ECONOMICS OF ALASKA NORTH SLOPE GAS UTILIZATION OPTIONS

EXECUTIVE SUMMARY

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. No significant commercial use has yet been made of this large natural gas resource because there are no facilities in place to transport this gas to current markets, which are outside of the North Slope. To date the economics have not been favorable to support development of a gas transportation system. 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).

Figure 1 is a map showing the known oil and gas accumulations and selected dry holes and suspended wells on the North Slope. Although discoveries of oil and gas have been made across Northern Alaska, the only development that has occurred is around the super giant Prudhoe Bay field. It is unlikely that any of the other North Slope fields would have been developed without facility cost-sharing made possible by the development of the Prudhoe Bay infrastructure and the construction of the Trans Alaska Pipeline System (TAPS).

About 26 TCF of the 38 TCF of technically recoverable gas is estimated to be available for sale. The balance will be consumed in oil and gas production operations on the North Slope. Although, there has been a high level of interest in developing a capability to bring the huge North Slope natural gas resource to market since the discovery of the Prudhoe Bay field, the urgency to develop the capability to sell the large, currently unmarketable, North Slope gas resources has increased in recent years because of the steep decline in North Slope oil production. ANS production has accounted for almost 25% of the daily U.S. domestically produced oil since production was initiated from the Prudhoe Bay field in 1977. As shown in **Figure 2**, North Slope oil production peaked in 1988 at 2.0 million barrels per day, declined to 1.5 million barrels per day in 1994, and will continue to decline, reaching about 200 million barrels per day by about 2015 unless large discoveries and developments are brought on line before then. North Slope oil production is dominated by the Prudhoe Bay field, which began to decline 1988. Continued decline of Prudhoe Bay oil production and its ultimate oil depletion is inevitable. Prudhoe Bay and Point Thomson (a smaller, undeveloped gas/gas condensate field 50 miles east of Prudhoe Bay) contain about 25 TCF of the 26 TCF

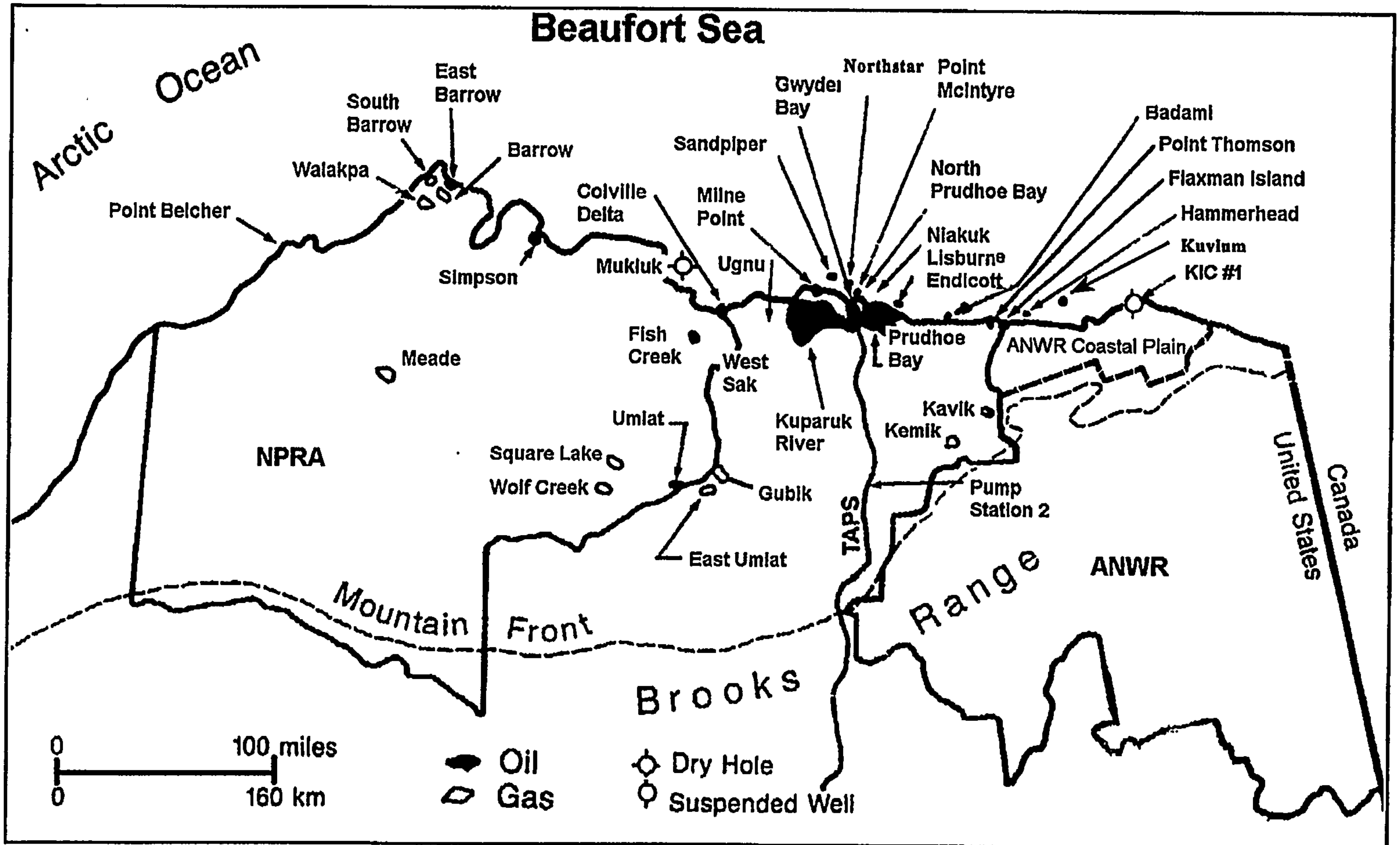

Figure 1. Known oil and gas accumulations, selected dry holes and suspended wells, and NPRA-ANWR boundaries, North Slope Alaska (DOE, 1991, ADNR, 1991a).

of the estimated recoverable natural gas discovered on the North Slope. This is a highly significant resource (over 4 billion barrels of oil equivalent) addition to the estimated remaining recoverable reserves of about 6 billion barrels (as of January 1, 1995) from producing North Slope fields.

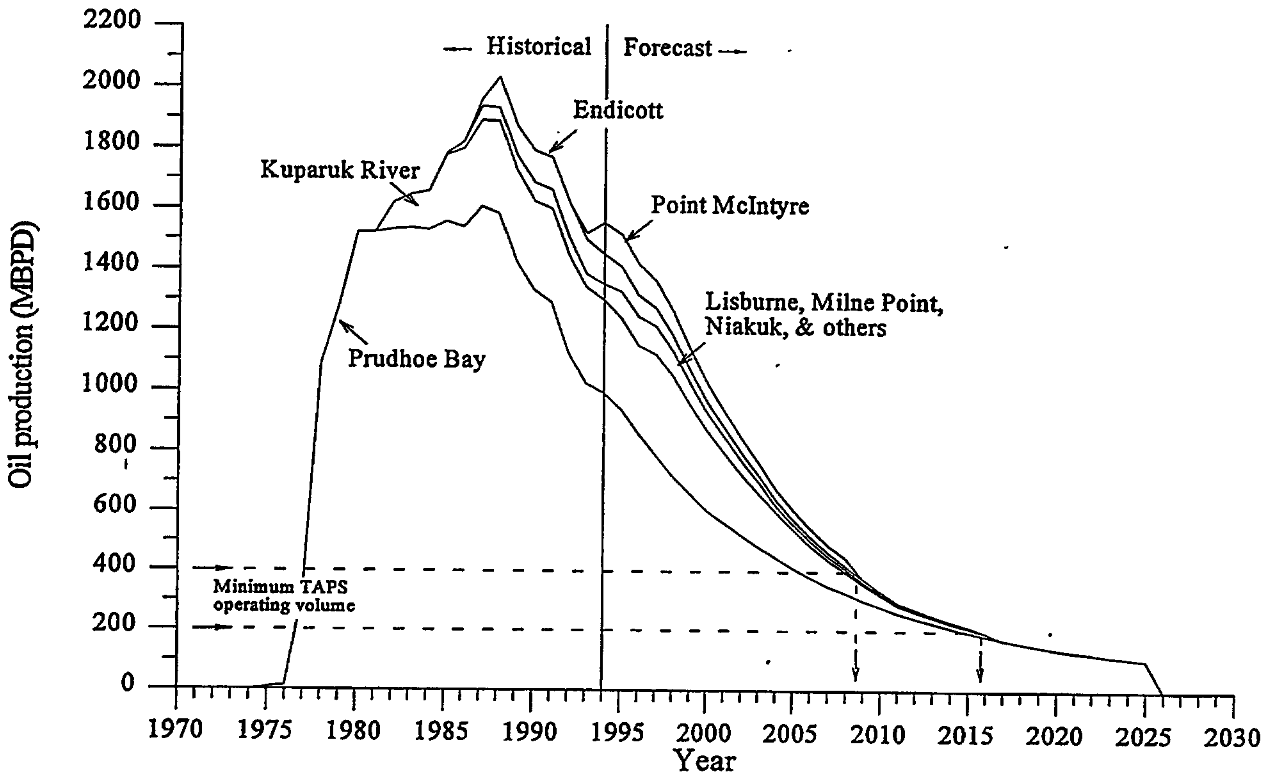

Figure 2. The Alaska North Slope historical production and production forecast at the Energy Information Administration (EIA) Reference Oil Price (economically recoverable oil).

The dashed lines at the bottom of **Figure 2** indicate the currently estimated range of the minimum liquid throughput rate for continued TAPS operation, which illustrates the looming potential of a shutdown of TAPS because of ANS production dropping to a minimum throughput rate for the pipeline in the 2009 to 2016 time frame. Such a shut down could result in the loss of as much as 1 billion barrels economically producible ANS reserves. The intersection of 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 evaluating the technical options that could influence the future of ANS oil production, as well as gas production.

To date, the only use of the gas that is currently produced at Prudhoe Bay with the crude oil, aside from local ANS use and the extraction of NGLs for sale with the crude oil, has been for reinjection to enhance recovery of crude oil. 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 original oil in place). Thus, the natural gas reinjected into the reservoirs has had significant interim value to the producers in improving production rates and ultimate oil recovery. However, the use of Prudhoe Bay gas for oil recovery is becoming less important and less valuable with the decline in oil production, which increases the urgency to develop the capability to market the gas, thereby extending the life of North Slope operations and continuing the generation of employment and revenue for the State of Alaska and the nation.

The possibility of exporting the gas via a pipeline from the North Slope to a Valdez LNG plant, followed by tanker shipment to Asian buyers, has long been suggested and studied as an ANS gas sales option. This study, however, sought to assess the economic and technical feasibility of a second option, based on newer technology than that well-established for LNG. This option involves the chemical conversion of gas to a distillate-type hydrocarbon liquid that could be transported and sold with continuing ANS crude oil production via the existing TAPS and tanker fleet. With the gas-to-liquids (GTL) option, a gas pipeline would not have to be built and additional volumes of hydrocarbon liquids would be available for transport through TAPS. This added liquid volume would assist in maintaining the viability of TAPS and result in lower tariffs for all liquids transported in TAPS. Lower TAPS tariffs return a higher net liquid sales price for all fields and projects, those currently producing and future developments.

Purpose

The primary purpose of this study was to provide a technical and economic evaluation of the feasibility 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. However, because of the long-standing interest and high visibility of the LNG option, which involves 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, it was apparent that an examination of how the gas-to-liquids (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.

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.

The report is organized as follows:

Section 1. Introduction describing the issues and problems associated with major gas sales from the ANS.

Section 2. Assessment of the ANS oil and gas resources.

Section 3. Discussion of the gas resource utilization options and technologies for physical conversion of natural gas to LNG and chemical conversion to hydrocarbon liquids.

Section 4. Overview of LNG and GTL product markets.

Section 5. Description of the economic analysis framework, the economic assumptions; and results of the baseline economic analysis, and the sensitivity analysis.

Section 6. Conclusions and recommendations for follow-up analyses by interested parties.

Appendix A. Descriptions of ANS fields currently producing and fields with development potential, and forecasts of production, investments, and operating costs.

Appendix B. Description of the procedures and input variables used in the economic analysis.

Appendix C. Description of the economic model.

Appendix D. Tables of values from the model runs.

Appendix E. Bibliography.

The following sections contain summaries of the approach, the economic variables used, the economic results, and the conclusions and recommendations.

Assessment Approach

The first step was to develop an updated outlook for prospective oil production from producing ANS reservoirs. These updated forecasts provide the basis for assessing the economic effects of major gas sales options on future ANS oil production and were necessary before the feasibility of the GTL option could be evaluated and compared with the LNG option. Prospective gas conversion technology was then examined for both the more established physical conversion to LNG, and the less well established GTL chemical conversion to liquid hydrocarbons. This examination included not only the state-of-the-art GTL technology but also included the most promising technology advancements known to DOE researchers that conceivably could have application on the North Slope. In spite of proponent optimism that such cost-cutting technology could be ready for application on a large scale by the time of decision making on ANS gas sales, about 4 to 7 years (consistent with investment lead time requirements and gas owner indications that the window of opportunity for major gas sales will be after 2005), the more conservative state-of-the-art LNG and GTL technologies were used as a basis for the evaluations. The GTL technology used for the assessment, assumes Shell's Middle Distillate Synthesis plant that has been operating in Malaysia since 1993. Likewise, the LNG option for gas sales assumes LNG conversion technology as planned by Yukon Pacific Corporation.

The projects and options were evaluated using a standard discounted cash flow analysis. The results were presented in terms of net present value using a discount rate of 10% (NPV_{10}). The NPV_{10} captures the sum, in 1995$, of annual revenues less expenses and investments, adjusted for a discount rate that provides a 10% rate of return on investment. The NPV_{10} analysis required the following input information:

(a) Oil and gas recovery forecasts for all developed and producing ANS oil fields and a forecast for the undeveloped PTU to provide the expected pipeline flow for determination of TAPS tariff schedules.

(b) A determination of the technology that might be employed to transport and convert ANS gas to a transportable and marketable commodity and estimates of the capital and operating costs for each option.

(c) A requirement that the gas sales option (LNG or GTL) provide a reasonable rate of return (assumed to be 10%) as a stand-alone operation before any "gas product net back" could be calculated for payment to the gas producing units.

The evaluations presented did not assume that major new discoveries would be made, but were based on oil (crude oil, condensate, and NGL) production from the currently developed fields coupled with major gas sales from the two principal ANS gas fields, the Prudhoe Bay field and the currently undeveloped Point Thomson field. The two gas sales options were evaluated as stand-alone projects that purchase gas from each of the fields. Finally, the impact on federal, state, and industry revenues for the combined field and gas sales project options were estimated.

Baseline Economic Variables

Baseline assumptions for the key economic variables were:

(a) The EIA 1995 Reference Oil Price (AEO95) case was used for the baseline economics. This case projects a future world oil price with a predicted real oil price increase of about 2.4% per year.

(b) The hydrocarbon composition and heating value of the ANS gas provided as feedstock to LNG or GTL options is assumed to remain consistent over the project life at 1150 BTU/SCF.

(c) Final product sales price is a direct function of world oil prices, adjusted upwards for their special value and desirability as a fuel. The adjustment for LNG is a 10% Asian bonus and a $5/BBL premium for GTL liquids.

(d) Annual operating costs of each gas project are assumed to be 5% of total capital investments for the LNG project and $6/BBL for the GTL project.

(e) Operation efficiencies relative to the conversion of feedstock gas to salable product is assumed to be 91% for LNG and 60% for GTL.

(f) No additional investments are required to sell gas from PBU because of the extensive gas-handling facilities already in place at PBU for separation and reinjection of 7.5 BCFPD. The estimated capital investment required to develop PTU is $900 million (1995$).

(g) Excluding PTU development costs, the total investment requirements for the LNG project are adjusted upward from the $14 billion (1995$) publicly announced in 1994 by Yukon Pacific for its proposed 14 MMTPA LNG project, to $16 billion (1995$) for the 17 MMTPA LNG project required to accommodate concurrent gas sales from PBU and PTU at 2.49 BFCPD. For the GTL option to handle the same gas volume as the LNG option, the plant investment is $12 billion (1995$), based on $40,000 per daily barrel of liquid (DBL) of output capacity for a large scale (300 MBPD) state-of-the-art GTL operation in the Prudhoe Bay field area.

(h) Major gas sales from PBU, starting in 2005 and ramping up to 2.05 BCFPD in 5 years, will reduce PBU oil recovery by 400 million barrels oil (MMBO). PBU gas sales will end in 2036.

(i) Gas sales from PTU start in 2008 at 0.44 BCFPD, providing a peak rate of gas sales from PBU and PTU of 2.49 BCFPD. PTU gas sales end in 2027.

(j) Federal and State of Alaska taxes and other charges are assumed to remain as they are at this date.

Baseline Economic Results

The economic model results for the baseline assumptions show that the LNG option would yield an NPV_{10} of \$11.5 billion (1995\$), while the GTL option could be expected to yield a \$10.7 billion (1995\$) NPV_{10}, or about 7% less. These results compare to the \$8.6 billion (1995\$) for the no major gas sales case. The total incremental investments required for these yields, however, would be 24% greater for the LNG option than for the GTL option, \$16.9 billion compared to \$12.9 billion. These results are shown in **Table 1.** The discounted cash flow model takes into account all income and expenses and provides for a 10% rate of return on the incremental investment for preparing and transporting the gas to market for the respective gas sales options. These comparative calculations show that, in spite of potential reductions in PBU recovery of as much as 400 MMBO upon major gas sales, both LNG and GTL gas sales options have a greater payoff than the option of not selling the gas and continuing to reinject gas until the oil recovery reaches its economic limit. It is not nearly as clear which gas sales option is more preferable, however.

Table 1. Summary of gas sales options NPV's and investments.

	NPV_{10} LNG Option (1995\$, billions)	NPV_{10} GTL Option (1995\$, billions)
Prudhoe Bay Unit - No major gas sales	8.6	8.6
Prudhoe Bay Unit	11.1	10.4
Point Thomson Unit	0.4	0.3
Total NPV_{10}	11.5	10.7
Total Investment (1995\$, billions)		
Gas option investment	16.0	12.0
Point Thomson development	0.9	0.9
Total	16.9	12.9

return for the gas projects and gas sales from PBU alone. For the LNG scenario, the breakeven flat oil price was $19.36/BBL; while the breakeven flat oil price for the GTL scenario was slightly higher at $19.94/BBL. Conversely, the sensitivity results showed that the delay of gas sales by as much as 5 yrs has only a slight effect on profitability of both the LNG and GTL options, assuming product sales are not deterred by such delay.

These sensitivity results, clearly show that changes in one or more of these assumptions could significantly alter the financial results:

- For example, in considering the LNG option, there are a large number of would be LNG suppliers in the world seeking to fill the expected LNG demand growth from gas-short Asian nations. Many of these suppliers are thought to have smaller capital outlays (not having the necessity of building an 800-mi gas pipeline as is required at the start for the Alaskan LNG project), and it is quite possible the LNG project Asian fuel bonus and its base LNG price will be less than anticipated, thereby reducing the LNG base economics. On the positive side, it is also possible, as more large LNG projects are designed and built around the world, that cost-saving measures will be found that would improve the LNG base economics.

- Likewise, for the GTL option, conversion efficiency might prove to be closer to the 57% level of the older South African plants rather than to the plant design level of 63% efficiency level for Shell's newer plant, thereby reducing the GTL base economics (a 60% conversion efficiency was used as the baseline assumption). In contrast, the target efficiency of 70 to 75% for advanced GTL technology under development may prove out in time to be ready for the rapid GTL deployment envisioned (or for major portions of the development, if such GTL development is phased in more slowly), which would improve the GTL base economics.

- Clearly, the economics of both of the gas sales options could be seriously impacted if investment cost contingencies associated with Alaska's climate, remoteness, and related factors prove to be underestimated; or if stand-alone projects such as the LNG and GTL projects require a greater than 10% rate of return to attract investors; or if world oil prices prove to be substantially lower than the DOE EIA reference oil price forecast (neither LNG nor GTL were found to be financially feasible at an $18/BBL flat oil price in this study's sensitivity analysis).

Conclusions

At this point in time, if the assumptions for the economic variables are valid, both the LNG and the GTL option can be considered as economically promising and warrant consideration in the decision-making process. (Although the variables are subject to normal levels of uncertainty, we believe they are valid based on the public information available to us.) However, it is not possible to conclude that one option is significantly better than the other.

This evaluation does, however, answer the specific question it was directed to address, namely: Is GTL conversion a feasible alternative for bringing ANS natural gas to market? 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.

Placing the issue of GTL feasibility aside, this ANS gas utilization assessment is not expected to be the last of what has been a number of studies focused on the marketing of Alaska's large, and potentially much larger, remote natural gas reserve. Alaskans face difficult gas development and marketing decisions in the near future, and need to develop the most complete understanding of the options possible. This is particularly so with respect to likely requests for State tax incentives and other actions that might be desired to move private commitments forward.

Recommendations

To assist in responding to such requests and other decisions that must be made to implement the sale of ANS gas, this report concludes with a number of recommended follow-up analyses that interested industry, State and federal parties may wish to pursue in a timely manner:

1. **Existing Infrastructure Savings**--The economics of both of the options could benefit through the utilization of portions of the infrastructure existing at Prudhoe Bay and along the TAPS pipeline. These possibilities should be examined on a site-specific basis, not only for a GTL plant that would be built on the North Slope, but also for the LNG gas pipeline and prospective Valdez liquefaction and shipping facilities. (YPC reports that basic engineering and design have been completed, but it is likely that further engineering

and design involving the Prudhoe Bay operators and Alyeska Pipeline Service Company will lead to additional refinements.)

2. **Specific Cost Estimates**--More precise, process- and site-specific cost estimates of the LNG and GTL options should be developed because of the important sensitivity of the economics of both of these options to capital costs in particular. These estimates should incorporate the latest in technologies and designs, attempting also to provide sufficient detail on the cost impact of technology advances possible within a meaningful timeframe.

3. **TAPS Tariff Impact on Future Oil Production**--A more complete assessment is desirable concerning the effect of reduced TAPS tariffs, anticipated from the envisioned GTL product volumes, on future ANS oil production from all existing fields and potential developments. The several dollar per barrel reduction suggested by this study could be important in determining how long selected ANS reservoirs might continue to produce, and could affect whether non-producing reservoirs might be brought on line.

4. **Optimization of GTL Product Composition**--To better refine the operating cost and price estimates of proposed GTL operations, technical assessments should be directed to delineating potential liquid product compositions with respect to: (a) feasible process chemistry, (b) methods of TAPS shipment (mixed with the crude or stored and batched separately, similar to oil product pipelines), (c) crude and GTL product separation and the refining process(es) required to obtain the ultimate GTL product value, and (d) other factors as appropriate.

5. **ANS Cost Factors**--A clearer picture should be developed of the cost penalties associated with capital construction and facility operation in the arctic climate and remote location of the ANS. This should be done for both GTL and LNG options and should also examine general Lower 48 and Alaskan capital and operating cost differences to provide the most reliable cost estimates for gas sales decision making.

6. **Gas Sales Benefit to Alaska**--The potential economic benefits of each gas commercialization option on the various regions and overall State should be assessed in detail to aid in decision making. Such examination might include: (a) an analysis of the types and aggregate of manufacturing and labor components for construction and operation of each gas option and the resulting stimulation of State and local economic development, (b) direct and indirect local employment to be generated (and saved or extended,

if such be the case), and (c) gross and net revenues to State and local jurisdictions through prevailing or alternative tax schedules, etc.

7. **Alternative GTL Development Schedule**--The GTL option does not have to be developed at the pace required for the LNG project (resulting from the requirement to build the pipeline up front). The development scale was chosen to match the proposed TAGS LNG scale, pace, and scope in an attempt to make the obvious comparisons between the two options as comparable as possible. Hence, it would be useful to consider a slower development of GTL that could take advantage of the learning curve associated with deployment of new technology to lower costs and potentially take advantage of advanced GTL technology in the later modules for improved conversion efficiencies. Slower, incremental development would also reduce the magnitude of the capital outlays required in the early years and allow them to be offset by the increased profits from GTL sales. Such a development scenario increases the possibility of constructing more of the plant modules in Alaska and pacing the development over a long period of time to sustain higher employment and infrastructure levels within the State.