UNITED STATES DEPARTMENT OF INTERIOR

U.S. GEOLOGICAL SURVEY

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

by

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U. S. Geological Survey Open-File Report 95-75H

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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

Estimates of economically recoverable conventional petroleum resources in undiscovered oil and gas fields in onshore and State offshore areas of the conterminous United States are presented. For the 1995 National Assessment, the mean estimates of the technically recoverable hydrocarbons in undiscovered conventional oil fields in onshore conterminous U.S. areas are 19.6 billion barrels (BBO) of crude oil, 31.4 trillion cubic feet (TCF) of associated gas and 1.9 billion barrels (BBL) of associated gas liquids. Similarly, 139.5 TCF of non-associated gas and 4.5 BBL of non-associated gas liquids are estimated to be technically recoverable in undiscovered conventional onshore non-associated gas fields. In conterminous U.S. State offshore areas 2.0 BBO crude oil and 3.1 TCF associated gas were assessed in undiscovered oil fields and 16.4 TCF non-associated gas and 0.29 BBL of non-associated gas liquids were assessed in undiscovered gas fields. Together, about 73 percent of the oil and 78 percent of the non-associated gas is expected to be contained in fewer than 5800 undiscovered fields having at least 1 million barrels of oil or 6 billion cubic feet of gas recoverable. The remaining 27 percent of the oil and 22 percent of the non-associated gas is contained in more than 84,000 undiscovered small fields. Technically recoverable undiscovered oil amounts to only 13 percent of past discoveries while assessed undiscovered gas resources equal 23 percent of past discoveries from the area. For onshore areas, just under 40 percent of technically recoverable undiscovered crude oil and half of the non-associated gas can be discovered, developed, and produced for $18 per barrel and $2.00 per thousand cubic feet (mcf). Allowing costs to increase to $30 per barrel and $3 34 per mcf increases the economic proportion of the technically recoverable oil and non-associated gas to two-thirds. However, even as costs approach $30 per barrel and $3 34 per mcf, only a fraction of the small undiscovered fields can be found and developed economically. In offshore outer continental shelf (OCS) areas under State jurisdiction about 37 percent of the technically recoverable oil and only 12 percent of the non-associated gas is economic at $18 per barrel and $2.00 per mcf. At $30 per barrel and $3.34 per mcf just over half of technically recoverable oil and non-associated gas in State OCS areas can be found, developed, and produced. In all the above, a 12 percent after-tax rate of return was assumed.

INTRODUCTION

This report summarizes the results of the economic analysis of undiscovered conventional oil and gas accumulations assessed in the U.S. Geological Survey's 1995 National Oil and Gas Assessment (U.S. Geological Survey, 1995) of conterminous U. S. onshore and State offshore areas. For the 1995 Assessment, *undiscovered technically recoverable resources* are defined as resources that are estimated to exist from geologic knowledge and theory, contained in undiscovered accumulations outside of known fields, and producible using current recovery technology but without reference to economic viability. *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. The 1995 National Assessment also included certain identified unconventional resources. Economic analysis of the continuous-type (unconventional) oil and gas accumulations and coalbed gas are reported by Attanasi, Schmoker, and Quinn (1995) and by Attanasi and Rice (1995), respectively. The 1995 Assessment excluded oil from tar sands and very heavy oil, as well as gas hydrates and gas in geopressured brines.

The commercial value of a newly discovered conventional field depends on its expected size, whether it is an oil or gas field, its depth, location, and well production profiles. Information on the expected number and nature of the undiscovered fields, expected field sizes, depths, and by-products was extracted from the geologic assessment. Fields and accumulations were defined as either oil or gas (non-associated) on the basis of their gas-to-oil ratios. Fields and accumulations having at least 20,000 cubic feet of gas per barrel of crude oil were classified as gas; otherwise, the fields and accumulations were classified as oil fields. *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 previously identified fields were considered to be field growth and were not part of the undiscovered resource assessment treated in this analysis. For the economic analysis, the principal results of the geologic assessment are characterized with a discrete frequency-size distribution of expected undiscovered oil and gas fields classified by 5,000 foot depth interval.

The economic component of the National Assessment is intended to place the geologic resource assessment into a context that is more accessible and easily understood by industry and government decision and policy makers. One goal of this economic analysis is estimation of the incremental costs of transforming undiscovered conventional resources into additions to proved reserves. Incremental cost functions show cost vs. 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.

In the following section, the methods and results of the geologic assessment of conventional undiscovered oil and gas are briefly reviewed for the purpose of highlighting the characteristics which affect economic analysis and incremental costs. The data, assumptions, and methods used in estimating the incremental costs of finding, developing, and producing the assessed undiscovered resources are then discussed. Results and interpretation of the economic analysis are presented in the concluding sections.

REVIEW OF ASSESSMENT OF UNDISCOVERED CONVENTIONAL ACCUMULATIONS

This section briefly describes the procedures and results of the assessment of the technically recoverable oil and gas in undiscovered accumulations. Appendix A provides definitions of technical terms used in the discussion that follows. More detailed explanations of the assessment methodology and procedures are presented in Gautier and Dolton (1995). 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. A *play* is a set of known or postulated oil and (or) gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration patterns, timing, trapping mechanism, and hydrocarbon type. Geologists estimated numbers, sizes, and the 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

A province geologist was assigned to assess plays in each province. Figure 1 shows province locations and table A-1 provides a complete list of provinces. The initial play definitions were based on the geologist's interpretation 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 recoverable, the geologist reviewed drilling penetration maps and historical discovery data. Generally, for confirmed plays a play probability of 1.0 was assigned. *Play probability* is defined as the likelihood that at least one accumulation remains that will contain technically recoverable hydrocarbons of at least 1 MMBO or 6 BCFG. 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* (see Appendix A for their technical definitions). The play probability was multiplied by the conditional resource estimates. Conditional resource estimates are amounts of oil and gas estimated to be present given that minimal quantities of oil and gas occur in the play.

The size distribution of the population of undiscovered fields with greater than 1 MMBO (or 6 BCFG) for each play was modeled using a Truncated Shifted Pareto (TSP) Distribution (Houghton, and others, 1993, Gautier and Dolton, 1995). After reviewing all pertinent data, the geologist chose a median and shape class for the field size distribution and also the low(95%), median(50%), and high(5%) number of undiscovered accumulations. The geologist similarly chose a minimum(100%), median(50%), and maximum(0%) depth for remaining resources in the play. Simulations were used to convolute the distributions of size and numbers of undiscovered accumulations and to estimate the fractiles of quantities of oil, associated gas, associated gas liquids, non-associated gas, and non-associated gas liquids.

Dependencies were characterized by pairwise correlations between plays in the province. These pairwise correlations were based upon the product of perceived similarities of source, reservoir, and trap. Simulation analysis was also used to aggregate plays to the province level. Aggregation to the regional level was based on the assumption that the province results were statistically independent. Similarly, aggregation to the national level assumed regional results were statistically independent.

Small field assessment:

The assessment of undiscovered resources in "small fields" that is, fields smaller than 1 MMBO (or 6 BCFG) was prepared at the province level by using a statistical extrapolation procedure similar to the method used in Mast and others (1989) and described by Root and Attanasi (1993). Estimates were based on the underlying assumption that the province frequency size distribution of the number of fields smaller than 1 MMBO or 6 BCFG can be described with a log-geometric size distribution. The choice of the log-geometric distribution was consistent with two empirical observations: (1) smaller size classes have more fields than larger size classes and (2) successively larger size classes have more total hydrocarbons. This size-frequency distribution is completely determined by the constant *ratio* of the number of fields in successive size classes. The *log-geometric ratio* is an indicator of the concentration of hydrocarbons in larger size classes. For example, if the ratio is 1.0, the number of fields in each size class is equal so that most of the hydrocarbons are in the large fields; if the ratio is near 2.0 then the hydrocarbons are more uniformly distributed among all size classes because there are many more small fields than large fields. Size-class definitions used in this report are shown in Table B-1 the Appendix B.

A *log-geometric ratio* was calculated for each province using estimates of the ultimate number of fields (past discoveries plus the assessed undiscovered fields) for size classes 7 through 11. This ratio was used (along with a the computed number of class 1 fields) to calculate the ultimate number of fields in classes 2 through 5. For an individual province, allocations of small fields to depth intervals and field type were based on province specific data that characterized discovered and expected undiscovered fields containing 1 to 5 million barrels of oil equivalent (MMBOE).

Undiscovered technically recoverable resources

Characteristics of the assessment that are important for understanding the economic analysis are highlighted in this summary of results. Table 1 and table 2 show the mean values of the assessed conventional undiscovered recoverable resources for conterminous U.S. onshore and State offshore areas, respectively. While the oil and gas estimates shown in the tables are small revisions to the estimates presented in U.S. Geological Survey Circular 1118 (1995), the technically recoverable natural gas liquids estimates correct those presented in the Circular 1118. Estimates in tables 1 and 2 are presented by field and commodity type. Non-associated gas fields account for more than four-fifths of total undiscovered gas. Undiscovered conventional resources in the United States that are not represented in tables 1 and 2 are located in Alaska and the Federal offshore areas. The technically recoverable oil and gas resources assessed in Alaska amount to about one third the combined resources shown in the tables. Tables 1 and 2 show more than 21 billion barrels of oil (BBO) and 190 trillion cubic feet of gas (TCFG) remain to be discovered in the onshore and State offshore areas in the conterminous United States. These undiscovered resources amount to only 13 percent of the oil and 23 percent of the gas already discovered in these areas, suggesting the areas have already been rather thoroughly explored for conventional resources. State offshore areas account for about 10 percent of the undiscovered conventional resources in the assessment area.

Figure 2A shows the field-size class frequency distribution of the ultimate (discovered plus undiscovered) and undiscovered fields containing at least 1 MMBOE. Size class definitions are found in table B-1 of Appendix B. The fields in the size class 6 and larger contain 73 percent of the undiscovered crude oil and 78 percent of the undiscovered non-associated gas. Figure 2B is similar to figure 2A but includes the small fields and shows that numbers of fields in classes 1 to 5 are much larger than the numbers of fields in the larger size classes. Close examination of the figures shows a fundamental difference in the distribution of discovered fields and the assessed undiscovered fields. The distribution of undiscovered fields is dominated by the smaller size classes. Data underlying the figures indicated that less than one-tenth of the oil and gas already discovered in the assessment area is in fields having 8 MMBOE or less (class 8 and smaller). However, the assessment places nearly half to the undiscovered hydrocarbons in such fields. More than 37,000 fields have been discovered in this area, including 8,915 having at least 1 MMBOE The assessment estimated the expected number of undiscovered fields having at least 1 MMBOE to be 5,800 and also estimated 89,000 undiscovered fields smaller than 1 MMBOE for a total of 94,800 fields. Less than 3 percent of the hydrocarbons in past discoveries have been in fields smaller than 1 MMBOE. In contrast, the assessment assigned 23 percent of the total undiscovered hydrocarbons to these small fields.

Assessment results of 55 provinces are presented in table 1. More then half of the undiscovered oil was assigned to only four provinces, (San Joaquin(10), Permian Basin(44), Western Gulf(47), and Louisiana-Mississippi Salt Basins(49)). Similarly, five provinces (Wyoming Thrust Belt(36), Permian Basin(44), Western Gulf(47), Louisiana-Mississippi Salt Basins(49), and Anadarko Basin(58)) account for three-fourths of expected onshore undiscovered non-associated gas. With the exception of the recent Wyoming Thrust Belt, these provinces have also dominated historical discoveries. In most provinces undiscovered resources amount to less than 20 percent of past discoveries.

Figures 3A and 3B depict regional mean values for onshore undiscovered oil and non-associated gas by depth interval. Region 6 leads all regions with more than one quarter of the onshore undiscovered oil and more than half of the onshore undiscovered non-associated gas. Region 4 follows with 24 percent of the undiscovered oil, then there is Region 5 with 18 percent and Region 2 with 15 percent. For non-associated gas, Region 6 is followed by Region 4 and Region 7, each with 12 percent and Region 5 with 10 percent of the total undiscovered non-associated gas. Overall, three fourths of the undiscovered oil is expected to be found at depths shallower than 10,000 feet. Almost 60 percent of the undiscovered non-associated gas was assessed at depths greater than 10,000 feet and nearly half of that (mostly in Region 6) is expected to be at depths greater than 15,000 feet. Past discoveries have generally been much shallower.

Expected (mean) numbers of undiscovered fields estimated from the geologic assessment (fields at least 1 MMBO) and the small field statistical extrapolation are shown in table 3. Region 6 contains the largest number of onshore oil and gas fields with 27 percent of the undiscovered large oil fields and half of the large gas fields. Region 4 accounts for 22 percent of the large oil fields, followed by Region 5 with 18 percent and Region 2 with 13 percent. Regions 4, 5, and 7 account for less than 10 percent each of the large gas fields..

In the State offshore areas, Region 2 contains most of the oil and Region 6 most of the gas (see table 2) Exploration and development of the State offshore resources shown for Region 7 have been prohibited because the resources are located beneath Lake Michigan and Lake Erie. For this report, these resources have been excluded from the economic analysis. Taking table 1 and 2 together, in Region 2 about 60 percent of the undiscovered crude oil assessed for the Santa Maria (012) and Ventura (013) basins were assigned to offshore State waters One-eighth of the Western Gulf's(047) non-associated gas and almost one-fourth of the non-associated gas assessed in the Louisiana-Mississippi Salt Basins (049) was assigned to state offshore areas.

The expected number of undiscovered oil and gas fields having 1 MMBOE recoverable (large) in State offshore areas is small. The mean estimates of the number of large oil and gas fields for Region 2 are only 60, and 16, respectively, and for Region 6, 46 oil and 177 gas fields were estimated. For the undiscovered gas in State offshore Region 6, almost two thirds is expected to occur at depths greater than 15,000 feet and nearly two-thirds of that amount is expected to have high hydrogen sulfide content (all the State offshore gas in province 049) Regions 2 and 6 can be expected to have high finding and production costs because of the small number of large undiscovered fields, offshore costs are typically higher than onshore costs, and a large proportion of the resource is expected to be deep and require extra expenses due to its high sulfur content .

In summary, for the assessment area the expected (mean) value of the undiscovered resources represents a relatively small fraction of past discoveries. The distribution of undiscovered fields shows increasing concentration in field size-classes that are considerably smaller than the historical discovery size distribution. Although numerous small fields (less than 1 MMBOE) were assessed, these small fields contain only 23 percent of the expected undiscovered hydrocarbons. More than half of the assessed undiscovered oil and three fourths of the non-associated gas is concentrated in only six provinces. About 10 percent of the expected (mean) value of undiscovered hydrocarbons were assigned to high cost State offshore areas.

DATA, ASSUMPTIONS, AND PROCEDURE FOR 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 for the following reasons. 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

Play assessments were aggregated to province assessments that were characterized with discrete size-frequency distributions of undiscovered oil and gas fields classified by 5,000 foot depth intervals. Province specific data such as gas-to-oil ratios and natural gas liquids-to-natural gas were derived from data provided by the geologic play assessments. The geologic assessments also provided data used to compute the expected depth of accumulations within 5,000 foot depth intervals.

Supporting data provided by the geologists identified plays expected to yield oil high in sulfur or gas containing high levels of hydrogen sulfide. Plays having sour oil and gas accounted for significant quantities of estimated undiscovered resources in the following provinces: Paradox Basin (21), Montana Thrust Belt (27), Big Horn Basin (34), Wind River Basin (35), Wyoming Thrust Belt (36), Southwestern Wyoming (37), Western Gulf (47), and Louisiana-Mississippi Salt Basins(49). About 8 percent of the undiscovered onshore oil and 13 percent of the non-associated gas had sufficiently high levels of sulfur that special drilling and production equipment would be required. About one third of the undiscovered state offshore gas had high hydrogen sulfide content.

Well drilling data and discovery field size data were used in development of province finding rates. Drilling data came from the Well History Control System (WHCS) available from Petroleum Information Corporation (PI). Data on fields containing at least 1 MMBO (or 6 BCFG) were from the *Significant Oil and Gas Fields of the United States* field file which is available commercially from NRG Associates. Along with field size, the NRG data provided information on field discovery date. depths of producing formations, discovery well depth, and the field's centerpoint location. Data on discoveries having less than 1 MMBO (or 6 BCFG) were taken from the Energy Information Administration's (EIA) Oil and Gas Integrated Field File (OGIFF) which is a proprietary file. These data included field size, discovery date, county identification but no depth information.

Technical data used in the onshore field discounted cashflow (DCF) analysis included field designs, well production profiles, and cost relationships. These data were drawn from previous studies on the Permian Basin (Attanasi and others, 1981, Attanasi, 1989), EIA natural gas studies (Energy Information Administration, 1986), EIA cost studies (Energy Information Administration, 1994), and drilling cost data presented in the Annual Joint Association Survey (JAS) (American Petroleum Institute, 1992,1993). Data for offshore field design and well production schedules were also taken from previous studies (Attanasi and Haynes, 1983, 1984; Attanasi, 1989; Vidas and others, 1993; American Petroleum Institute, 1994).

Assumptions

Economic models are abstractions designed to characterize real economic systems and are typically 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 change can be modeled. It was assumed in this analysis 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.

Costs used in this analysis were assumed to represent the costs that prevailed in January of 1993. Calculations were in terms of constant real dollars. Federal income tax provisions included the changes made in 1993. The 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, it was assumed that the 30 percent of the drilling cost of development wells 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. Depletion expenses are limited to the cost of exploratory geologic and geophysical work, wildcat drilling, and the cost of land acquisition. Such costs, when allocated to their respective fields, are recovered on a unit of production basis.

State taxes, including State severance and income tax, were the estimated regional tax rates used in the 1993 update of the Gas Research Institute's Hydrocarbon Supply Model (Vidas and others, 1993). The Federal corporate tax rate used in the project analysis was 35 percent A one-eighth royalty was assumed to be paid to the landowner for onshore areas (Vidas and others, 1993). A nominal bonus amounting to about $130,000 per onshore wildcat well was assumed. For State offshore areas, a one-sixth royalty rate and a nominal bonus of $250,000 per wildcat well was assumed.

Exploration effort leading to new field discoveries is represented in the drilling of wildcat wells. Publications by the US Bureau of Census (Survey of oil and gas, 1974 to 1988) and the American Petroleum Institute (Survey of oil and gas expenditures, 1983-1991) present aggregate data that cover the entire lower 48 states onshore and offshore. According to these data, averaged over various years , 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) account for about 50 percent of direct drilling costs (Vidas and others, 1993). This ratio was used in estimating total exploration costs.

During the last quarter-century wellhead oil prices have varied over a range from $3 to $40 per barrel and wellhead gas prices have varied from less than $1 to more than $11 per mcf. The Energy Information Administration (1995) has projected wellhead oil prices for 2010 to be between $23.30 and about $25 per barrel and the wellhead gas prices between $3.00 and $3.75 per mcf. Discussion in this report focuses on reserve additions from new fields which might be expected with an oil price range of $15 to $30 per barrel and a gas price range of $1.50 to $3.50 per mcf. Even though graphs may show additions to reserves for somewhat higher prices, if real oil prices rise to $50 per barrel and or gas prices rise to $9.00 per mcf, it would be quite unrealistic to assume that constant real costs would hold at the higher wellhead price levels. The historical experience has been that oil and gas price increases lead to escalation in industry capital and operating costs.

In the past, wellhead oil and gas prices have been linked. Oil exploration has often resulted in gas discoveries, associated gas has been a by-product of crude oil production, and in many important uses oil and gas are substitute fuels. However, wellhead gas prices have historically been less than oil prices when placed on an equivalent heat value basis. On a heat equivalent basis, gas prices were assumed to be two-thirds of oil prices. Also, the wellhead price per barrel of natural gas liquids was assumed to be 75 percent of the per barrel price of crude oil For example, if oil price is $18.00 per barrel, the gas price used is $2.00 per thousand cubic feet (per million British Thermal Units) and the per barrel natural gas liquids price is $13.50. The effect of the gas pricing assumption is examined by also computing results when oil and gas are priced on an energy equivalent basis.

Onshore field development and production costs

Onshore oil and gas field development costs include the cost of drilling and completing production wells, the cost of dry development wells, and the cost of lease equipment. Regional drilling cost estimates for development wells (see Attanasi, 1989) were updated by using the JAS of drilling costs (American Petroleum Institute, 1993). Lease equipment investment costs and annual operating costs were derived from "Costs and indices for domestic oil and gas field equipment and production operations, 1993" (Energy Information Administration, 1994). Per-well oil lease equipment and operating costs were specified as functions of depth and region. Gas lease equipment and operating costs per production well were specified as a function of region, depth, and maximum annual flow rates.

Oil well production schedules as well as field designs were based on those used in a previous study of the Permian Basin, (Attanasi and others, 1981; U.S. Geological Survey, 1980). These data were adjusted to reflect the field size classification used in this study (table B-1) and to reflect the oil-to-gas and gas-to-NGL ratios computed for the four depth intervals from the geologic assessment. Field design was based on standard engineering practices in the Permian Basin; the most prolific oil producing province in the United States. Application of those field designs to similar fields elsewhere is not expected to substantially bias the overall assessment.

Design criteria for non-associated gas fields reflected regional variations based on relationships presented in "An economic analysis of natural gas resources and supply" (Energy Information Administration, 1986). In particular, the estimated reserves per well were computed as a function of depth, field size, and region. Individual well reserve production profiles were assumed to follow the profiles observed for gas wells in fields of similar size and depth in the Permian Basin (see Attanasi and others, 1981; U.S. Geological Survey, 1980).

Drilling costs for onshore areas with high-sulfur hydrocarbons were increased by 25 percent for oil wells and 50 percent for gas wells. In such areas, oil field production equipment costs were increased by 20 percent and gas field production equipment costs were 300 percent of the standard gas equipment costs. Wellhead price penalties of $1.00 per barrel and $0.25 to $.35 per mcf of gas were also assumed.

Based on an earlier study (U S. Geological Survey, 1980), it was assumed that for fields larger than 1 MMBO or 6 BCFG, for every 10 successful development wells, 2 dry holes would be drilled. In smaller fields, it was assumed that 4 dry holes would be drilled for each set of 10 successful development wells. Because the geologic assessment was not based on prospect analysis, the specific locations of future discoveries are unknown. Most onshore provinces in the conterminous United States are mature. The oil and gas pipeline network was assumed to be sufficiently widespread that transport cost from the lease to the nearest pipeline was assumed to be negligible. For simplicity, development of onshore Lower 48 discoveries is assumed to be completed in 1 year.

Offshore field development and production costs

Geologists provided assessments for offshore State waters and the costs of offshore field development and production for these areas were computed. The economic analysis of new offshore fields followed the same procedures as the earlier assessment (Attanasi, 1989). Estimates of drilling costs, platform costs, platform operating costs were updated from previous studies (Vidas and others, 1994, Attanasi and Haynes, 1984). Field designs and production well characteristics were also taken from these studies. Although there may be some prospects that can be drilled with onshore offset wells, the geologic assessment did not provide estimates of the resources that could be accessed in that way. Thus, either jackup or platform rigs were assumed used for drilling. In densely developed State water areas such as in the Western Gulf of Mexico, small new discoveries (class 4 and 5 oil, and class 4, 5, 6 gas) are assumed to be developed with shared production platforms or as satellite fields where production wells are tied to an existing production platform Although the operator has higher operating costs, the initial investment is less than would be required if each field required a production platform.

Regional cost-adjustment factors were applied to costs developed for the Gulf of Mexico to estimate costs in State waters elsewhere. Basic engineering field design and well production characteristics as well as the costing algorithm were taken from Attanasi and Haynes (1983 and 1984) Drilling costs were increased by 50 percent, oil production equipment increased by 20 percent, gas production equipment increased to 300 percent of standard costs and platform costs increased by 10 percent in offshore provinces having plays with high sulfur hydrocarbons.

Procedure

Field size, depth, regional costs, and co-product ratios determine whether a field will be commercially developable. A new field is commercially developable if the after-tax net present value of its development is greater than zero. The algorithm that calculated incremental costs used the predicted size and depth distribution of undiscovered fields at the province level to compute the quantities of resources that are commercially developable at various prices. To compute finding costs, the geologic assessment is coupled with a finding rate model, presented in Appendix B, 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 and province 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. A representative field is determined to be commercially developable if the after-tax DCF for a well, representative of the field, is greater than zero, where the discount rate includes a hurdle rate representing 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 well 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, the sum of finding costs and development and production costs per barrel is equal to the wellhead price. These costs are 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 wellhead price.

Finding rate functions were calibrated for each province. Appendix B describes the calibration procedures and also discusses inherent biases in these models. Because the size, depth, and number of undiscovered fields were calculated from the geologic assessment data, the finding rate functions determined the ordering of new discoveries as well as the rate at which these fields would be found as a function of cumulative wildcats drilled in a particular depth interval. The allocations of wildcat wells by depth interval was 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

Commercially developable exploration targets

Incremental costs include the costs of finding, developing, and producing oil and gas in a particular geographic location. Development of the incremental cost functions started with an economic analysis of the assessed distribution of undiscovered oil and gas fields. The exploration effort, ordering and arrival rate of discoveries, and finding costs are then computed using province level finding rate functions. At a given price, the distribution of commercially developable fields is the economic target for exploration. The computational algorithm assumes exploration continues until the expected value of the resources discovered by the last increment of exploration is insufficient to pay for that increment. For an increment of wildcat wells (50 onshore or 20 offshore) the finding rate function generates a distribution of discoveries by size and depths, some of which will be commercially developable and some not developable.

Most of the onshore undiscovered hydrocarbons assessed were expected to be in fields of at least 1 MMBOE, so that it should not be surprising that even at relatively low wellhead prices a large proportion of the oil and gas assessed is commercially developable, if it is assumed that these resources have already been discovered. Commercially developable resources were calculated assuming a 12 percent required rate of return and wellhead prices of $15 per barrel for crude oil (and the equivalently based $1.67 per mcf for gas). With these assumptions, about two thirds of the oil and three fourths of the gas shown in table 1 are commercially developable if already discovered. These resources are contained in less than 10 percent of all the fields shown in table 3, because only a small fraction of the small fields are commercially developable. Three-fourths of the large oil fields and four-fifths of the large gas fields are commercially developable. Reasons why some large fields are not commercially developable include special situations, such as the encountered in province 5 Eastern Oregon - Washington (005) having special drilling conditions (see Lingley and Walsh, 1986), or areas such as in the Big Horn (034) and Louisiana-Mississippi Salt Basins (049) where high-sulfur product content drives up costs. When wellhead prices were increased to $30 per barrel for crude oil (and $3.33 per mcf for gas) the amount of commercially developable oil and gas increases to about 90 percent of the oil and gas shown in table 1. At that level nearly all of the large fields are commercially developable, but 70 percent of the small fields are still not commercial.

Similar calculations of the commercially developable undiscovered resources in State offshore areas showed that a $15 per barrel ($1.67 per mcf) about 70 percent of the oil and 52 percent of the non-associated gas would be commercially developable if they were already identified. Based on table 2, the provinces having the largest quantities of oil in state offshore areas were the Ventura (013) and Los Angeles (014) basins, while the Western Gulf (047) and the Louisiana-Mississippi Salt basins (049) had the largest quantities of non-associated gas. About 3 TCF of the 13 TCF in provinces 047 and 049 were assigned to small fields that are unlikely to become commercial. At $1.67 per mcf, only one-fourth of the non-associated gas in the province 049 is commercially developable. Most of the non-associated gas assessed in that province in State offshore areas is very deep and contaminated with high levels of hydrogen sulfide. As costs are allowed to increase more of this non-associated gas becomes commercially developable.

Finding, development, and production costs for the onshore conterminous United States

Full costs of oil and gas production include the finding, development, and production costs Incremental costs are linked to development and production costs by the finding rate functions used to predict discovery arrival rates and the discovery size distributions generated by increments of wildcat wells. Appendix B explains how the finding rate functions for individual provinces were calibrated using historical discovery data. With the integration of the finding rate models calibrated from historical data, incremental costs of finding, developing and producing oil and gas from conventional onshore undiscovered fields in the conterminous US were computed and are shown in the left-hand dotted curves of figures 4A and 4B.

At $18 per barrel ($2 per mcf), the computations that generated the left-hand dotted curves in figures 4A and 4B indicate that 33,000 wildcat wells are commercial to drill. In the past, wildcat well drilling rates have moved with oil and gas prices. During the early 1980's the rate reached a maximum of between 10,000 and 11,000 wildcat wells per year. Since 1989, the average number of wildcat wells drilled has been about 2,200 per year (American Petroleum Institute, 1995). At this rate, it would take 15 years to drill 33,000 wildcat wells.

Even if a model were constructed that ideally characterized the technical possibilities, there is no assurance that the industry, as a practical matter, operates at the technical frontier of the achievable exploration efficiency. Periods of inefficient drilling are well documented (Adelman, 1991). The productivity of future drilling as characterized by the finding rate that underlies the dotted left-hand curves of figures 4A and 4B is probably excessively conservative for the following reasons. First, as discussed in Appendix B, the use of so-called "targeted" wells in the finding rate functions likely overstates drilling required because one well can test more than a single depth interval. Secondly, discovery efficiencies will improve as state of the art technology is diffused throughout the industry and as technology is improved. Third, as applied here, no provision is made for characterizing the accumulation of knowledge that would improve the siting of wells. The dotted right hand curves in figures 4A and 4B represent incremental costs based on improved exploration efficiencies that roughly double exponential decline coefficients. While improvement in exploration efficiency does not increase the physical resource base, it allows faster and more efficient discovery of the undiscovered resource. Such an improvement could occur over a period of 15 years if the annual rate of improvement were as little as 5 percent per year. It is, therefore, likely that the appropriate incremental cost function lies between the two curves in figure 4A and 4B. For the purpose of this analysis the two curves are regarded as equally likely scenarios and each is given a probability of 0.5.

Table 4 summarizes the onshore regional and aggregate estimates of costs, expected reserve additions, and number of economic wildcat wells for the set of combined scenarios. Along with the primary products of oil and non-associated gas, the table shows associated gas, associated gas liquids and the non-associated gas liquids. At $18 per barrel ($2.00 per mcf) the table shows that two-fifths of the technically recoverable oil and almost half of the technically recoverable non-associated gas can be found, developed, and produced. At an incremental cost of $30 per barrel ($3.34 per mcf) two-thirds of the technically recoverable oil and gas is economic. The solid curves in figures

4A and 4B show the amounts of oil and gas that are added as costs are allowed to increase further. The figures show that about 80 percent of the technically recoverable oil and gas can be found, developed, and produced at marginal costs $50 per barrel ($5.54 per mcf).

Figures 5 and 6 show regional incremental cost functions associated with oil and non-associated gas, respectively Based on table 4 and the figures, the regions with the largest assessed economic amounts of undiscovered oil are Region 2, 4, 5 and 6. For these regions only one or two provinces account for the largest proportions of potential reserve additions. In Region 2, it is the San Joaquin (011) , Region 4; the Powder River Basin (033), Region 5, the Permian Basin (044), Regions 6; the Western Gulf (047) and Louisiana-Mississippi Salt Basins (049). Based on the absolute quantities of expected reserve additions and the fraction of technically recoverable oil that is economic to find, develop and produce at an incremental cost of $18 per barrel, Region 5 (W. Texas and E. New Mexico) is the lowest cost region for newly discovered oil followed by Region 6 and Region 4.

For gas, the dominant region is Region 6 (Gulf Coast), with much smaller but still significant amounts in Region 4, 5, and 7. In terms of non-associated gas, the most important province in Region 4 is the Wyoming Thrust Belt (036), Region 5; the Permian Basin (044), Region 6, the Western Gulf (047), Louisiana-Mississippi Salt Basins (049) and Region 7; the Anadarko Basin (058). Half the technically recoverable gas in Region 6 is economic to find, develop, and produce at an incremental cost of $2.00 per mcf. This quantity of gas is more than all the other regions combined at that cost.

The sensitivity of the results to the required return and the gas pricing assumptions were also examined. In both cases the effects on the onshore lower 48 states incremental cost is most conspicuous in the lower costs levels. It has been argued that, at the margin, the domestic industry receives about a 6 percent after tax rate of return. Dropping the required return to 6 percent increases both oil and non-associated gas reserve additions by 23 percent at $18 per barrel ($2.00 per mcf). Overall, at $30 (3.34 per mcf) 71 percent of the technically recoverable oil and three fourths of non-associated gas is economic The regional effect of the decline in required return generally resulted in a larger number of wildcat wells and reserve additions but did not change the relative position or ordering of the regions.

Historically, wellhead prices of gas have been significantly below that of oil when expressed on a heat equivalent basis. Consequently, it was assumed that gas would be priced at two-thirds oil prices on a heat equivalent basis. Because of the relatively small environmental impact of natural gas compared to oil or coal, it has been argued that future wellhead gas prices will increase relative to oil prices. Increasing gas prices to parity with oil prices on a BTU basis will increase cashflow to oil and gas operations, make more funds available to exploration, and encourage more drilling in gas-prone provinces. At the aggregate level, with an incremental cost of $18 per barrel ($3.00 per mcf), oil reserve additions increase by 15 percent and gas reserve additions by 25 percent over the values shown in table 4 As incremental costs increase to $30 per barrel ($5.00 per mcf), the effect of the changed oil/gas price relation is moderated but still shows an increase of 13 percent for non-associated natural gas over values in table 4. At $5.00 per mcf three-fourths of the technically recoverable gas is economic. Gas-prone provinces and regions had substantial wildcat drilling increases but Region 6 accounted for the largest part of the overall reserve increase.

In summary, 40 percent of the assessed technically recoverable onshore crude oil and half of the technically recoverable onshore non-associated gas have incremental finding, development, and production costs of $18.00 per barrel ($2.00 per mcf). The region with the lowest cost crude oil from new discoveries is West Texas and Eastern New Mexico (5) and similarly for non-associated gas the Gulf Coast Region (6) dominates at low cost levels. Reducing the required return to 6 percent after-tax increases reserve additions by 23 percent at the $18 per barrel ($2.00 per mcf). Changing the relative price of gas shifted the drilling effort and affected costs of both oil and gas reserve additions.

Finding, development, and production costs in State Outer Continental Shelf offshore areas of the conterminous United States.

State offshore resources in the Michigan Basin and the Appalachian Basin are underneath Lake Michigan and Lake Erie. Incremental costs for these resources were not calculated because for all practical purposes they are not development targets. The cost algorithm was applied to the other State offshore areas which are part of the U.S. Outer Continental Shelf (OCS) Table 5 and figures 7A and 7B present of incremental costs and cost functions. As described in Appendix B, the finding rate efficiencies were adjusted to reflect higher expected efficiencies associated with higher cost and less densely drilled State offshore areas. Each wildcat well increment evaluated consisted of 20 wildcat wells. The table shows that at $18 per barrel ($2.00 per mcf) just over one third of the undiscovered technically recoverable oil and one-eighth of the undiscovered technically recoverable non-associated gas is economic to find, develop, and produce. At $30 per barrel ($2.00 per mcf), 0.7 BBL of oil and 7.26 TCF of non-associated gas, or just over half of the undiscovered technically recoverable oil and non-associated gas of Region 2 and Region 6, is economic. Figures 7A and 7B shows that at $50 per barrel ($5.54 per mcf) the 0.85 BBO crude oil and 9.49 TCF non-associated gas is economic. This represents about two-thirds of the technically recoverable oil and gas assigned to State OCS offshore areas.

Region 2 and the Ventura Basin (013) in Region 2 are the dominant sources of oil in State OCS offshore areas. The representative water depth assumed for the Pacific Coast was 150 feet. Small fields were assigned 128 MMBO or 13 percent of the technically recoverable crude oil. Some prospects containing currently undiscovered resources may have been accessible from onshore but the assessment did not quantify those resources as a separate category. Pacific Coast State offshore areas are significantly less densely drilled than the Gulf of Mexico, so it is not likely that the satellite field development is a viable option for most small fields outside of the Gulf.

Most of the State OCS offshore non-associated gas is in the Gulf Coast Region. In State offshore areas of the Western Gulf (047) province though 80 percent of that gas is expected to occur at depths below 10,000 feet. Nearly all of the non-associated gas assessed in the State offshore areas of the Louisiana-Mississippi Salt Basins (049) was at depths below 15,000 feet and contained significant hydrogen sulfide contamination. Of the 13 TCF of non-associated gas assessed as technically recoverable in Region 6, almost 3 TCF is in small fields which typically are developed as a group of fields or as satellite fields of adjacent larger fields. In such systems, the product may be transported directly from wells to production facilities of an adjacent field.

Offshore exploration and development, even at water depths characteristic of State OCS offshore areas, typically require substantially more investment per well than onshore exploration and development. Furthermore, two-thirds of the non-associated gas assigned to State OCS waters required drilling below 10,000 feet. At any particular price (or incremental cost), a reduction in required return increases the after-tax net present value of the target fields. This leads to more drilling of wildcat wells and reduces the threshold size of commercially developable fields. When the required rate of return was reduced from 12 percent to 6 percent , the amount of economic non-associated gas at $2.00 per mcf more than doubled while wildcat drilling increased by less than 60 percent. As costs are allowed to increase to $3 34 per mcf the reduced return only results in only a 10 percent increase in economically recoverable gas. The decline in required return increased economic undiscovered crude oil reserves by only 11 percent at $18 per barrel (7 percent at $30 per barrel).

SUMMARY AND IMPLICATIONS

This report presented an overview of the economic component of the 1995 National Assessment that pertained to undiscovered conventional oil and gas resources. Technically recoverable oil and non-associated gas estimates and estimates of by-product associated gas, associated gas liquids, and non-associated gas liquids were presented . Onshore, 19.6 BBO of crude oil, 31.4 TCF of associated gas and 1.9 BBL of associated gas liquids are estimated to be technically recoverable in undiscovered conventional oil fields in the conterminous United States. Similarly, 139.5 TCF of non-associated gas and 4.5 BBL of non-associated gas liquids are estimated to be technically recoverable in undiscovered conventional onshore non-associated gas fields. Offshore, there was 2.02 BBO crude oil , and 3.1 TCF associated gas assessed in oil fields and 16.4 TCF non-associated gas and 0.29 BBL of non-associated gas liquids. Together, about 73 percent of the oil and 78 percent of the non-associated gas are expected to be contained in fewer than 5,800 fields having 1 MMBO or more or 6 BCF or more of gas. The remaining 27 percent of the oil and 22 percent of the non-associated gas is contained in more than 84,000 small fields. Estimates of technically recoverable undiscovered oil amounts to only 13 percent of past discoveries while assessed undiscovered gas resources are 23 percent of past discoveries in this area.

For onshore areas just under 40 percent of technically recoverable undiscovered crude oil and half of the non-associated gas can be discovered, developed, and produced for $18 per barrel and $2.00 per mcf. Allowing costs to increase to $30 per barrel and $3.34 per mcf increases the economic proportion of the technically recoverable oil and non-associated gas to two-thirds. However, even as costs approach $30 per barrel and $3.34 per mcf, only a fraction of the small undiscovered fields are found and developed. If only State offshore OCS areas are considered, then about 37 percent of the technically recoverable oil and, similarly, only 12 percent of the non-associated gas is economic at $18 per barrel and $2.00 per mcf. At $30 per barrel and $3.34 per mcf the just over half of the technically recoverable the State OCS oil and non-associated gas can be found, developed, and produced. In all the above, a 12 percent after-tax rate of return was required. Table 6 and figures 8A and 8B show the combined incremental cost functions for the onshore and State OCS offshore areas in the lower 48 states.

Computations with the costing algorithm showed that even at well-head prices of $15 per barrel ($1.67 per mcf) almost two-thirds of the onshore crude oil and three-fourths of the non-associated gas, contained primarily in the large fields and shallow small fields, would be commercially developable if already discovered. Full incremental costs, however, require accounting for finding costs. Finding rate functions are used to predict discovery arrival rates and to sequentially order discovery distributions generated by increments of wildcat wells Estimates of the technical discovery efficiencies were probably biased downward because it was unlikely that the industry was operating at its frontier of exploration technical efficiency during the period covering the historical data used in calibrating the models The use of 'targeted wells' as a measure of exploration effort was also imperfect and probably added to the conservative bias. Furthermore, the exponential finding rate models provide no direct means of capturing the accumulation of geologic knowledge that will, in practice, enhance the siting of future wildcat wells.

It is also clear that, even at low costs, improvements in exploration technology are likely to occur during the decade or more it will take to complete exploration. The base case incremental cost function analysis represented a weighted scenario based on the incremental costs associated with historical discovery efficiencies and costs computed where efficiencies had been increased to account for improvements in technology. Even though undiscovered resources are unchanged, changes in exploration efficiencies significantly affect quantity of resources found and developed at a given well head price/cost level because the discovery arrival rates increase. If the analysis were repeated and finding rates were double those in the base case analysis, at $18 per barrel ($2.00 per mcf) the quantity of crude oil and non-associated gas that is economic to find, develop and produce increases by more than one-third. As price/costs approach $30 per barrel ($3.34 per mcf) the quantity of economic crude oil and non-associated gas increases by about one-sixth over value shown in table 6.

For forecasting future incremental costs, modeling finding rates is probably the most critical component of the cost algorithm and clearly deserves further attention, particularly if the analysis is applied to long-term projections. It should also be noted that even if the technical finding rate efficiencies were known, there would be no assurance that the industry operates on this technical frontier. In the past, finding rates have generally reflected the economic conditions of the industry and have been depressed as explorationists sited wells targeted at marginal prospects.

Overall, the geologic assessment characterized the conterminous US onshore and State offshore areas as mature in terms of exploration for conventional oil and gas fields. The incremental costs projected here reflect this declining resource quality and are higher than the costs incurred with finding and developing most of the petroleum produced in the past. Most of conventional resources produced in the past were contained in large low cost fields that tended to be found early in the exploration process of an area.

Acknowledgements
The authors wish to acknowledge helpful reviews of K. Long and R. Mast. Province geologist responsible for assessing the conventional undiscovered resources considered in this report were M. Ball, C. Barker, L. Beyer, W. Butler, R. Charpentier, G. Dolton, T. Dyman, T. Fouch, J. Fox, J. Grow, J. Hatch, T. Hester, D. Higley, M. Henry, A. C. Hoffman Jr., S. Johnson, C. W. Keighin, M. Keller, B. Law, D. Macke, L. Magoon, R. Milici, C. Molenaar, J. Palacas, W. Perry Jr., J. Peterson, R. Pollastro, R. Powers, R. Ryder, C. Schenk, C. Spenser, R. Stanley, M. Tennyson, C. Wandrey.

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APPENDIX A. NOMENCLATURE AND COMPLETE LIST OF PROVINCES

barrels of oil equivalent (BOE) - gas volume and NGL volume that is 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 separating 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, for expulsion of sufficient quantities of oil and (or) gas and timing of expulsion of hydrocarbons 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 play being assessed.

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.

Table A-1 List of petroleum provinces covering onshore and State offshore areas in the conterminous United States

Region	Province code	province name
Region 2. Pacific Coast		
	004	Western Oregon-Washington
	005	Eastern Oregon-Washington
	006	Klamath-Sierra Nevada
	007	Northern Coastal
	008	Sonoma-Livermore Basin
	009	Sacramento Basin
	010	San Joaquin Basin
	011	Central Coastal
	012	Santa Maria Basin
	013	Ventura Basin
	014	Los Angeles Basin
	015	San Diego-Oceanside
	016	Salton Trough
Region 3. Colorado Plateau and Basin and Range		
	017	Idaho-Snake River Downwarp
	018	Western Great Basin
	019	Eastern Great Basin
	020	Uinta-Piceance Basin
	021	Parodox Basin
	022	San Juan Basin
	023	Albuquerque-Santa Fe Rift
	024	Northern Arizona
	025	Southern Arizona-South West New Mexico
	026	South-Central New Mexico
Region 4. Rocky Mountains and Northern Great Plains		
	027	Montana Thrust Belt
	028	Central Montana
	029	South West Montana
	031	Williston Basin
	032	Sioux Arch
	033	Powder River Basin
	034	Big Horn Basin
	035	Wind River Basin
	036	Wyoming Thrust Belt
	037	South West Wyoming
	038	Park Basins
	039	Denver Basin
	040	Las Animas Arch
	041	Raton Basin-Sierra Grande Uplift

Table A-1 continued

Region	Province code	province name
Region 5 West Texas and Eastern New Mexico		
	042	Pedernal Uplift
	043	Palo Duro Basin
	044	Permian Basin
	045	Bend Arch-Fort Worth Basin
	046	Marathon Thrust Belt
Region 6. Gulf Coast		
	047	Western Gulf
	048	East Texas Basin
	049	Lousiana-Mississppi Salt Basins
	050	Florida Peninsula
Region 7. Midcontinent		
	051	Superior
	052	Iowa Shelf
	053	Cambridge Arch-Central Kansas
	054	Salina Basin
	055	Nemaha Uplift
	056	Forest City Basin
	057	Ozark Uplift
	058	Anadarko Basin
	059	Sedgwick Basin
	060	Cherokee Basin
	061	Southern Oklahoma
	062	Arkoma Basin
Region 8. Eastern		
	063	Michigan Basin
	064	Illinois Basin
	065	Black Warrior Basin
	066	Cincinnati Arch
	067	Appalachian Basin
	068	Blue Ridge Thrust Belt
	069	Piedmont

Appendix B. Specification, Calibration, and Application of the Finding Rate Component of the Cost Algorithm

Purpose and specification

The finding rate model imbedded in 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 Past wildcat well depth allocations were not used to predict depths of future drilling because the past allocations were often the product of 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 rates component of the cost algorithm.

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 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 convoluted 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 17 size classes (see table B-1) 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 impossible to compute coefficients directly.

Examination of the c(j,k)'s for the aggregate lower 48 and the provinces where relatively complete sets of coefficients were computed showed existence of a reasonably stable relationship between the c(j,k)'s and the decline coefficients (hereafter denoted c(j)'s) that were calculated when the data for all depth intervals are collapsed and represented by wells and discoveries at the surface. 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. "Missing" c(j,k)'s occurred when there were no discoveries in a field size class in a particular depth interval. For all basins where data allowed, the a(k)'s were determined from the calculated c(j)'s and the c(j,k)'s. The larger size class c(j)'s were smoothed and the c(j)'s for smaller size classes were predicted from a regression used in smoothing the larger size classes. Then, the a(k)'s for the province were applied to the smoothed c(j)'s to estimate all the c(j,k) 's at depth. In provinces where a(k)'s could not be calculated for all depths because wells had not been drilled, the a(k)'s that were computed from the lower 48 data was applied to generate the province c(j,k)'s. In fact, as long as there was sufficient data to estimate and smooth c(j)'s based on the individual province data, the a(k)'s calculated from the aggregate lower 48 data could be used to generate the rest of the province coefficients. However, there were still a few provinces where not even the estimation of a sufficient number of the c(j)'s for subsequent smoothing could be accomplished.

A second empirical observation 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 provinces 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. Consequently, this relationship provided the basis for developing a default scheme for estimating the c(j)'s for provinces where the data were deficient. In these cases, to provide rough estimates of the c(j)'s the lower 48 coefficients were multiplied 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. For the models driving the State offshore costing algorithm, the province coefficients were increased to account for the higher costs and generally lower drilling density than onshore portions of the province. Based on available drilling density data, the offshore discovery decline rates were set at four times the onshore decline rates.

Application

Historical finding rates have been a product of industry behavior and have reflected past drilling efficiencies. An upward adjustment was made in the model coefficients so the model would reproduce more recent (since 1985) discovery rates, (covering almost 20,000 wildcat wells). Even with the upward adjustment there is no assurance that the industry was operating on its technical exploration efficiency frontier, as major restructuring occurred and is still ongoing. In fact, the more recent data since 1990, which are still incomplete for both discoveries and wildcat wells, roughly show a per well improvement of in terms of barrels of oil equivalent per well of about 60 percent over the rate since 1985. Thus, the upward adjustment of the efficiencies calibrated with historical data was probably conservative.

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 functions likely overstates required drilling because one well may test more than a single depth interval. An alternative to the use "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 B-1.--Field-size class definitions.

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 1. Mean values of undiscovered technically recoverable conventional onshore oil, gas, and natural gas liquids (NGL) in conterminous U. S. oil and gas fields by petroleum provinces and regions.

	Oil Fields			Gas Fields	
Province number and name	Oil	Associated Gas	NGL	Nonass. Gas	NGL
	(MMBBL)	(BCF)	(MMBBL)	(BCF)	(MMBBL)
004 Western Oregon-Wash.	21	31	2	751	0
005 Eastern Oregon-Wash.	0	0	0	392	1
007 Northern Coastal	30	10	0	847	0
008 Sonoma-Livermore Basin	9	9	0	53	0
009 Sacramento Basin	2	0	0	3328	9
010 San Joaquin Basin	1214	2027	105	537	0
011 Central Coastal	445	136	5	0	0
012 Santa Maria Basin	84	48	4	0	0
013 Ventura Basin	435	435	13	253	10
014 Los Angeles Basin	768	1307	47	0	0
TOTAL REG. 2-Pacific Coast	3008	4003	176	6161	20
017 Idaho-Snake R. Downwarp	1	0	0	12	0
018 W. Great Basin	1	0	0	5	0
019 E. Great Basin	488	78	1	261	6
020 Uinta-Piceance Basin	211	1737	64	2791	12
021 Parodox Basin	307	750	78	1234	9
022 San Juan Basin	162	293	6	661	25
023 Albuquerque-Santa Fe Rift	45	86	3	267	16
024 N. Arizona	65	41	2	133	13
025 S. Ariz.-S.W. New Mexico	24	2	0	203	20
TOTAL REG. 3-Colorado Plateau and Basin & Range	1304	2987	154	5567	101
027 Montana Thrust Belt	4	4	0	1919	6
028 Central Montana	268	97	2	749	0
029 S.W. Montana	27	25	1	382	2
031 Williston Basin	663	720	54	1003	125
033 Powder River Basin	1938	1220	77	401	24
034 Big Horn Basin	387	69	2	553	11
035 Wind River Basin	155	310	8	929	6
036 Wyoming Thrust Belt	625	2459	383	8222	784
037 S.W. Wyoming	167	333	4	1242	22
038 Park Basins	30	19	0	0	0
039 Denver Basin	228	192	20	563	6
040 Las Animas Arch	137	113	3	418	11
041 Raton B.-Sierra Grande Uplift	0	0	0	42	1
TOTAL REG. 4-Rocky Mt. & N. Great Plains	4629	5561	554	16423	998
043 Palo Duro Basin	33	3	0	6	0
044 Permian Basin	2882	4294	441	12108	200
045 Bend Arch-Ft. Worth Basin	638	802	48	1350	98
046 Marathon Thrust Belt	17	45	4	104	6
TOTAL REG. 5-W. Texas & E.N.Mexico	3570	5144	493	13568	304
047 Western Gulf	2118	5564	184	54794	1441
049 Louisiana-Miss. Salt Basins	2600	3897	155	19562	1331
050 Florida Peninsula	335	31	0	0	0
TOTAL REG. 6-Gulf Coast	5053	9492	339	74356	2772

Table 1. Continued

Province number and name	Oil Fields: Oil (MMBBL)	Oil Fields: Associated Gas (BCF)	Oil Fields: NGL (MMBBL)	Gas Fields: Nonass. Gas (BCF)	Gas Fields: NGL (MMBBL)
051 Superior	53	32	0	387	0
053 Cambridge Arch-C. Kansas	203	286	16	128	3
055 Nemaha Uplift	123	352	25	123	3
056 Forest City Basin	22	66	4	0	0
058 Anadarko Basin	383	1808	75	12398	143
059 Sedgwick Basin	61	165	14	134	1
060 Cherokee Basin	77	133	10	52	1
061 Southern Oklahoma	241	385	19	629	7
062 Arkoma Basin	11	18	1	2477	93
TOTAL REG. 7-Midcontinent	1174	3245	164	16328	251
063 Michigan Basin	460	671	50	2419	77
064 Illinois Basin	255	192	0	312	0
065 Black Warrior Basin	34	17	0	2012	8
066 Cincinnati Arch	18	18	0	0	0
067 Appalachian Basin	96	50	1	1956	3
068 Blue Ridge Thrust Belt	0	0	0	30	0
069 Piedmont	0	0	0	390	0
TOTAL REG. 8-Eastern	863	948	51	7119	88
TOTAL ONSHORE CONTERMINOUS U. S.	19601	31380	1931	139522	4534

* Provinces not listed include the Klamath-Sierra Nevada(006) and Salton Trough(016)where no resources were assigned, South Central New Mexico(026), Sioux Arch(032), Pedernal Uplift(042), Iowa Shelf(052), Ozark Uplift(057) where negligible resources were assessed and the San Diego-Oceanside(015)which was assessed by Minerals Management Service. The assessment of the East Texas Basin (048) is included in the values shown for the Louisiana-Mississippi Salt Basins (049) and the assessment for the Salina Basin(054) is included in the values shown for the Sedgwick Basin(059).

Table 2. Mean value of undiscovered technically recoverable conventional state offshore oil, gas, and natural gas liquids (NGL) in conterminous US oil and gas fields by petroleum provinces and regions.

Province number and name	Oil Fields			Gas Fields	
	Oil	Associated Gas	NGL	Nonass. Gas	NGL
	(MMBBL)	(BCF)	(MMBBL)	(BCF)	(MMBBL)
004 Western Oregon-Wash	4	6	0	8	0
006 Northern Coastal	0	0	0	227	0
011 Central Coastal	48	11	0	5	0
012 Santa Maria Basin	126	75	6	0	0
013 Ventura Basin	629	629	21	581	23
014 Los Angeles Basin	209	298	9	0	0
TOTAL REG. 2 - Pacific Coast	1016	1019	36	821	23
047 Western Gulf	169	560	11	7493	190
049 Lousiana-Miss. Salt	85	111	4	6000	9
050 Florida Peninsula	84	9	0	0	0
TOTAL REG. 6 - Gulf Coast	338	680	15	13493	199
063 Michigan Basin	653	1324	86	1733	69
067 Appalachian Basin	10	71	0	342	0
TOTAL REG. 8-Eastern	863	948	51	7119	69
TOTAL STATE OFFSHORE CONTERMINOUS UNITED STATES	2017	3094	137	16389	291

Table 3. Mean number of onshore fields in each region. Large fields contain at least 1 million barrels of recoverable oil equivalent, and smaller fields are called small fields.

Region number name	Oil Fields Total	Oil Fields Large	Oil Fields Small	Gas Fields Total	Gas Fields Large	Gas Fields Small
Region 2-Pacific Coast	3505	352	3153	2316	194	2122
Region 3-Colorado Plateau & Basin and Range	3003	164	2839	2617	148	2470
Region 4-Rocky Mountains & N. Great Plains	13641	598	13043	3245	266	2980
Region 5-West Texas & Eastern New Mexico	8784	486	8298	3125	251	2874
Region 6-Gulf Coast	13892	729	13163	19404	1469	17935
Region 7-Midcontinent	4829	213	4616	4662	267	4395
Region 8-Eastern	3805	146	3659	2870	217	2652
Total onshore conterminous United States	51458	2688	48770	38239	2812	35427

Table 4. Regional incremental costs of finding, developing, and producing undiscovered resources in oil and gas fields and associated wildcat wells for conterminous US onshore areas.

Region	Cost		Oil Fields: Oil	Oil Fields: Associated Gas	Oil Fields: NGL	Gas Fields: Nonass. Gas	Gas Fields: NGL	New Field Wildcats
	($/bbl)	($/mcf)	(BBO)	(TCF)	(BBL)	(TCF)	(BBL)	(Thous.)
2. Pacific Coast	12	1.33	0.38	0.51	0.02	0.29	0.00	1
	15	1.67	0.78	1.09	0.05	0.85	0.00	3
	18	2.00	1.20	1.71	0.07	1.38	0.01	4
	21	2.33	1.46	2.08	0.09	1.85	0.01	6
	24	2.67	1.67	2.35	0.10	2.24	0.01	7
	27	3.00	1.86	2.60	0.11	2.59	0.01	9
	30	3.34	1.99	2.78	0.12	2.79	0.01	10
3. Colorado Plateau and Basin & Range	12	1.33	0.30	1.32	0.05	0.96	0.01	1
	15	1.67	0.45	1.60	0.06	1.79	0.02	2
	18	2.00	0.58	1.83	0.08	2.41	0.02	3
	21	2.33	0.66	1.97	0.09	2.83	0.03	4
	24	2.67	0.73	2.10	0.09	3.19	0.03	4
	27	3.00	0.79	2.20	0.10	3.38	0.03	5
	30	3.34	0.84	2.28	0.11	3.55	0.04	6
4. Rocky Mountains & N. Great Plains	12	1.33	0.67	1.95	0.29	6.63	0.58	1
	15	1.67	1.16	2.42	0.33	7.84	0.65	3
	18	2.00	1.63	2.84	0.36	8.75	0.71	4
	21	2.33	2.07	3.24	0.39	9.56	0.74	6
	24	2.67	2.43	3.56	0.41	10.32	0.78	8
	27	3.00	2.63	3.76	0.43	10.80	0.80	10
	30	3.34	2.95	4.02	0.45	11.37	0.83	11
5. W. Texas & E. New Mexico	12	1.33	1.24	1.85	0.19	3.85	0.08	4
	15	1.67	1.68	2.50	0.26	5.27	0.12	7
	18	2.00	1.97	2.92	0.30	6.51	0.14	10
	21	2.33	2.25	3.31	0.33	7.27	0.16	13
	24	2.67	2.46	3.62	0.36	8.17	0.19	15
	27	3.00	2.62	3.83	0.38	8.75	0.20	18
	30	3.34	2.74	3.99	0.39	9.34	0.21	20
6. Gulf Coast	12	1.33	0.75	1.45	0.05	20.90	0.53	3
	15	1.67	1.30	2.64	0.09	30.45	0.80	6
	18	2.00	1.75	3.53	0.12	37.82	1.02	10
	21	2.33	2.15	4.36	0.15	43.31	1.21	13
	24	2.67	2.55	5.05	0.17	47.73	1.37	18
	27	3.00	2.89	5.69	0.19	50.69	1.48	22
	30	3.34	3.11	6.10	0.20	52.86	1.59	25
7. Midcontinent	12	1.33	0.10	0.44	0.02	3.79	0.08	1
	15	1.67	0.21	0.82	0.04	5.60	0.11	3
	18	2.00	0.33	1.14	0.05	6.98	0.13	4
	21	2.33	0.46	1.48	0.07	8.14	0.15	6
	24	2.67	0.57	1.75	0.08	9.14	0.16	9
	27	3.00	0.67	1.97	0.10	9.84	0.17	11
	30	3.34	0.72	2.12	0.10	10.39	0.18	12

Table 4. Continued

Region	Cost		Oil Fields: Oil	Oil Fields: Associated Gas	Oil Fields: NGL	Gas Fields: Nonass. Gas	Gas Fields: NGL	New Field Wildcats
	($/bbl)	($/mcf)	(BBO)	(TCF)	(BBL)	(TCF)	(BBL)	(Thous.)
8. Eastern	12	1.33	0.05	0.07	0.00	0.17	0.01	0
	15	1.67	0.13	0.16	0.01	0.74	0.01	1
	18	2.00	0.24	0.30	0.02	1.33	0.02	3
	21	2.33	0.34	0.41	0.03	1.86	0.03	5
	24	2.67	0.43	0.50	0.03	2.37	0.04	6
	27	3.00	0.50	0.57	0.03	2.82	0.05	8
	30	3.34	0.54	0.61	0.04	3.12	0.05	9
Conterminous Onshore United States	12	1.33	3.48	7.59	0.62	36.59	1.29	12
	15	1.67	5.71	11.24	0.83	52.55	1.71	25
	18	2.00	7.68	14.26	1.00	65.18	2.06	38
	21	2.33	9.39	16.84	1.14	74.81	2.34	53
	24	2.67	10.84	18.93	1.25	83.17	2.58	68
	27	3.00	11.94	20.63	1.34	88.88	2.75	81
	30	3.34	12.89	21.90	1.41	93.41	2.91	93

Table 5. Regional incremental costs of finding. developing and producing undiscoverd resouces in oil and gas fields and associated wildcat wells for conterminous State OCS offshore areas.

			Oil Fields			Gas Fields		
Region	Cost		Oil	Associated Gas	NGL	Nonass. Gas	NGL	New Field Wildcats
	($/bbl)	($/mcf)	(BBO)	(TCF)	(BBL)	(TCF)	(BBL)	
2. Pacific Coast	12	1.33	0.37	0.37	0.01	0.16	0.01	90
	15	1.67	0.41	0.42	0.01	0.22	0.01	120
	18	2.00	0.49	0.50	0.02	0.27	0.01	200
	21	2.33	0.53	0.54	0.02	0.29	0.01	250
	24	2.67	0.57	0.59	0.02	0.33	0.01	320
	27	3.00	0.60	0.62	0.02	0.35	0.01	390
	30	3.34	0.63	0.65	0.02	0.36	0.01	450
6. Gulf Coast	12	1.33	0.00	0.00	0.00	0.00	0.00	0
	15	1.67	0.00	0.00	0.00	0.28	0.01	10
	18	2.00	0.03	0.01	0.00	1.50	0.02	70
	21	2.33	0.04	0.03	0.00	3.57	0.04	170
	24	2.67	0.05	0.05	0.00	4.97	0.06	270
	27	3.00	0.06	0.06	0.00	6.04	0.08	370
	30	3.34	0.07	0.08	0.00	6.90	0.09	480
Conterminous State offshore United States	12	1.33	0.37	0.37	0.01	0.16	0.01	90
	15	1.67	0.41	0.42	0.01	0.49	0.02	130
	18	2.00	0.51	0.52	0.02	1.77	0.03	270
	21	2.33	0.57	0.57	0.02	3.86	0.06	420
	24	2.67	0.62	0.63	0.02	5.30	0.08	590
	27	3.00	0.66	0.69	0.02	6.39	0.09	760
	30	3.34	0.70	0.73	0.02	7.26	0.10	930

Table 6. Regional incremental costs of finding, developing, and producing and undiscovered resources in oil and gas fields and associated wildcat wells conterminous US conterminous onshore and State OCS offshore areas.

Region	Cost		Oil Fields: Oil	Oil Fields: Associated Gas	Oil Fields: NGL	Gas Fields: Nonass. Gas	Gas Fields: NGL	New Field Wildcats
	($/bbl)	($/mcf)	(BBO)	(TCF)	(BBL)	(TCF)	(BBL)	(Thous.)
2. Pacific Coast	12	1.33	0.80	0.95	0.04	0.50	0.01	1
	15	1.67	1.23	1.56	0.06	1.10	0.01	3
	18	2.00	1.74	2.28	0.09	1.69	0.02	4
	21	2.33	2.05	2.69	0.11	2.19	0.02	6
	24	2.67	2.30	3.01	0.13	2.60	0.02	8
	27	3.00	2.52	3.29	0.14	2.98	0.03	9
	30	3.34	2.68	3.49	0.15	3.19	0.03	10
3. Colorado Plateau and Basin & Range	12	1.33	0.30	1.32	0.05	0.96	0.01	1
	15	1.67	0.45	1.60	0.06	1.79	0.02	2
	18	2.00	0.58	1.83	0.08	2.41	0.02	3
	21	2.33	0.66	1.97	0.09	2.83	0.03	4
	24	2.67	0.73	2.10	0.09	3.19	0.03	4
	27	3.00	0.79	2.20	0.10	3.38	0.03	5
	30	3.34	0.84	2.28	0.11	3.55	0.04	6
4. Rocky Mountains & N. Great Plains	12	1.33	0.67	1.95	0.29	6.63	0.58	1
	15	1.67	1.16	2.42	0.33	7.84	0.65	3
	18	2.00	1.63	2.84	0.36	8.75	0.71	4
	21	2.33	2.07	3.24	0.39	9.56	0.74	6
	24	2.67	2.43	3.56	0.41	10.32	0.78	8
	27	3.00	2.63	3.76	0.43	10.80	0.80	10
	30	3.34	2.95	4.02	0.45	11.37	0.83	11
5. W. Texas & E. New Mexico	12	1.33	1.24	1.85	0.19	3.85	0.08	4
	15	1.67	1.68	2.50	0.26	5.27	0.12	7
	18	2.00	1.97	2.92	0.30	6.51	0.14	10
	21	2.33	2.25	3.31	0.33	7.27	0.16	13
	24	2.67	2.46	3.62	0.36	8.17	0.19	15
	27	3.00	2.62	3.83	0.38	8.75	0.20	18
	30	3.34	2.74	3.99	0.39	9.34	0.21	20
6. Gulf Coast	12	1.33	0.75	1.45	0.05	20.90	0.53	3
	15	1.67	1.30	2.64	0.09	31.00	0.82	6
	18	2.00	1.75	3.55	0.12	40.83	1.07	10
	21	2.33	2.20	4.41	0.15	48.38	1.29	14
	24	2.67	2.61	5.13	0.17	54.30	1.46	18
	27	3.00	2.95	5.78	0.19	57.93	1.58	22
	30	3.34	3.18	6.20	0.21	60.87	1.70	26
7. Midcontinent	12	1.33	0.10	0.44	0.02	3.79	0.08	1
	15	1.67	0.21	0.82	0.04	5.60	0.11	3
	18	2.00	0.33	1.14	0.05	6.98	0.13	4
	21	2.33	0.46	1.48	0.07	8.14	0.15	6
	24	2.67	0.57	1.75	0.08	9.14	0.16	9
	27	3.00	0.67	1.97	0.10	9.84	0.17	11
	30	3.34	0.72	2.12	0.10	10.39	0.18	12

Table 6. Continued

Region	Cost		Oil Fields: Oil	Oil Fields: Associated Gas	Oil Fields: NGL	Gas Fields: Nonass. Gas	Gas Fields: NGL	New Field Wildcats
	($/bbl)	($/mcf)	(BBO)	(TCF)	(BBL)	(TCF)	(BBL)	(Thous.)
8. Eastern	12	1.33	0.05	0.07	0.00	0.17	0.01	0
	15	1.67	0.13	0.16	0.01	0.74	0.01	1
	18	2.00	0.24	0.30	0.02	1.33	0.02	3
	21	2.33	0.34	0.41	0.03	1.86	0.03	5
	24	2.67	0.43	0.50	0.03	2.37	0.04	6
	27	3.00	0.50	0.57	0.03	2.82	0.05	8
	30	3.34	0.54	0.61	0.04	3.12	0.05	9
Conterminous Onshore and State Offshore United States	12	1.33	3.87	7.99	0.64	36.78	1.30	12
	15	1.67	6.15	11.69	0.85	53.30	1.73	25
	18	2.00	8.26	14.83	1.02	68.07	2.11	39
	21	2.33	10.02	17.49	1.16	79.83	2.41	53
	24	2.67	11.52	19.63	1.28	89.70	2.68	68
	27	3.00	12.66	21.39	1.37	96.20	2.85	82
	30	3.34	13.64	22.70	1.44	101.52	3.03	94

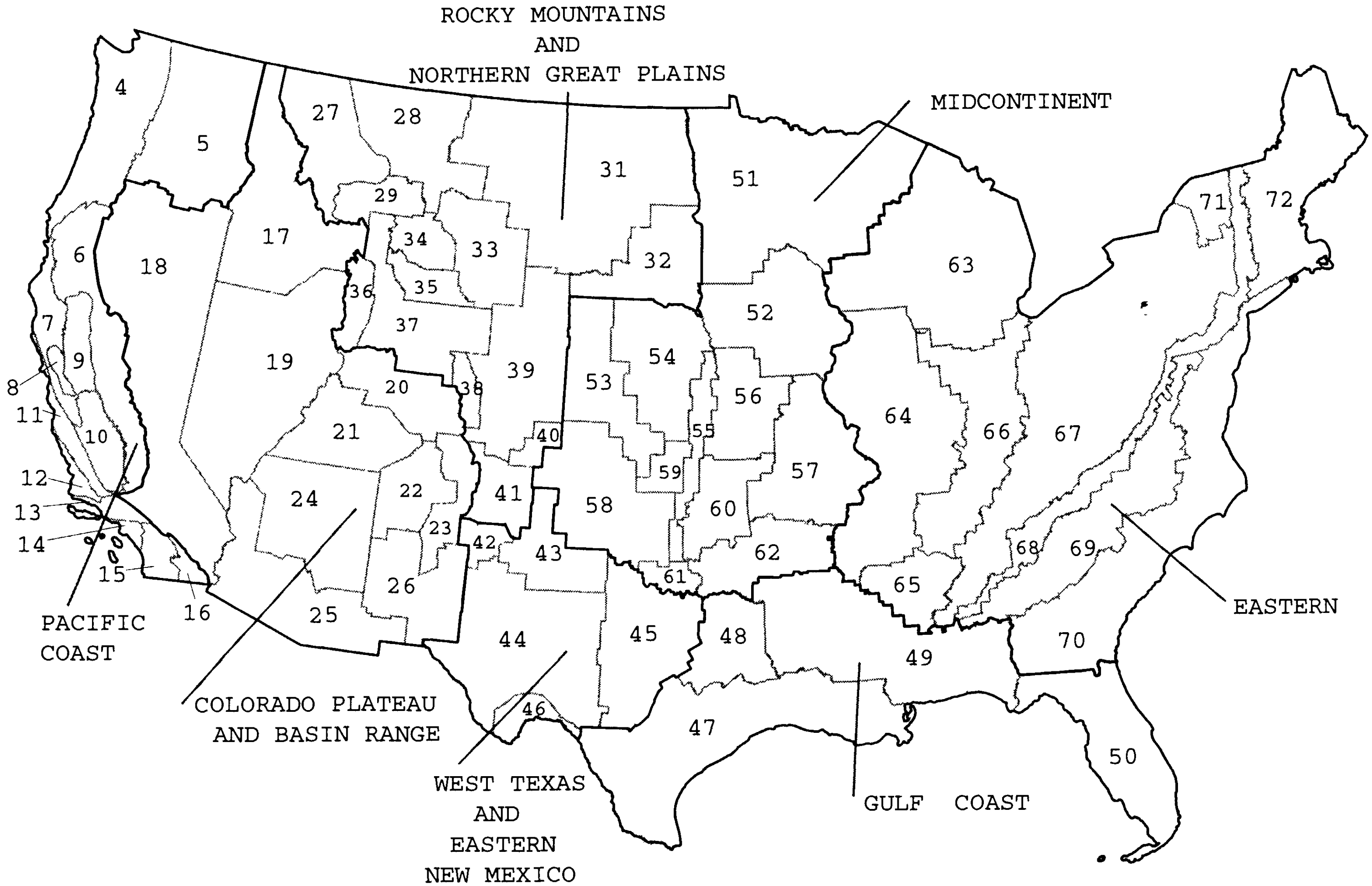

Figure 1. Petroleum regions and provinces in onshore and state offshore areas in the conterminous United States. Heavy lines are region boundaries and lighter lines are province boundaries. Province names are presented in table A-1 of Appendix A.

FIGURE 2A

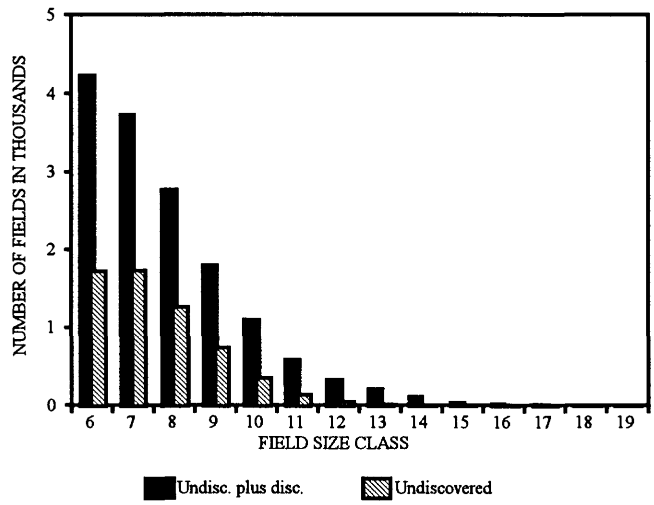

FIGURE 2B

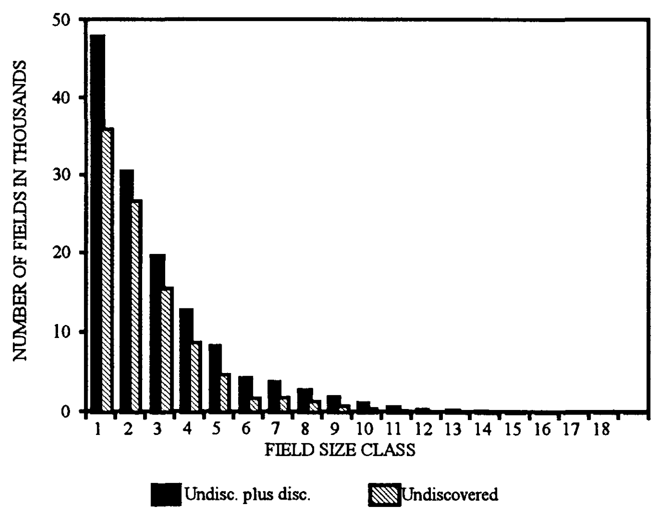

Figure 2. Field-size distribution of ultimate (discovered plus undiscovered) and undiscovered conventional oil and gas fields in onshore and State offshore areas of the conterminous United States. Figure 2A. shows part of distribution for fields containing at least 1 million barrels of oil equivalent. Figure 2B. shows entire distribution. Size classes, in terms of millions of barrels of oil equivalent, are defined in table B-1 of Appendix B.

FIGURE 3A

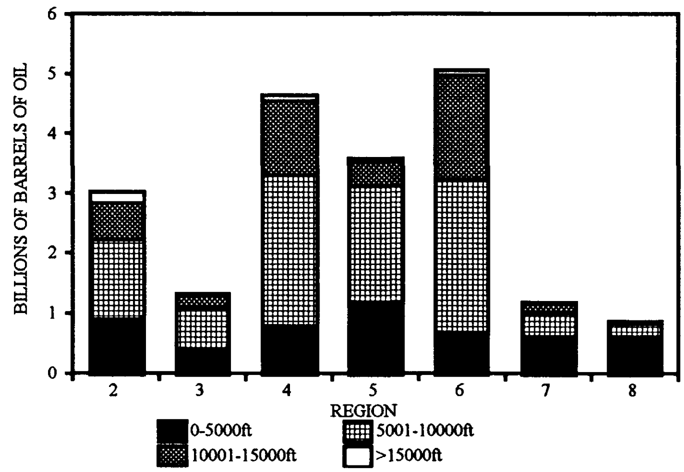

FIGURE 3B

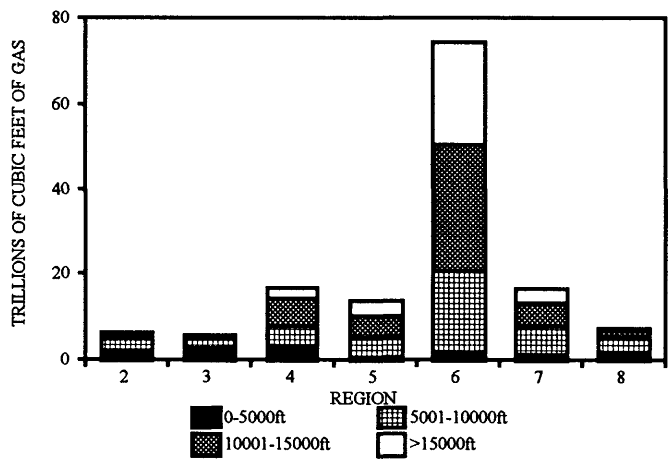

Figure 3. Mean values of undiscovered conventional technically recoverable oil (Figure 3A.) and non-associated gas (Figure 3B) by region and depth interval for onshore conterminous U.S. areas.

FIGURE 4A

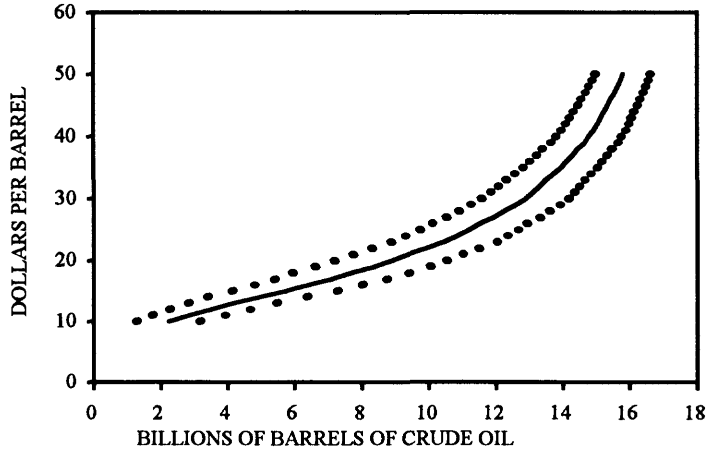

FIGURE 4B

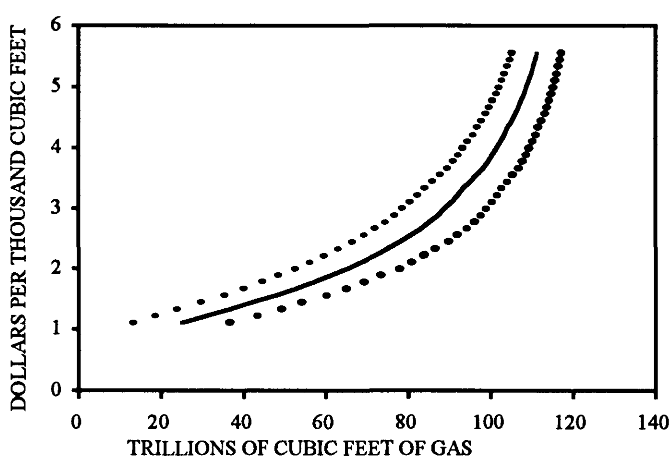

Figure 4. Incremental cost of finding, developing, and producing crude oil (Figure 4A) and non-associated gas (Figure 4B) from conventional undiscovered resources in onshore conterminous US areas. Dotted curve on left based on historical finding rate efficiencies and dotted curve on right assumed finding rates efficiencies showing a one hundred percent improvement over historical efficiencies. Curve in middle is resultant cost function based on equal weighting of dotted curves.

FIGURE 5A

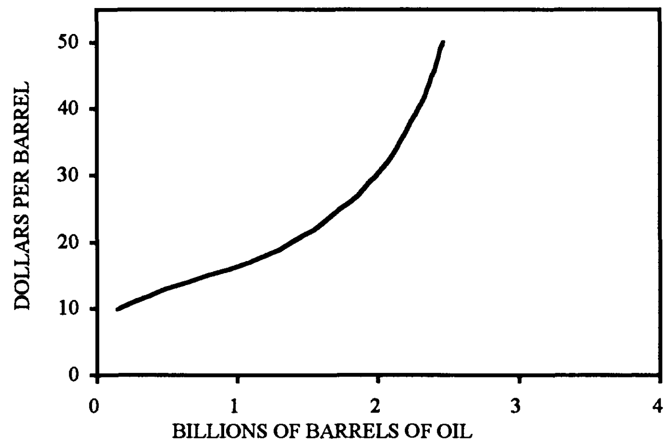

FIGURE 5B

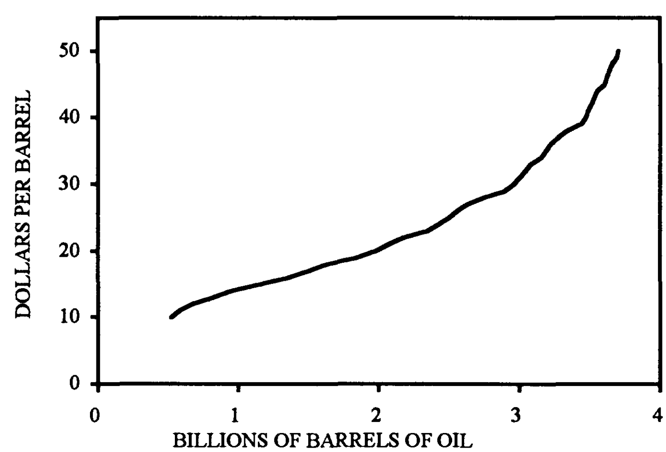

Figure 5. Incremental cost of finding, developing, and producing crude oil from conventional undiscovered oil fields in particular regions; A. Regions 2 Pacific Coast; B. Region 4 Rocky Mountains and Northern Great Plains; C. Region 5 West Texas and Eastern New Mexico; D. Region 6 Gulf Coast.

FIGURE 5C

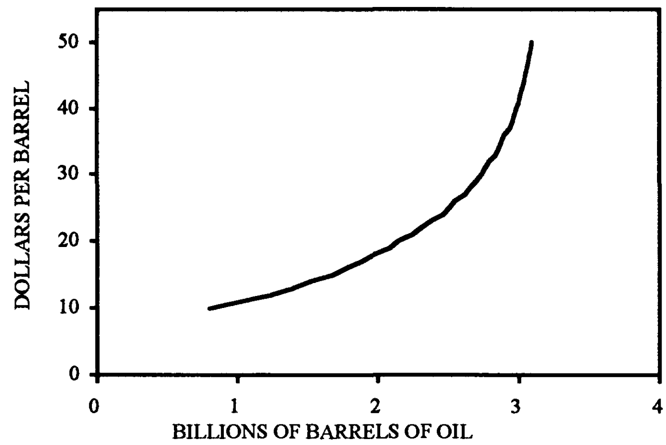

FIGURE 5D

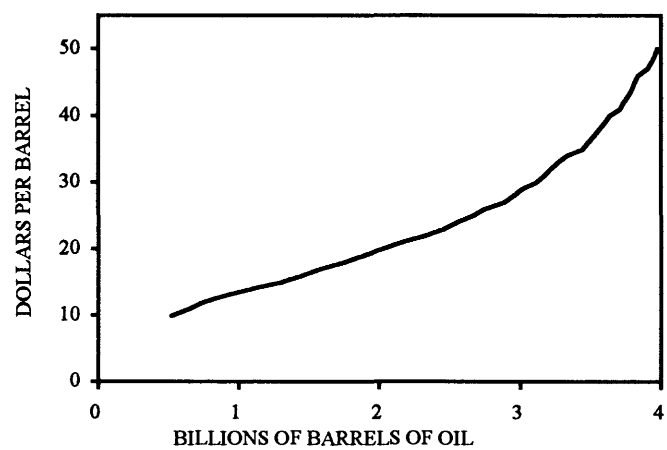

Figure 5. (cont.) Incremental cost of finding, developing, and producing crude oil from conventional undiscovered oil fields in particular regions; A. Regions 2 Pacific Coast; B. Region 4 Rocky Mountains and Northern Great Plains; C. Region 5 West Texas and Eastern New Mexico; D. Region 6 Gulf Coast.

FIGURE 6A

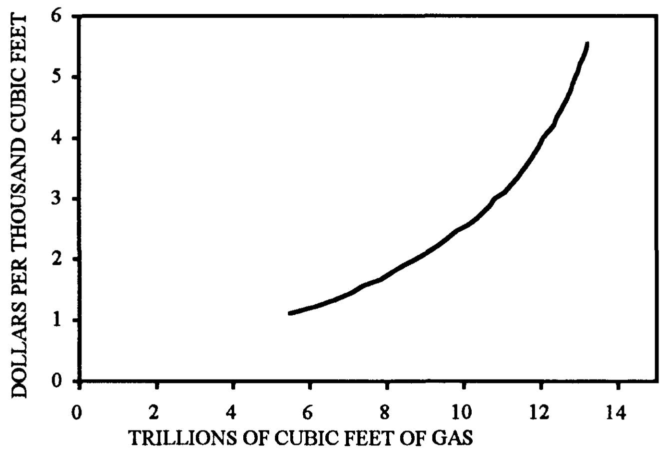

FIGURE 6B

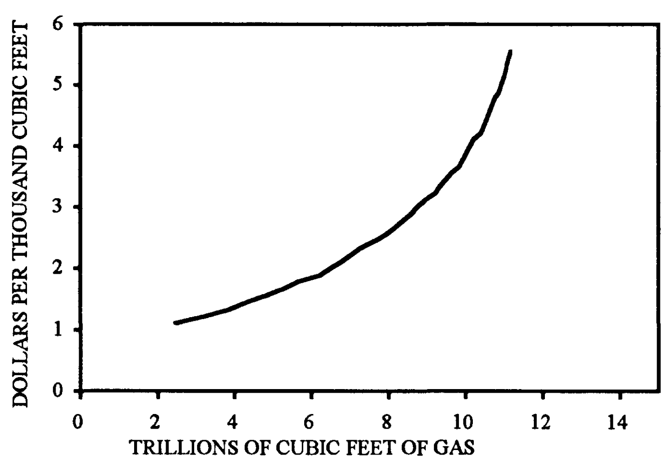

Figure 6. Incremental cost of finding, developing, and producing non-associated gas from conventional undiscovered gas fields in particular regions; A. Region 4 Rocky Mountains and Northern Great Plains; B. Region 5 West Texas and Eastern New Mexico; C. Region 6 Gulf Coast; D. Region 7 Midcontinent.

FIGURE 6C

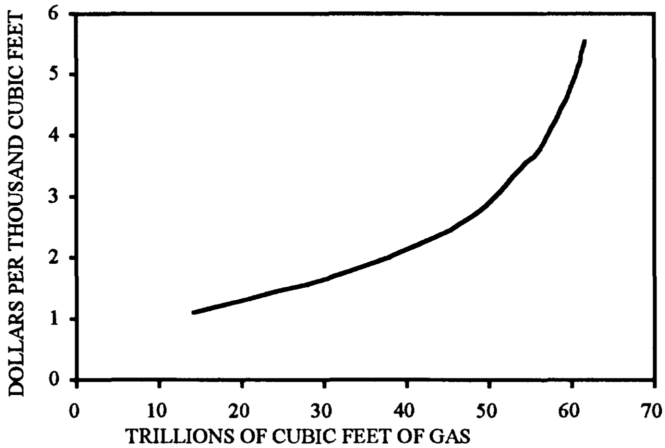

FIGURE 6D

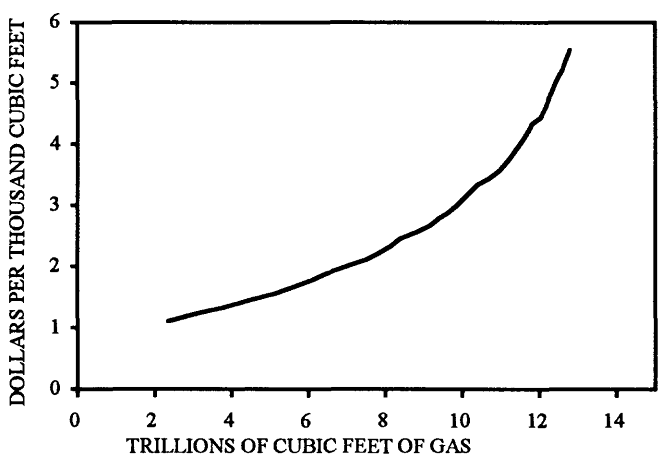

Figure 6.(cont.) Incremental cost of finding, developing, and producing non-associated gas from conventional undiscovered gas fields in particular regions; A. Region 4 Rocky Mountains and Northern Great Plains; B. Region 5 West Texas and Eastern New Mexico; C. Region 6 Gulf Coast; D. Region 7 Midcontinent.

FIGURE 7A

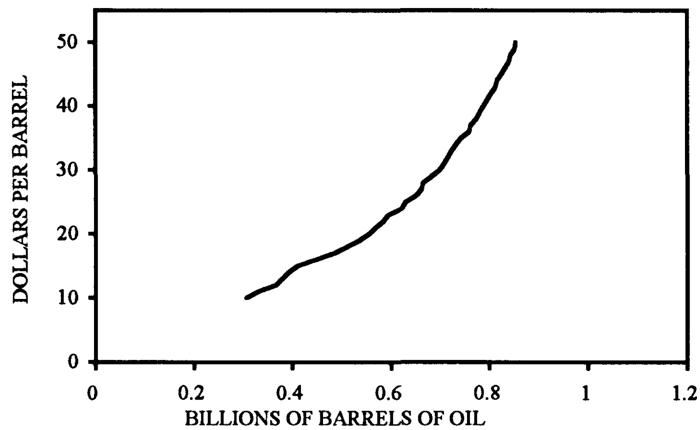

FIGURE 7B

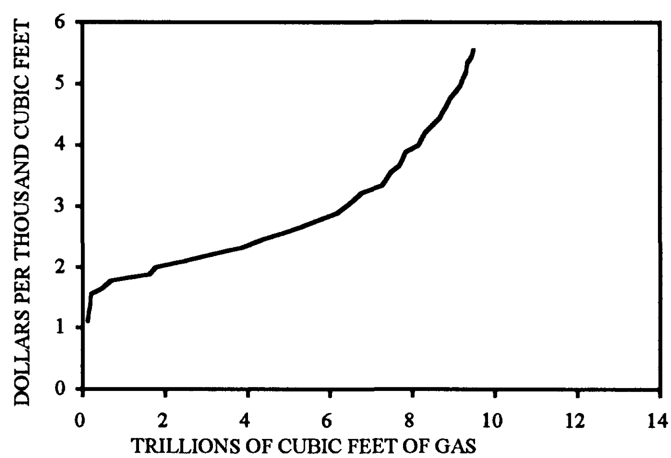

Figure 7. Incremental cost of finding, developing, and producing crude oil (Figure 7A) and non-associated gas (Figure 7B) from conventional undiscovered resources in State OCS offshore areas of the conterminous United States. Does not include resources assigned to the Great Lakes.

FIGURE 8A

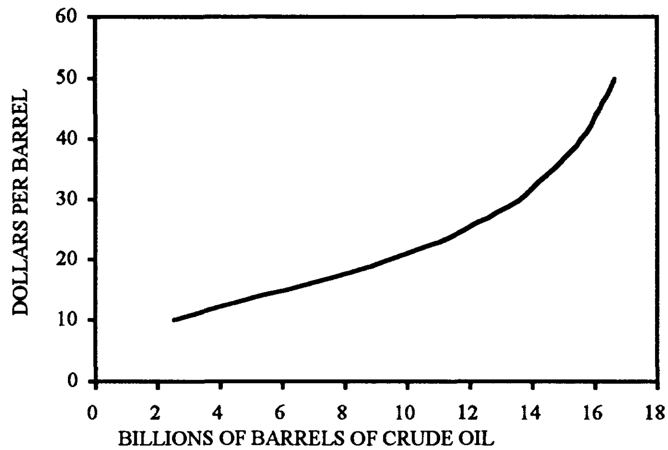

FIGURE 8B

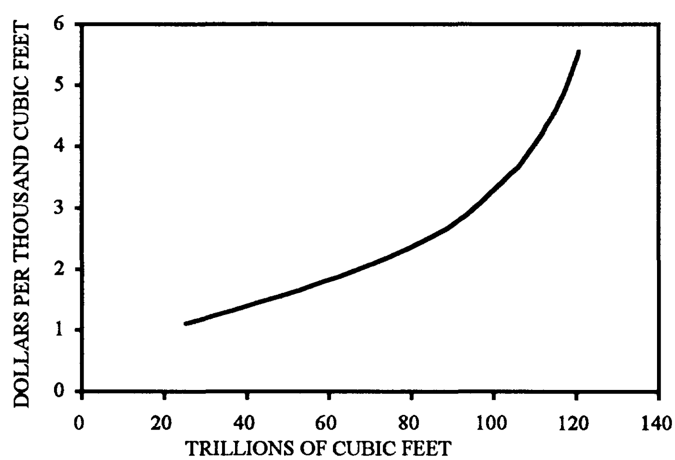

Figure 8. Incremental cost of finding, developing, and producing crude oil (Figure 8A) and non-associated gas (Figure 8B) from conventional undiscovered oil and gas fields, respectively, in onshore and State OCS offshore areas of the conterminous United States. Does not include resources assigned to the Great Lakes.