5. ECONOMIC ANALYSIS

The economic evaluations of different methods of bringing ANS gas to market are described in this section. Because PBU and PTU are the only units with more than 1 TCF of proved gas reserves, they are the only units included in the evaluation of gas production and sales. It should be kept in mind that major gas sales from PBU could affect the oil production. The rate of oil (and converted liquids) production has a significant effect on TAPS tariffs, which influences the economics of all producing units on the North Slope.

Three different scenarios are considered for PBU and PTU.

1. **No major gas sales:** Continue the current mode of operations without major gas sales; i.e., continue to reinject gas from PBU, do not develop PTU, and sell only oil (crude oil, condensate, and NGLs).

2. **LNG conversion:** Major gas sales by PBU and PTU to a gas pipeline/LNG project modeled after the TAGS project proposed by Yukon Pacific Corporation with the following components:

   - Construction and operation of an independently owned and operated gas pipeline/LNG plant, modeled after the proposed TAGS project, which purchases gas from PBU and PTU.

   - PBU and PTU deliver gas to the LNG project gas conditioning plant on the North Slope.

3. **GTL conversion:** Major gas sales by PBU and PTU to a GTL conversion plant located on the North Slope at or near TAPS pump station No.1 (PS No. 1) with the following components:

   - Construction and operation of an independently owned GTL conversion plant (including necessary gas conditioning facilities) located on the North Slope, which purchases gas from PBU and PTU. Converted liquid product will be transported to Valdez in TAPS along with the conventionally produced crude oil.

   - PBU and PTU deliver gas to the GTL conversion plant.

Figure 5.1 is a schematic diagram illustrating the gas and liquid flows from PBU for the LNG and the GTL conversion projects. It is assumed that all facilities outside the PBU boundary are independently owned and operated and are not part of the PBU facilities. It is possible that the gas conditioning plant could be owned by PBU and benefit from cost sharing with the existing PBU Central Gas Facility (CGF), which is currently processing 7.5 BCFPD of gas. However, the economics for both options assume the gas conditioning plant is built by the gas project developers.

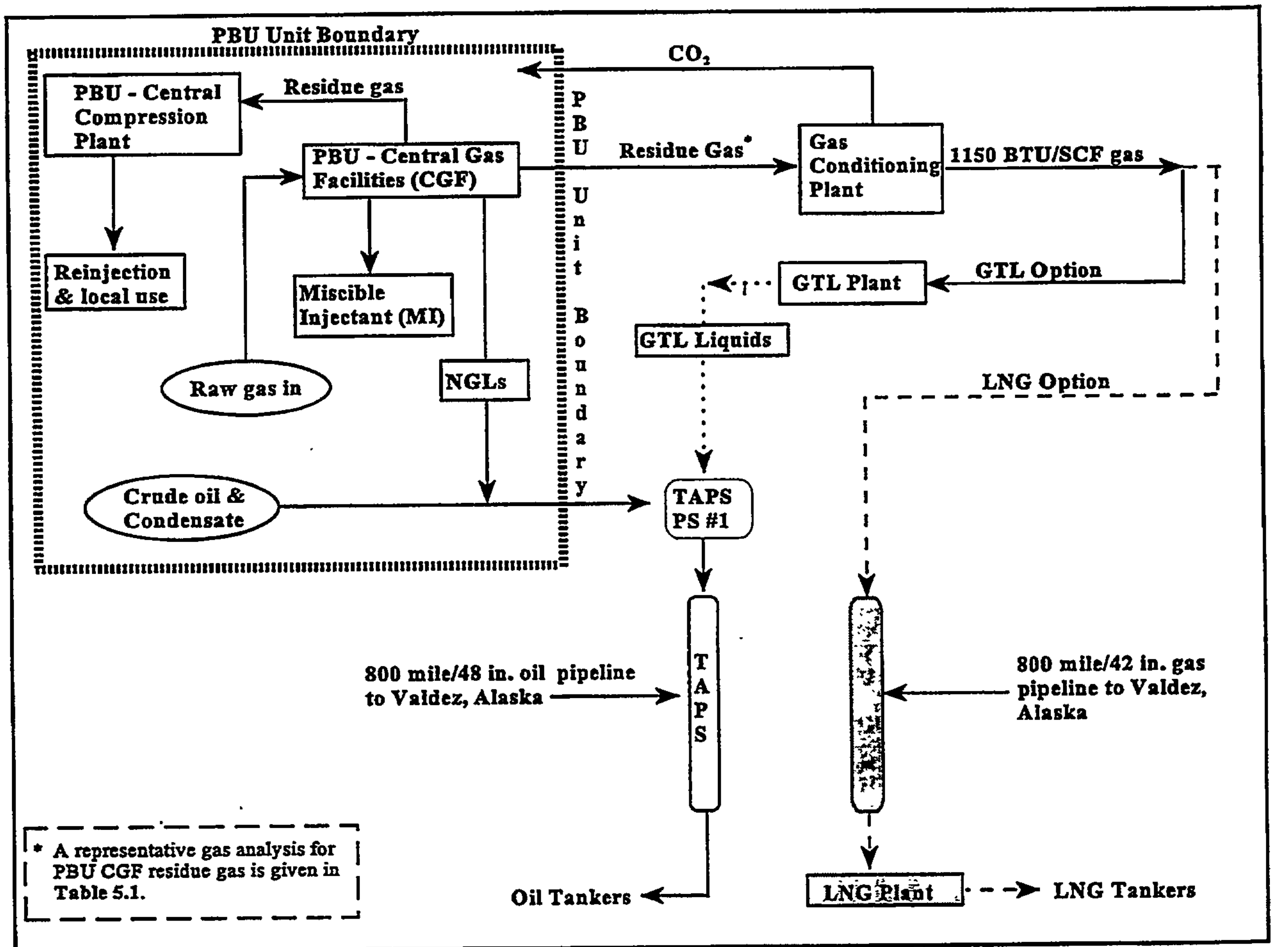

Figure 5.1. Schematic of gas and liquid flows from PBU for gas sales options.

The LNG project and the GTL plant are considered stand-alone entities that are separate from the gas producing units as well as the Trans Alaska Pipeline System (TAPS) operations and crude oil tanker delivery system. This enables the incremental investment required to market the presently unmarketable gas to be examined separately from the oil and gas extraction operations at PBU and PTU. PBU and PTU operations are examined separately to assess the effects of the gas projects on their economic value.

5.1 Comparative Analysis Framework

A discounted cash flow economic model previously developed at the INEL specifically for Alaska oil and gas projects was revised and expanded as necessary to evaluate the gas sales projects as well as the historical and projected economics of the producing units (DOE, 1991; DOE, 1993a). The model is described in **Appendix C.**

All the input variables required to economically assess the options are subject to uncertainties in their final values. The sensitivity of the economic results to changes in the input variables is used to illustrate the effects of changes in the variables. Some of the variables, such as gas and oil production forecasts, TAPS and marine tariff schedules, and the gas conversion technology used to establish the baseline economic variables, are not changed over the life of the projects and are not included as variables in the sensitivity analysis. Also, it is historically clear that world crude oil price predictions are unreliable. To illustrate the effects that wide variations in crude oil price expectations and the risks that such uncertainty imposes on investors, two separate world crude oil price schedules are used in the evaluations. The base case evaluations and the sensitivity analyses use the DOE's Energy Information Administration 1995 reference oil price forecasts (AEO95), which contains about a 2.4% annual increase (in addition to inflation) in oil prices. To show the effect of a flat oil price scenario, results are presented for an $18/BBL flat oil price and the base assumptions. Other input assumptions that are more subject to change from continued technology advancement, operator decisions, investor decisions, or government control, are included in the sensitivity analysis to evaluate the effects that conceivable changes in their values might have on the comparative economics of the gas conversion options or the producing units, or both. The base assumptions for all the variables are discussed below.

In addition to the net present value (NPV), discussed in **Section 1.3**, several other economic measures yield information about the relative value of the gas sales options. The measures examined include: (a) NPV_{10}, (b) ANS gas market price that each project can support, (c) overall revenues and costs over the lives of the respective projects; (d) and taxes, royalty, and other financial yields to the State and federal governments.

As discussed in **Appendix B.1.1.1**, a 10% discount factor is used for the analysis because the technological risks for LNG are low as the technology is in use at large scale around the world. GTL technology, on the other hand, is not as well established as LNG technology, but it is in use around the world on a smaller scale. However, a 10% discount rate is believed to be a reasonable assumption for a comparative analysis because, if advanced GTL technology is available by the time a final decision is made for the gas sales option, such improvement will have been demonstrated at plant scale, resulting in a relatively low technology risk. Individual companies will have internal financial and risk requirements based on their individual assessments and financial situations at the time of the decision making, which may be higher or lower than 10%.

Among the other economic measures for the projects, the ANS gas price is of particular interest in that it shows what the revenue yield could be to the separate gas producing units from the marketing of gas after all incremental "marketing" costs, including LNG or GTL conversion operations, are covered. The ANS gas price is the fraction of the final product sale price that could be paid to the gas producing units (PBU and PTU). For the LNG scenario, the final product sale price is the price received for the LNG as it is sold for revaporization in Japan. For the GTL scenario, the final product sale price is the price paid for the converted, high-quality liquids by West Coast refineries. The *ANS gas price* is determined such that the stand-alone gas projects provide a 10% rate of return on investment for the LNG and GTL projects with the baseline assumptions for capital investments and operating and maintenance costs. This price represents the upper limit of the fraction of the gas product price that the projects could potentially pay and provide the gas project developers a 10% rate of return. This upper limit value is used in the analyses in this study, although it is expected that gas sales contracts will be based on some formula that would provide a sharing of these potential revenues between the gas project developers and the gas producing units. This fraction of the gas product price is termed the "gas product net back" in this report.

The gas product net back is of interest in that it provides information relative to the gas purchasing contracts that will have to be set up between the gas producers and the gas sales projects developers. However, it is not a definitive measure by itself for determining which gas sales option should be pursued, because it does not take into account all the revenues to the producers. This is particularly important relative to the GTL option where the gas product net back does not include the effects of the TAPS tariff reductions that accrue to the crude oil producers from the GTL liquids absorbing a portion of the TAPS operating and capital amortization costs.

5.1.1 Fixed Economic and Technical Parameters

The gas and oil production forecasts determine the volume and rates of gas and oil production for the project economic evaluations. The forecasts, although subject to normal uncertainties in forecasting, such as unpredictability of long-term reservoir performance, changes in technology, fluctuations in oil and gas prices, and modifications in taxing structure, have been extensively reviewed and are kept fixed throughout the evaluations. The gas conversion technologies are not varied except through the sensitivity of the variables such as capital costs, operating and maintenance (O & M) costs, and conversion efficiency. The gas and oil production volume and rate forecasts are described in **Appendix A.** The technologies for gas conversion are discussed in **Section 3.3.**

5.1.1.1 Gas Production Forecast. For comparison purposes, the amount and rate of gas production and sale to the LNG and the GTL projects are identical, beginning in 2005 from PBU and 2008 from PTU, and ending in 2036 for PBU and 2027 for PTU. The total production forecast for major gas sales from PBU and PTU used in this analysis is 25 TCF of hydrocarbon gas (see **Table 2.3**). Annual production rates are developed in **Appendix A.2.2** and **Appendix A.3.1** for PTU. After startup and buildup over a 5-yr period, the PBU daily production is 2.05 BCFPD, consistent with the level proposed by the TAGS LNG proposal used to develop the LNG option in this study. PBU total production is 21.8 TCF over a 32-yr life. The PTU maximum gas sales rate is assumed to be 0.44 BCFPD and results in a 20-yr life for a total gas production of 3.18 TCF. The PTU portion of the project anticipates the desirability of PTU investment and production beginning after LNG or GTL operations have been started at PBU and being completed before PBU production ends.

5.1.1.2 Oil Production Forecast. The annual oil production forecasts of the North Slope oil operations are assumed to be the same for both gas sales options. For PBU, the ultimate oil production volume for a 2005 startup of both major gas sales options is reduced by 400 MMBO (about 3%) from the no major gas sales case forecast, as discussed in detail in **Section 2.2.4.** The oil production forecasts are described in detail for each of the currently developed North Slope fields and the undeveloped Point Thomson Unit in **Appendix A.** Other undeveloped fields are discussed but forecasts are not developed.

Under a GTL conversion sales option, the decrease in TAPS tariffs, resulting from the increased liquids transport through TAPS, may make it feasible to economically operate ANS oil fields longer than would be the case for the LNG option. However, the oil production forecasts used in this evaluation are the same for both gas sales options, except that the ultimate PTU condensate recovery is less for the LNG option than for the GTL option. This is because the economics of PTU condensate recovery under the LNG option do not benefit from the lower TAPS tariff resulting from the liquids produced in the GTL option. Hence, PTU condensate recovery under the LNG option reaches its economic limit earlier.

5.1.1.3 Technology for Gas Conversion. This analysis assumes that the LNG option will employ established physical conversion technology and will be supported by a gas conditioning plant, pipeline, and LNG tanker fleet similar to the TAGS project proposed by YPC (Alaska Conservation Foundation, 1994). The $14 million, 14 million metric tonnes per annum (MMTPA) LNG project, as planned by YPC, includes an over-sized gas pipeline capable of delivering enough gas to support a 25 MMTPA project with added compressor stations, LNG plant capacity, and tankers. The 14 MMTPA project as proposed by YPC could be supplied by gas only from PBU at a rate of 2.05 BCFPD. To accommodate PTU production of 0.44 BCFPD assumed in this analysis, the LNG conditioning and liquefaction plant, and tanker fleet are increased to accommodate 2.49 BCFPD for a sales capacity of 17 MMTPA. LNG technology is described briefly in **Section 3.3.4.**

The GTL conversion technology assumed for this study is state-of-the-art Fischer-Tropsch (FT) chemical conversion, as discussed in **Section 3.3.2.** After conditioning of the gas purchased from the PBU and PTU, the gas is converted to synthesis gas (CO and H_2) and subsequently to a distillate-type, liquid hydrocarbon product, suitable for shipment with North Slope crude oil through TAPS and in crude oil tankers to refineries. The GTL plant capacity in this analysis is assumed to be sized for 2.49 BCFPD of clean, dry, 1150 BTU/SCF gas, identical with the LNG project, for comparison purposes.

5.1.2 Variable Economic Parameters and Base Assumptions

The remaining variables and the base case assumptions for their value are discussed below.

5.1.2.1 Crude Oil Price Forecast. The record of the last 20 years shows clearly the uncertainty of future oil price forecasts. However, the feasibility of not only gas sales options, but continued ANS oil operations, ultimately depends upon world oil prices remaining high enough to cover costs associated with development and operation of the projects. For the base case analysis, it is assumed that world oil prices would follow DOE's Energy Information Administration reference oil price forecast (AEO95), as discussed in **Section 4.1** (EIA, 1995). These forecasts anticipate an average annual real oil price increase of approximately 2.4% per year over inflation through 2015 and beyond. In recent years, oil prices have fluctuated primarily in the $16 to $20/BBL range as supplies have continued to be ample. Thus, for comparison purposes, the impact of prices remaining stagnant within this range was evaluated by also using an $18/BBL (1995$) flat oil price. These forecasts and the EIA high and low forecast were discussed in **Section 4.1** and shown in **Figure 4.2.**

The oil price level is critical because wellhead oil price as well as GTL liquid and LNG sales values are a function of world oil prices. There are six components to wellhead oil price evaluation:

$$\begin{aligned}\textit{Wellhead Oil Price} = & (\textit{World Oil Price}) - (\textit{Marine Tariff}) - (\textit{TAPS Tariff}) \\ & - (\textit{Alaskan Crude Oil Adjustment}) - (\textit{Field Tariff}) - (\textit{Quality Adjustment}).\end{aligned}$$

The individual components in the wellhead oil price are defined in the following sections.

5.1.2.1.1 Marine Tariffs--Three years of history and the future estimated costs of shipping liquids from Valdez to West Coast and Gulf of Mexico delivery points are given in **Figure 5.2.** Factors considered in the estimate of marine tariffs include the assumption that there will be no shipments of ANS crude oil to Gulf of Mexico ports after 1998 because of the declining ANS crude oil production, the passage of the Alaska Export Bill in November 1995 allowing export of Alaskan crude (HOH, 1995), and the shorter haul from Alaska to the northern Pacific Rim. The increase in rates after 1999 results from the increased costs for replacement or retrofitting of existing single-hull ships with double-hull tankers (see **Appendix B.1**).

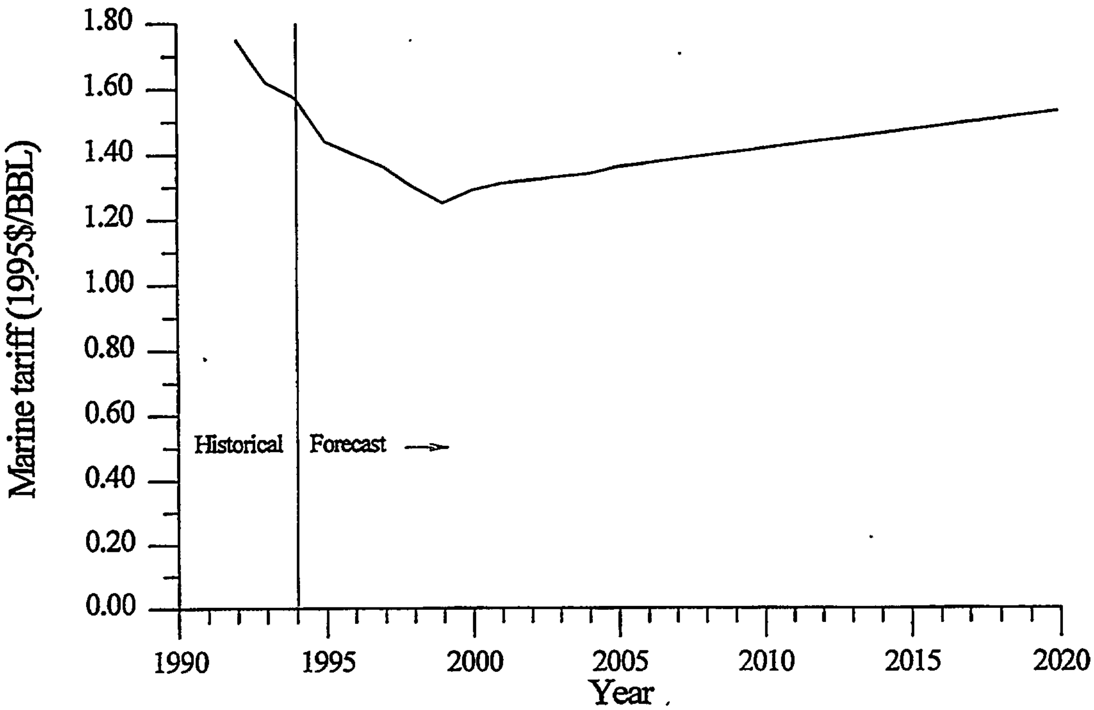

Figure 5.2. Average marine transportation costs to deliver crude oil from Valdez, AK to Lower 48.

5.1.2.1.2 TAPS Tariffs--Separate TAPS tariff schedules were estimated for each of the three ANS gas production scenarios: no major gas sales, gas sales to a LNG project, and gas sales to a GTL project. Three years of history and the future TAPS tariff schedules for the three scenarios are given in **Figure 5.3.** TAPS tariffs per barrel of transported liquid remain fairly steady under the GTL conversion option over the project life. In contrast, there is a sharp increase under the LNG and no major gas sales options. The reason for this difference is that the liquid volume generated by the GTL option absorbs an increasing amount of TAPS operating costs as the ANS crude oil production declines. Additional details of the TAPS tariff outlook are described in **Appendix B.1.1.**

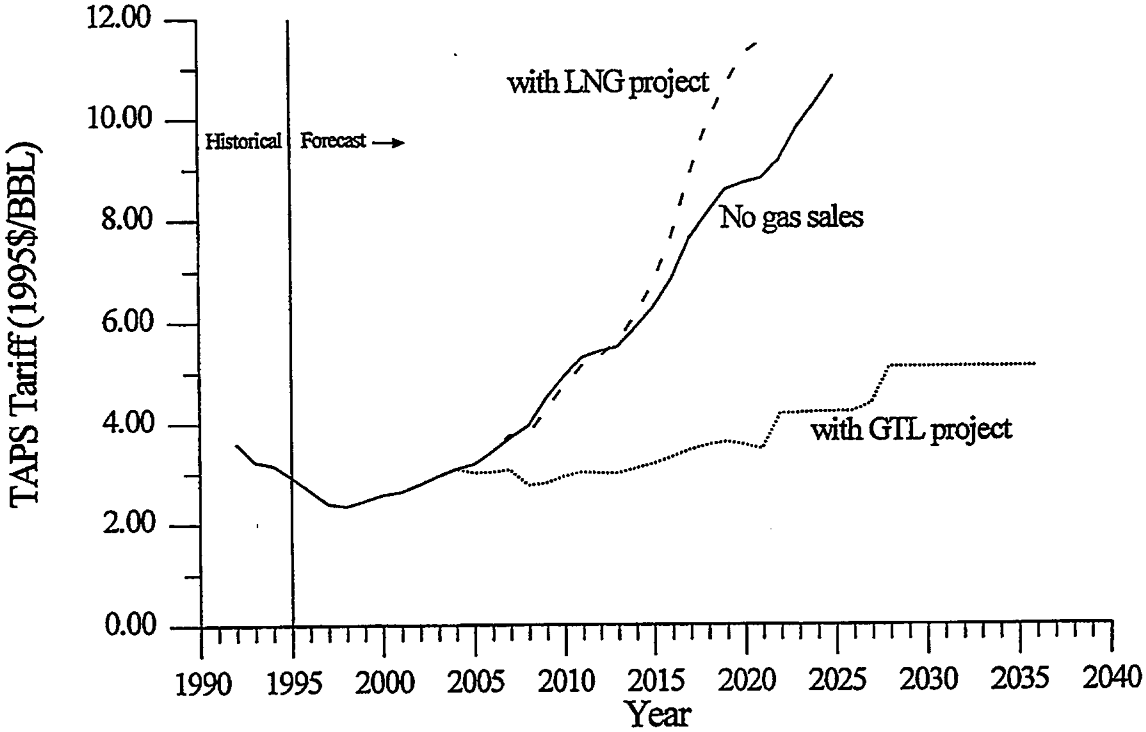

Figure 5.3. TAPS tariffs for three North Slope production scenarios.

5.1.2.1.3 Alaskan Crude Oil Adjustment--A deduction of 1.00 $/BBL is applied to the oil price forecasts shown in **Figure 4.2,** in determining ANS oil prices to account for gravity differences between ANS oil and "world" crude used to develop the price forecasts.

5.1.2.1.4 Field Pipeline Tariffs--A field pipeline tariff is charged against the oil and gas price of liquids delivered from any project through a common carrier pipeline to PS No. 1 or to the LNG or GTL project. This is applied in the PTU evaluations, but does not apply to PBU. Field tariffs are discussed in more detail in **Appendix B.1.1.1.4.**

5.1.2.1.5 TAPS Quality Adjustment--Effective December 1, 1993, the TAPS Quality Adjustment methodology was changed from a gravity-differential basis to a market-value basis. A market value differential is applied to each stream entering TAPS, such that delivered volumes with higher market values receive higher selling prices than those with lower market values (see **Appendix B.1.1.1.5**).

5.1.2.2 Gas Quality. The quality of the gas sold to both the LNG or the GTL project is assumed to have a heating value of 1150 BTU/SCF on a dry basis (State of Alaska, 1996). This BTU content exceeds typical U.S. pipeline specifications but provides an opportunity to sell ethane and propane that may not be possible to transport in TAPS because of vapor pressure limits. The principal raw gas impurity, CO_2, (12% in PBU gas and 4% in PTU gas) will be removed in the gas conditioning plants of the respective gas sales options. The quality of the LNG product is assumed to be equal to the input gas, 1150 BTU/SCF, on regassification. **Table 5.1** shows a typical composition of PBU gas on a dry basis before removal of CO_2.

Table 5.1. Example composition for PBU CGF residue gas.[a]

Component	Residue Gas Composition (vol%)
Methane	76.2
Ethane	6.4
Propane	3.2
I-Butane	0.3
n-Butane	0.8
C_5^+	0.1
CO_2	12.6
N_2	0.4
Total	100.0

5.1.2.3 Gas Product Price Estimates. Currently, the minor gas sales occurring on the North Slope are not considered representative of prices during major gas sales. The methodology used to estimate gas prices for the two major gas sales scenarios, sales to a gas pipeline/LNG plant and to a GTL plant, is described below.

a. Personal communication, Arco Alaska, Inc., May 1996.

5.1.2.3.1 LNG Price--For this evaluation, it is assumed that the LNG produced will be sold to Japan and other Pacific Rim countries. Thus, the North Slope gas price for the LNG scenario is determined as follows:

$$\textit{North Slope gas price} = (\textit{LNG price in Asia}) \times (\textit{gas product net back}).$$

The LNG sale price in Asia is calculated as follows:

$$\textit{LNG price in Asia} = \frac{\textit{World Oil Price} \times (1 + \textit{Asian LNG bonus})}{\textit{BTU conversion for LNG}};$$

$$\textit{where}: \quad \textit{BTU conversion for LNG} = \frac{5.9\,\dfrac{MMBTU}{BBL}}{1.15\,\dfrac{MMBTU}{MCF}} = 5.13\,\frac{MCF}{BBL},$$

$$\textit{Asian LNG bonus} = 0.1\ (10\%).$$

For example, the LNG sales value for the AEO95 reference oil price for 1995 of \$17.04/BBL would be about \$3.65/MCF (\$3.17/MMBTU).

5.1.2.3.2 GTL Price--The liquids produced from the GTL conversion plants are assumed to be high quality hydrocarbons with environmentally superior characteristics. For the base case analysis, the hydrocarbon liquid produced from the GTL plant receives a \$5.00/BBL premium price (see the discussion in **Section 4.1** and **Appendix B.1.2**). The GTL conversion plant liquid product price at the plant gate on the North Slope is calculated as follows:

$$\textit{GTL Hydrocarbon Price} = (\textit{World Oil Price}) + (\textit{Liquids Premium}) - (\textit{Marine Tariff}) - (\textit{TAPS Tariff}).$$

The gas prices for a GTL scenario are calculated as follows:

$$\textit{North Slope gas price} = \frac{\textit{World Oil Price} + \textit{liquids premium}}{\textit{BTU conversion for GTL}} \times \textit{gas product net back};$$

$$\textit{where}: \quad \textit{BTU conversion for GTL} = \frac{5.75\,\dfrac{MMBTU}{BBL}}{1.15\,\dfrac{MMBTU}{MCF}} = 5.00\,\frac{MCF}{BBL}.$$

For example, the GTL liquid product price at the GTL plant gate using the AEO95 reference oil price for

1995 of $17.04/BBL, $5.00/BBL premium, marine tariff of $1.44/BBL, and TAPS tariff of $2.93/BBL would be about $17.67/BBL or a GTL plant gate, gas equivalent price of $3.53/MCF.

5.1.2.3.3 Wellhead Gas Price--The wellhead gas price is equal to the North Slope gas price less any field pipeline tariffs.

5.1.2.4 Operating Costs. Operating costs may include, but are not limited to, the operating and maintenance costs of (a) facilities, (b) wells (including workovers), (c) material purchases, (d) shared facilities charges, and (e) overhead costs.

5.1.2.4.1 Gas Producing Unit Operating Costs--Operating cost estimates are based on publicly available data, engineering judgement, and experience for the existing oil operations. In general, as oil production declines, more of the costs are attributed to the cost of producing the gas and less to the oil. The procedure used is described in **Appendix A.2.2.1.5.**

5.1.2.4.2 LNG Project Operating Costs--An empirical method (**Appendix B.1.5.5**), using 5% of cumulative inflated investments, is used to estimate O&M costs. Total operating cost is the sum of O&M costs and the gas purchase cost.

5.1.2.4.3 GTL Plant Operating Costs--Total operating cost is the sum of the gas purchase cost and an estimated $6.00 per barrel of liquid output O&M cost (see **Appendix B.1.5.3**).

5.1.2.5 Gas Conversion Efficiency. Conversion efficiency is determined on a thermal equivalency basis and is based on information available for each gas option. For LNG, this includes any gas losses and use as fuel in the gas conditioning plant, gas pipeline, LNG conversion plant, and LNG tankers. For GTL, conversion efficiency refers to the BTU's in the product divided by the BTU's in the gas purchased from the producing units.

5.1.2.5.1 LNG Efficiency--The TAGS project assumes a daily input to the gas pipeline of 2.05 BCFPD to deliver the 14 MMTPA (the equivalent of 1.87 BCFPD) to the Pacific Rim, resulting in an overall thermal efficiency for the LNG project of 91% (Alaska Conservation Foundation, 1994). The base case LNG scenario in this analysis involves the purchase of 2.49 BCFPD from both PBU and PTU. With a 91% efficiency, this results in LNG sales of 17 MMTPA (2.27 BCFPD), a 21% increase in required capacity for LNG facilities over the 14 MMTPA project.

5.1.2.5.2 GTL Efficiency--An overall plant thermal efficiency of 60% is used in the GTL evaluations (see **Section 3.3.2**). This is 3 percentage points lower than the 63% design efficiency reported for Shell's Malaysia plant (Eilers, 1990). The 60% efficiency assumption may be conservative but is used because actual data from Shell's plant is not publicly available.

5.1.2.6 Investment Requirements. Investments for all the projects are based on the available public information for each project.

5.1.2.6.1 Producing Unit Investments--Total future investments for oil and gas extraction projects are based on the history of active projects and public information. Detailed investment information is found in **Appendix A** for all oil and gas projects used in this study. For PBU, all investments are related to the recovery of oil and total $1,790 million (1995$), as discussed in **Appendix A.2.1.2.3**. Because so many facilities are already in place for the recycling of the produced gas at PBU, it is assumed that no additional investments will be required for major gas sales. The gas conditioning plant investment is included in the gas sales projects. Investments for development of PTU, discussed in **Appendix A.3.1.3.7**, are estimated to be about $900 million (1995$).

5.1.2.6.2 LNG Investments--Public information available for this study placed the total project cost for the 14 MMTPA LNG operation proposed by YPC at $14 billion in 1995$ (Alaska Conservation Foundation, 1994). The LNG project option analyzed in this study has a capacity of 17 MMTPA to handle both PBU and PTU gas, as discussed in **Section 5.1.1.4**. Based on the additional equipment needed to reach this capacity from the 14 MMTPA TAGS project dimensions, the YPC capital costs are increased from $14 to $16 billion, about 14%. Details of the LNG project investments is contained in **Appendix B.1.7.3.**

5.1.2.6.3 GTL Investments--Based on a recent study by Hackworth, et al. (DOE, 1995), the investment required for a 300 MBPD GTL conversion plant (or multiple smaller plants) located on the North Slope is estimated to be between $27,700 and $39,900 per daily barrel (DBL) of output. For an unproven plant installation investment on the North Slope, the upper end of this investment range, $40,000/DBL (1995$), is assumed for the evaluation. The total investment of $12 billion (1995$) is scheduled over a 6-year period. A detailed discussion is contained in **Appendix B.1.7.2.**

5.1.2.7 State and Federal Taxes. State and federal tax calculations and the methodology used in the economic model are discussed in **Appendix C.1.1.** State taxes include: (a) severance tax (based on well and field rates), (b) conservation tax ($0.004/BBL conservation tax rate and $0.05/BBL conservation surtax rate), (c) property or ad valorem tax (2% of property tax base), (d) State income tax at an effective rate of 3%, and (e) royalty, where royalty rates are set on a lease-by-lease basis. The average project royalty ranges from 12.5% to about 20.0% depending on the individual lease royalty rates within the project area (see **Appendix B.1.10**). Federal income taxes are assessed at 34% as described in **Appendix C.1.1.7.**

5.1.2.8 Summary. The preceding paragraphs have summarized the base values of the variables needed to compare the feasibility of the three gas sales options for ANS gas: (a) no major gas sales (gas reinjected for pressure maintenance, enhanced oil recovery, etc.), (b) LNG conversion and sale, and (c) GTL conversion and sales. The next section presents the results of the economic assessment of these options using the variable assumptions described above.

5.2 Baseline Economic Assessment

The economic results, using the baseline assumptions, for the LNG and GTL projects and PBU and PTU with major gas sales are described in this section. All values are given in 1995$ unless specifically stated otherwise. The North Slope gas price is adjusted for each scenario so that each gas sales option (LNG or GTL) earns a 10% rate of return ($NPV_{10} = 0$). This provides the maximum possible income to PBU and PTU for the gas sold to the gas sales projects. The relative economic value of each gas sales option from the point of view of the producing units is determined by comparing the NPV_{10} of the producing units (PBU and PTU) under each option.

5.2.1 LNG Project Economics

A stand-alone LNG project consisting of a gas conditioning plant, a gas pipeline, a LNG conversion plant and associated facilities, and a LNG tanker fleet capable of handling gas from both PBU and PTU is evaluated. Baseline results from this gas sales option are summarized in **Table 5.2.** The estimated gas reserves and the LNG project facilities capacity are assumed to be sufficient for 32 years of LNG operations, as described in **Section 5.1.1.** Project investment is $16 billion, total operating costs (gas purchase costs and O&M costs) are about $65 billion, and after-tax cash flow is over $31 billion. The discounted cash flow for a 10% discount rate (NPV_{10}) for the LNG project is zero because the evaluation of stand-alone gas projects sets the North Slope gas purchase price such that the projects earn a 10% rate of return. The gas product net back for the LNG project calculated in this manner is 28.1%. Substantive LNG project investment begins in 2000 and is completed in 2008; major gas sales start in 2005 and end in 2036 for a 32-yr life (see **Appendix B.1.7 - B.1.9**). The impact of this scenario on the cash flow of PBU and PTU is discussed in **Section 5.3.3.**

Table 5.2. LNG project costs and net revenues (1995$).

Economic Factor	AEO95 Reference Oil Price
Project Life (2005 - 2036)	32 yrs
Investment ($, millions)	16,000
Total Operating Costs[a] ($, millions)	64,800
Rate of Return	10.0%
Gas Product Net Back	28.1%
After-Tax Cash Flow ($, millions)	31,500
a. Operating costs include O&M costs and cost of gas purchased from the producers.	

5.2.2 GTL Project Economics

A GTL plant capable of handling gas from both PBU and PTU is evaluated. Baseline results for the stand-alone GTL conversion plant, which includes facilities for any required gas conditioning as well as the conversion plant, as described in **Section 3.3.2,** are summarized in **Table 5.3**. The plant is enlarged at the PBU plant site to handle gas from PTU as it comes on line in 2008. Substantive investment begins in 2003 and is completed in 2007; the project life is the same as in the LNG case, 2005 to 2036 for a 32-yr life. The investment schedule is discussed in **Appendix B.1.7.**

Table 5.3. GTL project costs and net revenues (1995$).

Economic Factor	AEO95 Reference Oil Price
Project Life (2005 - 2036)	32 yrs
Investment ($, millions)	12,000
Total Operating Costs[a] ($, millions)	46,100
Rate of Return	10.0%
Gas Product Net Back	15.1%
After-Tax Cash Flow ($, millions)	20,900
a. Operating costs include O&M costs and cost of gas purchased from the producers.	

Like the LNG evaluation, the GTL plant also earns a 10% rate of return and the resulting gas product net back is 15.1%. Total GTL investment is approximately $12 billion, total operating costs are over $46 billion over the project life with a resulting total cash flow of over $20 billion in 1995$.

5.2.3 Economics for Prudhoe Bay Unit with Major Gas Sales

Both the LNG and the GTL options -- under the baseline assumptions -- have significantly better after-tax cash flows than the no major gas sales option. For PBU, the only costs are operating costs to continue production of oil and gas. It is assumed that no additional investments are required at PBU to produce the gas for the gas sales options because of the gas handling facilities already in place (**Section 5.1.2.6.1**). **Table 5.4** summarizes the baseline PBU economic results.

Table 5.4. Prudhoe Bay Unit economics - summary (1995$).

Economic Factor	PBU Cases (AEO95 Reference Oil Price)		
	No Major Gas Sales	LNG Sales	GTL Sales
Remaining Oil Project Life (1995 - 2025 or 2021) Gas Project Life (2005 - 2036)	31 0	27 32	27 32
Remaining Oil Reserves - billion BBL Gas Reserves - TCF (Sales)	4.2 0	3.8 21.8	3.8 21.8
Investments for oil production ($, millions) Investments for gas production ($, millions)	1,790 0	1,790 0	1,790 0
Gas Product Net Back (%)	—	28.1	15.1
Revenue From Oil Sales ($, millions) Maximum Revenue From Gas Sales ($, millions) Total Oil and Gas Sales Revenue ($, millions)	56,100 0 56,100	48,800 31,500 80,300	51,300 21,700 73,000
After-Tax Cash Flow ($, millions)	17,600	31,500	27,400
Discounted Cash Flow - NPV_{10} ($, millions)	8,600	11,100	10,400
Incremental NPV_{10} ($, millions)	0	2,500	1,800

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 option because it is assumed that withdrawal of gas for major gas sales starting in 2005 will reduce the ultimate oil recovery by 400 MMBO. Of the two gas sales options, oil revenues with the GTL option exceed those attainable in the

LNG case by $2,500 million 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 than the GTL project, the gas revenue is $9,800 million greater for the LNG option than for the GTL option. This difference is also shown by the gas market net back being 28.1% for the LNG option and 15.1% for the GTL option. Part of this gas revenue difference between the two options is offset by the oil revenue effects of the lower TAPS tariffs as shown by the increased revenue from oil sales for the GTL option, $51.3 billion, compared to the $48.8 billion for the LNG option. The LNG - GTL project difference narrows even more when examined in terms of discounted cash flow, the more critical measure of project value. The PBU NPV_{10} for the LNG scenario is $11.1 billion. The GTL scenario, with PBU producing and selling oil and gas on the same schedule as the LNG project, has a NPV_{10} of $10.4 billion, a difference of $700 million, or about 6%.

Wellhead oil and gas prices for PBU are shown in **Figure 5.4**. The impact of the TAPS tariff reduction resulting from the increased liquid transport through TAPS from GTL liquids is dramatic as illustrated in the wellhead oil price portion of **Figure 5.4**.

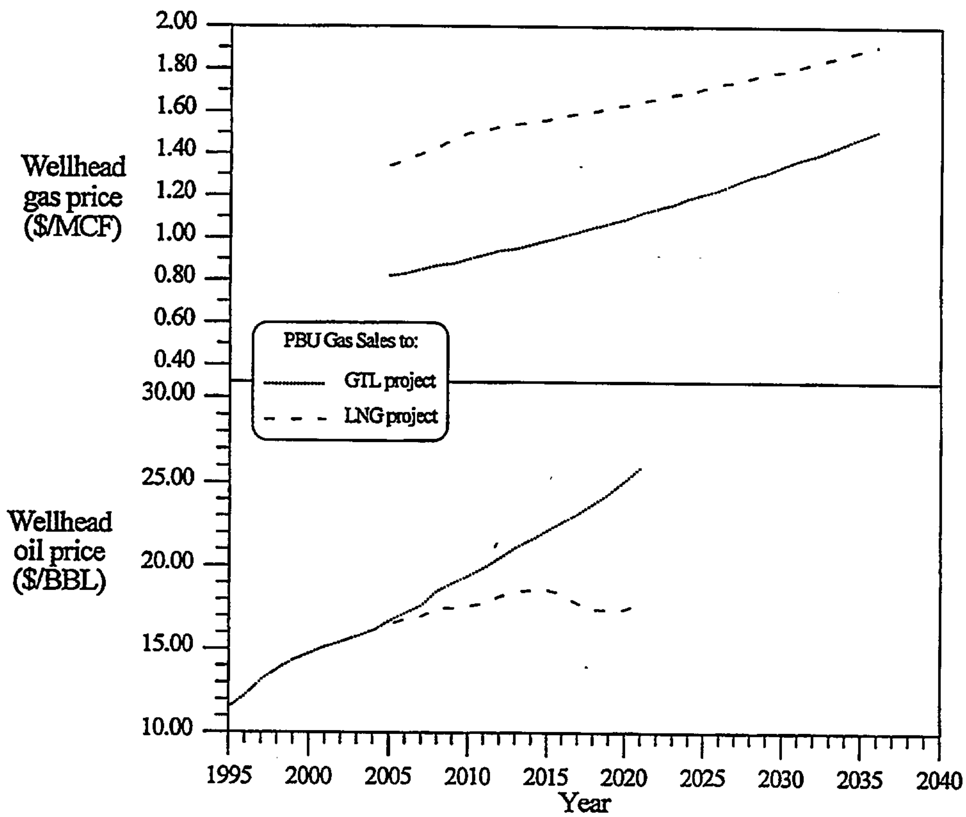

Figure 5.4. Wellhead gas and oil prices for the Prudhoe Bay Unit under LNG and GTL scenarios for the AEO95 reference oil price forecast (1995$).

5.2.4 Economics for Point Thomson Unit with Major Gas Sales. PTU lies 50 miles to the east of PBU and is presently undeveloped. Full field development costs must be incurred, including basic infrastructure and pipelines to the Prudhoe Bay Area, before liquids and gas sales can be realized. The same gas sales alternatives are evaluated for Point Thomson as for Prudhoe Bay: (a) sales to an LNG project, and (b) sales to a GTL plant located at Prudhoe Bay. The GTL plant module for PTU gas conversion is located in the Prudhoe Bay area because our analysis indicates that there is little economic advantage at either site, for the scenarios as set out in this study.

Results in **Table 5.5** compare the two gas sales scenarios for PTU. Gas sales from PTU lag 3 years behind PBU to account for the assumed field development schedule. The economic value (NPV_{10}) of the TU development for gas sales to either gas sales option is almost the same, \$350 million for LNG and \$330 million for GTL in 1995\$.

Table 5.5. Point Thomson Unit economics - summary (1995\$).

Economic Factor	**PTU Cases using AEO95 Reference Oil Price**	
	LNG Sales	**GTL Sales**
Remaining Oil Project Life (yrs) Gas Project Life w/sales beginning in 2008 (yrs)	14 20	20 20
Reserves - million BBL - TCF	181 3.18	207 3.18
Investments at PTU (\$, millions)	900	900
Gas Product Net Back (%)	28.1	15.1
Revenue from Condensate & Oil Sales (\$, Millions) Maximum Revenue from Gas Sales (\$, Millions) Total Revenue (\$, millions)	2,300 3,900 6,200	3,400 2,900 6,300
After Tax Cash Flow (\$, millions)	2,300	2,300
Discounted Cash Flow - NPV_{10} (\$, millions)	350	330

In the LNG sales scenario, PTU condensate is produced through 2021 and gas through 2027, while in the GTL sales scenario, PTU produces condensate 6 years longer, throughout the life of the GTL project (see **Appendix A.3.1.3.5**). 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 gas pipeline/LNG scenario.

5.2.5 State and Federal Government Revenue.

The State of Alaska and the federal government both receive substantial revenues from each of the three producing scenarios under the base case (AEO95 Reference Oil Price). **Tables 5.6** and **5.7** illustrate the potential future revenues collected by the State and federal governments under the three producing scenarios. The State receives income from royalty, severance taxes, property taxes, conservation taxes, and state income taxes where the federal government collects only income taxes (see **Section 5.1.9**). As shown in **Table 5.6**, Alaska revenue is about the same for both gas sales options. As shown in **Table 5.7**, federal income taxes are higher for the LNG option than for the GTL option. This results because the LNG project has an undiscounted after-tax cash flow of $31.5 billion (1995$) compared to the $20.9 billion (1995$) for the GTL project (**Tables 5.2** and **5.3**), even though both the LNG and the GTL project provide the same 10% rate of return on investment in this evaluation. However, federal income taxes from the TAPS pipeline and the tanker operations are not included in the GTL option, which would tend to reduce the difference.

Table 5.6. State of Alaska revenues under three producing scenarios - summary (1995$).

Scenario	Revenues ($, billions)				
	PBU	PTU	LNG project	GTL plant	Totals
No Major Gas Sales	20.6	0	0	0	20.6
Sales to LNG	26.4	1.9	3.5	0	31.8
Sales to GTL	24.2	1.9	0	4.8	30.9

Table 5.7. Federal government revenues under three producing scenarios - summary (1995$).

Scenario	Revenues ($, billions)				
	PBU	PTU	LNG project	GTL Plant	Totals
No Major Gas Sales	7.8	0	0	0	7.8
Sales to LNG	14.9	1.2	17.8	0	33.9
Sales to GTL	12.8	1.2	0	11.6	25.6

5.2.6 Baseline Economic Summary

The aggregate of the economics of PBU and PTU gas sales show a likely NPV_{10} to the gas producers of \$11.5 billion for the gas pipeline/LNG scenario, \$10.7 billion for the GTL conversion scenario, and \$8.6 billion if major gas sales are not undertaken (1995\$). Estimated baseline government revenues under the gas sales options for the State increase from the no major gas sales case by 54% with LNG sales and 50% with GTL sales and for the federal treasury by 435% and 330%, respectively. These economic measures reflect the baseline assumptions discussed earlier in **Section 5.2.** However, before conclusions can be reached, the sensitivity of such economic results to shifts in economic parameter values must be considered.

5.3 Sensitivity Analysis

Analysis of the sensitivity of project economics to the variables used in the calculations is intended to determine which economic input factors are most important to the economic outcome of a given project. By knowing which variables cause the greatest change in project economics, efforts can be focussed to decrease critical costs, refine critical technology, or evaluate tax incentives, whichever the case may be. Plots showing which variables are most critical to the economics of the four stand-alone projects (PBU and PTU producing units, and LNG and GTL conversion projects) are used to delineate the importance of the respective variables. The calculated data used in constructing the plots are shown in **Appendix D.**

Each plot shows the effect of varying certain input values on project net present value (NPV_{10}). In the analyses, one variable at a time is changed. Variables analyzed include: (a) gas product net back fraction, (b) royalty rates, (c) State and federal income taxes, (d) GTL liquids premium, (e) field pipeline tariffs, (f) GTL plant efficiency, (f) investments, (g) operating costs, (h) gas usage for the LNG project, (I) the BTU content of the gas sold from the Units, and (j) the Asian LNG bonus. The oil price projection, AEO95 reference oil price, is kept constant in this analysis. A separate evaluation of the effects of a constant \$18/BBL oil price is presented in **Section 5.4.**

Note that in the economic sensitivity analyses, operating and maintenance costs (op cost factor) are limited to the expenses of operating and maintaining project facilities, and do not include the cost of gas purchased. The cost of the gas feedstock is calculated directly from the gas product net back variable. Where applicable, State and federal taxes include severance, ad valorem, conservation, and income taxes. Although most of the input variables are changed by ±30%, some variables could easily range beyond 30%

and others may have a smaller range. The 30% range displayed on the plots is not meant to imply any limit or possible range of variance.

5.3.1 PBU and PTU Economic Sensitivity with Gas Sales to LNG Project

The sensitivity of the economics of selling gas from PBU to a gas sales project (either a LNG project or a GTL project) can be readily seen through changes in the Unit's incremental revenues above those revenues generated if no gas had been sold. The incremental NPV_{10} of PBU with gas sales to a LNG project is $2,500 million for the base case discussed above. **Figure 5.5** shows plots of the incremental NPV_{10} values for PBU relative to the no major gas sales case as each of the six variables change. These data show that the amount of State and federal taxes is the most critical variable for PBU under this scenario. For example (see **Figure 5.5**), a 15% reduction in State and federal taxes increases the incremental project NPV_{10} by $1,500 million to $4,000 million. The other variables are less critical to overall project economics. (Note that the gas product net back variable, the gas BTU content variable, and the LNG bonus variable overlap in this figure and in **Figure 5.6**.

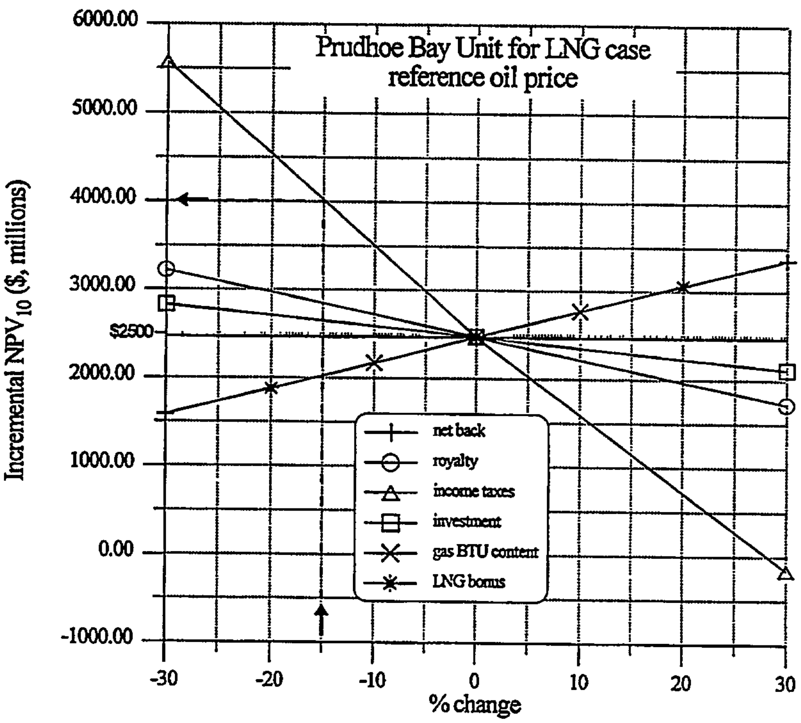

Figure 5.5. Variable sensitivity plot for Prudhoe Bay Unit with gas sales to a LNG project with illustration showing effect of lowering state and federal taxes by 15% - reference oil price forecast.

The base NPV_{10} for PTU with gas sales to a LNG project is \$340 million. The price received for the gas sold (gas product net back variable), the gas BTU content, and the LNG bonus are the most critical variables for PTU as shown in **Figure 5.6.** However, State and federal taxes and field investment are also critical variables for PTU under this scenario. Field pipeline tariffs and royalty rates play a less important role than the other variables analyzed.

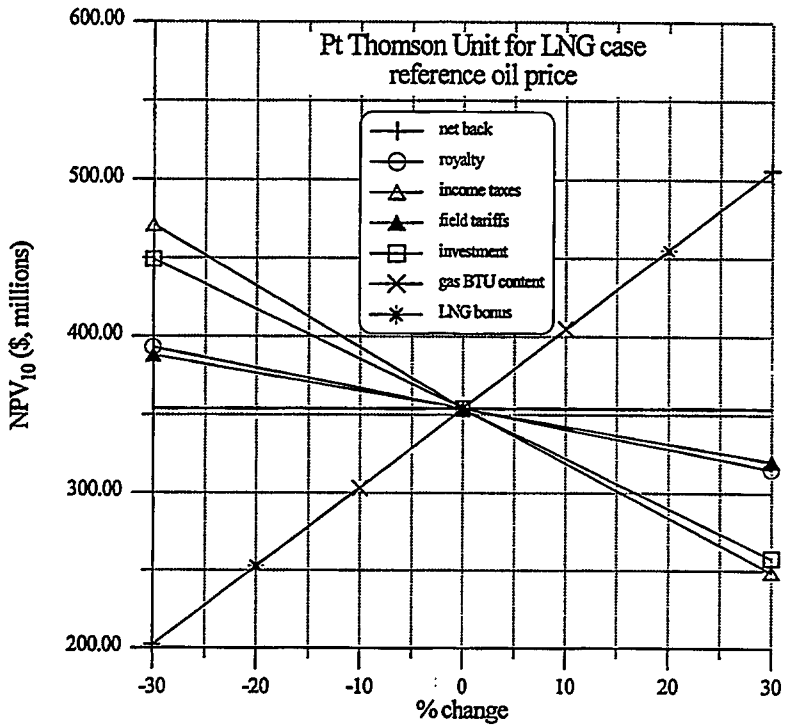

Figure 5.6. Sensitivity plot for Point Thomson Unit with gas sales to gas pipeline/LNG project - reference oil price forecast.

5.3.2 PBU and PTU Economic Sensitivity with Gas Sales to a GTL Plant.

Six variables were tested for economic sensitivity of the gas producing units for the GTL scenario. The variable most critical to both PBU and PTU economics under the GTL scenario is the combined State and federal taxes (see **Figure 5.7** and **Figure 5.8**). The gas product net back, gas BTU content, and field investment are also very critical for PTU. The effects of varying the liquid premium were small for both PBU and PTU compared to the impact of other variables.

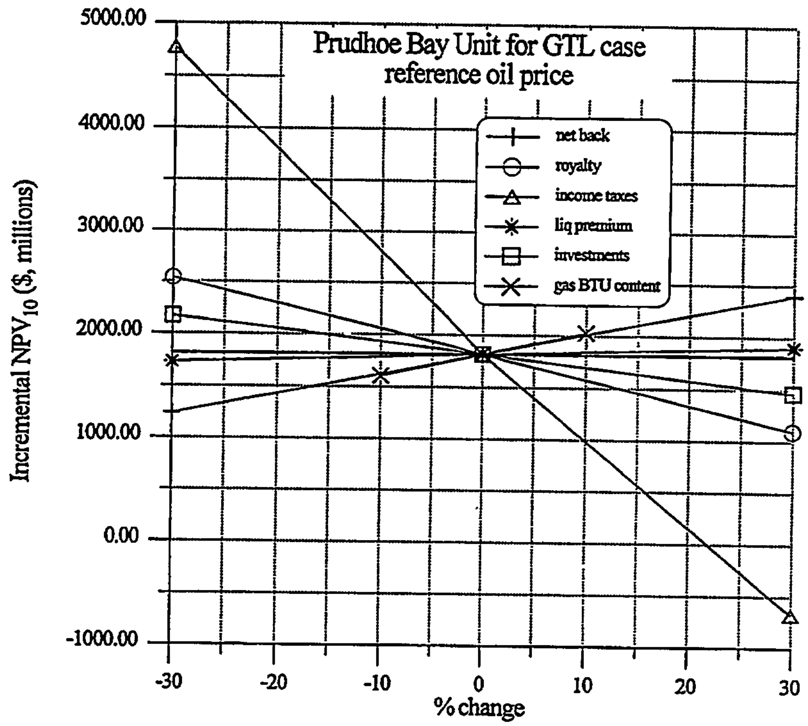

Figure 5.7. Variable sensitivity plot for Prudhoe Bay Unit with gas sales to GTL plant - reference oil price.

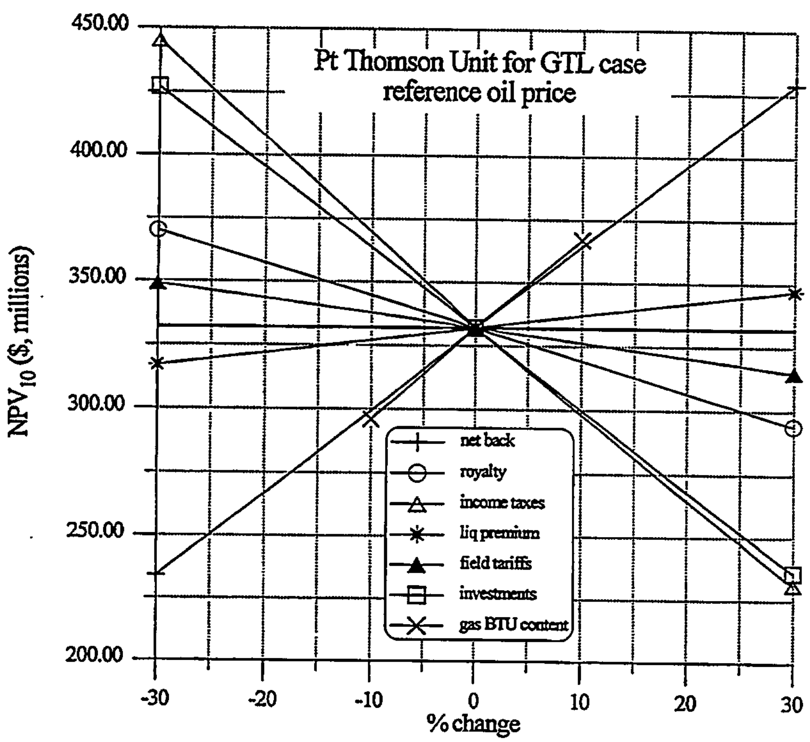

Figure 5.8. Variable sensitivity plot for PTU with gas sales to a GTL plant - reference oil price.

5.3.3 LNG Project Economic Sensitivity.

Variables analyzed to determine LNG project sensitivity include: investment, operating costs, State and federal taxes, gas producer net back, shrinkage, gas BTU content, and Asian LNG bonus. Shrinkage is the percentage of the purchased gas lost due to fuel usage and process efficiencies.

Sensitivity analysis results, shown in **Figure 5.9**, indicate that the gas BTU content, the LNG bonus, and the project investment are the most critical variables to project economics. Net back fraction, state and federal taxes, operating costs, and shrinkage are important, but less critical to total project economics.

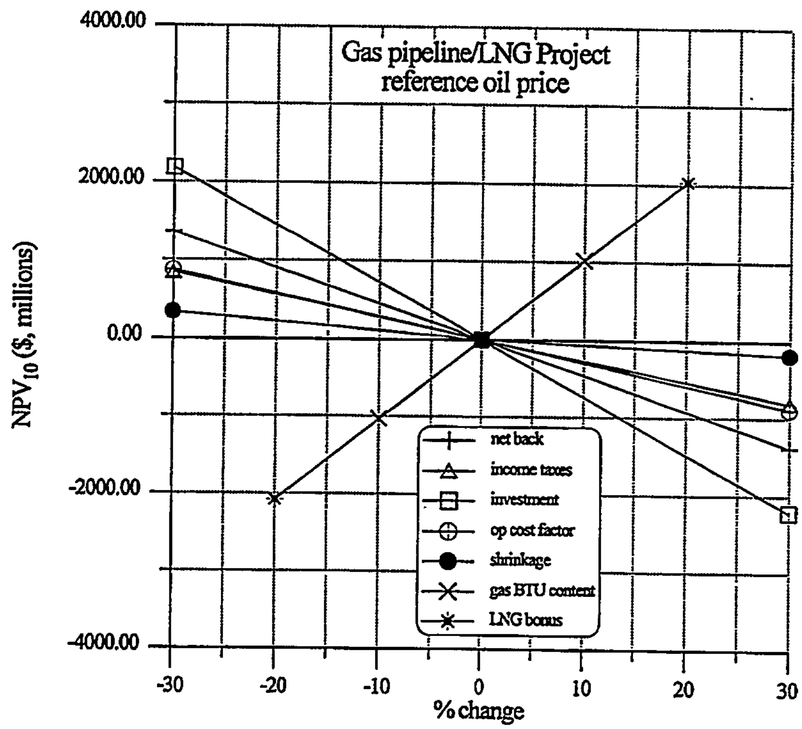

Figure 5.9. Variable sensitivity plot for LNG project showing effect of altering variables on project net present value - reference oil price.

5.3.4 GTL Conversion Plant Economic Sensitivity.

Variables analyzed to determine GTL project sensitivity include: operation and maintenance costs, liquid premium price, initial plant investment, state and federal taxes, GTL plant efficiency, gas product net back, and gas BTU content. The most critical variable in the GTL plant economics is the overall efficiency of gas usage and conversion as shown in **Figure 5.10**. Other important variables, listed in order of sensitivity, include plant investment, gas BTU content, net back fraction, O&M costs (op cost factor), State and federal taxes, and liquid premium price.

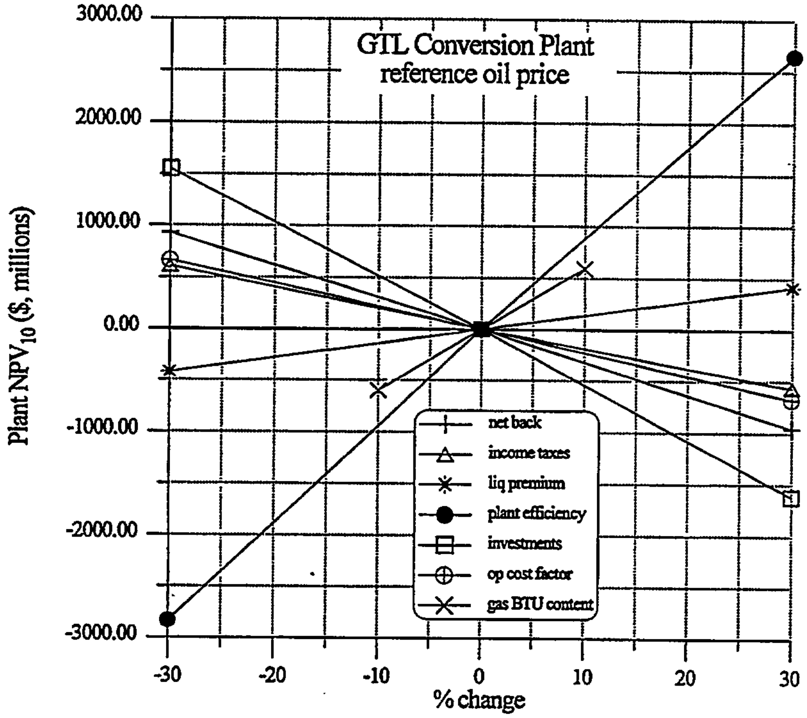

Figure 5.10. Variable sensitivity plot for GTL plant showing effect of changing input variables on the net present value of the plant - reference oil price.

5.3.5 Summary Discussion.

From this analysis it can be seen that a major cost driver for both the GTL and LNG conversion projects is initial investment costs. If this variable is successfully lowered or even held at the assumed value, both projects show acceptable rates of return for the reference oil price, while providing the Units a reasonable price for their gas. Of even greater significance to the GTL conversion project is plant efficiency. An increase in plant efficiency not only increases the profit stream by increasing liquid product sales volume, but the increased volume also decreases TAPS transportation costs for all transported liquids, providing a higher North Slope oil price than without GTL conversion. In the case of LNG, the delivered price as reflected by both the gas BTU content and the Asian bonus appear to be the most critical variables.

PBU is most affected by altering state and federal income taxes. For PTU, because it is less profitable, other variables come into play such as gas product net back fraction and field tariffs, as well as State and federal taxes and royalties. Because of its borderline economic status, government agencies are in a position to assist in improving the economic viability of the Point Thomson field.

5.4 Analyses Using the Flat Oil Price Forecast

A flat oil price forecast of \$18/BBL (1995\$) is used to evaluate the gas sales scenarios for a much more conservative oil price forecast than the EIA 1995 reference oil price forecast. Using the \$18/BBL flat oil price forecast, Point Thomson requires a gas product net back percentage much higher than either of the gas sales alternative projects can afford to offer to earn a 10% rate of return. For PTU to be economical for the \$18/BBL oil price, significant (and probably unreasonably large) changes in several of the input variables would be required. Therefore, the sensitivity analyses done with the \$18/BBL flat oil price forecast include gas produced from PBU alone at 2.05 BCFPD, yielding LNG sales of 14 MMPTA and GTL liquid sales of 250 MBPD. The capital investments are reduced to the levels required for the reduced scale of the projects; i.e., \$14 billion for the LNG project and \$10 billion for the GTL project.

The same approach is used with the flat oil price forecast as with the reference oil price forecast: both the LNG and GTL projects are forced to a 10% rate or return by varying the gas product net back fraction. Any economic advantage of the two options then shows up in the evaluation of PBU economics and are presented in terms of incremental NPV_{10} relative to the no major gas sales case. However, for the \$18/BBL flat oil price, neither of the two gas sales options can receive a 10% rate of return and return a positive incremental NPV_{10} to PBU -- in other words, for both gas sales projects to receive a 10% rate of return with these input variables and the \$18/BBL flat oil price, PBU would fare better by with the no major gas sales option.

Since it is necessary for both the gas projects and the PBU to provide reasonable rate of return, a breakeven flat oil price greater than \$18/BBL is calculated such that both the gas producer and buyer earn a 10% rate of return. Thus, both the NPV_{10} of the gas sales projects and the incremental NPV_{10} for PBU were held to be equal to zero, which means the value of the projects to the PBU owners would be equal to the no major gas sales case. This is accomplished by varying the gas product net back fraction until both the gas producer (PBU) and the gas buyer (either the LNG project or the GTL project) earn a 10% rate of return on their respective projects. As shown in **Figure 5.11,** the breakeven flat oil price for the LNG scenario is \$19.36/BBL; while the breakeven flat oil price for the GTL scenario is slightly higher at \$19.94/BBL.

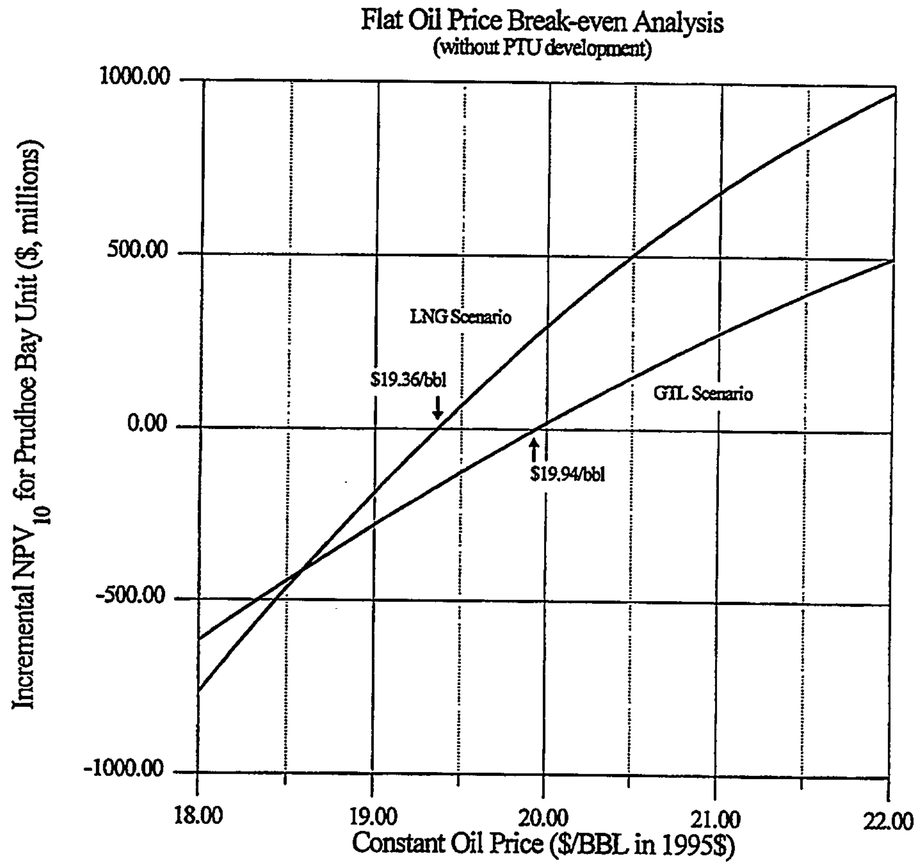

Figure 5.11. Analysis to determine the break-even ($NPV_{10} = 0$) flat oil price for each gas sales scenario for PBU.

5.5 Delaying Major Gas Sales Until 2010

Currently, the gas from Prudhoe Bay is being used to recover oil from PBU as well as the Kuparuk River Unit. Starting major gas sales from Prudhoe Bay in the year 2005 reduces the amount of gas available for oil recovery operations and causes a reduction in oil produced from the PBU. It is estimated that 400 MMBO of oil will be lost by starting major gas sales in 2005 (see **Section 2.3.7.1**). However, if the gas is not sold until a later date, the amount of lost oil recovery is reduced. By delaying major gas sales by 5 years, from 2005 to 2010, it estimated that from zero to 200 MMBO of oil recovery will be lost.[a] For this sensitivity analysis, it is assumed that gas sales beginning in 2010 cause no negative impact on PBU recovery. The economic ramifications to PBU and to both gas sales alternatives of delaying the sale of gas until 2010 using the AEO95 reference oil price is as follows.

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a. Estimate based on discussions with Arco Alaska, Inc. in August 1991 and March 1995.

By delaying project start up until 2010 using the AEO95 reference oil price forecast, the incremental NPV_{10} of the LNG scenario decreases from $2500 million to $2200 million. The incremental NPV_{10} of the GTL scenario decreases from $1800 million to $1700 million as shown in **Figure 5.12.**

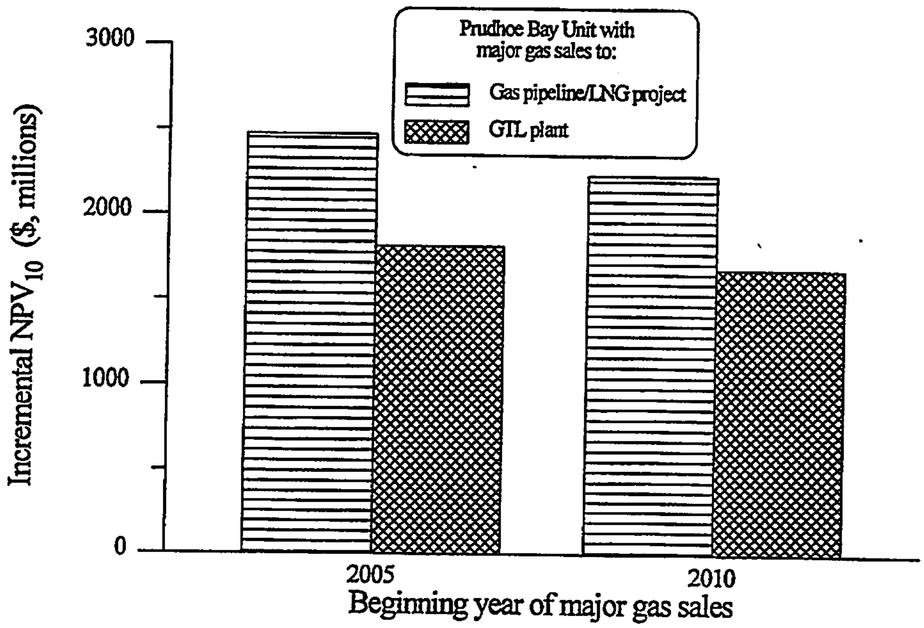

Figure 5.12. Effect of delaying major gas sales from PBU from 2005 to 2010 using AEO95 reference oil price.

5.6 Summary of Economic Results

The preceding sections summarize the analytical framework by which the three options for ANS gas can be compared. The projects and options were evaluated using a standard discounted cash flow analysis presented in terms of net present value (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.

(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.

This delineation of production, gas utilization option technology, and investment return requirement was then followed by summaries of the key variables that influence the economic acceptability of each option. Baseline assumptions for the variables were:

(a) The EIA 1995 Reference Oil Price (AEO95) case was used for the baseline economics. This case assumes 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; in the case of LNG by a 10% Asian bonus and in the case of GTL liquids by $5/BBL.

(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/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. The effects of any changes or incentives that could be provided to encourage development of one or the other of the gas sales options from tax or royalty changes were evaluated in the sensitivity analysis in **Section 5.3.**

The baseline 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 payoffs than the option of not selling the gas and continuing to reinject until the oil recovery reaches an economic limit. It is not nearly as clear which gas sales option is more preferable, however. As shown in **Table 5.8,** while the NPV_{10} for the producing units for the LNG option exceeds that of the GTL option by about 7%, the total investment for LNG is 24% greater than required for GTL.

Table 5.8. 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
Pt. Thomson development	0.9	0.9
Total	16.9	12.9

Variables in these computations and how their change might effect the comparison of the two gas sales options were then examined. For the baseline assumptions, the results showed that neither option is economic, if oil prices remain at a flat $18/BBL. Conversely, the 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. Of the variables examined, the State and federal tax burden appears to have the most effect on the economic feasibility of gas sales by the PBU and PTU. For the LNG project on a stand-alone basis, the Asian price bonus, gas feedstock quality, and total investment costs have the most impact on feasibility, while for the GTL project, plant efficiency and then total investment costs are the most critical variables.