Chapter EA (Economic Analysis)

ECONOMICS OF UNDISCOVERED OIL IN THE 1002 AREA OF THE ARCTIC NATIONAL WILDLIFE REFUGE

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TABLE OF CONVERSIONS TO SI UNITS

multiply unit	by	to obtain metric unit
barrel	0.159	cubic meter
cubic foot	0.02832	cubic meter
foot	0.3048	meter

Unit Abbreviations

bbl	Barrels
BBO	Billions of barrels of oil
BBL	Billions of barrels
BCFG	Billions of cubic feet gas
MCFG	Thousands cubic feet gas
MMBO	Millions of barrels of oil
TCFG	Trillions cubic feet gas

SUMMARY

This report summarizes the economic analysis of the U. S. Geological Survey's 1998 petroleum assessment of the 1002 area of the Arctic National Wildlife Refuge. Volumes of technically recoverable oil and gas were assessed by geologists. Estimates of technically recoverable oil in undiscovered accumulations in the 1002 area range from 4.25 billions of barrels of oil (BBO) to 11.80 BBO with a mean of 7.69 BBO. The ranges in estimated volumes correspond to the 95 percent probability (that is, a 19 in 20 chance of occurrence) and the 5 percent probability level (1 in 20 chance), respectively. Estimates of technically recoverable non-associated gas in undiscovered gas fields range from 0 to 10.02 trillions of cubic feet of gas (TCFG) with a mean value of 3.48 TCFG. Non-associated gas resources were not examined in the economic analysis because they are not expected to be a target of explorationists for at least two decades.

Characteristics of the assessment important for the economic analysis included the field size distribution, location, and depth. At the mean estimate, 3.26 BBO is in fields of at least 500 million barrels. Accumulation size-frequency distributions associated with the 95th and 5th fractiles indicate 1.12 BBO and 6.43 BBO were assessed in fields of at least 500 million barrels, respectively. Plays of the undeformed area, the western part of the 1002 area, were assessed to contain more than 80 percent of the oil. Just over three-fourths of the assessed oil was assigned to depths of 10,000 feet or less.

The economic analysis used the accumulation size-frequency distributions associated with the mean, 95th, and 5th fractile estimates of undiscovered technically recoverable oil. An after-tax 12 percent rate of return or hurdle rate was assumed. All calculations are in constant 1996 dollars. Transportation costs from the field to the market were included in the analysis so that prices and incremental costs are at the market rather than well-head. Incremental cost functions include the full costs of finding (exclusive of lease bonus), developing, producing, and transporting oil to market. Most of the fields with at least 500 million barrels of oil recoverable will meet costs of development, production, and transportation at $16 per barrel.

At an $18 per barrel market price, 2.4 BBO associated with the mean estimate and 6.2 BBO associated with the 5th fractile estimate are economic to find,

develop, produce and transport to market. For resources associated with the 95th fractile estimate, initial exploration costs are not compensated by the economic value of new finds until market prices reach at least $19 per barrel. At the higher market price of $24 per barrel, 47 percent of the oil assessed at the 95th fractile (2.0 BBO), 68 percent of the oil assessed at the mean (5.2 BBO) and 79 percent of the oil assessed at the 5th fractile (9.4 BBO) are economic to find, develop, produce, and transport to market.

INTRODUCTION

Economic analysis of the assessed undiscovered technically recoverable conventional oil and gas for the 1002 area of the Arctic National Wildlife Refuge (ANWR) is summarized in this report. Volumes of recoverable oil, gas, and natural gas liquids (NGLs) that could be added to proved reserves using current technology but without reference to costs or product prices were estimated as part of the geologic assessment. Costs and the required product prices to transform the undiscovered resources into producible reserves are computed here. This analysis estimates the part of the assessed distribution of undiscovered accumulations that can be commercially developed at a given market price level. It also calculates the incremental costs of finding, developing, producing. and transporting assessed undiscovered oil. Incremental cost functions show cost-resource recovery possibilities and are not supply functions as defined by economists. However, the incremental cost functions and the data which underlie the functions are often used in market supply models. *The economic analysis is confined to resources in the 1002 area. This analysis does not predict the revenue or bonus payments for leases in the 1002 area nor does it attempt to estimate regional or national secondary economic benefits.* The economic component of the 1002 area assessment is intended to place the geologic resource analysis into an economic context that is more informative and easily understood by government policy makers and industry decision makers.

Undiscovered technically recoverable conventional oil and gas resources are resources estimated to exist, on the basis of broad geologic knowledge and theory, in *undiscovered accumulations* outside of known fields. Technically recoverable resources are producible using current recovery technology but without reference to economic viability. *Conventional oil and gas accumulations* are discrete well-defined accumulations, typically bounded by a downdip water contact, from which oil, gas, and natural gas liquids (NGL) can be extracted using traditional development and production practices. *Accumulations assessed by geologists outside of known fields were considered for the purposes of the economic analysis as separate and discrete new fields. Economically recoverable resources* are that part of the assessed technically recoverable resource for which the costs of finding, development, and production, including a return to capital, can be recovered by production revenues at a given price.

The scope and nature of the assessment method are first briefly reviewed. Characteristics of the technically recoverable resources important for understanding the economic analysis are then summarized. Assumptions about markets, pricing, costs, and the technical relationships used in estimating the incremental costs functions are considered. Results and interpretations are presented in the concluding sections.

SUMMARY OF GEOLOGIC ASSESSMENT

The geologic assessment method and its scope are surveyed here. Specifics may be found in Schuenemeyer (Chap. ME). A conventional field's commercial value depends on its expected size, whether it is oil or gas[1], its depth, location, and reservoir properties. Characteristics of the assessment results, such as the accumulation size-frequency distribution, the depth distribution, and the expected geographical distribution of assessed resources are fundamental for understanding the economic analysis. These characteristics are described in some detail.

Geologic Assessment Procedures

For each play, the assessment geologist or assessor assigned probabilities and probability distributions to properties of undiscovered conventional oil and gas accumulations having hydrocarbons of at least 50 million barrels of oil (MMBO) or 300 billion cubic feet of gas (BCFG) in-place. A *play is* a set of known or postulated oil and (or) gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration patterns, timing, trapping mechanism, and hydrocarbon type. For each play geologists specified empirical probability distributions thought to characterize the play. These distributions include number of prospects, depths of

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[1] Fields and accumulations are defined as either oil or non-associated gas on the basis of their gas-to-oil ratios. Those having at least 20,000 cubic feet of gas per barrel of crude oil were classified as non-associated gas; otherwise, the fields and accumulations were classified as oil.

accumulations, various reservoir parameters, and play and prospect probabilities. Computer simulation analysis combined these probability distributions so that the assessment resulted in (*unconditional*) estimates of numbers and sizes of undiscovered accumulations, their depths, and ancillary information such as expected associated gas-to-oil ratios, natural gas liquids-to-gas ratios, and characteristic product quality.

Each of the 10 play definitions included a description of the geographic location and geologic characteristics (see Bird, Chap. AO). Most of the plays thought to occur in the 1002 area are also found in adjacent State lands, under State and Federal waters, or elsewhere on the North Slope. A number of supporting studies were prepared by the assessment geologist and other members of the Assessment Team that assisted the assessors in characterizing play properties with probability distributions. The *play probability* is the likelihood that the play contains at least one accumulation with 50 MMBO or 300 BCFG in-place. In cases where the assessor was not confident of the occurrence of at least one accumulation of that threshold size, the play probability was computed as the product of the occurrence probabilities of the three play attributes of *charge*, *reservoir*, and *timely trap formation* (see Charpentier, Chap. DF).

Even though the assessment was prepared at the play level, assessors anchored their estimates of the number of prospects on their interpretations of seismic information, other geophysical data, or analogues. Assessors were asked to specify an empirical distribution for the number of prospects. The *prospect probability* is the probability that a randomly chosen prospect contains at least 50 MMBO or 300 BCFG in-place. This probability may be computed as the product of the occurrence probabilities assigned by the geologist to the prospect attributes of *charge, reservoir, and timely trap formation*. The number of accumulations (meeting the threshold size) is then the product of the number of prospects and the play and prospect probabilities. Random values representing numbers of prospects were sampled from the prospect probability distribution.

The accumulation size (volume) distribution was *simulated numerically* by sampling the empirical distributions associated with each reservoir parameter. Reservoir parameter distributions characterized area of closure, pay thickness, trap fill, and porosity values. For each successful play realization, the accumulation size distribution was sampled and an accumulation size-frequency distribution obtained. The unconditional mean size-frequency distribution was calculated over all successful and unsuccessful trials. All size-frequency distributions used in the economic analysis were unconditional, that is, *fully risked*. The values of the reservoir parameters generated to calculate accumulation volumes were also used to estimate the production well recoveries and volumes of by-products.

The assessors specified dependencies among plays. These dependencies were standardized to represent correlations among volumes of oil across plays. The correlations were used in the aggregation of the play simulations to the distribution of undiscovered oil in the 1002 area. Dependency estimates among plays and the sampling procedures used for the aggregation are described in Schuenemeyer (Chap. ME).

The aggregations considered in this report are based on the resources assessed in the Federal 1002 area only (excluding State and Native lands, see figure EA1). The procedure used for the aggregation allowed one to identify the particular play realizations that resulted in a specific fractile value associated with, for example, a volume of oil. Individual play realizations can be quite variable and a procedure described in Schuenemeyer (Chap. ME) for using multiple realizations resulted in stable accumulation size-frequency distributions for each set of plays that corresponded to an aggregate fractile estimate of 1002 area undiscovered technically recoverable oil.

Characteristics of the Assessed Technically Recoverable Resources

Estimates of technically recoverable oil in undiscovered accumulations in the 1002 area range from 4.25 BBO to 11.80 BBO with a mean of 7.69 BBO. The ranges in estimated volumes correspond to the 95 percent probability (that is, a 19 in 20 chance of occurrence) and the 5 percent probability level (1 in 20 chance), respectively. Estimates of technically recoverable non-associated gas in undiscovered gas fields range from 0 to 10.02 TCFG with a mean value of 3.48 TCFG. Table EA1 presents play level and total mean estimates of oil, associated gas, associated gas NGL, non-associated gas, and non-associated NGL for the 1002 area. The Topset play accounts for 56 percent of total oil, and the Topset, Turbidite, and Thin-Skinned Thrust Belt plays together account for more than 86 percent of the total oil assessed. Results suggest that the likelihood is very low of a single large gas field occurring with a NGL to gas ratio sufficiently high for the field to be developed for its liquids. Technically recoverable oil accumulation size-frequency distributions shown in figure EA2 convey the

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economic implications of the oil estimates. Few small accumulations are shown because of the elimination of accumulations having oil in-place of less than 50 million barrels from the assessment.

Stand-alone fields as small as 120 to 150 million barrels (recoverable) are currently under development in the central coastal areas of the North Slope. Based on the size-frequency distribution associated with the mean estimates of undiscovered technically recoverable oil, 3.26 BBO (42 percent) of the assessed oil is assigned to accumulations of at least 500 million barrels. Similarly, accumulations of at least 500 MMBO account for 1.12 BBO (26 percent) and 6.43 BBO (54 percent) of the oil shown by distributions associated with the 95th and 5th fractile estimates, respectively (see table EA2). Table EA2 also shows that accumulations larger than 256 MMBO account for 4.99 BBO (65 percent), 2.22 BBO (52 percent), and 8.52 BBO (72 percent) of the oil associated with the mean, 95th, and 5th fractile estimates. Significant volumes of assessed oil are expected to be in accumulations that will be of economic interest.

Assessment results show, at the play level, that most of the oil is expected to be concentrated in plays located principally in the geographically confined undeformed area (see figure EA1). These plays - Topset, Turbidite, Wedge, Thompson, Kemik, and Undeformed Franklinian - account for 6.46 BBO in 31 accumulations (or about 84 percent at the mean oil estimate and 88 percent of mean number of accumulations). Overall, 6 BBO or 78 percent oil estimated at the mean was assigned to accumulations having depths shallower than 10,000 feet. Less than 6 percent of the oil was assigned to accumulations at depths greater than 15,000 feet.

The assessors were also required to describe the expected quality of the resource, in terms of the oil gravity and contaminants of oil and gas. The gravity of the assessed oil is somewhat lighter than oil found near the Prudhoe Bay area. The differences are attributed to a variety of factors and some are based on measurements from wells drilled at undeveloped discoveries near the 1002 area. The average gravity for the assessed oil was about 30 degrees API. There was also no indication that contaminants in the assessed oil would present special problems (for play assessment data see Schuenemeyer, Chap. RS).

The characteristics of the technically recoverable oil most important to the economic analysis are the volumes of oil, the oil accumulation-size distribution, depth of the oil, and geographical location of the resources. Distributions in figure EA2 and supporting data show that most of the assessed oil in the 1002 area was assigned to accumulations sufficiently large to be of economic interest. Furthermore, more than three-fourths of the oil assessed is in accumulations at depths of less than 10,000 feet. Finally, more than 80 percent of the oil was assigned to the western part of the 1002 area which is closest to existing infrastructure.

DATA, ASSUMPTIONS, AND PROCEDURE FOR THE ECONOMIC ANALYSIS

Data

Data from the assessment simulations included accumulation size (volume of recoverable oil, gas, and natural gas liquids), accumulation depth, accumulation area, for oil accumulations; the oil formation volume factor and for gas accumulations; the gas compressibility factor, initial gas pressure and the reservoir temperature. These data were used to develop expected production well recoveries for various accumulation sizes and at various depth intervals. The simulation data were used to compute ratios of gas-to-oil and NGL-to-natural gas by 5000-foot depth intervals.

Data were drawn from earlier economic studies of the 1002 area and elsewhere on the North Slope (J. Broderick, Bureau of Land Management, 1992, Young and Hauser, 1986, National Petroleum Council 1981A, 1981B, Thomas and others, 1993, Thomas and others, 1991, Han-Padron Associates, 1985). Additional data on recent cost trends were obtained from a variety of sources, including the North Star Development Report (British Petroleum, 1994), Alaska Pipeline Office, and the technical literature (Blount and others, 1993, Broman and others, 1992). Drilling cost data from the Annual Joint Association Survey (JAS) (American Petroleum Institute 1997, 1996) were used in formulating drilling cost estimates. The empirical relationship presented in Thomas and others (1993) was used to predict the water cut of produced oil as a function of field depletion. Details of specific cost relationships applied in the analysis are presented in Appendix EA-B.

General Assumptions and Scope of Analysis

The economic analysis presents estimates of the incremental costs of transforming undiscovered resources into additions to proved reserves. Cost functions include the costs of finding, developing, producing and transporting to market resources in currently undiscovered accumulations. These functions are not the same as the economist's market price supply predictions because at any given price the oil and gas industry will allocate funds over a number of provinces and sources of supply in order to meet market demand at lowest costs. An observed price-supply relationship represents the culmination of numerous supplier decisions over many projects and regions. Incremental cost functions represent costs that are computed independently of activities in other areas. Furthermore, the incremental cost functions are assumed to be time independent and should not be confused with the firm supply functions that relate marginal cost to production per unit time period. Because of the time-independent nature of the incremental cost functions and the absence of market demand conditions in the analysis, user costs or the opportunity costs of future resource use are not computed. However, the incremental cost functions and the data which underlie the functions can be used in market supply models.

Undiscovered non-associated gas fields were not evaluated in the economic analysis because a viable gas market appears to be at least two decades into the future. A supporting study did consider the option of transporting North Slope gas to the south and selling the gas as LNG to the Far East (Attanasi, 1994). It concluded that at least until 2015, North Slope gas would be at a competitive cost disadvantage to other existing and potential suppliers to that market. The US Energy Department forecast for 2020 projected no Alaskan natural gas would be transported to the conterminous United States (Energy Information Administration, 1997A, p. 61). In Northern Alaska 30 TCFG of associated gas has already been discovered that can be produced cheaply if a gas market develops. Associated gas produced with oil is typically stripped of its liquids and re-injected into the oil field or used as fuel on the lease. Some of the recovered natural gas liquids are mixed with crude oil and transported through Trans-Alaska Pipeline System and some are re-injected as a miscible fluid flood for enhanced oil recovery.

Economic Assumptions

Economic models are abstractions that characterize real economic systems and are typically just detailed enough to roughly approximate the outcomes of interactions between economic agents. Only the general direction and the approximate magnitude of the reaction of the system to price or cost change can be modeled. It was assumed that the industry is rational; an investment will not be undertaken unless the full operating costs, capital, and cost of capital are recovered. Values of physical and economic variables are assumed to be known with certainty by decision makers. It was assumed that areas considered in the economic analysis were available to exploration for oil.

Economic Parameters

Costs used in this analysis are assumed to represent those prevailing in January of 1996. *Calculations were in constant real 1996 dollars*. The discounted cash flow (DCF) analysis was specific to individual projects and ignored minimum income taxes and tax preference items that might be important from a corporate accounting stance. A 12 percent after-tax required rate of return was assumed. Federal income tax provisions included the changes made in 1993. Based on the 1986 Tax Reform Act, 30 percent of development well drilling cost is classified as tangible cost and therefore capitalized over 7 years. Of the remaining 70 percent of drilling cost (that is, the intangible drilling costs), 30 percent is depreciated over 5 years and the remaining 70 percent is expensed immediately.

Alaska State taxes include the severance, income tax, and ad valorem tax. The severance tax depends on field and well productivity (see Appendix EA-B for details). Although the nominal state income tax rate is 9 percent, the effective tax rate is set by a complex formula based on the specific firm's production and sales. For planning purposes, State agencies use a rate of 1.4 to 3.0 percent of net income. An effective tax rate of 2.2 percent is used here. The State's ad valorem tax is an annual charge equivalent to 2 percent of the economic value of equipment, facilities, and pipelines. The Federal corporate tax rate used in the project analysis was 35 percent. A one-sixth royalty was assumed to be paid to the Federal government (Young and Hauser, 1986).

During the last thirty-years nominal oil prices in the conterminous United States have varied over a range from $3 to $40 per barrel. Discussion in this report focuses on reserve additions from new fields which might be expected with an oil price range of $15 to $30 per barrel in 1996 dollars. The oil price discussed is the landed US West Coast price rather than the well-head price. In the absence of gas markets the well-head price of gas was assumed to be zero. The well-head price of natural gas liquids was assumed to be 75 percent of the per barrel price of crude oil. Though graphs may show additions to reserves for higher prices, if real oil prices rise to $50 per barrel, it is unrealistic to assume that constant real costs would hold. Historical experience has shown that oil and gas price increases lead to escalation in industry capital and operating costs (Kuuskraa and others, 1987).

Transportation, Infrastructure and Location Assumptions

Oil produced in Northern Alaska is shipped via the Trans-Alaska Pipeline System (TAPS) pipeline to the Port of Valdez in Southern Alaska for ocean tanker transport to market. In 1988, TAPS transported an average of 2.0 million barrels per day of oil. For 1997, about 1.4 million barrels per day of oil and natural gas liquids were transported, so that even now there is perhaps 600,000 barrels per day of unused capacity.

The 1002 area was partitioned into two subareas (see figure EA3) where new discoveries are expected to have roughly similar transportation costs. Appendix EA-B discusses the subarea allocation by play. With most of the assessed oil in the western area, it was assumed that an 85-mile pipeline at least 20 inches in diameter would be built from TAPS Pump Station 1 to a central location in the western subarea of the 1002 area. Transportation from the eastern subarea assumes extension of the regional pipeline about 50 miles to the east. The assumed pipeline route and distances are presented in Appendix EA-B.

Resources of the 1002 area were allocated to the western and eastern subareas by the assessment geologists. Distances from the designated centroid points within the two subareas to Pump Station 1 were used for estimating pipeline materials and construction investment cost. A regulated common carrier pipeline business entity is assumed to build and operate the regional pipeline to TAPS. Pipeline tariff charges were set to meet all operating costs, taxes and to assure investors a 12 percent after-tax return on investment. The pipeline liquid flow capacity is of at least 300,000 barrels per day. This approach may overstate costs somewhat because a pipeline with a larger capacity would in all likelihood result in lower unit transport costs. Pipeline investment cost functions originally presented in Young and Hauser (1986) and later updated by Broderick (1992) were further adjusted to reflect the continuing decline in pipeline costs experienced on the North Slope (see Appendix EA-B for details). Annual pipeline operating costs were computed as 2 percent of the initial investment cost. The pipeline business entity is assumed to be subject to all Alaska State taxes as well as Federal taxes.

In the western subarea, a field specific smaller diameter feeder line from the field to the regional pipeline of maximum length of 12 miles was assumed to be built. In the eastern subarea, the maximum length of the field specific feeder pipeline is 16 miles. The transportation charges of the feeder lines depend on field reserves. Details of the investment costs are presented in Appendix EA-B.

TAPS tariff rate and marine transport rate to market are projected semi-annually by the Alaska Department of Revenue. The marine transport rate represents the cost weighted by projected sales volumes of transporting crude oil from Valdez to a set of destinations which include the US lower 48 West Coast, the Far East, and the US midcontinent region. These rates are projected on an annual basis to 2020. (Alaska Department of Revenue, 1997). In constant real 1996 dollars, the average projected TAPS tariff for the period is $2.72 per barrel and similarly, the marine transport cost is $1.73 per barrel. For the western subarea, Table EA-B1 (Appendix EA-B) shows transportation cost for a 600 million barrel field to TAPS is $1.11 per barrel. Similarly, in the eastern subarea transportation cost for a 600 million barrel field is $1.66 per barrel. Well-head oil prices are assumed to be the market oil price less all transportation costs.

Exploration and field development costs

Exploration, field design, and field development methods on the North Slope differ from that of the lower 48 States. Wildcat drilling typically occurs in the winter when temporary ice roads, ice pads, and ice airstrips can be constructed to support drilling activities. After the ice melts there is generally no sign of the winter's activity. Seasonal instability of the permafrost requires construction of gravel pads to support production wells and facilities. Production wells are drilled directionally from the pads to target depths and lateral locations. Gravel drilling pads can typically support as many as 40 well collars spaced at 10 foot intervals along with production equipment. Sidetrack and multilateral drilling of two or more wells using a single well collar enable the maximum utilization of individual drilling pads. The remoteness of the targets, the climate, and the absence of infrastructure impose high initial exploration and development costs on prospects.

For a stand-alone field, produced oil is processed at the field's central processing facility and the final product is transported from the periphery of the field to TAPS. Because developed accumulations are typically very large and provide large payoffs in terms of the volumes of oil that incremental increases in oil recovery can yield, operators typically introduce technological innovations quickly. For example, the application of extended reach drilling has allowed production wells access to distant reaches of the reservoir, sometimes eliminating the need for additional drill pads or allowing satellite field development from existing drill pads. Because of this technology, it was assumed that any offshore accumulations of the 1002 area that occur beneath the lagoonal areas between the shoreline and barrier islands can be developed from onshore drilling pads.

Exploration costs

Exploration effort leading to new field discoveries is represented by the drilling of wildcat wells. Exploration costs are accounted for after the lease is acquired. Non-drilling exploration expenditures (exclusive of lease bonuses) were assumed to amount to no more than 50 percent of the drilling cost (Vidas and others, 1993). Non-drilling exploration expenditures include geologic and geophysical data collection after lease acquisition, scouting costs, and overhead charges associated with land acquisition. Wildcat well drilling costs were assumed to be twice the cost of drilling production wells in the 1002 area.[2] However, for the first ten wildcat wells drilled a minimum cost of 10 million dollars per well was assumed and the second ten wildcat wells had a minimum cost of 8 million dollars per well. Exploration was evaluated in increments of 20 wildcat wells. Actual exploration and development costs depend on site-specific characteristics of the prospect. Play analysis does not provide specific locations, so generic costs were used.

Field development costs

The continuing reduction in capital and operating costs for new discoveries on the North Slope has been substantial and well documented (Nelson, 1997, Oil and Gas Journal, 1994, Thomas and others, 1993, Harris, 1987A, 1987B). Drilling and completion costs of production and injection wells and

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[2] For example, a development well drilled to a depth of 7500 feet in the 1002 Area is estimated to cost 2.73 million dollars. Total costs for a comparible wildcat well, including non-drilling costs that amount to 50 percent of drilling cost, are 8.19 million dollars.

facilities' costs constitute the two principal field development costs categories. To keep the discussion brief, design and cost data details are presented in Appendix EA-B.

Field drilling costs were based on the number of wells required to develop fields and the cost per well. Per well drilling cost estimates were assumed to represent long-run future costs and were estimated using data from the Joint Association Survey (American Petroleum Institute, 1996, and 1997). The estimated Prudhoe Bay area drilling costs were increased by 30 percent to compensate for a lack of infrastructure or special environmental precautions associated with the 1002 area. Estimated drilling and completion cost per production well for depths to 5000 feet is $2.2 million, 5000 feet to 10000 feet $2.7 million, 10000 feet to 15000 feet $3.3 million, and depths greater than 15000 feet $5.8 million.

The number of wells required to develop a discovery depends on well productivity. Expected values for the well productivity were calculated first using the play level assessment simulated reservoir parameter values. For each field size and depth category, average well productivity was calculated as the weighted average of the well productivity of the predicted fields occurring in that classification. Across different depth intervals well productivity estimates varied substantially even within the same field size category reflecting the broad variations in reservoir quality of the plays occurring in the depth interval. Appendix EA-B discusses the estimation process and Table EA-B2 shows the well productivities used in the analysis. For each production well, 0.4 injection wells (water or gas) would also be drilled (NPC, 1981A, Young and Hauser, 1986).

Facilities include drill pads, flow lines from drilling sites, the central processing unit, and infrastructure required for housing workers, including amenities. Facilities design and costs depend on peak fluid flow rates and ultimately on the field size. This cost category has had the most dramatic reduction in recent years, as operators have introduced new field designs and systems in an effort to minimize costs. The application of technology that resulted in extended reach and multilateral production wells has reduced the number and size of drill pads needed for field development. Appendix EA-B discusses the procedure applied to recalibrate the facilities cost functions used in earlier studies. Table EA-B3 presents the cost estimates by field size class that were used in this study. Figure EA4 compares earlier cost functions with the newly recalibrated cost function.

As of the end of 1997, the five oil fields developed on a stand-alone basis in Northern Alaska are Prudhoe Bay, Kuparuk, Lisburne, Milne Point, and Endicott. Other producing fields or producing entities, specifically, Point McIntyre, Niakuk, North Prudhoe Bay, and West Beach use the central processing facilities of the Lisburne field. Development of such fields on a satellite basis or cost sharing of new facilities by two or more discoveries can dramatically reduce facilities costs as well as reduce the time to production. Actual savings are site-specific because certain facilities costs such as drill pads, internal roads, and product transportation are location dependent. It was assumed that facilities sharing would, on average, result in a 30 percent reduction in facilities investment costs (Thomas and others, 1993). Facilities sharing was limited to fields smaller than 130 million barrels in the western subarea only. In the eastern subarea, the small numbers of assessed fields and possibly greater distances between fields make facilities sharing unlikely.

Field operating costs include labor, supervision, overhead and administration, communications, catering, supplies, consumables, well service and workovers, facilities maintenance and insurance, and transportation. Some costs, such as well workover costs have declined because of the introduction of new materials such as coiled tubing (Oil and Gas Journal, 1994). Annual field operating costs were estimated as a function of hydrocarbon and water fluid volumes (see Appendix EA-B). These volumes were projected annually using field production forecasts and a water cut function presented in figure EA-B3, Appendix EA-B, (Thomas and others, 1991). As fields are depleted the water cut increases, thereby increasing the per barrel cost of oil.

Economic rationale for computations

Field size, depth, regional costs, and co-product ratios determine whether a field will be commercially developable. A new field is *commercially developable* if the after-tax net present value of its development is greater than zero. The algorithm that calculated incremental costs used the predicted size and depth distribution of undiscovered fields (at the subarea level) to compute quantities of resources that are commercially developable at various prices. To compute finding costs, the geologic assessment is coupled with a finding rate model (Attanasi and Bird, 1996) to forecast the size and depth distribution of new discoveries from increments of wildcat drilling. These forecasts drive the economic field development and production process model to determine the aggregate value of new discoveries and consequently, how many successive increments of exploration effort should be expended.

In particular, at a given price, the commercial value of developing a representative field from a specific field size class and depth category is determined by the results of a discounted cashflow (DCF) analysis. The net after-tax cash flow consists of revenues from the production of oil less the operating costs, capital costs in the year incurred and all taxes. All new discoveries of a particular size and depth category are assumed to be developed if the representative field is found to be commercially developable, that is the after-tax DCF is greater than zero, where the discount rate (12 percent) represents the cost of capital and the industry's required return. It is assumed that when operator income declines to the sum of direct operating costs and the operator's production-related taxes, the economic limit rate is reached and field production stops. Newly discovered commercially developable fields are aggregated to provide an estimate of potential reserves from undiscovered fields for a given price and required rate of return. *The results from this procedure do not imply that every field determined to be commercially developable is worth exploring for.*

The basis for the estimates of recoverable undiscovered petroleum as a function of price is that the incremental units of exploration, development, and production effort will not take place unless the revenues expected to be received from the eventual production will cover the incremental costs, including a normal return on the incremental investment. Exploration is assumed to continue until the incremental cost of drilling wildcat wells is equal to or greater than the net present value of the cost of the commercially developed fields discovered by the last increment of wildcat wells. For the last increment of oil and gas produced from a field, operating costs (including production related taxes) per barrel of oil equivalent are equal to price.

These two assumptions together imply that for the commercially developable resources discovered by the last economic increment of wildcat wells, that is, for those reserves found, developed and produced at the economic margin, the sum of finding costs and development and production costs per barrel equals the well head price. These costs are frequently called the marginal finding costs and the marginal development and production costs. The marginal finding costs are calculated by dividing the cost of the last increment of wildcat wells (which is approximately equal to the sum of the after-tax net present value of all commercially developable fields discovered in that last increment of exploration) by the amount of economic resources discovered by the last increment of exploration. Marginal development and production cost per barrel (for the economic resources discovered in that last increment of exploration) are calculated by subtracting the marginal finding costs from the well head price.

Finding rate functions provide the critical link between the field development costs and exploration costs. The size, depth, and number of undiscovered fields were computed from the *geologic assessment data*. However, *finding rate functions determine ordering of new discoveries and rates at which new fields are found as a function of cumulative wildcats drilled in a particular depth interval.* A consistent set of finding rate coefficients could not be calculated for Northern Alaska. A procedure for obtaining default coefficients is described in Attanasi and Bird (1996). Allocations of wildcat wells by depth interval were made in such a way that for each increment of wildcat wells evaluated, the after-tax net present value of the oil fields discovered was maximized.

INCREMENTAL COSTS: RESULTS AND INTERPRETATION

Commercially developable resources

Table EA3 shows the allocations of the technically recoverable oil, associated gas, and natural gas liquids in oil fields by subarea. Estimates shown are those associated with the mean, 95th fractile, and 5th fractile of the distribution of assessed oil. For each case, the western subarea accounts for more than 80 percent of the oil. Transportation costs for a 600 million barrel field range from \$5.57 per barrel for the western coastal subarea to \$6.11 per barrel for the eastern foothills subarea. So, an \$18 per barrel oil market price translates into a well-head price of between \$12.43 and \$11.89 per barrel.

Commercially developable resources are the economic target for exploration. The amount of oil estimated to be *commercially developable (that is, developable if already discovered)* at each price is a direct consequence of the field size distributions shown in figure EA2. Table EA3 shows that even at a market price of \$12 per barrel at the mean and 5th fractile estimates, about 5 percent and 11 percent of assessed oil, respectively, is commercially developable. At $15 per barrel (not shown), for the mean, 95th, and 5th fractiles estimates, respectively, 2.5 BBO , 0.5 BBO, and 5.3 BBO is commercially developable. By $18 per barrel about 60 percent of the oil assessed at the mean, 70 percent of the oil at 5th fractile, and 48 percent of the oil assessed at the 95th fractile is commercially developable. The quantity of commercially developable oil approaches the assessed technically recoverable oil as the minimum economic commercially developable fields become smaller.

For a market crude oil price of $15 per barrel, the minimum commercially developable field is about 0.5 BBO for fields in the western subarea to depths of 10,000 feet. Deeper fields of that size require one or two dollars more to be commercially developable in the western subarea. In the eastern subarea, a 0.5 BBO is not commercially developable until the market price is $16 per barrel if its depth is 10,000 feet or less. Beyond 10,000 feet the eastern subarea threshold price increases to $20 per barrel. Development well productivity estimates shown in Table EA-B2 indicate that plays present at these depths were inferior in terms of reservoir quality to plays occurring at depths of less than 10,000 feet. Costs for these deeper fields not only escalate because of higher per well drilling costs, but because of inferior well productivity. However, less than one-fourth of assessed oil was assigned to depths deeper than 10,000 feet.

At $18 per barrel, fields in both subareas of at least 260 million barrels and less than 10,000 feet are commercially developable. It is assumed that fields in the western subarea smaller than 130 million barrels can be developed as satellite units of other fields by participating in facilities sharing. The threshold price that would allow commercial development of resources already identified in satellite fields between 64 an 130 million barrels (at less than 10,000 feet) is $23 per barrel. Without facilities sharing, these fields might become commercially developable at $26 per barrel.

Incremental costs: finding, development, production and transportation

The full costs include finding, development, production and in the case of Northern Alaska, transportation costs. Incremental costs are linked to development, production, and transportation cost by finding rate functions that predict the discovery size distributions generated by increments of wildcat wells. Appendix EA-C presents the structure of the model and its application. Computations were based on successive increments of 20 wildcat wells. Figure EA5 presents the incremental cost functions for crude oil for the 1002 area based on the undiscovered field size distributions associated with the 95th fractile, the mean, and 5th fractile estimates. Table EA4 summarizes the subarea and province estimates of incremental costs, expected reserve additions, number of economic wildcat wells, and finding costs. Along with crude oil, the table shows the associated gas and associated gas liquids in developable oil discoveries.

Examination of the table allows one to compute the oil finding rate implied by the model parameters. The table shows, at the mean an average finding rate for the first 120 wildcat wells (at $18 per barrel) is about 20 million barrels per well. For the second 120 wells the average finding rate declines rapidly to about 13 million barrels per wildcat well.[3] Based on a compilation of data from the recently published literature and other sources and wildcat well counts from Petroleum Information Inc. from 1981 through 1990, the discovery rate (representing roughly 50 wildcat wells after about 160 wildcats were drilled through 1980) for the rest of the North Slope was estimated to be 18 to 20 million barrels per wildcat well. The finding rates predicted in this analysis are not outside of historical experience. Technological advances that have occurred in the last decade have undoubtedly improved discovery efficiency and enhanced finding rates.

Figure EA5 shows, rather dramatically, the differences in incremental costs that result from the different frequency-size distributions associated with estimates of the 95th fractile, the mean, and 5th fractile of the 1002 area oil distribution. As noted earlier, not only is the 95th fractile estimate smaller in the volume of oil assessed but the oil is distributed in smaller fields that in many cases are not only harder to find but may not even be commercially developable. The threshold prices at which wildcat drilling and development starts are $18.90 per barrel for the 95th fractile distribution, $15.30 per barrel of the distribution associated with the mean, and $13.40 per barrel for the distribution associated with the 5th fractile estimates. Furthermore, because such a large proportion of the oil associated with the mean and 5th fractile distributions is in large fields (greater than 500 million barrels, see Table EA2), the incremental cost functions show large additions to reserves as

[3] Using the mean distribution, at $21 per barrel 240 wildcat wells would be economic to drill amounting to a drilling density of 1 wildcat well for 10 square miles. Finding rate calculations made from the data presented in Table EA4 are confounded by changing economic conditions. However, discovery sizes reported by government or industry are also affected by prevailing economic conditions.

prices initially increase beyond the threshold price at which exploration is initiated. Discovery rates decline rather rapidly after the initial increments of wildcat drilling are completed and the large low cost discoveries are depleted.

For the mean and 5th fractile distributions at $18 per barrel, 2.40 BBO and 6.15 BBO are economic to find, develop, produce, and transport to markets. This amounts to 31 percent and half of the total volume of oil that was assessed at these respective estimates. At $30 per barrel, 82 percent of the assessed oil for the mean, 89 percent of the 5th fractile estimate, and 70 percent of the assessed oil for the 95th fractile estimates is economic. Table EA4 shows, as might have been expected from the geologic assessment, that the eastern subarea always has a higher threshold cost at which exploration is initiated than the western subarea.

The analysis was repeated using the undiscovered field size distribution corresponding to the *mean oil estimate* assuming alternatively an 8 percent and 16 percent required return. Reducing the required return to an after-tax rate of 8 percent increased the volume of economic oil available at $18 per barrel by 1.0 BBO and reduced the threshold price at which exploration becomes economic from $16 to $14 per barrel. Increasing the required return to 16 percent resulted in a reduction of economic oil at $18 per barrel by about 1.1 BBO and an increase in the price at which exploration becomes economic from $16 to $17 per barrel. Hurdle rate changes affect minimum commercially developable field size, and by changing marginal commercial value of new discoveries affects the number of wildcat wells that can be drilled profitably. As incremental costs increase, absolute and relative differences in the estimates of the volumes of economic oil tend to decline (see figure EA6).

To summarize, the assessed field size distributions associated with the mean, 95th, and 5th fractile estimates, respectively, to a large part determine the threshold prices at which the exploration can be initiated, as well as, the position and shape of the incremental cost functions shown in Figure EA5. Estimates representing larger volumes of technically recoverable oil generally have field size distributions with greater proportions of the resources assigned to large fields that typically have lower development costs and are found early in the exploration process. In an environment such as the North Slope where minimum commercial field size is large, such differences in field size distributions magnify differences in estimates of economically recoverable oil beyond what would be expected by different volumes. The relative effects of

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alternative hurdle rates were most noticeable at the lower incremental cost levels but diminished as market prices approached $30 per barrel. Computations based on the field size distribution corresponding to the mean estimate showed that by accepting a one-third reduction in rate of return (to 8 percent.), exploration becomes economic at threshold market prices as low as $14 per barrel.

CONCLUSIONS AND LIMITATIONS

Technically recoverable resources assessed for the 1002 area at the 95th and 5th fractiles estimates were 4.25 BBO and 11.80 BBO, respectively. The mean technically recoverable oil amounted to the 7.69 BBO. Undiscovered size-frequency distributions corresponding to the 95th fractile, the mean, and 5th fractile estimates showed fields with at least 260 million barrels accounting for 2.21 BBO, 4.97 BBO, and 8.52 BBO, respectively. Consequently, most of the oil resources assessed will be in field sizes of economic interest.

Incremental costs include the *full costs of finding, developing, producing, and transporting oil to market*. At incremental costs of $18 per barrel, 2.4 BBO associated with the mean and 6.2 BBO associated with the 5th fractile is economic to find, develop, produce, and transport to market. Based on the field size distribution associated with the 95th fractile estimate, full costs will not be met until market prices exceed $18.90 per barrel. Because most of the resources assigned the mean and 5th fractile estimates were in large accumulations, the associated incremental cost functions showed large additions to reserves as market prices increase above threshold prices of $16 and $14 per barrel, respectively. At a market price of $24 per barrel 2.0 BBO or 48 percent of the oil assessed at the 95th fractile is economic. Similarly, for the mean estimate, 5.2 or 68 percent of the assessed oil is economic and for the 5th fractile estimate 9.4 BBO or 79 percent of the assessed oil is economic. It is important to keep in mind that with only one set of exceptions[4], accumulations were evaluated as standalone fields. In the western subarea, it is likely that fields could include more than a single accumulation and thus our estimates of development costs will overstate actual costs.

[4] The single exception was for accumulations smaller than 130 million barrels fields in the western subarea were assumed to be developable as satellite fields.

The 1002 area accounts for 1.55 million acres of the more than 19 million acres of the Arctic National Wildlife Refuge. It is approximately 104 miles long with a maximum width of 33 miles and a minimum width of 16 miles (Department of Interior, 1986). The western border of the 1002 area is approximately 50 miles due east of the Trans-Alaska pipeline. The geologic assessment has represented a significant change in viewpoint from the 1987 study and from later studies associated with US Geological Survey National Oil and Gas Assessments. Until a systematic subsurface evaluation is accomplished, uncertainty about the size and nature of the resource will remain significant. There are also important sources of uncertainty attached to the economic evaluation of the resources by virtue of the many assumptions that were required. Furthermore, wide variations in world oil prices increase the risks of investing in high cost areas such as the North Slope that are beyond the scope of this analysis to capture.

This analysis was time independent. At recently prevailing rates of wildcat drilling for the North Slope it could take perhaps a decade to drill the number of well increments that might be economic at an incremental cost of $18 per barrel for either the mean estimate or 5th fractile estimate. During that time additional improvements in technology could lower costs further. Alternatively, any attempt to rapidly increase drilling rates would undoubtedly drive up drilling rig day rates and cause increasing costs, voiding a central assumption in this analysis of constant real costs. The incremental cost functions do not show what the industry will do but what is possible given that the volumes and distribution of resources occur and economic assumptions match reality.

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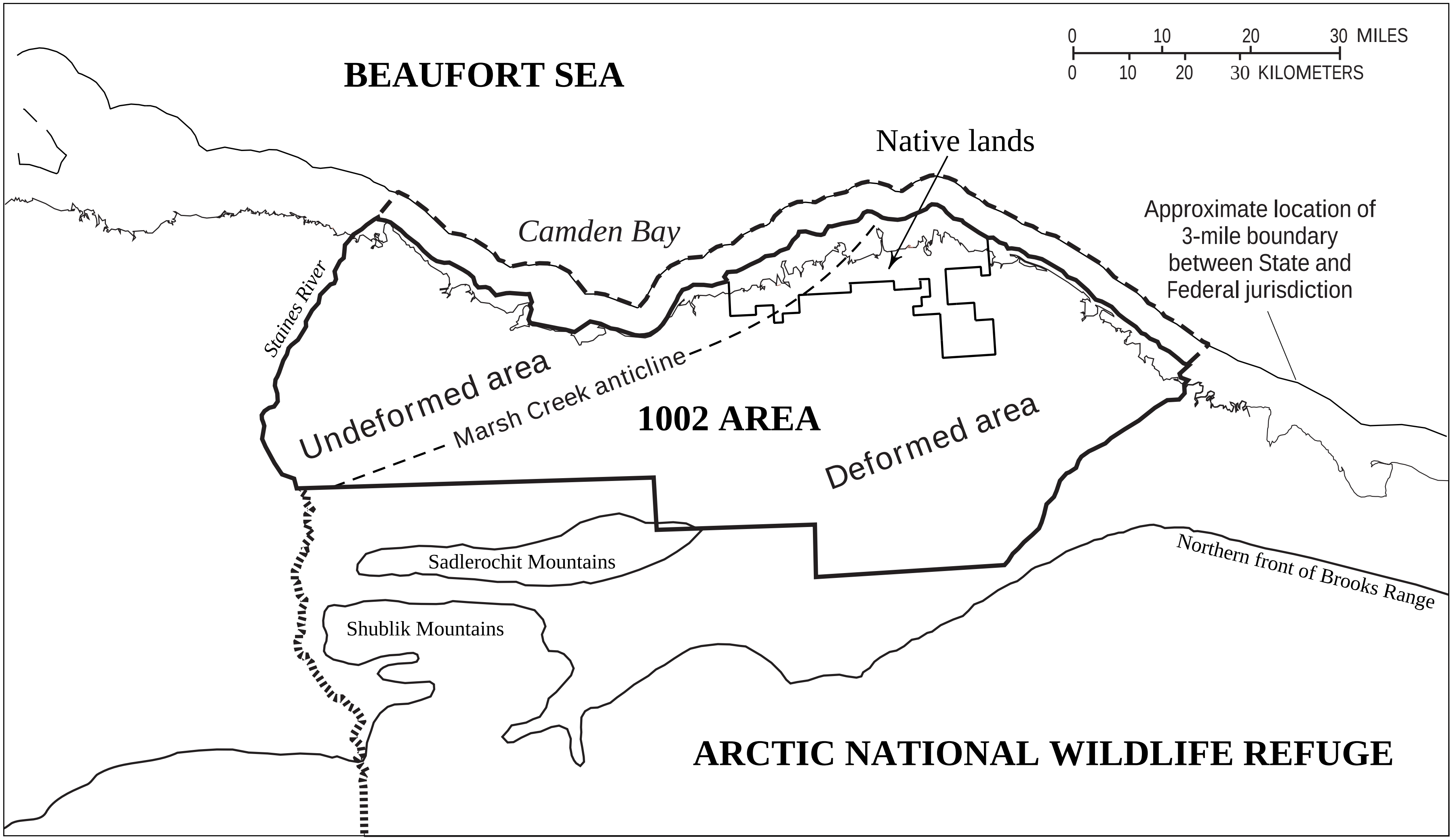

Figure EA1. Map of Northeastern Alaska showing the1002 area location in relation to the Arctic National Wildlife Refuge and the Undeformed and Deformed areas of the 1002 area. Petroleum plays principally in the Undeformed area are the Topset, Turbidite, Wedge, Thomson, Kemik, and Undeformed Franklinian. Plays principally in the Deformed area include the Thin-Skinnned Thrust Belt, Ellesmerian Thrust Belt, Deformed Franklinian, and Niguanak/Aurora.

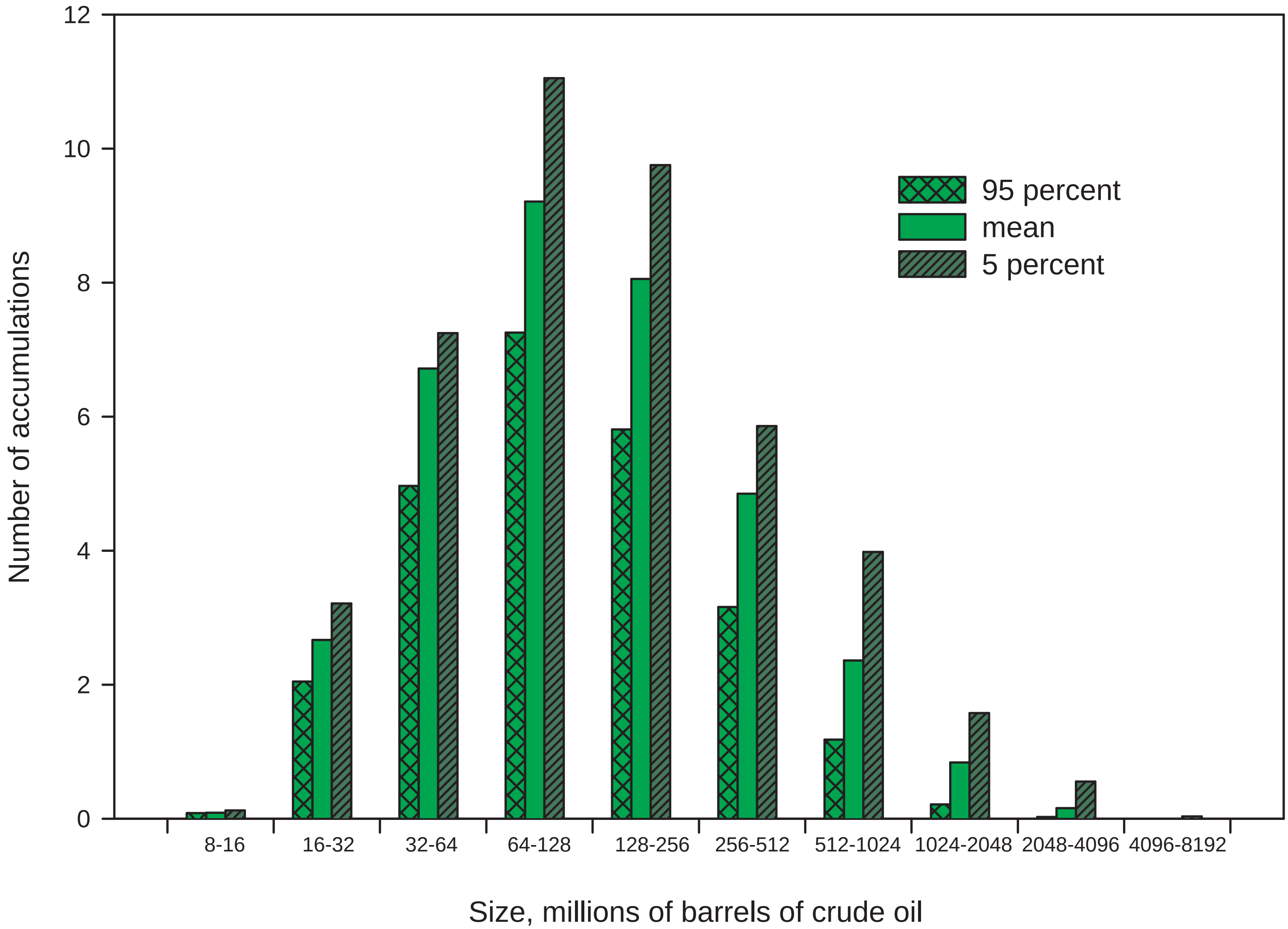

Figure EA2. Size frequency distribution of undiscovered conventional oil accumulations associated with the 95th fractile estimate, the mean estimate, and the 5th fractile estimate of the assessed distribution of undiscovered oil for the 1002 area.

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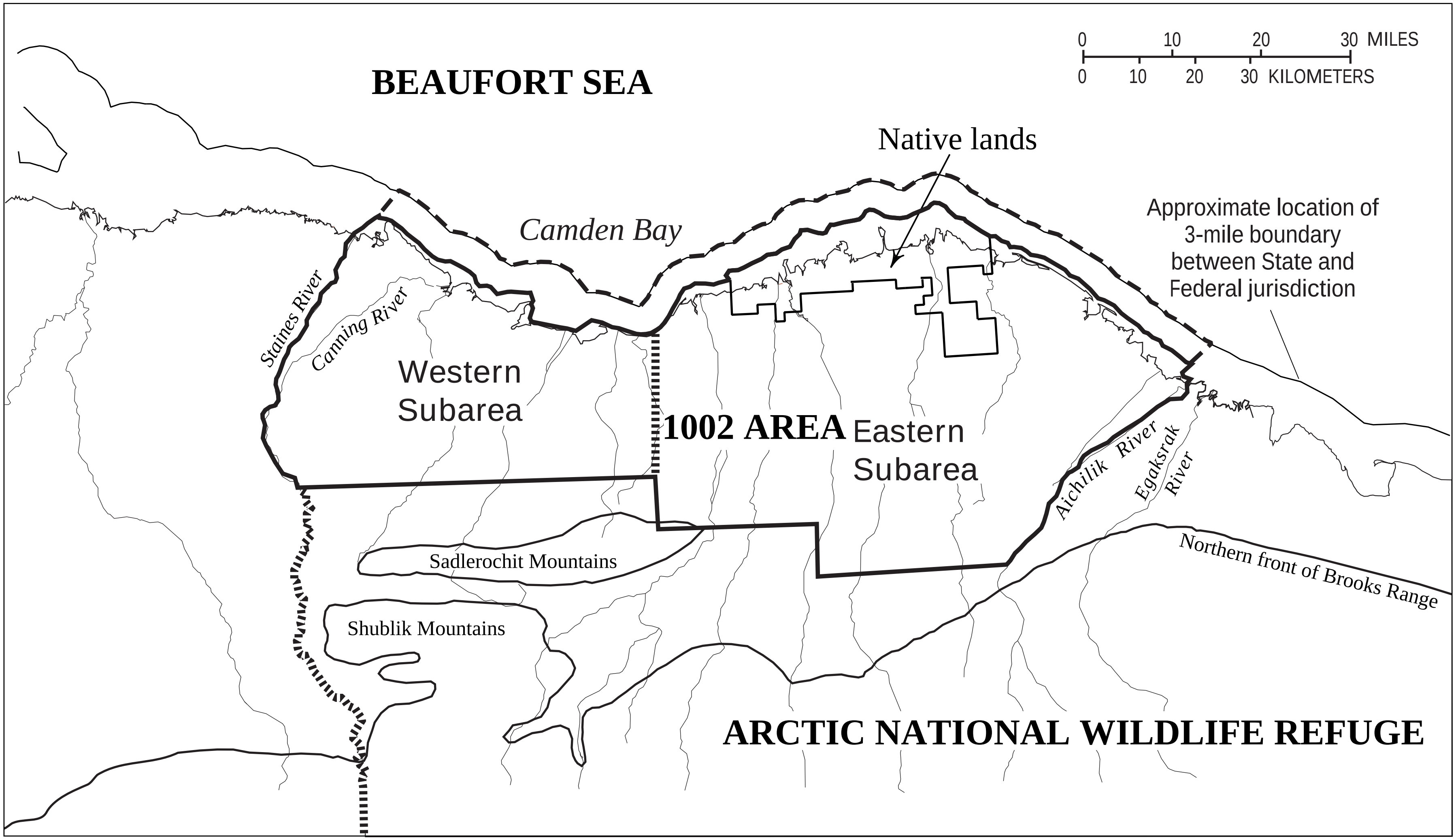

Figure EA3. Map showing the partitioning of the 1002 area into the western and eastern subareas.

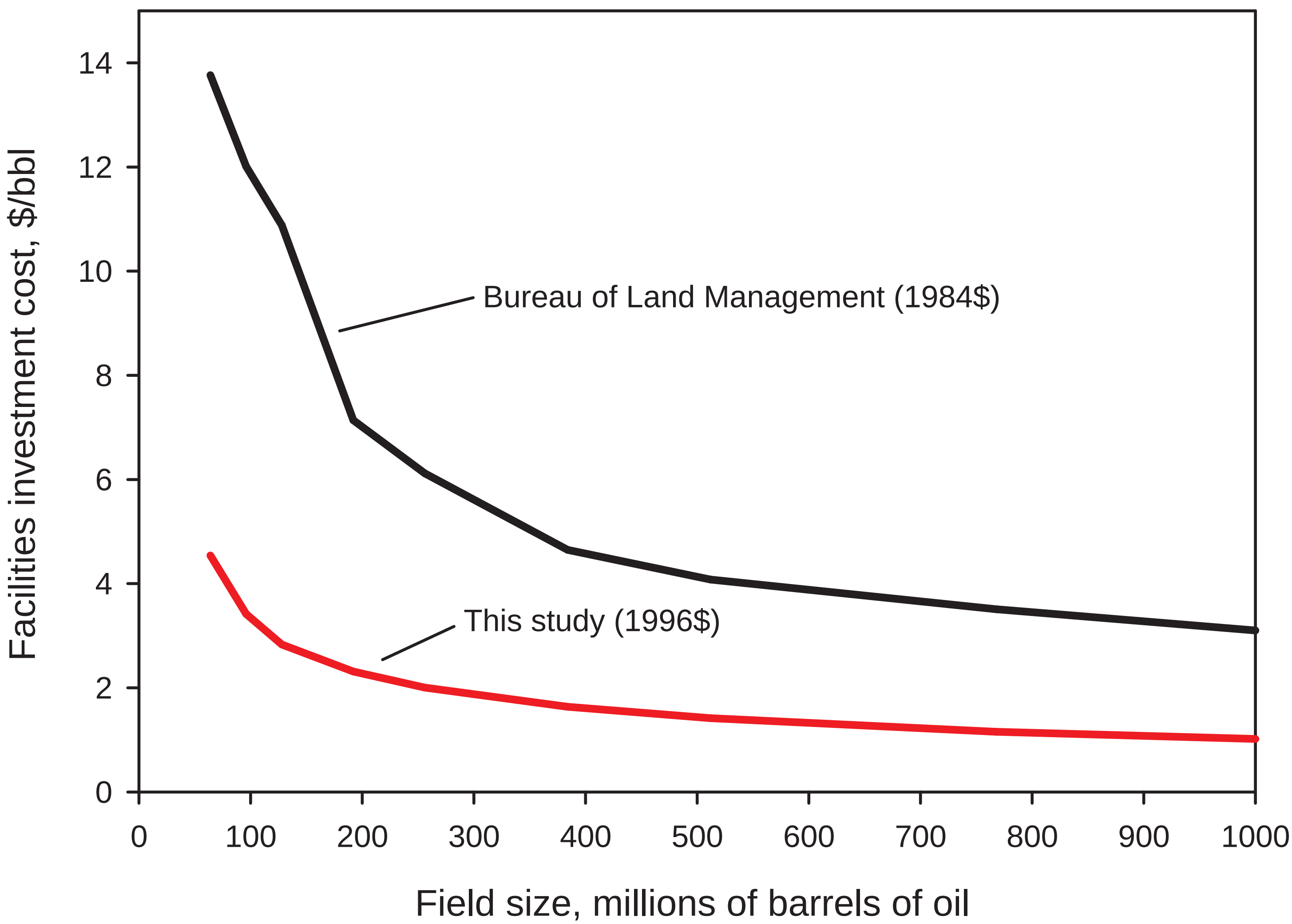

Figure EA4. Facilities investment cost per barrel as a function of field size. Data represented in top function are from Young and Hauser (1986) in 1984 dollars and the data represented by the bottom function are those used in this study and are in 1996 dollars. Description of cost estimation procedure can be found in Appendix EA-B.

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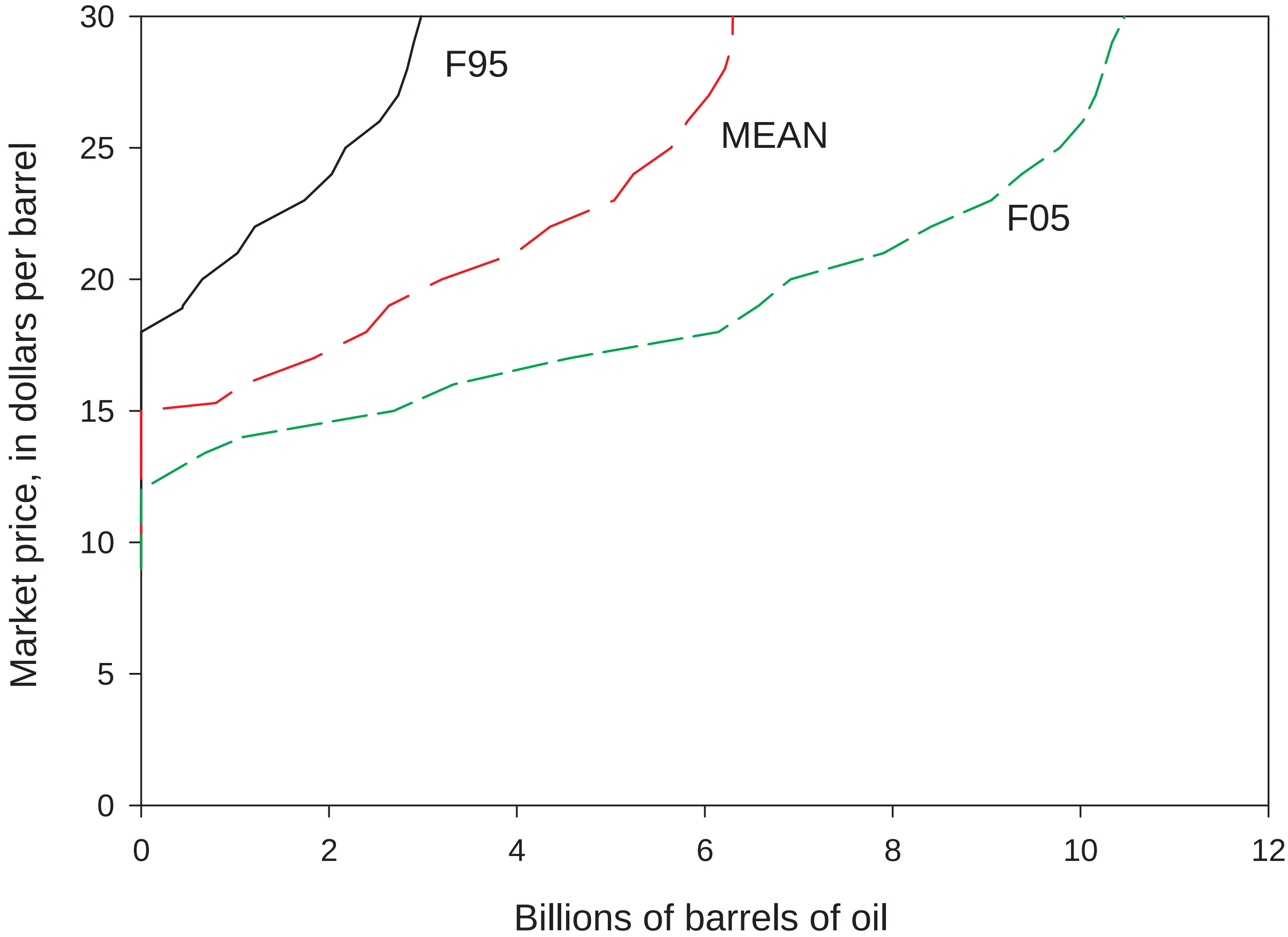

Figure EA5. Incremental costs, in dollars per barrel, of finding, developing, producing, and transporting crude oil from undiscovered fields in the 1002 area of Northern Alaska to market.

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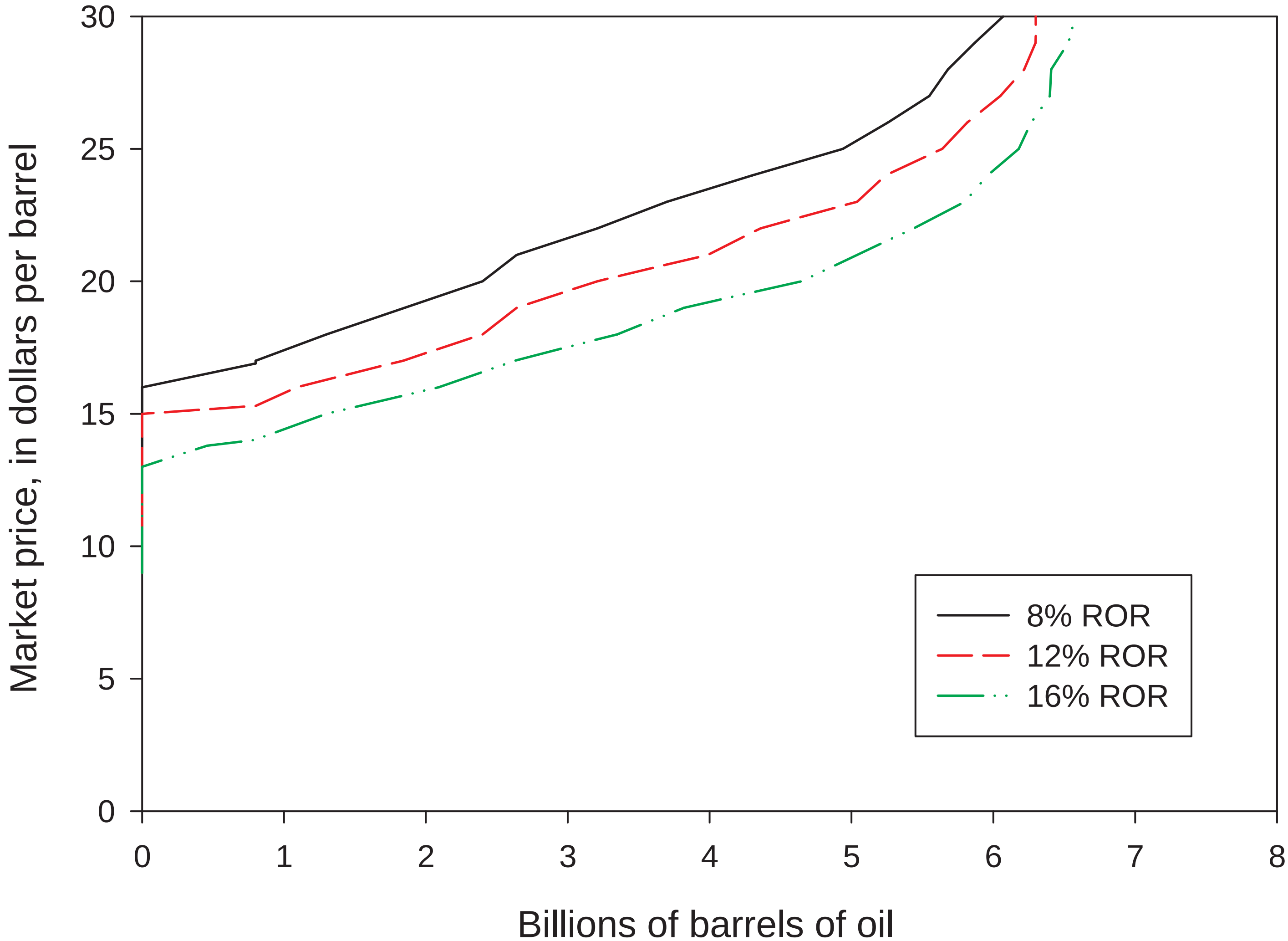

Figure EA6. Incremental costs, in dollars per barrel, of finding, developing, producing, and transporting crude oil from undiscovered fields in the 1002 area of Northern Alaska based based on required rates of return of 8 percent, 12 percent, 16 percent.

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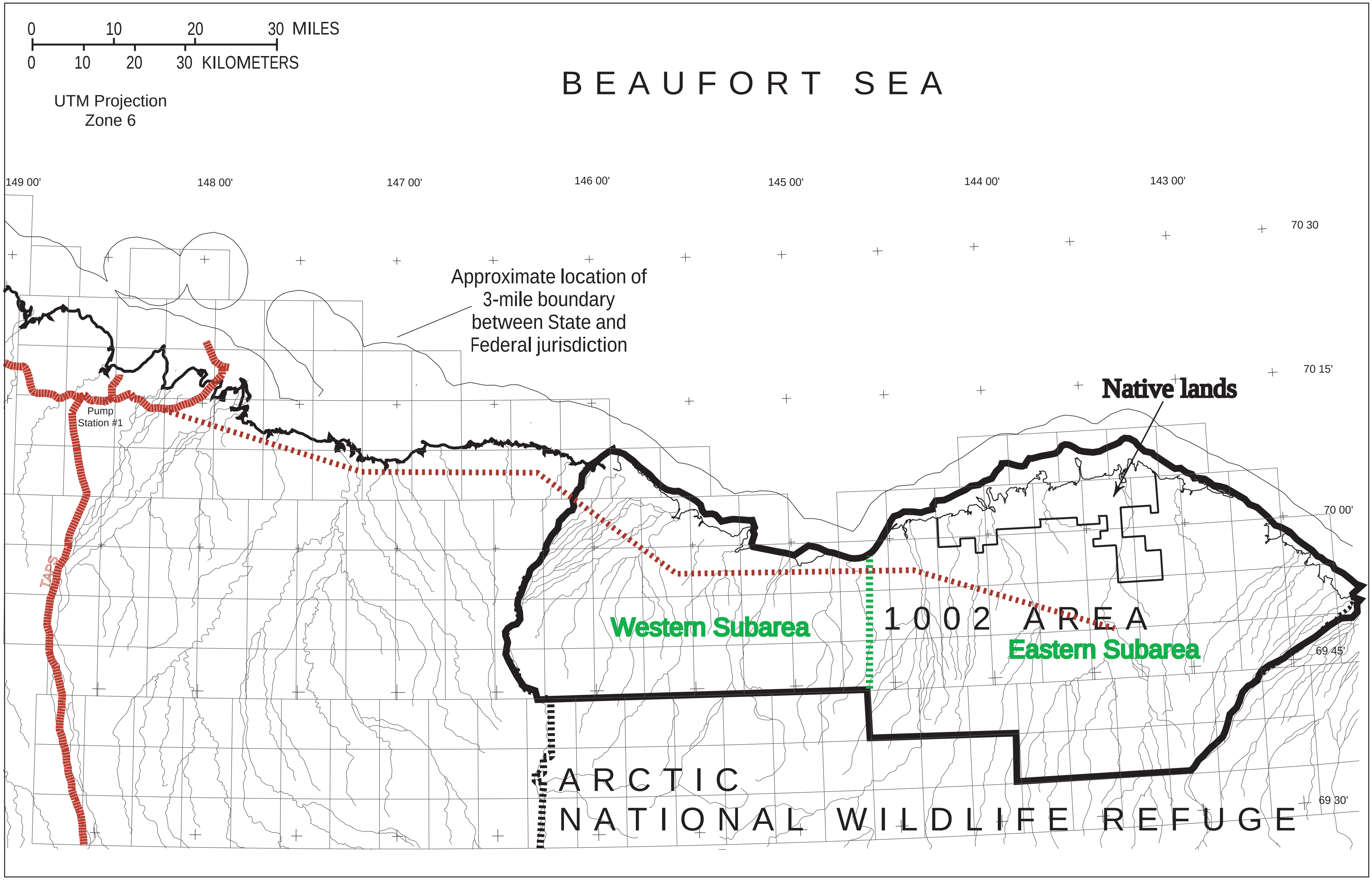

Figure EA-B1. Map showing the partitioning of the 1002 area into the western and eastern subareas and the proposed pipeline transport system (shown as red dotted line from pump station 1 to the eastern subarea of the 1002 area). Solid red line shows existing Trans-Alaska Pipeline System (TAPS).

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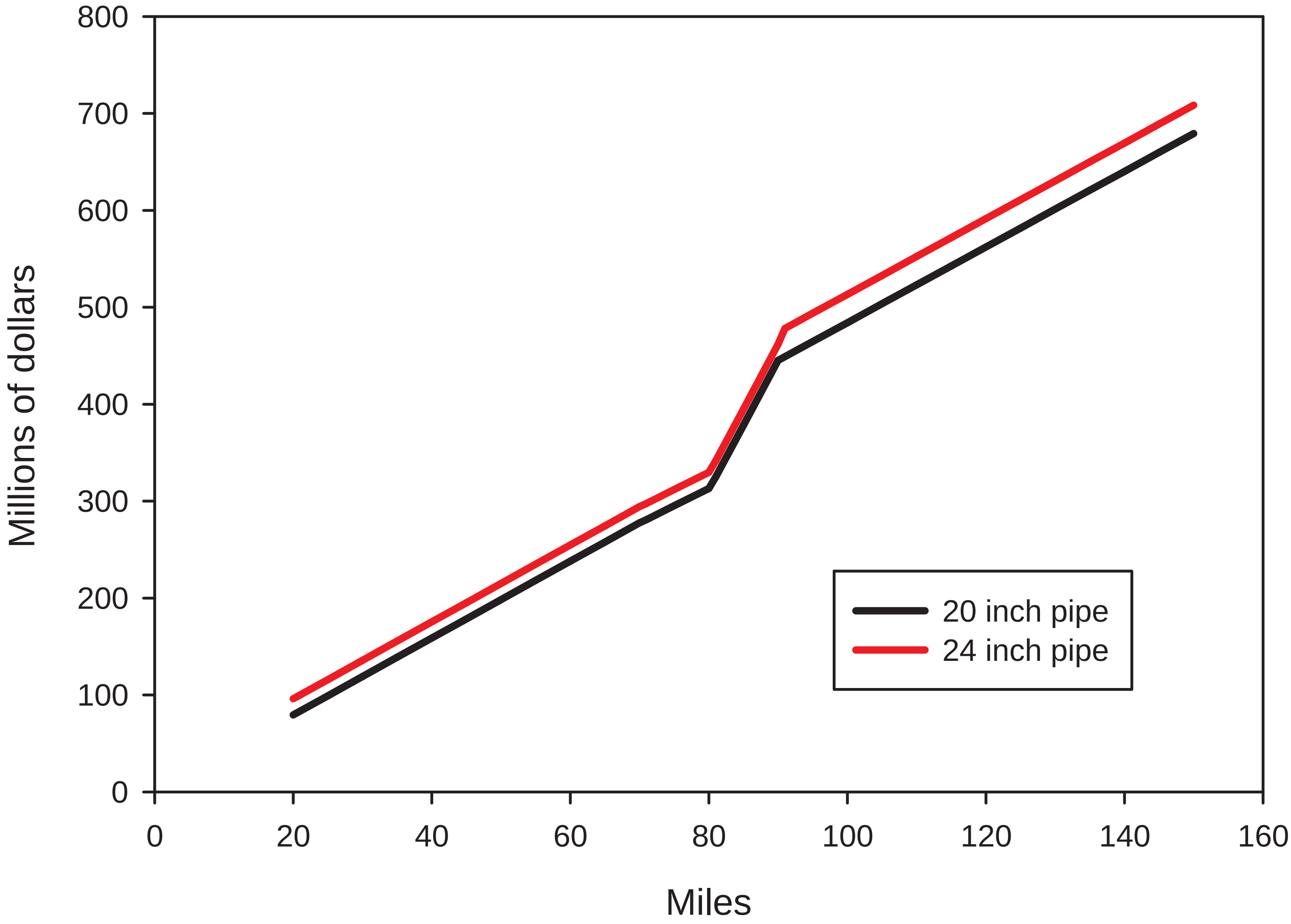

Figure EA-B2. Pipeline investment cost estimates for the regional pipeline as a function of distance. Function updated from Broderick (1992). The discontinuity in the function at 80 miles of length indicates a requirement for an intermediate pump station.

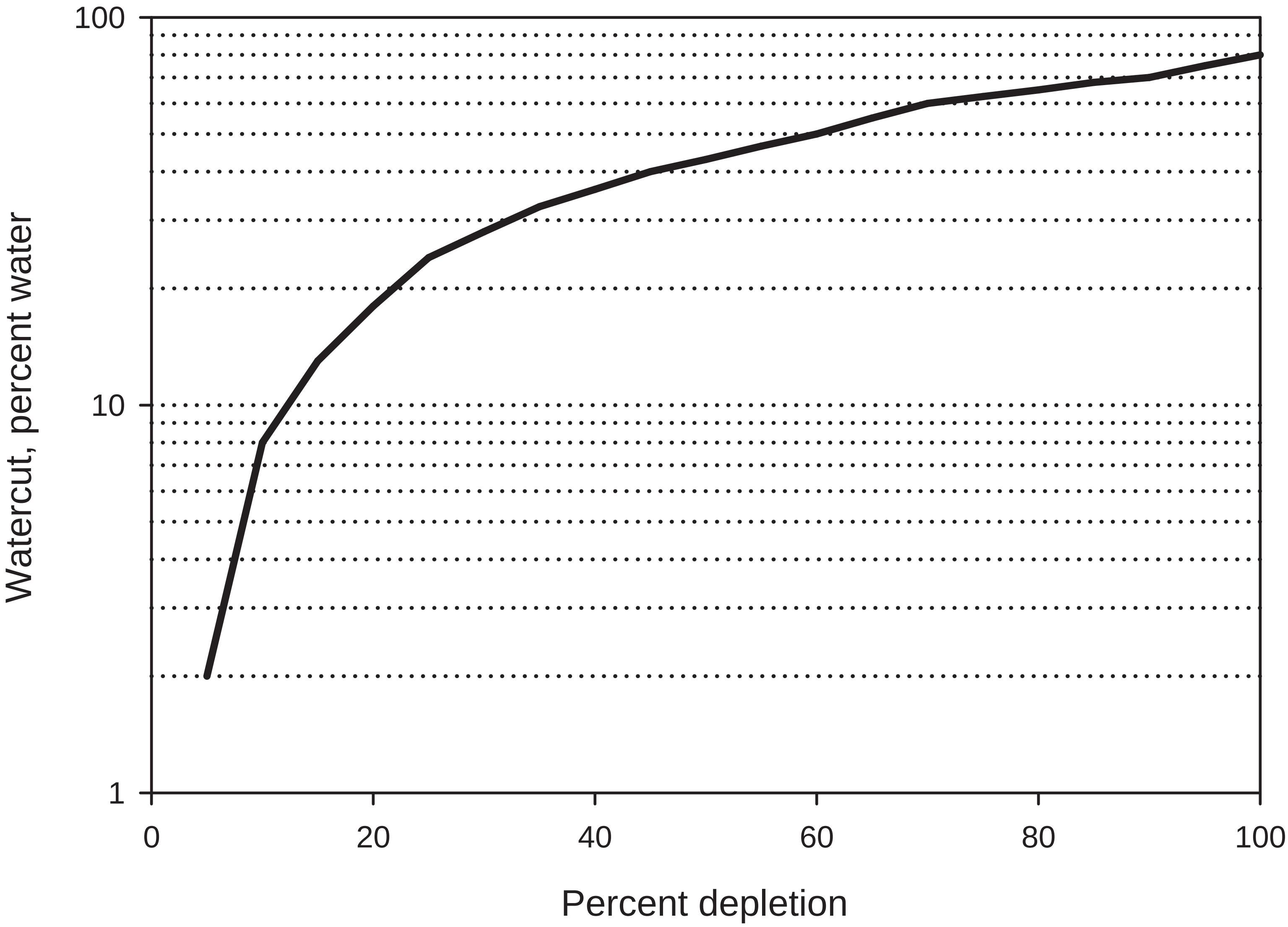

Figure EA-B3. Percentage of water in production stream as a function of reservoir depletion. Data are from Thomas and others (1991).

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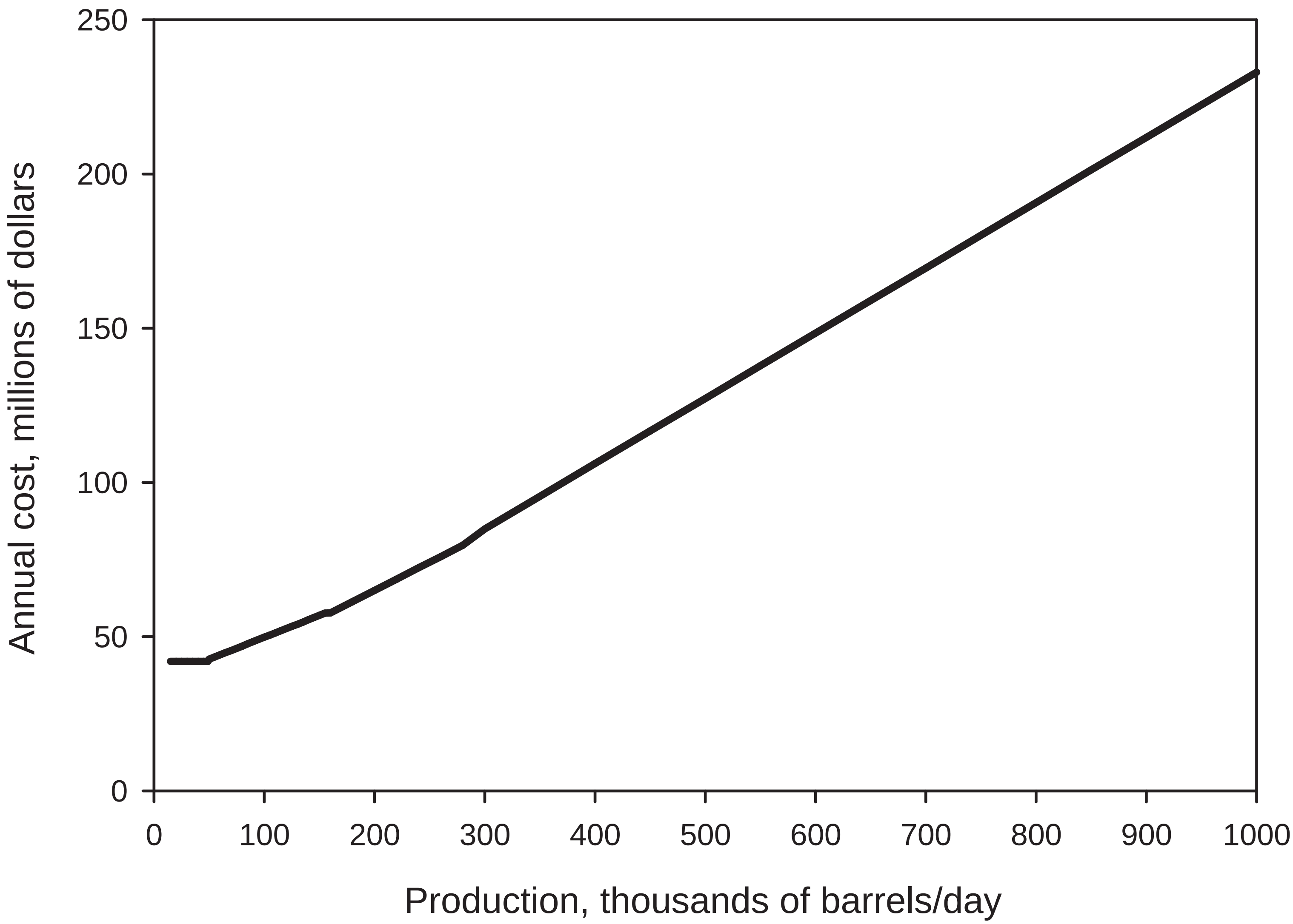

Figure EA-B4. Annual operation costs as a function of average daily fluid production rates in thousands of barrels per day. Data are in 1996 dollars. See Appendix EA-B for a description of the cost estimation procedures.

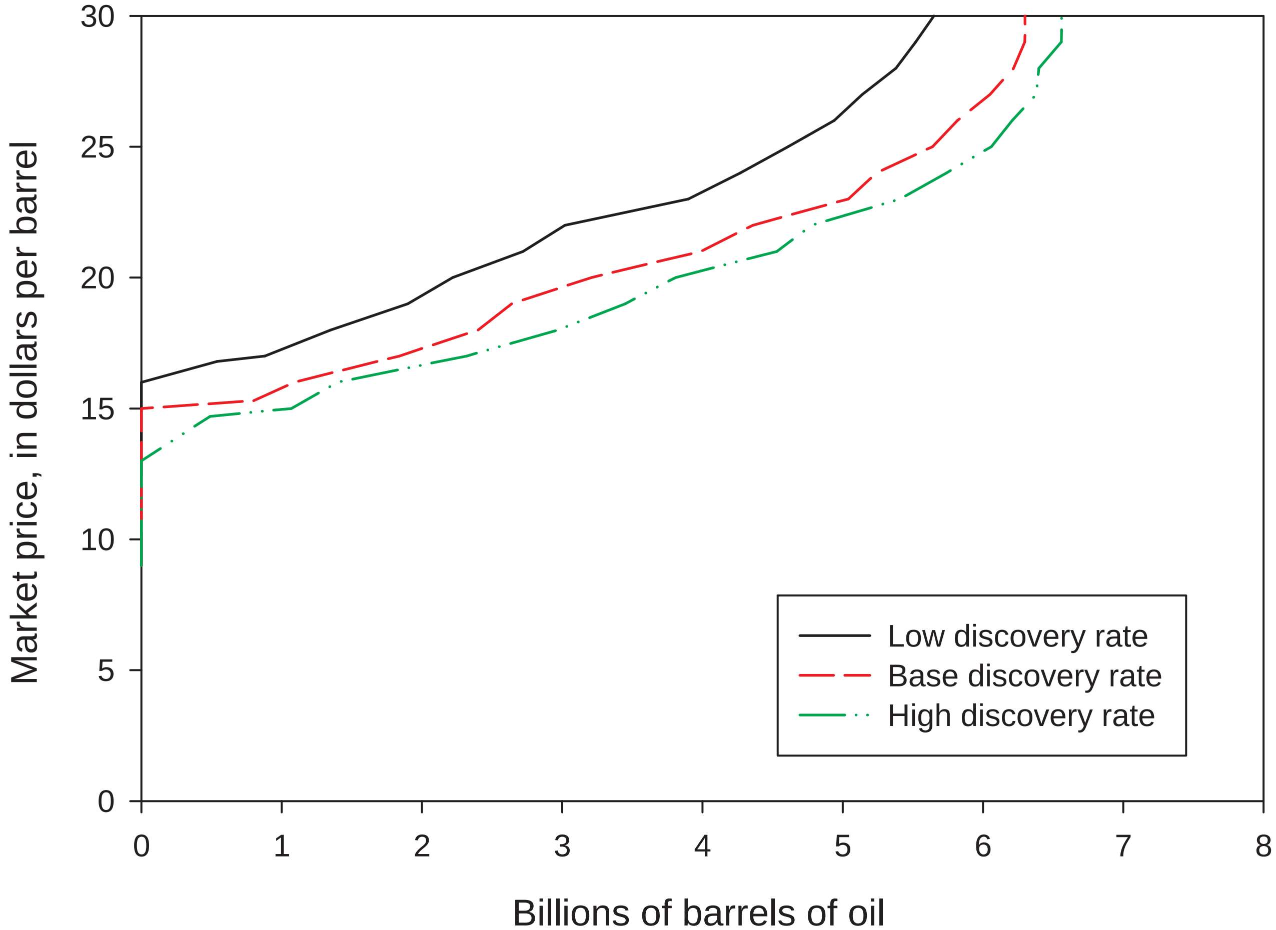

Figure EA-C1. Incremental costs, in dollars per barrel, of finding, developing, producing, and transporting crude oil from undiscovered fields in the 1002 area of Northern Alaska for three different discovery efficencies. The low discovery rate function is based on discovery efficiency values half the base case and the high disovery rate function is based on discovery efficiency values 50 percent greater than the base case.

Table EA1. Mean value of undiscovered technically recoverable conventional oil, natural gas, and natural gas liquids (NGL) in the 1002 area of the Arctic National Wildlife Refuge as of January 1998. [BBO, billions of barrels of oil; TCFG, trillions of cubic feet gas, BBL, billions of barrels of NGL]

Area/Play Name	Oil Fields			Gas Fields	
	Oil (BBO)	Gas (TCFG)	NGL (BBL)	Gas (TCFG)	NGL (BBL)
Undeformed					
Topset	4.325	1.193	0.010	0.000	0.000
Turbidite	1.279	1.120	0.065	0.000	0.000
Wedge	0.438	0.226	0.005	0.000	0.000
Thomson	0.246	0.314	0.026	0.156	0.013
Kemik	0.047	0.060	0.005	0.056	0.005
Undeformed Franklinian	0.085	0.150	0.015	0.150	0.014
Subtotal	6.420	3.063	0.127	0.361	0.032
Deformed					
Thin-Skinned Thrust Belt	1.038	0.283	0.003	1.325	0.014
Ellesmerian Thrust Belt	0.000	0.000	0.000	0.876	0.018
Deformed Franklinian	0.046	0.044	0.003	0.816	0.043
Niguanak/Aurora	0.183	0.168	0.010	0.105	0.006
Subtotal	1.267	0.496	0.016	3.121	0.080
Total 1002 area	7.687	3.558	0.143	3.483	0.112

Table EA2. Distribution of Assessed 1002 area Resources of Crude Oil. Crude oil volumes are based on field size distributions associated with the estimates of undiscovered oil at the 95th fractile, the mean, and the 5th fractile.

Class Number	Oil Field Size (MMBO)	Cumulative Percentage 95TH (PERCENT)	MEAN (PERCENT)	5TH (PERCENT)
18	4096-8192	0.00	0.56	1.36
17	2048-4096	1.39	5.90	12.60
16	1024-2048	7.83	20.82	31.34
15	512-1024	26.30	42.43	54.49
14	256-512	52.18	64.87	72.19
13	128-256	77.29	83.84	87.36
12	64-128	93.29	94.94	96.26
11	32-64	98.77	99.11	99.28
10	16-32	99.97	99.98	99.98
9	8-16	100.00	100.00	100.00

Table EA3. Technically recoverable and commercially developable oil and natural gas liquids (NGL) in the 1002 area by subareas. Commercially developable oil based on $12,$18, and $24 dollar per barrel market prices. [BBO-billions of barrels of oil, TCFG-trillions of cubic feet of gas, BBL-billions of barrels of NGL, Asc. gas-Associated gas]

Subarea Estimate	Technically Recoverable Crude oil (BBO)	Asc. gas (TCFG)	NGL (BBL)	$12/bbl Crude oil (BBO)	Asc. gas (TCFG)	NGL (BBL)	$18/bbl Crude oil (BBO)	Asc. gas (TCFG)	NGL (BBL)	$24/bbl Crude oil (BBO)	Asc. gas (TCFG)	NGL (BBL)
95th Fractile												
western	3.46	1.98	0.10	0.00	0.00	0.00	1.60	0.71	0.02	3.05	1.60	0.07
eastern	0.80	0.30	0.01	0.00	0.00	0.00	0.46	0.15	0.00	0.64	0.22	0.01
Total	4.25	2.28	0.11	0.00	0.00	0.00	2.06	0.86	0.03	3.69	1.82	0.08
Mean values												
western	6.13	3.00	0.13	0.32	0.10	0.00	3.65	1.41	0.04	5.38	2.38	0.09
eastern	1.56	0.55	0.01	0.06	0.01	0.00	1.07	0.33	0.01	1.37	0.46	0.01
Total	7.69	3.55	0.14	0.38	0.11	0.00	4.72	1.73	0.04	6.75	2.85	0.10
5th Fractile												
western	9.40	4.37	0.16	1.03	0.34	0.00	6.45	2.60	0.08	8.53	3.66	0.12
eastern	2.40	0.79	0.02	0.22	0.05	0.00	1.88	0.59	0.01	2.16	0.68	0.01
Total	11.80	5.16	0.18	1.25	0.39	0.01	8.32	3.19	0.08	10.69	4.34	0.13

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Table EA4. Incremental cost of finding, developing, producing, and transporting oil and natural gas liquids (NGL) from undiscovered oil fields in the 1002 area of the Arctic National Wildlife Refuge and associated wildcat wells and finding costs. [BBO-billions of barrels of oil, TCFG-trillions of cubic feet of gas, BBL-billions of barrels of NGL, Asc. gas-Associated gas]

		95TH FRACTILE ESTIMATE					MEAN ESTIMATE					5TH FRACTILE ESTIMATE				
Subarea	Cost ($/bbl)	Crude Oil (BBO)	Asc. Gas (TCFG)	NGL (BBL)	Wildcat Wells	Finding Cost ($/bbl)	Crude Oil (BBO)	Asc. Gas (TCFG)	NGL (BBL)	Wildcat Wells	Finding Cost ($/bbl)	Crude Oil (BBO)	Asc. Gas (TCFG)	NGL (BBL)	Wildcat Wells	Finding Cost ($/bbl)
Western	12	0.00	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00
	15	0.00	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00	2.69	0.84	0.01	80	0.32
	18	0.00	0.00	0.00	0	0.00	2.40	0.78	0.01	120	0.55	5.27	1.94	0.04	180	0.61
	21	1.03	0.43	0.01	80	0.68	3.50	1.31	0.03	180	0.77	6.56	2.50	0.06	240	0.88
	24	2.03	1.04	0.04	160	0.94	4.45	1.89	0.07	240	0.98	7.69	3.20	0.10	300	1.07
	27	2.45	1.35	0.06	220	1.39	5.03	2.33	0.09	300	1.39	8.29	3.68	0.13	360	1.53
	30	2.63	1.47	0.07	260	1.87	5.22	2.45	0.10	340	1.91	8.47	3.79	0.13	400	2.16
Eastern	12	0.00	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00
	15	0.00	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00
	18	0.00	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00	0.87	0.27	0.01	60	0.59
	21	0.00	0.00	0.00	0	0.00	0.49	0.12	0.00	60	1.05	1.35	0.42	0.01	120	1.13
	24	0.00	0.00	0.00	0	0.00	0.80	0.24	0.00	100	1.26	1.69	0.52	0.01	160	1.49
	27	0.29	0.10	0.00	60	1.80	1.02	0.32	0.01	140	1.73	1.87	0.59	0.01	180	1.71
	30	0.35	0.13	0.00	80	2.05	1.09	0.35	0.01	160	2.09	2.00	0.63	0.01	220	2.39
Total	12	0.00	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00
	15	0.00	0.00	0.00	0	0.00	0.00	0.00	0.00	0	0.00	2.69	0.84	0.01	80	0.32
	18	0.00	0.00	0.00	0	0.00	2.40	0.78	0.01	120	0.55	6.15	2.21	0.05	240	0.61
	21	1.03	0.43	0.01	80	0.68	3.99	1.43	0.04	240	0.80	7.91	2.92	0.07	360	0.92
	24	2.03	1.04	0.04	160	0.94	5.24	2.13	0.07	340	1.02	9.37	3.72	0.11	460	1.14
	27	2.74	1.46	0.07	280	1.43	6.05	2.65	0.10	440	1.44	10.16	4.27	0.14	540	1.56
	30	2.98	1.60	0.07	340	1.89	6.30	2.79	0.10	500	1.94	10.47	4.42	0.14	620	2.20

Appendix EA-A. Tables showing volumes of undiscovered technically recoverable hydrocarbons estimated at the mean, 95th and 5th fractile estimates of the distribution for the 1002 area allocated to the western and eastern subareas.

Table EA-A1. Volumes of undiscovered technically recoverable conventional oil, natural gas, and natural gas liquids (NGL) in the western and eastern subareas of the 1002 area of the Arctic National Wildlife Refuge as of January 1998 based on the *mean estimate of the assessed oil in the 1002 area*. [BBO, billions of barrels of oil; TCFG, trillions of cubic feet gas, BBL, billions of barrels of NGL]

Area/Play Name	Oil Fields			Gas Fields	
	Oil	Gas	NGL	Gas	NGL
	(BBO)	(TCFG)	(BBL)	(TCFG)	(BBL)
Western subarea					
Topset	3.707	1.022	0.008	0.000	0.000
Turbidite	1.279	1.120	0.065	0.000	0.000
Wedge	0.438	0.226	0.005	0.000	0.000
Thomson	0.246	0.314	0.026	0.156	0.013
Kemik	0.047	0.060	0.005	0.056	0.005
Undeformed Franklinian	0.085	0.150	0.015	0.150	0.014
Thin-Skinned Thrust Belt	l.288	0.079	0.001	0.368	0.004
Ellesmerian	0.000	0.000	0.000	0.088	0.002
Deformed Franklinian	0.041	0.040	0.003	0.734	0.039
Subtotal	6.132	3.011	0.129	1.551	0.076
Eastern subarea					
Topset	0.618	0.170	0.001	0.000	0.000
Thin-Skinned Thrust Belt	0.750	0.205	0.002	0.957	0.010
Ellesmerian Thrust Belt	0.000	0.000	0.000	0.788	0.016
Deformed Franklinian	0.005	0.004	0.000	0.082	0.004
Niguanak/Aurora	0.183	0.168	0.010	0.105	0.006
Subtotal	1.555	0.548	0.014	1.931	0.036
TOTAL 1002 area	7.687	3.558	0.143	3.483	0.112

Appendix EA-A. Tables showing mean, 95th and 5th fractile estimates of 1002 area to western and eastern subareas - Continued

Table EA-A2. Volumes of undiscovered technically recoverable conventional oil, natural gas, and natural gas liquids(NGL)in the western and eastern subareas of the 1002 area of the Arctic National Wildlife Refuge as of January 1998 based on the *95th fractile estimate of the assessed oil in the 1002 area.* [BBO, billions of barrels of oil; TCFG, trillions of cubic feet gas, BBL, billions of barrels of NGL]

Area/Play Name	Oil Fields			Gas Fields	
	Oil	Gas	NGL	Gas	NGL
	(BBO)	(TCFG)	(BBL)	(TCFG)	(BBL)
Western subarea					
Topset	1.795	0.499	0.004	0.000	0.000
Turbidite	1.026	0.892	0.051	0.000	0.000
Wedge	0.206	0.116	0.003	0.000	0.000
Thomson	0.157	0.200	0.017	0.000	0.000
Kemik	0.016	0.023	0.002	0.051	0.004
Undeformed Franklinian	0.083	0.178	0.018	0.155	0.014
Thin-Skinned Thrust Belt	0.138	0.035	0.000	0.325	0.003
Ellesmerian Thrust Belt	0.000	0.000	0.000	0.093	0.003
Deformed Franklininian	0.035	0.039	0.003	1.049	0.076
Subtotal	3.456	1.981	0.099	1.673	0.099
Eastern subarea					
Topset	0.299	0.083	0.001	0.000	0.000
Thin-skinned Thrust Belt	0.358	0.090	0.001	0.845	0.009
Ellesmerian Thrust Belt	0.000	0.000	0.000	0.834	0.025
Deformed Franklinian	0.004	0.004	0.000	0.117	0.008
Niguanak/Aurora	0.137	0.124	0.007	0.005	0.000
Subtotal	0.799	0.301	0.009	1.799	0.043
TOTAL	4.254	2.282	0.107	3.472	0.142

Appendix EA-A. Tables showing mean, 95th, and 5th fractile estimates of 1002 area to western and eastern subareas –continued.

Table EA-A3. Volumes of undiscovered technically recoverable conventional oil, natural gas, and natural gas liquids(NGL)in the western and eastern subareas of the 1002 area of the Arctic National Wildlife Refuge as of January 1998 based on the *5th fractile estimate of the assessed oil in the 1002 area*. [BBO, billions of barrels of oil; TCFG, trillions of cubic feet gas, BBL, billions of barrels of NGL]

Area/Play Name	Oil Fields			Gas Fields	
	Oil	Gas	NGL	Gas	NGL
	(BBO)	(TCFG)	(BBL)	(TCFG)	(BBL)
Western subarea					
Topset	5.978	1.732	0.016	0.000	0.000
Turbidite	1.751	1.542	0.089	0.000	0.000
Wedge	0.804	0.410	0.009	0.000	0.000
Thomson	0.252	0.310	0.026	0.155	0.012
Kemik	0.034	0.036	0.002	0.138	0.011
Undeformed Franklinian	0.109	0.206	0.020	0.165	0.016
Thin-Skinned Thrust Belt	0.472	0.132	0.002	0.425	0.005
Ellesmerian Thrust Belt	0.000	0.000	0.000	0.128	0.002
Deformed Franklinian	0.000	0.000	0.000	0.210	0.021
Subtotal	9.399	4.369	0.165	1.220	0.068
Eastern subarea					
Topset	0.996	0.289	0.003	0.000	0.000
Thin-skinned Thrust Belt	1.228	0.343	0.004	1.104	0.013
Ellesmerian Thrust Belt	0.000	0.000	0.000	1.154	0.022
Deformed Franklinian	0.000	0.000	0.000	0.023	0.002
Niguanak/Aurora	0.176	0.155	0.009	0.004	0.000
Subtotal	2.400	0.787	0.015	2.285	0.038
TOTAL	11.799	5.156	0.180	3.505	0.106

Appendix EA-B. Documentation of costs

Product transportation costs

The 1002 area was partitioned into two subareas (see figure EA3) in order to more accurately estimate transportation costs to TAPS. Assessed resources of the 1002 area were assigned by play to the two subareas. In particular, the western subarea accounted for 86 percent of the resources of the Topset Play, all the Turbidite, Wedge, Thomson, Kemik, Undeformed Franklinian, 28 percent of the Thin-Skinned Thrust-Belt, 10 percent Ellesmerian and 90 percent of the Deformed Franklinian. Alternatively, the eastern subarea accounted for 14 percent of the resources in the Topset, 72 percent of the Thin-Skinned Thrust-Belt, 90 percent Ellesmerian, 10 percent of the Deformed Franklinian, and all of the Niguanak-Aurora Play resources that were assessed for the 1002 area. Based on the allocation of play resources just described, for the mean estimate of technically recoverable oil, the western subarea was assigned 6.13 BBO, leaving 1.56 BBO assigned to the eastern subarea. It was assumed that at least a 20 inch regional pipeline would initially be built from the TAPS Pump Station 1 to a location about 18 miles into the western boundary of the 1002 area. All pipelines are elevated over land and buried at major river crossings. Transportation to the eastern subarea assumes extension of the pipeline of about 50 miles to the east. According to Han-Padron Associates (1985) such a pipeline would have a capacity of at least 300,000 barrels per day. A pipeline with larger capacity would, in all likelihood, result in lower unit transport costs than those presented here.

The path of the regional pipeline from Pump Station 1 is assumed to be roughly parallel to the path taken by the Badami pipeline which joins the Endicott pipeline about 12 miles from Pump Station 1. The pipeline distance between the Endicott/Badami junction to the Badami field is about 25 miles. Continuing east from the area of the Badami field, the 1002 area regional pipeline proceeds just southeast toward the Sourdough prospect (28 miles), enters 1002 area western boundary, and terminates at a location about 20 miles southeast (see figure EA-B1). Total distance from Pump Station 1 is about 85 miles. The pipeline leg to the eastern subarea would extend the pipeline parallel to the coast line for about 22 miles and proceed southeast another 28 miles for total extension of a distance of 50 miles. Within each subarea it is assumed that either 12 or 18 inch diameter feeder lines from the field to the regional pipeline would be constructed and operated as a separate common carrier. In the western subarea the feeder line is assumed to be a maximum length of 12 miles and in the eastern subarea the feeder line is assumed to have a maximum length of 16 miles.

A regulated common carrier pipeline entity was assumed to build and operate the regional pipeline to TAPS. Pipeline tariff charges were set to assure investors a 12 percent after-tax return on investment. Cost functions presented in Broderick (1992) were updated to reflect reductions in costs since 1990. First, recent pipeline cost data gathered from the literature and applications to the Alaska State Pipeline Office (T. Braden, Alaska Pipeline Office, personal communication 1998). These data were analyzed and extrapolated to compute costs of pipelines of comparable sizes to those depicted by Broderick (1992). These estimates, typical of the Prudhoe Bay-Kuparuk area, were increased by 30 percent to compensate for the absence of infrastructure and the special costs of operating in the 1002 area. Based on the Han-Padron Associates report (1985) investment costs were increased another 20 percent for construction of a haul road parallel to the pipeline. The resulting cost function is shown in figure EA-B2. The discrete shift in the cost function reflects the requirement of installation of facilities for an intermediate pump station (see Young and Hauser, 1986, Broderick, 1992). Industry practices have moved toward elimination of parallel gravel haul roads, at least in a 30 mile radius of existing infrastructure around the Prudhoe Bay-Kapurak area. Haul roads are not planned for the new pipelines to the Alpine or the Badami fields. Elimination of the haul road would reduce investment costs about 20 percent.

The estimated investment of the 85 mile regional pipeline to the western subarea is 378 million dollars. For the 50 mile leg to the eastern subarea, an additional investment of 198 million dollars is required. Estimated investment costs include the materials, pipe, installation, pump stations and a parallel gravel haul road. Annual pipeline operating costs were 2 percent of the initial investment cost. The pipeline business entity is assumed to be subject to all the Alaska State taxes as well as Federal taxes.

The estimated tariff for the feeder lines from the individual field to the regional pipeline was based on field specific reserves. The following formula presented in Thomas and others (1993) and Broderick (1992) was used to provide an approximation to the corresponding levelized tariff:

trf=[(investment cost)/(field recovery)]*3.35

where the investment cost was calculated for an 12 or 18 inch diameter line either 12 or 16 miles in length but without a haul road. Table EA-B1 shows the distances and examples of the pipeline tariffs used in the economic analysis.

Development Costs

Field development costs include well drilling and completion costs and the cost of facilities. Actual field development costs would depend on site-specific characteristics of prospects. Play analysis, however, is not location specific. In the process of developing generic cost functions a number of simplifying assumptions were made to keep the economic analysis tractable. The assessed undiscovered accumulations were first grouped into field size categories (Table EA-B2 provides the field size classes) and into 5000-foot depth intervals also. Development cost estimates for a representative accumulation for each size and depth class were estimated and tested against an economic screen to determine whether all the accumulations in the size and depth category were commercially developable.

Field design

It was assumed that the fields were developed on well spacing that allowed each production well a drainage area of 160 acres (0.16 thousand acres). For each field simulated, the reservoir parameter values associated with (1) net reservoir thickness *t*, in feet; (2) porosity *p*, as a decimal fraction; (3) trapfill *f*, as a decimal fraction, (4) depth, *d* in feet, and (5) *cw* defined as the quantity-(100-water saturation), as a decimal fraction. The assessors provided estimates of the recovery factor as a fraction of the in-place resources that are recoverable, *rf*, and the formation volume factor, *fvf*, was calculated as a function of reservoir depth (see Assessment Forms in Results section by Schuenemeyer, Chap. RS). Production well productivity, *wp*, in millions of barrels per well for an individual accumulation was calculated with the following equation,

$$wp = 7.758(t)(p)(cw)(f)(rf)(0.16) / (fvf)$$

Well productivity associated with the representative accumulation for each size and depth class was calculated as the weighted average of the well productivities associated with the accumulations assigned to that category.

The required number of production wells for the representative accumulation was calculated by dividing the recoverable volume of oil divided by the estimated well productivity. It was assumed that for each production well 0.4 injection wells are drilled (NPC, 1981, Young and Hauser, 1986). This assumption insures there are sufficient injection wells for pressure maintenance via water and gas injection.

Well productivity values in Table EA-B2 do not reflect the application of fracturing or horizontal drilling technologies that might be applied if site-specific conditions are favorable. Inasmuch as the analysis does not capture the tradeoff in applying these slightly more costly technologies that increase recovery of the in-place oil, cost estimates presented here may overstate actual costs.

Drilling costs

Estimated total drilling costs are based on the number of wells and well drilling and completion costs. Production well drilling and completion costs were estimated from the historical costs reported in the Joint Association survey on 1995 and 1996 drilling costs (American Petroleum Institute, 1996, and 1997) for Alaska oil wells. Data from the cost survey were smoothed and cost estimates prepared for the four 5000-foot vertical depth intervals. Costs were increased by 30 percent to offset extra costs expected to be incurred because of the absence of infrastructure or special environmental precautions. Development well drilling and completion cost estimates are $2.16 million at depths to 5 thousand feet, $2.73 million at depths of 5 to 10 thousand feet, $3.31 million at depths of 10 to 15 thousand feet and $5.76 million for wells deeper than 15 thousand feet.

Facilities Costs

Production facilities include drill pads, flow lines from drilling sites, the central processing unit, and infrastructure required for housing workers, including amenities. Facilities design and costs depend on peak production rates and field size. As of the beginning of 1998, there are five standalone fields operating in Northern Alaska. These fields include Prudhoe Bay, Kuparuk, Lisburne, Milne Point, and Endicott. Endicott, which started producing in 1987, was the last stand-alone field developed. Recent discoveries under active development as stand-alone fields include Alpine

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and Badami. Northstar and Liberty fields, (formerly Seal Island and Tern Island) are in the latter planning stages for commercial development as stand-alone fields. Northstar, Badami, and Liberty have estimates of ultimate recovery of not more than 150 million barrels.

Although little information is in the public domain, a version of the Northstar development plan, including development cost estimates, was submitted by British Petroleum to the State of Alaska for evaluation with its request for relief of profit sharing provisions of the State lease. With this information and inferred facilities cost estimates from published reports for other fields under development, the facilities cost relationship originally presented in the National Petroleum Council (1981b) and Young and Hauser (1986) was recalibrated. To compensate for the absence of infrastructure and the extra costs associated with field development in the 1002 area, facilities cost estimates that might be characteristic of the Prudhoe Bay area were increased by 30 percent. The cost function used in the analysis is shown in figure EA4 along with the cost function calculated for the Young and Hauser (1986). Table EA-B3 shows estimates of the facilities investment costs by accumulation size class.

The Point McIntyre, Niakuk, North Prudhoe Bay and West Beach fields, developed between 1988 and 1996, share the central processing facilities at the Lisburne field. The use of the Lisburne field's central processing unit (Thomas and others, 1993) saved the Point McIntyre operators 35 percent in facilities costs. Savings, however, are highly site-specific. Distances between production wells and central processing units may limit sharing opportunities. The small expected number of discoveries in the eastern subarea made facilities sharing opportunities unlikely. Facilities sharing was therefore limited to the western area and to fields having less than 130 million barrels of technically recoverable oil. It was assumed that facilities sharing would, on average, result in a 30 percent reduction in facilities investment costs.

Field Production Profile

Future discoveries are assumed to attain peak annual rates of production equal to the percentage of the field's ultimate oil recovery. Table EA-B4 shows the assumptions relating to the field production profile. Fields having less than 130 million barrels of recoverable oil are assumed to reach peak production in the second production year and maintain the peak production level for 2 years thereafter, after which annual production declines 12 percent per year. Fields larger than 130 million barrels would reach peak production in the third year and maintain the peak production level through year 5, and then production begins to decline at 12 percent per year.

At first glance the 12 percent field production decline rate appears very sharp. Observed field decline rates are typically more subdued because of the application of enhanced recovery techniques to prolong field life. However, the appropriate enhanced recovery application and its success often depends on site-specific conditions. Recovery factors of oil-in-place that were posited by the assessors seemed to include only limited enhanced recovery possibilities. Posited recovery factors of the oil-in-place by play are the following: Topset 40 percent, Turbidite 30 percent, Wedge 30 percent, Thomson 45 percent, Kemik 30 percent, Undeformed Franklinian 35 percent, Thin-Skinned Thrust Belt 40 percent, Deformed Franklinian 35 percent, and Naguanak-Aurora 35 percent.

The volume of produced water was projected by using the field production profile for oil, the degree of field depletion, and the water cut functions presented by Thomas and others (1991). Figure EA-B3 shows percentage water expected in production with depletion of the field. Volumes of natural gas and natural gas liquids production were projected using annual oil production, the expected values of the gas to oil ratio, and NGL to gas ratios associated with the representative field's size and depth classification.

Operating costs

Field operating costs include labor, supervision, overhead and administration, communications, catering, supplies, consumables, well service and workovers, facilities maintenance and insurance, and transportation. Some of these costs, such as well workover and labor costs have declined dramatically during the last decade due to the introduction of coiled tubing technology and institution of automation in field operations. Annual operating costs are characterized as a function of daily fluid volumes (NPC, 1981, Young and Hauser, 1986). The annual operating cost function presented by Hauser and Young were updated using the Energy Information Administration's index of oil field operating costs for 1996 (Energy

Information Administration, 1997B). Fluid (hydrocarbon and water) volumes were projected annually using field production forecasts and a water cut function presented in figure EA-B3, Appendix EA-B, (Thomas and others, 1991), so that per barrel costs of oil reflected increases in costs that result from a higher water cut as the field is depleted.

Alaska Taxes

Severance Tax for oil:

12.25 % years 1 through 5 adjusted for economic limit factor (elf)
15.00 % after year 5 adjusted for the economic limit factor
floor of $0.80 per barrel adjusted for the economic limit factor
elf = $(1-(300/ADWR))^a$
where a = $(150000/ADFR)^{1.5333}$
ADWR = average daily production per producing well (bbl/d)
ADFR= average daily field production (bbl/d)

Severance Tax for gas:

10.00 % adjusted for the economic limit factor
floor $0.064 per thousand cubic feet adjusted for the economic limit factor
elf = (1-(3000/ADWR))
ADWR = average daily production per producing well (MCFG/d)
For both cases, if elf less than or equal to zero, severance tax is zero

Ad valorem tax

Tax equal to 2 percent of the economic value of pipelines, facilities, and equipment. For pipelines, a 25 year life was assumed. For tangible well costs, oil field equipment costs, and facilities costs, depreciation of the asset was based on the unit of production method.

State Income tax

For planning purposes the Alaska state agencies use 1.4 to 3.0 percent of net income. The rate used here was 2.2 percent of net income. Depreciation of capital assets associated with oil field development is permitted on a unit of production basis. For other capital, depreciation depends on the economic life of the equipment.

State conservation tax

Tax is $0.004 per barrel and the conservation surcharge tax is $0.03 per barrel.

Federal Taxes

Federal royalty rate

Royalty rate is considered to be a payment to the landowner was assumed to be 16.7 percent of gross revenue.

Federal income taxes

Federal income tax rate of 35 percent of taxable income was assumed. Based on the 1986 Tax Reform Act, 30 percent of development well drilling costs is classified as tangible cost and therefore capitalized over 7 years. Of the remaining 70 percent of drilling cost (that is, the intangible drilling costs), 30 percent is depreciated over 5 years and the remaining 70 percent is expensed immediately.

Table EA-B1. 1002 Subareas and distances from the regional pipeline to Trans-Alaska Pipeline System (TAPS), estimated pipeline tariff to TAPS and tariff from feeder pipeline to regional pipeline.

Area	Regional pipeline distance	tariff	Feeder Pipeline distance	tariff*	distance	tariff**
	mi	$/bbl	mi	$/bbl	mi	$/bbl
Western subarea	85	0.97	12	$0.21	12	$0.14
Eastern subarea	135	1.48	16	$0.28	16	$0.18

* Based on field with reserves of 300 million barrels, 12 inch pipe.
** Based on field with reserves of 600 million barrels, 16 inch pipe.

Table EA-B2. Recovery per well, in millions of barrels per well, by field size, depth category, and subarea.

Field Size class	Recovery per production well in millions of barrels			
	Depth class in thousands of feet			
MMBO	0-5	5-10	10-15	>15
Western subarea				
8-16	-	1.53	1.50	1.47
16-32	3.69	2.96	1.98	1.92
32-64	5.50	4.26	2.75	2.62
64-128	8.59	6.27	3.63	3.53
128-256	12.37	9.19	4.88	4.93
256-512	15.22	11.91	6.27	6.53
512-1024	17.56	15.16	7.65	8.22
1024-2048	24.11	21.79	11.21	13.19
2048-4096	30.00	29.66	19.28	20.06
4096-8192	30.00	30.00	0.00	0.00
Eastern subarea				
8-16	-	-	-	-
16-32	2.73	2.87	1.10	0.47
32-64	4.14	4.18	1.48	0.75
64-128	6.20	6.29	1.93	1.20
128-256	8.57	8.63	2.54	1.76
256-512	10.73	10.37	2.92	2.17
512-1024	13.58	13.23	3.21	2.85
1024-2048	20.01	19.22	3.46	4.05
2048-4096	29.86	26.50	4.57	5.29
4096-8192	30.00	30.00	5.26	0.00

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Table EA-B3. Facilities investment cost in 1996 dollars.

Field Size (MMBO)	Cost ($/bbl)
32	7.38
48	5.55
64	4.54
96	3.42
128	2.83
192	2.31
256	2.00
384	1.64
512	1.42
768	1.16
1024	1.00
1536	0.82
2048	0.71
3074	0.71
4096	0.71
8192	0.71

Table EA-B4. Field production profiles assumed in the economic analysis

field sizes MMBO	years buildup	peak as percent of ultimate	years of peak prd.
8-16	2	11	3
16-32	2	11	3
32-64	2	11	3
64-128	2	11	3
128-256	3	10	3
256-512	3	10	3
512-1024	3	9	3
1024-2048	3	9	3
2048-4096	3	9	3
4096-8192	3	9	3

Appendix EA-C. Specification and Application of the Finding Rate Component of the Cost Algorithm

Purpose and specification

The finding rate model imbedded in the cost algorithm (1) predicts the arrival rates of discoveries as a function of wildcat wells, (2) orders discoveries, and (3) allows the cost algorithm to determine, on the basis of rational economic criteria, how much additional wildcat drilling is economically justified. The number of wildcat well increments and the allocation of wells by depth is endogenous to the model. In general, past wildcat well depth allocations are not used to predict depths of future drilling because the past allocations were often affected by regulations and subsidies. For areas like Northern Alaska and particularly the 1002 area, undiscovered resources are assessed where there is little or no historical drilling. This appendix discusses the specification and application of the finding rate component of the cost algorithm as well as providing results of a sensitivity analysis of the incremental cost functions to changes in the discovery efficiency values. A more detailed development of the model and the various calibration procedures applied to obtain finding rate coefficients for the provinces in the 48 conterminous States is discussed in Attanasi and others (1996).

The functional form of the finding rate model specifies that within a field size class, j, and depth interval, k, the rate of discovery declines exponentially:

$$F(j,k,t) = F(j,k,u)(1.- \exp(-c(j,k)w(t,k))) \qquad (1)$$

where F(j,k, t) = number of discoveries in the *jth* field size class and *kth* depth interval, found with w(t,k) cumulative wildcat wells drilled through time t that bottom in the *kth* depth interval;

F(j,k.u) = number of undiscovered fields in the *jth* field size class and *kth* depth interval;

c(j,k) = discovery efficiency for *jth* field size class and *kth* depth interval;

w(t,k) = cumulative wildcat wells drilled from the start of first period to the *t-th* period that bottom in the *kth* depth interval, that is, are targeted to the *kth* depth interval.

In the application of the model in equation (1) in the cost algorithm, F(j,k,t) is the *predicted number* of fields in size class j and depth k found after drilling w(t,k) wildcat wells targeted to the *kth* depth interval, F(j,k,u) is the *assessed number of undiscovered fields* in the *jth* field size class and *kth* depth interval, and w(t,k) is the *number of new wells drilled* starting from the date of the assessment forward and targeted to the *kth* depth interval. Simulations of undiscovered fields were generated using the probability distributions specified by the geologists on the assessment forms. Size-frequency distributions of undiscovered fields by depth interval (that is the F(j,k,u) values) associated with the 95th fractile, the mean, and the 5th fractile estimates of 1002 area's undiscovered oil were calculated from the simulation data. The c(j,k)'s, representing the discovery decline coefficients or discovery efficiencies by depth interval, remain the only parameters requiring estimation. The application of the model in equation (1) required calibration of the c(j,k)'s for the size classes shown in table EA2 and four depth intervals (0-5,000; 5,000-10,000, 10,000-15,000, and greater than 15,000 feet).

The c(j,k)'s were calibrated for most of the oil and gas provinces of the United States assessed in the 1995 National Oil and Gas Assessment. The calibration procedure is described in detail in Attanasi and others (1996). For the Northern Alaska province a set of default coefficients were adjusted by a scalar multiple so that the projected overall wildcat well discovery rate would provide a reasonable extension of the empirical discovery rate realized between 1981 and 1990. Using the Northern Alaska province as the analogue, the coefficients from Attanasi and Bird (1996) were initially applied to the 1002 area assessment. However, at their mean estimates the 1002 area Assessment generally assigned more fields to size classes of greater than 260 million barrels than the 1995 Assessment had assigned to those size classes for all of Northern Alaska. To have discovery rates comparable to recent discovery experience, the discovery efficiency values used in Attanasi and Bird (1996) were reduced by about 25 percent and then applied in this study (see footnote 3 in the text).

To test the sensitivity of the incremental cost functions to the discovery efficiency values, the computation of the incremental cost functions was repeated using the field size distributions associated with the *mean oil estimate* with exploration efficiency values reduced by half and then increased by 50 percent. Figure EA-C1 shows that the values of the economic oil given by these cost functions to be fairly robust to these rather large changes in finding rate function discovery efficiency levels. At a market price of $18 per barrel the base case yielded 2.40 BBO. Increasing discovery efficiency values by 50 percent reduced the threshold price for the start of exploration from just over $15 to just over $14 per barrel and at a market price of $18 per barrel 2.98 BBO is economic. Cutting discovery efficiency values in half increases the threshold price by $1 to about $16.80 per barrel. At a market price $18 per barrel, 1.35 BBO is economic. Finding rate functions with higher discovery efficiency values deplete undiscovered fields more quickly so that the finding rates tends to decline more rapidly. At a market price $30 per barrel, the predicted economic volumes are 5.65 BBO, 6.30 BBO, and 6.56 BBO.

Caveats

There are two reasons to expect an inherent downward bias in the predictions of the finding rate model. First, the use of so-called "targeted" wells in the finding rate function likely overstates required drilling because one well may test more than a single depth interval. An alternative to the use of "targeted wells" is the concept of net wells which assumes that wells test all intervals. The net well scheme gives partial or full credit to a well if it has partially or completely penetrated the interval. For example, a well drilled to 7,500 feet would count as one complete well in the 0 to 5,000 foot interval and as 0.5 wells in the 5,000 to 10,000 foot interval. In experiments where finding rate models were parameterized using net wells and models were incorporated into the costing algorithm, the optimization routine determining drilling depth would generally allocate all wells to the deepest depth. Such behavior is not consistent with past or current industry practice so that the use of the "targeted wells framework" was chosen. Moreover, it may be just as incorrect to assume every interval is tested as to assume only the target depth interval is tested.

A second inherent downward bias in the finding rates modeled here occurs because the exponential function makes no explicit provision for the accumulation of knowledge or learning by explorationists that would improve the siting of wells. Modeling such improvements might take the form of specifying efficiencies as increasing functions of cumulative drilling. However, this would also require quantifying the contribution of wells to the knowledge base and estimating the contribution of increments in knowledge to improvements in siting subsequent wildcat wells. Currently, there are no standard or accepted methods for measuring the contribution of individual wildcat wells to the scientific understanding of the resource.

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