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Economics and undiscovered conventional oil and gas accumulations in the 1995 National Assessment of U.S. Oil and Gas Resources: Alaska

by

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This report is preliminary and has not been reviewed for conformity to U.S. Geological Survey editorial standards and stratigraphic nomenclature.

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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

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ABSTRACT

This report presents the economic analysis of the 1995 USGS Assessment of the technically recoverable oil, gas, and natural gas liquids resources in undiscovered conventional oil and gas fields of Alaska. Expected or mean values of technically recoverable hydrocarbons in undiscovered oil fields in Alaska are 8.42 billion barrels (BBO) of oil, 6.96 trillion cubic (TCF) of associated gas and 0.13 billion barrels (BBL) of associated gas liquids. Similarly, 61.52 TCF of non-associated gas and 1.02 BBL of non-associated gas liquids are estimated in undiscovered non-associated gas fields. Alaska was partitioned into three petroleum provinces; Northern Alaska, Central Alaska, and Southern Alaska. The non-associated gas resources of Northern Alaska were not examined in the economic analysis because those resources are not expected to be a target of exploration and commercial development during the next two decades. Resources assessed in plays in the provinces of Central Alaska and Southern Alaska outside of the Cook Inlet area were also not examined by the economic analysis because assessed resources were not sufficient to support the required infrastructure and transportation system to bring the product to market.

The Northern Alaska and the Cook Inlet area economic analysis uses the mean or expected values of the geologic assessment and assumes a required 12 percent after-tax rate of return. For Northern Alaska, transportation costs from the field to the US West Coast, which ranged from $5.41 to $9.38 per barrel, were included in economic analysis. About 27 percent (1.94 BBO) of the technically recoverable undiscovered oil in Northern Alaska can be discovered, developed, produced, and transported to the US West Coast market for $24 per barrel. Allowing costs to increase to $30 per barrel increases the economic portion of the technically recoverable oil to 45 percent. At costs of $18 per barrel only 8 percent of the mean technically recoverable oil is economic. The wide range in the distribution of undiscovered technically recoverable oil, 2.3 BBO to 15.4 BBO at the 95th and 5th fractiles, respectively, tempers conclusions drawn from the economic results based mean value estimates. For the Cook Inlet area, which has sufficient local oil and gas markets, nearly half of the mean value of undiscovered technically recoverable oil and only 13 percent of the non-associated gas can be found, developed, and produced for $18.00 per barrel and $2.00 per thousand cubic feet (mcf). Likewise at $30 per barrel ($3.34 per mcf) three-fourths of the undiscovered oil and 30 percent of the non-associated gas can be found, developed and produced.

INTRODUCTION

This report summarizes the basic results of the economic analysis of the undiscovered conventional oil and gas accumulations assessed for onshore and State offshore areas in Alaska in the U.S. Geological Survey's (USGS's) 1995 National Oil and Gas Assessment (USGS Circular 1118, 1995). Economic analysis of undiscovered resources of the conterminous US onshore and State offshore areas was reported in

Attanasi, Gautier, and Root (1996). The magnitude of the resources assessed for Alaska and its unique nature as the last onshore US frontier area justified a more detailed economic analysis than was applied to other US areas.

Undiscovered technically recoverable oil and gas resources are defined as resources estimated to exist on the basis of broad geologic knowledge and theory that are contained in *undiscovered accumulations* outside of known fields. These resources are considered to be producible using current recovery technology but without reference to economic viability. *Accumulations assessed by geologists as outside of existing fields were considered for the purposes of the economic analysis as separate and discrete new fields.* Accumulations anticipated to become parts of identified fields are considered field growth and are not treated in this analysis. *Conventional accumulations* are defined as oil and gas 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.

A newly discovered conventional field's commercial value depends on its expected size, whether it is an oil or gas field, its depth, location, and well and reservoir production characteristics. The geologic assessment of undiscovered accumulations provided information on the expected number and nature of the undiscovered fields, expected field sizes, depths, and co-products. 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.

The economic component of the National Assessment is intended to place the geologic resource assessment into an economic context that is more accessible and easily understood by industry and government decision and policy makers. One goal of the economic analysis is estimation of the incremental costs of transforming undiscovered conventional resources and selected unconventional resources into additions to proved reserves. Incremental cost functions show cost-resource recovery possibilities and are not supply functions as strictly defined by economists. However, the basic data used to construct the functions could be used as input data for oil and gas supply models. The conterminous US economic analysis was at the province level whereas the economic analysis for Alaska treated plays and geographically grouped parts of plays.

The method and results of the geologic assessment are reviewed for the purpose of highlighting characteristics that affect the economic analysis and incremental costs. The data, assumptions, and methods used in estimating the incremental cost functions are then discussed. Results and interpretations are presented in the concluding sections.

ASSESSMENT OF UNDISCOVERED CONVENTIONAL ACCUMULATIONS

Geologists assessed conventional undiscovered accumulations having technically recoverable hydrocarbons of at least 1 million barrels of oil (MMBO) or 6 billion cubic feet of gas (BCFG) *at the play level* (more detail is provided in Gautier and Dolton, 1995). A *play* is defined as 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. The assessment resulted in estimates of numbers and sizes of undiscovered accumulations, distribution of depths for undiscovered accumulations, as well as ancillary information such as expected associated gas-to-oil ratios, natural gas liquids-to-gas ratios, and typical product levels of sulfur or hydrogen sulfide.

Geologic assessment procedures

Alaska was subdivided into three provinces for the 1995 National Oil and Gas Assessment (see figure 1). Petroleum plays within these provinces are listed in Table 1. Initial play definitions were based on the assessor's interpretations of the geology and hydrocarbon generation, past discovery information, and past drilling information. Each play definition included a description of the geographic location and geologic characteristics of the play (see Gautier and others, 1995 for play descriptions). In the case of *confirmed plays*, that is, plays already having discoveries of at least 1 MMBO or 6 BCFG, the geologist reviewed drilling penetration maps and historical discovery data. The *play probability* is the likelihood that at least one accumulation remains that will contain a quantity of technically recoverable hydrocarbons of at least 1 MMBO or 6 BCFG. For confirmed plays a *play probability* of 1.0 was assigned. In cases where the geologist posited a hypothetical play, the play probability was computed as the product of the occurrence probabilities of the three play attributes of *charge*, *reservoir*, and *trap* The play probability is multiplied by conditional resource estimates which assumed occurrence of the threshold quantity of oil or gas remained.

The size distribution of undiscovered accumulations for each play was modeled with a Truncated Shifted Pareto (TSP) distribution (Houghton, and others, 1993). The geologist chose a median and shape class for the TSP distribution along with the minimum (95%), median (50%), and largest (5%) *numbers* of undiscovered accumulations. The assessor also chose a minimum, median, and maximum depth for remaining resources in the play. Simulations were used to combine distributions of size and numbers of undiscovered accumulations to generate field-size frequency distributions and to estimate the fractiles of quantities of oil, associated gas, associated gas liquids, non-associated gas, and non-associated gas liquids.

For an individual province dependencies among plays were characterized by pairwise correlations. Simulations were used to aggregate plays to the province level. Regional level results were obtained by aggregating the simulated province results given that the province results were distributed independently.

Small field assessment

The size-frequency distribution of undiscovered "small fields" that is, fields smaller than 1 MMBO (or 6 BCFG) was derived with a statistical extrapolation procedure described by Root and Attanasi (1993). The underlying assumption is the province size-frequency distribution of small fields can be described with a log-geometric size distribution. Table 2 presents the field size class definitions used here. A *log-geometric ratio* was calculated for each province using estimates of the ultimate number of fields (past discoveries plus the estimated number of undiscovered fields) for size classes 7 (2-4 MMBO) through 11 (32-64 MMBO). This ratio was used to calculate the ultimate number of fields in size classes smaller than 1 million barrels of oil equivalent (MMBOE). Default values for the geometric ratio were applied in provinces where reliable estimates could not be obtained because data were insufficient. For an individual province, allocations of small fields to depth intervals by field type were based characteristics of fields containing 1 to 5 MMBOE.

Undiscovered technically recoverable resources

Table 1 presents estimates of the mean technically recoverable conventional undiscovered oil and gas by play for the three provinces of Alaska and estimates of the fraction of each play's resources thought to occur in State offshore waters. Northern Alaska was assigned mean values of 7.40 billion barrels of oil (BBO) and 63.5 trillion cubic feet of gas (TCFG), Central Alaska 0.06 BBO and 2.7 TCFG and Southern Alaska 1.0 BBO, and 2.1 TCFG. To place these estimates in prospective, through 1990 cumulative discoveries in Northern Alaska amount to more than 14 BBO and 32 TCF natural gas and in Southern Alaska discoveries amount to about 1.2 BBO and 6.8 TCF of gas (NRG Associates, 1993). The Central Alaska province has no reported discoveries. In Northern Alaska, assessed undiscovered oil is less than 40 percent of past discoveries but the undiscovered gas is much larger than past discoveries. In Southern Alaska, estimated undiscovered oil is 80 percent of past discoveries and undiscovered gas is 30 percent of past discoveries. According to Petroleum Information Inc. (1993), through 1990 Northern Alaska had 214 wildcat wells, Central Alaska 10 wildcat wells, and Southern Alaska 303 wildcat wells. Overall, this region is the least explored of any US region.

The largest quantity of undiscovered oil of any province in the 1995 USGS National Assessment (USGS Circular 1118, 1995) was assigned to Northern Alaska. The expected (mean) values of technically recoverable resources in oil fields included 7.4 BBO crude oil, 5.9 TCF of associated gas and 0.13 BBL associated gas liquids. The expected values of resources in gas fields included 57.6 TCF non-associated gas and 1.0 BBL non-associated gas liquids (Bird, 1995). In figure 2, panels A through I show the geographic locations of the plays assessed. These plays may be grouped geographically into the plays of the coastal plain, that include the Topset (figure 2A), Turbidite (2B), Barrow Arch Beaufortian (2C), Barrow Arch Ellesmerian (2D), Ellesmerian-Beaufortian Clastics (2E), and Lisburne play(2F), and plays of the Brooks Range foothills which include the Fold Belt (2G) and the Western and Eastern Thrust Belt plays (2H). In the eastern part of the province, the Fold Belt play overlays the Eastern Thrust Belt Play. Two-thirds of the undiscovered oil was assigned to the coastal plain group and 22 percent was assigned to the Eastern Thrust Belt play. The coastal group was assigned only 28 percent of the non-associated gas and the foothills group was assigned the remaining 72 percent.

The 1995 mean value estimate of undiscovered oil of 7.40 BBO for Northern Alaska is a 41 percent reduction from the 12.6 BBO estimated in the 1989 assessment (see Mast and others, 1989). Assessed undiscovered gas increased by about 10 percent over the 1989 analysis. The oil assessment was reduced because of information from new drilling and results of new studies of the thermal history of the province (USGS Circular 1118, 1995). Diminished oil potential was, in part, the result of a reduction in perceived maximum depths where oil was thought to occur. In the 1995 Assessment, more than three-fourths of the estimated undiscovered oil was assigned to depths shallower than 10,000 feet and only 2 percent was assigned to depths greater than 15,000 feet.

Figure 3 shows the size distribution of Northern Alaska's undiscovered oil and gas fields of at least 1 million barrels of oil equivalent. Data in figure 3 represent 154 oil fields and 225 gas fields. At their expected values, undiscovered gas fields accounted for 19 percent more hydrocarbons than undiscovered oil fields. Almost 90 percent of the assessed undiscovered oil was assigned to 29 oil fields having at least 64 million barrels of oil equivalent (size class 12 and larger).

Oil produced in Northern Alaska is shipped via the Trans-Alaska Pipeline system (TAPS) to the Port of Valdez in southern Alaska for tanker transport to market. Non-associated gas is only developed for local use because there is no transportation system to major gas markets. More than 30 TCF of associated gas has already been discovered in Northern Alaska (Attanasi and others, 1993). The associated gas produced with oil is typically stripped of its liquids and reinjected into the oil field or used as fuel on the lease. Some of the recovered natural gas liquids are mixed with the crude oil and sent through TAPS and some are reinjected as a miscible fluid flood for enhanced oil recovery.

No commercial oil or gas fields have been found in the Central Alaska province. Plays defined by the geologist are all hypothetical plays. At their expected (mean) values, the oil amounted to only 62 million barrels and the gas in non-associated gas fields was estimated at 2.7 TCFG (Stanley, 1995). Most of the province is sparsely populated and devoid of infrastructure so that exploration and development costs are high and any commercial development would require construction of a transportation system to markets. The amounts of oil assessed, the small number of fields, and relatively small field sizes are too small to justify an oil transportation system to the coast. There is little local gas demand and no transportation system to bring gas to major markets.

In Southern Alaska, the only producing oil and gas discoveries are in the Cook Inlet area in the Hemlock-Tyonek (304) oil play and the Beluga-Sterling (303) non-associated gas play. The expected values of the resources in undiscovered oil fields are 0.65 BBO crude oil and 0.65 TCF of associated gas and the expected value of non-associated gas resources in gas fields is 0.74 TCF (Magoon, 1995). Half of the oil and 30 percent of the non-associated gas was assigned to Cook Inlet State offshore areas. Cook Inlet oil is refined and marketed in Southern Alaska or exported and gas is used locally or converted to liquefied natural gas (LNG) and exported to Japan.

In the Southern Alaska province, plays of the Alaskan Peninsula (301, 302) and the Gulf of Alaska (308, and 309) have no producing fields; plays defined in these areas are all hypothetical. In the Alaskan Peninsula plays, there have been at least 18 wildcat wells drilled without a discovery and the two plays were assessed only 0.06 BBO oil and 0.28 TCFG (Molenaar, 1995). Plays of the Gulf of Alaska have also been drilled. In the Yakataga Fold Belt play (308), a small field produced 154,000 barrels in the early part of the century. Since that time, 16 wells have tested the most favorable accessible structures without a discovery. Similarly, for the Yakutat Foreland play (309), most larger structures have already been tested. At the expected value, only 0.23 BBO was assigned to these combined plays (Bruns, 1995). The Alaskan Peninsula and the Gulf of Alaska areas are sparsely populated and the play areas are remote, with little or no infrastructure and transportation system to get products to markets.

In summary, Alaska's hostile climate, lack of infrastructure, and remoteness from major markets impose significant cost barriers to oil and gas exploration and development.

The amount of undiscovered technically recoverable oil assessed for Northern Alaska is larger than any other onshore US province assessed by the USGS. In Northern Alaska, infrastructure and an oil transportation system have been constructed for development of Prudhoe Bay and other North Slope fields. The Cook Inlet area in Southern Alaska has a much less hostile climate, a mature infrastructure, significant local markets as well as facilities for exporting crude oil, petroleum products, and liquefied natural gas. Elsewhere in the Southern and Central Alaska provinces, the plays defined by the geologists have been drilled and remain hypothetical. In general, these plays have limited potential and expected discovery size is unlikely to be large enough to overcome the natural cost barriers imposed by the hostile climate, primitive infrastructure, and remoteness from markets.

DATA, ASSUMPTIONS, AND PROCEDURE FOR THE ECONOMIC ANALYSIS

The economic analysis provides estimates of the incremental costs of transforming undiscovered resources into additions to proved reserves. The cost functions include the costs of finding, developing, and producing currently undiscovered resources. The incremental cost 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 as basic data for market supply models.

Data

Results of the play assessments were discrete size-frequency distributions of undiscovered oil and gas fields classified by 5,000 foot depth intervals. Expected ratios of gas-to-oil and gas liquids-to-natural gas were also derived from the geologic play assessments (Gautier and others, 1995). Wildcat drilling data and discovery field-size data were used to calibrate finding rates applied in this analysis. Data on past wildcat drilling were from the Well History Control System (WHCS) available from Petroleum Information Corporation (PI) and data pertaining to fields of at least 1 MMBO (or 6 BCFG) were from the *Significant Oil and Gas Fields of the United States* field file (NRG Associates, 1993) and various sources in the more recent trade literature.

Technical data used in the economic analysis included field designs, well production profiles, and cost relationships. For Alaska's frontier areas, data were drawn from previous studies (J. Broderick, Bureau of Land Management, 1992, Attanasi, 1989, Young and Hauser, 1986, National Petroleum Council 1981a, 1981b), US Department of Energy studies (Thomas and others, 1993, Thomas and others, 1991), and drilling cost data from the Annual Joint Association Survey (JAS) (American Petroleum Institute, 1992, 1993, 1994). Field development costs used for the Cook Inlet were based on costs of analogue areas and were taken from previous studies (Energy Information Administration, 1994, Attanasi, 1989; Attanasi and Haynes, 1984; Vidas and others, 1993).

General Assumptions

Scope of Analysis

The economic analysis did not evaluate Northern Alaska's undiscovered non-associated gas fields 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. Moreover, a US Energy Department forecast for 2015 projected no Alaskan natural gas would be transported to the conterminous United States (EIA, 1996). Although it is possible that a non-associated gas field might have sufficient condensate to be commercially developable for its liquids, development will depend on site specific characteristics. For example, Pt. Thomson is a large gas field thought to have about 0.3 BBL of condensate. The field is overpressured so without a market the extracted gas would have to be reinjected into the reservoir at high pressures. In Northern Alaska 30 TCF of associated gas has already been discovered that can be cheaply produced if a market develops. Northern Alaska oil fields smaller than 16 MMBO represent less than 4 percent of the assessed resource and were also not evaluated.

Central Alaska play areas and Southern Alaska play areas outside of the Cook Inlet are remote, sparsely populated, and distant from any market or mode of transportation to market. Oil resources assessed were small. Plays of Central Alaska, the Alaskan Peninsula (301, 302) and the Gulf of Alaska (308, 309) have been drilled without success and remain hypothetical. Consequently, technically recoverable oil and gas resources in these plays were not evaluated by the economic analysis.

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 areas considered in the economic analysis were available to exploration for oil and gas.

Costs used in this analysis represent the costs prevailing in January of 1993. Calculations were in terms of constant real dollars. Federal income tax provisions included the changes made in 1993. 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. 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. All dry hole costs are expensed in the year incurred or as a carry-over expensed cost.

Alaska State taxes include the severance, income tax, and ad valorem tax. The severance tax depends on field and well productivity (see Appendix 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-eighth royalty was assumed to be paid to the mineral rights owner for the Cook Inlet onshore area and for State offshore areas and areas in Northern Alaska a one-sixth royalty rate was assumed.

During the last quarter-century nominal oil prices in the conterminous United States have varied over a range from \$3 to \$40 per barrel and gas prices have varied from less than \$1 to more than \$11 per thousand cubic feet (mcf). Discussion in this report focuses on reserve additions from new fields which might be expected with an oil price range of \$18 to \$30 per barrel in 1993 dollars. For Northern Alaska, oil the price 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. In the Cook Inlet area, gas prices ranged of \$1.50 to \$3.50 per mcf. Well head gas prices, on an energy equivalent basis, have historically been lower than oil prices. Here, gas prices are assumed to be two-thirds of oil prices (see Attanasi and others, 1996). 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 or gas prices rise to \$6.00 per mcf, 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).

Infrastructure and Location Assumptions

Oil and gas development costs of the Cook Inlet are comparable to costs in the lower 48 states because of the Cook Inlet's milder climate and infrastructure. Even in the State waters of the Cook Inlet, jackup rigs and steel jacket platforms of standard designs are in use. Elsewhere in Alaska, the remoteness of the plays, the climate, and the absence of infrastructure impose high initial exploration and development costs on prospects. To sustain exploration, expected discoveries must be of sufficient size to overcome these cost barriers and to carry part of the capital costs of the product transportation system to market. Actual exploration and development costs will depend on site-specific characteristics of prospects. However, play analysis, as applied in the USGS assessment, does not give location information, so the generic costs presented in this analysis could be substantially different if prospect locations were known. Some simplifying assumptions were made to keep the economic analysis tractable.

In the Northern Alaska Province, all oil is assumed to be transported through the TAPS pipeline to Valdez and then to market. For this analysis Northern Alaska was partitioned into subareas having similar exploration, development, and transportation costs. The east-west distance to TAPS from the central part of each subarea was computed and used for estimating product transportation costs to TAPS. In particular, for field development a pipeline to TAPS was assumed to be built and operated by a separate entity. Pipeline tariff charges were set to assure investors a 12 percent after-tax return on investment. The pipeline is assumed to service several fields, is sized for 250,000 barrels per day throughput, and is operated at a minimum capacity of 65 percent. Pipeline investment cost functions originally presented in Young and Hauser (1986) were adjusted to reflect the rather dramatic decline in pipeline costs experienced on the North Slope (J. Broderick, Bureau of Land Management, 1992). Annual pipeline operating costs were computed as 2 percent of the initial investment cost. The pipeline business entity is subject to all the Alaska State taxes as well as Federal taxes.

While the export prohibition on Northern Alaska crude oil was recently lifted, the impact on long-term well head prices was projected to be negligible (K. Banks, Alaska Department of Natural Resources, personal communication, 1995) because the long-term glut of heavier oils at US West Coast refineries is expected to disappear by 1997. The 1993 tariff rate of $3.25 per barrel was assumed for the cost of transportation through the TAPS line to Valdez and cost of tanker transport from Valdez to the US West Coast was assumed to be $1.40 per barrel. Northern Alaska well head oil prices are net of the transportation cost to market.

Northern Alaska Exploration and Development Costs

Partitioning Northern Alaska into smaller subareas or zones allowed more accurate estimation of exploration and development costs and costs of product transport to TAPS. The eastern zone was defined as extending from TAPS east to the Canadian border, the central zone; from TAPS west to longitude 155 degrees west, and the western zone; from longitude 155 degrees west to Alaska's west coast. Plays containing oil resources were allocated to each zone by the province geologist (see Table B-1, Appendix B). Within each zone, plays were aggregated into two groups, those of the coastal plain - the Topset, Turbidite, Barrow Arch Beaufortian, and Barrow Arch Ellesmerian- and those of the foothills - Fold Belt and the Eastern and Western Thrust Belt. Northern Alaska was divided, in essence, into six subareas represented by the coastal plain and foothills groups that were further partitioned into the three zones. For the purpose of estimating transportation costs to the TAPS line, fields were assumed to be located near the geographic center of the oil prone part of each subarea. Table B-1, Appendix B, shows distances and computed tariffs for each subarea.

Field design and development methods in Northern Alaska differ from those of the lower 48 states. Onshore oil production requires construction of gravel pads to support wells and production equipment because of the seasonal instability of the permafrost and to minimize environmental degradation. Wells are drilled directionally from the pads to target depths. Onshore pads may support up to 40 production or injections wells along with production equipment. For a standalone field, well production is sent to the field's central processing facility and the final product is transported from the periphery of the field to TAPS. Temporary ice roads and pads may be constructed to support exploratory well drilling activities.

Water depths in the prospective State offshore areas of the Beaufort Sea are shallow and reach perhaps a maximum of 40 feet. At such water depths gravel islands are constructed to support production wells and equipment rather than traditional offshore platforms. Offshore gravel islands accommodate up to 90 wells and production equipment and are generally accessible via a constructed causeway. The gravel island allows use of onshore drilling and production equipment. Temporary ice islands that are constructed for offshore wildcat drilling permit use of onshore drilling equipment. Because of the similar equipment and procedures, *it was assumed that the costs of standalone fields in State offshore waters would not differ significantly from costs of onshore fields.* Development costs of the Endicott field, which is located in State offshore waters, were actually less than costs of similar size onshore fields developed to that time.

Exploration costs

Exploration effort leading to new field discoveries is represented by the drilling of wildcat wells. For the lower 48 states, data indicate that non-drilling exploration expenditures (exclusive of lease bonuses) amount to about 50 percent of the drilling cost (Vidas and others, 1993). Exploration well drilling costs were somewhat higher than costs of production wells and drilling costs also varied with subareas. Non-drilling exploration expenditures include geologic and geophysical data collection, scouting costs, and overhead charges associated with land acquisition. Data for Northern Alaska are incomplete, however, non-drilling exploration costs typically represent a larger share of the exploration expenditures for frontier areas than for areas having infrastructure. It was assumed that non-drilling exploration expenditures (exclusive of lease bonuses) were 100 percent of drilling costs. Exploration was evaluated in increments of 20 wildcat wells.

Theoretically, lease bonus levels are fixed by the degree of competition for the particular prospect and reflect the expected economic rent associated with the prospect. By definition economic rent is a surplus above and beyond the cost of supply of the input. Lease bonus payments can account for substantial expenditures that reflect not only site-specific characteristics of the prospects but also operator expectations about future oil prices and costs. Although to the individual operator lease bonus expenditures represent very real costs, economists generally do not consider bonus payments as costs but as transfer payments to the land or mineral right owner which, if set in a competitive market, do not ultimately affect whether the prospect will be developed. The purpose of this analysis is not to estimate or forecast such expenditures Only nominal lease bonuses were included. These costs amounted to 1 million dollars per wildcat well.

Field development costs

Northern Alaska still represents a frontier area where there is much uncertainty about field production characteristics and field development and production costs. During the last 12 years, the reduction in capital and operating costs for new discoveries has been substantial and well documented (Oil and Gas Journal, 1994, Thomas and others, 1991, Harris, 1987a, 1987b). Drilling and completion of production and injection wells and facilities' costs constitute the two principal field development costs categories. To keep the discussion brief, design and cost data details are presented in Appendix 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 (Amercian

Petroleum Institute, 1993) and Vidas and others (1993). The Prudhoe Bay area (central coastal plain subarea) costs per well for the four depth intervals considered are: $1.5 million, $2.4 million, $3.4 million, and $4.5 million. Outside of the central zone costs were increased to compensate for a lack of infrastructure or special environmental precautions (see Appendix B for details).

The number of wells required to develop a field depends on well productivity. Estimates were based on published North Slope data and scale factors computed from historical well productivities for fields of similar size in the North Sea (see Table B-3, Appendix B). According to the National Petroleum Council (NPC) Arctic study (NPC , 1981a), average well productivity for development wells in a 500 million barrel (size class 15) oil field, assuming an additional 0.4 wells per producer for water and gas injection, is 7.5 million barrels over the life of the average well. With this information and North Sea scale factors, reserves per well were estimated for other field sizes.

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 field production rates. A cost function was estimated using data originally presented by the National Petroleum Council (1981b) and in Young and Hauser (1986). The cost function was adjusted so facilities costs are consistent with published costs of the Endicott field (Harris, 1987a), the latest standalone field commissioned. Facilities investment costs are shown in Table B-3, Appendix B.

Currently there are five standalone fields in Northern Alaska. These fields include Prudhoe Bay, Kuparuk, Lisburne, Milne Point, and Endicott. Other producing fields or producing entities, specifically, Point McIntyre, Niakuk, and North Prudhoe Bay utilize central processing facilities of the declining Lisburne field. Development of such satellite fields or cost sharing of new facilities by two or more discoveries can dramatically reduce facilities costs as well as reduce the time to production. The use of the Lisburne's processing unit (Thomas and others, 1993) saved the Point McIntyre operators 40 percent in facilities costs. 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) for new fields less than 130 million barrels (class 12 and smaller) in the eastern zone and central coastal subareas. Elsewhere, the small numbers of assessed undiscovered fields and absence of commercial production make facilities sharing much less likely.

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 recent years. Annual field operating costs are shown in figure B-1, Appendix B, as a function of hydrocarbon and water fluid volumes (NPC, 1981, Young and Hauser, 1984). These volumes were projected annually using field production forecasts and a water cut function presented in figure B-2, Appendix B, (Thomas and others, 1991), so that costs per barrel of oil reflected increases in costs that result from a higher water cut as the field is depleted.

Cook Inlet exploration and developments costs

Exploration costs

Exploration costs were computed on a wildcat well basis and classified into drilling and nondrilling costs. Historical data covering the conterminous United States show non-drilling exploration costs, such as the costs of geologic and geophysical data collection, scouting costs, and overhead charges associated with land acquisitions, exclusive of lease bonuses, averaged about 50 percent of direct drilling costs (Vidas and others, 1993). This factor was used in estimating total exploration costs. Onshore drilling cost data were compiled from the JAS drilling reports and used to calibrate a drilling cost model that had been developed for an analogue region in the lower 48 states. Offshore drilling costs for State waters were assumed to be 60 percent greater than the drilling costs of Gulf of Mexico wells for comparable water depths (Vidas and others, 1993). For onshore areas a nominal lease bonus amounting to about $130,000 per wildcat well was assumed and for offshore areas a nominal lease bonus of $250,000 per wildcat well was assumed.

Field development costs

Onshore oil and gas field development costs include the costs of drilling and completing production wells, costs of dry development wells, and lease production equipment costs. Available Cook Inlet cost data are sparse but were used to calibrate cost models that had been developed for the Rocky Mountain region (see Attanasi and others, 1996 for discussion of cost models). In particular, Cook Inlet area drilling and equipment cost estimates were on average 50 percent greater than computed Rocky Mountain costs and well operating costs were double Rocky Mountain costs. Well production schedules and field designs were the same as those applied in the Rocky Mountain region.

Onshore development well success rates were the same as those applied in the conterminous US analysis (Attanasi and others, 1996, Attanasi and others, 1981). For large fields, 2 dry holes would be drilled for each set of 10 development wells and in smaller fields, 4 dry holes would be drilled for each set of 10 successful development wells. The oil and gas pipeline network was assumed to be sufficiently widespread that transport cost from the lease to the nearest pipeline is assumed to be negligible. For simplicity, development of onshore Cook Inlet area discoveries is assumed to be completed in 1 year.

The drilling technology, production platform, and systems designs used in the State offshore waters of the upper Cook Inlet are similar to those used at similar water depths in the Gulf of Mexico. Costs of Cook Inlet State offshore field development were estimated from the cost estimates prepared for Gulf of Mexico (see Attanasi and others, 1996). In particular, Gulf of Mexico operating and production equipment costs were doubled, production platform costs were multiplied by 2.33, and drilling costs were increased by 60 percent. (Vidas and others, 1993).

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. For the analysis of Alaskan resources, the algorithm that calculated incremental costs used the predicted size and depth distribution of undiscovered fields (at the sub-area or sub-province levels) 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 (for details see Attanasi and others, 1996) to forecast the size and depth distribution of new discoveries from increments of wildcat drilling. These forecasts are used to drive the economic field development and production process model, which in turn, determines 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 feasibility of developing a representative field from a specific field size class and depth category is determined by the results of a DCF analysis. The net after-tax cash flow consists of revenues from the production of oil and/or gas less the operating costs, capital costs in the year incurred and all taxes. All new discoveries of a particular size and depth class 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 and the Cook Inlet area from historical data. A procedure for obtaining default coefficients is described in Appendix C. 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 and gas fields discovered was maximized.

INCREMENTAL COSTS: RESULTS AND INTERPRETATION

Northern Alaska - Commercially developable resources

Table 3 shows allocations of the mean or expected value of the technically recoverable oil, associated gas, and natural gas liquids resources by subarea. The eastern zone accounts for half the oil, central zone about 40 percent and the western zone about 10 percent of the oil. Transportation costs range from $5.41 per barrel for the eastern coastal subarea to $9.38 per barrel for the western foothills subarea. So, an $18 per barrel oil price translates into a well head price of between $12.59 and $8.62 per barrel.

The calculation of commercially developable resources *assumes fields are already discovered and the remaining costs are development and operating costs*. Commercially developable undiscovered resources are the economic target for exploration. At $18 per barrel, 2.28 BBO or 31 percent of the 7.40 BB of technically recoverable oil (including small fields) is commercially developable. Similarly, at $30 per barrel 4.87 BBO or two-thirds of the technically recoverable oil is commercially developable. Across the subareas, at $18 per barrel the eastern foothills shows the largest quantity of commercially developable oil of any subarea because the Eastern Thrust Belt play assessment included the likelihood of undiscovered fields larger than 1 BBO. At $30 per barrel the quantity of commercially developable oil in the eastern and central coastal subareas increases substantially as the minimum commercially developable field size declines and larger numbers of fields become commercial.

At $18 per barrel the dominant minimum commercially developable field size for the eastern and central coastal subareas and central foothills subarea is size class 14 (fields of size 256 to 512 million barrels). At that same price the minimum commercial field size for the eastern foothills is size class 15 (512 to 1024 million barrels) and for the western coastal and foothills subareas it is class 16 (1024 to 2048 million barrels). At $30 per barrel, the minimum commercially developable fields in the eastern and central coastal subareas, where facilities sharing was allowed for fields smaller than class 13, is size class 12 (64 to 128 million barrels). Elsewhere, at $30 per barrel the minimum field size class was class 13 (128 to 256 million barrels). Minimum commercially developable field sizes were relatively insensitive to depth because field drilling costs are not the dominant field development cost component in Northern Alaska as they are in the lower 48 states.

The amount of oil estimated to be commercially developable at each price is a direct consequence of the field size distribution in figure 3. More than half of the assessed oil was assigned to fields having sizes from 64 to 512 million barrels (class 12, 13, 14) and another 9.5 percent was assigned to the 512 to 1024 million barrel size class (class 15). The field size distribution also determines how estimates of commercially developable oil change with cost changes. With oil prices at $30 per barrel, the marginally economic field size classes contain about one-third of the oil, so that changes in costs that affect these field sizes produce asymmetric changes in the quantity of commercially developable oil. For example, at $30 per barrel if facilities costs were reduced 30 percent, commercially developable oil increases 3 percent. Alternatively, a facilities cost increase of 30 percent reduces commercially developable oil by 18 percent. Similarly, at that oil price, a 30 percent reduction in operating cost increases commercially developable oil by 2 percent while a 30 percent increase reduces commercially developable oil by 11 percent.

Northern Alaska 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 C presents the structure of the model and explains how the finding rate functions were calibrated. Computations were based on successive increments of 20 wildcat wells. Figure 5 presents the incremental cost function for crude oil for Northern Alaska. Table 4 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. At $18 per barrel the table shows that only 0.59 BBO or 8 percent of 7.40 BB of technically recoverable oil is economic. Similarly, at $30 per barrel, 3.33 BBO or 45 percent of the technically recoverable oil is economic. At the cost of $24 per barrel, 1.94 BBO will be found and developed. The figure shows that the incremental cost function becomes less elastic as prices increase beyond $30 per barrel. At $18 per barrel the implied discovery rate is 14.75 million barrels per wildcat well. Based on data from the literature and wildcat well counts from Petroleum Information Inc., from 1981 to 1990, the discovery rate (representing roughly 50 wildcat wells) was estimated to be 17 to 19 million barrels per wildcat well, so that the finding rates used in this analysis appear reasonable.

Table 4 shows that economic resources available at $18 per barrel are located in the eastern foothills subarea. This result was not unexpected because the geologic assessment predicted (at the expected value) the Eastern Thrust Belt play to have much larger fields than any other play in the province. However, as incremental costs are allowed to increase to $30 per barrel, fields located in the eastern coastal and central coastal subareas become economic to find and produce so that these two areas account for nearly 60 percent of the 3.33 BBO shown in table 4 at that incremental cost level. It does not become economic to begin exploration of the western coastal subarea until incremental costs increase to $32 per barrel. Similarly, based on the geologic assessment exploration of the western foothills subarea should not begin until prices (incremental costs) reach $47 per barrel.

Sensitivity of the results to the overall required rate of return was also examined. Effects are most conspicuous at the lower price (cost) levels. It has been argued that over the long run, the domestic oil and gas industry received at the margin a 6 percent after-tax rate of return. Reducing the required marginal rate of return to 6 percent increases new discoveries at $18 per barrel to 1.51 BBO. At $24 ($30) per barrel the new discoveries increase to 2.88 BBO (4.0 BBO), an increase of over 48 (20) percent from the base case. Increases in reserves that result from the reduced rate of return come from increases in wildcat drilling and resulting discoveries, rather than a decline in the marginal size of commercially developable fields. At $18 per barrel, the number of economic wildcat wells increased from 40 to 200 wells and at $30 per barrel it increased from 480 to 780 wildcat wells.

In summary, 8 percent of the assessed technically recoverable crude oil has incremental finding, development, production, and transportation costs of $18 per barrel or less. At $24 and $30 per barrel, 26 percent and 45 percent, respectively, of the technically recoverable resources are economic to find and develop. The eastern foothills subarea, the eastern coastal subarea, and central coastal subarea account for nearly all of the economic resources when incremental costs are $30 per barrel. Based on the geologic assessment and the assumptions used in this analysis, the threshold incremental costs at which wildcat drilling becomes commercial for the eastern foothills subarea was $16 per barrel, similarly, for the central coastal subarea $19, eastern coastal subarea $21 and for the central foothills subarea $23. Reducing the required return to 6 percent after-tax increases expected additions to reserves by 48 percent at incremental costs of $24 per barrel.

Cook Inlet - Commercially developable resources

The Cook Inlet area has an active local oil and gas market so transport costs are assumed to be negligible. Estimates of sizes and number of *small fields* were originally prepared for the Southern Alaska province. Small fields were assigned to the Cook Inlet area on the basis of its share of fields in size classes 7 through 11. Small oil fields account for less than 3 percent of total oil assessed in the Cook Inlet area and small gas fields represent 20 percent of the assessed non-associated gas. For all field sizes, technically recoverable resources in oil fields amounted to 0.663 BBO and 0.663 TCF associated gas, and technically recoverable resources in gas fields amounted to 0.922 TCF of non-associated gas. Half of the oil and 30 percent of the non-associated gas was assigned to State offshore areas.

Overall, 84 percent of the oil and 61 percent of the non-associated gas is commercially developable at $18 per barrel ($2.00 per mcf) *if fields were assumed to be already discovered*. At that price level 91 percent of onshore oil and 66 percent of the onshore non-associated gas is commercially developable. Similarly, 77 percent of offshore oil and 49 percent of offshore non-associated gas is commercially developable. The high percentage of commercially developable oil is a direct result of the distribution of undiscovered fields. *About 93 percent of the oil was assigned to fields having at least 8 MMBO*. At the higher prices of $30 per barrel and $3.34 per mcf, about 93 percent of the oil (96 percent of onshore; 90 percent offshore) and 73 percent of the non-associated gas (77 percent of onshore; 63 percent offshore) is commercially developable.

Cook Inlet incremental costs: finding, development, and production

Although field data used in the assessment showed 22 fields with reported recoveries of larger than 1 MMBOE in plays of the Cook Inlet (NRG Associates, 1993), standard calibration procedures based on the Cook Inlet's drilling and discovery data did not produce a usable set of finding rate coefficients. Therefore, the procedure for obtaining default coefficients was applied (see Appendix C). Again, the geologic assessment provides the estimates of undiscovered fields and the finding rate function merely orders the discovery times on the basis of wildcat wells drilled.

Figures 6 and 7 show the incremental cost functions for oil and non-associated gas from undiscovered oil and gas fields in onshore and State offshore areas of the Cook Inlet. Half the oil and 30 percent of the non-associated gas was assigned to offshore fields. The onshore finding rate model used exploration increments of 50 wildcat wells and the offshore model used 20-well increments. Table 5 summarizes the incremental costs for each area and the combined area. Overall, at $18 per barrel ($2 per mcf) 48 percent of the oil and the 13 percent of the non-associated gas is economic and at $30 per barrel ($3.34 per mcf) 74 percent of the oil and 31 percent of the non-associated gas is economic. At $18 per barrel ($2 per mcf) it is economically justified to drill 240 new wildcat wells and at $30 per barrel ($3.34 per mcf) 550 new wildcat wells are commercial.

Overall, a higher percentage of the technically recoverable oil than the non-associated gas is expected to be found and developed. This is a consequence of the undiscovered oil and gas field size distribution and targeting of wildcat wells by depth. About 93 percent of the undiscovered oil is concentrated in fields larger than million barrels. Alternatively, the non-associated gas is concentrated in much smaller fields. For each size class more than half of the gas fields were assigned to the first 5000 foot depth interval while no oil fields were assigned to this depth interval. Wildcat wells are targeted to drilling depths on the basis of maximizing the expected net present value of the fields expected to be discovered. Apparently, the typically smaller gas fields are less profitable to target than the oil fields even though the gas fields were concentrated at shallow depths. To test this, incremental costs were recalculated where *gas was assumed to be priced equal to oil on an energy equivalent basis*. The most dramatic change was onshore; the percentage of wildcat wells targeted to the shallow gas fields increased from 17 to 34 percent of the total number of wildcat wells at $30 per barrel ($5 per mcf). At that level reserve additions of onshore non-associated gas increased by 40 percent over that shown in table 5. Offshore, the pricing change had little effect because of the relatively small amount of gas assigned to the offshore and larger minimum commercial field sizes The effects of a reduction to a 6 percent required rate of return were also examined. At $30 per barrel ($3.34 per mcf) results show a 5 percent overall increase in expected oil discoveries and a 20 percent increase in expected non-associated gas discoveries.

To summarize, Cook Inlet field development and production costs were are generally higher than lower 48 states costs. However, nearly all of the assessed undiscovered oil is expected to be concentrated in fields greater than 8 million barrels. This characteristic of the assessed undiscovered field size distribution accounts for the relatively high percentage of the technically recoverable oil expected to be found and developed even at low incremental costs. At $18 per barrel ($2.00 per mcf) almost half the oil but only 13 percent of the non-associated gas is economic. The costing algorithm, which chooses wildcat drilling depths to maximize the after-tax net present value of expected discoveries, preferentially targets oil fields. Only when gas prices increased relative to oil prices or when oil prospects suffered depletion were non-associated gas fields targeted.

SUMMARY AND IMPLICATIONS

This report presents the economic analysis of the 1995 USGS assessment of the technically recoverable oil, gas, and natural gas liquids resources in undiscovered conventional oil and gas fields of Alaska. At their mean values, more than 8 BBO and 70 TCFG were assessed in conventional undiscovered oil and gas fields in the three petroleum provinces of Alaska. Plays assessed in the Central Alaska petroleum province and those outside of the Cook Inlet in Southern Alaska were in remote areas having little or no infrastructure to support a petroleum industry or means of transporting oil and gas to market. Moreover, the quantity and market potential of the resources assessed appear too small to support required new infrastructure construction. Accordingly, the resources associated with the plays of the Central Alaska and the plays of Southern Alaska in the Alaskan Peninsula area and the Gulf of Alaska were not evaluated by a detailed economic analysis. In Northern Alaska, the 57 TCFG assessed in undiscovered gas fields was also not evaluated by the economic analysis. Currently, there is no means of transporting this gas to market nor is a market expected to develop during the next the two decades. Further, more than 30 TCFG has already been identified in discovered oil fields. The analysis also did not account for potential effects on the TAPS tariff rates of declining production in currently operating fields.

For Northern Alaska, the economic analysis focused on oil fields. Northern Alaska was partitioned into subareas consisting of groups of play segments, having similar exploration, development, and transportation costs. The economic analysis assumed that all of the province was available to explorationists. Transportation costs from the field to market ranged from $5.41 per barrel to $9.38 per barrel. About 27 percent of the technically recoverable oil or 1.94 BBO can be discovered, developed, produced, and transported to market for $24 per barrel. Allowing costs to increase to $30 per barrel increases the economic proportion of the technically recoverable oil to 43 percent. At incremental costs of $18 per barrel only 8 percent of the technically recoverable oil is economic.

For Northern Alaska, computations showed that even at a US West Coast price of $18 per barrel almost one-third of the oil would be commercially developable *if already discovered*. Similarly, at $30 per barrel almost two-thirds of the assessed oil would be commercially developable if already discovered. Full incremental costs, however, require accounting for finding costs. The finding rate functions are used to predict the discovery arrival rates and to sequentially order the discovery distributions generated by increments of wildcat wells. These functions provide the crucial link between commercially developable resources and fully costed resources. The exponential function coefficients used in the analysis appeared to produce a reasonable, albeit probably conservative set of projections. The exponential finding rate functions, however, provide no direct means of capturing the accumulation of geologic knowledge that will, in practice, enhance the siting of future wildcat wells.

Even at relatively low oil prices, improvements in exploration technology are likely to occur during the next decade. During the last decade significant improvements in production technology have been made and applied in Northern Alaska, despite low well head prices (Oil and Gas Journal, 1995). For a given distribution of undiscovered resources, increased exploration efficiency can significantly increase resources found and developed for a given cost level. If the analysis for Northern Alaska were repeated and finding rates were double those in the base case, at $18 per barrel price at the US West Coast, 0.992 BBO is economic to find, develop, produce, and transport, representing an increase of 68 percent. Similarly, at $24 and $30 per barrel 2.57 BBO and 3.87 BBO, respectively are economic, representing increases of 32 percent and 16 percent.

For the Cook Inlet plays, nearly half of the technically recoverable oil but only 13 percent of the non-associated gas can be found, developed and produced for $18.00 per barrel ($2.00 pre mcf). Although a much larger proportion of the non-associated gas would be commercially developable if already found, most of the projected wildcat drilling is targeted to oil horizons for discoveries with greater expected net present values. Only when gas prices increased relative to oil prices or when oil prospects suffered depletion were non-associated gas fields targeted.

The results of the economic assessment of the undiscovered conventional oil and gas fields of Alaska should be interpreted in light of the uncertainty surrounding the geologic estimates. According to Petroleum Information Inc. (1993), Alaska has less than 600 wildcat wells drilled onshore and in State offshore waters though 1990. The geologic assessment depended principally on publicly available information and for some of the plays shown in table 1 available information was insufficient to make a quantitative assessment. While the mean value of technically recoverable oil in Northern Alaska, for example, was estimated at 7.4 BBO, estimates of recoverable oil range from 2.3 BBO to 15.4 BBO at the 95th and 5th fractiles. In no other US province was there such a wide range and magnitude of the uncertainty attached to the estimates. Continued exploration will undoubtedly yield some surprises that could narrow but also expand the range of uncertainty.

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APPENDIX A. NOMENCLATURE

barrels of oil equivalent (BOE) - gas volume and NGL volume expressed in terms of its energy equivalent in barrels of crude oil. For this assessment, 6,000 cubic feet of gas equals 1 barrel of crude oil and 1 barrel of NGL equal 0.667 barrels of crude oil.

conditional estimates - sizes, numbers, or volumes of oil or natural gas that are estimated to exist in an area, assuming that at least some oil and gas is present. Conditional estimates do not incorporate the risk that the area may be devoid of oil or natural gas.

conventional accumulations - discrete deposits bounded by downdip water contact, from which oil, gas, or NGL can be extracted using traditional development practices.

crude oil - a mixture of hydrocarbons that exists in the liquid phase in underground reservoirs and remains liquid at atmospheric pressure after passing through surface gas separation facilities.

field - an individual producing unit consisting of a single pool or multiple pools of hydrocarbons grouped on, or related to, a single structural or stratigraphic feature.

a. crude oil fields - fields where the ratio of natural gas to crude oil is less than 20 thousand cubic feet of gas per barrel of crude oil.

b. non-associated gas fields - fields where the ratio of natural gas to crude oil is at least 20 thousand cubic feet of gas per barrel of crude oil.

field growth (inferred reserves) - that part of the identified resources over and above proved (measured) reserves that will be added to existing fields through extension, revision, improved efficiency, and the addition of new pools or reservoirs.

gas-oil ratio (GOR) - average ratio of associated-dissolved gas to oil.

NGL to non-associated gas ratio - volume of natural gas liquids (in barrels) contained in 1 million cubic feet of gas in a known or postulated gas accumulation

NGL to associated-dissolved gas ratio - volume of natural gas liquids (in barrels) in 1 million cubic feet of associated-dissolved gas in a known or postulated oil accumulation.

natural gas - a mixture of hydrocarbon compounds and small quantities of non-hydrocarbons existing in gaseous phase or in solution with crude oil in natural underground reservoirs at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentanes.

natural gas liquids - those hydrocarbons in natural gas which are separated from the gas through the processes of absorption, condensation, adsorption, or other methods in gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as natural gasoline or liquefied petroleum gases.

play - 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.

a. confirmed plays - plays where one or more accumulations of minimum size (1 million barrels of oil or 6 billion cubic feet of gas) have been discovered in the play.

b. hypothetical plays - plays identified and defined based on geologic information but for which no accumulations at minimum size (1 MMBO or 6 BCFG) have, as yet, been discovered.

play attributes - geologic characteristics thought to characterize the principal elements necessary for occurrence of oil and (or) gas accumulations of some minimum size. Attributes used in this assessment; charge, reservoir, and trap are defined as :

a. charge - occurrence of conditions of hydrocarbon generation and migration adequate to cause an accumulation of the minimum size. Subsidiary elements of charge are source rocks with sufficient organic matter, temperature and duration of heating to generate and expel sufficient quantities of oil and (or) gas, and timing of expulsion of hydrocarbons from source rocks to available traps.

b. reservoir - occurrence of reservoir rocks of sufficient quantity and quality to permit containment of oil and (or) gas in volumes sufficient for an accumulation of minimum size.

c. trap - occurrence of those structures, pinch-outs, permeability changes, and similar features necessary for the entrapment and sealing of hydrocarbons in at least one accumulation of minimum size.

play probability - for recoverable resources, represents the likelihood that technically recoverable quantities of oil or natural gas exists in at least one undiscovered accumulation of the minimum size (1 MMBO or 6 BCFG) in the assessed play.

proved (measured) reserves - estimated quantities of crude oil, natural gas, or natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Reserves are proved if economic productivity is supported by actual production or conclusive formation tests (drill stem or wireline), or if economic producibility is supported by core analyses and/or electric or other log interpretations.

reservoir - a porous and permeable underground formation containing an individual and separate accumulation of producible hydrocarbons which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

risked (unconditional) estimates -resources estimated to exist, including the possibility that the area may be devoid of oil or natural gas. For example the risked mean may be determined by multiplication of the mean of a conditional distribution by the related probability of occurrence. Resource estimates presented in this report are risked estimates.

technically recoverable - estimated to be producible using current technology but without reference to economic profitability.

undiscovered resources - resources postulated, from geologic information and theory, to exist outside of known oil and (or) gas fields.

APPENDIX B. COSTS FOR NORTHERN ALASKA

Allocation of plays to subareas and transportation to the Trans-Alaska Pipeline System

Partitioning Northern Alaska into smaller subareas or zones allowed more precise estimation of exploration and development costs and costs of product transport to the Trans-Alaska Pipeline System (TAPS). The eastern zone was defined as extending from TAPS east to the Canadian border, the central zone; from TAPS west to longitude 155 degrees west, and the western zone; from longitude 155 degrees west to Alaska's west coast. Plays containing oil resources were allocated to each zone by the province geologist (Bird, personnel communications 1996). Within each zone, plays were aggregated into two groups, those of the coastal plain - the Topset, Turbidite, Barrow Arch Beaufortian, and Barrow Arch Ellesmerian- and those of the foothills - Fold Belt and the Eastern and Western Thrust Belt. Northern Alaska was divided, in essence, into six subareas designated by the coastal plain and foothills groups, that were further partitioned into three zones. Table B-1 shows the allocation percentages across zones.

For the purpose of estimating transportation costs to the TAPS line the representative field was assumed to be located near the geographic center of the oil prone part of each subarea. In particular, a pipeline to TAPS was assumed to be built and operated by a separate entity. Pipeline tariff charges were set to assure investors a 12 percent after-tax return on investment. The pipeline is assumed to service several fields, is sized for 250,000 barrels per day throughput, and is operated at a minimum capacity of 65 percent. Pipeline investment cost functions originally presented in Young and Hauser (1986) were adjusted to reflect the rather dramatic decline in pipeline costs experienced on the North Slope (J. Broderick, Bureau of Land Management, 1992). Annual pipeline operating costs were computed as 2 percent of the initial investment cost. The pipeline business entity is subject to all the Alaska State taxes as well as Federal taxes. Table B-2 shows distances and computed tariffs based on 6 and 12 percent required rates of return for each subarea.

Field Costs

Drilling costs were assumed to reflect costs as of 1993. Development drilling costs for the four depth intervals in the central zone was 1.5 million dollars (3,000 feet), 2.4 million dollars (7200 feet), 3.4 million dollars (12000 feet), 4.5 million dollars (16000 feet). For other subareas drilling costs were estimated as a multiple factor of the corresponding central zone cost. These factors are eastern coastal 1.05, eastern foothills 1.10, western coastal 1.29 and western foothills 1.29. In addition, for the eastern and central zones wildcat drilling costs were increased by 10 percent above standard drilling costs. Wildcat drilling costs for the western zone were increased by 50 percent above the standard drilling costs of the western zone.

Table B-3 shows estimates of development well productivity for the representative well for each field size class that was evaluated. This table also shows the estimated per barrel facilities costs for the central zone for the representative stand-alone field for each field size class evaluated. Outside the central zone, facilities costs were increased by 15 percent to compensate for the deficiency of infrastructure in these other areas. In the central and eastern coastal subareas, it was assumed that fields smaller than class 13 would be developed with shared facilities that would save, on average, 30 percent of the total facilities investment costs.

Field operating costs include labor, supervision, overhead and administration, communications, catering, supplies, consumables, well service and workovers, facilities maintenance, facilities insurance and labor transportation. Some of these costs, such as well workover and labor costs have declined dramatically during recent years. Annual field operating costs are specified as a function of hydrocarbon and water fluid volumes (NPC, 1981, Young and Hauser, 1984). These volumes were projected annually using field production forecasts and the water cut functions presented by Thomas and others (1991). Figure B-1 shows annual costs expressed as a function of fluid volume and figure B-2 shows percentage water expected in production with depletion of the field.

Field development and investment profile

Future discoveries are assumed to attain peak annual rates of production equal to 10 percent of the field's ultimate oil recovery. Fields with less than 100 million barrels are assumed to reach peak production in the second production year and maintain the peak for three full years, after which a 12 percent annual production decline would occur. Fields larger than 100 million barrels but smaller than 1 billion barrels would reach peak production in the third year and maintain that level for four years, after which production decline would begin. Similarly, for fields larger than 1 billion barrels of oil, peak production is delayed one more year and the peak rate is maintained for 5 years before the production decline begins. Fields smaller than 100 million barrels are assumed to start production the second year of development. Fields larger than 100 million barrels but still smaller than 400 million barrels start production in the third year of development, and for larger fields, production starts in the four year of development. A charge of $0.25 per barrel was taken to cover the cost of field abandonment.

Alaska Taxes

Severance Tax:

oil is 12.25% years 1 through 5 adjusted for economic limit rate (elr)
15.00% after year 5 adjusted for the economic limit rate
floor of $0.80 per barrel adjusted for the economic limit
elr = $(1-(300/ADWR))^{a}$
where a = $(150000/ADFR)^{1\ 5333}$
ADWR = average daily production per producing well (bbo/d)
ADFR= average daily field production (bbo/d)

gas is 10% adjusted for the economic limit rate
elr = (1-(3000/ADWR))
ADWR = average daily production per producing well (mcf/d)
For both cases, if elr 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 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.

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 B-1 Northern Alaska plays, zones, and subarea allocations

	Western (percent)	Central (percent)	Eastern (percent)
Coastal			
Topset	20	50	30
Turbidite	10	30	60
Barrow Arch-Beaufortian	5	60	35
Barrow Arch-Ellesmerian	5	60	35
Foothills			
Fold Belt	20	50	30
Western Thrust Belt	40	50	10
Eastern Thrust Belt	0	5	95

Table B-2 Northern Alaska subareas, distances to the Trans-Alaska Pipeline (TAPS) and estimated* pipeline tariff to TAPS based on a permitted after-tax return of 6 and 12 percent on investment.

SUBAREA	Distance to TAPS	Tariff to TAPS 6% RR	12% RR
	(miles)	($/bbl)	($/bbl)
Eastern Coastal	45	0.47	0.76
Eastern Foothills	80	0.83	1.33
Central Coastal	70	0.74	1.18
Central Foothills	70	0.74	1.18
Western Coastal	205	2.12	3.91
Western Foothills	245	2.96	4.73

Table B-3 Reserves per development* well and facilities investment costs**

Size Class	Reserves per well	Facilities costs
	(mmbo)	($/bbl)
9	0.95	18.63
10	1.38	12.29
11	2.00	8.11
12	2.90	5.35
13	4.20	3.18
14	5.40	2.07
15	7.50	1.52
16	10.70	1.28
17	14.30	1.11
18	14.30	1.11

* Includes 0.4 wells for gas and water injection

** Based on standalone field design

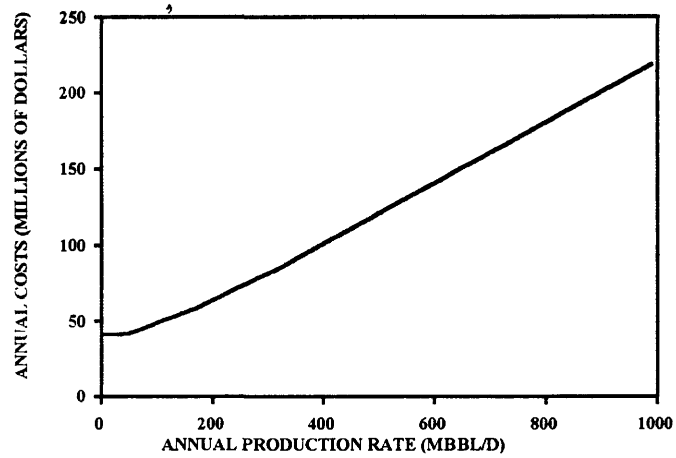

Figure B-1. Annual operating costs as a function of average daily fluid production rates in millions of barrels per day (MBBL/D).

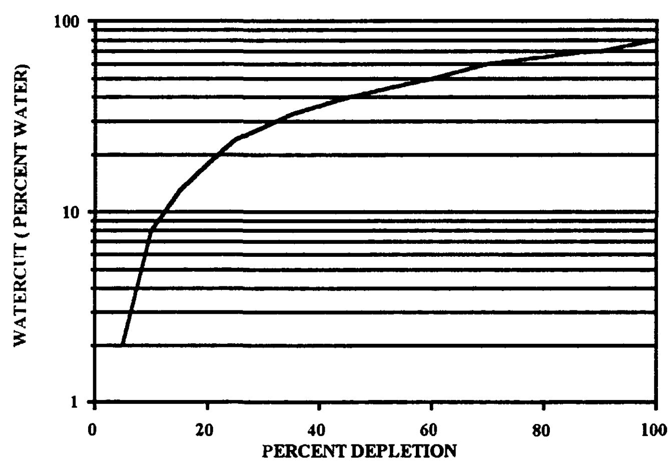

Figure B-2. Percentage of water in production stream as a function of reservoir depletion.

Appendix 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 were not used to predict depths of future drilling because the past allocations were often affected by regulations and subsidies. Furthermore, in many provinces undiscovered resources were assessed at depths having little or no historical drilling. This appendix discusses the specification, calibration, and application of the finding rate component of the cost algorithm as applied to the Cook Inlet plays and the Northern Alaska province. 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. From the geologic assessment, distributions of size and number of undiscovered fields were combined into a size-frequency distribution and then the expected numbers of undiscovered fields by size and depth interval, that is the F(j,k,u) values, were calculated. 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 18 size classes (see table 2) and four depth intervals (0-5,000; 5,000-10,000, 10,000-15,000, and greater than 15,000 feet) for each province.

Calibration

The calibration of the c(j,k)'s used discovery and wildcat well data aggregated over the lower 48 states and data for individual provinces. Sources for field data were the *Significant Oil and Gas Field File* (NRG Associates, 1993) for fields greater than 1 MMBOE. Sizes of fields used in the calibration were adjusted to include field growth. Wildcat well data were compiled from the Well History Control File (Petroleum Information, Inc., 1993). Wildcat wells were assigned to depths based on the completion or total depth in the drilling record. Initial estimates if the c(j,k)'s for each depth interval were computed with drilling and discovery data from 1903 to 1990 using the following formula:

$$c(j,k) = -[\ln(F(j,k,u)-F(j,k,t))/F(j,k,t))](1/w(t,k)) \qquad (2)$$

where F(j,k,u) is the ultimate number of fields and t starts with 1903 and the other variables are defined as above.

Models were calibrated for the aggregate lower 48 states and for nearly all provinces individually. However, complete sets of coefficients were obtainable only for the lower 48 states and a few provinces that had a large number and range of discoveries and extensive drilling. A scheme was devised to use available province data and information from the lower 48 aggregate model to estimate missing coefficients for cases where it was possible to compute some but not all of the coefficients directly from the data. In some cases where the province's discoveries and drilling were too sparse to obtain useful coefficients from the data, a default set of coefficients were applied.

Examination of the c(j,k)'s for the aggregate lower 48 and the provinces where relatively complete sets of coefficients were computed showed the existence of a reasonably stable relationship between the c(j,k)'s and the decline coefficients calculated when the data for all depth intervals are collapsed and are represented by wells and discoveries at the surface, hereafter denoted c(j)'s. The relationship indicated that the c(j,k)'s could be approximated by applying a scalar multiple (say a(k),) to the c(j)'s. In particular, across all size classes, that is, for j = 1,2,...

$$c(j,k) = a(k)c(j) \qquad (3)$$

Although the a(k)'s were peculiar to the province, they typically increased with depth and with costs. The a(k)'s were used to fill in for "missing" coefficients that could not be calibrated from the province's past discovery history.

The default procedure was motivated by the empirical observation that related the c(j)'s computed using the aggregate lower 48 data and the c(j)'s calculated for several major provinces (Permian, Western Gulf, Louisiana-Mississippi Salt Basins). When compared to the lower 48 coefficients, the relative magnitude of province coefficients, that is the c(j)'s, was inversely proportional to the province's share of total wildcat wells. For example, if a province accounted for 10 percent of the lower 48 wildcat drilling, the estimated province c(j)'s were roughly, in terms of order of magnitude, 10 times the c(j)'s calculated from the aggregate lower 48 data. In cases where the empirical coefficients were unusable, estimates of the c(j)'s were obtained by multiplying the lower 48 coefficients by the reciprocal of the province's share of the aggregate lower 48 wells. Then the a(k)'s computed from the lower 48 data were applied to the province c(j)'s to estimate the remaining c(j,k)'s. If the province accounted for less than 1 percent of lower 48 wildcat drilling, the share was set to 1 percent so that the default province coefficients were no larger than 100 times the lower 48 coefficients. Cumulative wildcat wells in the Cook Inlet area and Northern Alaska represented only a tiny fraction of the more than 370 thousand wildcat wells drilled in the conterminous States. For Northern Alaska, default province coefficients as a set were adjusted by a scalar multiple so that the projected overall discovery rate, oil per barrel, would provide a reasonable extension of the empirical discovery rate realized since 1981. For the Cook Inlet, the projected discovery rates were slightly adjusted to be consistent projected rates for the lower 48 provinces.

Application

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.

Table 1. Mean values of undiscovered technically recoverable oil, gas, and natural gas liquids (NGL) in Alaska's oil and non-associated gas fields by play and province.

Province No.	Play name	Oil Fields: Crude Oil (MMBBL)	Oil Fields: Assoc. Gas (BCF)	Oil Fields: NGL (MMBBL)	Gas Fields: Non-assc. Gas (BCF)	Gas Fields: NGL (MMBBL)	Offshore percent
NORTHERN ALASKA							
101	Topset	1564	626	0	313	3	15
102	Turbidite	1254	1254	38	4470	134	15
103	Barrow Arch Beaufortian	1489	1117	34	2042	61	40
104	Barrow Arch Ellesmerian	494	370	15	0	0	40
105	Ellesmerian-Beaufortian Clastics	0	0	0	5627	84	5
106	Lisburne	0	0	0	3944	59	5
107	Lisburne Unconformity	NOT ASSESSED					
108	Endicott	NOT ASSESSED					
109	Fold Belt	617	617	12	13297	266	5
110	Western Thrust Belt	227	227	2	1887	19	5
111	Eastern Thrust Belt	1593	1593	24	23739	356	5
	Province small fields	161	129	3	2302	41	
	Northern Alaska Province Total	7399	5933	127	57620	1024	
CENTRAL ALASKA							
201	Central Alaska Cenozoic Gas	0	0	0	2210	0	5
202	Central Alaska Mesozoic Gas	0	0	0	0	0	0
203	Central Alaska Paleozoic Oil	NOT ASSESSED					
204	Kandik Pre-Mid-Cretaceous	NOT ASSESSED					
205	Kandik Upper Cret. & Tert.	61	61	0	116	0	0
	Province small fields	2	2		374	0	
	Central Alaska Province Total	63	63	0	2700	0	
SOUTHERN ALASKA							
301	Alaska Peninsula - Mesozoic	52	52	0	0	0	15
302	Alaska Peninsula - Tertiary	9	9	0	179	0	25
303	Cook Inlet Beluga-Sterling Gas	0	0	0	738	0	30
304	Cook Inlet Hemlock-Tyonek Oil	647	647	0	0	0	50
305	Cook Inlet Late Mesozoic Oil	NOT ASSESSED					
306	Copper R. Upper Cret. & Tert.	NOT ASSESSED					
307	Copper R. Mesozoic Oil	NOT ASSESSED					
308	Gulf of Alaska Yakataga Fold Belt	173	173	0	0	0	10
309	Gulf of Alaska Yakutat Foreland	57	57	0	0	0	15
	Province small fields	27	27	0	279	0	
	Southern Alaska Province Total	964	964	0	1196	0	
	Region 1 Total	8427	6960	127	61516	1024	

Table-2.--Oil and non-associated gas field-size class definitions used in this report.

Class	Oil field size (Millions barrels)	Gas field size (Billions cubic feet)
1	.03125- .0625	.1875 - .375
2	.0625 - .125	.375 - .750
3	.125 - .25	.75 - 1.50
4	.25 - .5	1.50 - 3.00
5	.5 - 1	3.00 - 6.00
6	1 - 2	6 - 12
7	2 - 4	12 - 24
8	4 - 8	24 - 48
9	8 - 16	48 - 96
10	16 - 32	96 - 192
11	32 - 64	192 - 384
12	64 - 128	384 - 768
13	128 - 256	768 - 1536
14	256 - 512	1536 - 3072
15	512 -1024	3072 - 6144
16	1024 - 2048	6144 - 12288
17	2048 - 4096	12288 - 24576
18	4096 - 8192	24576 - 49152

Table 3. Technically recoverable and commercially developable oil and gas liquids in the Northern Alaska province by subarea. Commercially developable oil based on $18 and $30 per barrel US West Coast price.

	Technically rec.*			$18 Commercially rec.			$30 Commercially rec.		
Subarea	Crude Oil	Assoc. Gas	NGL	Crude Oil	Assoc. Gas	NGL	Crude Oil	Assoc. Gas	NGL
	(BBO)	(TCF)	(BBO)	(BBO)	(TCF)	(BBO)	(BBO)	(TCF)	(BBO)
Eastern Coastal	1.921	1.464	0.040	0.349	0.266	0.007	1.152	0.878	0.024
Eastern Foothills	1.721	1.721	0.027	1.017	1.017	0.016	1.445	1.445	0.022
Central Coastal	2.344	1.579	0.040	0.628	0.423	0.011	1.520	1.024	0.026
Central Foothills	0.502	0.502	0.009	0.247	0.247	0.004	0.350	0.350	0.006
Western Coastal	0.537	0.324	0.006	0.020	0.012	0.000	0.275	0.166	0.003
Western Foothills	0.214	0.214	0.003	0.014	0.014	0.000	0.132	0.132	0.002
TOTAL	7.239	5.804	0.114	2.275	1.979	0.038	4.874	3.995	0.083

* Technically recoverable does not include resources in small fields.

Table 4. Incremental cost of finding, developing, producing and transporting oil and natural gas liquids from undiscovered oil fields in Northern Alaska and associated drilling and finding costs.

Subarea	Cost ($/bbl)	Crude Oil (BBO)	Assoc. Gas (TCFG)	NGL (BBL)	Wildcat Wells	Finding Cost ($/bbl)
Eastern Coastal	12	0.000	0.000	0.000	0	0.00
	15	0.000	0.000	0.000	0	0.00
	18	0.000	0.000	0.000	0	0.00
	21	0.133	0.101	0.003	20	0.89
	24	0.314	0.239	0.006	40	1.00
	27	0.452	0.345	0.009	60	1.17
	30	0.763	0.581	0.016	100	1.42
Eastern Foothills	12	0.000	0.000	0.000	0	0.00
	15	0.000	0.000	0.000	0	0.00
	18	0.592	0.592	0.009	40	0.59
	21	0.943	0.943	0.015	80	0.99
	24	1.021	1.021	0.016	100	1.34
	27	1.196	1.196	0.019	120	1.71
	30	1.251	1.251	0.019	140	1.98
Central Coastal	12	0.000	0.000	0.000	0	0.00
	15	0.000	0.000	0.000	0	0.00
	18	0.000	0.000	0.000	0	0.00
	21	0.213	0.144	0.004	40	0.93
	24	0.536	0.361	0.009	80	0.96
	27	0.729	0.491	0.012	120	1.27
	30	1.144	0.771	0.020	180	1.58
Central Foothills	12	0.000	0.000	0.000	0	0.00
	15	0.000	0.000	0.000	0	0.00
	18	0.000	0.000	0.000	0	0.00
	21	0.000	0.000	0.000	0	0.00
	24	0.070	0.070	0.001	20	1.30
	27	0.129	0.129	0.002	40	1.61
	30	0.174	0.174	0.003	60	2.06
Western Coastal	12	0.000	0.000	0.000	0	0.00
	15	0.000	0.000	0.000	0	0.00
	18	0.000	0.000	0.000	0	0.00
	21	0.000	0.000	0.000	0	0.00
	24	0.000	0.000	0.000	0	0.00
	27	0.000	0.000	0.000	0	0.00
	30	0.000	0.000	0.000	0	0.00
Western Foothills	12	0.000	0.000	0.000	0	0.00
	15	0.000	0.000	0.000	0	0.00
	18	0.000	0.000	0.000	0	0.00
	21	0.000	0.000	0.000	0	0.00
	24	0.000	0.000	0.000	0	0.00
	27	0.000	0.000	0.000	0	0.00
	30	0.000	0.000	0.000	0	0.00
Northern Alaska Province	12	0.000	0.000	0.000	0	0.00
	15	0.000	0.000	0.000	0	0.00
	18	0.592	0.592	0.009	40	0.59
	21	1.288	1.187	0.021	140	0.97
	24	1.940	1.691	0.033	240	1.18
	27	2.507	2.162	0.043	340	1.48
	30	3.332	2.777	0.058	480	1.72

Table 5. Incremental costs of finding, developing, and producing undiscovered resources in oil and gas fields and associated wildcat wells and finding costs in onshore and State offshore areas of the Cook Inlet

			Oil Fields		Gas Fields		
	Cost		Oil	Assoc. Gas	Non-assc. Gas	Wildcat Wells	Finding Cost
	($/bbl)	($/mcf)	(mmbo)	(bcf)	(bcf)		($/boe)
Onshore	12	1.34	117	117	54	100	1.16
	15	1.67	159	159	78	150	1.62
	18	2.00	195	195	99	200	2.08
	21	2.34	219	219	126	250	2.59
	24	2.67	248	248	175	350	3.76
	27	3.00	258	258	204	400	4.25
	30	3.34	265	265	232	450	4.81
Offshore State waters	12	1.34	0	0	0	0	0
	15	1.67	72	72	11	20	1.32
	18	2.00	125	125	21	40	1.75
	21	2.34	172	172	33	60	2.37
	24	2.67	203	203	42	80	3.24
	27	3.00	207	207	44	80	3.24
	30	3.34	231	231	52	100	4.38
Combined Onshore and Offshore State waters	12	1.34	117	117	54	100	1.16
	15	1.67	231	231	89	170	1.53
	18	2.00	321	321	120	240	1.95
	21	2.34	392	392	158	310	2.50
	24	2.67	450	450	217	430	3.53
	27	3.00	465	465	248	480	3.82
	30	3.34	496	496	283	550	4.62

* Combined total may differ from sum of onshore and offshore values shown due to rounding.

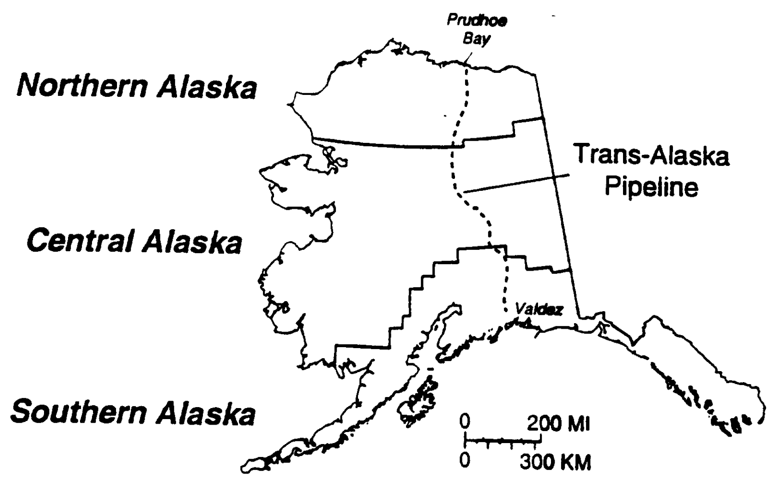

Figure 1. Petroleum provinces of the onshore and State offshore waters of Alaska (Region 1).

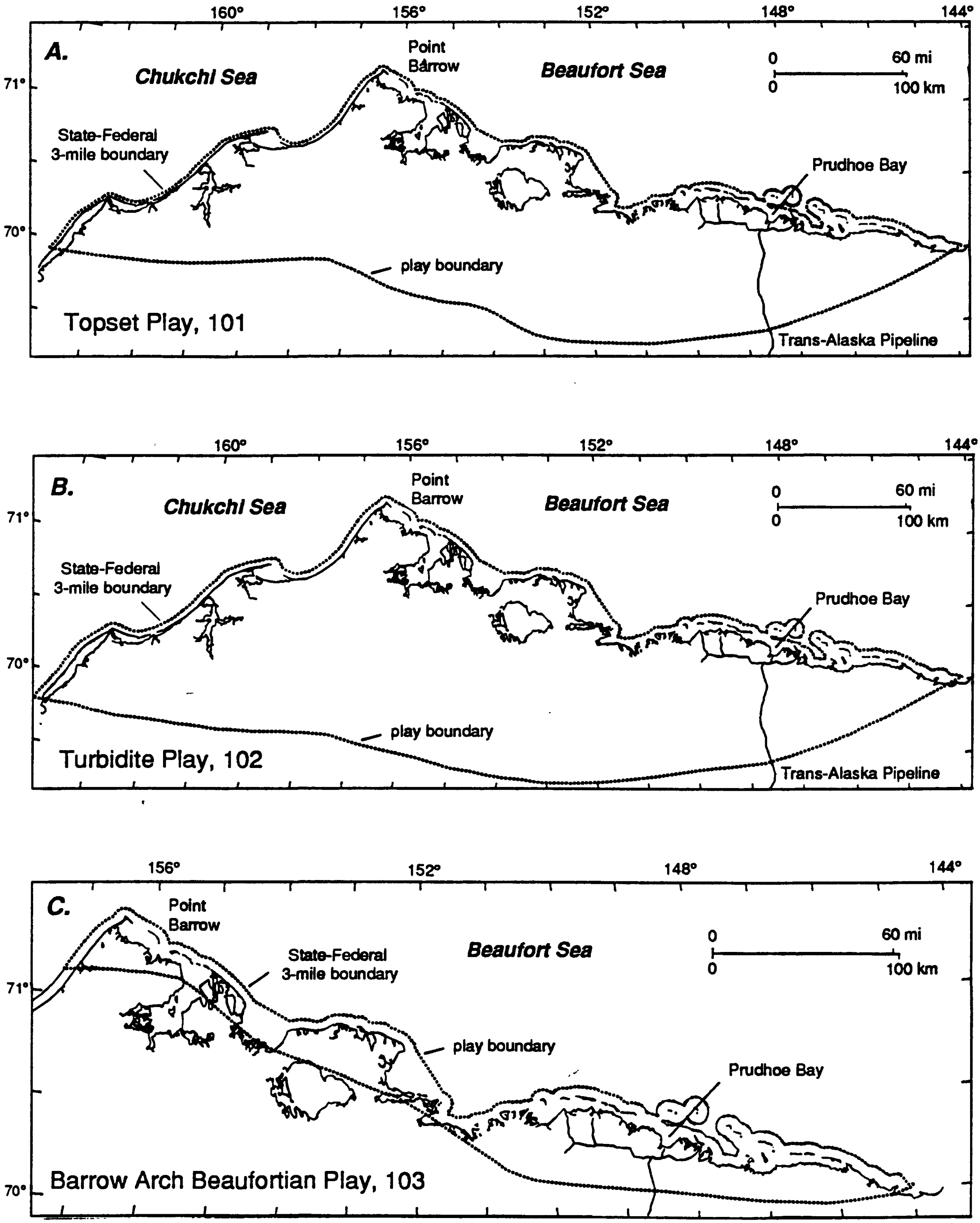

Figure 2. Plays of the Northern Alaska petroleum province assessed in the 1995 USGS National Assessment of Oil and Gas Resources (Bird, 1995); A. Topset (101), B. Turbidite (102), C. Barrow Arch Beaufortian (103).

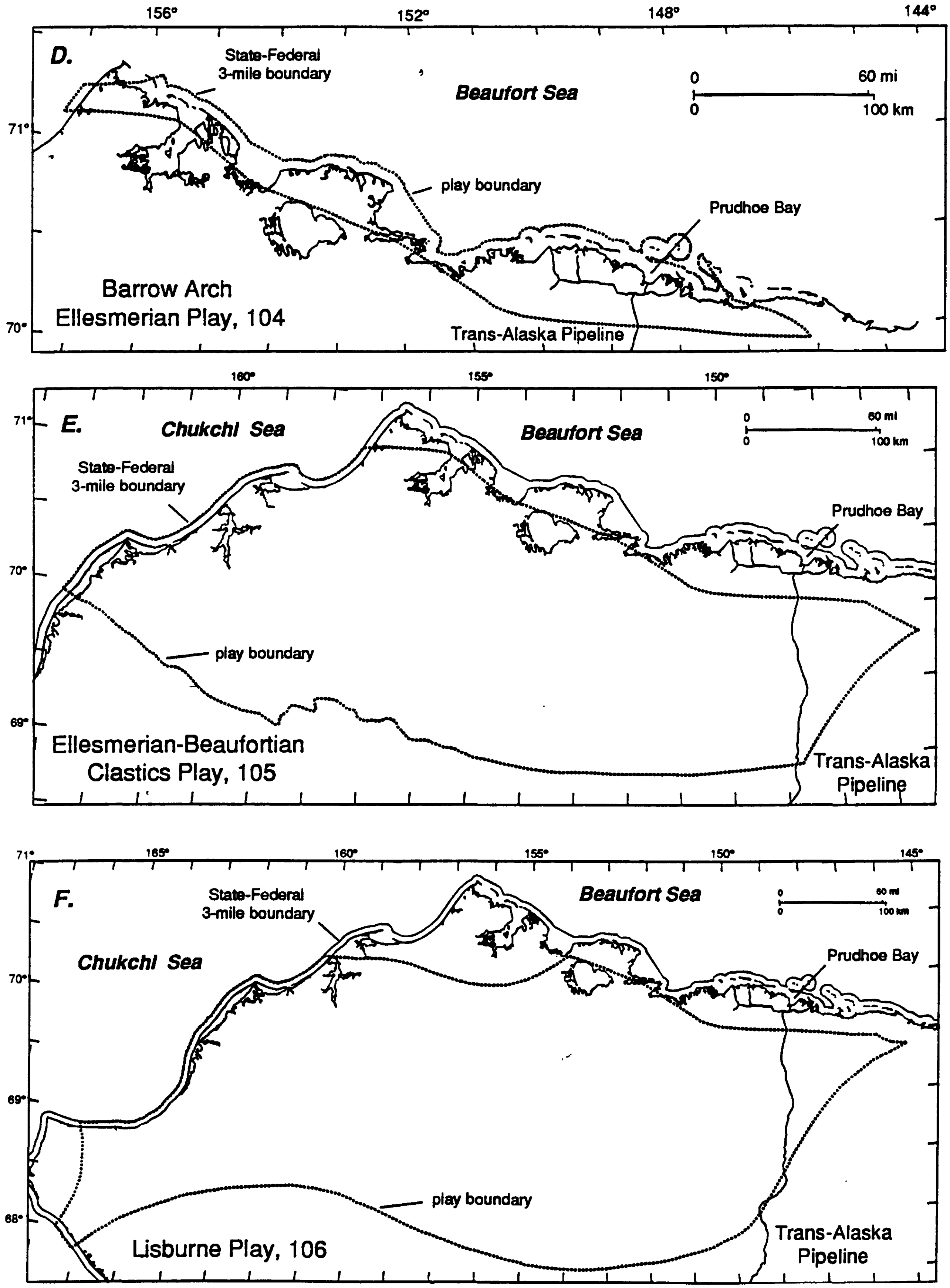

Figure 2: Continued. Plays of the Northern Alaska petroleum province assessed in the 1995 USGS National Assessment of Oil and Gas Resources (Bird, 1995); D. Barrow Arch Ellesmerian (104), E. Ellesmerian-Beaufortian Clastics (105), F. Lisburne (106).

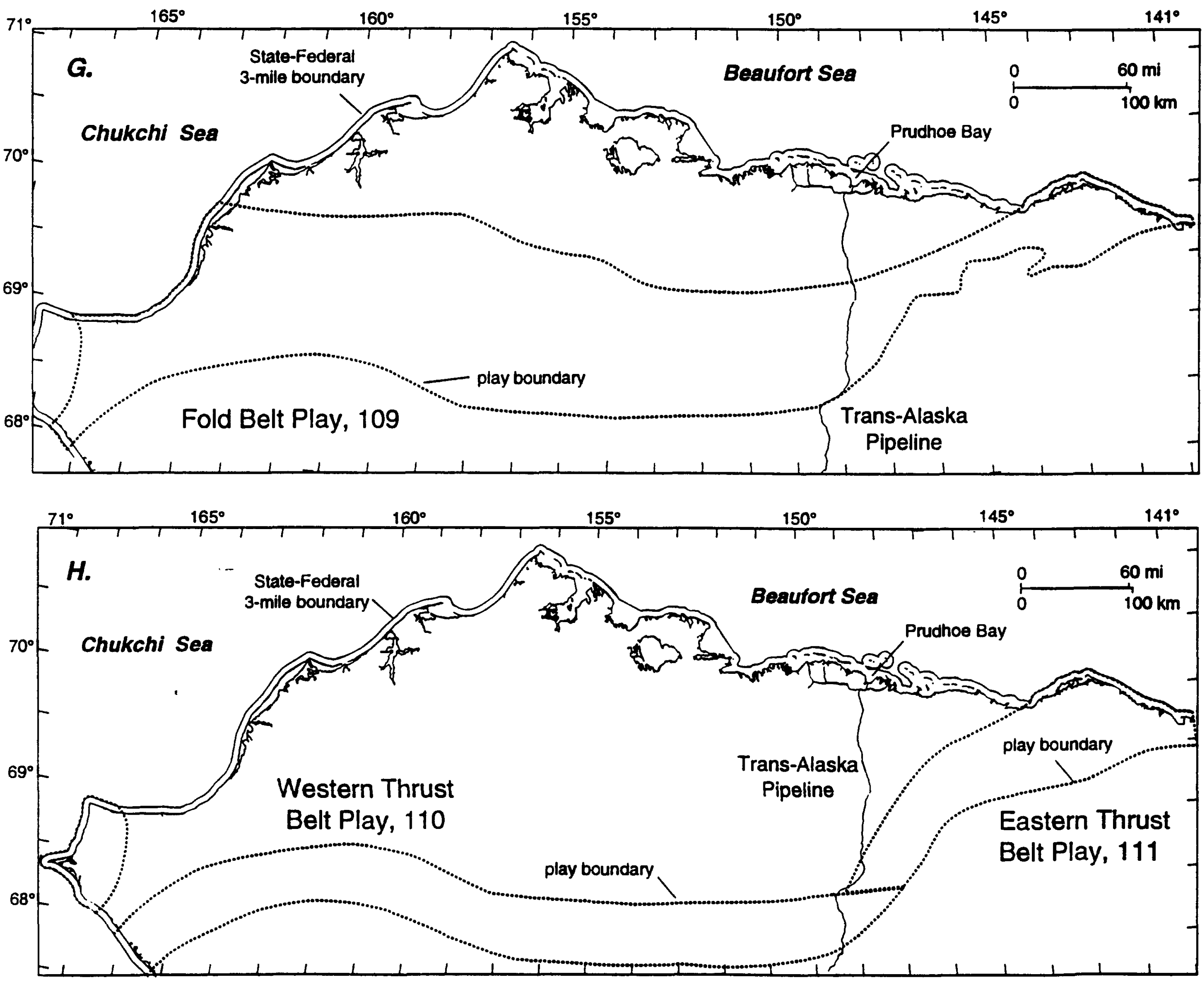

Figure 2. Continued. Plays of the Northern Alaska petroleum province assessed in the 1995 USGS National Assessment of Oil and Gas Resources (Bird, 1995); G. Foldbelt (109), H. Western Thrust Belt (110) and Eastern Thrust Belt (111).

FIGURE 3

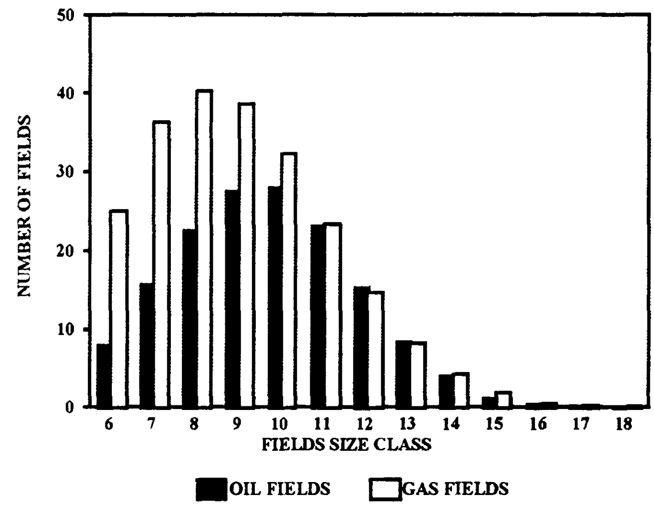

Figure 3. Expected field-size distribution of undiscovered conventional oil and gas fields containing at least 1 MMBOE in the Northern Alaska province (see table 2 size class definitions).

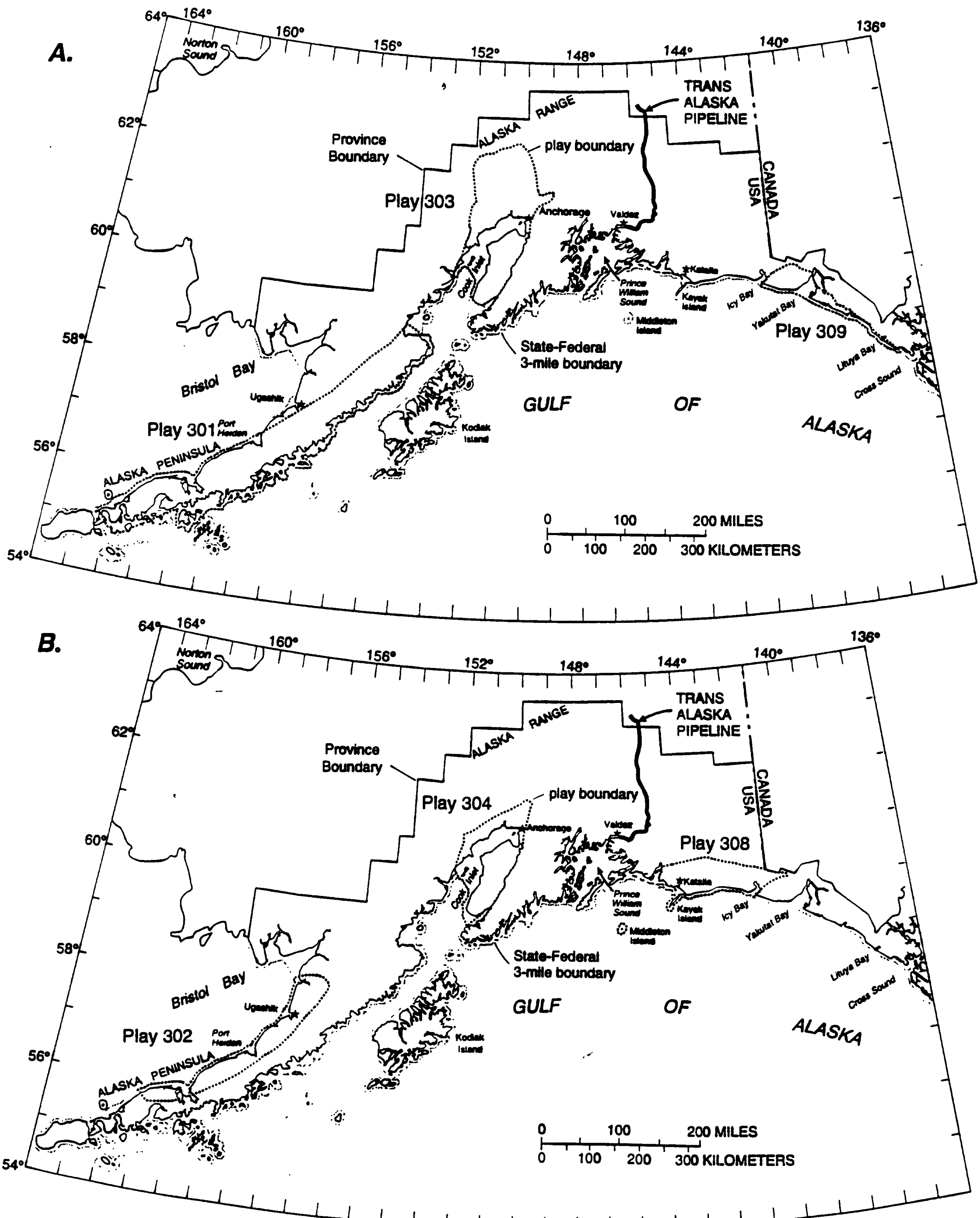

Figure 4. Plays of the Southern Alaska petroleum province assessed in the 1995 USGS National Assessment of Oil and Gas Resources (Magoon, 1995): 4A. 301 - Alaska Peninsula Mesozoic Oil; 303 - Cook Inlet Beluga-Sterling Gas; 309 - Gulf of Alaska Yakutat Foreland. 4B. 302 - Alaska Peninsula Tertiary Gas; 304 Cook Inlet Hemlock-Tyonek Oil; 308 - Gulf of Alaska Yakataga Fold Belt.

FIGURE 5

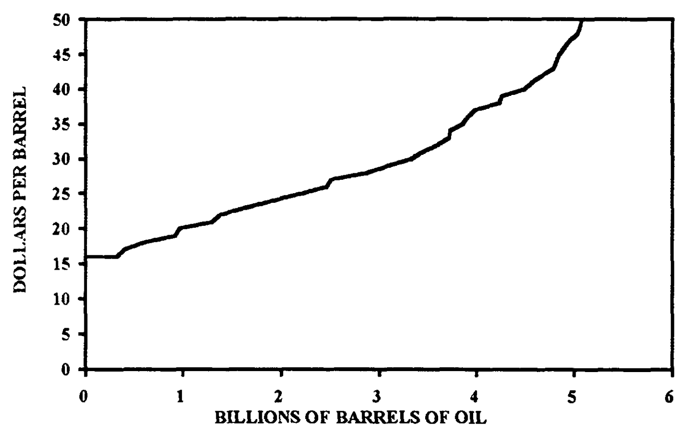

Figure 5. Incremental costs, in dollars per barrel, of finding, developing, producing, and transporting crude oil from undiscovered conventional oil fields in Northern Alaska to the US West Coast.

FIGURE 6A

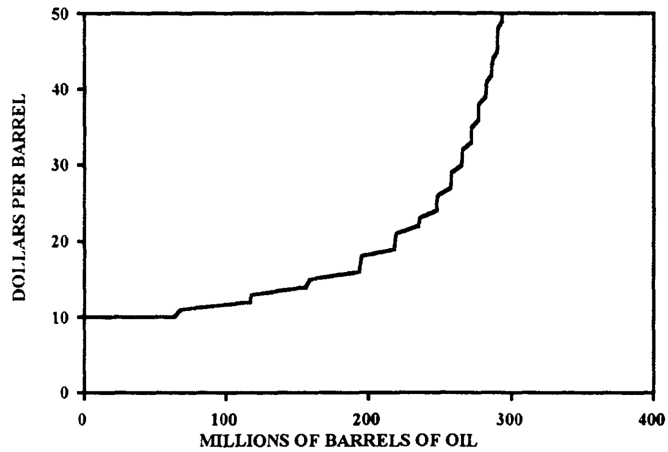

FIGURE 6B

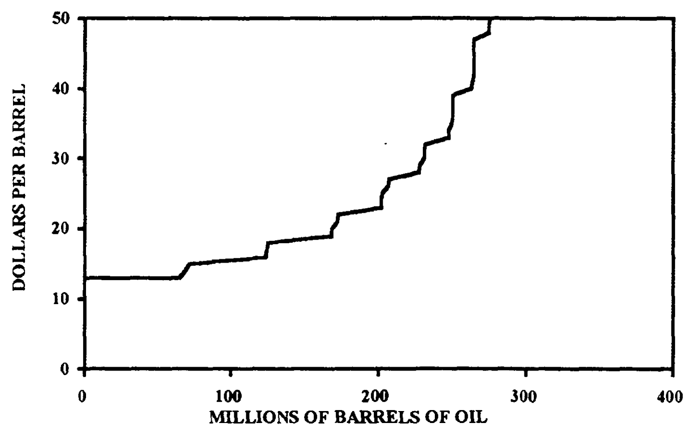

Figure 6. Incremental costs, in dollars per barrel, of finding, developing and producing crude oil from undiscovered conventional oil fields in the Cook Inlet area; A Onshore Cook Inlet area, B. State Offshore Cook Inlet waters.

FIGURE 7A

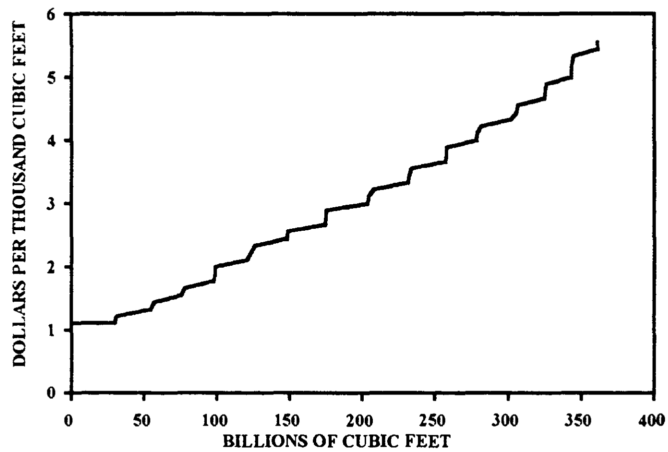

FIGURE 7B

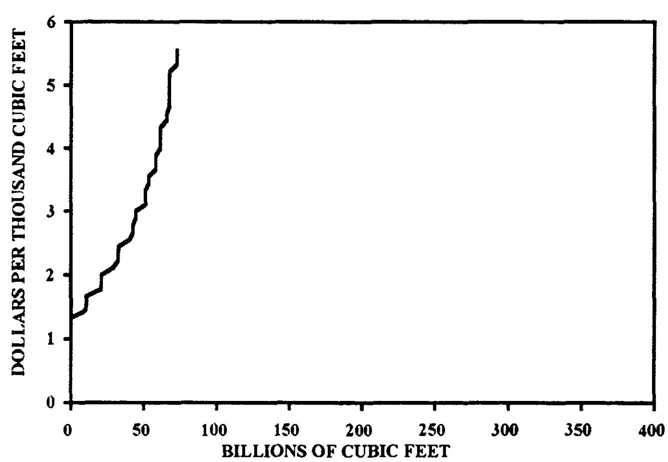

Figure 7. Incremental costs, in dollars per thousand cubic feet, of finding, developing and producing non-associated gas from undiscovered conventional gas fields in the Cook Inlet area: A Onshore Cook Inlet area; B. State Offshore Cook Inlet waters.