2. NORTH SLOPE OIL AND GAS RESOURCE ASSESSMENT

This section provides a review of ANS oil and gas resources and an assessment of the fields and quantities of those resources. This section also contains a review of the historical oil and gas production on the North Slope, the factors that will influence future production of oil and gas, a summary of the production forecasts described in detail in **Appendix A**, and the anticipated impact of major gas sales on ANS oil and gas production.

2.1 Background

The remaining gas and oil resources in the developed and known undeveloped fields on Alaska's North Slope at the beginning of 1995 totaled over 38 TCF of recoverable gas and over 6 billion barrels of recoverable oil (crude, condensate, and NGLs). Undiscovered, technically recoverable, conventional natural gas resources in northern Alaska are estimated by the U.S. Geological Survey to be between 23 TCF (95% probability) and 124 TCF (5% probability), with a mean value of 64 TCF (USGS, 1995). **Figure 2.1** shows the known oil and gas accumulations and selected dry holes and suspended wells across the North Slope. **Figure 2.2** is a North Slope map showing the locations of producing pool and unit boundaries and undeveloped discoveries and accumulations. It is unlikely that any of the other North Slope fields would have been developed without facility cost-sharing made possible by the development of the Prudhoe Bay field infrastructure and the existence of TAPS. A more detailed discussion of the history of North Slope oil and gas exploration is presented in Section 2 of a 1991 DOE report entitled "Alaska Oil and Gas - Energy Wealth or Vanishing Opportunity" (DOE, 1991). The fields and pools shown in **Figure 2.2** are described in **Appendix A**.

All of the major producing ANS fields contain both oil and gas in common reservoirs and gas is being produced along with the oil as a part of the oil production process. All of the produced gas, except that used for production operations, NGL components sold with crude oil production, and local sales, has been reinjected back into the reservoirs to maintain reservoir pressure and for improved oil recovery projects. ANS gas that is injected back into the reservoirs will be available for sale when a gas marketing system is developed.

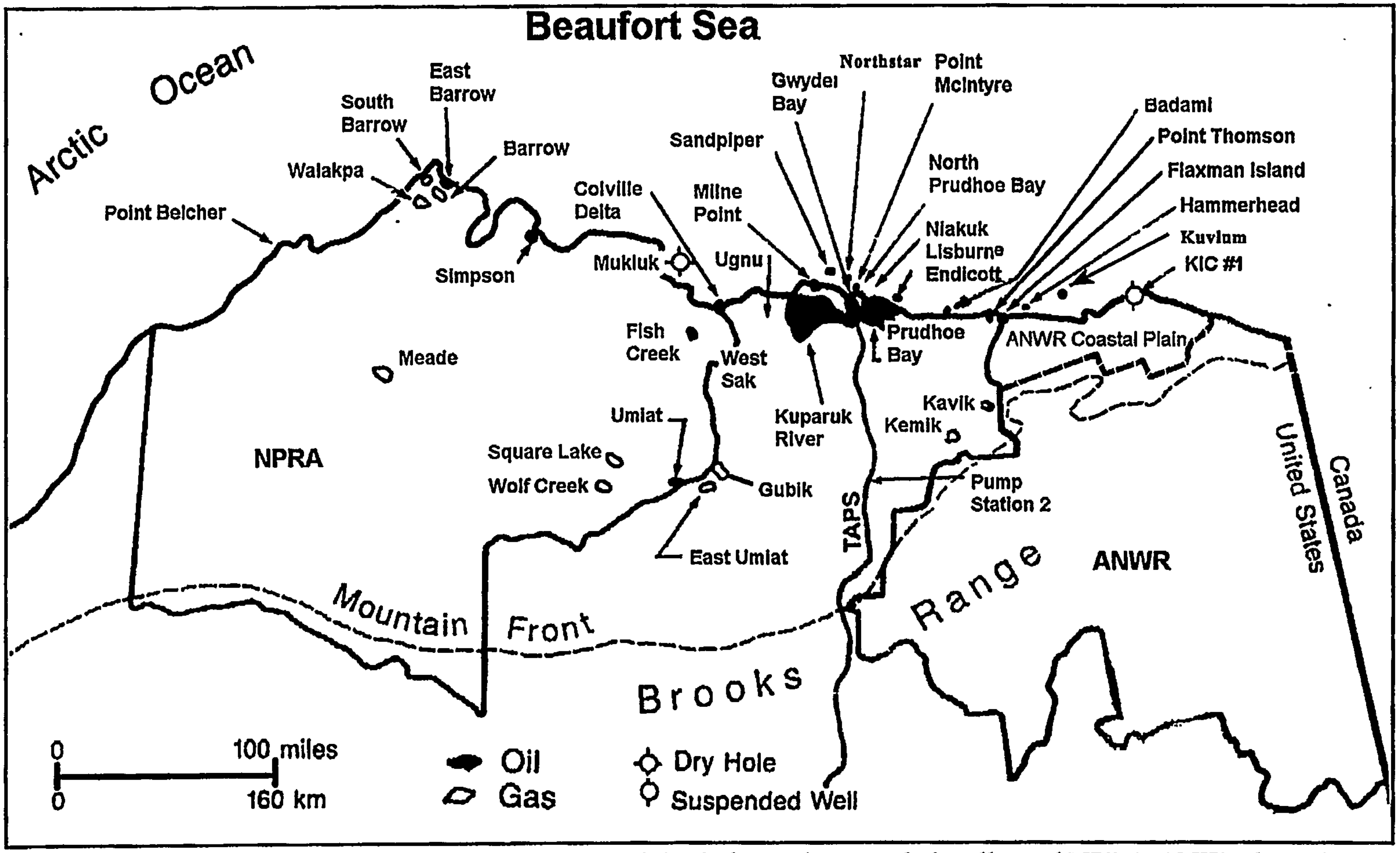

Figure 2.1. Known oil and gas accumulations, selected dry holes and suspended wells, and NPRA-ANWR boundaries, North Slope Alaska (DOE, 1991, ADNR, 1991a).

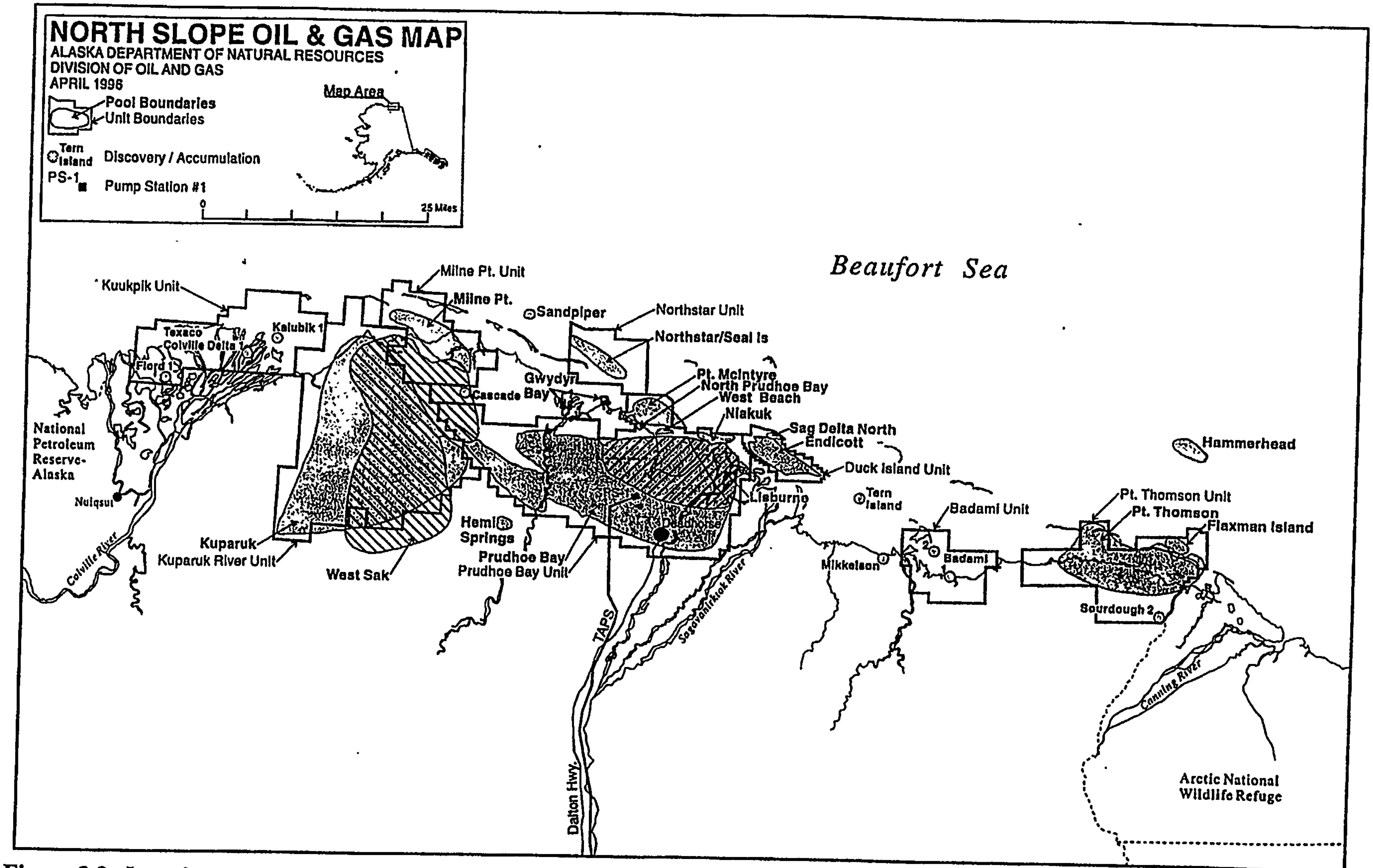

Figure 2.2. Location of North Slope oil and gas accumulations and fields (courtesy of Alaska Department of Natural Resources, Division of Oil and Gas).

2.1.1 Prudhoe Bay Unit

The Prudhoe Bay field, discovered in 1968, is the largest oil field in North America and is located adjacent to the Beaufort Sea coast line about 200 miles east of Point Barrow, Alaska (see **Figure 2.1**). The field was unitized as the Prudhoe Bay Unit (PBU) in 1976 and production started in 1977. PBU production peaked at 1,600 MBPD during 1987 and had declined to 1,057 MBPD by December 1994. The decline has continued into 1996.

The extensive efforts to increase oil recovery beyond the early estimates throughout the life of the PBU have been highly successful. These efforts include gas reinjection for pressure maintenance, recycled gas to strip retrograde condensate and residual oil above the gas/oil contact (compositional/vaporization incremental production), miscible injectant (MI) in a water-alternating-gas (WAG) enhanced oil recovery process, waterflooding, and the drilling of infill and horizontal wells. It is anticipated that such efforts will continue but are not expected to significantly alter the present rate of decline in production.

PBU facilities have a current gas handling capacity of about 7.5 BCFPD. Most of the gas is used in PBU operations with some being sold in the form of NGLs and minor amounts sold for non-unit consumption on the North Slope. The gas handling facilities are depicted schematically in **Figure 2.3.**

The successful recovery projects and processes have increased the current total estimated ultimate recovery to 13 BBO, as compared to the estimate at startup in 1977 of less than 10 BBO ultimate recovery (AOGCC, 1991). The currently estimated reserve components compared to 1977 are shown in **Figure 2.4.**

2.1.2 Point Thomson Unit

The other known major gas field on the ANS is the Point Thomson field (see **Figure 2.2**). Point Thomson, discovered in 1977, is a gas condensate field about 50 miles east of TAPS PS No. 1. The Point Thomson Unit (PTU) was formed in 1977 and currently contains about 83,000 acres. PTU is listed in the by the Alaska Department of Natural Resources, Division of Oil and Gas (ADNR, 1996) as containing 200 million barrels (MMBBLS) of recoverable oil and condensate and 3 TCF of recoverable gas (earlier estimates were 300 MMBBLS condensate and 5 TCF gas) (DOE, 1993a). PTU currently covers a deep, overpressured reservoir that is located mostly offshore (see **Figure 2.2**). Development of PTU is hindered by the lack of existing infrastructure and facilities that benefit fields in the vicinity of PBU. A PTU

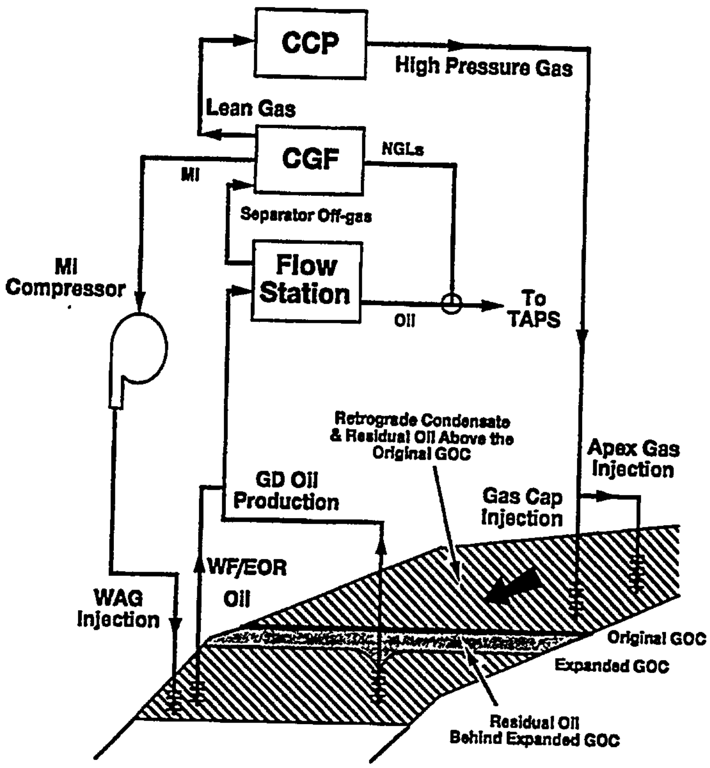

Figure 2.3. PBU gas handling and reservoir mechanism schematic (AOGCC, 1992). (GD - Gravity drainage area; WF/EOR - Waterflood/Enhanced Oil Recovery; CGF - Central Gas Facility; CCP - Central Compression Plant, MI - miscible injectant, GOC - gas/oil contact).

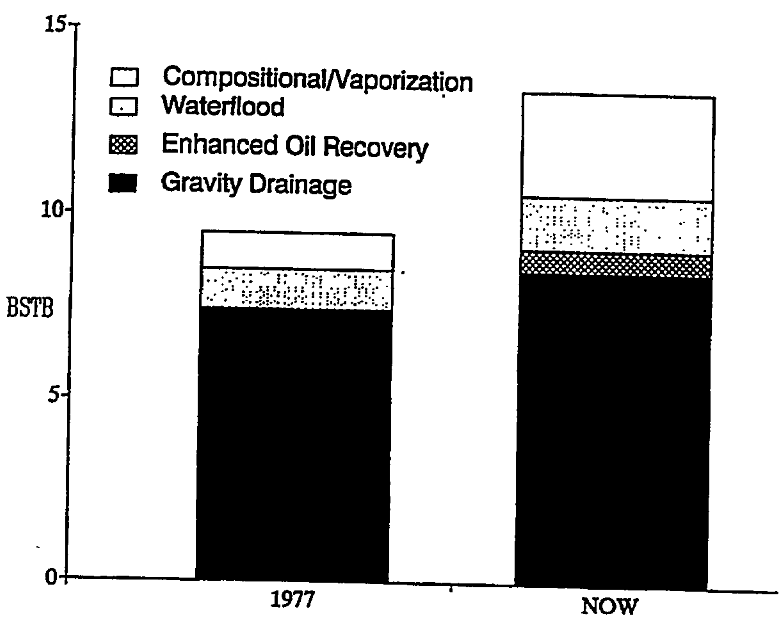

Figure 2.4. PBU currently estimated reserve components compared to 1977 (AOGCC, 1992).

development project must support the construction of field delivery lines to the Prudhoe Bay field area that will encounter five major river crossings as they cross the Arctic Coastal Plain. The impact of these conditions will not be determined until environmental assessments are conducted.

2.1.3. Other Fields

There are a number of non-producing gas fields, other than the Point Thomson field, scattered over the North Slope in the vicinity of TAPS (see **Figure 2.1** and **Table 2.1** and Oil & Gas J., 1995c). These fields were discovered in the course of oil exploration but were never sufficiently explored to establish the size of the accumulations. These gas fields could collectively contain as much as 1 TCF of recoverable gas.

Because the area is remote from existing gas pipeline systems and historically the economics of ANS gas sales projects have been poor, there has been virtually no exploration specifically for gas on the North Slope. Several small gas fields (Walakpa - 28 BCF, East Barrow - 6 BCF, and South Barrow - 4 BCF) located near Barrow, Alaska have been developed to supply local area natural gas market needs (ADNR, 1995c, p. 4). Other ANS gas discoveries, such as Square Lake - 58 BCF, Wolf Creek - unknown, East Umiat - 4 BCF, Gubik - 600 BCF, Kavik - unknown, and Kemik - unknown, have been temporarily abandoned without additional delineation (DOE, 1991, p. 2-19). Until an acceptable ANS gas market is established, further ANS gas field delineation and future ANS gas exploration cannot be economically justified.

2.2 Oil and Gas Production

This review is limited to currently producing fields and the undeveloped PTU. By the end of 1994, ANS fields had produced 10.5 billion barrels of oil (BBO), 84% from PBU, 11% from Kuparuk River Unit (KRU), and 4% from the combined other pools (ADNR, 1995c). PBU is currently expected to ultimately produce 13 BBO. The ANS historical and projected production for currently producing fields is shown in **Figure 1.2 in Section 1**. The projected production in **Figure 1.2** is a composite of individual forecasts developed in **Appendix A** in this study based on publicly available information obtained from North Slope producers, the Alaska Department of Natural Resources (Oil and Gas Conservation Commission and Division of Oil and Gas), and previous studies performed for the DOE at the INEL (DOE, 1991; DOE, 1993a).

Table 2.1. North Slope undeveloped oil and gas accumulations as of January 1, 1992 (after Bird, 1990).

Location	Year	Amount
Umiat	1946	70 MMBO
Fish Creek	1949	Oil
Simpson	1950	12 MMBO
Meade	1950	20 BCF
Wolf Creek	1951	Gas
Gubik	1951	600 BCF
Square Lake	1952	58 BCF
E. Umiat	1963	4 BCF
Kavik	1969	Gas
West Sak	1969	20 BBO[a]
Ugnu	1969	15 BBO[a]
Gwydyr Bay	1969	30-60 MMBO
No. Prudhoe	1970	75 (?) MMBO
Kemik	1972	Gas
Flaxman Island	1975	Oil
Point Thomson	1977	300 MMBO,[b] 5000 BCF
Walakpa	1980	Gas
Niakuk	1981	58 MMBO, 30 BCF
Tern Island	1982	Oil
Seal Island	1984	150 MMBO
Hammerhead	1985	Oil
Colville Delta	1985	Oil
Sandpiper	1986	Oil and Gas
Barrow	1988	Gas
Point McIntyre	1988	300 MMBO
Badami	1990	Oil

a. Heavy oil (Mahmood, 1995)
b. Condensate

2.2.1 Reserves Estimates

Original oil in place (OOIP) for PBU is estimated at about 23 BBO and the original gas in place (OGIP) is estimated at about 46 TCF. The Point Thomson field is estimated to contain about 400 million barrels of oil (MMBO), principally condensate, and the original gas in place is estimated at about 5 TCF (**Appendix A.3.1**). In addition to PBU, there may be some gas from the other currently producing oil fields that will be available for sale. Although it is estimated that the KRU contains 0.68 TCF of recoverable gas, it is expected that KRU will need all of that gas for field use and that there will be no net gas available for major gas sales.

In addition to PBU and KRU, there are several smaller fields currently producing oil and gas. These other fields are Point McIntyre, Endicott, Lisburne, Milne Point, Niakuk/Alapah, North Prudhoe Bay State, and West Beach. Of these fields only Point McIntyre, Endicott, and Lisburne may have gas reserves in excess of lease operation requirements. The total volume of potential sales gas could be about 1 TCF.

A summary of oil production and remaining potentially recoverable oil reserves (as of 1/1/95) without major gas sales is presented in **Table 2.2**. The oil reserves forecasts are developed by continuing production to the economic limit for each field without being impacted by a shutdown of TAPS. **Table 2.3** is a summary of estimated OGIP, recoverable natural gas, net gas production (i.e., produced gas, including CO_2, that has not been reinjected), and net *hydrocarbon* gas available for major gas sales (i.e., after CO_2 removal, lease usage, local sales, and shrinkage) -- referred to hereafter as potential gas sales volumes. These future oil and gas reserves estimates are discussed in detail in **Appendix A**. The method of estimating the potential gas sales volumes from PBU and PTU are depicted on **Figures 2.5** and **2.6**, respectively.

Table 2.2. Potential future production (without major gas sales) for North Slope oil fields.

Fields	Original Oil In Place[a] (BBO)	Producible Oil[a] (BBO)	Production to 1995[a] (BBO)	Potential Future Production[a] (BBO)
Prudhoe Bay	23.0	13.0	8.8	4.2
Kuparuk	4.0	2.3	1.2	1.1
Pt. Thompson	0.4	0.2	0.0	0.2
Other Fields	3.3	1.3	0.5	0.8
Total	30.7	16.8	10.5	6.3

a. Oil volumes include crude oil, condensate, and NGLs.

The estimates in **Table 2.2** indicate that 63% of the potential economically producible North Slope oil has already been produced. The remaining potential North Slope oil is estimated at 6.3 BBO. In contrast, except for a small amount of local use there has been no commercial North Slope gas sales.

Table 2.3. Potential future production (available for major gas sales) for North Slope gas fields.

Fields	Original Gas in Place (TCF)	Recoverable Gas (TCF)	Net Gas Prod. to 1995 (TCF)	Potential Gas Sales Volumes[a]	
				Gas (TCF)	Eq. Oil (BBO)
Prudhoe Bay	46.0	33.6	1.9	21.8	3.8
Kuparuk	1.4	1.0	0.3	0.0	0.0
Pt. Thompson	5.3	3.7	0.0	3.2	0.5
Other Fields	3.0	2.1	0.2	1.0	0.2
Total	55.7	40.4	2.4	26.0	4.5

a. Net hydrocarbon gas available for sale after CO_2 removal, lease usage, local sales, and shrinkage.

PBU Original Gas in Place = 46.0 TCF

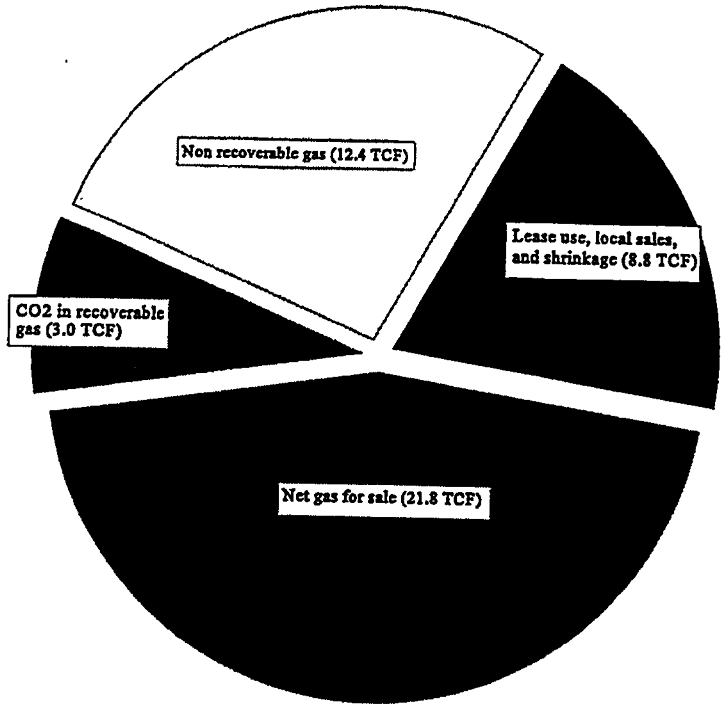

Figure 2.5. Net hydrocarbon gas available for sale from PBU.

PTU Original Gas in Place = 5.26 TCF

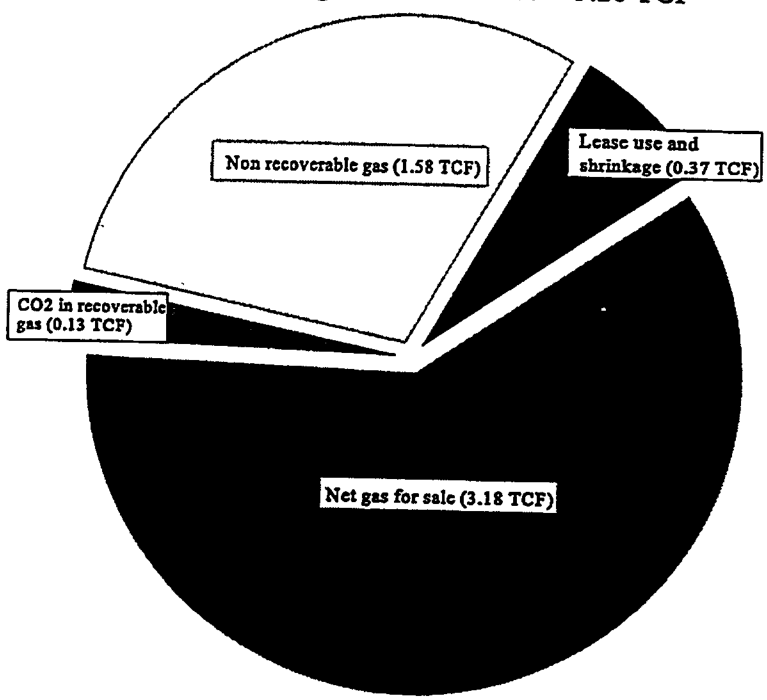

Figure 2.6. Net hydrocarbon gas available for sale from PTU.

2.2.2 Production Scenarios

Future North Slope oil and gas production will depend on a number of factors:

- Oil Production:
  - World oil prices
  - Remaining oil reserves
  - Natural gas production and disposition (major commercial sales vs. field usage)
  - Future oil reserve additions and timing for available production
  - Continued operation of TAPS.
- Gas Production:
  - World oil and gas prices
  - Remaining gas reserves
  - Need and value of gas for oil production
  - Availability of gas pipeline or GTL conversion facilities, or both
  - Future gas reserve additions.

As these factors indicate, the future production scenarios possible for the ANS will be determined by: (a) world oil and gas prices; (b) government (State of Alaska and federal) policy for exploration and production opportunities; (c) technology development for enhancing oil and gas exploration and production capabilities; and (d) development of infrastructure for marketing gas; e.g., LNG facilities or GTL conversion facilities, or both. Prices and technology development will determine the ability of industry to develop ANS heavy oil resources, to continue development of marginal fields across the North Slope, to continue exploration activities, and to develop facilities for major gas sales.

The evaluations presented in this study do not assume that major new discoveries will be made but are based on oil production from the currently developed fields coupled with major gas sales from the PBU and development and sales of gas and condensate from the currently undeveloped PTU. The two gas sales options evaluated are an LNG project and a GTL conversion project. These projects are evaluated as stand-alone projects that purchase gas from the units.

Although the scenarios and options evaluated do not cover all possibilities, they provide a basis for evaluating the requirements for GTL processes to be viable on the North Slope and allow some LNG and GTL options to be compared for their impact on current and future ANS development.

2.2.3 Production Forecasts

The sources and quantities of gas available for sale on the ANS are discussed in the following sections. Because oil production and gas production are integral with each other, oil production forecasts are developed for each ANS producing field using production, investment, and operating cost forecasts using available sources of information as described in detail in **Appendix A**. The production forecasts are first developed assuming no major gas sales, then modified, where necessary, to take into account the impact of major gas sales.

First, an oil production profile is estimated based only on oil reserves remaining at 1/1/95, assuming no major commercial sales of gas. Estimated remaining oil reserves as of 1/1/95 are shown in **Table 2.2.** The composite production forecast for the ANS producing fields without major commercial gas sales is shown in **Figure 2.7.** The production curve extends to 2026 when costs would bring about a shutdown of production. However, production could actually be stopped earlier because of minimum throughput requirements for TAPS. The estimates for the minimum throughput volume necessary to keep TAPS operating range from 200 MBPD to 400 MBPD (DOE, 1993a). If the higher level of 400 MBPD is assumed, then the pipeline and oil production would be terminated in 2009, as indicated by Point A in **Figure 2.7**, with a loss in ultimate ANS recovery of 1.2 BBO. At the lower end of the range, 200 MBPD, the pipeline and production shutdown would come in 2016 (Point B), with a corresponding loss in ultimate ANS recovery of 0.5 BBO. It is clear that it is in the best interest of industry and State and federal governments to continue the operation of TAPS as long as oil can be economically produced from any of the fields and transported in an environmentally safe manner. This could result in operation of TAPS to a level of 100 MBPD or lower, which would mean all the economically recoverable oil from PBU would be recovered.

The potential gas sales volume available for major gas sales is estimated to be 26.0 TCF **(Table 2.3)**. However, the gas production forecasts used in the economic evaluations for the two gas sales scenarios only include gas production for PBU and PTU since they are the only currently known fields with gas reserves greater than 1 TCF. The gas production forecasts for PBU and PTU total about 25 TCF **(Table 2.3)**. As described in **Appendix A.2.2.1.3** for PBU, this forecast provides for a 32-yr gas project life with a maximum

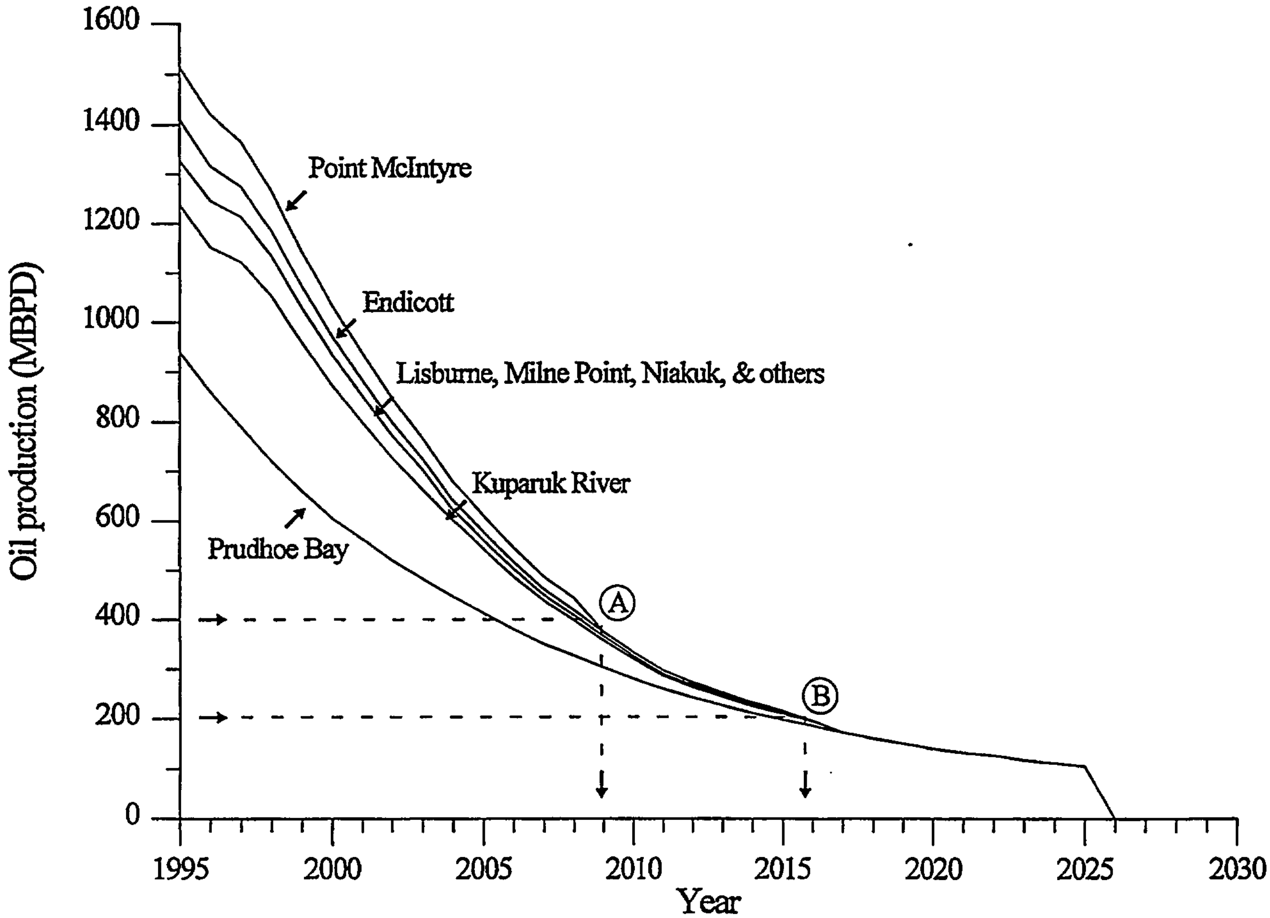

Figure 2.7. Composite North Slope producing fields production forecasts - no major gas sales.

rate of 2.05 BCFPD for a total of 21.8 TCF. It is assumed that PBU will be capable of delivering this sustained rate throughout the project life without significant falloff until the last year of production. As discussed in **Appendix A.3.1.3.4** for PTU, the PTU forecast provides for a 20-yr gas project life at a maximum rate of 0.44 BCFPD for a total of 3.18 TCF. This forecast also assumes that PTU will be capable of delivering gas at the assumed gas sales rate without a falloff until the last year of production. For both of the options for commercial sale of North Slope natural gas (LNG or GTL), gas production is assumed to begin from PBU in 2005 and from PTU in 2008. The maximum production rate of 2.49 BCFPD (2.05 BCFPD from PBU and 0.44 BCFPD from PTU) would be reached in 4 years and be maintained for about 19 years (until 2026). At that time, PTU gas sales will decrease to 0.35 BCFPD for 1 yr and then cease. The sales rate drops to 2.05 BCFPD from PBU alone and continues at this rate through 2035, as shown in **Figure 2.8** (see also **Appendix B, Table B.12**).

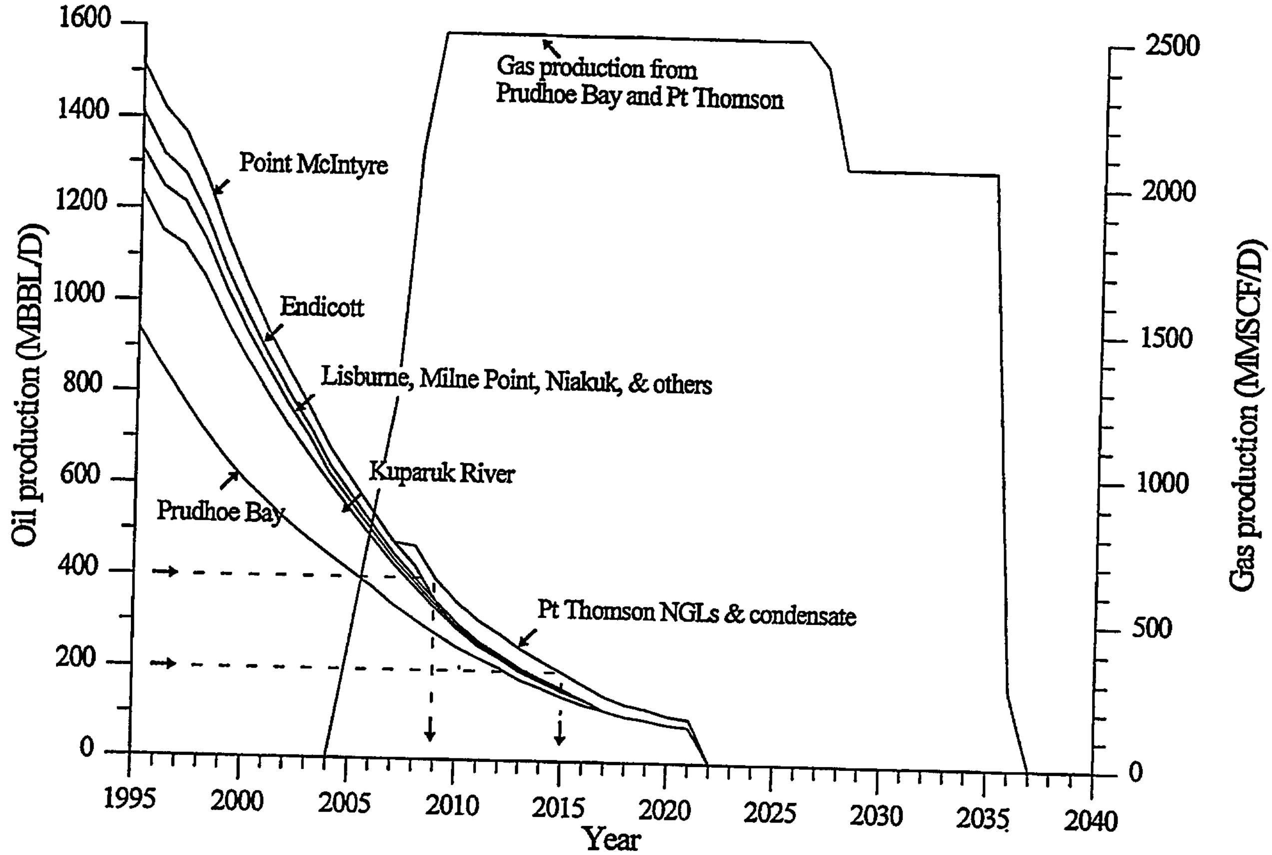

Figure 2.8. Composite North Slope oil and gas production forecast with major gas sales from PBU and PTU.

2.2.4 Impact of Major Gas Sales on ANS Activities

Major gas sales will have an impact on ANS production rates and remaining oil recovery, TAPS operations, and future ANS development activities. The extent of this impact depends on such things as the timing of gas sales, the major gas sales scenario chosen (LNG plant scenario, GTL conversion plant scenario, or both), and the volumes of gas available for sale.

2.2.4.1 Impact of Gas Sales on Oil Production. When gas production begins for commercial sales, it will significantly reduce the gas available for reinjection and continuation of the on-going improved oil recovery processes in the Prudhoe Bay field. Major gas sales from the Prudhoe Bay field could result in a reduction in the total oil recovery achieved depending on the timing and rate of gas sales. The reduction in oil recovery could vary from about 900 MMBO for major gas sales starting as early as 2000, to 400 MMBO for a 2005 start, to little or no effect for a 2015 start.[a] The PBU owners continue to evaluate the issues, impacts, and options for major gas sales and to review the options for reducing the influence on oil recovery (Petro. Information Corp., 1994a; Energy Daily, 1995; Oil Daily, 1995a).

A loss in oil recovery of 400 MMBO is assumed for the economic evaluation in **Section 5** as a result of major gas sales starting in 2005. It is assumed that the impact on oil production will begin in 2007 at low volumes and increase over time (see **Table A.1** and **Table A.4, Appendix A**). The oil production schedule during major gas sales resulted in a shortened oil recovery period of 4 years, as can be seen from **Figure 2.7** and **Figure 2.8**, and a total recovery of 12.6 BBO. The PBU gas production forecast is given in **Table A.5.** This forecast also assumes that TAPS remains operational as required to recover the 12.6 BBO. This forecast is used for both gas sales scenarios. It is possible that some or all of this initial loss in oil recovery will be made up on the tail end of the production and result in a delay in recovery rather than in a permanent loss of reserves. However, this can only happen if TAPS remains in operation and the economics allow continued operation of the field.

2.2.4.2 Impact of GTL Conversion Scenario on Oil Production. Whether the gas production goes to LNG or GTL production, it is assumed that major gas sales have the same impact on reducing PBU annual crude production as discussed above. However, the GTL conversion option would also act to increase the total cumulative ANS oil production in two ways through the additional GTL liquids for transport in TAPS.

Without the addition of any new liquid streams, the minimum TAPS throughput rates of 200 and 400 MBPD would be reached in the years 2009 to 2016. (The effects of a lower limit for TAPS such as 100 MBPD, can be estimated directly from the forecast in **Table A.4**). There would be a significant loss of recoverable oil as compared to producing the fields to their economic limits, as illustrated by the arrows shown in **Figure 2.8.** The GTL scenario produces an additional 300 MBPD of liquids that can be shipped through TAPS with the oil from 2009 through 2026 and 250 MBPD from 2027 through 2035 (See **Appendix B, Table B.12**). With the additional GTL conversion liquids, TAPS shutdown could be delayed until somewhere between 2021 and 2035 at the minimum TAPS throughput rates, as illustrated by the arrows in **Figure 2.9.** This would allow ANS production to continue until it reached the economic limit for each producing property. The life of TAPS and of the producing properties, would be extended beyond the point in time at which TAPS shutdown would occur without major gas sales.

a. ARCO Alaska, Inc., personal communication, March 1995.

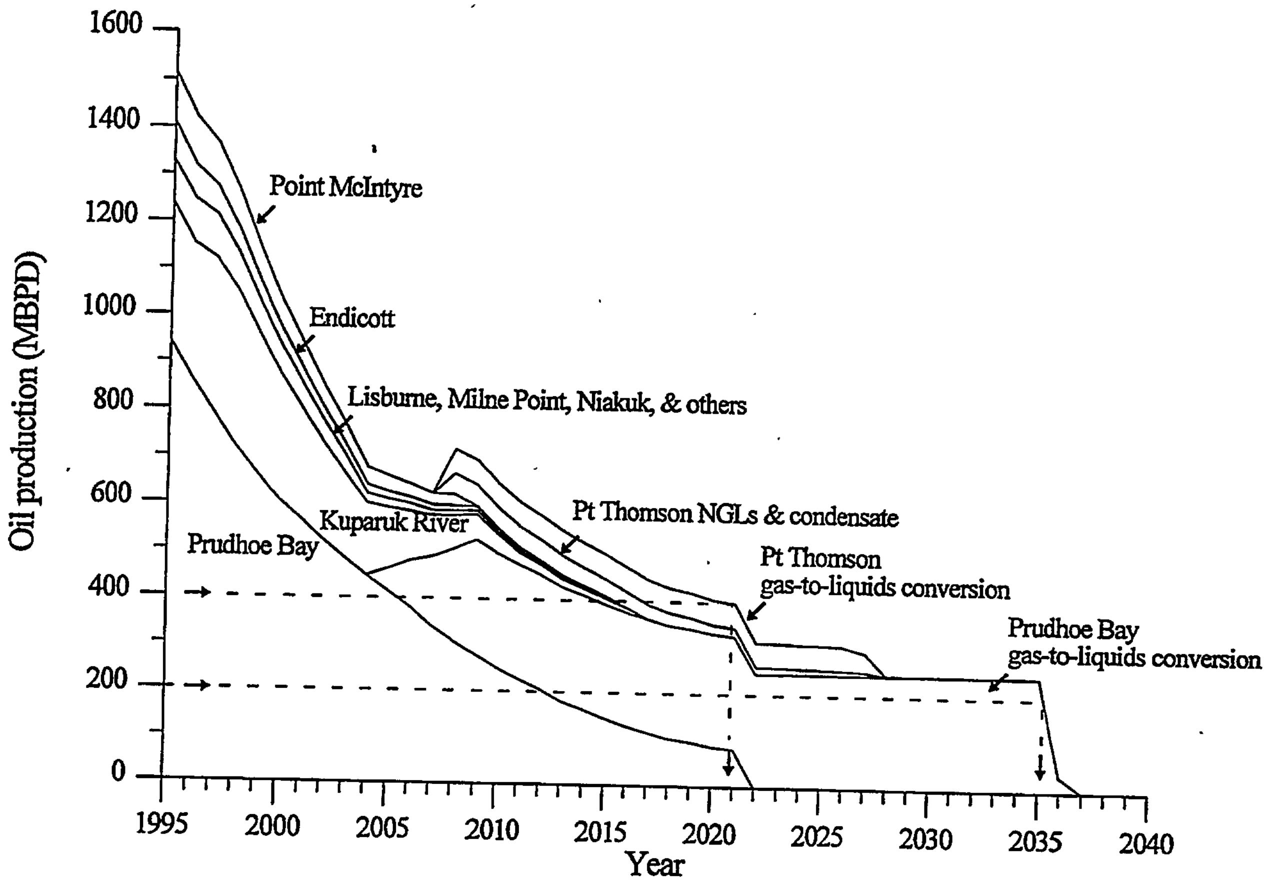

Figure 2.9. Composite North Slope production forecast with GTL conversion from PBU and PTU.

The other benefit is that the additional volume of liquids from the GTL conversion process, when blended with the ANS oil production, would increase the TAPS throughput volume used in determining TAPS tariffs. The TAPS tariff, calculated by distributing the allowed pipeline costs over the total throughput volume, would decrease, providing a higher wellhead oil price. These effects on TAPS tariffs are discussed further in **Section 5.** Hence, the GTL scenario would be more likely to allow the recovery of the lost or delayed PBU production than the LNG option through the reduction in tariffs resulting from more liquids for transport in TAPS.

2.3 Summary

The technically recoverable undiscovered conventional natural gas resources on the ANS are estimated by the U.S. Geological Survey to have a mean value of 64 TCF. The remaining potentially recoverable oil reserves without major gas sales and the remaining potential net gas production (gas, including CO_2, produced and not reinjected) are estimated to be 6.3 BBO and 38 TCF of gas. About 26 TCF of hydrocarbon gas will be available for major gas sales after CO_2 removal, lease usage, local sales, and shrinkage. Forecasted net gas sales volumes for this evaluation are 21.8 TCF from PBU, and 3.2 TCF from PTU. In addition to PBU and PTU, potential gas sales volumes exist in some producing fields in the PBU area. During ANS oil exploration efforts, numerous small, isolated gas reservoirs have been discovered. Except for fields furnishing gas to Barrow, Alaska, these accumulations have not been developed. ANS fields had produced 10.5 BBO and 2.4 BCF of net gas at the end of 1994. All of the produced North Slope gas, except for that used for production operations, local gas sales, and recovered NGLs, has been reinjected into the reservoirs to maintain reservoir pressure and to improve oil recovery potential. Currently, ANS gas is not marketed off the North Slope, except for recovered NGLs, because there are no gas transportation facilities providing access to the existing gas markets. Major gas sales possibilities include a gas pipeline/LNG project for transport to Asian LNG markets, and a GTL conversion option delivering converted hydrocarbon liquids to TAPS to be blended (or batched) with produced oil and transported to existing oil markets.

ANS major gas sales will depend on establishing an acceptable gas market, the economic optimization of gas utilization between oil recovery and gas sales, and the continuation of production operations on the North Slope to maintain the existing infrastructure. Studies by the major PBU owners indicate that the most likely timing for ANS major gas sales from PBU will occur after 2005 with a maximum rate of about 2.05 BCFPD and continue to the depletion of the economic gas reserves (Energy Daily, 1995; Oil Daily, 1995a). Development of PTU is estimated to add 0.44 BCFPD and is assumed to start selling gas in 2008. It is estimated that gas sales starting in 2005 and building up to a rate of 2.05 BCFPD over 5 years will reduce PBU oil recovery by 400 MMBO. Establishing an ANS gas market will have the effect of encouraging ANS gas exploration activities, and in the course of that exploration activity, provide for the possibility of additional oil as well as gas discoveries.

In addition to the gas resource utilization, it is assumed that the GTL conversion option, using the 2.49 BCFPD from PBU and PTU would produce an additional 300 MBPD of gasoline/diesel quality hydrocarbon liquids that can be blended with the produced oil being delivered to TAPS and transported to existing oil product markets. This additional liquid volume would extend the operational life of TAPS to 2035 and result in reduced TAPS tariffs for all liquid throughput volumes. Extending TAPS operational life will allow ANS production from existing fields to continue for several additional years, resulting in increased ultimate oil recovery, and providing additional time for ANS exploration activities.