# Oil and Gas in the ANWR? It's Time to Find Out!

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Division of Oil and Gas

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## Introduction

The petroleum potential of the North Slope's coastal plain, including that of the Arctic National Wildlife Refuge (ANWR), has been the object of speculation and geological exploration since about 1906. Oil seeps and exposed oil-stained rocks across the North Slope long hinted of the area's petroleum potential. Within the 1002 Area of the ANWR coastal plain several oil seeps and surface exposures of oil-stained rocks occur along the Katakturuk and Jago rivers and at Manning Point and Angun Point on the sea coast. Many geologists regard the area as the most prospective unexplored onshore area in North America.

The 1002 Area consists of 1,500,000 acres of highly prospective terrain in the northeastern portion of the North Slope. The region is situated between the prolific North Slope oil fields to the west and the petroleum-rich Canadian Mackenzie Delta province to the east. A very large gas field with a significant volume of recoverable liquid hydrocarbons and two large offshore oil accumulations have been discovered nearby, clearly demonstrating that the 1002 Area is a prime target for oil and gas exploration (fig. 1). The state's and the nation's need for additional oil and gas reserves and production, the need to maintain the life and deliverability of TAPS, and the promise of a gas pipeline to transport North Slope gas to fill the growing supply void in the Lower 48 all justify development of the ANWR 1002 Area's oil and gas potential.

## Geology

All of the key geologic elements needed to produce major hydrocarbon accumulations occur beneath the coastal plain of the ANWR. Geological studies and seismic, gravity and magnetic geophysical data suggest reservoir rocks similar to those found in the Prudhoe-Kuparuk area to the west and the Mackenzie Delta to the east may be present in the subsurface of the ANWR coastal plain. Interpretation of the seismic data collected to date has identified numerous prospective structures and structural and stratigraphic leads beneath the surface of the ANWR coastal plain. Based upon field observations of oil seeps and oil-stained reservoir rocks at surface outcrops in the area, it is evident that oil has been generated and perhaps has been trapped within reservoir rocks in these prospective features.

Trapping mechanisms abound in the ANWR 1002 Area. Interpretation of seismic data shows that the structural style of the area becomes increasingly complex from west to east and that the region can be divided into two structural zones, the undeformed zone and the deformed zone (fig.2). The boundary between the two zones lies along the Marsh Creek anticline. Rocks in the undeformed zone in the northwest part of the coastal plain are characterized by nearly flat-lying strata cut by faults with only small displacements. Fault-block traps and subtle anticlinal traps may be present in this area. The deformed zone is characterized by thrust-faulted basement highs overlain by northeast-trending, complexly deformed structures. Within both zones the probability of encountering stratigraphic traps is moderate to high. However, such subtle features are extremely difficult to locate and identify without a 3-D seismic program.

Figure 3 illustrates the locations of wells surrounding the ANWR coastal plain. Significant proven accumulations (Pt. Thomson, Flaxman Island, Sourdough) immediately west of the 1002 Area may, in part, extend beneath the 1002 Area. Offshore, north of the undeformed area, what are rumored to be large discoveries, each in the range of 200-400 MMBO, apparently have been found at Hammerhead and Kuvlum (operators have not disclosed reserve estimates). Prohibitively costly to develop offshore in the Beaufort Sea, fields of this size would quickly be brought on line were they located onshore. The 430 MMBO Alpine field is the largest onshore oil field discovered in North America in the last 15 – 20 years. If Hammerhead and Kuvlum are of comparative size they are significant discoveries. Most significant, however, is the probability that the geology in the undeformed area is very similar to that of the Point Thomson, Sourdough, Hammerhead and Kuvlum accumulations to the west and to the north where oil and gas are known to occur in large quantities.

## Petroleum Exploration History

Despite opposition by the state of Alaska and by the U.S. Geological Survey (USGS) the northeast corner of Alaska was created as the Arctic National Wildlife Range (ANWR) by PLO 2214 in 1960. In 1972 the state and the Department of Interior (DOI) failed in an attempt to exchange sensitive waterfowl habitat for prospective ANWR acreage. The area was substantially enlarged to 19 million acres, renamed and designated as the Arctic National Wildlife Refuge by the Alaska National Interest Land Claims Act (ANILCA) in 1980. Section 1002(h) of the ANILCA set aside approximately 1.5 million acres on the refuge's coastal plain for assessment of its petroleum potential. Upon completion of the assessment the congress is to determine final classification of the area.

To that end, a group of twenty-two oil companies joined to conduct a widely gridded (3 miles by 6 miles) 2-D seismic, gravity and shallow geology survey of the 1002 Area during the winters of 1983-84 and 1984-85. Approximately 1,450 line-miles of seismic and gravity data were acquired across the coastal plain and adjacent lands. In addition individual companies also conducted surface geology studies within the refuge. Industry submitted these data to the DOI for its use in preparation of the required petroleum potential assessment of the 1002 Area. Since that time two Interior agencies (the Bureau of Land Management (BLM) and the USGS), the Energy Information Administration, and the State of Alaska Division of Oil and Gas have published several assessments and reassessments of the petroleum potential of the 1002 Area.

In a separate proprietary program, Chevron and predecessor companies of BP Amoco conducted a smaller geophysical survey of the Kaktovik village selection lands in the north-central area of the ANWR coastal plain. Subsequently this group drilled the KIC well. Results of the geophysical survey and the well remain confidential to the participants and unavailable for use in the resource assessments.

## ANWR Petroleum Assessments

At least eight assessments of the hydrocarbon potential of the 1002 Area have been released since 1986 – one by the Alaska Division of Oil and Gas, one by the Energy Information Administration, three by the BLM, and three by the USGS. Results of these resource assessments differ somewhat because, over time, additional data have become available, analytical methods have changed, lower-cost technology has evolved, and significant technical data-collection and data-processing advances have occurred. Some assessments were restricted to only the 1002 Area and others, more regional in scale, encompassed surrounding onshore and offshore areas. Consequently, there is not a common denominator for all of the assessments. The results of those assessments are displayed in figure 4.

The most recent petroleum assessment of the ANWR 1002 Area was prepared by the USGS in 1998 (Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998; OFR 98-34). It is important to note that in this assessment the resources are quantified as "technically recoverable," the volume of hydrocarbons that can be recovered with existing technology without consideration of commodity price.

This assessment emphasized the oil potential of the study area and, based upon identification of ten prospective plays in the 1002 Area, predicts a technically recoverable mean crude oil resource of 7.7 billion barrels of oil (BBO). (Note that "resource" means the quantity of hydrocarbons <u>inferred</u> to exist from analyses of technical data. This differs from "reserves" which are generally regarded as the quantity of <u>discovered</u> <u>producible</u> resources.) The range of technically recoverable oil is estimated to be between 4.3 BBO and 11.8 BBO (i.e. there is a 95 percent probability that as much as 4.3 BBO exists, but only a 5 percent probability that at least 11.8 BBO might occur) (fig. 5).

Unlike earlier assessments, the 1998 study estimates that the quantities of technically recoverable oil are not expected to be uniformly distributed throughout the ANWR 1002 Area. The undeformed area is estimated to contain between 3.4 and 10.2 billion barrels of oil (BBO) (95- and 5-percent probability), with a mean of 6.4 BBO. The deformed area is estimated to contain between 0 and 3.2 BBO (95- and 5-percent probability), with a mean of 1.2 BBO.

The same USGS assessment estimated technically recoverable gas reserves within the 1002 Area to be in the range of 0.0 TCF (F95) to 10.0 TCF (F5), with a mean value of 3.5 TCF. Most of these reserves are expected to occur in the deformed area. At the time of the assessment, however, non-associated gas was not considered to be a likely exploration objective and the resource was not rigorously evaluated by the USGS. Since that time gas has become a more economically desirable objective and recent USGS reassessments of other areas (NPR-A, Rocky Mountain basins) have resulted in significantly higher natural gas potential than have past assessments. Consequently, the 1998 estimates might be conservative.

The 1998 estimates are somewhat higher than earlier estimates because:

- the existing seismic data have been reprocessed and re-evaluated using more modern processing and analytical techniques, and
- the results of near-by wells drilled since the earlier assessments have been incorporated in the evaluation.

The 1998 USGS assessment did consider the sensitivity of ANWR production to crude oil price (fig. 6). At a market price (landfall price plus 12 percent ROR) of $30.00 per barrel (1996 dollars) the assessment suggests that virtually all technically recoverable oil is economically recoverable. Economics become positive for large accumulations at about $13.00 per barrel. Smaller fields might not be economic at prices less that $24.00 per barrel.

Because the reprocessed seismic data and recent well data were incorporated and more rigorously evaluated than in the past, the investigators were able to better identify the distribution of plays across the 1002 Area. ("Play" may be defined as a rock volume exhibiting geological characteristics conducive to entrapment of petroleum.) The 1998 USGS assessment distributes the potential of the 1002 Area among ten prospective plays, each an extension of a play-type known to exist in neighboring petroleum-bearing areas and, on the basis of geological and geophysical data, thought to extend beneath the study area.

While earlier assessments generally assumed uniform distribution of plays and resources across the coastal plain, the 1998 study correctly concludes that the play-type, the number of prospects, potential field size and potential technically recoverable resource are differentially distributed across the undeformed and deformed areas because of the differing geologic histories of the undeformed and deformed areas.

The undeformed area lies in the northwestern one-third of the 1002 Area and is closer to existing infrastructure, a significant economic advantage. The USGS estimates that technically recoverable oil in three plays evaluated in this area ranges between 3.4 and 10.2 BBO with the mean value being 6.4 BBO. Field-size simulation models suggest these reserves will be found in about 31 accumulations (mean case) with technically recoverable oil volumes ranging from 8 to 4,096 MMB (million barrels).

The remainder of the 1002 Area comprises the deformed area. Here seven prospective plays were modeled with an estimated range of technically recoverable oil between none and 3.2 BBO and with an expected mean of 1.2 BBO. The highly complex geological style of this area results in a higher geological risk because the subsurface structure is more difficult to interpret with data now available. Here the simulation model suggests that the expected mean number of accumulations is only three pools and that about 85 per cent of the recoverable oil will occur in fields smaller than about one billion barrels.

The 1998 USGS assessment concludes that the expected mean of 7.7 BBO recoverable for the 1002 Area, as a whole, will be distributed among approximately 35 accumulations. The most common field size will be in the range of 64 – 256 MMBO recoverable. Approximately 80 per cent of the recoverable resource is expected to be found in accumulations smaller that 2.048 BBO recoverable. Chapter AO in the USGS Open File Report 98-34 offers a comprehensive overview of the methods and results achieved.

The proximity of the undeformed area to existing infrastructure suggests that relatively smaller field sizes will be economically developable there. Today satellite fields with recoverable reserves of less than 30 MMBO recoverable are being developed near the major North Slope fields. A successful discovery in the undeformed area might well provide the financial incentive to extend production infrastructure eastward from Badami to the Pt. Thomson, Sourdough, and Flaxman Island accumulations and to bring those fields on stream. Availability of facilities in this area also might make it possible to develop the offshore Hammerhead and Kuvlum pools. Combined, these accumulations could add one billion barrels or more to the nation’s domestic crude oil inventory.

Unless development proceeds easterly across the 1002 Area, the deformed area’s greater distance from now-existing infrastructure suggests that fields there will have be larger than those in the undeformed area if they are to prove commercial. Geological structures there are large and complex so the traps and the field sizes can be large. However, success in the undeformed area to the west will provide the facilities to support development in the deformed area and, as a result, fields smaller than otherwise required might prove economical in the deformed area. Clearly, while it may now be a cliché, the “string of pearls” concept applies here. Facilities and significant known, but undeveloped, reserves exist nearby. The incremental reserves necessary to lead to their development might lie beneath the undeformed area of the ANWR 1002 Area.

The 1998 assessment cannot be meaningfully compared to all earlier 1002 Area assessments because the assessment methods used in some earlier studies are not documented. However, both the BLM assessment submitted in the 1987 Report to Congress and the 1998 USGS assessment did attempt to quantify the estimated oil-in-place (OIP) resource. The 1987 study concluded that the range of OIP is between 4.8 and 29.4 BBO (95 and 5 percent) while the current assessment estimates the OIP to be between 11.6 and 31.5 BBO (95 and 5 percent). The respective 1987 and 1998 mean OIP estimates are 13.8 and 20.7 BBO. Clearly the recent evaluation assigns greater potential to the area than did the original 1987 Report to Congress.

The other significant difference between the 1987 and 1998 assessments is the distribution of the resource. In the 1987 report approximately 75 percent of the estimated mean OIP was assumed to be in what is now identified as the deformed area. The 1998 assessment assigns only 15 percent of the mean OIP to the deformed area. In 1987 the undeformed area was thought to contain only 25 percent of the OIP. Current thinking is that 85 percent of the OIP occurs in the undeformed area on the northwestern coastal plain.

As previously stated these changes reflect the impact of improved seismic processing and analytical methods and inclusion of geological analogs derived from recent drilling results near the 1002 Area. Furthermore, modern understanding of the geohistory of the ANWR coastal plain suggests that the deformed area, underlain by more thermally mature sediments than is the undeformed area, may be more prospective for gas than for oil**.**

## North Slope and Potential ANWR Contribution to Domestic Supply

Having discussed the oil and gas potential of the ANWR 1002 Area, it seems appropriate to place that potential in a national perspective. Alaska's North Slope currently produces approximately one million barrels of oil a day, a significant decline since the peak production of 2.2 million barrels of oil a day transported through the Trans-Alaska Pipeline System (TAPS) in 1988. At that time the Alaska North Slope provided about twenty-five percent of the nation's domestic crude oil production. According to the American Petroleum Institute 2002 report, Alaska's North Slope production represents about 18 percent of the nation's domestic crude production and 5.6 percent of the nation's daily demand of 19 million barrels. In 2002 the United States imported 57.6 per cent of its total crude oil products demand.

With Figure 6 the USGS report displays graphically how <u>economically</u> recoverable oil volume might vary across a range of oil prices (1996 dollars). Given the mean technically recoverable resource, the field number and field size distributions modeled, possible success rates and other parameters, somewhat more than 6 BBO could be economically produced from the 1002 Area at today's $28.00 - $30.00/barrel price. An oil price of about $15.25/barrel would support exploration for and development, production and transport of only a few hundred million barrels.

In its May 2000 report, "Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment", the U.S. Department of Energy (DOE), Energy Information Administration, estimated daily production schedules for the 5 per cent, mean and 95 per cent technically recoverable oil cases described in the 1998 USGS assessment. The DOE assigned a range of production volumes, based upon engineering assessments and the development history of the area, to each case in order to determine the cumulative production levels and project life for each model. The methodology used by the DOE to simulate field production curves assumes that daily production will peak in the third year at about ten per cent of the total technically recoverable volume. Production rates during years one and two are approximately one-quarter and one-half respectively of the peak rate. After year three, production declines exponentially at ten per cent each year until all technically recoverable reserves are produced. The DOE study projects peak production rates ranging from 600,000 to 1.9 MMBO per day with production peaks estimated to occur about 20 – 30 years after sustained production begins. Production could continue for 50 – 60 years. Note, however, that the DOE report considers technically recoverable oil from <u>all</u> of the coastal plain area, including Native and adjoining state lands. These lands will contribute only 26 per cent of the production rates and volumes assigned to the entire area by the DOE (the 1002 Area will contribute 74 per cent).

In the mean case, for example, the DOE postulated development rates of 400 and 600 MMBO per year. The methodology assumes that a new 400 or 600 MMBO recoverable development volume ("unit") will be brought on line each year and produced until all technically recoverable oil assigned to the mean case is depleted. For the 400 MMBO per year development case a new 400 MMBO “unit”, each with a life of about 40 years, will be brought on line each year for 25 years. Under this scenario, peak production for the 400 MMBO per year case is about one million barrels per day 26 years after start of sustained production. Forty years after the 25th “unit” is placed on production the total technically recoverable oil resource (mean case) will be depleted. The total production phase will take approximately 65 years (a new “unit” each year for 25 years and a 40-year life for the last “unit”).

In the higher rate 600 MMBO per year development model only about 18 “units” are needed to deplete the mean case technically recoverable resource. Peak production will occur in the 18th year at a rate of about 1.35 MMBO per day. Assuming a 40-year life for each “unit” the total production phase might continue for about 48 years, by which time the mean case resource will be depleted.

The reality is that development will not occur on an annually replicated schedule. The number of fields, field sizes and production schedules can not be determined until the area is further explored with modern seismic methods and the drill bit. Clearly, however, potential production of at least 7.7 BBO from the 1002 Area would be a significant contribution to the nation’s domestic production.

## Minimum Economic Field Size, Technology and the Environment

A critical criterion when evaluating a prospect is to determine whether it equals or exceeds the minimum economic field size (MEFS) - the volume of recoverable oil necessary to make the project an economic success. MEFS is the product of numerous technical and economic variables - among them the value of oil; the finding costs; the productivity, depth and thickness of the reservoir; the proximity to and cost of infrastructure; the cost of applicable technology; royalty payments; transportation tariffs; regulatory costs and tax structure. Recent dramatic changes in oil prices make it clear that prospects must be evaluated across a range of prices and that, in a fluctuating oil market, a MEFS for any given price represents only a snapshot in time.

On the North Slope, as elsewhere, the MEFS has decreased significantly. Fields as small as 30 – 50 MMBO recoverable are being developed around the Prudhoe Bay and Kuparuk River fields west of the ANWR. Two significant contributing factors are technology-based: 3-D seismic and advances in directional drilling.

3-D seismic field acquisition and processing methods have evolved to the point where potential reservoirs and traps only several hundred feet wide can be identified at substantial depths. Once used to aid delineation of field limits <u>after</u> a discovery well was drilled, 3-D seismic is now less costly than an exploration well and the technique has evolved to the point where it now is employed <u>before</u> the wildcat well is drilled. Modern digital seismic recording and processing methods allow certain attributes to be extracted from the data and analyzed to better locate and characterize the exploration target.

Furthermore, experienced explorationists have come to recognize certain data characteristics as typical of common prospect types in an area. The technique has also advanced to the point where repeated 3-D seismic surveys (4-D seismic) can be used to design and monitor secondary recovery programs. Unfortunately no 3-D seismic surveys have been conducted in the 1002 Area where such information would contribute significantly to a more definitive assessment of the area's petroleum potential. Combined with modern directional drilling engineering methods, 3-D seismic allows selection of drill-sites having the least environmental impact within a prospective area.

Directional control of the drill bit is an engineering marvel. A drilling engineer can now plan a well-bore trajectory that will penetrate one or more small targets, identified by the 3-D seismic, at distances of more than four miles from the drill rig location. Application of this "extended reach" drilling method - "designer well" as it is sometimes called - allows numerous exploration and development wells to be drilled within a radius of nearly five miles from a single drill pad. North Slope satellite fields such as Midnight Sun and Aurora were discovered and are being developed from existing surface facilities several miles from those fields. In the not-too-distant past new drill pads, roads and pipelines might have been necessary to drill and develop these fields and the cost of doing so might have been high enough to prevent carrying the projects forward. Hundreds of millions of barrels of oil would have remained in the ground.

Accurate spatial control of the drill bit offers other advantages to the operator. Horizontal production wells are now routinely completed, the well bore penetrating thousands of feet of reservoir strata horizontally and increasing reservoir volume exposed to the borehole and production tubing. Production is more efficient and much less costly. Virtually all North Slope wells are now drilled using horizontal drilling methods.

Coiled tubing units, much smaller that conventional rotary drill rigs, are now frequently used to drill and complete many wells. They are often used to sidetrack existing wells to prolong well life or to complete new production zones in the producing reservoir. Here, too, development of small diameter down-hole drilling tools allows the operator to control directional drilling with precision.

Advances in directional drilling methods and associated improvements in production technology now allow multi-lateral long-reach completions. Multi-lateral drilling consists of several extended-reach horizontally-completed wells drilled and produced from a single pilot hole. Pilot holes can be drilled only a few feet apart by a mobile conventional drilling rig leaving a very small "footprint" on the surface. The number of wells that once were completed on a 65-acre gravel pad can now be confined to an area of only nine acres. Here too, the Alpine field, now under development by Phillips Petroleum Company and Anadarko Petroleum Company, is the best example of modern oil field development using multi-lateral completions.

Also recently developed is through-tubing rotary drilling which is used to drill a new borehole through existing production tubing without pulling and replacing that tubing. Savings in rig-time and materials are substantial.

A combination drilling/production/camp platform being tested on the North Slope this winter is intended to extend the North Slope drilling season, to reduce surface disturbance and to greatly reduce the need for gravel and ice pads and roads. Developed by the Anadarko Petroleum Company, it consists of light-weight, inter-locking Rolligon-transportable aluminum modules mounted above the tundra on vertical pilings. Camp facilities will be mounted on a similar, but smaller, adjacent structure. Designed to be easily constructed and, if necessary, removed, it promises significant environmental and economic advantages.

Many of these advances in drilling engineering, now used around the world, were conceived and developed by North Slope operators as they tried to reduce costs and environmental impacts. Not only do these engineering advances reduce the surface area of individual drill sites, they also reduce the number of drill sites required. As a result the operator uses less gravel and the disturbances that accompany field construction are significantly reduced. Remember, too, that grind-and-inject methods whereby drilling mud and cuttings are injected back into the well, have virtually made mud pits a thing of the past and also have significantly reduced water demand. Remote sites often can be supported by seasonal ice roads and by air. Production facilities can be remotely operated with minimum or no permanent on-site staffing. Clearly, “lean is clean” in the oil patch. Cost-efficiency and reduced environmental impact are joined at the hip.

The use of 3-D seismic and extended-reach drilling have contributed significantly to lower finding costs by substantially increasing the probability of commercial success. From 1995 – 2001 inclusive, the commercial success rate on the North Slope was at least 32 per cent (at least 8 of 25 exploration wells). Statistics published by the Division of Oil and Gas indicate that the commercial success rate between 1959 and 1995 (prior to the use of 3-D seismic as an exploration tool and the advent of modern directional drilling technology) was only 3.3 per cent. The ten-fold increase between 1995-2001 is attributable to the improved subsurface knowledge now attainable from 3-D seismic data and the advances in drilling methods.

Operational costs have dropped dramatically over the last twenty years as North Slope operators have sought to remain competitive under intense public scrutiny. Reduced materials, rig-time and construction costs have contributed significantly to lower operational costs. For example (all estimates in 1996 dollars):

- In a 1984 report by the BLM exploration drilling costs were estimated to be $22MM per well. The 1998 USGS study estimated the cost to be $15MM.
- The BLM estimated a 10,000 foot development well then cost about $7MM. The USGS estimate is $2.73MM.
- Facilities investment was estimated to be $10 per barrel in 1984 - today about $2 per barrel.
- A 20-inch 85-mile pipeline was estimated to cost $9.8MM in the 1984 BLM report. The 1998 USGS assessment estimated a similar pipeline would cost $2.7MM.

## Drainage Issue

Several major accumulations are known to adjoin the western boundary of the refuge's coastal. Directly abutting the northwest boundary of the ANWR is the Point Thomson Unit with development expected to begin by 2006. This field is expected to produce 8 TCF of natural gas and perhaps as much as 400 MMB of natural gas liquids, the latter transportable through the near-by Badami facilities to the TAPS system. Several years ago British Petroleum Alaska and ChevronTexaco announced discovery of a 100 MMBO field at their Sourdough field, also within the Point Thomson Unit. Whether these gas and oil pools extend under the 1002 Area remains a matter of speculation today. A short distance offshore lie two more undeveloped pools rumored to contain nearly a billion barrels of oil. Due to the confidential nature of much the exploration data within the Point Thomson Unit, in the area offshore of the 1002 Area, and in the 1002 Area proper, the possible occurrence and extent of these resources within the 1002 Area remain speculative. However, most petroleum explorationists working the area believe the same reservoirs are very likely to occur beneath the ANWR coastal plain and regard the area as the most prospective unexplored onshore area in North America.

If left undrilled any recoverable reserves beneath the western margin of the 1002 Area might be drained by wells on adjacent state leases. While any such oil or gas will find its way into the nation's energy supply, the federal government will not be compensated for drainage extracted by the state and/or its lessees. If drainage is an issue it is the state's legal opinion that the "rule of capture" prevails and that a state lessee can drain oil from adjacent federal land. The federal government can protect its equitable share of the resource by having a drainage lease sale or by allowing offset wells to be drilled within the 1002 Area, possibly from state land utilizing extended reach methods. Clearly the only way to protect federal revenue is to drill in the area with either a government program or by offering the area for leasing.

## Conclusion

What quantity of oil and gas lies beneath the tundra of the ANWR 1002 Area? Despite repeated sophisticated analyses by government and industry geoscientists, only additional seismic surveys and the drill bit will reveal what lies beneath the study area. The 3-by-6 mile seismic grid acquired during the assessment phase served its intended reconnaissance purpose, but prospects of substantial size could be missed by such a large grid. Clearly, modern in-fill seismic coverage is needed to better evaluate the area.

That exploration, development and production technologies have evolved to mitigate or eliminate many environmental and economic issues is apparent. It is reasonable to believe that practice will continue. The Alpine field-development program on the Colville Delta to the west is the most recent example of those advances - many of which had their origin in the uniquely demanding arctic environment of the North Slope.

Too often overlooked in the controversy surrounding the future of the 1002 Area is the fact that much of the information germane to the living and renewable resource assets of the area was gathered in conjunction with the ANWR petroleum exploration programs of the mid-80s. Those programs provided the impetus, support and means to compile comprehensive studies of the environmental and wildlife values of the area. That development and the environment can co-exist in the Arctic has been clearly demonstrated over the last 25-30 years. To believe otherwise is short-sighted and detrimental to our nation's energy needs.

## Acknowledgements

The Alaska Department of Natural Resources, Division of Oil and Gas, originally prepared this report in support of Governor Knowles' testimony before the United States Senate Energy and Resource Committee on April 5, 2000. All information contained in this report is from various public sources. Information regarding the geology and petroleum potential of the 1002 Area, including figures 1–3, 5 and 6, is from the USGS Open File Report 98-34 and the USGS Bulletin 1778. While this informational report addresses only the oil potential of the 1002 Area, the USGS publications discuss the natural gas resource of the area also. The staff of the Division of Oil and Gas wishes to thank USGS scientists Emil D. Attanasi, Kenneth J. Bird and David W. Houseknecht for their contributions to the body of science regarding the petroleum potential the Arctic National Wildlife Refuge 1002 Area.

Oil production rate information is extracted from the DOE-EIA report "Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment, May 2000". For a more comprehensive review of the petroleum potential of the Arctic National Wildlife Refuge coastal plain and surrounding areas please refer to the acknowledged publications.

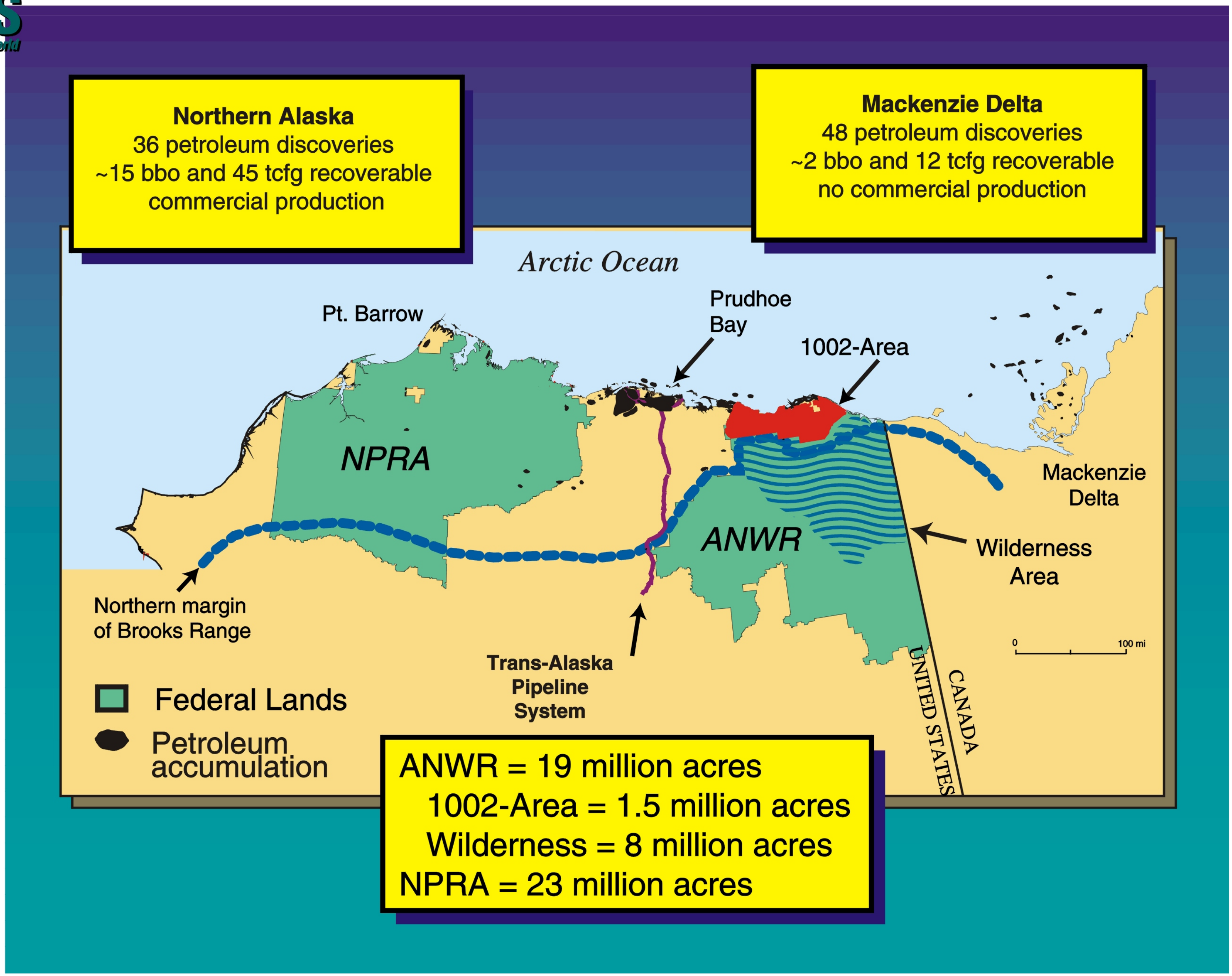



Figure 1. Map of northern Alaska and nearby parts of Canada showing locations of the Arctic National Wildlife Refuge (ANWR), the 1002 assessment area, and the National Petroleum Reserve - Alaska (NPRA). Locations of known petroleum accumulations and the Trans Alaska Pipeline System (TAPS) are shown, as well as summaries of known petroleum volumes in northern Alaska and the Mackenzie delta of Canada. bbo = billion barrels of oil, includes cumulative production plus recoverable resources; tcfg = trillion cubic feet of gas recoverable resources.

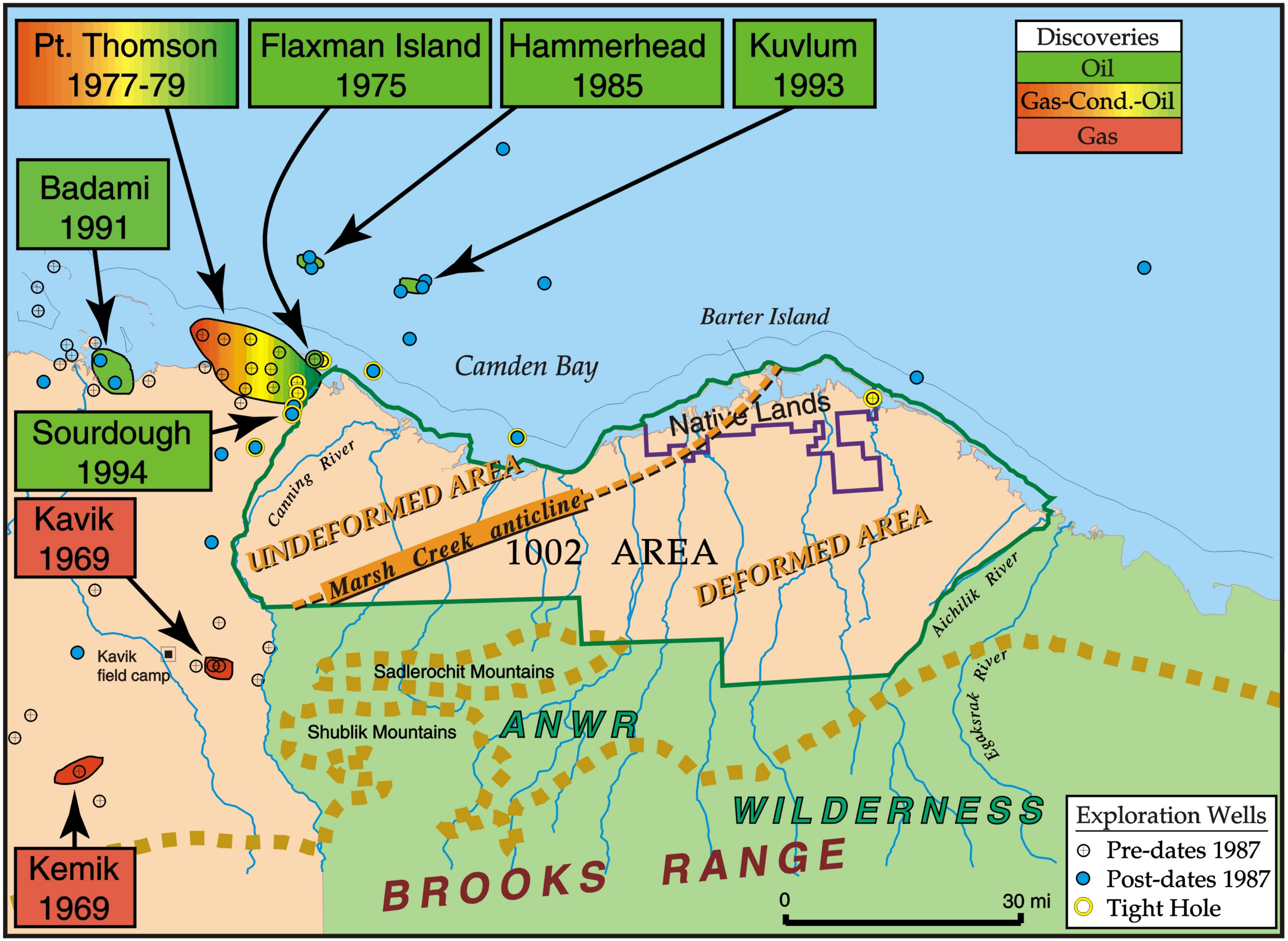



Figure 2. Map of the ANWR 1002 and adjacent areas showingpetroleum discoveries and status of exploratory wells relative to 1987 USGS assessment. Orange dashed line marks approximate boundary between undeformed area, where rocks are generally horizontal, and deformed area, where rocks are folded and faulted.

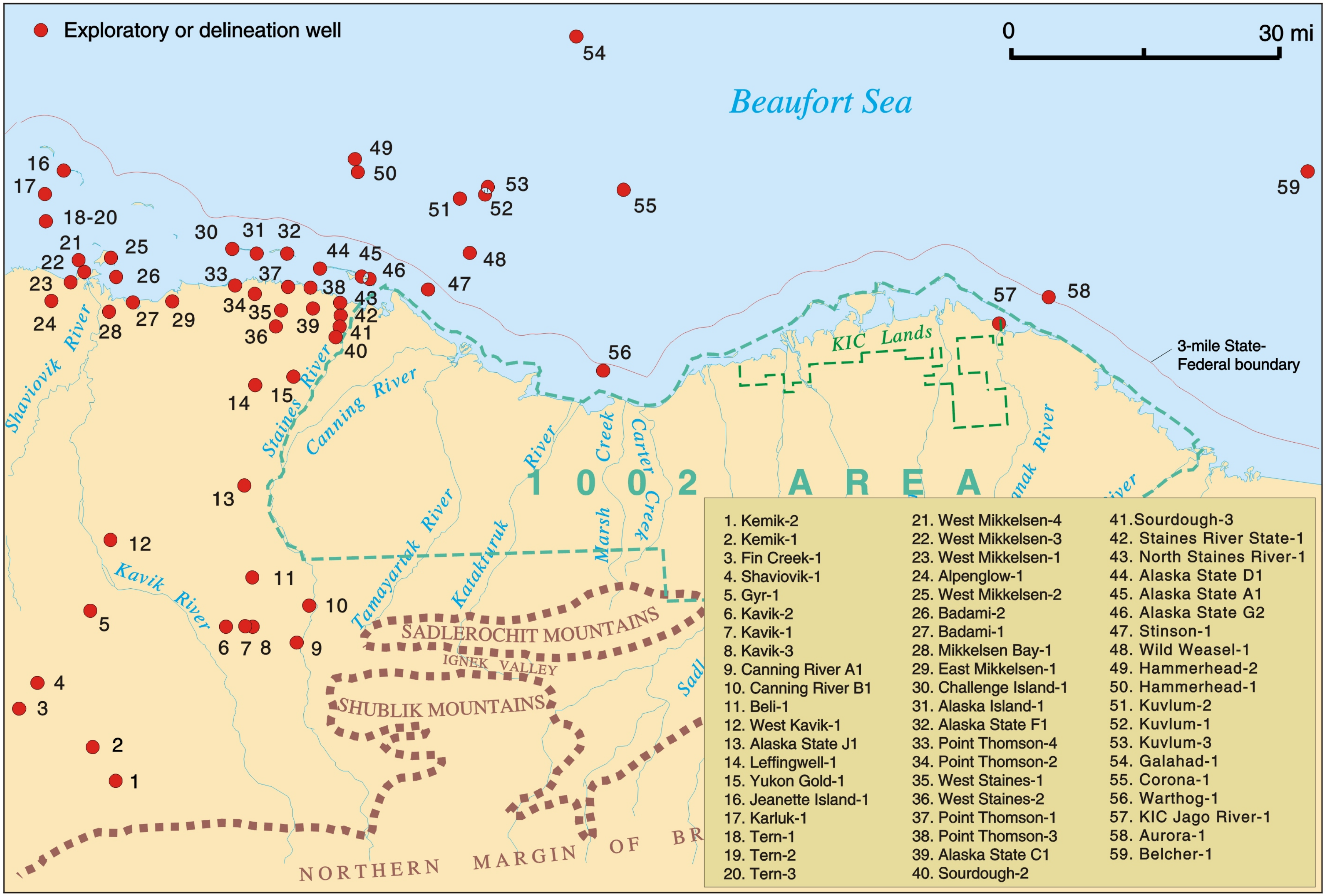
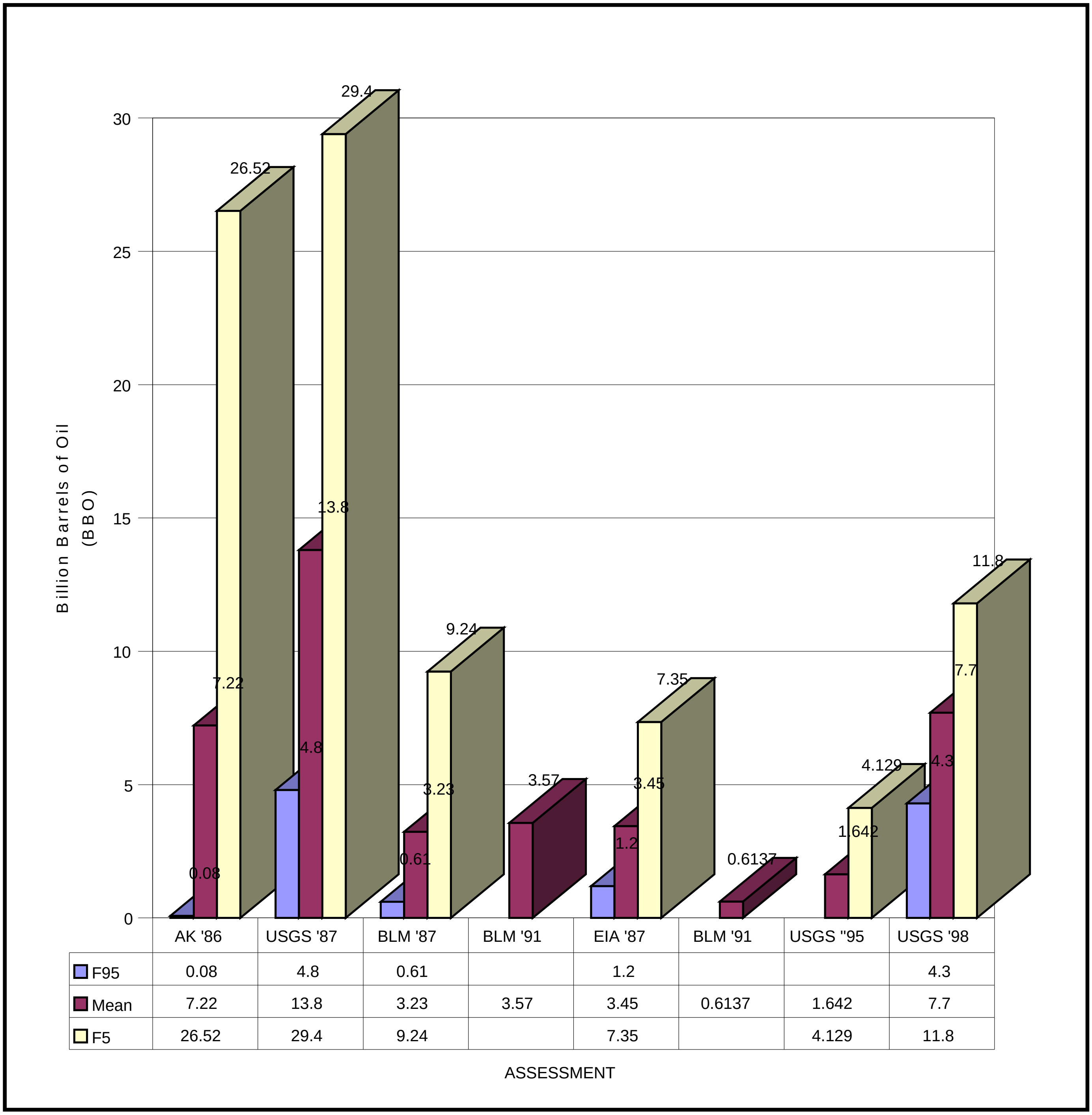



Figure 3. Location map of wells near the ANWR 1002-area.




DO&G 4/00

| ASSESSMENT | BBO | | |
|---|---|---|---|
| | F95 | Mean | F5 |
| AK DO&G "in place", 1986 | 0.08 | 7.22 | 26.52 |
| USGS "in place", 1987 | 4.8 | 13.8 | 29.4 |
| BLM Undiscovered conditional economically recoverable oil, 1987 | 0.61 | 3.23 | 9.24 |
| BLM Undiscovered conditional economically recoverable oil, 1991 | | 3.57 | |
| EIA Unconditional (risked) economically recoverable oil, 1987 | 1.2 | 3.45 | 7.35 |
| BLM Unconditional (risked) economically recoverable oil, 1991* | | 0.6137 | |
| USGS Unconditional (risked) economically recoverable oil, 1995 | | 1.642 | 4.129 |
| USGS Technically recoverable oil, 1998 | 4.3 | 7.7 | 11.8 |

* Reflects a change in original probability from 19% to 46%

Figure 4. ANWR 1002 Area Assessment Results

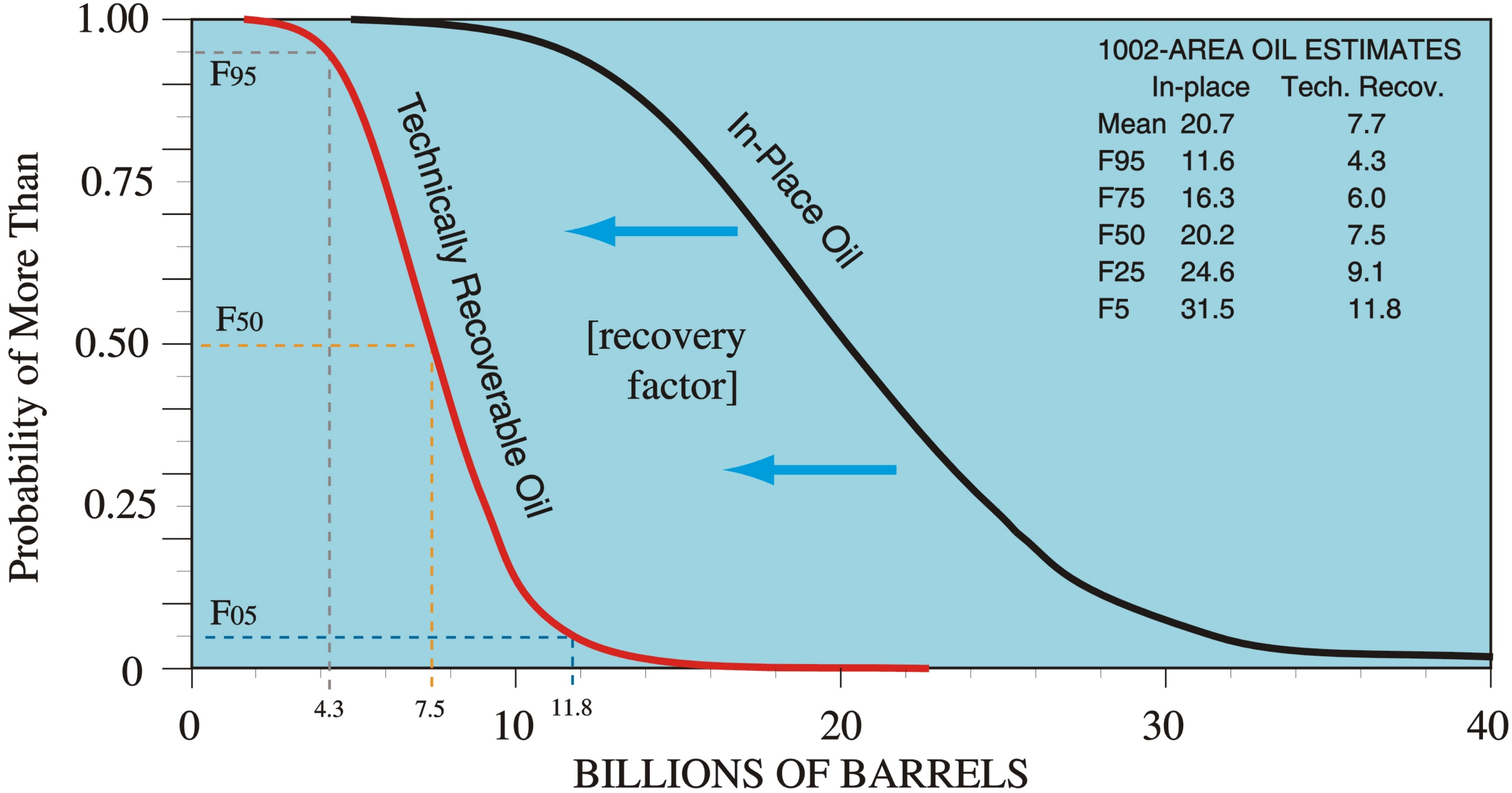



Figure 5. Graph illustrating oil volumes and probabilities for the 1002 area. Curves represent categories of oil in assessment. The larger volumes of oil are represented by the in-place curve and lesser amounts by the technically recoverable curve. An example of how one reads this graph is illustrated by the dashed lines projected to the red curve for technically recoverable oil. There is a 95-percent chance (i.e., probability $F_{95}$) of at least 4.3 billion barrels of technically recoverable oil; there is a 50-percent chance ($F_{50}$) of at least 7.5 billion barrels of recoverable oil; and there is a 5-percent chance ($F_{05}$) of at least 11.8 billion barrels of recoverable oil. The $F_{05}$ and $F_{95}$ values are considered reasonable maximum and minimum values, while the mean expresses the average or expected value.

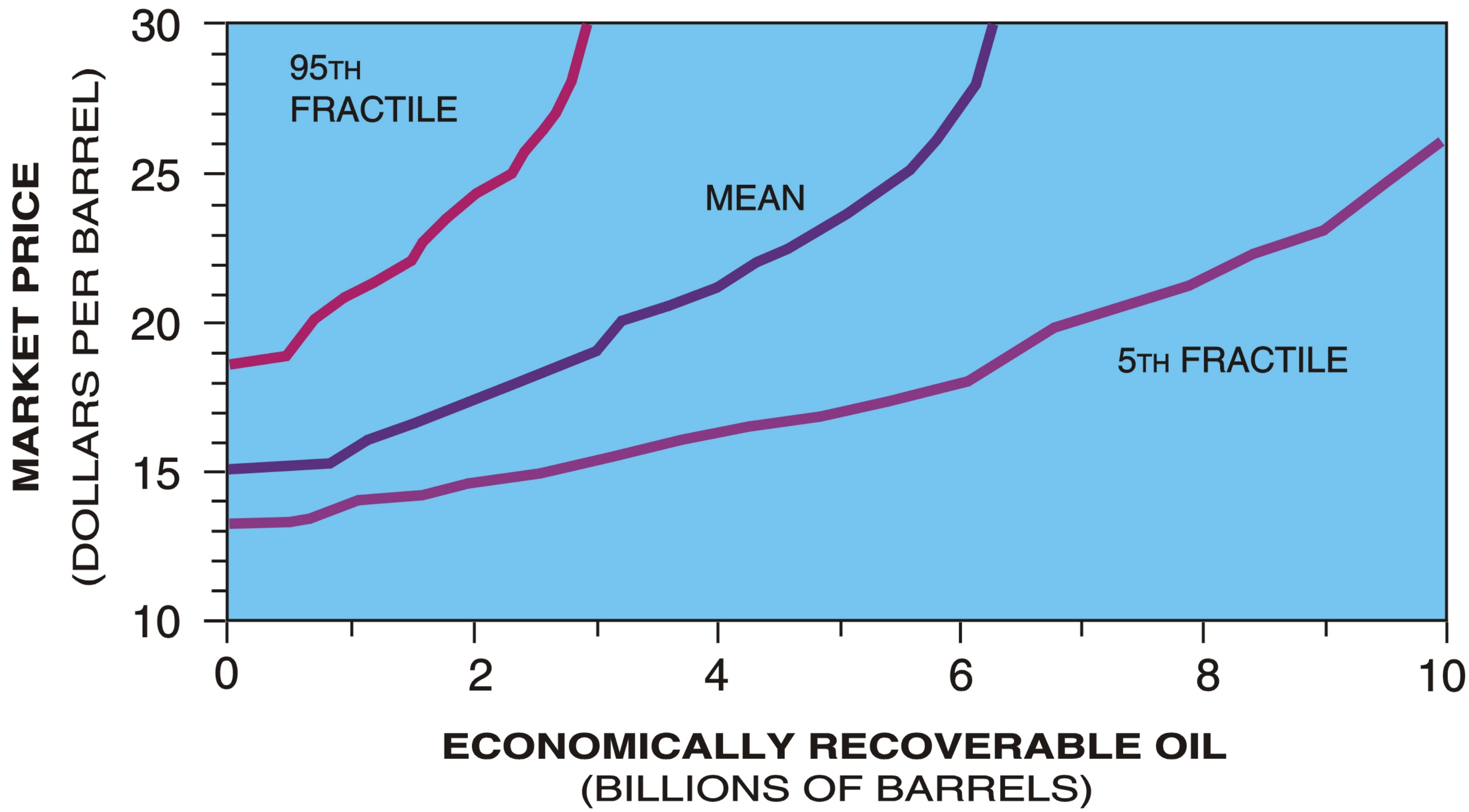



Figure 6. Graph showing increasing volumes of oil that could be profitably recovered at increasing commodity prices from undiscovered fields in the 1002 area of the Arctic Refuge. Analysis includes costs of finding, developing, producing, and transporting oil to market, as well as a 12-percent return to capital.