in the oil price (because of lower TAPS tariffs) and gas price. The gas sold to the GTL plant is converted to liquids and transported through TAPS which causes the pipeline tariff to remain at a fairly constant level even though oil production decreases over the life of PBU. Selling gas to a North Slope GTL plant indirectly increases oil revenue by lowering the TAPS tariff.

The wellhead gas price in the GTL scenario is set by the economics of the GTL project and is calculated as follows:

$$\textit{North Slope gas price}\left(\frac{\$}{Mcf}\right) = \frac{\textit{West Coast GTL price}}{\textit{BTU conversion for GTL}} \times \textit{gas product net back}\,. \qquad \textbf{(2)}$$

The GTL product is a gasoline/distillate range product having about 5.75 MMBTU/bbl. Using 1.15 MMBTU/Mcf for the gas sold from PBU to the GTL plant, the BTU conversion for GTL becomes 5.0 Mcf/bbl. The gas product net back in this scenario is 15.1%; therefore, for a world oil price of $20/bbl, the North Slope gas price would be $0.76/Mcf.

Point Thomson Unit - Point Thomson investments, total gas recovery, and gas production rates are the same under the GTL scenario as under the TAGS/LNG scenario. Because of the GTL liquids being produced, TAPS would not be closed after PBU oil production ceases. Condensate recovery from PTU continues to the end of gas production and is increased from 169 million barrels under the LNG scenario to 194 million under the GTL scenario. This increase in liquid production also lowers the pipeline tariff for transporting PTU liquids to the Prudhoe Bay area from $2.64/bbl to $2.35/bbl. Gas and oil revenues are calculated as in the TAGS/LNG scenario.

Economic Comparison of Three Scenarios

Prudhoe Bay Unit Economics - Results shown in **Table 3** compare PBU operations under the three

Table 3. Prudhoe Bay Unit economics - summary.

Economic Factor	No Major Gas Sales Scenario	TAGS/LNG Scenario	GTL Scenario
Last year of oil production	2025	2021	2021
Last year of gas production	---	2036	2036
Remaining oil reserves (billion bbl)	4.2	3.8	3.8
Gas reserves (Tcf)	0	21.8	21.8
Unit investments ($, billions)	1.8	1.8	1.8
Revenue from oil sales ($, billions)	56.1	48.8	51.3
Revenue from gas sales ($, billions)	0	31.5	21.7
Total revenue ($, billions)	56.1	80.3	73.0
After-tax cash flow ($, billions)	17.6	31.5	27.4
Discounted cash flow- NPV_{10} ($, billions)	8.6	11.1	10.4

producing scenarios. These results were obtained assuming that TAPS will not be shut down until the economic limit of PBU oil production is reached. As a result of reduced effectiveness of field recovery systems with the removal of large volumes of gas from the reservoir beginning in 2005, both gas sales scenarios reduce oil recovery by 400 million barrels from the case without major gas sales.

On a net present value basis, both gas sales options show positive economics for PBU relative to the no major gas sales option. The oil revenue is higher for the no major gas sales scenario because it is assumed that withdrawal of gas for major gas sales starting in 2005 will reduce the ultimate oil recovery by 400 million barrels. Of the two gas sales scenarios, oil revenues with the GTL option exceed those attainable in the TAGS/LNG scenario by $2.5 billion because of the benefits of GTL liquids in reducing TAPS tariffs on all liquid products shipped through the line. Conversely, because the LNG project can support a higher ANS gas price, the gas revenue is $9.8 billion

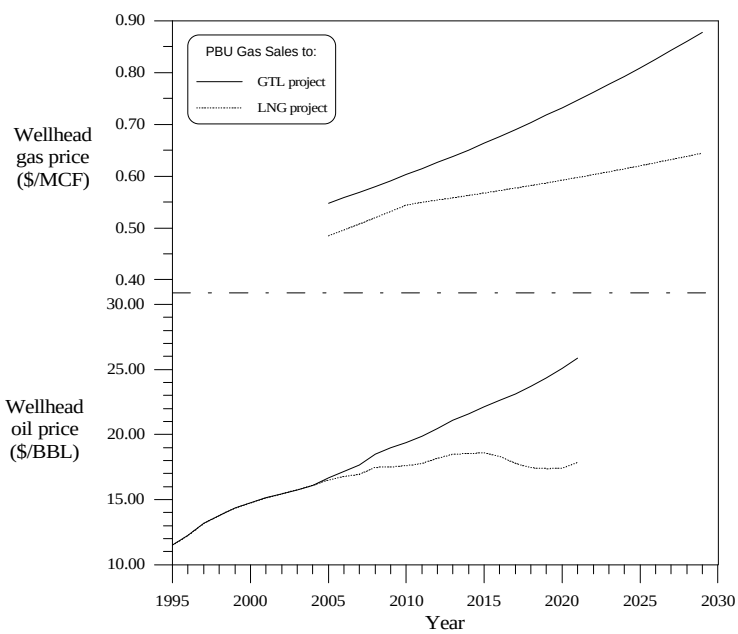

Figure 9. Wellhead gas and oil prices for PBU under LNG and GTL scenarios.

greater for the LNG option than for the GTL option. The net present value using a discount rate of 10% (NPV_{10}) for PBU under the no major gas sales scenario is $8.6 billion, $11.1 billion for the TAGS/LNG scenario, and $10.4 billion for the GTL scenario.

Wellhead oil and gas prices for PBU under the two gas sales scenarios are shown in **Figure 9**. The impact of the TAPS tariff reduction in the GTL scenario is effectively illustrated in the wellhead oil price portion of this figure.

Point Thomson Unit Economics - The same gas sales alternatives were evaluated for PTU as for PBU. Results in **Table 4** compare the two gas sales scenarios for PTU. Gas sales from PTU lag three years behind PBU to account for the assumed field development schedule. The net present value of the PTU field for gas sales to either gas sales scenarios is almost the same, $0.35 billion for the TAGS/LNG scenario and $0.33 billion for the GTL scenario.

Table 4. Point Thomson Unit economics - summary.

Economic Factor	TAGS/LNG Scenario	GTL Scenario
Last year of oil production	2021	2027
Last year of gas production	2027	2027
Remaining oil reserves (billion bbl)	0.18	0.21
Gas reserves (Tcf)	3.2	3.2
Unit investments ($, billions)	0.9	0.9
Revenue from oil sales ($, billions)	2.3	3.4
Revenue from gas sales ($, billions)	3.9	2.9
Total revenue ($, billions)	6.2	6.3
After-tax cash flow ($, billions)	2.3	2.3
Discounted cash flow- NPV_{10} ($, billions)	0.35	0.33

In the LNG scenario, PTU condensate is produced through 2021 and gas through 2027, while in the GTL scenario, PTU produces condensate 6 years longer, throughout the life of the GTL project. This difference in condensate production life is a result of the shutdown of PBU oil production in 2021, which would cause a drastic increase in TAPS tariffs and the inevitable shutdown of TAPS. Without GTL production to adsorb a portion of TAPS operating costs after the end of PBU oil production in 2021, TAPS tariffs would become prohibitively high even if the pipeline could continue to be operated at such low throughput rates. Thus, condensate production would halt in 2021 under the LNG option but continue to completion under the GTL option. As a result, PTU produces 26 million barrels more condensate with gas sales to a GTL plant than under the TAGS/LNG scenario.

Economic Sensitivity to Changes in Input Variables

Sensitivity analyses were performed to evaluate effects of changing various economic factors that influence the economic viability of potential gas utilization scenarios. At the same time they also provide a measure of the effects that potential cooperative efforts by state and federal agencies and industry can have to foster ANS gas utilization. Variables that were analyzed include changes in: (a) total investment level (b) plant O&M costs, (c) state and federal taxes, (d) royalty rates, (e) product sales price, (f) GTL plant efficiency, (f) PTU pipelines tariffs, (g) LNG gas usage, and (h) BTU content of gas sold from PBU and PTU. In the analyses, one variable at a time was changed and its impact on the NPV_{10} of the gas sales project or the incremental NPV_{10} of the producing unit was determined.

PBU and PTU Sensitivity

The most sensitive variable for the sale of PBU gas to the LNG project as well as to the GTL project is the state and federal tax burden as shown in **Figure 10**. For example, a 15% decrease in state and federal tax burden on the sale of PBU gas to the LNG plant would increase the incremental NPV_{10} of this PBU option from $2.5 billion to $4.0 billion, a $1.5 billion increase. For the PTU, the gas product net back fraction, income taxes, and field development costs were the most critical variables for both scenarios.

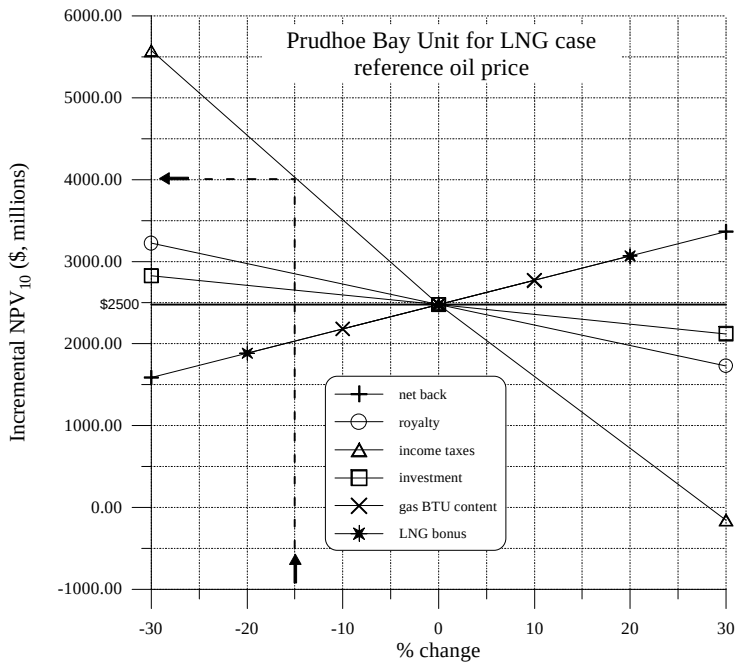

Figure 10. Variable sensitivity plot for PBU with gas sales to the TAGS/LNG project with arrows showing effect of lowering taxes.

Gas Sales Projects Sensitivity

For the GTL conversion plant, the principal variables were: (1) overall plant efficiency, (2) plant investment, (3) O&M costs, (4) state and federal taxes, and (5) liquid premium price. For the TAGS/LNG project, project investment, LNG bonus, and BTU content were the most critical variables.

Flat Oil Price Analysis

In the previous analyses in this study, the EIA AEO95 reference oil price forecast was used. This forecast assumes a 2.4%/yr real growth in world crude oil prices plus inflation. A flat oil price forecast with no real growth in oil price was also used to determine a break even price for the two gas sales projects using only gas from PBU.

For the AEO95 reference oil price, the economics were compared such that each of the gas projects were forced to a 10% ROR (NPV_{10} = $0) while the producing unit (PBU) had much larger incremental net present values: $2.5 billion for the TAGS/LNG scenario and $1.8 billion for the GTL scenario. For the break even flat oil price analysis, the North Slope gas price is adjusted for each scenario such that the incremental NPV_{10} for PBU equals $0 and the NPV_{10} for the gas projects is also equal to $0. (The incremental NPV_{10} for PBU is equal to the difference in the NPV_{10} under the gas sales scenarios and the NPV_{10} for the no gas sales case.)

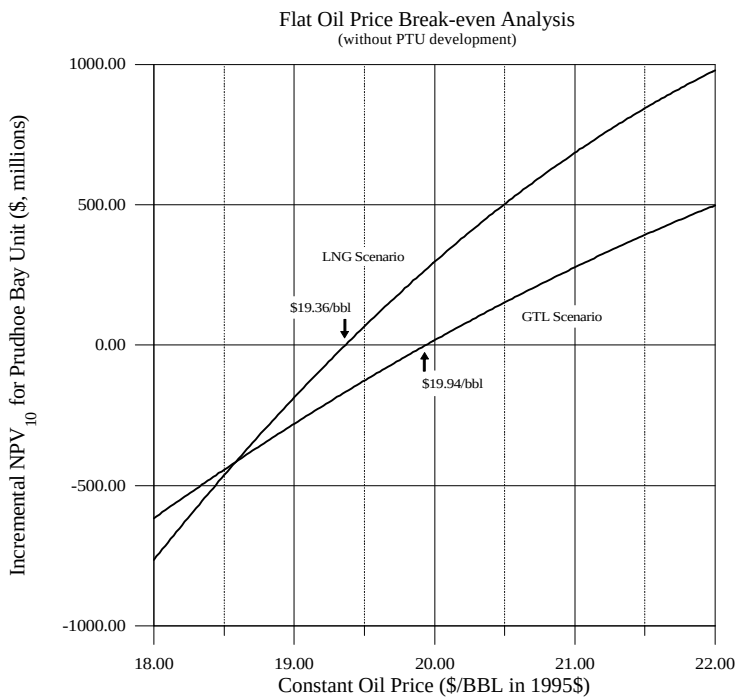

Figure 11. Flat oil price break-even analysis for scenarios with gas sales from PBU only.

Figure 11 shows the results of the flat or constant oil price analysis. Under the assumptions used in the analyses, the LNG scenario would be economical (defined as achieving a 10% ROR for both the gas seller and buyer) given a flat oil price of $19.36/bbl; while the GTL scenario would be economical at $19.94/bbl. The difference in slopes of the two curves in **Figure 11** is largely a result of the pricing scheme of the final end-products. As the oil price increases, LNG's 10% bonus becomes progressively larger; whereas GTL's $5/bbl premium remains constant with increasing oil prices.

Discussion on Effect of TAPS Shutdown

TAPS was designed to handle large volumes of crude oil. When first completed its designed optimum throughput rate was 1.42 MMBPD. The use of drag-reducing agents increased the maximum to over 2.1 MMBPD. Mechanical considerations limit the amount of oil being transported through the pipeline; both maximum and minimum rates. Although there has been some speculation as to the minimum throughput rate and no exact value has been determined, a range of minimum throughput rate for TAPS has been tentatively set at 200 MBPD to 400 MBPD.[3] The economic evaluations discussed above did not consider the effect of discontinuing TAPS operation below a minimum value. The effects of discontinuing TAPS operation below a minimum of 200 MBPD on project and unit economics are summarized below.

In the no major gas sales case, a TAPS shutdown at 200 MBPD would shorten the life of the Prudhoe Bay field by 9 years (from 2025 to 2016). The oil lost from those 9 years of production would be about 500 million barrels. For the LNG scenario, a TAPS shutdown at 200 MBPD would shorten the oil production life of PBU by 6 years from 2021 to 2015. The oil lost from those 6 years of production would total about 300 million barrels.

In the case of major gas sales to a GTL conversion plant, the plant is expected to convert the produced gas into almost 300 MBPD of TAPS-compatible liquids. Under that assumption, there would be no premature shutdown of TAPS at the 200 MBPD minimum and all the oil reserves would be produced with no loss in associated revenues to industry, the state, and the federal government.

Conclusions

At this point in time, it appears that both the TAGS/LNG and the GTL options as outlined in this paper appear economically promising and warrant consideration in the decision-making process. Because the variables are subject to normal levels of uncertainty, it is not possible to conclude that one option is significantly better than the other.

Results are dependent on the particular oil price forecast used. All three options evaluated for the use of North Slope gas (no gas sales, sales to an LNG project, and sales to a GTL project) appear to economically viable when the AEO95 reference oil price forecast is used in the analyses. However, using a flat oil price forecast of $19/bbl or below, neither of the two gas sales options are economically viable; both options are viable with a flat oil price forecast of $20/bbl or higher.

The future market for potential Alaskan North Slope LNG is less certain than a potential market for GTL products.

Does GTL technology offer a feasible alternative for bringing ANS natural gas to market? Yes, the conclusion from this assessment is that state-of-the-art GTL conversion technology appears to be feasible and could be deployed within a meaningful time frame to sustain ANS and TAPS oil operations for 20 or more years beyond what might be anticipated without GTL.

Acknowledgments

This paper was prepared with funds from the U.S. Department of Energy under contract DE-AC07-94ID13223. The authors thank the U.S. Department of Energy and Lockheed Martin Idaho Technologies Co. for permission to publish this paper. We also acknowledge the contributions made by Tom Doughty, Walter North, John Hackworth, and Ralph Avellanet. We also thank the industry representatives in Alaska and the Alaska Department of Natural Resources and Department of Revenue for their assistance.

References

1. "1995 Assessment of United States Oil and Gas Resources," U.S. Geological Survey, Circular 1118 (1995).
2. Historic Natural Gas Annual 1993 through 1995," Energy Information Administration, DOE/EIA-0131(95)/2 (November 1996).
3. Thomas, C.P., Allaire, R.B., Doughty, T.C., Faulder, D.D., Irving, J.R., Jamison, H.C., and White, G.J.: "Alaska North Slope National Energy Strategy Initiative." U.S. Department of Energy, DOE/ID/01570-T164 (May 1993).

4. Thomas, C.P., Doughty, T.C., Hackworth, J.H., North, W.B., and Robertson, E.P.: "Economics of Alaska North Slope Gas Utilization Options," INEL-96/0322 (August 1996).

5. “North Slope Natural Gas Pipeline, Coming Soon to a Theater Near You?” Alaska Conservation Foundation (August 1994).

6. Tijm, P.J.A., van Wechem, H.M.H., and M.M.G. Senden:, 1993, "The Shell Middle Distillate Synthesis Project-New Opportunities for Marketing Natural Gas," Alternate Energy 1993, Colorado Springs, CO., (April 27-30, 1993).

7. "Regulatory Costs May Hasten TAPS Shutdown, Alyeska President Warns," Platt's Oilgram News, (1991).

8. "Arco, BP: Market Will Demand Alaskan Gas After 2000," The Energy Daily (July 24, 1995).

9. "Asia Doesn't Need Alaska's Gas Until After 2005, Firms Say," The Oil Daily (July 24, 1995).

10. "Commercialization of North Slope Gas - What Should the State Be Doing?" Memorandum prepared by the Alaska Department of Revenue for the Governor of the State of Alaska (22 January 1996).

11. Hackworth, J.H., Koch, R.W., Rezaiyan, A.J.: "Economic Evaluation and Market Analyses for Natural Gas Utilization," Final Report, U.S. Department of Energy (April 15, 1995).

12. Eilers, J., Posthuma, S.A., Sie, S.T.: "The Shell Middle Distillate Synthesis Process (SMDS)," Catalysis Letters 7 (1990) 253-270.

13. Carot-Gandolphe, S., Rojey, A., and Raimbault, C: "Development Prospects for International LNG Trade," Eleventh International Conference & Exhibition on Liquefied Natural Gas (July 3-6, 1995).

14. Hawkshaw, H.J. and Flower, R.A.: "Will New LNG Supplies be Developed to Meet Asian LNG Demand to 2015?" Eleventh International Conference & Exhibition on Liquefied Natural Gas (July 3-6, 1995).

15. "BP Review of Natural Gas," British Petroleum (1995).

16. "Petroleum Supply Annual 1994," Volume 2., Energy Information Administration, DOE/EIA-0340(94)2 (June 1995).

17. "Annual Progress Report, Plan of Development and Operation, Prudhoe Bay (Permo-Triassic) Reservoir," Alaska Department of Natural Resources (June 30, 1994).

18. "Democrat Governor of Alaska Seeks New Era of Cooperation with Oil Cos.," Platt's Oilgram News (January 10, 1995) 2.

SI Metric Conversion Factors

ft^3	x 2.831 685	E-02	= m^3
bbl	x 1.589 873	E-01	= m^3
tonne (metric)	x 1.0	E+03	= kg