APPENDIX B

ECONOMIC ANALYSIS

The technical and economic parameters that are used in the economic evaluations of North Slope gas utilization scenarios are defined and described in this section. These technical and economic parameters are also used to determine the economics of continued operation of the currently producing projects and other potential developments on the North Slope.

The analyses for currently producing fields and other potential developments are discussed in **Appendix A**. The treatment of taxes, royalty rates, and other economic variables used in the analyses are discussed and the financial model is described in **Appendix C**.

B.1 Definitions and Assumptions of Technical and Economic Parameters

The technical and economic parameters used in the evaluation of continued oil operations, and operations with major gas sales, either through an LNG project or a GTL project, are discussed in this section. These parameters, as appropriate, are also used in the evaluation of currently producing projects.

B.1.1 Oil Prices

Several oil price forecasts are available for use. Three Energy Information Administration (EIA) Annual Energy Outlook (AEO) oil price cases; low, reference, and high scenarios, are discussed in "Annual Energy Outlook 1995," (EIA, 1995). An oil price projection is also discussed in a Gas Research Institute (GRI) publication, "1995 Policy Implications of the GRI Baseline Projection of U.S. Energy Supply and Demand in 2010." The GRI oil price projection, which is more conservative than the EIA reference base, shows little real growth through 2010.

To present a range of oil price sensitivities, the three EIA oil price scenarios (AEO95) are used in the evaluations. To further test oil price sensitivity, a no-growth, flat oil price (FOP) of $18.00/BBL (1/1/95$) is assumed. This is based on the year-end 1994 North Slope crude price of about $16.70/BBL (1/1/95) (rounded to $17.00/BBL), which is assumed to be the delivered price in the Lower 48 states. A quality differential of $1.00/BBL is used to relate the North Slope crude price with prices for better quality oil sources. As discussed in **Appendix B.1.1.1.3,** this price reduction is applied to all oil price forecasts in the project evaluations.

The four oil price forecasts are shown graphically in 1995 constant dollars in **Figure B.1** and in detail in **Table B.1.**

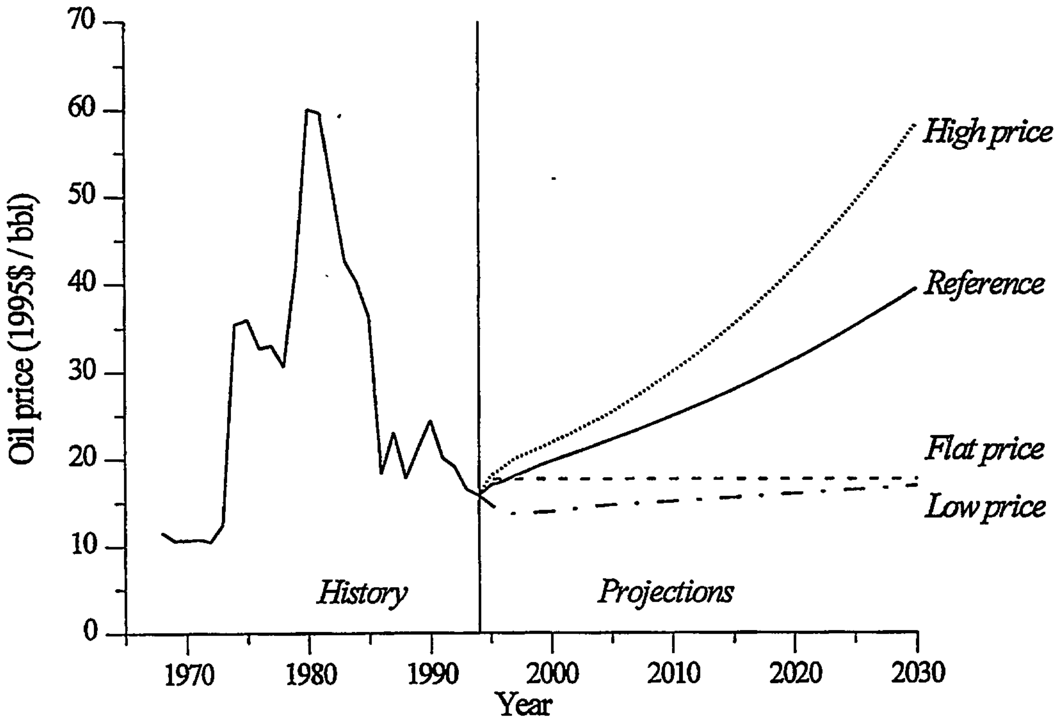

Figure B.1. Historical world oil prices and world oil price assumptions (EIA 1995).

Table B.1. World oil price cases ($/BBL, constant 1/1/95$).

Year	1995	2000	2005	2010	2015	2020
AEO95 High	18.08	21.85	25.36	29.95	35.36	41.76
AEO95 Reference	17.04	19.76	22.21	24.92	27.95	31.35
AEO95 Low	14.72	13.97	14.72	15.13	15.56	16.00
Flat oil price	18.00	18.00	18.00	18.00	18.00	18.00

B.1.1.1 Wellhead Oil Price. The following definitions are used to calculate wellhead oil price:

- Wellhead price = World Oil Price - Oil Net Back
- Oil Net Back = Marine Tariff + TAPS Tariff + Alaskan Crude Differential Adjustment + Field Tariff + Quality Adjustment

The individual components in the oil net-back deductions are discussed in the following section.

B.1.1.1.1 Marine Tariffs--The crude oil, GTL plant hydrocarbon liquids, condensate, and NGL mixture is shipped from Valdez to West Coast and Gulf of Mexico delivery points. At present, about 15% of ANS crude is shipped to delivery points in the gulf of Mexico. Estimates of future marine transportation costs include consideration of:

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

In 1991, the Alaska Department of Revenue (ADOR) completed a study of tanker rates for North Slope crude (ADOR, 1991). The State of Alaska's mid-range marine tariff schedule in constant 1/1/1992$ was adopted for the 1993 DOE study (DOE, 1993). A review of the marine tariff rates shown in the ADOR Fall 1994 and Spring 1995 Revenue Source Books (ADOR, 1994a, ADOR, 1995) reveal that the projected rates vary from year to year but are within 10% of those determined in the 1993 DOE study.

A forecasted decrease in near-term tanker rates is primarily a result of phasing out of crude shipments to points other than the U.S. West Coast by the year 2000. With export of Alaskan crude approved in November 1995 (HOH, 1995), and decline in ANS production, shipments to the Gulf of Mexico area are expected to end. However, the timing is uncertain and, although it could occur in mid-1996, it is assumed that shipments to the Gulf of Mexico will phase out by the end of 1998. The later increase in rates results from the increased costs of constructing new double-hull tankers or to retrofit existing single hull ships. The projected rates in the previous DOE study (1993) are adopted for this study after revising the rates from 1996 through 1999 to account for issues described above.

The yearly schedule of marine tariffs is developed as follows:

- Data points between 1999 and 2005 are obtained by interpolation.
- Data points after 2005 are obtained by using a straight line extrapolation.

The schedule in constant 1/1/1995$ is given in **Table B.2.**

Table B.2. Marine transportation costs, Valdez to Lower 48 ($/BBL).[a]

Fiscal Year	Marine Tariff (constant 1/1/1995$)[b]
1995	1.44
1996	1.40
1997	1.36
1998	1.30
1999	1.25
2000	1.29
2005	1.36

a. Average cost of West Coast/Gulf Coast delivery mix.
b. 1/1/1992$ values from DOE 1993 inflated at 2.2% per year.

Three years or history and the future estimated cost of shipping liquids from Valdez to West Coast and Gulf of Mexico delivery points are shown in **Figure B.2.**

B.1.1.1.2 TAPS Tariffs--TAPS tariffs are determined individually by TAPS owner companies according to a 1985 settlement agreement between the owners and the State. A brief discussion of the method used to calculate TAPS tariff follows. A more complete discussion on TAPS tariffs can be found in Section 3.2.5.1 of the 1991 DOE publication (1991). Simplifying assumptions are:

- Single ownership of pipeline
- Total throughput goes to Valdez
- Minor investments after 1995
- Operating expenses adjusted to current level; currently about $700 million/yr (Platts, 1992)

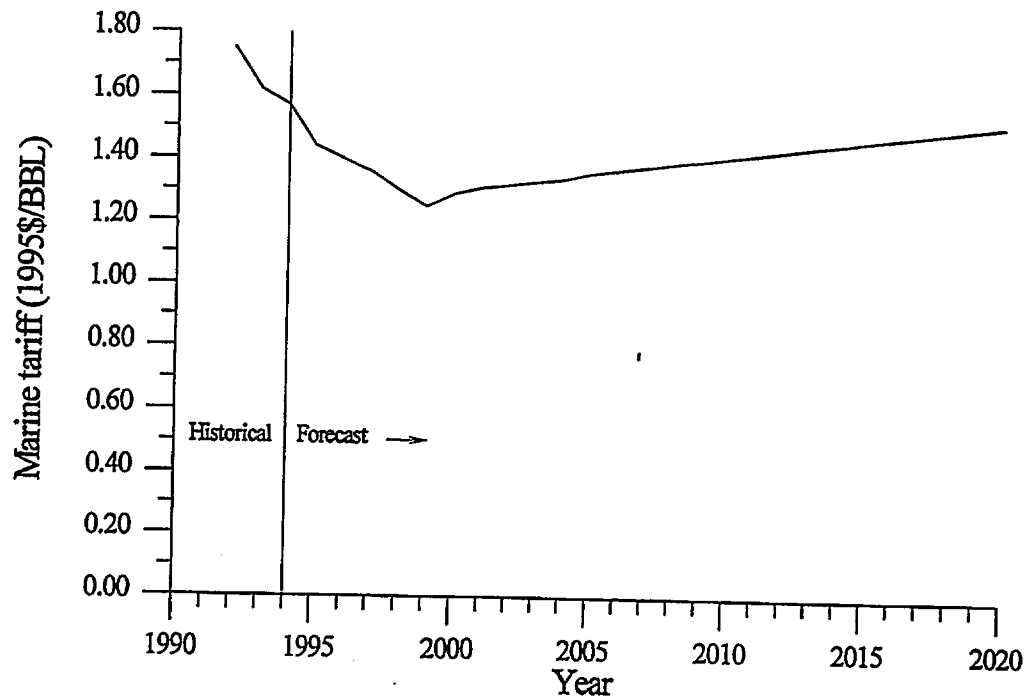

Figure B.2. Average marine transportation costs to deliver crude oil from Valdez, AK to lower 48.

- Operating expenses are cut by 1/3 by 12/31/96[a]
- Operating expenses are cut by another 30% by 2021 as more pump stations are demobilized
- Pipeline owners after-tax margin is limited to an inflation adjusted \$0.35/BBL (\$1983\$) (FERC, 1985; ADOR, 1995)[b] This is \$0.53/BBL (1/1/95\$) of hydrocarbons shipped during 1995.
- Simplified depreciation
- Net carry-overs are zero
- State and federal income taxes remain at current level
- Field production volumes reduced by a factor to account for fuel usage and losses.

The method results in an estimated annual total revenue requirement (ATRR) necessary for TAPS owners to receive the allowed return on their investment. A base TAPS tariff schedule was prepared using updated information, including the current production forecasts of North Slope field rates for the active fields shown in **Figure 1.1**. The TAPS tariff schedule, for currently producing fields in 1/1/95\$, is given in **Table B.3**.

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

b. The after-tax margin is adjusted annually, beginning in 1983, using the Consumer Price Index for all Urban Consumers (CPI-U) (http://www.stls.frb.org/fred/data/cpi/cpiaucsl).

Revised TAPS tariff schedules are determined and used when different liquid streams are delivered to TAPS PS No.1 under the two major gas sales scenarios. The revised TAPS tariff schedules for the two major gas sales scenarios and the base TAPS tariff schedule, are shown in **Figure B.3.**

Table B.3. TAPS tariff schedule for currently producing fields (1/1/95$).

Year	$/BBL	Year	$/BBL	Year	$/BBL	Year	$/BBL	Year	$/BBL
1995	2.93	2002	2.78	2009	4.49	2016	6.83	2023	9.81
1996	2.66	2003	2.95	2010	4.92	2017	7.61	2024	10.29
1997	2.39	2004	3.09	2011	5.29	2018	8.10	2025	10.83
1998	2.34	2005	3.18	2012	5.41	2019	8.58		
1999	2.45	2006	3.43	2013	5.50	2020	8.71		
2000	2.57	2007	3.70	2014	5.88	2021	8.79		
2001	2.63	2008	3.94	2015	6.27	2022	9.16		

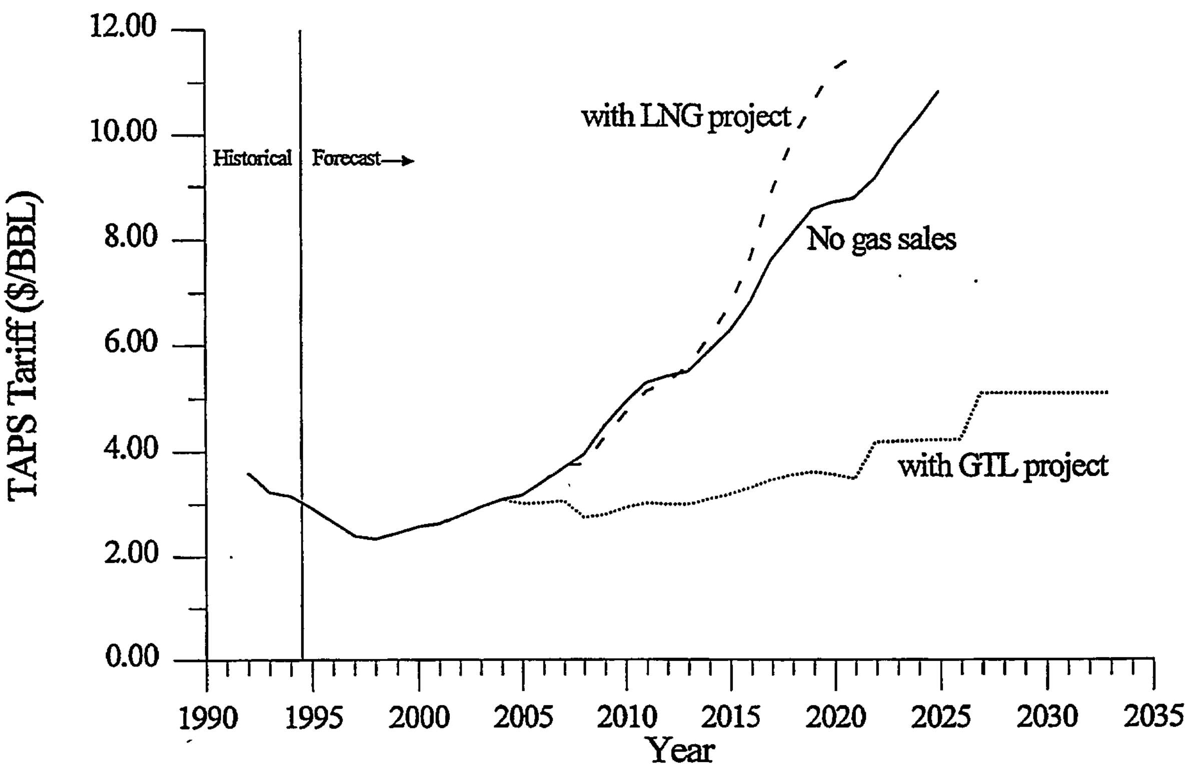

Figure B.3. TAPS tariffs for three North Slope production scenarios (1/1/95$).

In the LNG scenario the decrease in TAPS tariff from 2007 through 2011 results from increased TAPS throughput from Point Thomson production. The increase in TAPS tariffs after 2011 results from decreased TAPS throughput due to lower production rates projected from PBU during gas sales to an LNG project. The large decrease in TAPS Tariffs under the GTL scenario beginning in 2005, is a result of the increased throughput of this scenario. As an example of the effect on wellhead prices under the three different production scenarios, estimated PBU wellhead oil prices are shown in **Figure B.4**.

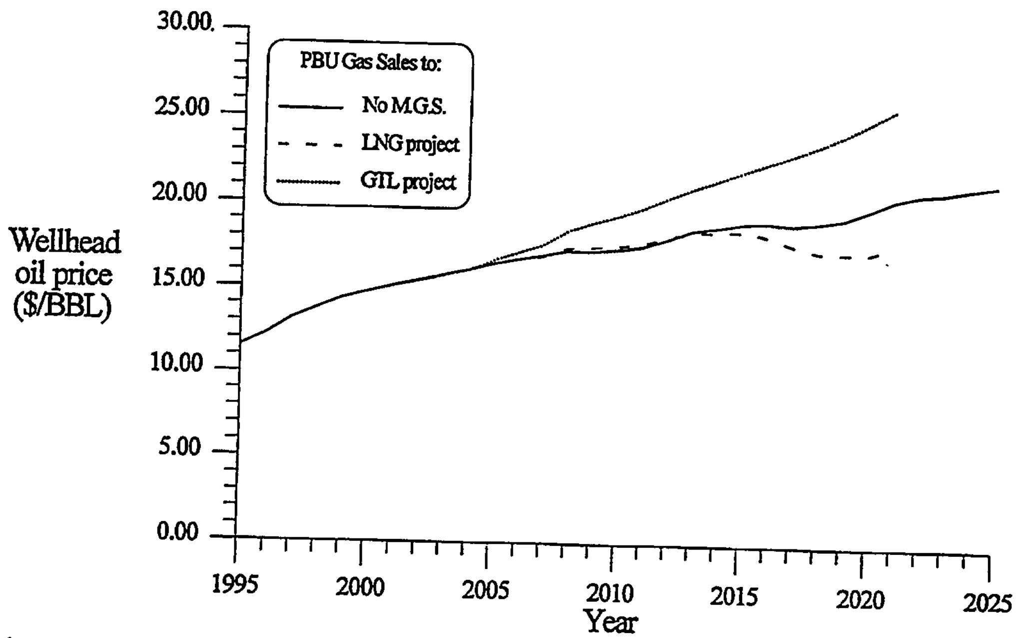

Figure B.4. PBU wellhead liquid prices in 1995$ under different production scenarios.

B.1.1.1.3 Alaskan Crude Oil Adjustment–ANS crude mix receives a lower price than the "world" crude used to develop the crude oil price forecasts (See **Table B.1**). This is primarily due to the lower assumed 28 degree API gravity of the ANS crude mix as compared to the average of about 31 degree API for the mix of imported crudes (OJG 1995f). At present, this differential in price is about $1.00/BBL. It is assumed that this differential will be in effect throughout the evaluation period of any project evaluated. A $1.00/BBL deduction is applied to the oil price schedules given in **Table B.1**.

B.1.1.1.4 Field Tariffs–PS No. 1 is located near the center of PBU (see **Figure B.5**). The producers deliver crude oil (a mixture of oil, condensate, and NGLs) to PS No. 1 for shipment to pipelines. When a producer transports crude through a field pipeline to PS No. 1, a field tariff is paid to the pipeline owners. If the pipeline tariff is known, it is used. When the development of a new field is evaluated, the cost of the pipeline to deliver crude to PS No. 1 or to an existing field pipeline is estimated and a field pipeline tariff determined.

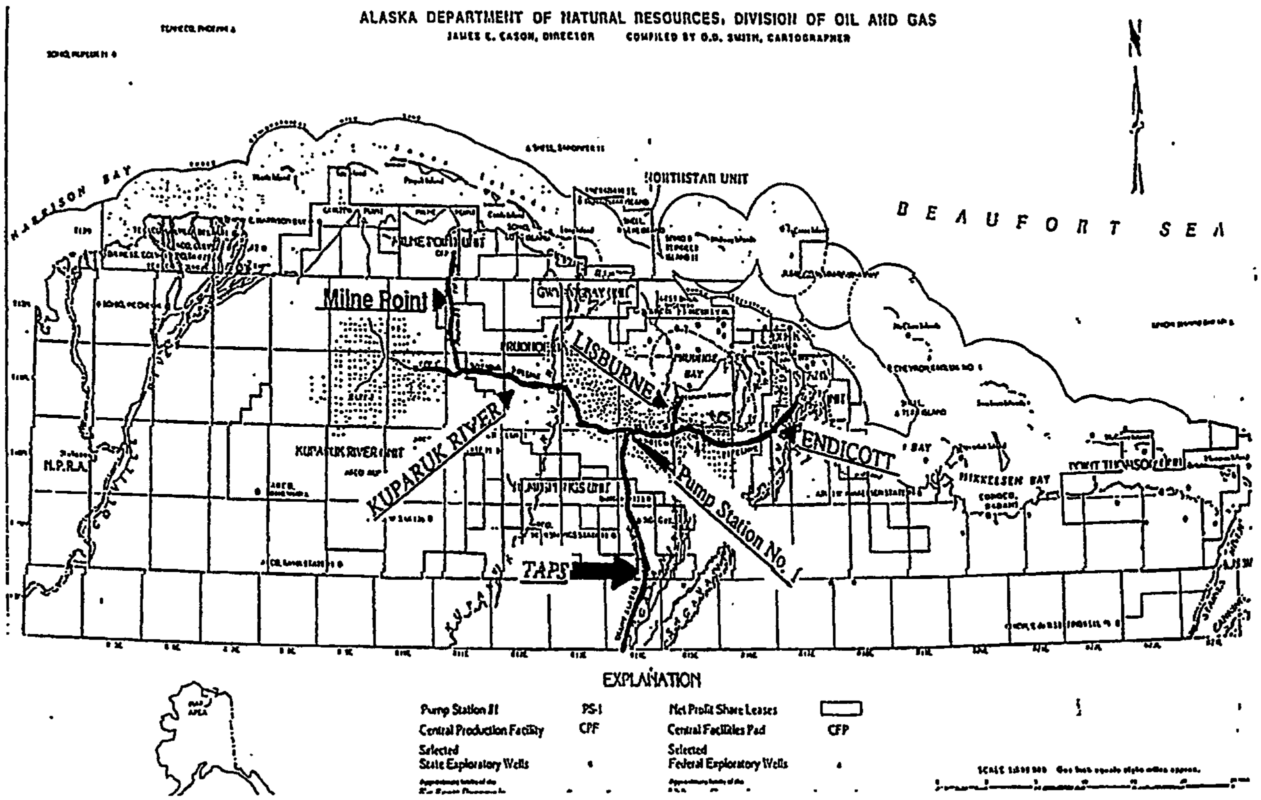

Figure B.5 North Slope Unit map showing field pipelines (from ADNR, 1995c).

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

$$\text{Tariff} = \frac{\text{Cost of pipeline, haul road and pump stations (1/1/95\$)}}{\text{Total volume to be transported (BBL)}} \times 3.35 = \text{\$/BBL (1/1/95\$)}$$

Pipeline construction costs presented by Young (1986) and the National Petroleum Council (NPC) (1981) are used for each field pipeline situation. For the PTU gas pipeline, the same formula is used with the total gas volume in MCF to yield a $/MCF tariff estimate.

Field pipeline tariffs applicable to currently producing projects are give in **Table B.4**.

B.1.1.1.5 TAPS Quality Adjustment--Effective December 1, 1993, the TAPS Quality Adjustment methodology was changed from a gravity-differential basis to a market-value basis. The market

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

Table B.4 Field Pipeline Tariffs ($/BBL, 1/1/95$).

Project	Tariff
KRU	0.19
MPU	0.90
DIU	0.68
LPA	0.32
PMPA	0.32
Niakuk	0.30

value of each hydrocarbon stream being delivered to TAPS at PS No.1 is compared to the market value of the blended stream of all hydrocarbon streams being delivered to TAPS at PS No. 1. The market value of each lighter-end component and heavier-end distillation cut in a stream is volume weighted to determine that product's market value. The market value differential of each component is then applied to the delivered stream such that delivered streams with higher market values receive a higher selling price than delivered streams of lower market value.

The market value of each stream depends on the stream's composition, the then current market value of each of those components, and the volume of each component being blended into PS No. 1. To simplify this method, the delivered hydrocarbon's API gravity is used to estimate the market value. Generally, a product's market value increases as API gravity increases up to an intermediate API gravity due to the higher refinery value of lighter gasoline and diesel distillates and then decreases at very high API gravity due to the lower refinery value of very light NGLs. A general approximation of the market value to API gravity relationship (**Figure B.6**) is applied to each product's API gravity to determine that product's TAPS Quality Adjustment.

B.1.2 GTL Hydrocarbon Pricing

The liquids sales prices for the GTL scenario are based on the manufacture of a high quality hydrocarbon liquid that will be compatible with the crude oil delivery streams from the current and future producing fields, such as liquids in the 200 to 600°F boiling range (gasoline to distillate range). The exact specifications for the hydrocarbon liquid product will be determined by the characteristics of the total crude mix being delivered to TAPS at GTL plant startup and the characteristics, capabilities, and economics of the

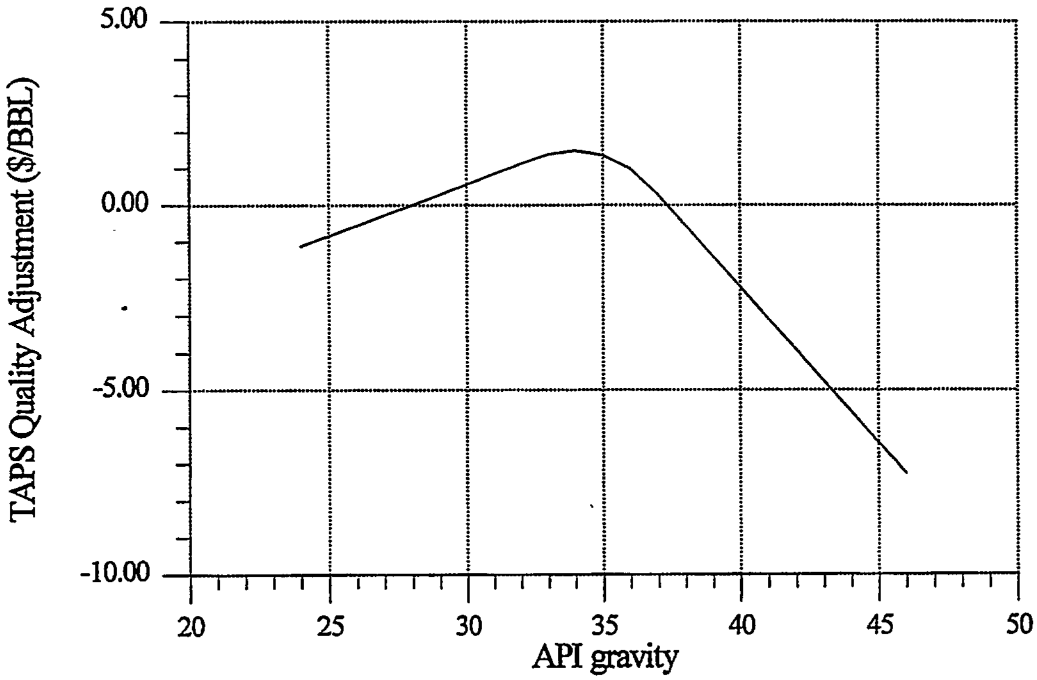

Figure B.6. TAPS Quality Adjustment for North Slope liquid product.

GTL process. These liquids will ostensibly have zero sulfur and require a minimum of refining to process them to high quality transportation fuels. Based on the value of gasoline and distillate relative to benchmark crude oils, as published in the Oil and Gas Journal, the differential value is about $6 to $7/BBL. For the base case analysis, it is assumed the hydrocarbon liquid from the GTL plant will yield a $5.00/BBL (1/1/95$) premium price above the price forecasts in Appendix B.1.1 The TAPS Quality Adjustment (**Appendix B.1.1.1.5**) and the $1.00/BBL Alaskan Crude Oil Adjustment (**Appendix B.1.1.1.3**) are not applied to the GTL products as they are to the ANS crude. The wellhead oil prices are determined by adding the premium to the price forecasts in **Appendix B.1.1** and deducting only the transportation costs discussed in **Appendix B.1.1.1.** The effect of changing this premium is evaluated in the sensitivity analysis.

B.1.3 Gas Prices

Currently, only minor gas sales are occurring on the North Slope, and are not considered representative of prices during major gas sales. The actual gas prices will be determined by economic conditions at the time of sales. Gas prices are determined for two major gas sales scenarios: sales to a gas pipeline/LNG plant system and sales to a GTL plant. These forecasts are discussed in the following sections.

B.1.3.1 Gas Prices - LNG Scenario. Currently, Cook Inlet gas is being sold in Japan as LNG. The possibility that North Slope gas may be sold in Asian markets is well known. For this evaluation, it is assumed that the LNG produced will be sold to Japan and other Pacific Rim countries. LNG prices in the Asian market are tied to the average price of a "basket" of imported liquid hydrocarbons. Because gas is a cleaner burning fuel, the LNG price at various times has received a bonus over crude oil. It is assumed that the bonus is 10% greater than the world oil price. The world oil price forecasts in **Table B.1** are assumed to be representative of the "basket-of crude" price forecasts in Asia. Thus, the North Slope gas price for the LNG scenario is determined as follows:

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

LNG sale price in Asia is calculated as follows:

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

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

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

With changing world oil prices LNG prices determined by this method could reach high or low levels that would be inconsistent with existing LNG price levels. To offset this effect, the above calculation is modified for oil prices below \$14/BBL (1/1/95\$) and above \$25/BBL (1/1/95\$). Yearly oil price above \$25/BBL are modified as follows:

$$Modified\ oil\ price\ =\ \$25/BBL\ +\ \frac{world\ oil\ price/BBL\ -\ \$25/BBL}{3}$$

Yearly oil prices below \$14/BBL (1/1/95\$) are modified as follows:

$$Modified\ oil\ price\ =\ \$14/BBL\ +\ \frac{world\ oil\ price/BBL\ -\ \$14/BBL}{3}$$

An example of the resulting Asian LNG prices for changes in world oil price are shown in **Figure B.7.**

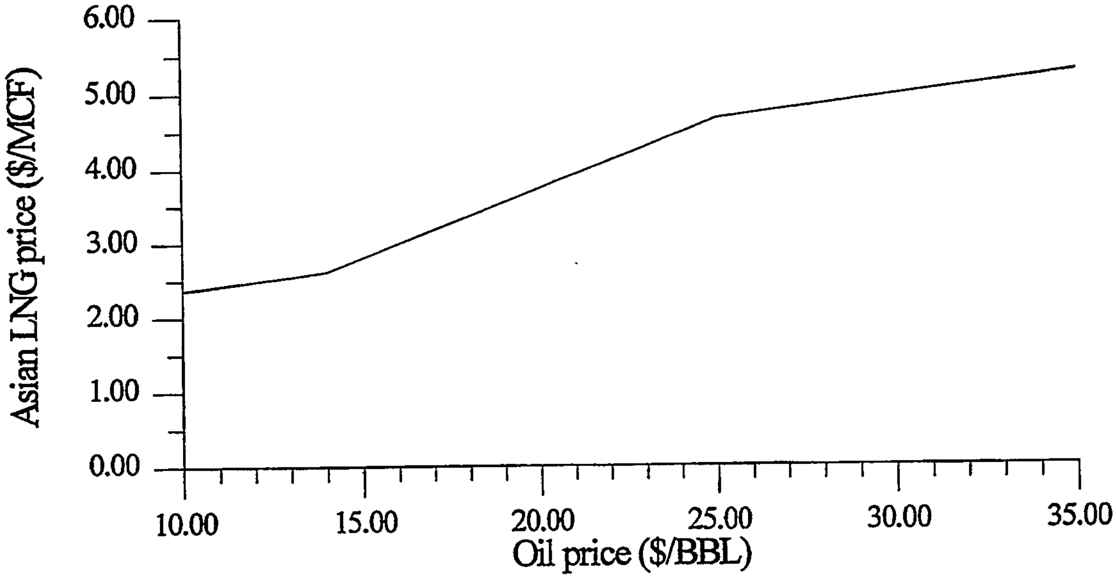

Figure B.7 LNG Prices showing high and low price restrictions (1/1/95$).

To determine the price a North Slope producer would receive for gas sold, a producer's gas net-back fraction is applied to the Asian LNG price as determined above. Possible gas product net back fractions, as percentages, could vary depending on many factors. North Slope gas prices (1/1/95 $/MCF) shown in **Table B.5** are determined using the above calculation, oil prices in **Table B.2**, and net-back factors between 5 and 25% to illustrate the effects of varying gas product net back fractions.

Table B.5. North Slope gas sales prices for LNG project ($/MCF, 1/1/95$).

Oil Price	**2005 Asian LNG prices - $/MCF**	**2005 Gas prices at various net-back factors - $/MCF**				
		5%	**10%**	**15%**	**20%**	**25%**
1995 Flat oil price	3.86	0.19	0.39	0.58	0.77	0.97
AEO95 Low	3.00	0.15	0.30	0.45	0.60	0.95
AEO95 Reference	4.76	0.24	0.48	0.71	0.95	1.19
AEO95 High	5.44	0.27	0.54	0.82	1.09	1.36

Gas prices, using 2005 oil prices, are shown as examples only in **Table B.5**. A producers net back gas price that gives the TAGS project owners a 10% return on investment is used in the base case.

B.1.3.2 Gas Prices - GTL Scenario. The gas prices for a GTL scenario (the prices received by the unit owners and the gas cost to the plant owners) are estimated as follows:

$$North\ Slope\ gas\ price\ =\ \frac{world\ oil\ price\ +\ liquids\ premium}{BTU\ conversion\ for\ GTL} \times\ producer\ net\ back;$$

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

The BTU conversion factor for the GTL scenario is less than for the LNG scenario because different liquids are being compared (ADNR, 1995c, p 60). For the LNG scenario, the BTU conversion is for crude oil imported into Japan, while in the GTL scenario the BTU conversion is for the distillate range GTL product. A gas product net back that gives the GTL plant owners a 10% return on their investment is used in the base case. Example gas prices are shown in **Table B.6**. These prices are slightly higher than those shown in **Table B.5** because of the higher value assumed for the converted hydrocarbon liquids. Actual gas prices will be determined by economic conditions at the time of sale.

Table B.6. North Slope gas prices for GTL project ($/MCF, 1/1/95$).

Oil Price in 2005		2005 Gas prices at various net-back factors ($/MCF)				
		5%	10%	15%	20%	25%
1995 Flat oil price	18.00	0.20	0.40	0.60	0.80	1.00
AEO95 Low	14.72	0.17	0.34	0.51	0.69	0.86
AEO95 Reference	22.21	0.24	0.47	0.71	0.95	1.18
AEO95 High	25.36	0.26	0.53	0.79	1.06	1.32

B.1.3.3 Wellhead Gas Price. The following definitions are used to calculate wellhead gas price.

- Wellhead Gas Price = North Slope Gas Price less field pipeline tariffs.

B.1.4 Inflation Adjustment

Historical information on the Gross Domestic Product Index was obtained from the U. S. Department of Commerce, Federal Reserve Bank of St. Louis' Federal Reserve Economic Database (FRED) (http://www.stls.org/fred/data/gdp, April 1996). A future inflation adjustment of 2.2% is used through the entire evaluation period. This is based on information in the Annual Energy Outlook 1995, with Projections to 2010, (EIA 1995). The historic and future inflation adjustment information is shown in **Figure B.8.**

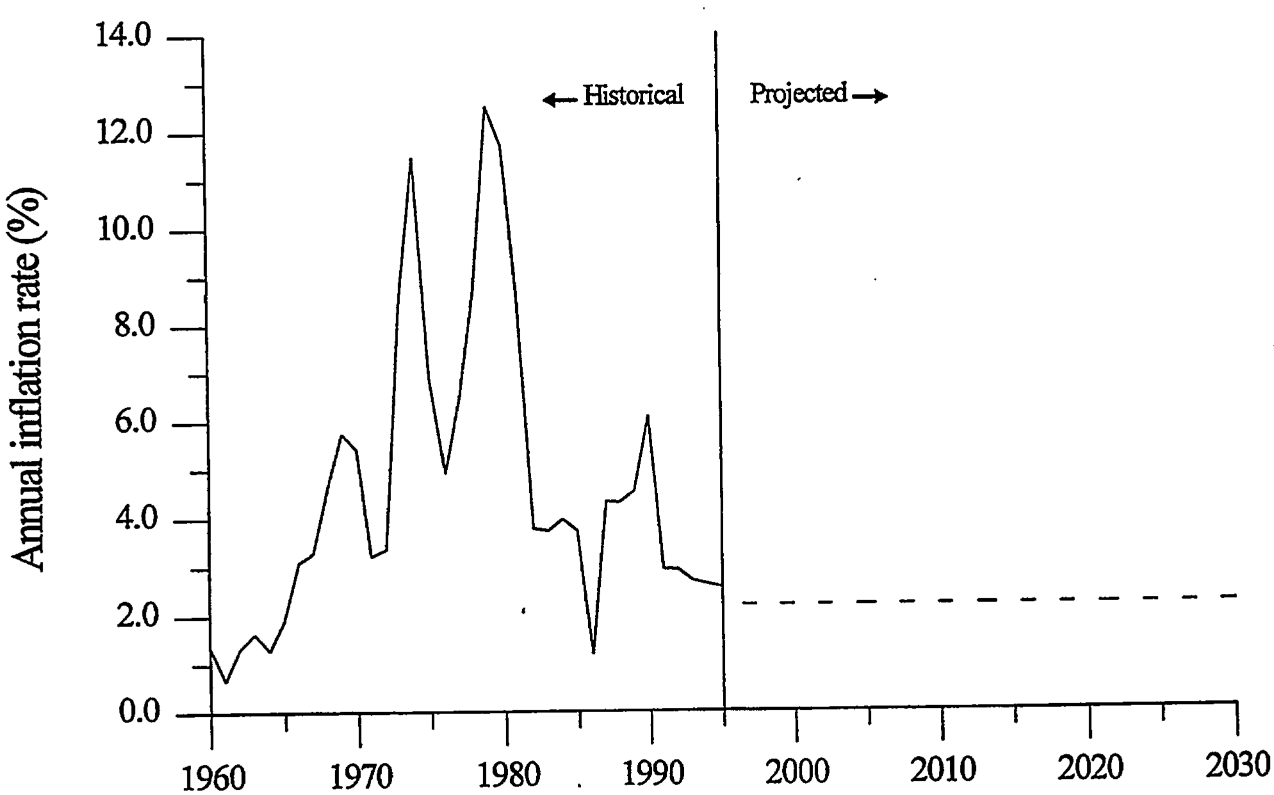

Figure B.8. Historical annual percent change in the Gross Domestic Product price deflator.

B.1.5 Operating Costs

Operating costs include, but are not limited to, the operating and maintenance costs of (a) facilities, (b) wells (including workovers), (c) roads, (d) pipelines, (f) solvent, (g) fuel, (h) overhead costs, (I) shared facilities charges (infrastructure use, processed water, and compression costs), (j) estimated purchase cost of miscible injectant (MI). Operating costs also include the non-capital costs of environmental and regulatory compliance, (k) GTL plant gas feed stream purchase costs, (l) GTL operating and maintenance costs (O & M), (m) LNG gas feed stream purchase costs, and (n) LNG project operating costs.

B.1.5.1 Oil Operating Costs. Operating costs are based on publicly available data, engineering judgment and experience for the existing oil operations. Generally, operating costs are determined by using cost per barrel of total fluid. Annual total fluid volumes are estimated using a water cut versus percent recovery data (**Appendix B.1.5.1.1**).

When a project is utilizing facilities of another project (shared facilities), that project's operating costs are reduced, and are replaced by the facility sharing fees paid to the processing facility. The operating cost for the processing facility is incrementally increased as a result of the increased volume of fluids processed.

B.1.5.1.1 Water-cut Data--Forecasts of operating costs are prepared, for some of the projects in this study, using a relationship between percent water cut and percent of ultimate recovery. The 1991 DOE publication (1991) developed this relationship for PBU and KRU using historical data with future data estimated on industry experience and from reservoir performance model results for the Milne Point Kuparuk and Endicott reservoirs. The Endicott model results are used directly in the Endicott evaluation. The MPU model water cut versus percent cumulative recovery relationship has been modified slightly for use in determining future total fluid production for the Milne Point Kuparuk, the Schrader Bluff, and the Northwest Milne Point area reservoirs. The KRU water-cut relationship was revised in the previous DOE Publication (1993). Review of recent KRU production data shows further revision of that relationship is not justified at this time. After review of the recent production data from PBU, that relationship is adopted without revision. These four current water-cut relationships are shown graphically in **Figure A.2**, **Figure A.5**, **Figure A.8**, and **Figure A.10**. The 1993 DOE publication (1993) developed a water-cut relationship for LPA, and is used in this evaluation without revision.

B.1.5.1.2 Facilities Sharing Fee--The determination of fees for the use of shared facilities is based on published information where available. For projects where no information is available on sharing fees, the determination of these fees is assumed to be similar to the method used to determine pipeline tariffs. Therefore, the tariff formula in **Appendix B.1.1.1.4** is adapted for these calculations as follows:

$$\text{Facilities sharing fee} = \frac{\text{Facilities cost savings (1/1/95\$)}}{\text{Estimated volume of total fluid processed for sharing project}} \times 3.35$$

Facilities sharing fee = \$/BBL (1/1/95\$) of converted hydrocarbon liquids.

This formula is useful for projects where the basic infrastructure in already in place and may not provide good estimates for new developments in areas without existing facilities.

B.1.5.2 Gas Operating Costs. In PBU, operating costs are incurred in three phases of field operation. These are: (1) oil-only sales, (2) oil and gas sales, and (3) gas-only sales. Engineering judgment is used to determine the transition shares between oil and gas, of total operating costs and finally the level of gas only operating costs. This is discussed in detail in **Appendix A.2.2.1.5.**

There are no published estimates of operating costs for PTU. An empirical method is used to estimate total PTU operating costs **(Appendix B.1.5.5)**.

B.1.5.3 GTL Plant Total Operating Cost. A Department of Energy study entitled "Economic Evaluation and Market Analyses for Natural Gas Utilization," (DOE 1995) included operating and maintenance (O&M) cost estimates for various processes that can convert natural gas to several hydrocarbon materials. An O&M cost of about \$7.60 (1/1/95\$) is shown for a plant design capacity of 58,000 barrels per day of converted liquids (gasoline/diesel range). This operating cost is used as a guide for these analyses. Because the ANS projects will require larger units to meet the forecasted rates, an 21% reduction in O&M costs is assumed to be possible as a result of increased capacity, giving a GTL plant O&M cost of \$6.00/BBL (1/1/95\$) of converted hydrocarbon liquids for use in the ANS evaluation.

The cost of plant feed is the price paid to the gas seller and is a part of the plant operating cost. Gas used for fuel and for heat or power generation is included in the overall conversion efficiency used in the economic evaluation. The total plant operating cost includes the cost of gas purchased from the producers in addition to the \$6.00/BBL .

B.1.5.4 TAGS Project Total Operating Costs. Direct operating costs are not available for the entire project nor for the separate segments of the TAGS project (i.e., plants, pipeline, and ships). As noted in **Section 5**, Tags economics are determined on a project total basis, therefore, operating are estimated using the empirical method discussed in **Appendix B.1.5.5**, using a 5% factor.

LNG production, LNG tanker transportation, and pipeline transportation costs are available for comparison with the empirically derived operating costs (Hydrocarbon Processing, 1987). Those costs included taxes, debt retirement, interest, fuel and direct operating costs, however, they show the empirically derived costs to be reasonable on a project total basis.

B.1.5.5 Empirical Operating Cost Method. When there are no published estimates of operating costs available, an empirical method is used. For large projects, such as offshore U.S. and Europe, industry uses the cumulative inflated investment and a certain percentage factor to estimate annual operating costs. This factor varies, but most commonly is between 5% and 7%. After all investments are completed, the operating cost for the final year of investment, is inflated annually thereafter. The operating cost may be lowered in later years to account for reduced operations.

B.1.6 GTL Plant Efficiency.

Of the total gas purchases by the plant, only a portion is converted to liquid hydrocarbon. The remainder is used for plant fuel and generation of electricity or is converted by the process to other by-products. The liquids conversion process efficiency can range from about 80 to 88% and the overall product efficiency can range from about 62 to 69% (SNC, 1985), where total product efficiency is [(total feed) − (fuel usage) − (by-product volume)] ÷ [(total feed)]. It is assumed that 25% of the plant feed will be used for fuel and that 80% of the remaining inlet stream will be converted to liquid hydrocarbons. The remaining 20% will be converted to by-products with any combustible materials supplementing the fuel stream. This results in an overall plant efficiency of 60% and is used in the GTL evaluations.

B.1.7 Investments

Future investments are based on available public information for each project. Other investment estimates are discussed in the following sections. These estimated investments are also included in each project description.

B.1.7.1 Field Development. Field development costs are separated between facilities investments and the cost to drill development wells.

B.1.7.1.1 Facilities Costs--There are other sources of data for estimating facility investments (NPC, 1984; MMS, 1985). However, in addition to some published data, a method was developed in the 1991 DOE pulublication (1991) that was based on data from developed North Slope projects. Data were tabulated on a a project basis that included historical investment data and estimates of future investments. The future invivestments were based on public information. Investments for individual projects were related to the peakak oil rate of the project and resulted in investment per barrel of peak production rate.

A facility cost factor wasis determined for PBU, Kuparuk River Unit (KRU), Milne Point Unit (MPU), Duck Island Unit (Endicocott), and Lisburne Participating Area (LPA). The PBU facilities cost factor was excluded when the avererage factor was determined because PBU was responsible for setting up the core infrastructure and, in additition, the other four projects benefitted from technology improvements, joint use of facilities, reduced coststs due to design modification, and use of in-place infrastructure. The average of the remaining facility coost factors is $16,210/BBL of peak rate (1/1/95$). This factor may be increased by 10% to 20% for prorojects with development difficulties or projects located outside the PBU/KRU area.

B.1.7.1.2 Drilling g Costs--Drilling costs are based on public information when available. Such drilling data are assumed to bee applicable in different projects for similar development well schemes (i.e.,. extended reach wells, simililar depths, same formation, etc.). When no public information is available, empirical methods can bee used to estimate drilling costs (MMS, 1985; NPC, 1981).

B.1.7.2 GTL Plant. Estimatated costs to construct a gas conversion facility on the North Slope are presented in a draft DOE report t titled "Economic Evaluation and Market Analysis for Natural Gas Utilization (DOE, 1995). Two esstimates are provided that include the placement of an operating infrastructure. PBU, which is assummed to be the site of a central ANS GTL plant, already has an in-place infrastructure. The installed investmeients were for a plant capacity of 14,500 barrels per day (BPD). A plant of that capacity is much smaller thaian required for this study. The study (DOE, 1995) also showed that quadrupling the plant size resulted inin an estimated savings of about 33%. To estimate the cost of a GTL plant to process ANS gas, it is assumeed that: (1) no infrastructure investments are required at PBU, and (2) a savings is realized when the plant s size is enlarged. It is assumed the larger plant size of 58,000 BPD discussed in the report (DOE, 1995) caan be modified to a size suitable for future plant feed volumes as they are developed. Depending on future tetechnology this could be six units of about 50,000 BPD each for PBU and PTU or some larger version, such a as 150,000 to 200,000 BPD per unit. The report shows an additional savings is possible of between 20 and 3 30% by building successive plants patterned on a first-of-kind process plant. For base case economics, it is assumed that for multiple plant constructions, a savings of 25% will be possible. Estimation of the investment required for a gas-to-liquid plant on the ANS varies between $27,700 and $39,900 (1/1/95$) per daily barrel of liquids (DBL) produced and is determined as illustrated in **Table B.7**.

Table B.7. Investment for a GTL plant on the Alaska North Slope.

	Basic Unit	Enlarged Plant[a]	Multiple Plant[b]
Plant w/infrastructure - BPD	14,500	58,000	
Chem Systems ($MM, 1995$)	1802.9		
Less Infrastructure	-650.3		
Net Plant Cost	1152.6	3089.0	2316.8
Cost/DBL[c] ($M, 1995$)	79.5	53.3	39.9
Bechtel ($MM, 1995$)	1250.6		
Less infrastructure[d]	-450.2		
Net Plant Cost	800.0	2144.0	1608.0
Cost/DBL ($M, 1995)	55.2	37.0	27.7

a. Based on estimated savings of about 33%.
b. 75% of enlarged plant.
c. Daily barrel of plant output.
d. Reduction of about 31% based on Chem Systems estimate.

Discussion with industry representatives indicates that the difference in costs to fabricate, transport, and install identical processing facilities in West Texas and on the ANS can vary from 1.0 (under most ideal conditions) to 2, depending on the design configuration. The DOE report (1995) estimates for a plant on ANS resulted in costs about 50% higher (after deducting infrastructure estimates) than a plant constructed on the Gulf Coast. At the very best a gas conversion plant on the ANS would require the use of some existing equipment to result in a factor closer to 1. However, as this is unlikely for a new plant installation investment, DOE's multiple plant investment range of between $27.7M/DBL and $39.9M/DBL is reasonable. The upper end of estimated ANS plant investment of about $40M/DBL is used for base comparative economics. Lower and higher plant costs are used in sensitivity evaluations.

GTL plant investments are based on total throughput volumes from PBU and PTU. The total investment of $11.8 B (1/1/95$) is scheduled over a 6-year period as required to process the forecasted annual gas production rates from PBU and PTU. The schedule developed is given in **Table B.8.**

Table B.8. GTL plant investment schedule (1995$).

Year	$, millions
2003[1]	358
2004	2,390
2005	3,586
2006	3,586
2007	2,032
TOTAL	11,952

1. Includes two prior year expenditures for design permits and site acquisition.

B.1.7.3 LNG Project. The most recent estimate of the 14 MMPTA TAGS project total cost (including a gas conditioning plant, a gas pipeline, an LNG plant, storage, a marine terminal, and LNG tankers) is about $14 billion (1995$) (Alaska Conservation Foundation, 1994). Although discussions have indicated some reduction in investments may be possible, the $14 billion per 14 MMPTA is used as a basis to scale up to the 17 MMPTA project evaluated in this work.

B.1.7.3.1 Conditioning Plant Cost. The cost of the North Slope conditioning plant is estimated to be $0.1 billion per MMPTA (State of Alaska, 1996). For a 17 MMPTA project the conditioning plant total cost becomes $1.7 billion.

B.1.7.3.2 Pipeline cost. The pipeline for the TAGS project can handle 14 MMPTA with three compressor stations, but can be increased to its design capacity of 25 MMPTA by the addition of 6 additional stations (Alaska Conservation Foundation, 1994). Pipeline cost (including 3 compressor stations) has been estimated to be $6.38 billion (Alaska Conservation Foundation, 1994; FERC, 1995). Increasing the capacity from 14 MMPTA to 17 MMPTA requires the addition of 2 compressor stations to the pipeline. Each compressor stations costs about $0.100 billion.[a] Adding two stations to the pipeline increases the total

a. Yukon Pacific Corporation, personal communication, May 1996.

cost for 17 MMPTA to $6.59 billion.

B.1.7.3.3 LNG Plant Cost. Construction costs for a 14 MMTPA LNG plant are estimated to be $2.3 billion in 1991$ (FERC, 1995). Escalating that cost to 1995$ and accounting for increasing the plant size to 17 MMPTA, the total cost for the LNG plant and facilities becomes $3.04 billion

B.1.7.3.4 LNG Tanker Cost. To transport 14 MMTPA from Valdez to ports in the Far East, 15 LNG tankers would be required at a cost of $3.35 billion in 1991$ (Alaska Conservation Foundation, 1994). Escalating that cost to 1995$ and accounting for 4 more LNG tankers to transport the 17 MMPTA of LNG, the total cost for LNG tankers becomes $4.69 billion in 1995$.

B.1.7.3.5 Summary. The indicated breakdown between the different segments of the project is given in **Table B.9.**

Table B.9. LNG project investment breakdown.

Segment	Cost - 1995$, billions
Conditioning plant	1.70
Pipeline	6.59
LNG plant, storage, and dock	3.04
LNG tankers (19)	4.69
Total	16.03

Published information on the project timing (FERC, 1995) and the investment breakdown in **Table B.9** are used to develop an estimated investment schedule. The assumed scheduling of the overall project with a start-up date of 2005 is given in **Table B.10.**

B.1.8 Oil Production Forecasts.

Annual production rates are determined for economic evaluation and can be used to determine ultimate project recovery estimates and future economically recoverable oil under the different price scenarios (**Appendix B.1.1**).

Table B.10. LNG project investment schedule.

Year	% of Total Investments
2000	3.8
2001	6.6
2002	15.2
2003	20.3
2004	22.9
2005	11.4
2006	11.4
2007	5.9
2008	2.5

B.1.8.1 Historical Data. When sufficient interpretable historical production data is available (such as; ADOR, 1995; AOGCC, 1995), that data is used to predict future project producing rates. Those projections are modified as needed based on published project plans.

B.1.8.2 Oil Production Forecast Parameters. Before well test and/or production are available for use in estimating total project producing rates, empirical methods are used. Such methods are presented in a U.S. Department of the Interior publication by Young (1985) and NPC (1981). After the total recoverable reserve volume is determined, the annual peak production rate is set as a percentage of the ultimate recovery. The producing rates for the early years are increased until the peak rate is reached. The peak rate is held constant for a number of years, then the peak production rate is declined. The decline rate is usually between 12% and 15% per year. For smaller projects the life is about 15 years, but the life of larger projects may exceed 25 years. These factors are used as guidelines to prepare production forecasts. Modifications have been made using the engineering judgment and experience of the authors. These factors are listed in **Table B.11.**

B.1.9 Gas and GTL Liquids Sales Forecasts

The annual gas sales volumes from PBU and PTU are developed in **Table A.5** and **Table A.31.** These gas sales volumes, or plant purchase volumes, are applicable to both LNG and GTL projects.

Table B.11. Production forecast parameters.

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

Under the GTL sceanrio, these gas volumes are converted to hydrocarbon liquids by applying the overall plant efficiency of 60% (discussed in **Section 5.1.6**) to the BTU conversion factor of 5.00 MCF/BBL (discussed in **Section 5.1.3.2**). The converted liquid volumes are also shown in **Table B.12.**

B.1.10 Royalty.

Royalty is calculated by multiplying the royalty rate for a specific field by the gross wellhead revenue. The royalty rate ranges from 12.5% to about 20.0%, depending on the field. The State royalty rate, if unknown, is assumed to be 12.5%. In certain projects, royalty oil processing fees are paid by the State to the producers for treating the State's royalty oil to meet pipeline specifications.

B.1.10.1 Royalty Oil Processing Fee. Royalty oil processing fee is the price per barrel that the State is charged by the producer for processing the State's royalty oil. This charge was negotiated between the State and the producers and does not apply to all North Slope projects. The processing fee is deducted from the State's royalty. The established field oil processing fees are given in **Table B.13.**

Current information shows that certain of the oil pools in the evaluation are not allowed to deduct the royalty processing fee. These are: Milne Point Kuparuk, Milne Point Schrader Bluff, Northwest Milne Point, and Point Thomson.

Table B.12. Annual gas sales and converted liquids volumes - GTL Project.

Year	Gas Sales (BCFD)			Converted Liquid Sales (MBD)
	PBU	PTU	Total	
2005	0.41	0	0.41	49
2006	0.82	0	0.82	98
2007	1.23	0	1.23	148
2008	1.64	0.44	2.08	250
2009	2.05	0.44	2.49	299
2010	2.05	0.44	2.49	299
2011	2.05	0.44	2.49	299
2012	2.05	0.44	2.49	299
2013	2.05	0.44	2.49	299
2014	2.05	0.44	2.49	299
2015	2.05	0.44	2.49	299
2016	2.05	0.44	2.49	299
2017	2.05	0.44	2.49	299
2018	2.05	0.44	2.49	299
2019	2.05	0.44	2.49	299
2020	2.05	0.44	2.49	299
2021	2.05	0.44	2.49	299
2022	2.05	0.44	2.49	299
2023	2.05	0.44	2.49	299
2024	2.05	0.44	2.49	299
2025	2.05	0.44	2.49	299
2026	2.05	0.44	2.49	299
2027	2.05	0.35	2.40	288
2028	2.05	0.00	2.05	246
2029	2.05	0.00	2.05	246
2030	2.05	0.00	2.05	246
2031	2.05	0.00	2.05	246
2032	2.05	0.00	2.05	246
2033	2.05	0.00	2.05	246
2034	2.05	0.00	2.05	246
2035	2.05	0.00	2.05	246
2036	0.28	0.00	0.28	34
Total	21.8 TCF	3.18 TCF	24.98 TCF	3.0 Billion BBLS

Table B.13. Royalty oil processing fees.

Field	$/BBL (1/1/95$)
Prudhoe Bay	0.79
Kuparuk	0.37
Endicott	0.44
Lisburne	0.79
Niakuk	0.79
Point McIntyre	0.79

B.1.11 Discount Rate.

The base year used for constant dollar analysis is 1/1/95. The discount rates or hurdle rates used by individual companies are not known and will vary from company to company and over time based on their estimates of oil and gas prices, project risks, and competing investment options. The cumulative discounted total cash flow provides a reasonable measure for comparing future potential projects. For the purposes of this study, a nominal discount rate of 10% is used in all economic evaluations. However, in practice, operators may require a higher discount rate for projects with greater risk, such as Point Thomson Unit.