OCS Report
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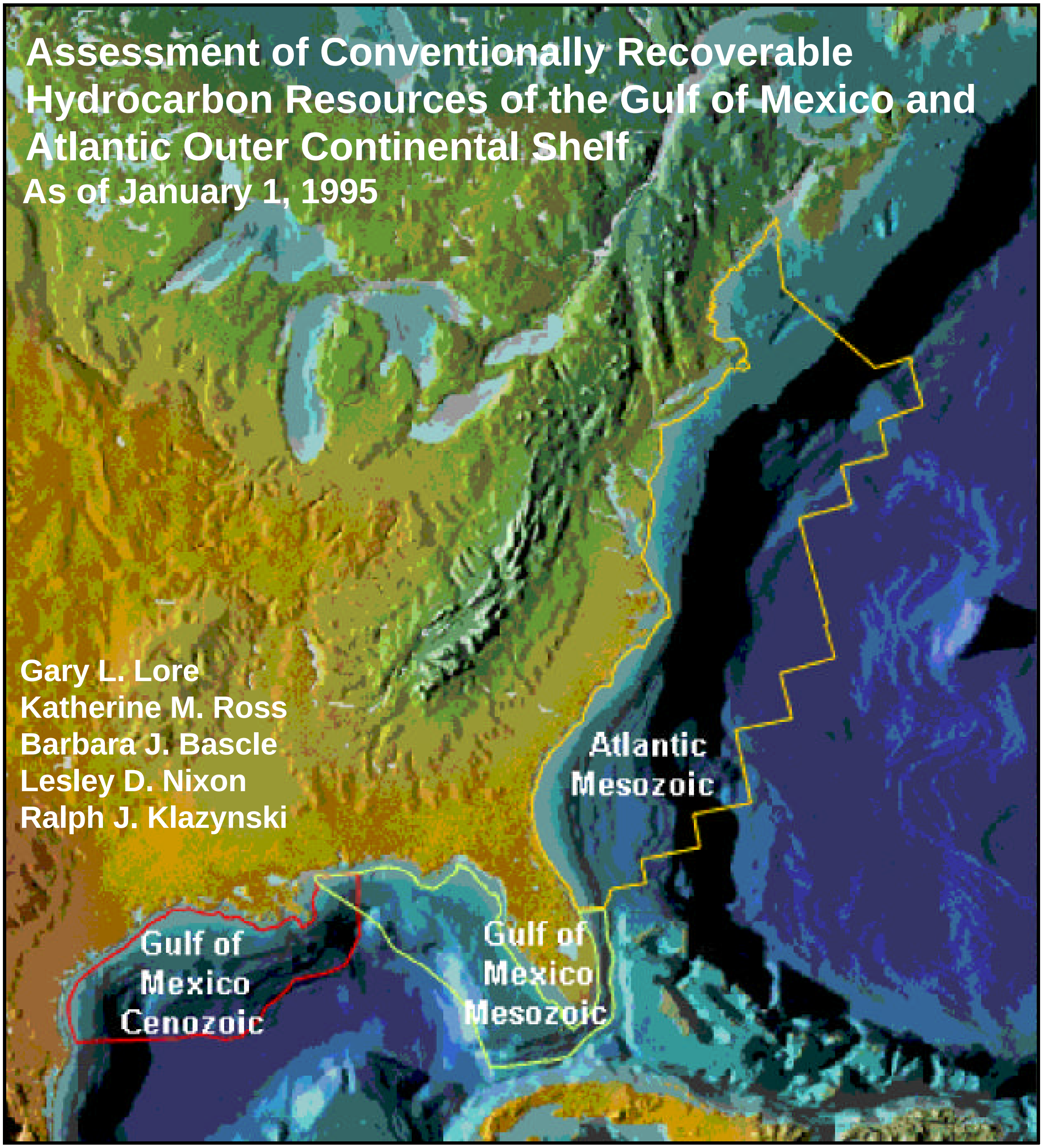
Assessment of Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf

As of January 1, 1995

Gary L. Lore
Katherine M. Ross
Barbara J. Bascle
Lesley D. Nixon
Ralph J. Klazynski



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CONTENTS

SUMMARY

This report presents the results of the 1995 assessment of the conventionally recoverable hydrocarbon resources for the Gulf of Mexico and Atlantic Outer Continental Shelf (OCS). Conventionally recoverable resources are hydrocarbons potentially amenable to conventional production regardless of the size, accessibility, and economics of the accumulations assessed. The OCS comprises the portion of the seabed of the United States whose mineral estate is subject to Federal jurisdiction. The Minerals Management Service (MMS) and the U.S. Geological Survey have previously completed several assessments of the undiscovered conventionally recoverable oil and gas resources of the United States OCS. This 1995 assessment was part of a comprehensive appraisal of the conventionally recoverable petroleum resources of the Nation. This appraisal considered data and information available as of January 1, 1995, and incorporated improved assessment methodologies.

Worldwide reliance on petroleum resources will continue to be the principal means to satisfy future energy demand for decades. Petroleum resources are usually considered as finite since they do not renew at a rate remotely approaching their consumption. Since petroleum also fuels the Nation’s economy, there is considerable interest in the magnitude of the resource base from which future domestic discoveries and production will occur.

Resource estimates are just that— estimates. All methods of assessing potential quantities of conventionally recoverable resources are efforts in quantifying a value that will not be reliably known until the resource is nearly depleted. Thus, there is considerable uncertainty intrinsic to any estimate. Scientists can generate estimates of conventionally recoverable resources based on current geologic, engineering, and economic knowledge and a consideration of future conditions. The estimates incorporate uncertainty, but they cannot account for the unforeseen or serendipity. As such, resource estimates should be used as general indicators and not predictors of absolute volumes. In spite of this inherent uncertainty, resource assessments are valuable input to developing energy policy and in corporate planning (e.g., ranking exploration opportunities, performing economic analyses, and assessing technology and capital needs).

Hydrocarbon resource assessments have been performed by geologists, statisticians, and economists for decades. To be used effectively, a knowledge of the terminology, commodities, regions assessed, methodology, and statistical reporting conventions is essential. Much of the confusion attending the use of published petroleum resource and reserve estimates is the result of misunderstanding or inappropriately interchanging the data and terminology. An ideal basis for the inevitable comparisons among assessments does not exist.

The petroleum commodities assessed in this study are crude oil, natural gas liquids (condensate), and natural gas that exist in conventional reservoirs and are producible with conventional recovery techniques. The volumetric estimates of oil resources reported represent combined volumes of crude oil and condensate. In developing these estimates, it was necessary to make fundamental assumptions regarding future technology and economics. The inability to predict the magnitude and effect of these factors accurately introduces additional uncertainty to the resource assessment. Although not considered in this report, the continued expansion of the technologic frontiers can be reasonably

assumed to partially mitigate the impacts of a lower quality remaining resource base (i.e., smaller pool sizes, less concentrated accumulations, more remote locations) and less favorable economic conditions.

In this assessment, the Atlantic and Gulf of Mexico Continental Margin was divided into two regions and three provinces (figure 1), which included 72 plays. Due to the inherent uncertainties associated with an assessment of undiscovered resources, probabilistic techniques were employed and the results reported as a range of values corresponding to different probabilities of occurrence. A good resource assessment model must appropriately express the effect of the various geologic, technologic, and economic forces that impact a forecast of quantities of undiscovered conventionally or economically recoverable resources. This resource assessment used a play analysis approach, which represents a major change from the procedures used by MMS for previous assessments (Cooke, 1985; Cooke and Dellagiarino, 1990). A major strength of this method is that it has a strong relationship between information derived from oil and gas exploration activities and the geologic model developed by the assessment team. An extensive effort was involved in defining plays, in delineating the geographic limits of each play, and in compiling data on critical geologic and reservoir engineering parameters (Hunt and Burgess, 1995; Seni *et al.*, 1997; Hentz *et al.*, 1997). These parameters were critical input in the determination of the total quantities of recoverable resources in each play. The basic assumption employed in this assessment was that the distribution of individual pool

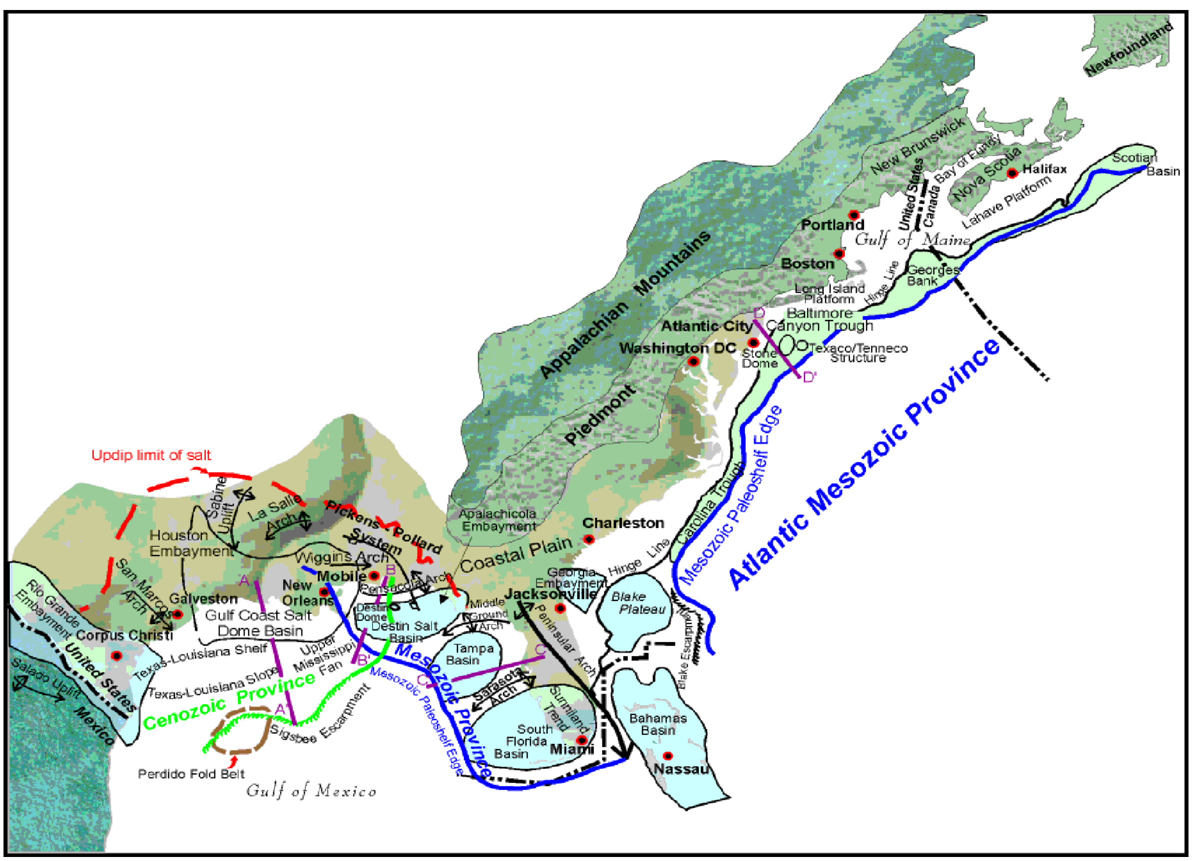


Figure 1. Physiographic Map of the Gulf of Mexico and Atlantic Continental Margin.

sizes for accumulations in a play is characteristically lognormal.

A significant aspect of the method used in this assessment of undiscovered resources involved the “matching” of existing discoveries with the projected pool size distributions of the geologic model. A more subjective variation of this process employing appropriately scaled analogs was used for conceptual and immature plays. This report presents for each play the assessment results, pool rank plots, maps, play descriptions, and a series of additional analyses including discovery histories.

ASSESSMENT RESULTS

The total endowment (all conventionally recoverable hydrocarbon resources) of the Gulf of Mexico and Atlantic OCS as of January 1, 1995, is shown in table 1. The Atlantic and Gulf of Mexico OCS total endowment, which includes cumulative production, isestimated to be between 23.016 and 28.688 Bbo and 280.808 and 320.533 Tcfg (73.811 and 84.626 billion barrels of oil equivalent [BBOE]). This range of estimates corresponds to a 95-percent probability (19 in 20 chance) and a 5-percent probability (1 in 20 chance) of there being more than those amounts, respectively. Please note that fractile values are not additive. The mean estimates are 25.614 Bbo and 299.662 Tcfg (78.935 BBOE). Nearly 15 Bbo and 177 Tcfg (46 BBOE), or approximately 59 percent, of this mean total endowment is represented by cumulative production, remaining proved reserves, unproved reserves, and reserves appreciation. Undiscovered conventionally recoverable resources (UCRR) are believed to be discoverable and producible utilizing existing and reasonably foreseeable technology. The estimates of UCRR for oil range from 8.017 to 13.689 Bbbl; the estimates for gas range from 104.286 to 144.011 Tcf; and the estimates for BOE range from 27.402 to 38.217 Bbbl. The mean estimates of UCRR are 10.615 Bbo and 123.140 Tcfg (32.526 BBOE). On a BOE basis, approximately 91 percent of the mean total endowment and 78 percent of the mean UCRR are projected to be in the Gulf of Mexico Region.

There are beneath the Gulf of Mexico and Atlantic Continental Margin approximately 13.679 to 19.351 Bbbl of remaining conventionally recoverable oil, with a mean of 16.276 Bbbl. This includes remaining reserves (proved and unproved), reserves appreciation, and UCRR. The estimates of remaining conventionally recoverable gas resources range from 168.175 to 207.900 Tcf, with a mean of 187.029 Tcf; and the estimates of remaining conventionally recoverable BOE resources range from 44.432 to 55.247 Bbbl, with a mean of 49.556 Bbbl. Based on BOE, most of these mean resources, 86 percent, are again believed to be in the Gulf of Mexico Region.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	2,114	11.853	141.891	37.101
Cumulative production	--	9.338	112.633	29.379
Remaining proved	--	2.516	29.258	7.722
Unproved	69	0.639	3.603	1.280
Appreciation (P&U)	--	2.507	31.028	8.028
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	8.017	104.286	27.402
Mean	2,475	10.615	123.140	32.526
5th percentile	--	13.689	144.011	38.217
Total Endowment				
95th percentile	--	23.016	280.808	73.811
Mean	4,658	25.614	299.662	78.935
5th percentile	--	28.688	320.533	84.626

Table 1. Total Hydrocarbon Endowment of the Gulf of Mexico and Atlantic Continental Margin.

An economic analysis determined the portion of the UCRR that over the long term are anticipated to be commercially viable under a specific set of economic conditions. The basic economic analysis was performed at the prospect level with regional transportation infrastructure and costs considered at the area level. The economic evaluation was performed as both full- and half-cycle appraisals. Full-cycle analysis is measured from the point in time of a decision to explore. It considers all subsequent leasehold, geophysical, geologic, exploration, and development costs in determining the economic viability of a prospect. In a half-cycle evaluation, leasehold and exploration costs, as well as delineation costs incurred prior to the field development decision, are assumed to be sunk costs and are not considered in the discounted cash flow calculations to determine whether a field is commercially viable.

Estimates of undiscovered economically recoverable resources (UERR) are sensitive to price and technology assumptions and are primarily presented as a functional relationship to price, in the form of price-supply curves. Two specific prices from the distribution were chosen for discussion and are presented as the $18/bbl ($18.00/bbl and $2.11/Mcf) and the $30/bbl ($30.00/bbl and $3.52/Mcf) scenarios. The results of both the full- and half-cycle economic analysis for the Gulf of Mexico and Atlantic Continental Margin and at the regional level are shown in table 2. In the full-cycle, $18/bbl scenario, the estimates of UERR for oil range from 4.364 to 7.094 Bbbl; the estimates for gas range from 57.252 to 70.695 Tcf; and the estimates for BOE range from 14.551 to 19.674 Bbbl. The mean estimates of UERR are 5.350 Bbo and 63.295 Tcfg (16.613 BBOE). Again, most of these resources, 92 percent, are forecast to be in the Gulf of Mexico Region. In the $30/bbl scenario, the estimates of mean UERR increase by approximately 43 percent for oil and 35 percent for gas.

In the half-cycle, $18/bbl scenario, the estimates of UERR for oil range from 4.791 to 7.374 Bbbl; the estimates for gas range from 62.301 to 76.883 Tcf; and the estimates for BOE range from 15.876 to 21.055 Bbbl. The mean estimates of UERR are 5.784 Bbo and 68.462 Tcfg (17.966 BBOE). This represents an increase of 8 percent over the equivalent full-cycle analysis. In the half-cycle, $30/bbl scenario, the mean estimates of UERR increase by approximately 40 percent for oil and 31 percent for gas over the $18/bbl scenario assessment.

Approximately 50 percent of the mean undiscovered conventionally recoverable oil and gas resources are economic in the full-cycle, $18/bbl scenario. The percentages increase to 72 percent of the oil and 70 percent of the gas in the $30/bbl scenario. In the half-cycle analysis, these percentages are approximately 55 for both oil and gas in the $18/bbl scenario and 76 and 73 percent, respectively, for oil and gas in the $30/bbl scenario.

Although useful as a comparative measure of the total quantities of hydrocarbons estimated to exist in the study area, the assessment results do not imply a rate of discovery or a likelihood of discovery and production within a specific time frame. In other words, they cannot be used directly to draw conclusions concerning the rate of conversion of these resources to reserves and ultimately production.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	1.00			
95th percentile		4.364	57.252	14.551
Mean		5.350	63.295	16.613
5th percentile		7.094	70.695	19.674
Half-Cycle	1.00			
95th percentile		4.791	62.301	15.876
Mean		5.784	68.462	17.966
5th percentile		7.374	76.883	21.055
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		6.632	79.526	20.783
Mean		7.672	85.684	22.918
5th percentile		9.367	92.942	25.905
Half-Cycle	1.00			
95th percentile		7.019	83.936	21.954
Mean		8.077	89.895	24.072
5th percentile		9.892	97.023	27.156

Table 2. Undiscovered Economically Recoverable Resources of the Gulf of Mexico and Atlantic Continental Margin.

INTRODUCTION

An essential ingredient in performing the resource management mission responsibilities of the Department of the Interior is a sound knowledge of the mineral resource base. This knowledge provides an understanding of the characteristics and distribution of the resource, establishing a sound basis for decisions related to resource management issues. With this as the primary objective, the MMS and the U.S. Geological Survey (USGS) completed an assessment of the undiscovered conventionally recoverable oil and gas resources of the United States, which reflects data and information available as of January 1, 1995 (USGS, 1995; MMS, 1996). This assessment was the culmination of a multi-year effort that included data and information not available at the time of the previous assessment (Mast *et al*., 1989; Cooke and Dellagiarino, 1990), incorporated advances in petroleum exploration and development technologies, and used new methods of resource assessment. This report presents the results of the 1995 assessment of the conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic OCS. It provides a more detailed presentation of the results previously summarized in Lore *et al.* (1996).

The principal purpose of this report is to present estimates of the total endowment of conventionally recoverable oil and gas that may be present beneath the Gulf of Mexico and Atlantic Continental Margin. Secondary objectives are to describe the geologic and mathematical methodologies employed in the assessment, present an economic analysis of the undiscovered conventionally recoverable resources of the area, and provide a historical perspective in which to review the results. We are also providing sufficient geologic, reservoir engineering, and production data here, in conjunction with a separate series of gas and oil atlases (Seni *et al*., 1997; Hentz *et al*., 1997), to allow others to use their own techniques to perform a resource assessment or evaluate the economic viability of the postulated resources.

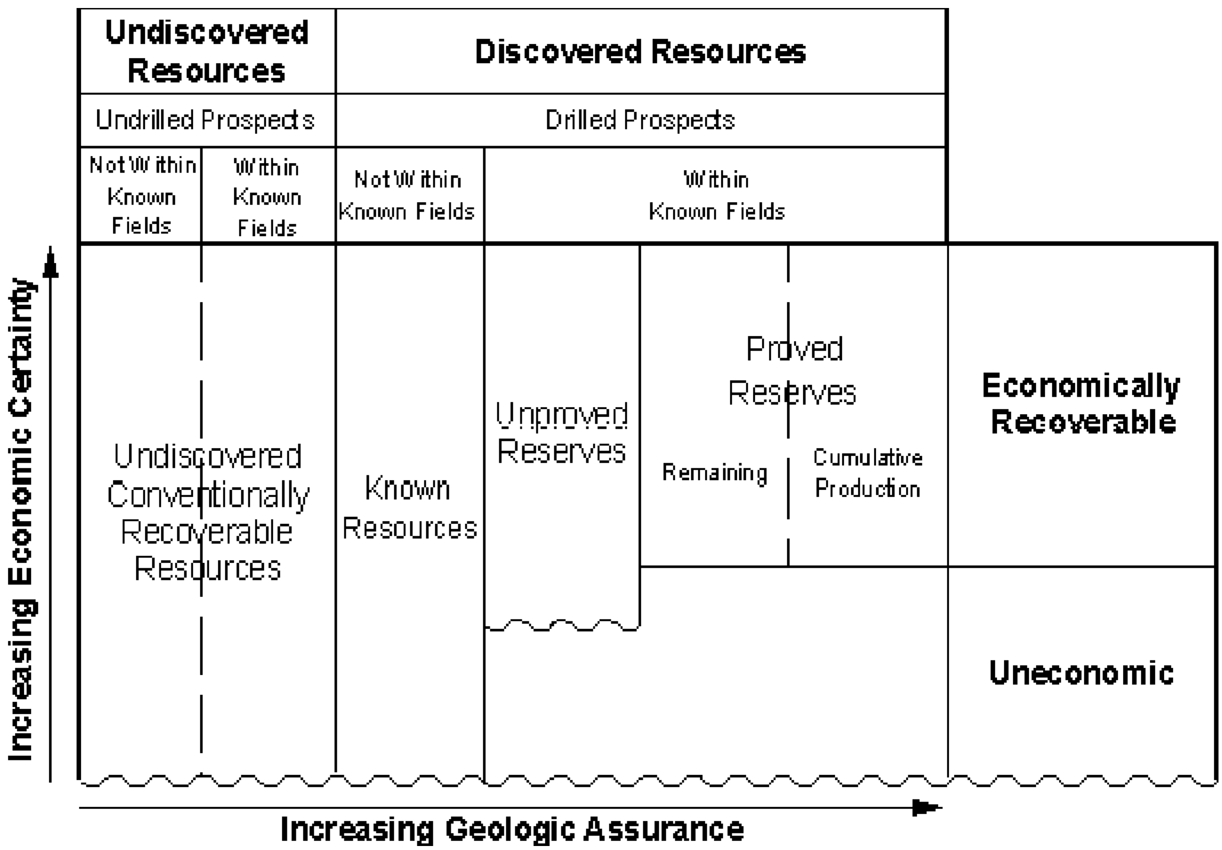
Energy is the lifeblood of the world's economy. In 1994, oil and gas resources were the major contributor to the world energy supply, 38 and 22 percent, respectively (MacKenzie, 1996). Worldwide reliance on petroleum resources as the principal fuel to satisfy future energy demand is likely to continue for decades. However, petroleum resources are usually considered as finite since they do not renew at a rate remotely approaching their consumption. Since these minerals also power the Nation's economy, there is considerable interest in the magnitude of the resource base from which future domestic discoveries and production will occur. Knowledge concerning the potential quantities of remaining conventionally recoverable oil and gas resources is required by governments for strategic planning and formulating domestic land use, energy, and economic policies. Financial institutions and large corporations use resource estimates for long-term planning and decisions concerning investment options. Exploration companies use assessments to design exploration strategies and target expenditures. Petroleum industry trade associations use resource assessments to gauge trends and the relative health of the industry. The Gulf of Mexico OCS, which contributed 13 and 25 percent, respectively, of the United States domestic oil and gas production in 1994, is obviously a critical component of any deliberations concerning future domestic petroleum supplies (Francois, 1995).

Uncertainty is inherent in estimating quantities of hydrocarbon resources prior to actual drilling. Imperfect knowledge is associated with almost every facet of the assessment process. It is vital to recognize that estimates are just that— *estimates*. The estimates presented in this report should be viewed as indicators and not predictors of the petroleum potential of the provinces and regions. It is also important to realize that the undiscovered conventionally recoverable resources estimated may not be found or, in fact, produced. It is, however, implied that these resources have some chance of existing, being discovered, and possibly produced.

Hydrocarbon plays, comprising pools that share common factors influencing the accumulation of hydrocarbons, were the basic building blocks for this assessment. The results were subsequently aggregated to the province and region levels. The assessment methodology incorporated existing data and information available from exploration and development activities, knowledge of particular plays, and assumptions regarding technology and costs. For each play a geologic description, reservoir characteristics, discovery history, reserves, and cumulative production are provided. Additionally, the play's resource potential is portrayed as a pool rank plot, identifying both discovered and undiscovered pools. Undiscovered pools are shown as bars that are indicative of their range of probable sizes. An economic analysis was performed under two scenarios, with and without a consideration of exploration costs, to determine quantities of hydrocarbon resources that may be commercial under given conditions. The results are presented as ranges of values with associated probabilities of occurrence. This report presents play, chronozone, series, system, province, region, planning area, and margin level data and information.

DEFINITION OF RESOURCE TERMS

The terminology associated with resource assessments is involved, but it must be understood so that the results can be correctly interpreted and applied. The lexicon used in this report conforms with past assessments and general industry usage. The MMS scheme of classifying conventionally recoverable hydrocarbons is modified from the McKelvey diagram (U.S. Bureau of Mines and U.S. Geological Survey, 1980) (figure 1). The scheme is dynamic with hydrocarbon resources migrating from one



(U.S. Bureau of Mines and U.S. Geological Survey, 1980)

Figure 1. MMS Classification Scheme for Conventionally Recoverable Hydrocarbon Resources.

category to another over time. Resource availability is expressed in terms of the degree of certainty about the existence of the resource and the feasibility of its economic recovery. As such, resource estimates should be used as general indicators and not predictors of absolute volumes. The overall movement of petroleum resources is to the right as accumulations are discovered and upward as development and production ensue. The degree of uncertainty as to the existence of resources decreases to the right in the diagram. The degree of economic viability decreases downward and also implies a decreasing certainty of technologic recoverability.

Other key terms used in this report are included in the glossary, and the definitions presented both here and in the glossary should be viewed as general explanations rather than strict technical definitions of the terms.

Conventionally recoverable: Producible by natural pressure, pumping, or secondary recovery methods such as gas or water injection.

Marginal probability of hydrocarbons (MPhc): An estimate, expressed as a decimal fraction, of the chance that an oil or natural gas accumulation exists in the area under consideration. The area under consideration is typically a geologic entity, such as a pool, prospect, play, basin, or province; or a large geographic area such as a planning area or region. All estimates presented in this report reflect the probability that an area may be devoid of hydrocarbons or, in the case of estimates of economically recoverable resources, that commercial accumulations may not be present.

Cumulative production: The sum of all produced volumes of hydrocarbons prior to a specified point in time.

Resources: Concentrations in the earth's crust of naturally occurring liquid or gaseous hydrocarbons that can conceivably be discovered and recovered. Normal use encompasses both discovered and undiscovered resources.

Recoverable resources: The volume of hydrocarbons that is potentially recoverable, regardless of the size, accessibility, recovery technique, or economics of the postulated accumulations.

Conventionally recoverable resources: The volume of hydrocarbons that may be produced from a wellbore as a consequence of natural pressure, artificial lift, pressure maintenance (gas or water injection), or other secondary recovery methods. They do not include quantities of hydrocarbon resources that could be recovered by enhanced recovery techniques, gas in geopressured brines, natural gas hydrates (clathrates), or oil and gas that may be present in insufficient quantities or quality (low permeability "tight" reservoirs) to be produced via conventional recovery techniques.

Remaining conventionally recoverable resources: The volume of conventionally recoverable resources that has not yet been produced and includes remaining proved reserves, unproved reserves, reserves appreciation, and undiscovered conventionally recoverable resources.

Economically recoverable resources: The volume of conventionally recoverable resources that is potentially recoverable at a profit after considering the costs of production and the product prices.

Undiscovered resources: Resources postulated, on the basis of geologic knowledge and theory, to exist outside of known fields or accumulations. Included also are resources from undiscovered pools within known fields to the extent that they occur within separate plays.

Undiscovered conventionally recoverable resources (UCRR): Resources in undiscovered accumulations analogous to those in existing fields producible with current recovery technology and efficiency, but without any consideration of economic viability. These accumulations are of sufficient size and quality to be amenable to conventional primary and secondary recovery techniques. Undiscovered conventionally recoverable resources are primarily located outside of known fields.

Undiscovered economically recoverable resources (UERR): The portion of the undiscovered conventionally recoverable resources that is economically recoverable under imposed economic and technologic conditions.

Reserves: The quantities of hydrocarbon resources which are anticipated to be recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty.

Proved reserves: The quantities of hydrocarbons which can be estimated with reasonable certainty to be commercially recoverable from known accumulations and under current economic conditions, operating methods, and government regulations. Current economic conditions include prices and costs prevailing at the time of the estimate. Estimates of proved reserves equal cumulative production plus remaining proved reserves and do not include reserves appreciation.

Remaining proved reserves: The quantities of proved reserves currently estimated to be recoverable. Estimates of remaining proved reserves equal proved reserves minus cumulative production.

Unproved reserves: Reserve estimates based on geologic and engineering information similar to that used in developing estimates of proved reserves, but technical, contractual, economic, or regulatory uncertainty precludes such reserves being classified as proved.

Reserves appreciation: The observed incremental increase through time in the estimates of reserves (proved and unproved [P & U]) of an oil and/or gas field. It is that part of the known resources over and above proved and unproved reserves that will be added to existing fields through extension, revision, improved recovery, and the addition of new reservoirs. Also referred to as reserves growth or field growth.

Total reserves: All hydrocarbon resources within known fields that can be profitably produced using current technology under existing economic conditions. Estimates of total reserves equal cumulative production plus remaining proved reserves plus unproved reserves plus reserves appreciation.

Total endowment: All conventionally recoverable hydrocarbon resources of an area. Estimates of total endowment equal undiscovered conventionally recoverable resources plus cumulative production plus remaining proved reserves plus unproved reserves plus reserves appreciation.

SOURCES OF DATA

The assessment of the total endowment of the Atlantic and Gulf of Mexico OCS required the compilation and analysis of published information and vast amounts of geologic, geophysical, and engineering data obtained by industry and furnished to MMS from operations performed under permits or mineral leases. Since 1954, nearly 8,850 permits to conduct prelease geologic or geophysical exploration have been issued in the study area. In addition, more than 12,050 leases have been awarded to industry for the exploration, development, and production of oil and gas. As a condition of these permits and leases, MMS has acquired approximately 1.2 million line-miles of two-dimensional common depth point (CDP) seismic data and 28,000 square miles of three-dimensional CDP seismic data. Moreover, MMS has accumulated geologic information from over 31,000 wells drilled on the Gulf of Mexico and Atlantic Continental Margin. These activities resulted in the discovery in the Gulf of Mexico of 876 proved fields and 77 active unproved fields containing over 22,000 reservoirs. A single noncommercial field/structure has been encountered on the Atlantic OCS. Additionally, the Canadian and Nova Scotian Governments have released significant seismic and well data acquired from industry exploration activities on the Scotian Shelf. This database, in its entirety, was the primary information source for the play delineation process, as well as the basis for determining key parameters of geologic variables and pool size distributions, for the Atlantic OCS.

Much of the geologic and reservoir information supporting this assessment for the Gulf of Mexico Region has been released and is available on the Internet at http://www.gomr.mms.gov. Additionally, more detailed analyses have been released as part of a series of offshore Gulf of Mexico gas and oil atlases (Seni *et al.*, 1997; Hentz *et al.*, 1997).

COMMODITIES ASSESSED

The petroleum commodities assessed in this study are crude oil, natural gas liquids (condensate), and natural gas that exist in conventional reservoirs and are producible with conventional recovery techniques. Crude oil exists in a liquid state in the subsurface and at the surface; it may be described on the basis of its API gravity as "light" (i.e., approximately 20 to 50° API) or "heavy" (i.e., generally less than 20° API). Condensate is a very high-gravity (i.e., generally greater than 50° API) liquid; it may exist in a dissolved gaseous state in the subsurface but liquefy at the surface. Crude oil with a gravity greater than 10° API and condensate can be removed from the subsurface with conventional extraction techniques and have been assessed for this project. Natural gas is a gaseous hydrocarbon resource, which may consist of associated and/or nonassociated gas; the terms natural gas and gas are used interchangeably in this report. Associated gas exists in spatial association with crude oil; it may exist in the subsurface as undissolved gas within a gas cap or as gas that is dissolved in crude oil (solution gas). Nonassociated gas (dry gas) does not exist in association with crude oil. Gas resources that can be removed from the subsurface with conventional extraction techniques have been assessed for this project. Crude oil and condensate are reported jointly as oil; associated and nonassociated gas are reported as gas. Oil volumes are reported as stock tank barrels and gas as standard cubic feet. Oil-equivalent gas is a volume of gas (associated and/or nonassociated) expressed in terms of its energy equivalence to oil (i.e., 5,620 cubic feet of gas per barrel of oil) and is reported in barrels. The combined volume of oil and oil-equivalent gas resources is referred to as combined oil-equivalent resources or BOE (barrels of oil equivalent) and is reported in barrels (Dunkel and Piper, 1997).

This report encompasses only a portion of all the oil and gas resources believed to exist on the Gulf of Mexico and Atlantic Continental Margin. This assessment does not include potentially large quantities of hydrocarbon resources that could be recovered from known and future fields by enhanced recovery techniques, gas in geopressured brines, natural gas hydrates (clathrates), or oil and gas that may be present in insufficient quantities or quality (low permeability "tight" reservoirs) to be produced via conventional recovery techniques. In some instances the boundary between these resources is rather indistinct; however, we have not included in this assessment any significant volume of unconventional resources. These unconventional resources have yet to be produced from the OCS; however, with improved extraction technologies and economic conditions, they may become important future sources of domestic oil and gas production.

Estimates of the quantities of historical production, reserves, and future reserves appreciation are presented to provide a frame of reference for analyzing the estimates of undiscovered conventionally recoverable resources. Furthermore, reserves appreciation and undiscovered conventionally recoverable resources comprise the resource base from which the near to midterm future oil and gas supplies will emerge.

ROLE OF TECHNOLOGY AND ECONOMICS IN RESOURCE ASSESSMENT

This study assesses only conventionally recoverable hydrocarbon resources. In developing these estimates it is necessary to make fundamental assumptions regarding future technology and economics. The inability to predict accurately the magnitude and effect of these factors introduces additional uncertainty to the resource assessment. There is a technologic and economic limit to the amount of in-place oil and gas resources that can be physically recovered from a reservoir. Within conventional reservoirs in the study area, approximately 30 to 40 percent of the in-place oil and 65 to 80 percent of the in-place gas resources are typically recovered. Additional technologic and economic constraints are applicable to the circumstances under which exploration and development activities can occur (e.g., ultra-deepwater). Continued expansion of the technologic frontiers can be reasonably assumed to partially mitigate the impacts of a lower quality resource base and less favorable economic conditions.

Scientists can estimate the quantity of conventionally recoverable resources (both discovered and undiscovered) on the basis of the present state of geologic and engineering knowledge, modified by a subjective consideration of future technologic advancement. However, the quantity of resources that may ever actually be produced is dependent in large part upon economics. Actual cost/price relationships are critical determinants. New capital intensive exploration and development technologies require higher product prices for implementation. Typically, as these high-cost technologies are more widely employed, costs decrease, resulting in even more widespread use of these techniques. On the other hand, new modest-cost exploitation technologies that increase recoveries or decrease finding, development, or operating costs can markedly increase estimates of conventionally recoverable resources without requiring an increase in product prices. A decrease in price as experienced in the late 1980's can be moderated or offset by the implementation of a technology that reduces unit costs or vice versa. Generally, the effects of price and technology can be considered interchangeable within the context of a resource assessment.

Another important aspect of the role of technology in a resource assessment is the ability through the deployment of new technology to rethink fundamental approaches to developing exploration play concepts. Basic geologic knowledge concerning the origin, migration, and entrapment of petroleum resources has remained relatively unchanged for the past several decades. However, scientific advances aided by new technologies have affected our ability to identify hydrocarbon plays and, thus, the assessment of the conventionally and economically recoverable resources in discovered and undiscovered accumulations and plays. A prime example of this is the imaging of subsalt accumulations in the Gulf of Mexico. The recent, increased availability or access to massively parallel computers has made depth migration of three-dimensional seismic data practical in terms of computer time and costs. Subsequent subsalt discoveries have demonstrated that drilling is practical and the costs can be controlled as experience is gained and techniques developed. This type of technologic advance is not explicitly considered in this resource assessment.

The National Research Council (1991) in its examination of the previous national resource assessment summarized the complex problems intrinsic to the conventional-unconventional and recoverable-unrecoverable boundaries and resource assessments. Both of these boundaries are in flux due to changing economic viability over time and are dependent upon a complex set of economic and technologic variables. Significant changes in the cost/price relationship or fundamental changes in technologic capabilities can shift these boundaries, causing modifications in perceptions and the practical meaning of the definitions. Thus, uncertainties in economic and technologic conditions contribute to the substantial uncertainties in the resource assessment.

A perceptive Lewis Weeks (1958), in considering this issue, wrote four decades ago:

> "While research adds to our proved reserves by developing new ways to find and produce oil, it is a field of activity whose advances are impossible to predict. This is because they depend to a large degree on such important, intangible human resources as initiative and ingenuity."
>
> "... man's mind is his most valuable asset— a 'natural resource' of unlimited potential— and the key to an abundant supply of fuel in the future."

METHODOLOGY INTRODUCTION

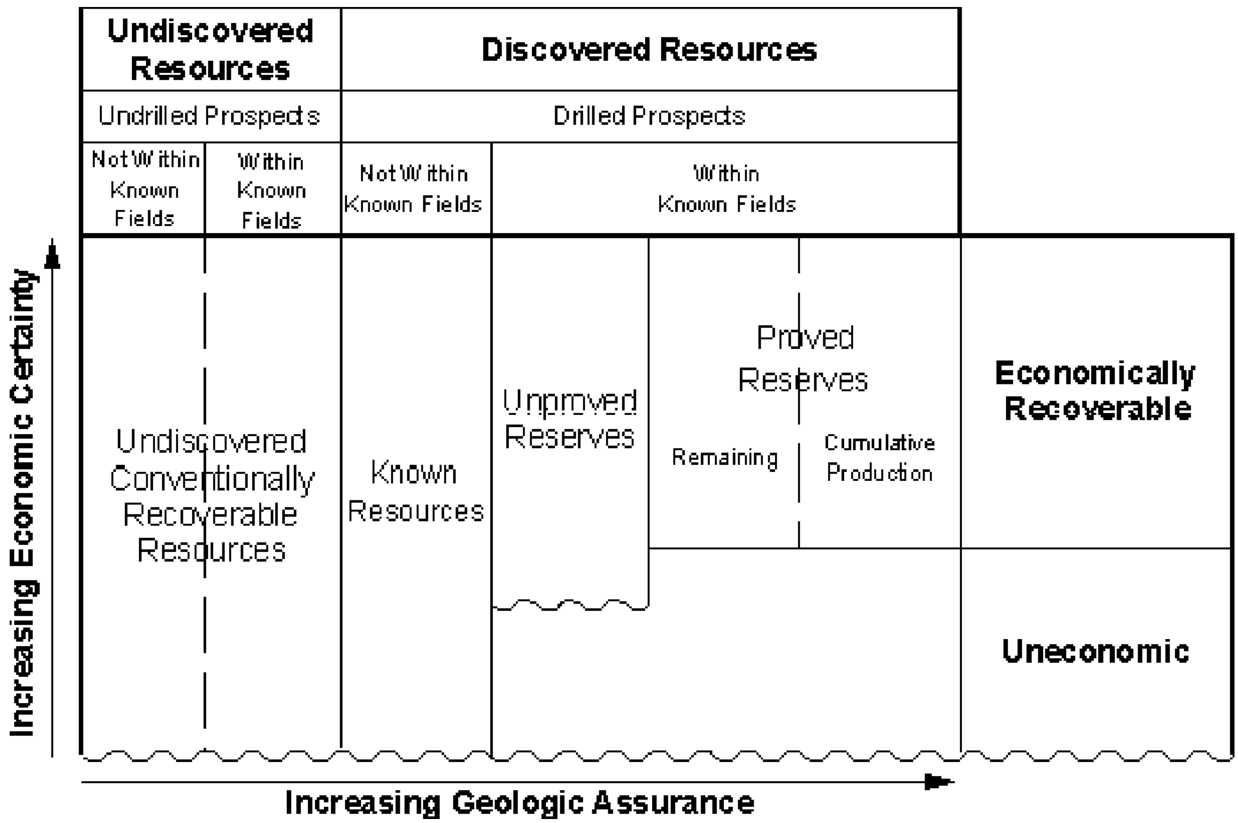
Previous MMS assessments presented estimates of undiscovered conventionally recoverable oil and gas resources as cumulative distributions of the quantities of resources expected in a particular area. Knowledge of both the total amount of undiscovered conventionally recoverable oil and gas resources and the number and size distribution of potential individual accumulations is an important factor that must be considered in formulating a corporate exploration strategy or national policy. The methodology used in this assessment also provides this information in the form of pool rank plots for each play.

Estimates of undiscovered economically recoverable oil and gas resources were also previously presented only as cumulative distributions at discrete sets of economic conditions. In this assessment, these estimates are also presented as price-supply curves that show incrementally the costs associated with transforming a volume of undiscovered conventionally recoverable resources to economically recoverable resources.

Among MMS's objectives for this assessment was the use of an appraisal method allowing the input of a wide variety and wealth of data, while at the same time providing sufficient flexibility for use in areas with a scarcity of data. It also sought to employ a geologic framework that would facilitate periodic updating as an adjunct to ongoing activities. A play assessment framework was judged to be the best approach to meeting these objectives. Thus, the basic building block of this assessment of undiscovered conventionally recoverable resources is the hydrocarbon play (White and Gehman, 1979; White 1980, 1993).

RESERVES

The MMS scheme of classifying conventionally recoverable hydrocarbons is modified from the McKelvey diagram (U.S. Bureau of Mines and U.S. Geological Survey, 1980) (figure 1). With increasing economic certainty, resources progress from uneconomic



(U.S. Bureau of Mines and U.S. Geological Survey, 1980)

Figure 1. MMS Classification Scheme for Conventionally Recoverable Hydrocarbon Resources.

to marginally economic. With increasing geologic assurance, hydrocarbon accumulations advance from resources to unproved reserves. Reserves can be classified as proved when sufficient economic and geologic knowledge exists to confirm the likely commercial production of a specific volume of hydrocarbons. Proved reserves must, at the time of the estimate, either have facilities that are operational to process and transport those reserves to market, or a commitment or reasonable expectation to install such facilities in the future (Society of Petroleum Engineers, 1987).

Reserves are frequently estimated at different stages in the exploration and development of a hydrocarbon accumulation (i.e., after exploration and delineation drilling, during development drilling, after some production and, finally, after production has been well established). Different methods of estimating the volume of reserves are appropriate at each stage. Reserve estimating procedures generally progress from volumetric to performance-based techniques as the field matures. The relative uncertainty associated with these estimates decreases as more subsurface information and production history become available.

Volumetric estimates are based on subsurface geologic information from wells, geophysical data, and limited production and test data. An estimate of the volume of hydrocarbon-bearing rock is determined and an estimate of the recovery factor applied to calculate reserves (Arps, 1956; Wharton, 1948).

Performance-based methods are primarily variations of production decline curve analyses. Generally, they involve plotting production rate versus time or cumulative production and projecting the trend to the economic limit of the accumulation. These empirical extrapolations assume that whatever factors have caused the historical trend in the curve will continue to uniformly govern the trend in the future (Arps, 1945).

Cumulative production is a measured quantity that can be accurately determined. Estimates of proved reserves are uncertain; however, traditional industry practice has been to calculate reserves through a deterministic process and present the results as single point estimates. The uncertainty associated with these estimates is less than with comparable estimates of volumes of unproved reserves and considerably less than estimates of undiscovered resources.

RESERVES APPRECIATION GENERAL DISCUSSION

Reserves appreciation or reserves growth is the observed incremental increase through time in the estimates of proved reserves of an oil and/or gas field. The objective of the reserves appreciation effort was to estimate the quantity of reserves from known fields that, because of the reserves appreciation phenomenon, will ultimately contribute to the future oil and gas supply. The reserves growth phenomenon is the result of numerous factors that occur as a field is developed and produced. These factors include

- standard industry practices for reporting proved reserves,
- an increased understanding of the petroleum reservoir,
- physical expansion of the field, and
- improved recoveries due to experience with actual field performance, the implementation of new technology, and/or changes in the cost-price relationships.

Growth functions can be used to calculate an estimate of a field's size at a future date. In this assessment, growth factors were calculated from the MMS database of 876 OCS fields with proved reserves at the end of 1994. Annual growth factors (AGF's) were calculated by dividing the estimate of proved reserves for all fields of the same age by the estimate of proved reserves for the same fields in the previous year. The same fields are included in both the numerator and denominator. The set of fields used to calculate AGF's is likely to differ from one year to the next as some fields are depleted and abandoned and others are discovered. Growth factors can also be expressed as cumulative growth factors (CGF's), which represent the ratio of the size of a field several years after discovery to the initial estimate of its size in the year of discovery. The assumptions central to this approach are

- the amount of growth in any year is proportional to the size of the field,
- this proportionality varies inversely with the age of the field,
- the age of the field is a reasonable proxy for the degree to which the factors causing appreciation have operated, and
- the factors causing future appreciation will result in patterns and magnitudes of growth similar to that observed in the past.

The estimate of total reserves appreciation in known fields to a particular point in time, the year 2020 in this assessment, was developed by applying regression analyses to the observed field-level AGF's to develop a function relating the AGF's to the age of the field. The modeled CGF's were then calculated from the model AGF's. It should be noted that the growth factors previously reported (Lore *et al*., 1996) were not the ones actually used in this assessment, but were the results of an intermediate evaluation. Figure 1 shows the actual observed and modeled growth factors. Over time, the AGF's asymptotically approach a value of 1.0, coinciding with no growth, and the CGF values asymptotically approach a limit of about 3.8, also representing no additional

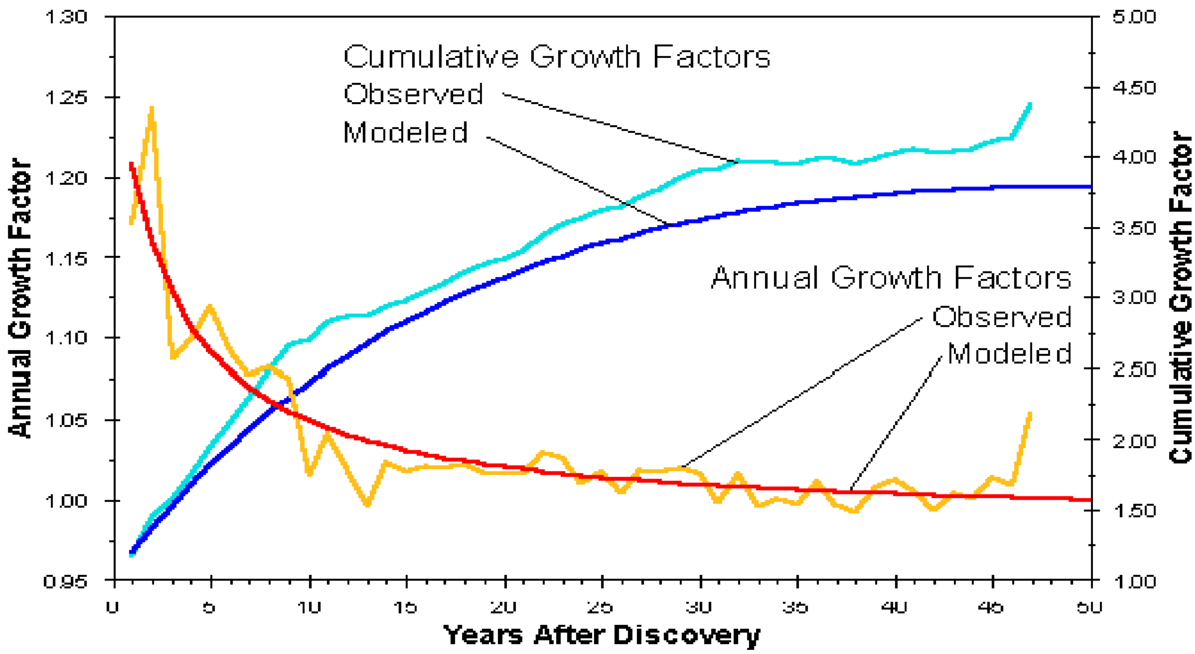


Figure 1. Observed and Modeled Annual and Cumulative Growth Factors.

appreciation with time. These limiting bounds of the curves are a function of the volume of the original in-place resource.

The oldest fields in the database were 47 years old. The appreciation model used in this assessment projects no growth for fields 50+ years of age. This is a reasonable conclusion since it fits well with the observed data and does not entail extending projections considerably beyond the time frame of the observations. Because the age and estimate of reserves for 924 fields (876 proved and 48 unproved) as of January 1, 1995, were known, the growth model was applied to this set of fields to develop an aggregate estimate of appreciation through the year 2020.

RESERVES APPRECIATION DETAILED DISCUSSION

Estimates of the quantity of proved reserves in a field typically increase as the field is developed and produced. Reserves appreciation or reserves growth was first reported by Arrington (1960). Subsequent analyses of field reserves growth have shown consistently that it results in significant additions to estimates of proved reserves and helps to maintain reserves to production ratios. Root and Attanasi (1993) estimated that from 1978 to 1990 the growth of known fields in the United States accounted for 90 percent of the annual additions to domestic reserves. The National Petroleum Council (NPC) (1992) estimated that field growth accounts for about two-thirds of the annual additions to domestic proved reserves. Similarly, MMS data for Gulf of Mexico OCS fields reveal that, since 1981, increases to proved reserves through appreciation have greatly exceeded new field discoveries and comprise about two-thirds of the total increase. These figures clearly illustrate why reserves appreciation should be a very important consideration in determining possible future domestic oil and gas supplies. Historically, most reserve and resource estimates have failed to account for this phenomenon.

Characteristically, the relative magnitude of this growth is proportionally larger the younger the field. This appreciation phenomenon is complex and incompletely understood. It is, however, a consequence of a multitude of factors, which include

- areal extension of existing reservoirs (extensions),
- discovery of new reservoirs (additions),
- increases in reserve estimates in existing reservoirs as production experience is gained (revisions),
- improved recovery technologies (revisions),
- increases in prices and/or reductions in costs, which reflect the influences of market economics and technology (revisions),
- field expansion via mergers with newer fields (extensions),
- systematic assessment bias toward conservativism, which typically exists in initial estimates of field sizes (revisions), and
- reporting practices with respect to proved reserves.

Thus, the prediction of ultimate recovery is highly uncertain, since it depends upon a highly simplified model of the geologic, technologic, economic, and dynamic properties of a complex field. See Hatcher and Tussing (1997) for an excellent overview of this issue.

The objectives of the reserves appreciation effort in this resource assessment were twofold: (1) to estimate the quantity of reserves from known fields that, owing to the reserves appreciation phenomenon, will contribute to the Nation’s future oil and gas supply; and (2) to explicitly incorporate field growth in the measure of past performance, which forms the basis for projecting future discoveries within defined plays. The latter objective represents the first effort in a large-scale assessment to incorporate the reserves appreciation phenomenon explicitly as an integral component in developing the forecast of the number and sizes of future discoveries. Previous resource assessments addressed field growth only within the context of the first objective.

GROWTH FUNCTIONS

Growth functions can be used to calculate an estimate of a field's size at a future date. In modeling reserves growth, the age of the field is typically used as a surrogate for the degree of field development, primarily because it is easy to determine and simple to use. Other assessments have incorporated drilling activity as a variable in the appreciation model (NPC, 1992). The degree of development represents the opportunity for the previously listed causal agents to impact the estimates of field reserves. Techniques for modeling reserves appreciation have been almost universally applied to large areas, such as countries, states, provinces, and basins, using highly aggregated data.

Growth functions reflect technology and market and economic conditions existing over the period spanned by the estimates. A consistent observation throughout the history of the petroleum industry has been the emergence of one major technologic advancement after another. More recently, the petroleum industry has been characterized by a high volatility in product prices. It is, therefore, important that the period encompassed by the reserve estimates data series reflects the cyclic nature of technologic innovations as well as market conditions. Obviously the effect on reserves appreciation of a recent technologic application will not be incorporated in the data series. However, it is implicitly assumed that the impact of new applied technologies will be similar to those introduced during the time span encompassed by the data series.

The MMS has been systematically developing estimates of reserves for fields on the Gulf of Mexico OCS since 1975. The historical database available for this analysis consisted of field-level data for 876 proved fields and 48 unproved fields with reserves discovered between 1947 and 1995. Due to the scarcity of data and the inherent uncertainty of the estimates of reserves for the unproved fields, the analysts decided to use only the estimates of reserves for the 876 proved fields in the determination of reserves appreciation. The estimates are available only from 1975 onward and are incomplete for years prior to 1988. Thus, the growth for all fields across all years cannot be examined. For example, data do not exist to calculate a growth function for 5-year old fields in 1960 or 1970 (Drew and Lore, 1992). This data set, as do similar ones for the entire United States (American Petroleum Institute [API], American Gas Association [AGA], Canadian Petroleum Association [CPA] (1967-1980), and Energy Information Administration [EIA] (1990)), presents modeling challenges since the estimates are available for only a relatively short period of time and do not encompass all fields throughout their entire lives.

Root and Attanasi (1993) recently reviewed the history and basic approaches traditionally employed to model the reserves appreciation phenomenon. The approach employed in this study was to calculate annual growth factors (AGF's) as first implemented by Arrington (1960). This technique utilizes the age of the field, as measured in years after discovery, as the variable to represent the degree of field maturity. The AGF's were calculated from the MMS database of 876 OCS fields with proved reserves. The procedure involves developing AGF's from equation 1 (Root and Attanasi, 1993):

$$\mathrm{AGF} = \sum_{d} c(d,e+1) / \sum_{d} c(d,e) \qquad (1)$$

where c(d,e) is the estimate of the quantity of reserves discovered in fields of age d, as estimated in year e or (e+1).

The same fields are included in both the numerator and denominator. The set of fields used to calculate AGF's is likely to differ from one year to the next as some fields are depleted and abandoned and others are discovered. The assumptions central to this approach are that the amount of growth in any year is proportional to the size of the field and that this proportionality varies inversely with the age of the field.

Growth factors can also be expressed from equation 2 as cumulative growth factors (CGF’s), which represent the ratio of the size of a field t years after discovery to the initial estimate of its size in the year of discovery.

$$CGF = c(d,e+t)/c(d,e) \qquad (2)$$

where c(d,e) is as described above and t is the time in years between the early estimate year, e, and the late estimate year, e+t. The assumptions central to this approach are

- the amount of growth in any year is proportional to the size of the field,
- this proportionality varies inversely with the age of the field,
- the age of the field is a reasonable proxy for the degree to which the factors causing appreciation have operated, and
- the factors causing future appreciation will result in patterns and magnitudes of growth similar to that observed in the past.

Since growth factors are calculated from revisions to estimates of proved reserves, the individual growth factors are specific to the particular data set used. Assessors that are more aggressive in their revisions of the initial estimate will calculate different AGF’s than more cautious assessors, although given the same initial estimate of reserves, both should arrive at the same final CGF (Megill, 1993).

The working hypothesis for this effort was that OCS fields in the Gulf of Mexico characteristically grow at a lower rate and possibly for a shorter duration than onshore fields; therefore, growth functions specific to the OCS were required. Previous work by Drew and Lore (1992) with the MMS data series supports this premise. The CGF’s calculated using the MMS data were in the range of 4.5 for OCS fields, while studies using the API, AGA, and CPA (1967 to 1980) and EIA (1990) data series developed CGF’s that were in general considerably higher, in the range of 4.0 to 9.3 (NPC, 1992; Root and Mast, 1993). The NPC (1992), using the EIA oil and gas integrated field file (OGIFF) data series, noted that the initial determination of proved reserves and estimates of field size were typically reported later for offshore fields than for onshore fields. The overall lower growth rates observed for OCS fields are interpreted to reflect better initial estimates than for typical onshore fields. The better initial estimates are probably the result of a combination of factors, including

- the incorporation of high-quality marine seismic data in the initial estimate, providing a better measure of the ultimate lateral extent of reservoirs,
- the drilling of additional exploration and/or delineation wells offshore and the integration of these data with seismic data prior to field development

decisions,

- the additional years elapsed after field discovery prior to the initial estimate of proved reserves, and
- the obligation of the assessor to not intentionally and significantly underestimate reserves. This is inherent in requirements to reflect reserves potential more accurately at the time development decisions are made because of the increased capital requirements and more rigorous design criteria for offshore versus onshore infrastructure.

TOTAL RESERVES APPRECIATION

The technique to resolving the first objective of the reserves appreciation effort, estimating the total reserves appreciation in known fields to a particular point in time, was relatively straightforward. Regression analyses were applied to the observed field-level AGF's to develop a function relating the AGF's to the age of the field. It should be noted that the growth equations and factors previously reported (Lore *et al*., 1996) were not the ones actually used in this assessment, but were the results of an intermediate evaluation. Equation 3 is the model used as the basis for the projection.

$$AGF = 0.98595+0.728314/(y+2.5) \qquad (3)$$

where y is the age of the field in years. The correlation coefficient for this model was 0.8775, indicating a high degree of correspondence between the observed results and the outcomes predicted by the model. The actual observed and modeled growth factors are presented in both tabular (table 1) and graphical (figure 1) format. Note that with time, the AGF's asymptotically approach a value of 1.0, coinciding with no growth, and the CGF values asymptotically approach a limit of about 3.8, also representing no additional appreciation with time. These limiting bounds of the curves are a function of the volume of the original in-place resource. Since the age and estimate of reserves for 924 fields (876 proved and 48 unproved) as of January 1, 1995, were known, the growth model was applied to this set of fields to develop an aggregate estimate of appreciation through the year 2020.

The oldest fields in the database were 47 years old and the appreciation model (equation 3) implies no growth for fields 50+ years of age. This is a reasonable conclusion since it fits well with the observed data and does not entail extending projections considerably beyond the time frame of the observations. This assumption is conservative when compared to the 60 to 138 years' duration of reserves growth assumed by other assessments (Hubbert, 1974; Root, 1981; EIA, 1990; NPC, 1992; Root and Mast, 1993). These assessments, however, addressed the United States as a whole and not specifically the OCS with its unique development considerations and higher economic thresholds. For example, through 1994, 133 OCS fields had already been depleted and abandoned. Proved reserves in these fields totaled 28.2 MMbo and 3.0 Tcfg (558.9 MMBOE), with a mean field size of 4.2 MMBOE. Field life for these depleted fields ranged from 2 to 40 years with a mean of 11.5 years. While these depleted fields represent 15 percent of the total number of proved fields discovered through 1994, they account for only 1.5 percent

Years After Discovery	Annual Growth Factor		Cumulative Growth Factor	
	Observed	Modeled	Observed	Modeled
1	1.17132	1.20831	1.17132	1.19404
2	1.24264	1.16069	1.45552	1.37052
3	1.08683	1.12977	1.58191	1.53274
4	1.09934	1.10808	1.73905	1.68295
5	1.11969	1.09203	1.94720	1.82273
6	1.09219	1.07967	2.12670	1.95330
7	1.07791	1.06985	2.29240	2.07561
8	1.08188	1.06187	2.48010	2.19042
9	1.07531	1.05526	2.66687	2.29837
10	1.01532	1.04968	2.70772	2.39999
11	1.04166	1.04492	2.82051	2.49575
12	1.01905	1.04081	2.87425	2.58604
13	0.99612	1.03722	2.86311	2.67122
14	1.02384	1.03406	2.93135	2.75160
15	1.01805	1.03126	2.98427	2.82745
16	1.02075	1.02876	3.04629	2.89904
17	1.02007	1.02651	3.10733	2.96658
18	1.02288	1.02448	3.17844	3.03030
19	1.01684	1.02263	3.23196	3.09037
20	1.01626	1.02095	3.28450	3.14699
21	1.01624	1.01941	3.33782	3.20030
22	1.03012	1.01800	3.43837	3.25048
23	1.02582	1.01669	3.52714	3.29764
24	1.01036	1.01549	3.56369	3.34194
25	1.01779	1.01437	3.62709	3.38350
26	1.00490	1.01333	3.64485	3.42242
27	1.01845	1.01235	3.71210	3.45883
28	1.01712	1.01145	3.77563	3.49283
29	1.02001	1.01059	3.85117	3.52452
30	1.01625	1.00980	3.91374	3.55398
31	0.99899	1.00904	3.90979	3.58131
32	1.01614	1.00834	3.97288	3.60660
33	0.99601	1.00767	3.95703	3.62992
34	1.00036	1.00704	3.95845	3.65135
35	0.99768	1.00644	3.94929	3.67096
36	1.01222	1.00587	3.99753	3.68883
37	0.99739	1.00533	3.98710	3.70502
38	0.99220	1.00482	3.95599	3.71959
39	1.00765	1.00433	3.98627	3.73261
40	1.01244	1.00386	4.03585	3.74413
41	1.00607	1.00342	4.06034	3.75421
42	0.99366	1.00300	4.03459	3.76291
43	1.00423	1.00259	4.05164	3.77027
44	1.00048	1.00220	4.05357	3.77635
45	1.01379	1.00183	4.10948	3.78120
46	1.00896	1.00147	4.14631	3.78485
47	1.05342	1.00113	4.36782	3.78736
48		1.00080		3.78877
49		1.00049		3.78912
50		1.00018		3.78845

Table 1. Observed and Modeled Annual and Cumulative Growth Factors.

of the total estimated proved reserves. The distribution of abandoned fields by U.S. Geological Survey (USGS) size class and the mean life for each class are presented in graphical format (figure 2). Only 14 fields were in class 9 or larger (>8 MMBOE). The largest depleted field produced 56.8 MMBOE. The next four largest fields ranged in size between 28.3 and 34.4 MMBOE. While the number of depleted fields on the OCS is significant, their sizes are such that they are not a material consideration in this analysis of reserves appreciation.

Another concern with the reserves appreciation effort was the recent speculation (Ahlbrandt and Taylor, 1993) that fields discovered in the 1980's experience less annual appreciation early in their lives and for a shorter duration than their predecessors. They postulated that this was the product of smaller fields being discovered, coupled with the new seismic techniques that better define reserves earlier in the life of a field. While this may prove to be true onshore, the MMS data for OCS fields discovered after 1980 do not support this conclusion for the OCS. The data show the mean field size continuing to decrease from 26.8 MMBOE in 1980 to 3.2 MMBOE in 1989 (Lore, 1992), but the magnitude and rate of appreciation (table 2) are considerably greater than that observed for the database comprising all OCS fields. On average, fields discovered since 1980 double in size within two years after discovery and grow to four times their initial estimate within 12 years of discovery.

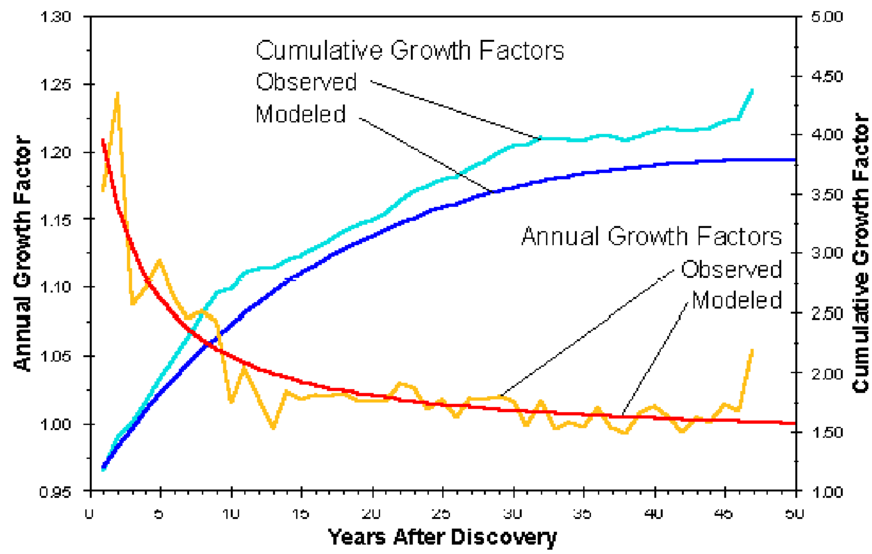


Figure 1. Observed and Modeled Annual and Cumulative Growth Factors.

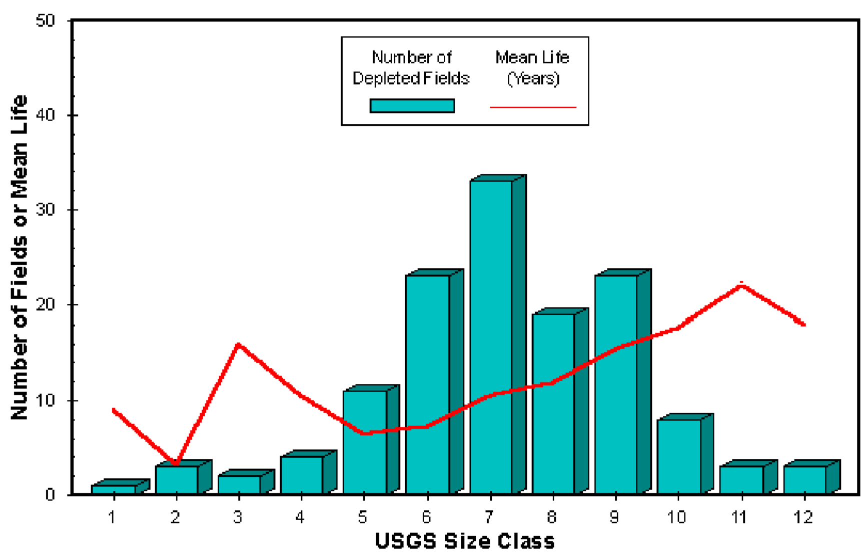


Figure 2. Abandoned Fields by USGS Size Class.

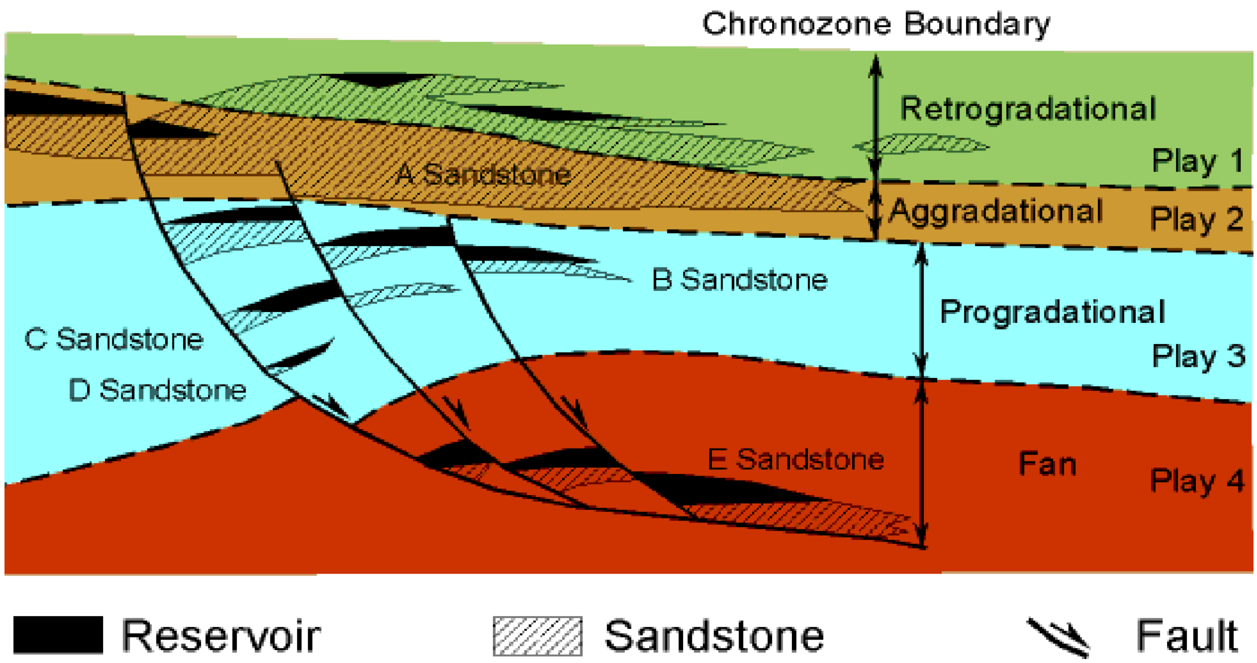
The MMS historical series of field-level estimates of proved reserves is included as a database file (94resgrw.dbf).

POOL SIZE DISTRIBUTIONS

The second objective of the reserves appreciation effort was to consider field growth in the measure of past performance. Incorporating reserves growth in developing pool size distributions addresses a systemic bias inherent in previous assessments, which assumed, often implicitly, that the ultimate size of existing discoveries was known at the time of the assessment. Historical data related to the number and size of accumulations in conjunction with the current geologic knowledge concerning the play are fit to the statistical model that allows extrapolation of past achievements into the future. Accurately measuring past performance is crucial to an assessment process that extrapolates past accomplishments or relies on analogies with other areas to predict future performance. Reliably determining the estimated ultimate reserves of the discovered fields, the largest field in particular, is central to the assessment process used by MMS. Thus, it is imperative that the reserves appreciation phenomenon be considered as an integral part of the assessment process. This was accomplished in this study by appreciating the discovered pools prior to matching them to a characteristically lognormal distribution of individual pool sizes for accumulations in a play (Lee and Wang, 1986).

Years After Discovery	Number of Fields	Observed Growth Factors	
		Annual	Cumulative
1	46	1.710062	1.710062
2	132	1.208422	2.066477
3	224	1.083970	2.239999
4	239	1.062253	2.379445
5	233	1.156642	2.752166
6	233	1.055735	2.905558
7	196	0.979681	2.846520
8	171	1.002880	2.854718
9	155	1.168975	3.337094
10	133	1.134668	3.786494
11	64	1.015646	3.845737
12	45	1.048979	4.034098
13	19	1.023745	4.129888

Table 2. Observed Growth Factors for Fields Discovered Since 1980.



(Modified from Seni *et al*., 1997)

Figure 3. Stacked Pools.

Efforts to quantify appreciation were complicated by the play approach utilized in this resource assessment. Ideally, reserves growth factors would be calculated from play data sets and then applied directly to play-level size distributions to derive ultimate recoveries, which included reserves appreciation to a given point in the future. The complication arises because the play consists of grouped reservoirs (termed pools or accumulations in this effort) within individual fields that produce from the same chronozone and depositional sequence and not entire fields. In other words, an accumulation or pool represents that portion of the field's ultimate recovery that is attributable to a particular play. These pools are in turn vertically stacked within fields (figure 3).

Conceptually, the NPC (1992) strategy was initially appealing because it tied reserves appreciation to both time and the level of development activity as reflected in the cumulative number of well completions. In practice, however, the NPC applied the same growth function to all regions of the United States. Furthermore, the use of this approach would require a projection of future levels of drilling activity for the Gulf of Mexico OCS that would be complex and inherently uncertain. A rigorous application of this technique to the problem at hand, estimating the growth of pools associated with specific plays, would require that projected drilling activity be apportioned to the appropriate plays and that play specific growth functions be developed. The allocation of both historical and projected drilling activity to an individual play in an area typified by vertically stacked plays would be a highly speculative endeavor; thus, this particular approach to the problem was not pursued.

Number of Pools	Number of Fields	Number of Fields with Multiple Play Types	Number of Fields with a Single Play Type					
			Total	Pro	Agg	Ret	Fan	Other
1	274	27	247	151	24	7	51	14
2	256	117	139	102	2	0	28	7
3	155	93	62	52	0	0	10	0
4	87	77	10	9	0	0	1	0
5	53	47	6	4	1	0	1	0
6	24	24	0	0	0	0	0	0
7	15	15	0	0	0	0	0	0
8	6	6	0	0	0	0	0	0
9	5	5	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0
11	1	1	0	0	0	0	0	0
Total	**876**	**412**	**464**	**318**	**27**	**7**	**91**	**21**

Table 3. Distribution of Fields by Number of Pools and Play Type Family.

The strategy used to resolve the dilemma regarding the use of pool-level plays in this assessment initially centered on the hypothesis that the different play families—retrogradational, aggradational, progradational, and fans— developed for the assessment of the Cenozoic Province of the Gulf of Mexico have disparate geologic characteristics and experience distinct patterns of growth which, in turn, differ from that experienced by the complete database of fields. The historical database used to evaluate reserves appreciation consisted of field-level estimates of reserves for 876 proved fields. The first two columns of table 3 show the distribution of the number of fields versus the number of pools for these proved fields. The database of historical estimates of proved reserves was initially examined to determine the number of fields consisting of pools, all of which belonged to the same play family, the premise being that these fields could be a proxy for pools in the actual plays assessed. Fields consisting of a single play family comprised 464 out of the 876 fields. A closer examination of the available reserve estimates for each play family revealed that there were inadequate observations, in terms of either the number of fields or the years after discovery, to perform a meaningful analysis on the basis of fields consisting of pools of the same play family. This was true even if multiple-pool fields were considered. For example, the most robust play family in terms of both numbers of fields and years with observations is the progradational play family. The span of available estimates incorporating more than a single field covers 38 years, with a maximum number of observations of 194 for 6-year-old fields. This is contrasted with the retrogradational play family, which has a span of observed estimates of only 10 years, peaking with six values for 4-year-old fields. In all cases, AGF's in the out-years (latter years) become highly variable because they are dependent upon individual changes in the estimates of only a very few fields. Therefore, it was concluded that reasonably complete historical data do not exist for fields producing solely from a single play family to apply directly to pools to compute meaningful measures of reserves appreciation.

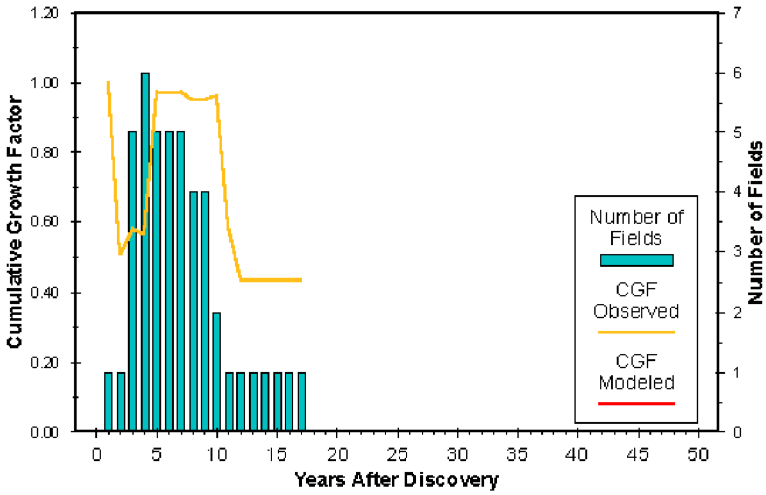


Figure 4. Retrogradational Play Family Cumulative Growth Factors (CGF).

Nevertheless, regressions were run on the appreciation data for each set of fields consisting of a single play family and for all fields. The actual observed and modeled CGF's and the number of observations are presented graphically for each play family. As expected, the curves for each type of play differ dramatically, exhibiting dissimilar rates of growth and total amounts of appreciation. Fields consisting purely of retrogradational pools are rare, and the observed data are highly variable; thus, it was not possible to model the data reasonably (figure 4). Fields consisting solely of aggradational pools, while few, seem to be better behaved, doubling in size after six years, but experiencing only modest appreciation thereafter (figure 5). Fields producing solely from fans initially grow at a slightly slower rate, but appreciate steadily throughout their lives. The fan CGF's exceed 4.8 at the end of 20 years and are projected to exceed 7.8 at the end of 50 years (figure 6). Progradational pools are intermediate, doubling in size within three years, but are anticipated to ultimately appreciate to only 4.2 times the initial estimate after 40 years

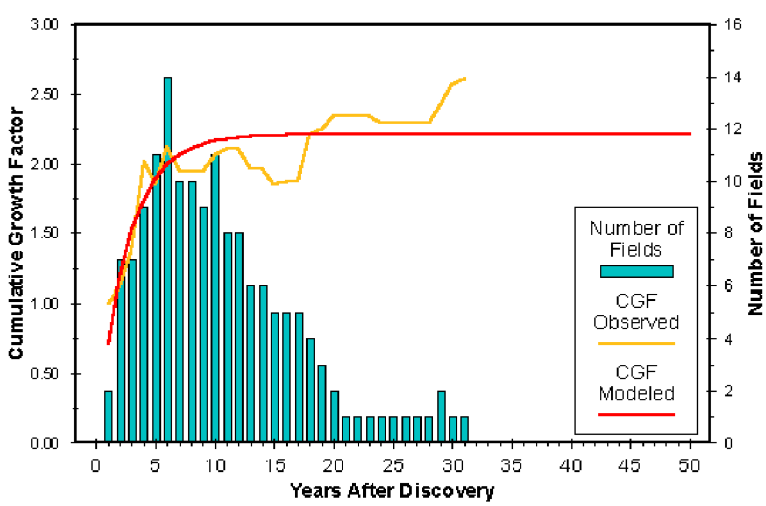


Figure 5. Aggradational Play Family Cumulative Growth Factors (CGF).

(figure 7). The relatively short duration of observations for each play family and the variability in the out- year AGF's for the few observations make these projections highly uncertain.

On the other hand, the entire population of OCS fields represented a very robust database. Because of the aforementioned modeling hurdles, the appreciation model, developed from the entire set of OCS fields (figure 1) and equations 1 and 3, was applied to the pool size distribution for each individual play, resulting in an intermediate projection of ultimate appreciation. The ultimate CGF was 3.8 after 50 years. This result is not surprising since progradational pools comprise 69 percent and fans nearly 20 percent of the proved reserves.

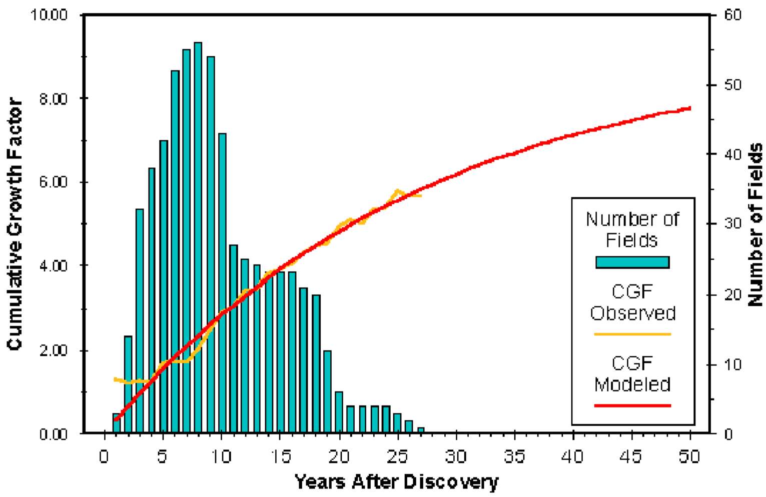


Figure 6. Fan Play Family Cumulative Growth Factors (CGF).

The effects of incorporating reserves appreciation into the assessment process are rather subtle. In mature plays with reasonably complete pool size distributions, the commonly older, large accumulations are not projected to experience significant growth as expressed as a percentage of the current estimate of field size. Consistent with the concept of resource exhaustion, smaller accumulations, which are generally younger, experience proportionately more appreciation and grow to fill "gaps" in the pool size distribution, leaving behind gaps in their old, smaller size position in the distribution. This occurs with all pools throughout the distribution. Conversely, in immature plays, the overall empirical distribution is not well developed. The largest pools will be projected to experience significant appreciation, creating gaps in the projected pool size distribution, which will then accommodate significant-sized pools. The effect of explicitly considering reserves appreciation is that an assessment for an active, mature play that acknowledges reserves growth will tend to result in a smaller estimate of the quantity of resources remaining to be discovered than one that does not incorporate the reserves appreciation phenomenon. Alternatively, a resource assessment for moderately

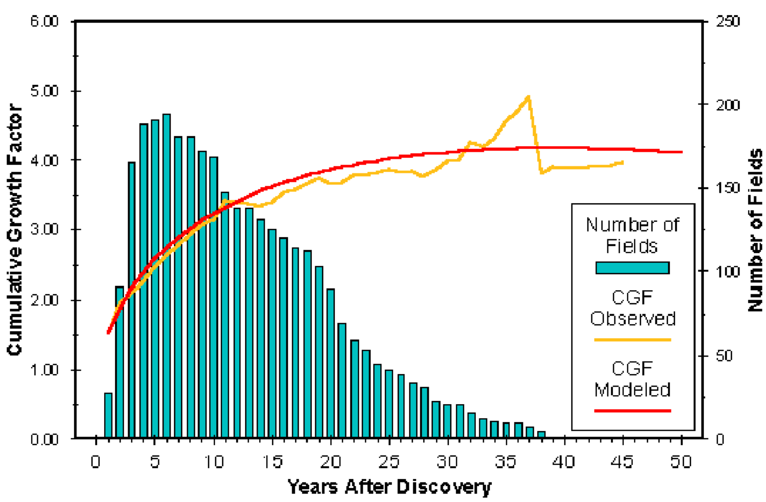


Figure 7. Progradationall Play Family Cumulative Growth Factors (CGF).

mature to immature plays will project larger quantities of undiscovered resources when appreciation is considered.

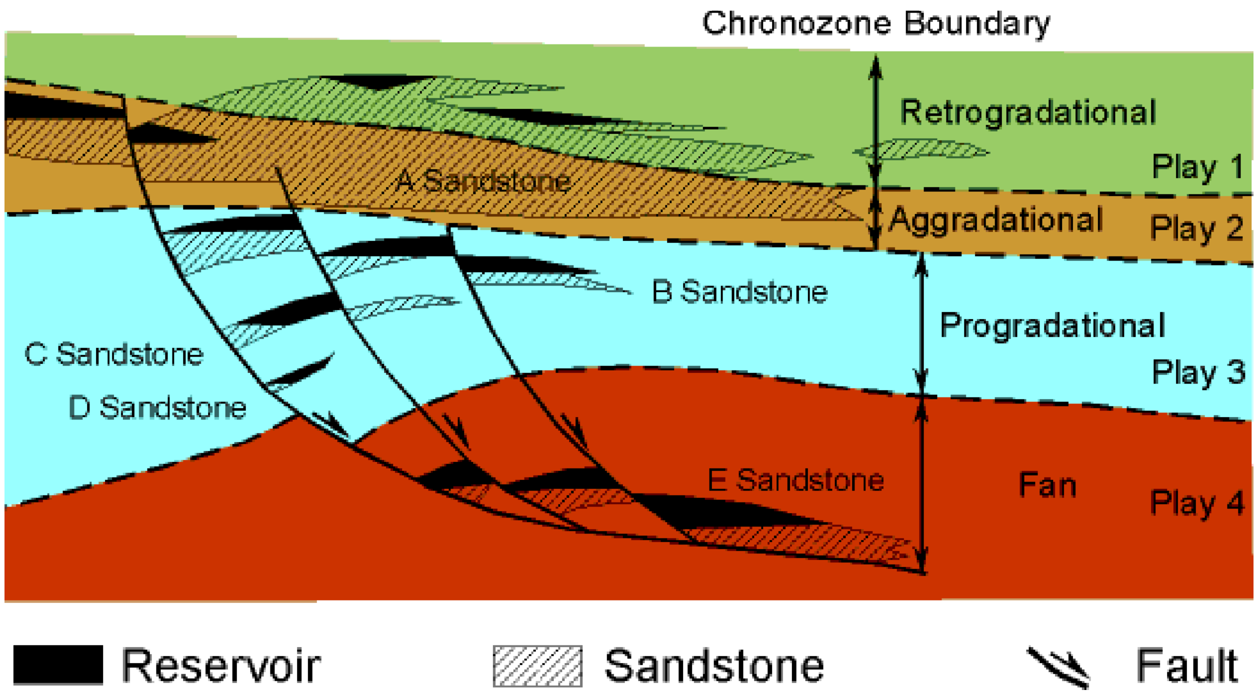
PLAY DELINEATION PROCEDURES GENERAL DISCUSSION

A play is defined primarily on the basis of the geologic parameters that are responsible for a petroleum accumulation. The significance of the play analysis approach to resource assessment is that it explicitly links the observed outcomes of oil and gas exploration and development activities to the assessment. The impacts of economics and technologic advances can be clearly observed at the play and basin level. At higher levels, such as national or regional aggregations, these effects are often masked (Grace, 1991). A properly defined play can be considered as a single population for statistical analysis resulting in play analysis techniques that can be incorporated into probabilistic models to yield a number of possible future outcomes from exploration and development in the area under consideration. The strengths of play analysis are that it deals with natural exploration units— plays, prospects, pools, and fields— and with specified pool or field size distributions. This process also provides for the systematic documentation, integration, and analysis of the play's geologic model and exploration history, and an assessment of the size and number of undiscovered hydrocarbon accumulations. The assessment results, in terms of pool rank plots, can be readily used for economic analyses and discovery forecasting.

To explain the distribution and composition of the hydrocarbon resources, all existing offshore hydrocarbon reservoirs with proved reserves in the northern Gulf of Mexico Basin were organized into plays and subplays that are characterized by geologic and engineering attributes, such as age, depositional style or facies, and structural style. The endeavor resulted in the two-volume *Atlas of Northern Gulf of Mexico Gas and Oil Reservoirs* (Seni *et al.*, 1997; Hentz *et al.*, 1997) from which much of the discussion concerning the play delineation process is taken. The objectives were to (1) organize all offshore gas and oil sandstone-body reservoirs into plays on the basis of geologic and engineering parameters; (2) illustrate and describe each play and typical reservoirs within each play; and (3) provide descriptive and quantitative summaries of play characteristics, cumulative production, reserves, and various other engineering and geologic data. Most offshore fields produce hydrocarbons from multiple reservoirs representing one or more plays, depositional styles, and structural settings. This is demonstrated in the accompanying figure (figure 1), which shows the schematic cross section of a typical field, showing 12 fault-block reservoirs, 7 sandstone-body reservoirs, 4 pools, 4 plays, and 4 depositional styles/facies.

A play is defined as a group of reservoirs genetically related by depositional origin, structural style or trap type, and nature of source rocks or seals (White and Gehman, 1979; White, 1980). Once divided into plays, all reservoirs within a particular play will have production characteristics that are more closely related than those of reservoirs in other plays, and better known reservoirs can have their attributes extrapolated to lesser known reservoirs (Galloway *et al.*, 1983).

The play concept was the basic framework for organizing MMS's extensive geologic and reservoir engineering files, including all well logs, paleontological reports, seismic data, and oil and gas production data. We identified chronostratigraphic units and the primary geologic and engineering attributes that influence the distribution and makeup of plays.



(Modified from Seni *et al*., 1997)

Figure 1. Schematic Cross Section of Typical Field (showing 12 fault-block reservoirs, 7 sandstone-body reservoirs, 4 pools, 4 plays, and 4 depositional/facies styles.

Initially all reservoirs were organized by geologic age and producing chronostratigraphic unit (chronozone). The Cenozoic sediments were grouped into 16 chronozones for this assessment (figure 2). Then each reservoir was characterized by interpreting depositional style (figure 3 and figure 4), structural style, lithology, trapping mechanism, and other features. Within the Cenozoic Province of the Gulf of Mexico, the principal emphasis was on determining depositional styles (figure 1) because they strongly influence the distribution of reservoir-quality sandstones.

Since a single field mayproduce hydrocarbos from several reservoirs that vary in geologic age, depositional environment, lithology, and many other attributes used to characterize a play, it may be represented in more than one play. Because most existing offshore fields are associated with growth-fault systems and salt domes, they are structurally complex (as a result of postdepositional modification). As a result, an originally continuous sandstone body may eventually be segmented into separate reservoir compartments by displacement along faults. In order to manage the large volume of exploration and production data, individual sands were aggregated into reservoir pools (herein referred to as pools), which are aggregations of all reservoirs within a field that occur in the same play. Click the *Schematic* button to view a generalized cross section of a typical field that illustrates this organizational framework.

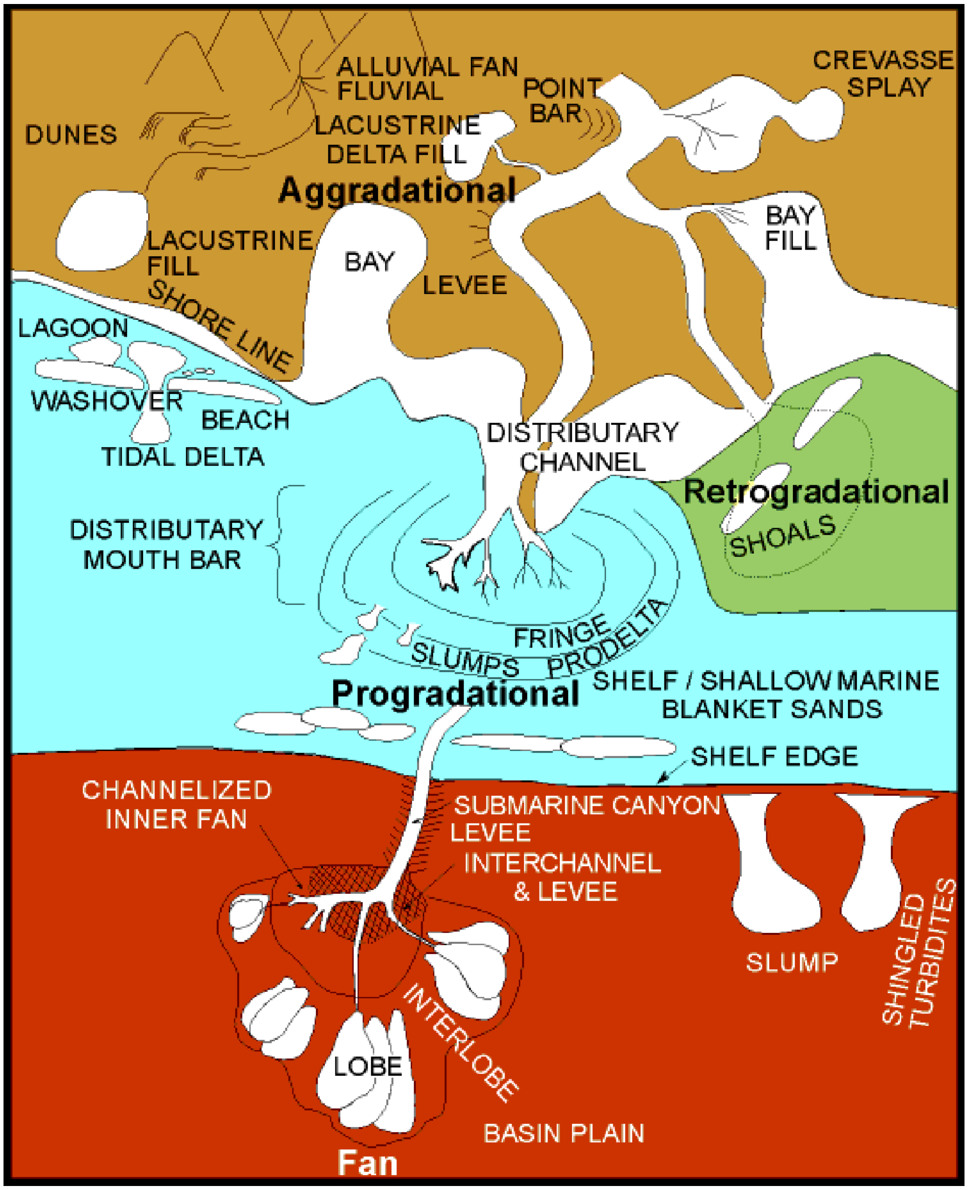
By comparison with the Cenozoic Province, within the Mesozoic Provinces of the eastern Gulf of Mexico and Atlantic Continental Margin, similar data are not as readily available to identify the depositional styles of plays as precisely. In the eastern Gulf of

Geologic Time (M.Y.)	Province	System	Series	National Assessment Chronozone	Chronozone	Biozone: Gulf of Mexico	Biozone: Atlantic
~0.01	Cenozoic	Quaternary	Pleistocene	UPL	UPL-4 UPL-3 UPL-2 UPL-1	*Sangamon fauna* *Trimosina* "A" *1st* *Trimosina* "A" *2 nd* *Hyalinea* "B" / *Trimosina* "B"	
				MPL	MPL-2 MPL-1	*Angulogerina "B"* 1 st *Angulogerina "B"* 2 nd	
				LPL	LPL-2 LPL-1	*Lenticulina* 1 *Valvulineria* "H"	
~2.8		Tertiary	Pliocene	UP	UP	*Buliminella* 1	
				LP	LP	*Textularia* "X"	
~5.5			Miocene	UM3	UM-3 UM-2	*Robulus* "E" / *Bigenerina* "A" *Cristellaria* "K"	
				UM1	UM-1	*Discorbis* 12	
~10.5				MM9	MM-9 MM-8	*Bigenerina* 2 *Textularia* "W"	
				MM7	MM-7 MM-6 MM-5	*Bigenerina humblei* *Cristellaria* "I" *Cibicides opima*	
				MM4	MM-4 MM-3 MM-2 MM-1	*Amphistegina* "B" *Robulus* 43 *Cristellaria* 54 / *Eponides* 14 *Gyroidina* "K"	
~18.5				LM4	LM-4 LM-3	*Discorbis* "B" *Marginulina* "A"	
				LM2	LM-2	*Siphonina davisi*	
				LM1	LM-1	*Lenticulina hanseni*	
~24.8			Oligocene	O		*Marginulina texana*	
~38.0			Eocene	E			
~55.0			Paleocene	L			
~63.0	Mesozoic	Cretaceous	Upper	UK		*Rotalipora cushmani*	
~97.5			Lower	LK		*Lenticulina washitaensis* *Fossocytheridea lenoirensis* *Cythereis fredericksburgensis* *Dictyoconus walnutensis* *Eocytheropteron trinitiensis* *Orbitolina texana* *Choffatella decipiens* *Schuleridea lacustris*	*Favusella washitaensis* *Muderongia simplex* *Choffatella decipiens* *Polycostella senaria*
~138.0		Jurassic	Upper	UU		*Pseudocyclammina jaccardi*	*Ctenidodinium penneum* *Epistomina uhligi* *Senoniasphaera jurassica* *Pseudocyclammina jaccardi*
~163.0			Middle	MU			*Gonyaulacysta pectinigera* *Gonyaulacysta pachyderma*
~183.0			Lower	LU			
~205.0		Triassic	Upper	UTR			

(Modified from Melancon, et al., 1995)

Figure 2. National Assessment Chronostratigraphic Chart.

Mexico, only about 110 wells penetrating the Mesozoic section (as of this study's cutoff date of January 1, 1995) have been drilled. Commercially recoverable hydrocarbons have been discovered and resulted in the development of nine fields of upper Jurassic age and two fields of lower Cretaceous age. On the Atlantic Continental Margin, only 51 wells have been drilled, resulting in several subeconomic hydrocarbon flows from upper Jurassic and lower Cretaceous clastic reservoirs.

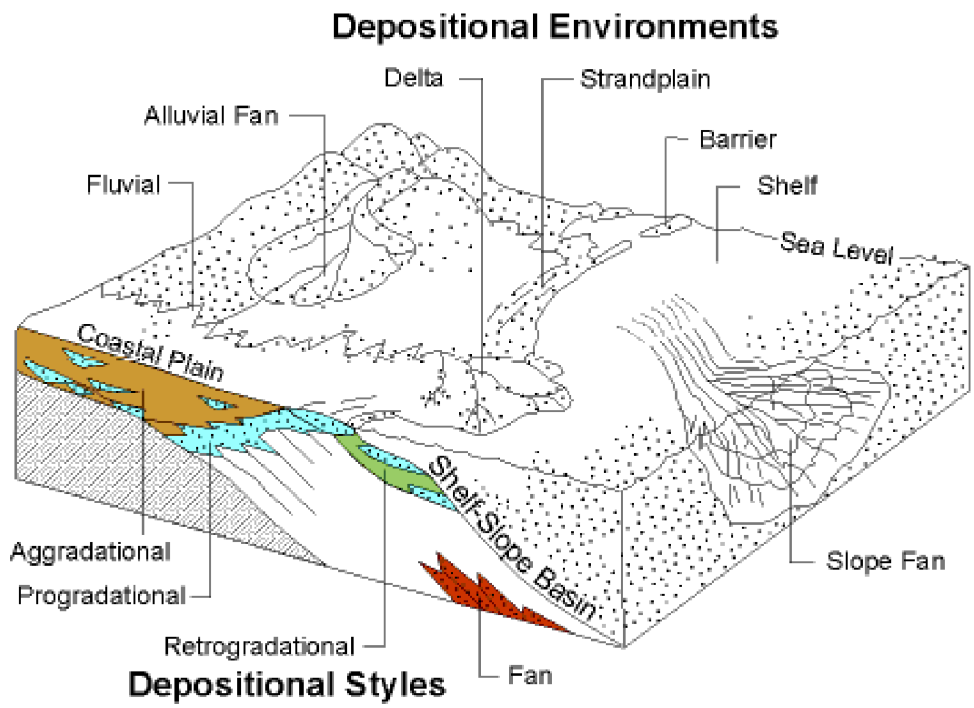


(Modified from Seni *et al.*, 1997)

Figure 3. Model for Deltaic Deposition.

A key problem in assessing such areas with little available data is the selection of an appropriate analog(s). A suitable analog is an established play that possesses similar depositional environments, structural features, and geologic ages as the play being assessed. To identify analogs for the Mesozoic Provinces, we evaluated all available geologic and/or geophysical data and performed an extensive search of the literature. Identifying adequate analogs for the Gulf of Mexico Mesozoic Province was not difficult, since there has been an extensive record of exploration onshore along the United States Gulf Coast within the Mesozoic section, and several OCS Mesozoic plays are offshore extensions of the onshore United States Gulf Coast plays. Even though identifying adequate analogs for the Atlantic Mesozoic Province was more problematic, two analog areas were identified as possible models for assessing the clastic plays: the onshore United States Gulf Coast and the Scotian Shelf offshore Canada. The carbonate plays in the Atlantic were modeled using onshore United States Gulf Coast carbonate plays as analogs.

Because less data exist and analogs were necessary for the evaluation, the play descriptions for the Mesozoic Provinces are less precise than those of the CenozoicProvince. The Mesozoic sediments were grouped into six chronozones for this assessment (figure 2). In contrast to the Cenozoic chronozones, the Mesozoic chronozones are at the series level, and the depositional style is described as either clastic or carbonate (e.g., Lower Cretaceous Clastic [LK CL] or Atlantic Middle Jurassic Carbonate [AMU CB] play). The carbonate deposits include strata of Jurassic and Cretaceous shelf-edge reef systems and associated back-and fore-reef environments. These carbonate facies were identified from well log and seismic analysis, conventional and sidewall cores, and cuttings.



(Modified from Seni *et al*., 1997)

Figure 4. Block Diagram of Siliciclastic Depositional Environments that Host Hydrocarbons (GOM).

PLAY DELINEATION PROCEDURES DETAILED DISCUSSION

A play is defined as a group of reservoirs genetically related by depositional origin, structural style or trap type, and nature of source rocks or seals (White and Gehman, 1979; White, 1980). A play forms a natural geologic population and is limited areally and stratigraphically. Once divided into plays, all reservoirs within a particular play will have production characteristics that are more closely related than those of reservoirs in other plays (Galloway *et al.*, 1983). A play is, for assessment purposes, represented as a single statistical model.

The play concept was the basic framework for organizing MMS's extensive geologic and reservoir engineering files, including all well logs, paleontological reports, seismic data, and oil and gas production data from 1,096 OCS fields (876 proved, 77 unproved, and 143 expired with no production) containing over 22,000 reservoirs. A principle objective in the play delineation portion of this effort was to keep the number of plays to a manageable number and yet produce a level of detail and analyses that provided meaningful, practical information. Brekke and Kalheim (1996) discuss the "splitter versus lumper" dilemma faced by assessors. The decision as to whether the differences in geologic attributes among pools and prospects are important enough that they must be split among two or more plays, or could be ignored, is not straightforward. It has been recognized that at the early stages of exploration in a frontier area, additional data typically lead to splitting plays since, in the absence of information, large-scale relatively simple regional models must be developed. These simple models will become more complex as data become available. It is, however, impossible to know beforehand how the model will change with additional information. Thus, in frontier areas, "splitters" were forced to develop "lump" models that could be adequately defined.

The opposite situation occurs in extensively explored mature areas, such as the shelfal portions of the central and western Gulf of Mexico. Here the huge volume of detailed data and information could lead to endless "splitting" and defining of new plays. The pressure applied to the assessment teams was to focus on major differences in the attributes of hydrocarbon accumulations so as to minimize the number of plays to be analyzed.

CENOZOIC PROVINCE

Much of the discussion concerning the play delineation process in the Cenozoic Province is taken from Seni *et al.* (1997). Play delineation identifies the major geologic processes and their temporal and spatial response within a basin as the key in determining their uniqueness. This was decided on the basis of first order depositional processes. The plays possess different trapping styles but originate from first order processes. The MMS followed the generalized play delineation procedure outlined in Seni *et al.* (1994; 1995) and Lore and Batchelder (1995):

- Construct type logs identifying all reservoirs in each field.
- Identify chronozones and depositional styles and facies on each type log.
- Correlate depositional styles and facies, reservoirs, and chronozones on strike and dip geologic and seismic cross sections.

- Construct reserves limit maps by grouping reservoirs producing from the same depositional style or facies within a chronozone.
- Determine hydrocarbon and play limits for each play in each chronozone.
- Tabulate geologic, reservoir engineering, and production data for each play.

CHRONOZONES

Traditionally, benthonic foraminifera biostratigraphic zones have been used with electric logs to subdivide the highly repetitive and structurally complex Cenozoic sandstone and shale sections present in the Gulf of Mexico Basin. The MMS previously integrated these paleontological markers and electric log patterns with seismic data to establish a chronostratigraphic synthesis or temporal framework consisting of 26 Cenozoic chronozones in the OCS portion of the basin (Reed *et al.*, 1987) (this biostratigraphic chart is too large to be presented in text format, but is available for viewing in the interactive report, and also as a free poster from the MMS GOM OCS Region [call 1-800-200-GULF]). Continuing with this method, we further grouped Cenozoic strata into 16 chronozones for this assessment (figure 1). Major flooding surfaces were important reference horizons for this grouping. The correlation framework of the assessment was based on these grouped chronozones.

The Mississippi River and other ancient river systems to the west transported siliciclastic sand and mud to the Texas and Louisiana Gulf Coast throughout the Cenozoic Era; the depocenters of these rivers generally shifted from west to east and prograded north to south through time (McGookey, 1975; Winker, 1982) (figure 2). Deposition of these gulfward prograding depocenters was interrupted repeatedly by transgressions that reflected increases in relative sea level and resulted in the deposition of marine shales. Regional marine-shale wedges reflect these widespread periods of submergence of the continental platform. Chronozone boundaries of many Gulf Coast depositional sequences are typically defined by the maximum flooding surface of these marine-shale wedges (Morton *et al.*, 1988). Progradation after these flooding events resulted in deposition of progressively more sandstone-rich sediments of the next-youngest depocenter.

DEPOSITIONAL STYLES

Three depositional styles (retrogradational, aggradational, and progradational) and one depositonal facies (fan) were utilized to define the large-scale patterns of basin fill in the northern Gulf of Mexico and provide a framework for classifying and predicting reservoir trends, distribution, and quality (figure 3). The retrogradational style, characterized by thick shale sections and thin sandstone beds, represents major or widespread transgressive events. The lower part of the retrogradational section commonly contains thin sandstone units that are products of reworking of the top of the underlying shallow-water sandstones. Within the retrogradational package are thinner packages of sandstone that typically comprise upward-coarsening progradational parasequences. When stacked, the thin progradational parasequences form a back-stepping

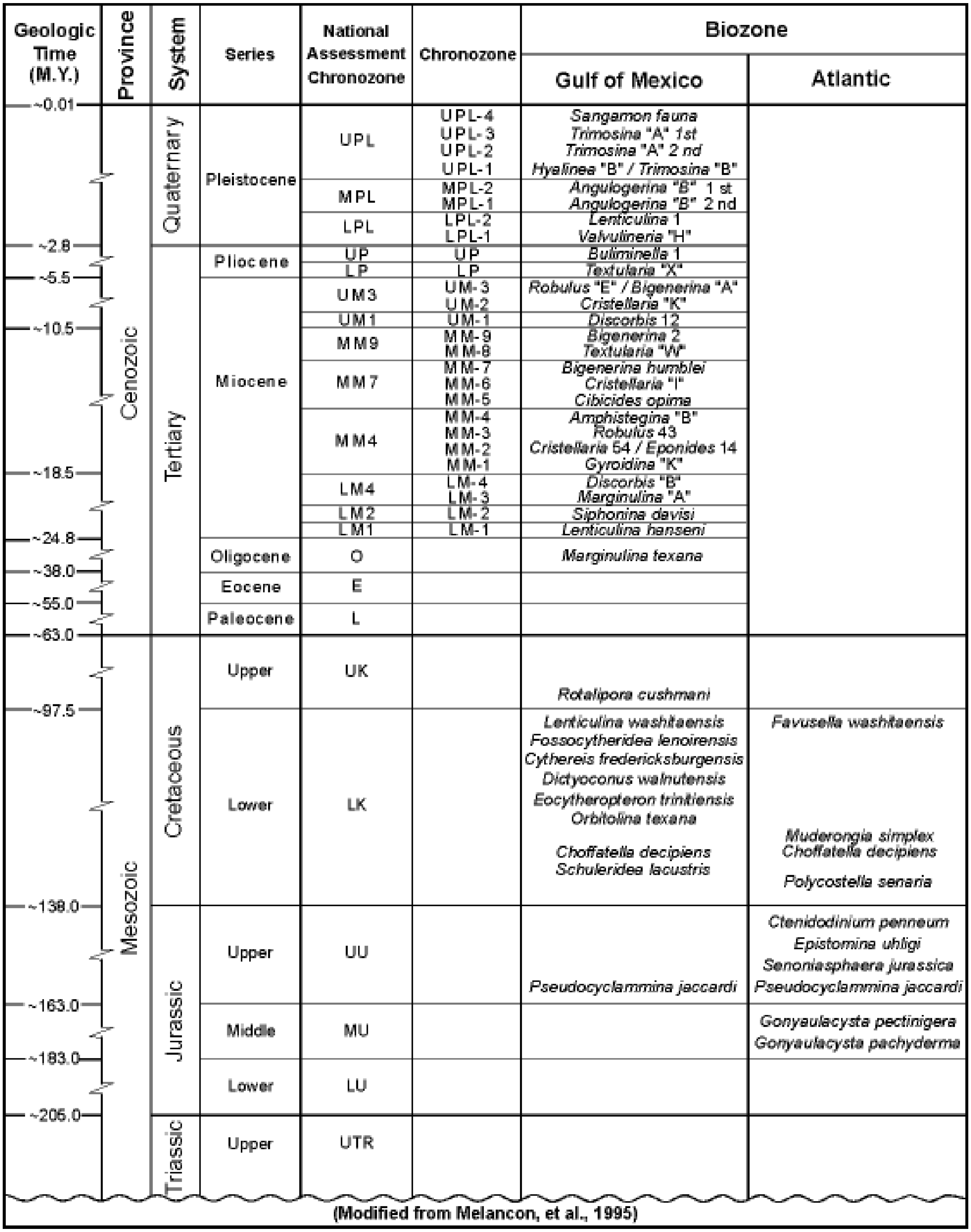
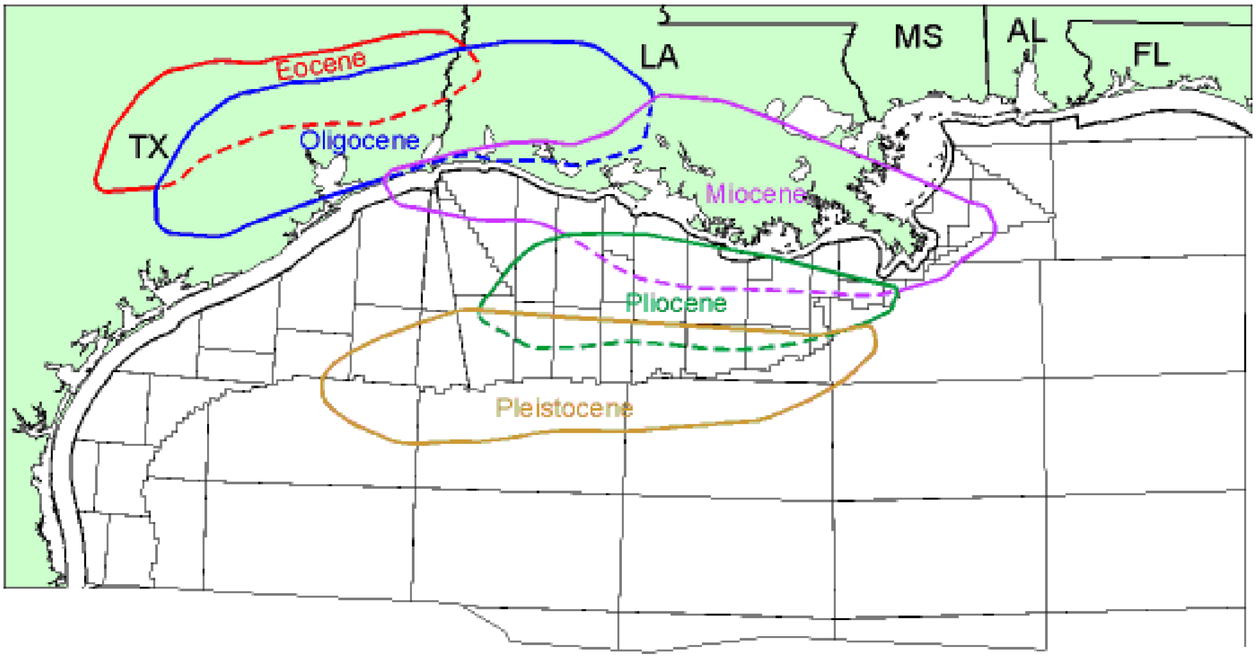


Figure 1. National Assessment Chronostratigraphic Chart.



(Modified from Seni *et al*., 1997)

Figure 2. Sites of Major Deltaic Depocenters.

architecture, reflecting the increasing amount of accommodation space and the retreat of depositional environments during relative sea level rise.

The aggradational style comprises thick sandstone beds separated by thin shale units. Depositional environments represented by aggradational sediments include fluvial-streamplain, bay-lagoon, barrier island, coastal strandplain, and marine shelf (Morton *et al.*, 1988). Fluvial and strandplain depositional environments dominate the aggradational depositional style.

The progradational style is characterized by deeper water shale at the base, along with thin sandstone units that grade upward into dominantly shallow marine deltaic and shoreline sandstones that are topped by thin shale interbeds. A broad spectrum of paralic depositional environments, including deltaic, shoreline, strandplain, barrier bar, shelf, and coastal plain, are subsumed under the progradational style. Deltaic depositional environments are dominant. Progradational architecture is constructed of thinner packages of dominantly progradational parasequence sets. Minor or local retrogradational events are typically interspersed within the overall progradational style.

The fan facies is a sandstone-rich, deepwater environment, characterized by a variable pattern of sandstone-body thickness (including thick to thin and blocky to upward-fining sandstones), sharp-based channel-fill sandstones, and serrated, thin to thick sandstones interbedded with thick shale units. Fan environments are characteristically overlain by hundreds of feet of deepwater shale.

Depositional styles are important elements of the sequence stratigraphic systems tracts model (Vail, 1987; Van Wagoner *et al.*, 1988) and the genetic stratigraphic sequences of Galloway (1989). The internal architecture of both models is similar; the difference lies in the choice of sequence boundaries. Sequence stratigraphic systems tracts are bound by unconformities and genetic stratigraphic sequences by flooding surfaces. We chose to identify depositional styles instead of depositional facies or systems tracts, except for the fan facies, because styles (1) capture the appropriate scale of geologic variability in a basinwide resource investigation, (2) dovetail with existing chronostratigraphic divisions in the Gulf of Mexico, (3) are readily interpreted from well logs and seismic data, and (4) avoid the complications inherent in local depositional events.

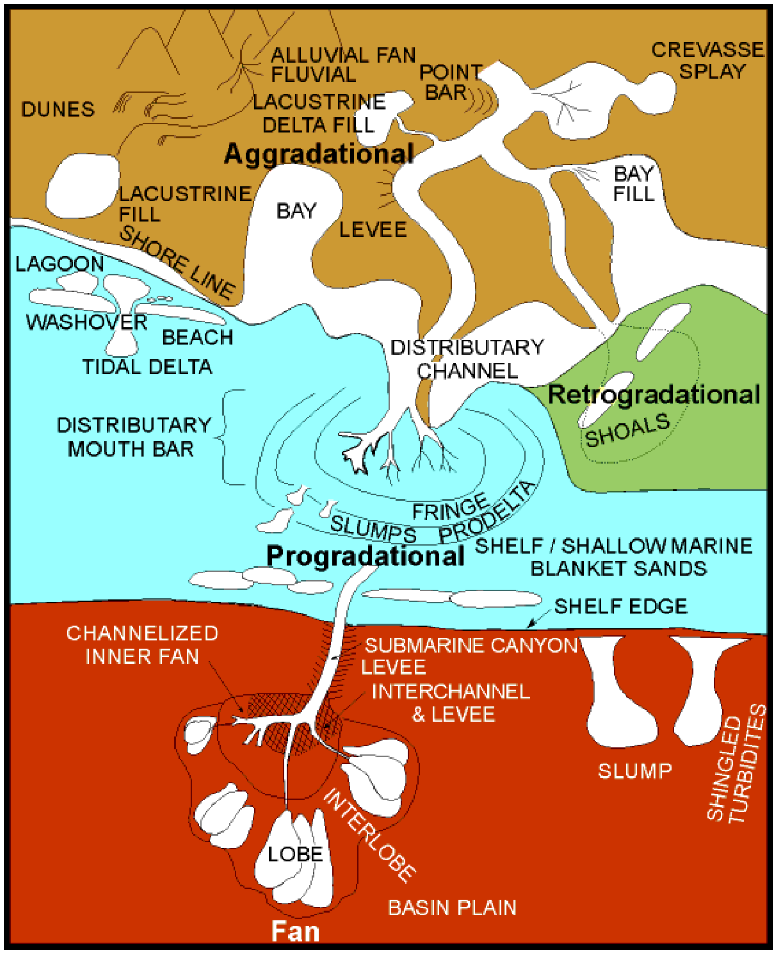


Figure 3. Model for Deltaic Deposition.

Electric-log (spontaneous potential, SP) patterns representing these depositional styles and facies are repeated in sediments deposited during the Cenozoic Era throughout the Gulf of Mexico Basin (figure 4). They were the primary means to classify the thick package of sediments within the Cenozoic Era into the aforementioned depositional styles and facies. This was done on the basis of relative proportions of sandstone and shale, log patterns, ecozones, and parasequence stacking patterns (Galloway *et al.*, 1986; Morton *et al.*, 1988). Although the fan facies is not confined to a single depositional style, it was identified uniquely because fan sands (1) have distinct distribution patterns, (2) relate more closely together than to other styles of sands, and (3) contrast with prograding distal deltaic sands on the slope. Correlation of these depositional styles and facies from well to well throughout the study area depends on the recognition of shale-dominated sections according to characteristic marker foraminifera (biozones) that identify specific marine flooding events that bound the chronozones.

STRUCTURAL STYLES

In addition to age and depositional style and facies, structural style is an important component of hydrocarbon plays in the Gulf of Mexico. It is often the key determinant of the trapping mechanism. The structural framework of the northern Gulf of Mexico reflects extensional tectonics that characterized the Cenozoic Era as a result of gravitationally induced gliding and gravity spreading of thick depocenters over mobile salt and shale (Worrall and Snelson, 1989). Faults in Cenozoic strata form two distinct styles: (1) the Texas style of very long, coast-parallel, basinward-dipping growth faults that dominate the areas of Texas offshore State waters and the nearshore Federal OCS of offshore Texas and (2) the Louisiana style of short, arcuate growth-fault systems in central offshore Louisiana and eastern far-offshore Texas that have variable dip orientations. Extensive lateral displacement (in some areas exceeding tens of miles), listric geometries, deep detachment along salt and zones formerly occupied by salt, and palinspastic reconstructions all indicate that stratal expansion along growth faults and accompanying extension were largely accommodated by regional-scale salt displacement (Worrall and Snelson, 1989). Texas-style faults have a linear, listric geometry as a result of efficient salt displacement through loading by laterally continuous, linear, strandplain/barrier-island depositional systems. In contrast, the arcuate Louisiana-style faults result from point-

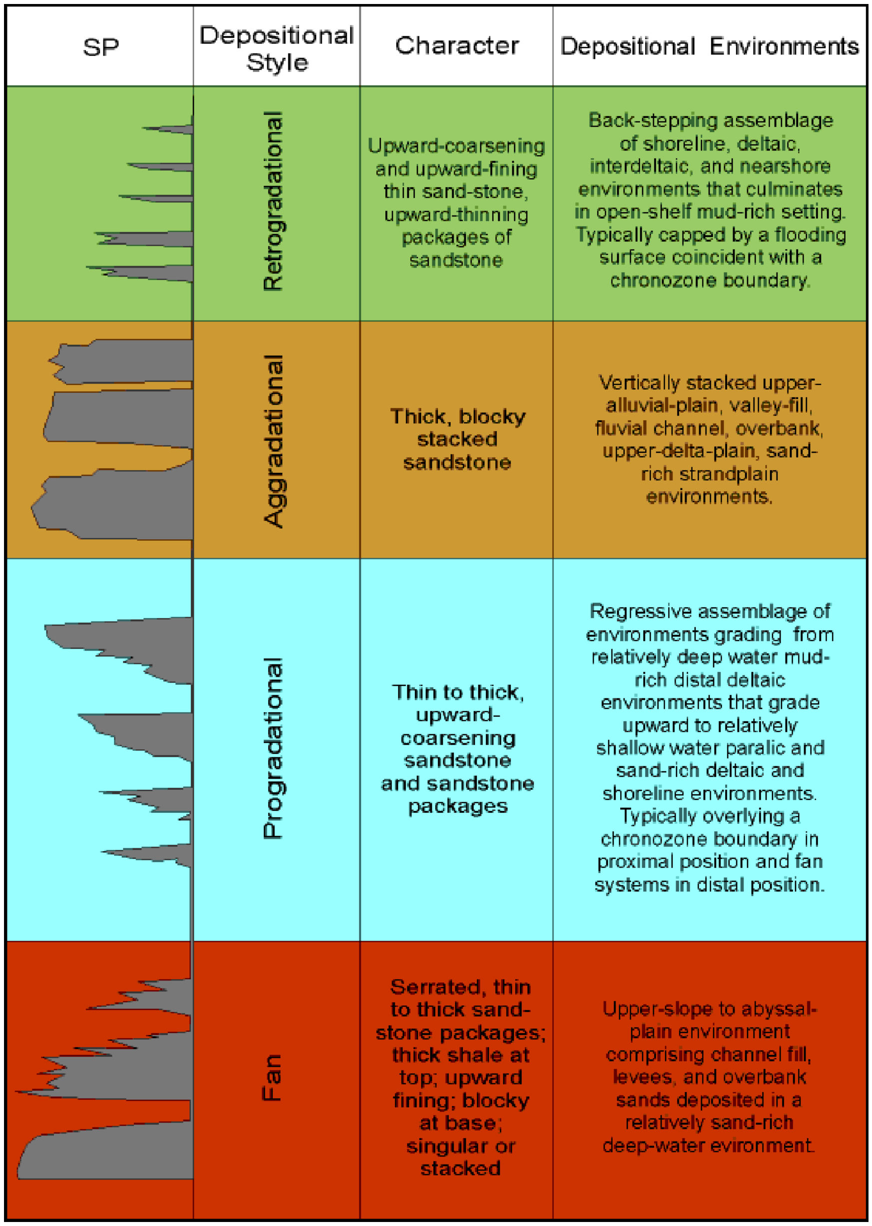


Figure 4. Representative Electric Log Characteristics by Depositional Style.

source loading by rapidly shifting deltaic depocenters associated with massive loading of the subdeltas of the Mississippi River.

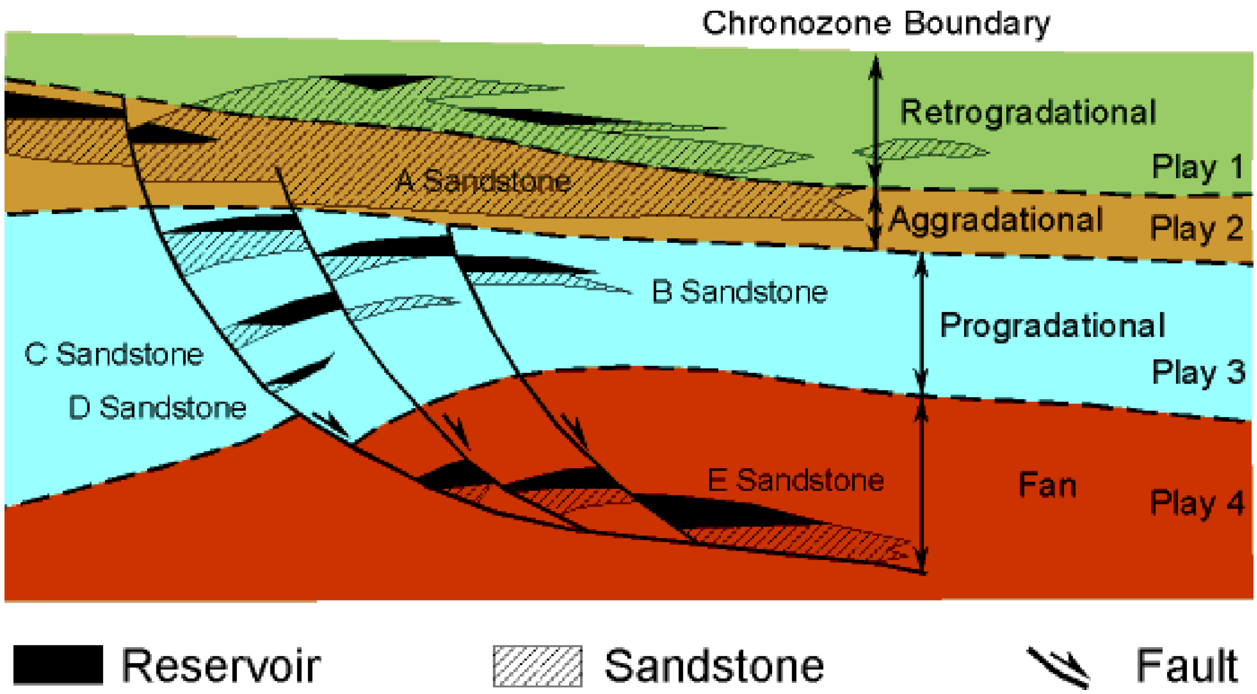
Structural control over the distribution of reservoirs and plays can be identified in local areas, such as along the Corsair Fault System and locally over salt structures. However, the extent of subregional hydrocarbon plays in the Province depends principally on the distribution of depositional facies containing favorable reservoir rocks. Hydrocarbons are trapped where structures coincide with favorable facies or where favorable facies create positive structures or traps. We found depositional style to be a robust attribute of plays.

METHODS

Type logs were constructed for each of the fields to illustrate chronostratigraphic boundaries, reservoir stratigraphy, and depositional styles and facies. Each type log is a composite of field wells so that all productive sands and stratigraphic sequences in a field are represented in their correct chronological order. All reservoirs in a field are correlated to the type log. Next, an extensive grid of approximately 100 geologic cross sections with parallel interpreted seismic cross sections was assembled correlating each of the 1,096 OCS fields (876 proved, 77 unproved, and 143 expired with no production) with 8,856 producible sands containing 22,172 individual reservoirs (Melancon *et al*., 1995). Chronozone maps illustrating depositional styles and facies were then constructed across the entire Cenozoic Province. Each of these combinations of chronozone and depositional style or facies formed a play.

Next, three distinct limits were constructed for each established play. The reserves limit for each of the plays includes all active fields with proved reserves and selected unproved fields that were deemed to be economically viable at the time of this assessment. These reserves limits were then extended by correlating outlier exploratory or field wells (e.g., wells in fields that had expired with no reserve estimates or production, or wells in unproved fields that were deemed to be economically nonviable under current conditions) containing hydrocarbon shows to the respective productive wells within the play. This enabled a determination of the known hydrocarbon limit for each play. Finally, the same procedure was used to determine the limits of sand occurrence, or the overall play limit. The only significant exception was for fan plays where, because of limited well control and sparse regional seismic data of variable quality in areas of ultra-deepwater, the maximum basinward extent of sands was selected as the Sigsbee Escarpment. The general progression from established reserves and production within the reserves limits, to known hydrocarbon occurrences within the hydrocarbon limits, to known sand occurrences within the play limits is observed for each play. This progression can be used in a general sense to extrapolate hydrocarbon trends and as a play occurrence guide.

Because a single field may produce hydrocarbons from several reservoirs that vary in geologic age, depositional environment, lithology, and many other attributes used to characterize a play, the field may be represented in more than one play. Because most



(Modified from Seni *et al*., 1997)

Figure 5. Schematic Cross Section of Typical Field (showing 12 fault-block reservoirs, 7 sandstone-body reservoirs, 4 pools, 4 plays, and 4 depositional styles/facies).

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MESOZOIC PROVINCES

There is very little information available pertaining to the Mesozoic section within the central and western portion of the Gulf of Mexico OCS to describe sediments and construct a conceptual model. There is also a lack of known worldwide productive analogs to apply to an initial conceptual model. Thus, there would be an extremely large degree of risk and uncertainty attached to any plays developed. Therefore, it was decided at this time not to develop highly speculative estimates for any plays in this area.

The Mesozoic Provinces in the eastern Gulf of Mexico and Atlantic Continental Margin contain relatively few fields, and a limited number of wells have been drilled. In the eastern Gulf of Mexico, only about 110 wells penetrating the Mesozoic section (as of this study's cutoff date of January 1, 1995) have been drilled. Commercially recoverable hydrocarbons have been discovered and resulted in the development of nine fields of upper Jurassic age and two fields of lower Cretaceous age. On the Atlantic Continental Margin, only 51 wells have been drilled, resulting in several subeconomic hydrocarbon flows from upper Jurassic age and lower Cretaceous age clastic reservoirs.

A significant problem in assessing plays which are immature or conceptual is the selection of an appropriate analog(s). A suitable analog is an established play that possesses similar depositional environments, structural features, and geologic ages as the play being assessed. To identify analogs for the Mesozoic Provinces, we evaluated all available geologic and/or geophysical data and performed an extensive search of the literature. Identifying adequate analogs for the Gulf of Mexico Mesozoic Province was not difficult, since there has been an extensive record of exploration onshore along the United States Gulf Coast within the Mesozoic section, and several OCS Mesozoic plays are offshore extensions of the onshore United States Gulf Coast plays. Even though identifying adequate analogs for the Atlantic Mesozoic Province was more problematic, two analog areas were identified as possible models for assessing the clastic plays: the onshore United States Gulf Coast and the Scotian Shelf offshore Canada. The carbonate plays in the Atlantic were modeled using onshore United States Gulf Coast carbonate plays as analogs.

Because less data exist and analogs were necessary for the evaluation, the play descriptions for the Mesozoic Provinces are less precise than those for the Cenozoic Province. The Mesozoic sediments were grouped into six chronozones for this assessment (figure 1). In contrast to the Cenozoic chronozones, the Mesozoic chronozones are at the series level, and the depositional style is described as either clastic or carbonate (e.g., Lower Cretaceous Clastic (LK CL) or Atlantic Middle Jurassic Carbonate (AMU CB) play). The carbonate deposits include strata of Jurassic and Cretaceous shelf-edge reef systems and associated back-and fore-reef environments. These carbonate facies were identified from well log and seismic analysis, conventional and sidewall cores, and cuttings.

GEOLOGIC RISK ASSESSMENT

Geologic risk assessment is the process of subjectively estimating the chance that at least a single hydrocarbon accumulation is present somewhere in the area being assessed (i.e., the marginal probability of hydrocarbons [MPhc]). Once a conceptual or frontier play has been defined, it is necessary to address the question of its probable existence. As part of the play description, it is assumed that critical geologic factors such as adequate hydrocarbon source rocks, thermal maturation, migration pathways and timing, and reservoir facies are present. However, in conceptual plays and at the earliest stages of exploration in frontier plays, we cannot state with absolute confidence that these critical factors occur throughout the extent of the delineated play.

The play-level assessment of MPhc consists of a subjective analysis performed on each of the critical components necessary for a productive play— the hydrocarbon fill, reservoir, and trap components. The MPhc or play chance (White, 1980, 1993) analysis assesses individually the probability of existence for each of the critical geologic factors. If a play contains more than a minimal show of hydrocarbons as in an established play, all critical geologic factors are present. If any of these essential factors are not present or favorable, the play will not exist. The risk assessment is documented on a worksheet (figure 1) used by the assessment teams for this analysis. The probability of the presence of each factor is subjectively estimated by the assessment team. The presence or absence of direct evidence supporting the play model is a major consideration in the analysis for each component. Because conceptual plays have little or no direct data, the risk assessment is guided by the evaluation of an analog play(s) and judgment as to the likelihood that the play actually reflects the analog model. Each component is considered to be geologically and thus statistically independent from the others. Therefore, the product of the marginal probabilities for each individual component represents the chance that all factors simultaneously exist within the play.

This play-level MPhc differs from the prospect-level MPhc, which relates the chance of all critical geologic factors being simultaneously present in an individual prospect. The play-level MPhc reflects the regional play-level controls affecting all prospects within the play. The fact that an individual prospect may be devoid of hydrocarbons does not mean that the play is nonproductive, nor does the presence of hydrocarbons in a play ensure their presence in a particular prospect. However, if the play is devoid of hydrocarbons, so are all of its prospects.

Figure 1. MPhc Worksheet and Guidelines for Estimating Play Geologic Risk.

Play Risk Analysis Form **1995 National Assessment** **Established Plays**	
For each component, a *quantitative* probability of success (i.e., between zero and one, where zero indicates no confidence and one indicates absolute certainty) based on consideration of the *qualitative* assessment of ALL elements within the component was assigned. This is the assessment of the probability that the minimum geologic parameter assumptions have been met or exceeded.	
1. Hydrocarbon Fill component a. Source rock b. Maturity c. Migration d. Timing	**1.00**
2. Reservoir component a. Reservoir quality b. Depositional environment c. Diagenesis	**1.00**
3. Trap component a. Closure b. Seal	**1.00**
Play Success (Marginal Probability of hydrocarbons, MPhc) (1) x (2) x (3)	**1.00**
Play Risk (1 - Play Success)	**0.00**
Comments: This is an established play from which hydrocarbons have been produced.	

Guidelines for Estimating Play Geologic Risk

Scoring is based on a central 50/50 chance value:

0.0-0.2 component is probably lacking
0.2-0.4 component is possibly lacking
0.4-0.6 equally likely component will be present or absent
0.6-0.8 component will possibly exist
0.8-1.0 component probably exists

Hydrocarbon Fill Component

This component assesses the probability that hydrocarbons exists in the play. Elements which affect the probability of hydrocarbon existence are source rock, maturity, migration, and timing.

Scoring: The score range used to estimate adequacy of hydrocarbon charge is determined by the most pessimistic of the charge parameters (i.e., source rock, maturity, migration, and timing). For example, if source rock, maturity, and migration qualify for the range 0.8-0.6. but timing only qualifies for the range 0.6-0.4, then the overall chance of charge must be scored in the range 0.6-0.4.

Score 1.0-0.8

Source rock: Presence of source rock within the play is clearly indicated by the existence of pools or implied by well and seismic data. Source rock (predicted or directly measured) should be of high quality.

Maturity: Hydrocarbon expulsion from the source rock is clearly indicated by the existence of pools or implied (e.g., borehole shows, hydrocarbon seeps, and possibly seismic direct hydrocarbon indicators [DHI's]). The source rock is clearly defined and of sufficient volume to source the minimum size prospect assessed within the play.

Migration: A viable migration pathway is clearly supported by the distribution of pools, hydrocarbon shows, and possibly seismic DHI's. The geometry and effectiveness of the migration pathway should be clearly apparent on seismic data.

Timing: Prospects' (or leads') closures should clearly pre-date the main phases of hydrocarbon expulsion.

Score 0.8-0.6

Source rock: Presence of source rock within the play is probable based on well and seismic data or the basin model. Source rock quality (predicted or directly measured) should be high. Slightly leaner source rocks may be considered if it can be demonstrated that the migration pathway is highly efficient.

Maturity: Hydrocarbon expulsion from the source rock is probable based, for example, on the presence of borehole shows, hydrocarbon seeps, and possibly seismic DHI's. The source rock is probably of sufficient volume to source prospects (or leads) of the minimum assessed size.

Migration: A viable migration pathway is probable as implied by the distribution of surrounding hydrocarbon shows, seeps, and possibly seismic data. A probable migration pathway should be apparent on seismic data.

Timing: It should be at least probable that the prospects' (or leads') closures pre-date the main phases of hydrocarbon expulsion.

Score 0.6-0.4

Source rock: Source rock may or may not be present based on well and seismic data or basin modeling. There may be no data to support or deny the presence of high quality source rock.

Maturity: Hydrocarbon expulsion from the source rock is supported by maturation modeling. The basin model and seismic interpretation should give some indication of source rock volumes. The source rock may or may not be of sufficient volume to source the minimum sized prospect (or lead).

Migration: A viable migration pathway may or may not exist.

Timing: The prospects' (or leads') closures may or may not pre-date the main phases of hydrocarbon expulsion.

Score 0.4-0.2

Source rock: Well and seismic data or the basin model indicate that high quality source rocks may be absent.

Maturity: Maturation modeling indicates the possibility that source rock volume is insufficient to source the minimum sized prospect (or lead).

Migration: The distribution (or absence) of hydrocarbon shows and possible seismic DH'Is, or the results of seismic structural mapping, indicate the possibility that the prospects (or leads) do not lie on a viable migration pathway.

Timing: Seismic interpretation and basin modeling indicate the possibility that the prospects' (or leads') closures post-date the main phases of hydrocarbon expulsion.

Score 0.2-0.0

Source rock: Well and seismic data or the basin model indicate that high quality source rocks are probably absent.

Maturity: Maturation modeling indicates the probability that source rock volume is insufficient to source prospects (or leads) of the minimum size assessed.

Migration: The distribution (or absence) of hydrocarbon shows and possible seismic DHI's, or the results of seismic structural mapping, indicate the probability that the prospects (or leads) do not lie on a viable migration pathway.

Timing: Seismic interpretation and basin modeling indicate the probability that throughout the play the prospects' (or leads') closures post-date the main phases of hydrocarbon expulsion.

Reservoir Component

This component assesses the presence of reservoir rock. It also estimates the chance that applicable reservoir parameters exceed specified minimums for porosity, permeability, fracturing, shaliness, cementation, and thickness.

Score 1.0-0.8

Reservoir quality, depositional environment, and diagenesis: Presence of reservoir rock within the play is clearly indicated by pools and wells. The reliability of reservoir presence is confirmed by seismic facies analysis (i.e., there is no evidence of reservoir deterioration between wells and prospects). Reservoir presence may also be supported by seismic attributes. Both wells and seismic data yield a consistent depositional and diagenetic model.

Score 0.8-0.6

Reservoir quality, depositional environment, and diagenesis: Presence of reservoir rock is proven in at least one well in the play, and its presence throughout the play is confirmed by seismic data (facies and/or attributes). It may not be possible to predict reservoir rock from seismic facies analysis; however, a positive indication should come from the depositional and diagenetic model.

Score 0.6-0.4

Reservoir quality, depositional environment, and diagenesis: Presence of reservoir is neither confirmed nor denied by well or seismic data and the associated depositional and diagenetic model. In rank wildcat areas, the chance of reservoir presence will often be the same as risk of reservoir absence.

Score 0.4-0.2

Reservoir quality, depositional environment, and diagenesis: Wells and seismic data indicate possible absence of a reservoir. Seismic facies analysis and the depositional and diagenetic model indicate the possibility of reservoir absence.

Score 0.2-0.0

Reservoir quality, depositional environment, and diagenesis: Wells and seismic data indicate probable absence of a reservoir. Seismic facies analysis and the depositional and diagenetic model indicate the probability of reservoir absence.

Trap Component

This component assesses the existence of closure in the trap (structural, stratigraphic, or combination of both) and considers the existence and quality of seal. The presence of a seal is required when assessing the trap component. The quality of the seal can favorably or adversely affect the assessment of the trap and must be reflected in the overall score of the trap component. The score range used to estimate the adequacy of trap is determined by the most pessimistic range of the trap parameters. For example, if the presence of seal qualifies for the 0.6-0.4 range and this is less than success probability of the closure parameter, then the overall chance of the trap component must be in the 0.6-0.4 range.

Score 1.0-0.8

Closure: Presence of minimum structural or stratigraphic closure within the play is clearly indicated by the existence of pools or implied by well and seismic data. Available well and seismic data allow accurate depth conversion. Closures should be identified from the top reservoir pick, which should be clearly registered on seismic. Stratigraphic closures should be further defined by a reliable base reservoir pick, and wedge-out geometry should be clearly resolved on seismic data.

Seal: Presence of seal is clearly calibrated by wells and seismic data. The integrity of seal is confirmed by the existence of pools or implied by seismic facies analysis; there is no evidence of seal lithofacies deterioration between wells and prospects. Predicted reservoir pressure is not sufficient to break seal (consider capillary entry pressure of seal lithology). There is no evidence of widespread structural breaching such as faults, jointing, or fracture cleavage.

Score 0.8-0.6

Closure: Presence of minimum structural or stratigraphic closure is probable based on seismic coverage and depth conversion. Closures should be identified from the top or near-top reservoir pick. For stratigraphic traps, wedge-out geometry should be clearly apparent on at least some seismic lines.

Seal: Presence of seal is proven in at least one well, and its presence within the play is confirmed by seismic data. It may not be possible to predict seal from seismic facies analysis. Available reservoir pressure data are insufficient to demonstrate a lack of seal integrity. At worst there is only a small risk of structural breaching.

Score 0.6-0.4

Closure: Based on seismic coverage and depth conversion, there is a near equal chance of minimum structural or stratigraphic closure being present or absent within the play. This may be because the mapped seismic horizon is significantly above the target as a result of limited seismic quality.

Seal: Presence of seal is neither confirmed nor denied by well or seismic data. In rank wildcat areas, the chance of seal presence will often be the same as risk of seal absence.

Score 0.4-0.2

Closure: Closures exceeding minimum size are inadequately defined by seismic data.

Seal: Wells and seismic data indicate possible absence of a seal. Reservoir pressure data suggest some risk of seal failure. Structural breaching of the seal is also possible.

Score 0.2-0.0

Closure: Seismic data indicate that closures exceeding minimum size are not present.

Seal: Well, seismic, or reservoir pressure data indicate high risk of seal failure.

Modified from B.A. Duff and D. Hall. 1996. A model-based approach to evaluation of exploration opportunities, *in* A.G. Dore and R. Sinding-Larson, eds., Quantification and prediction of petroleum resources: Norwegian Petroleum Society Special Publication No. 6, p. 183-198.

UNDISCOVERED CONVENTIONALLY RECOVERABLE RESOURCES (UCRR) GENERAL DISCUSSION

Geologists, statisticians, and economists have been performing resource assessments for decades in an attempt to estimate the future petroleum supply in an area. The demands of and uses for these assessments have led to the evolution of increasingly complex quantitative techniques and procedures to meet the challenge. Generally, the evolution has been from deterministic to stochastic methods, incorporating sensitivity and risk analyses. Scientific disciplines involved in the assessment process have evolved in parallel with the methodology from geology to a complex multi-disciplinary array of geology, geophysics, petroleum engineering, economics, and statistics.

The basic building block of this assessment of undiscovered conventionally recoverable resources is the play. A play is defined primarily on the basis of the geologic parameters that are responsible for a petroleum accumulation. The play analysis technique can be incorporated into probabilistic models to yield a number of possible future outcomes from exploration and development in the area under consideration. The strengths of this procedure are that it deals with natural exploration units— plays, prospects, pools, and fields— and with specified pool or field size distributions. The assessment results, in terms of pool rank plots, can be readily used for economic analyses and discovery forecasting. Serendipitous plays, those found as surprises, were not considered in this assessment. These unknown plays do not have a geologic model that can be logically assessed, and rather than add resources without a framework to determine where and how much, these potential resources were not included.

The assessment of undiscovered conventionally recoverable resources of the Gulf of Mexico and Atlantic Continental Margin was performed irrespective of any consideration of economic constraints. Commerciality of the resource is considered in the subsequent economic analysis phase. The assessment was conducted using a computer program called GRASP (Geologic Resources ASsessment Program). The program was adapted by MMS from the Geological Survey of Canada's PETRIMES (PETroleum Resources Information Management and Evaluation System) suite of programs.

It has been recognized empirically for decades that within any petroleum province, and particularly within plays, the size distribution of accumulations is highly skewed (i.e., there are many small accumulations and very few large ones) (Arps and Roberts, 1958; Kaufman, 1963; McCrossan, 1969; Barouch and Kaufman, 1977; Forman and Hinde, 1985). Commonly, the large deposits contain the majority of the resources. Kaufman (1965), Meisner and Demirmen (1981), Crovelli (1984), Davis and Chang (1989), and Power (1992), among others, have reviewed the lognormal distribution and the many properties that make it a reasonable choice as a probability model for the relative frequency distribution of pool sizes in a play. The ultimate choice, however, of a particular probability model is subjective.

The realization that the logarithms of pool sizes are normally distributed and the knowledge that distributions can therefore be completely specified by the mean (μ, a statistical measure of central tendency) and variance (σ^2, a measure of the amount of dispersion in a set of data) of the log-transformed data constitute the major assumptions of the GRASP model. A convenient characteristic of lognormal distributions is that a plot of the log of the values in the distribution approximates a straight line (figure 1).

The objectives of this assessment of undiscovered conventionally recoverable resources were

- estimate the number of undiscovered pools,
- estimate the sizes of the undiscovered pools, explicitly considering the reserves appreciation phenomenon,
- estimate reservoir characteristics of the undiscovered pools,
- provide adequate information for economic analysis, and
- validate exploration concepts and geologic models against known information.

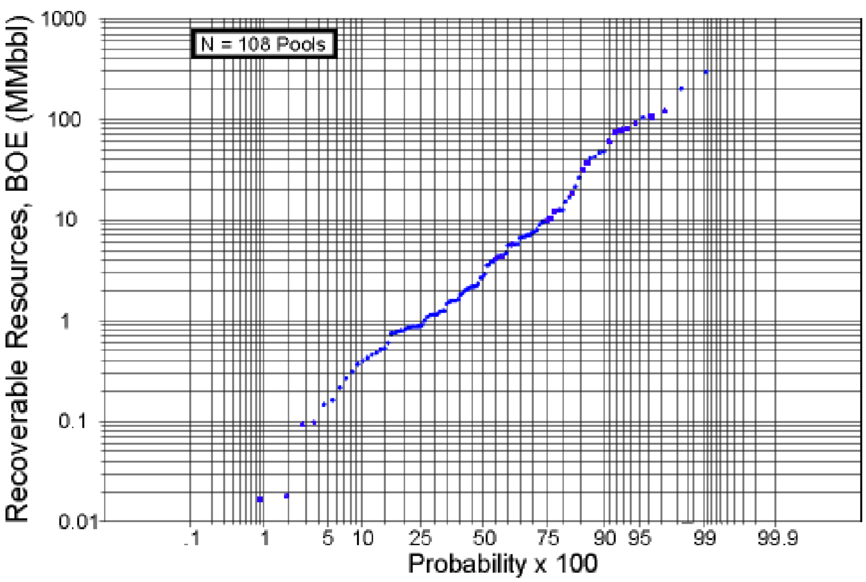

Figure 1. Sample Lognormal Distribution.

A comprehensive resource assessment must combine within the context of the play model empirical field data with information acquired from regional analysis and comparative studies. In the GRASP model, exploration data are expressed as probability distributions. The major strengths of probabilistic methods are the formal recognition of uncertainty, the ability to enable professionals to make judgments in their area of expertise without requiring additional, often arbitrary, judgment, and the useful added dimension provided to the analysis and results. The model relies heavily on the technical judgments of the geoscientist teams working with the other assessors.

The basic procedures used in this resource assessment were the pool generation and matching processes described by Lee and Wang (1986). The major steps (figure 2) include

- data organization,
- play delineation,
- compilation of play data,
- estimation of play and prospect chance of success,
- preparation of discovery histories and pool size distributions for discoveries in established or analog plays,
- estimation of the number of pools distribution,
- estimation of the play pool size distribution,

- estimation of individual ranked pool size distributions and matching of discovery data with forecast pool sizes, and
- estimation of play resource distribution.

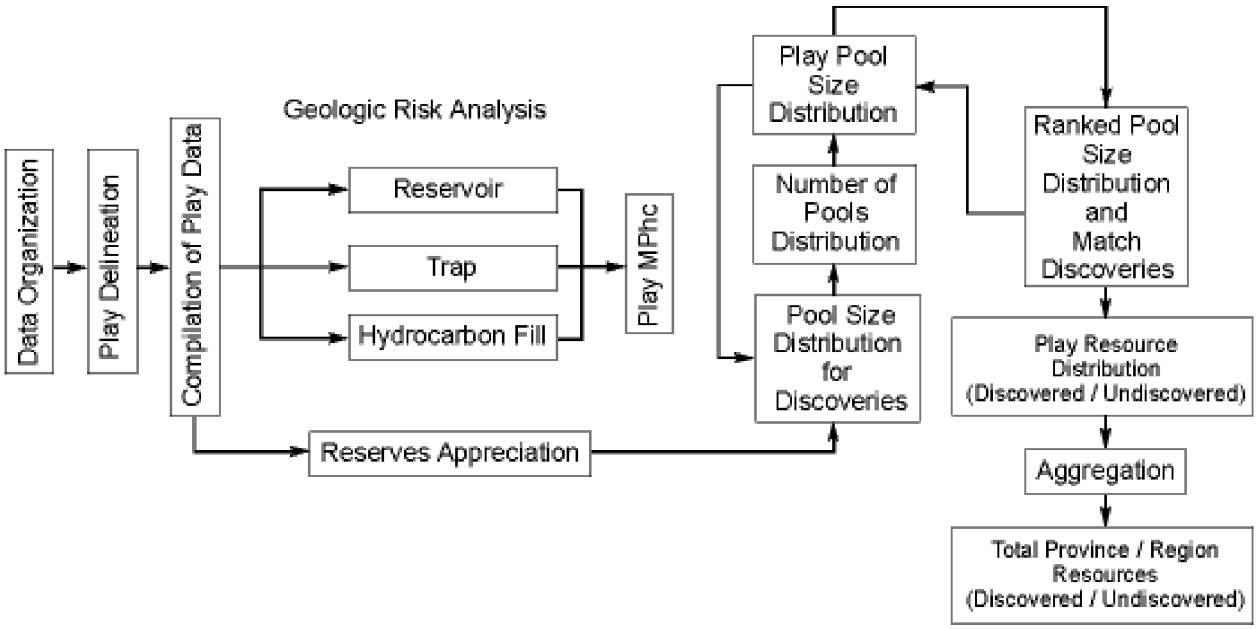

Figure 2. UCRR Process.

ESTABLISHED PLAYS

An effective assessment of undiscovered petroleum in a play can be developed from estimates of the size distribution of the potential pools in the play and the range in the total number of discovered and undiscovered pools (N), assuming that the play exists, in conjunction with an assessment of the appropriate marginal probability of hydrocarbons (MPhc) (Baker *et al.*, 1984). Pool size distributions describing the size range of individual pools in the play and their frequency of occurrence are the most important elements of the resource appraisal process. The pool size distribution is a function of the geologic model for the play. It describes the expected population of pools that would result from repeated exploration of a particular play model. The number of pools distribution is derived from a consideration of the number of existing discoveries, the number of prospects, average prospect risk, areal extent of the play, and the degree of exploration maturity for the play (figure 3).

Next, the pool size distribution is conditioned on the existing discoveries. The pool size distribution is ascertained by the matching process where hypothetical pool size distributions are determined stochastically from different values for the parameters μ, σ^2, and N. The model selects values from the distribution of each parameter and generates pool rank plots. The discovered pools are then matched to the predicted pool size distribution for each iteration. The best statistical fits are then presented for further analysis. Statistical “goodness-of-fit” tests are applied, but the implications of the best statistical solutions must be subjectively compared with the geologic model. Since there is no unique measure to determine the best model for the play, selection of the appropriate match is one of the most challenging aspects of the resource assessment process.

In the matching process, the discoveries in a play are recognized as a sample taken from the play’s population of pool sizes. The standard statistical practice of estimating the population μ and σ^2 from the sample is valid only if the sample is assumed to be a random sample from the pool population or is large enough to represent the distribution of the population. In reality, neither of these situations is usually valid. Large pools are usually discovered early because the largest prospects are generally defined and drilled first— the principle of resource exhaustion. The sample set is usually clearly biased. The undrilled prospects will include a disproportionate number of small pools. The effect of this bias in the selection process is a progressive change in the pool size distribution through time. If the population is lognormal, samples at different times will also tend to be lognormal. These sample distributions will migrate downward from an initial distribution with unrealistically high μ and low σ^2 values. Therefore, μ of the sample would be an overestimate and σ^2 an underestimate of the population parameters. Kaufman *et al.* (1975) illustrated this process through a series of Monte Carlo simulations of a random discovery process in a hypothetical basin.

1995 National Assessment Play Analysis Worksheet Part 1 (Prior to GRASP)	Name of Play: ______ Chronozone: ______ Depositional style/facies: ______
Play characteristics	
Number of discovered pools in the play	______
Estimated prospective area of play within geologic limit	______ MM acres
Estimated area of play relatively unexplored	______ MM acres
Proved reserves of play	
as of 1/1/95	
Oil	______ MMbo
Gas	______ Bcfg
BOE	______ MMBOE
after reserves appreciation (through 12/2020)	
Oil	______ MMbo
Gas	______ Bcfg
BOE	______ MMBOE
Unproved reserves of play	
as of 1/1/95	
Oil	______ MMbo
Gas	______ Bcfg
BOE	______ MMBOE
after reserves appreciation (through 12/2020)	
Oil	______ MMbo
Gas	______ Bcfg
BOE	______ MMBOE
Types of pools in play	
What is the observed percentage of:	
Oil pools	______ % oil
Gas pools	______ % gas
Mixed pools	______ % mixed
What do you expect the final percentages to be (with additional discoveries)?	
Oil pools	______ % oil
Gas pools	______ % gas
Mixed pools	______ % mixed
Largest discovered pool in play	
Pool name	______
Pool discovery year	______
Pool hydrocarbon pore volume	______ acre-feet
Pool reserves, after appreciation	
Oil	______ MMbo
Gas	Bcfg
BOE	______ MMBOE

Figure 3. Play Worksheet, Part 1 (Prior to GRASP).

The matching process requires a careful consideration of all available information pertaining to the play: petroleum geology, discovery history, play maturity, etc. (figure 4). Typically this is accomplished by responding to questions such as

- Has the largest pool been discovered? If not, what are the largest pools that could remain to be discovered?
- How many undrilled prospects are likely to remain in the play? What is their

size distribution and average prospect risk?

- How does the play's exploration and discovery history fit the pool size distribution?
- Do the parameters of the predicted pool size distributions relate logically with similar plays?

1995 National Assessment Play Analysis Worksheet Part 2 (GRASP Input)	Name of Play: ______ Chronozone: ______ Depositional style/facies: ______

Answer the following questions after reviewing and considering the play's: discovery history, pool size distribution, available geological and geophysical analysis, and exploration status.

Largest pool in play

Has the largest pool in the play been discovered? Yes / No

What is your best estimate of the approximate size, in terms of recoverable reserves after appreciation, of the largest pool remaining to be discovered?

Oil ______ MMbo

Gas ______ Bcfg

BOE ______ MMBOE

Number of pools in play

Using your knowledge of the play and the untested acreage within the limit of the play; how many pools remain to be discovered:

Low estimate ______ pools
(3 chances in 4 that at least this many pools remain to be discovered)

High estimate ______ pools
(1 chance in 4 that at least this many pools remain to be discovered)

Mean estimate ______ pools
(2 chances in 4 that at least this many pools remain to be discovered)

Play analogs

What play(s) is a good analog for this play? ______

Describe how this play differs significantly from its analog(s), e.g. 50 % less area, 25 % less volume, more intensely faulted, fewer salt domes, significantly less sand, etc. Attach additional sheets if necessary.

Figure 4. Play Worksheet, Part 2 (GRASP Input).

The responses to these and similar questions may lead to changes in the distribution parameters. This is an iterative process that permits the assessor to challenge the geologic model, consider the feedback from "what if" analyses, and refine the model as new information becomes available (figure 5). For each play there is a set of μ, σ^2, and N values related to the play's geologic model. Different geologic models may have different values for these parameters and thus different pool size distributions.

Once a final acceptable model has been determined, additional program modules constrain predicted pool size ranges by the discovered sizes. The subjective process of matching discoveries to the pool size distributions further reduces the uncertainty associated with the potential resource volume of the play. The pool rank plots and cumulative probability distributions illustrate this process. In the pool rank plots, discovered pools are shown as single point values (dots) and projected undiscovered pools as distributions (bars). The length of the bar represents the F95 to F5 (the 95th and 5th percentiles, respectively) estimate of pool size. The undiscovered pool sizes must fit within the discoveries. Figure 6 shows an example of a pool rank plot and cumulative probability distribution from a very mature progradational play. Contrast this with the example of an immature play with considerable remaining potential (figure 7). Notice that in both figures the range of possible sizes for individual pools decreases in proximity to discovered pools. These figures illustrate the greater uncertainty in individual pool sizes and aggregate play resource distributions associated with conceptual and immature plays, which have not been demonstrated to contain significant quantities of hydrocarbons and/or discovered pools. Generally, the greater the number of discoveries in the play, the less uncertainty in the number and sizes of undiscovered pools; therefore, there is less uncertainty in the total quantity of undiscovered resources for the play. The relatively narrow range of values associated with the distribution for the mature play is a reflection of the resource size constraints imposed by the discoveries. A more comprehensive description of PETRIMES is found in Lee and Wang (1990).

1995 National Assessment
Play Analysis Worksheet
Part 3 (After GRASP)

Name of Play: ____________________
Chronozone: ____________________
Depositional style/facies: ____________________

Review the GRASP model runs for this play and select the statistical model that you believe best approximates the actual geologic model for this play. Consider the following:

If there is not a satisfactory fit
Document the changes and then rerun GRASP.
Attach additional sheets if necessary.

Once a satisfactory fit has been determined
Document and provide the rationale for this selection.
Attach additional sheets if necessary.

From the pool size distribution (including appreciation), answer the following:
- How many pools are in the play? ________ pools
- How many pools remain to be discovered? ________ pools
- Has the largest pool in the play been discovered? Yes / No
- What is the rank of the largest pool remaining to be discovered? ________ pool rank
- What is the size of the largest pool remaining to be discovered?
  - Oil ________ MMbo
  - Gas ________ Bcfg
  - BOE ________ MMBOE
- What is the value of mu? ________
- What is the value of sigma squared? ________

What is the total hydrocarbon endowment of the play?
- Oil ________ MMbo
- Gas ________ Bcfg
- BOE ________ MMBOE

Signatures of all play assessment team members

Figure 5. Play Worksheet, Part 3 (After GRASP).

Conceptual and Frontier Plays

Disparate approaches to resource assessment are appropriate for different plays, particularly if, as in the Atlantic and Gulf of Mexico OCS, there are different levels of exploration maturity with very diverse amounts of geophysical, geologic, and production data available. In established plays in mature basins, the geologic concepts are well understood, and the data are both abundant and reliable. At the other end of

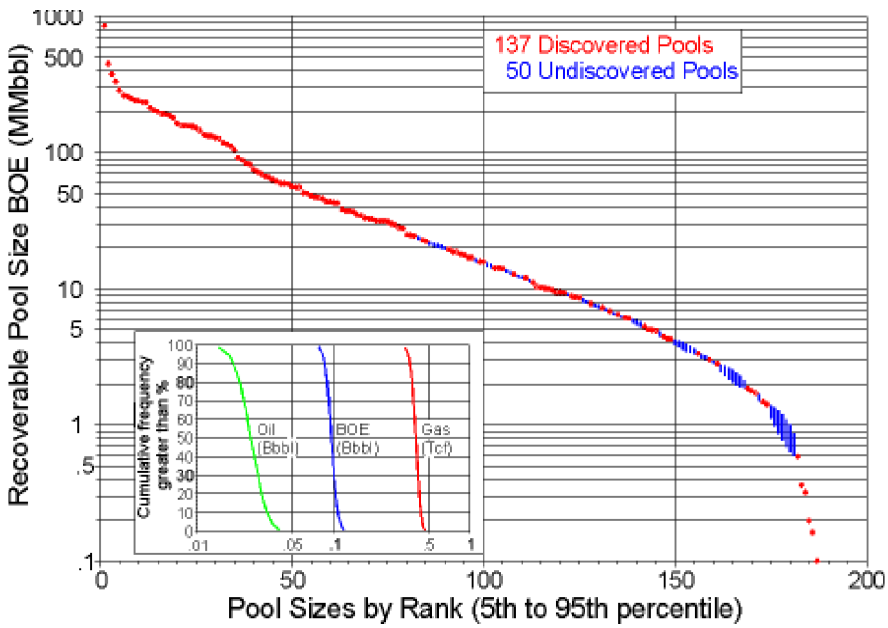

Figure 6. Mature Play Pool Rank Plot.

the spectrum are plays in immature basins where their premise is based solely on regional analysis and comparisons with plays in analog basins. The available data may consist only of regional geophysical information and the results from a few exploratory wells; the extensive database of the mature play is replaced in large part by subjective judgments and experience gained from observations in more mature areas. The key problem in assessing the immature or conceptual play is in the selection of an appropriate analog(s). A suitable analog is an established play that possesses geologic attributes similar to the play being assessed. The use of the analog requires subjective modification of the play model through the appropriate scaling of the factors (i.e., MPhc, μ, σ^2, and N) affecting the forecast for the play being assessed.

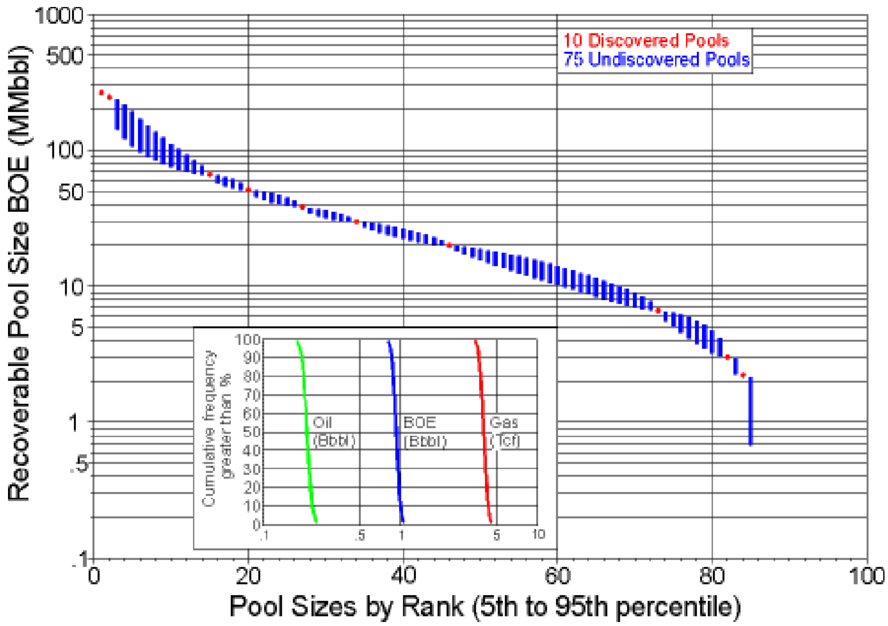

Figure 7. Immature Play Pool Rank Plot.

The basic pool-level data used in this resource assessment for the Cenozoic Province of the Gulf of Mexico have been released on the Internet at http://www.gomr.mms.gov. However, the Mesozoic Provinces of the Gulf of Mexico and Atlantic OCS have a limited amount of direct information available. Only the Upper Jurassic Aggradational (UU A) play (Norphlet Formation) in the Gulf of Mexico has more than one significant hydrocarbon accumulation. It was therefore essential to identify analogous plays to assess these Mesozoic Provinces properly. Identifying adequate analogs in the Gulf of Mexico Mesozoic Province was not difficult since there has been an extensive record of exploration onshore along the United States Gulf Coast within the Mesozoic section. In the Atlantic OCS, two analog areas were identified as possible models for assessing the clastic plays: the onshore United States Gulf Coast and the Scotian Shelf offshore Canada. The carbonate plays in the Atlantic were modeled using onshore United States Gulf Coast carbonate plays as analogs.

The approach used in assessing conceptual and frontier plays involved first assessing the analog plays, which parallels the process used in assessing the established plays. The first step after completion of play delineation was to assemble all relevant analog play data. This consisted primarily of pool maps, pool size information, discovery histories, well logs, and relevant reports and publications. Seismic data were also available for the Scotian Shelf analog. Once all relevant data are gathered, there are three critical steps involved in the evaluation process (1) assessing the play marginal probability, (2) developing number of pools distributions for the analogs and scaling them to the play being assessed, and (3) developing pool size distributions for the analogs and scaling them to the play being assessed.

AGGREGATION

Cumulative probability distributions of undiscovered conventionally recoverable resources for areas larger than the play were developed by statistically aggregating the probability distributions for individual plays to progressively higher levels using the computer program FASPAG (Fast Appraisal System for Petroleum AGgregation) (Crovelli, 1986; Crovelli and Balay, 1988, 1990). The aggregation hierarchy was play, chronozone, series, system, province, region, and the combined Gulf of Mexico and Atlantic Continental Margin. An estimate of the degree of geologic dependency was incorporated at each level of aggregation. For instance, plays were aggregated within chronozones on the basis of estimates of the geologic dependence among the plays. The dependence reflects commonality among the plays with respect to factors controlling the occurrence of hydrocarbons at the play level: charge, reservoir, and trap. Dependencies also reflect the degree of coexistence among the plays. Values for dependency can range from one, in which case each play would not exist if the other(s) did not exist, to zero, in which case the existence of each play is totally independent from all others. A very accurate dependency value is impossible to derive because of the geologic complexity of the plays. Therefore, a dependency value of 0.5 was generally used for all aggregations except when regions were aggregated. Regions were assumed to be independent.

UNDISCOVERED CONVENTIONALLY RECOVERABLE RESOURCES (UCRR) DETAILED DISCUSSION

The resource assessment process is iterative, comprising phases of data acquisition, analysis, and interpretation, followed by model modification and refinement. The strengths of this approach are in its predictive capabilities and ease of refinement. The principal objectives of this assessment of undiscovered conventionally recoverable resources were

- estimate the number of undiscovered pools,
- estimate the sizes of the undiscovered pools, explicitly considering the reserves appreciation phenomenon,
- estimate reservoir characteristics of the undiscovered pools,
- provide adequate information for economic analysis, and
- validate exploration concepts and geologic models against known information.

Geologists, statisticians, and economists have been performing resource assessments for decades in an attempt to estimate the future petroleum supply in an area. The demands of and uses for these assessments have led to the evolution of increasingly complex quantitative techniques and procedures to meet the challenge. Generally, the evolution has been from deterministic to stochastic methods, incorporating sensitivity and risk analyses. Scientific disciplines involved in the assessment process have evolved in parallel with the methodology from geology to a complex multi-disciplinary array of geology, geophysics, petroleum engineering, economics, and statistics. The MMS required for this assessment an appraisal method that would permit the use of a wide variety and wealth of data, but was flexible enough to be applied in areas with a scarcity of data. It also sought to employ a geologic framework that would facilitate periodic updating as an adjunct to ongoing activities. A play assessment framework was judged to be the best approach toward meeting these objectives. Thus, the basic building block of this assessment of undiscovered conventionally recoverable resources is the play.

The assessment of undiscovered conventionally recoverable resources of the Gulf of Mexico and Atlantic Continental Margin was performed irrespective of any consideration of economic constraints using a computer program called GRASP (Geologic Resources ASsessment Program). The program was adapted by MMS from the Geological Survey of Canada's PETRIMES (PETroleum Resources Information Management and Evaluation System) suite of resource assessment programs. A more comprehensive description of PETRIMES is found in Lee and Wang (1990). The program incorporates two distinct approaches toward resource assessment: the subjective approach and the discovered play approach. The subjective approach is based on the direct subjective assessment of probability distributions for each relevant geologic factor affecting the assessment (e.g., productive area and hydrocarbon pay thickness). It is designed primarily for use in areas with little or no discovery information. Dunkel and Piper (1997) employed this approach in the assessment of frontier and conceptual plays on the Pacific OCS. The discovered play approach, based on a statistical analysis of the history of discoveries in an area, was used here. Play analysis using a parametric distribution provides a flexible method to optimally use available data in a resource assessment. GRASP utilizes a single parametric distribution, the lognormal distribution. The basic procedures used in this resource assessment were the pool generation and matching processes described by Lee and Wang (1986). The major steps (figure 1) include

- data organization,
- play delineation,
- compilation of play data,
- estimation of play and prospect chance of success,
- preparation of discovery histories and pool size distributions for discoveries in established or analog plays,
- estimation of the number of pools distribution,
- estimation of the play pool size distribution,
- estimation of individual ranked pool size distributions and matching of discovery data with forecast pool sizes, and
- estimation of play resource distribution.

An effective assessment of undiscovered petroleum in a play can be developed from estimates of the size distribution of the potential pools in the play and the range in the total number of discovered and undiscovered pools (N), assuming that the play exists, in conjunction with an assessment of the appropriate marginal probability of hydrocarbons (MPhc) (Baker *et al.*, 1984). Pool size distributions describing the size range of individual pools in the play and their frequency of occurrence were the most important elements of the resource appraisal process. The expected pool size distribution is a function of the geologic model for the play. It describes the expected population of pools that would result

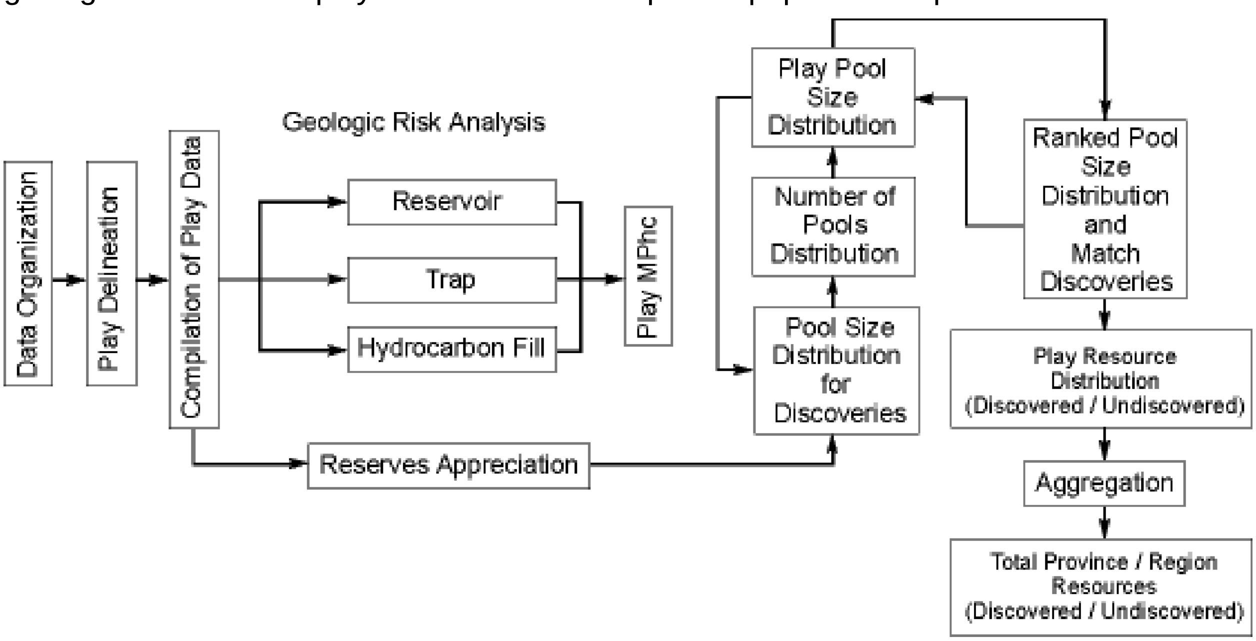

Figure 1. UCRR Process.

from repeated exploration of a particular play model.

A statistically significant number of commercial discoveries existed in 50 of the 62 plays assessed. These plays are referred to as established plays. The remainder of the plays identified on the Atlantic and Gulf of Mexico Continental Margin had either no or a minor number of commercial or noncommercial discoveries at the time of this assessment. These plays are referred to as either frontier or conceptual plays.

THE MODEL— GEOLOGIC AND STATISTICAL

The first step in the resource assessment process is to define the geologic model that will serve as the framework for the statistical analysis. Geologic processes related to petroleum generation, migration, and accumulation are complicated processes that no model can accurately simulate. Lee and Wang (1990) define a geologic model as representing a natural population and possessing a group of pools and/or prospects sharing common petroleum habitats. The latter part of this definition equates to a hydrocarbon play. The play delineation procedures employed in this assessment are described in the ***General Text, Methodology, Play Delineation*** sections. Observed pool sizes in established plays can be considered as samples from a superpopulation or parent population. Thus, geologic models possess continuous pool size distributions estimated from samples.

Serendipitous plays, those found as surprises, were not considered in this assessment. These unknown plays do not have a geologic model that can be logically assessed, and rather than add resources without a framework to determine where and how much, these potential resources were not included.

GEOLOGIC RISK ASSESSMENT

Geologic risk assessment is the process of subjectively estimating the chance that at least a single hydrocarbon accumulation is present somewhere in the area being assessed (i.e., the marginal probability of hydrocarbons [MPhc]). Once a conceptual or frontier play has been defined, it is necessary to address the question of its probable existence. As part of the play description, it is assumed that critical geologic factors such as adequate hydrocarbon source rocks, thermal maturation, migration pathways and timing, and reservoir facies are present. However, in conceptual plays and at the earliest stages of exploration in frontier plays, we cannot state with absolute confidence that these critical factors occur throughout the extent of the delineated play.

The play-level assessment of MPhc consists of a subjective analysis performed on each of the critical components necessary for a productive play— the hydrocarbon fill, reservoir, and trap components. The MPhc or play chance (White, 1980, 1993) analysis assesses individually the probability of existence for each of the critical geologic factors. If a play contains more than a minimal show of hydrocarbons as in an established play, all critical geologic factors are present. If any of these essential factors are not present or favorable, the play will not exist. The risk assessment is documented on a worksheet (figure 2) used by the assessment teams for this analysis. The probability of the presence of each factor is subjectively estimated by the assessment team. The presence or absence of direct evidence supporting the play model is a major consideration in the analysis for each component. With conceptual plays having little or no direct data, the risk assessment is guided by the evaluation of an analog play(s) and judgment as to the likelihood that the play actually reflects the analog model. Each component is considered to be geologically and thus statistically independent from the others. Therefore, the product of the marginal probabilities for each individual component represents the chance that all factors simultaneously exist within the play.

This play-level MPhc differs from the prospect-level MPhc, which relates the chance of all critical geologic factors being simultaneously present in an individual prospect. The play-level MPhc reflects the regional play-level controls affecting all prospects within the play. The fact that an individual prospect may be devoid of hydrocarbons does not mean that the play is nonproductive, nor does the presence of hydrocarbons in a play ensure their presence in a particular prospect. However, if the play is devoid of hydrocarbons, so are all of its prospects.

THE LOGNORMAL DISTRIBUTION— THE PARAMETRIC SPECIFICATION FOR POOL SIZE DISTRIBUTIONS

It has been recognized empirically for decades that within any petroleum province, and particularly within plays, the size distribution of accumulations is highly skewed (i.e., there are many small accumulations and very few large ones) (Arps and Roberts, 1958; Kaufman, 1963; McCrossan, 1969; Barouch and Kaufman, 1977; Forman and Hinde, 1985). Commonly, the few largest deposits contain the majority of the resources. Kaufman (1965), Meisner and Demirmen (1981), Crovelli (1984), Davis and Chang (1989), and Power (1992), among others, have reviewed the lognormal distribution and the many properties that make it a reasonable choice as a probability model for the relative frequency distribution of pool sizes in a play. Investigators, however, have pointed out that this assumption may not always be the best choice (Kaufman, 1993). Crovelli (1986, 1987) demonstrated that within the bounds of situations encountered within a basin, the lognormal distribution provides reasonable results, except at the extreme tails of the distribution. The ultimate choice, however, of a particular probability model is subjective.

The observation that the logarithms of pool sizes are normally distributed and the knowledge that pool size distributions can therefore be completely specified by the mean (μ, a statistical measure of central tendency) and variance (σ^2, a measure of the amount of dispersion in a set of data) of the log-transformed data constitute the major assumptions of the GRASP model. Another convenient characteristic of lognormal distributions is that a plot of the log of the values in the distribution approximates a straight line (figure 3).

The methodology employed by MMS in the resource assessment of plays having known accumulations of hydrocarbons uses the observed discovery history of an area in combination with a mathematical model (lognormal distribution) of the underlying population of pool sizes as the basis for predicting the future. A random variable, Y, has a lognormal distribution if it may be expressed as:

$$Y = \exp(X);\ X \sim N(\mu,\sigma^2),$$

where $X \sim N(\mu,\sigma^2)$ means that X is normally distributed with mean and variance σ^2. This distribution is described as parametric because it is defined by a functional form in conjunction with a limited number of parameters (μ and σ^2). Historical data related to the number and size of accumulations in conjunction with the current geologic knowledge concerning the play are fit to the statistical model that allows extrapolation of past performance into the future. Critical to this approach is the concept of resource exhaustion, the largest fields tend to be discovered early in the exploration of an area. Coincident with this concept are the observations that the average size of discovered fields tends to systematically decrease with time and new discoveries result from increasingly greater effort. Meisner and Demirmen (1981) and later Forman and Hinde (1986) observed these phenomena in several basins, determined they were attributes characteristic of the exploration of a play or basin, and applied the term "creaming" to the process. Moreover, they maintained that exploratory success rates reflect depletion of a potentially productive sediment volume. As additional wells are drilled within a particular volume of sediment, the chance of discovering a field of any given size is decreased; the resource potential is exhausted.

These characteristics are primarily an outgrowth of the highly skewed underlying field size distribution. The observed conformance of the discovery process as it unfolded for the Gulf of Mexico OCS to these traits was clearly illustrated by Lore (1992, 1995) who demonstrated that the historical record of cumulative mean field size and probability of success is distinguished by a persistent rapidly decreasing trend. As dictated by the size distribution of undiscovered pools, prospects (with the notable exception of the new ultra-deepwater frontier) are becoming increasingly smaller, more difficult to identify, and more expensive on a unit recovery basis to exploit.

Besides being a good measure for the distribution of potential sizes for an individual pool, lognormality is also a reasonable approximation for the distribution of accumulation sizes within a play or basin. The lognormal distribution has some favorable properties that make it a convenient choice for a parametric distribution to be used in an assessment model:

- The product of many independent variables is a lognormal distribution.
- The product of independent lognormal random variables is itself lognormal.
- The shape of the lognormal distribution is easy to work with.

GRASP requires that the play be defined such that the size distribution of the pools in each play comprises a single population. For each play there is a set of μ, σ^2, and N values related to the play's geologic model. Different geologic models may have different values for these parameters and thus different pool size distributions.

ESTABLISHED PLAYS

POOL SIZE DISTRIBUTION FOR DISCOVERIES

Even if there is a discovery with historical production in a play, there is still considerable uncertainty related to the volume of recoverable reserves (see the reserves appreciation discussion in the ***General Text, Methodology, Reserves Appreciation*** sections). Nevertheless, estimates of discovered pool sizes are typically expressed as single point estimates of size. In this assessment, pool sizes were expressed in terms of hydrocarbon pore volume in surface equivalent units (the reservoir volume occupied by hydrocarbons at surface standard temperature and pressure [STP]). Hydrocarbons obey complex laws related to pressure, volume, and temperature (PVT) relationships. As a result, the volume of a given quantity of hydrocarbons, expressed in terms of mass or numbers of molecules, will change as it is brought to the surface from reservoir PVT (RPVT) conditions.

The net volume of a reservoir formation is the product of rock volume and pore volume (porosity). The pore volume is occupied by both formation water and hydrocarbons. The fraction of the interstitial voids occupied by water is the water saturation; therefore the remainder of the interstitial voids is filled with hydrocarbons (1-water saturation). When the hydrocarbon pore volume is brought to the surface, that volume will change in a manner described by the formation volume factor (FVF). The FVF is defined as the ratio of the volume at RPVT conditions to the volume at STP. The in-place pool size in terms of hydrocarbon pore volume is defined by the following equation:

in-place pool size = [(reservoir volume)(porosity)(hydrocarbon saturation)]/FVF

where (reservoir volume) = (productive area of pool)(net hydrocarbon pay thickness), and
(hydrocarbon saturation) = (1-water saturation).

Only a fraction of the hydrocarbons in the reservoir are recoverable. This fraction is called the recovery efficiency. Thus, the recoverable pool size in terms of hydrocarbon pore volume is defined by:

recoverable pool size = (in-place pool size)(recovery factor)

where (recovery factor) = (yield)(recovery efficiency), and
yield = volume of hydrocarbons per unit reservoir volume.

The reserves appreciation phenomenon is considered at this point by applying the appreciation model to the estimates of discovered pool sizes. Using field discovery year, each pool is appropriately grown through the year 2020.

As seen previously, a lognormal distribution may be described by a simple equation that is the function of two parameters, μ and σ^2. If it is assumed that the pool size distribution is lognormal, the value for any individual pool can be estimated. Figure 4 shows an example of this principle of lognormality. The single point estimates, presented in blue, of discovered pools in BOE (MMbbl) are plotted against the Y-axis which is a lognormal scale. The X-axis is a probability scale which indicates the percentile likelihood of size of each of the discovered pools as well as undiscovered pools which will be estimated by the GRASP program. These points generally trend along a straight line and indicate that the discovered pools are in fact lognormal. The size distribution of discovered pools is plotted and tested to check for possible mixed populations (pools misassigned to the play). The points confirm a likely representation of the super population of pool sizes. The program calculates μ and σ^2 that represent the lognormal approximation of the distribution of these known pools. This log approximation is displayed as a red line and is utilized by GRASP in determining individual pool sizes which satisfy the parameters of μ, σ^2, and N. Probability distributions for the size of each of the undiscovered pools are then calculated.

NUMBER OF POOLS DISTRIBUTION

The discrete distribution of the total number of discovered and undiscovered pools (N) is derived from a consideration of the number of existing discoveries, the number of prospects, average prospect risk, areal extent of the play, and the degree of exploration maturity for the play. The Gulf of Mexico Region play analysis worksheet (figure 5) shows how these estimates were derived for a mature play. Prospect densities were considered when postulating the numbers of likely, but unseen, prospects by comparing what is known about a play being assessed with a more thoroughly drilled and/or mapped analog.

PLAY POOL SIZE DISTRIBUTION

The most distinctive output from GRASP is a distribution of pool sizes by rank for a play— the size of the largest pool, the second largest pool, etc. The play pool size distribution is constructed to fit the geologic model and then conditioned on the existing discoveries. The sizes of these individual discovered pools are assumed to be drawn independently from a single, known play pool size distribution— the superpopulation. GRASP uses a range for the variables μ and σ^2 (adjusted from those developed directly from the discovered pools), in conjunction with an estimate N to develop numerous combinations of these parameters describing candidates for the “true” parent lognormal pool size (hydrocarbon pore volume) distribution for the play. Each combination of μ and σ^2 is ranked on how well statistically it and the estimate of N reflect the degree to which the means of predicted individual pool sizes fit the discovered accumulations.

The discoveries in a play are recognized as a sample taken from the play’s population of pool sizes. The standard statistical practice of estimating the population μ and σ^2 from the sample is valid only if the sample is assumed to be a random sample from the pool population, or is large enough to represent the distribution of the population. In reality, neither of these situations is usually valid. Large pools are usually discovered early because the largest prospects are generally defined and drilled first— the principle of resource exhaustion. The sample set is usually clearly biased. The undrilled prospects will include a disproportionate number of small pools. The effect of this bias in the selection process is a progressive change in the pool size distribution through time. If the population is lognormal, samples at different times will also tend to be lognormal. These sample distributions will migrate downward from an initial distribution with unrealistically high μ and low σ^2 values. Therefore, μ of the sample at any point in time prior to discovery of all pools would be an overestimate and σ^2 an underestimate of the population parameters. Kaufman *et al.* (1975) illustrated this process through a series of Monte Carlo simulations of a random discovery process in a hypothetical basin. Recognizing this, the assessment team develops ranges (specified as minimum, maximum, and step size) of possible values for both μ and σ^2 for the play pool size distribution.

The play pool size distribution is then ascertained by the matching process where hypothetical pool size distributions are determined stochastically from different combinations of values for the parameters μ, σ^2, and N. The model selects values from the distribution of each parameter and generates lognormal pool rank plots. The discovered pools are then matched by GRASP to the predicted pool size distribution for each iteration. The best statistical fits are then presented to the assessors for further analysis. Statistical "goodness-of-fit" tests are applied, but the implications of the best statistical solutions must be subjectively compared with the geologic model. Since there is no unique measure to determine the best model for the play, selection of the appropriate match is one of the most challenging aspects of the resource assessment process

The pool rank plot constrained by N indicates the size and rank of both the discovered and undiscovered pools. A sample pool rank plot (figure 6) indicates that the first two largest pools have been discovered with the largest undiscovered pools in the third through the fourteenth rank. Each potential match is examined along with others to see if they are consistent with judgments concerning remaining exploration opportunities in the play. A satisfactory fit is one that is statistically reasonable and reflects the assessor's geologic model for the play. The matching process requires a careful consideration of all available information pertaining to the play: petroleum geology, discovery history, play maturity, etc. (figure 7). Typically, this is accomplished by responding to questions such as

- Has the largest pool been discovered? If not, what are the largest pools that could remain to be discovered?
- How many undrilled prospects are likely to remain in the play? What is their size distribution and average prospect risk?
- How does the play's exploration and discovery history fit the pool size distribution?
- Do the parameters of the predicted pool size distributions relate logically with similar plays?

The responses to these and similar questions may lead to changes in the choice of distribution parameters. This iterative matching procedure provides the assessment team an essential and valuable feedback mechanism, which allows them to challenge the geologic model, consider the feedback from "what if" analyses, and consider new information to refine the pool size distribution parameters and the total number of pools in the play (figure 8).

The model generates the ranked pools consistent with the inputs of μ, σ^2, and N, and discovered pools are matched by GRASP as described above. At this point, the "best fit" results in pool sizes each with a large degree of size uncertainty and considerable overlap with neighboring pools (figure 9 shows an example of matched ranked pools and discoveries). Not only does the overlap exist among the undiscovered pools, but the discovered pools also seem to have many possible matches with nearby undiscovered pools.

Once a final acceptable statistical model for the play has been determined, additional steps refine the predicted pool size ranges by a more rigorous consideration of the estimated sizes of the observed discovered pools. The distribution of hydrocarbon pore volumes for the play matched on the size of individual discovered pools is then constrained by the deterministic estimate of size for each discovered pool. The size ranges of the discovered or "matched" pools are replaced with their deterministic estimate and the uncertainty in the rest of the pool rank sizes adjusted to reflect this added information. The rank of the discovered pools is locked in, and the size range of adjacent undiscovered pools adjusted so that the rank size order of the discoveries is maintained under all possible size scenarios. This reflects the fact that the *rank - (r + 1)* pool must be smaller than the *rank - r* pool. If the *rank - r* pool is discovered, and adjacent ranked pools are undiscovered, then the lowest possible value for the *rank - (r - 1)* pool must be larger than the discrete estimate of size for the *rank - r* pool. Under the same conditions, the lowest possible value for the *rank - (r + 1)* pool must be smaller than the discrete estimate of size for the *rank - r* pool. Previously, the uncertainty in pool sizes resulted in a large degree of overlap between adjacent pools.

The subjective process of matching discoveries to the pool size distributions further reduces the uncertainty associated with the potential resource volume of individual pools in the play. The pool rank plots and cumulative probability distributions of mature and immature plays illustrate this process. In the pool rank plots, discovered pools are shown as single point values (dots) and projected undiscovered pools as distributions (bars). The length of the bar represents the F95 to F5 (the 95th and 5th percentiles, respectively) estimate of pool size; thus it encompasses 90 percent of the predicted size range for each pool. The undiscovered pool sizes must fit within the discoveries. Figure 10 shows an example of a pool rank plot and cumulative probability distribution from a very mature progradational play. Contrast this with the example of an immature play with considerable remaining potential (figure 11). Notice that in both figures, the range of possible sizes for individual pools decreases in proximity to discovered pools. These figures illustrate the greater uncertainty in individual pool sizes and aggregate play resource distributions associated with conceptual and immature plays, which have not been demonstrated to contain significant quantities of hydrocarbons and/or discovered pools. Generally, the greater the number of discoveries in the play, the less uncertainty in the number and sizes of undiscovered pools; therefore, there is less uncertainty in the total quantity of undiscovered resources for the play. The relatively narrow range of values associated with the distribution for the mature play is a reflection of the resource size constraints imposed by the discoveries.

PLAY RESOURCE DISTRIBUTION

Up to this point in the assessment, all pool sizes have been expressed as hydrocarbon pore volumes at STP conditions. Since we are interested in the actual volumes of undiscovered hydrocarbons that may exist in a play, distributions of these hydrocarbon pore volumes for the pools were used, in conjunction with individual distributions of GOR (solution gas-oil ratio, in scf/stb), YIELD (gas condensate ratio, in stb/MMcf), RECO (recoverable oil, in bbl/acre-foot), RECG (recoverable gas, in MMcf/acre-foot), and PROP (proportion of net pay oil, as a fraction), to generate the hydrocarbon volumes expressed in barrels of oil and cubic feet of gas. This process uses a Monte Carlo simulation and samples the aforementioned pore volume distributions to produce resource distributions of gas, oil, and BOE for each pool. The following equations were applied, over 1,000 trials, in order to generate the gas, oil, and BOE distributions:

Gas volume = (pore volume)(RECG)(YIELD)(1-PROP)

Oil volume = (pore volume)(RECO)(GOR)(PROP)

BOE volume = Oil volume+(Gas volume)/(oil-equivalency factor)

The model then aggregates the pool resource distributions to generate the play resource distribution.

CONCEPTUAL AND FRONTIER PLAYS

Disparate approaches to resource assessment are appropriate for different plays, particularly if, as in the Atlantic and Gulf of Mexico OCS, there are different levels of exploration maturity with very diverse amounts of geophysical, geologic, and production data available. In established plays in mature basins, the geologic concepts are well understood, and the data are both abundant and reliable. At the other end of the spectrum are plays in immature basins where their premise is based solely on regional analysis and comparisons with plays in analog basins. The available data may consist only of regional geophysical information and the results from a few exploratory wells. The assessor lacks a discovery record to use as the basis for constructing sample and play pool size distributions. The extensive database of the mature play is replaced in large part by subjective judgments and experience gained from observations in more mature areas. Probability distributions of variables (e.g., net pay thickness, recovery factor, etc.) could be subjectively developed based on comparisons with other basins and plays and the expert judgment of the assessors. If sufficient subsurface mapping was available in the area, distributions for prospect size (area), number of prospects, and an average prospect-level MPhc could be estimated. Finally, an estimate for a trap fill factor would be needed to develop possible hydrocarbon volumes for prospects. These subjective judgments would then be combined to form a pool size distribution for the play. Alternatively, comparative studies with exploration and production data from similar more mature basins and plays could be undertaken to develop analog geologic models. The assessors could then perform analyses, similar to those done on established plays, of the mature analogs resulting in a play analog expressed in terms of μ, σ^2, and N. This was the approach to assessing conceptual and frontier plays taken by MMS. This procedure allowed us to deal with the products of combinations of variables in the pool size equation rather than each variable individually.

The key problem in this approach to assessing the immature or conceptual play is in the selection of an appropriate analog(s). A suitable analog is an established play that possesses geologic attributes similar to the play being assessed. The use of the analog requires subjective modification of the play model through the appropriate scaling of the factors (Mphc, μ, σ^2, and N) affecting the forecast for the play being assessed.

The basic pool-level data used in this resource assessment for the Cenozoic Province of the Gulf of Mexico have been released on the Internet at http://www.gomr.mms.gov and through the *Atlas of Northern Gulf of Mexico Gas and Oil Reservoirs* (Seni *et al.*, 1997; Hentz *et al.*, 1997). However, the Mesozoic Provinces of the Gulf of Mexico and Atlantic OCS have a limited amount of direct information available. Only the Upper Jurassic Aggradational (UU A) play (Norphlet Formation) in the Gulf of Mexico has more than one significant hydrocarbon accumulation. It was therefore essential to identify analogous plays to assess these Provinces properly. Identifying adequate analogs in the Gulf of Mexico Mesozoic Province was not difficult, since there has been an extensive record of exploration onshore along the United States Gulf Coast within the Mesozoic section. In the Atlantic OCS, two analog areas were identified as possible models for assessing the clastic plays: the onshore United States Gulf Coast and the Scotian Shelf offshore Canada. The carbonate plays in the Atlantic were modeled using onshore United States Gulf Coast carbonate plays as analogs.

The approach used in assessing conceptual and frontier plays involved first assessing the analog plays, which parallels the process used in assessing the established plays. The first step after completion of play delineation was to assemble all relevant analog play data. This consisted primarily of pool maps, pool size information, discovery histories, well logs, and relevant reports and publications. Seismic data were also available for the Scotian Shelf analog. Once all relevant data are gathered, there are three critical steps involved in the evaluation process (1) assessing the play marginal probability, (2) developing number of pools distributions for the analogs and scaling them to the play being assessed, and (3) developing pool size distributions for the analogs and scaling them to the play being assessed.

The marginal probability estimation for conceptual and frontier plays is a subjective judgment. Because conceptual plays, and quite often frontier plays, have little or no direct data, the risk assessment is guided by the evaluation of an analog(s) play. Judgment as to the likelihood that the play being assessed actually reflects the analog model (structural style, source rock type, burial history, etc.) is considered in determining an appropriate marginal probability for the play.

To develop number of pools distributions, a careful consideration of each play's discovery history, pool density, and degree of exploration maturity was undertaken, and a potential range for N was estimated. Estimates of the range of N in conceptual and frontier plays were derived from the use of both prospect densities (in conjunction with associated average prospect-level MPhc) and pool densities observed in mature, well-explored analogs. Prospect densities were typically calculated by first counting all prospects in a well-mapped portion of the play. Next, the assessment team would subjectively estimate the range in the number of prospects that could possibly fall within the seismic control grid. The two estimates were summed and divided by the area mapped to determine a range of prospect densities (number of prospects per 1,000 square miles). This range of prospect densities was then multiplied by play area after possible adjustments for areal variations in hydrocarbon prospectiveness to calculate a number of prospects distribution. Finally, the number of prospects distribution was multiplied by the average prospect-level MPhc to derive a number of pools distribution. The prospect-level MPhc was subjectively determined by experience in the play and/or success ratios in analog plays. The number of pools distribution was further checked against assessed mature analogs.

To develop pool size distributions, the particular characteristics (areal extent, hydrocarbon type, richness, prospect size and density, etc.) of the frontier or conceptual play were compared with the statistical model derived from the geologic analog and scaled appropriately. Hydrocarbon pore volumes from observed discoveries in the analog play were then calculated and used by GRASP to form lognormal approximations of hydrocarbon pore volumes for the play being assessed. The program calculates a probability distribution for the size of each of the discovered pools in the play, and derives a μ and σ^2 from the log approximation of the distribution of these known pools. Sample pool size distributions for the discoveries in two analog plays, the Gulf Coast analog and the Scotian Shelf analog, can be seen in figures 12 and 13, respectively.

Once the above steps were completed, the result was the development of a statistical model for each analog play fully described by Mphc, μ, σ^2, and N. Each analog play was then assessed following the same process as used for established plays on the OCS.

AGGREGATION

Cumulative probability distributions of undiscovered conventionally recoverable resources for areas larger than the play were developed by statistically aggregating the probability distributions for individual plays to progressively higher levels using the computer program FASPAG (Fast Appraisal System for Petroleum AGgregation) (Crovelli, 1986; Crovelli and Balay, 1988, 1990). The aggregation hierarchy was play, chronozone, series, system, province, region, and the combined Gulf of Mexico and Atlantic Continental Margin. An estimate of the degree of geologic dependency was incorporated at each level of aggregation. For instance, plays were aggregated within chronozones on the basis of estimates of the geologic dependence among the plays. The dependence reflects commonality among the plays with respect to factors controlling the occurrence of hydrocarbons at the play level: charge, reservoir, and trap. Dependencies also reflect the degree of coexistence among the plays. Values for dependency can range from one, in which case each play would not exist if the other(s) did not exist, to zero, in which case the existence of each play is totally independent from all others. A very accurate dependency value is impossible to derive because of the geologic complexity of the plays. Therefore, a dependency value of 0.5 was generally used for all aggregations except when regions were aggregated. Regions were assumed to be independent.

Figure 2. MPhc Worksheet and Guidelines for Estimating Play Geologic Risk.

Play Risk Analysis Form
1995 National Assessment
Established Plays

For each component, a *quantitative* probability of success (i.e., between zero and one, where zero indicates no confidence and one indicates absolute certainty) based on consideration of the *qualitative* assessment of ALL elements within the component was assigned. This is the assessment of the probability that the minimum geologic parameter assumptions have been met or exceeded.

1. Hydrocarbon Fill component a. Source rock b. Maturity c. Migration d. Timing	**1.00**
2. Reservoir component a. Reservoir quality b. Depositional environment c. Diagenesis	**1.00**
3. Trap component a. Closure b. Seal	**1.00**
Play Success (Marginal Probability of hydrocarbons, MPhc) (1) x (2) x (3)	**1.00**
Play Risk (1 - Play Success)	**0.00**

Comments:
This is an established play from which hydrocarbons have been produced.

Guidelines for Estimating Play Geologic Risk

Scoring is based on a central 50/50 chance value:

0.0-0.2 component is probably lacking
0.2-0.4 component is possibly lacking
0.4-0.6 equally likely component will be present or absent
0.6-0.8 component will possibly exist
0.8-1.0 component probably exists

Hydrocarbon Fill Component

This component assesses the probability that hydrocarbons exists in the play. Elements which affect the probability of hydrocarbon existence are source rock, maturity, migration, and timing.

Scoring: The score range used to estimate adequacy of hydrocarbon charge is determined by the most pessimistic of the charge parameters (i.e., source rock, maturity, migration, and timing). For example, if source rock, maturity, and migration qualify for the range 0.8-0.6. but timing only qualifies for the range 0.6-0.4, then the overall chance of charge must be scored in the range 0.6-0.4.

Score 1.0-0.8

Source rock: Presence of source rock within the play is clearly indicated by the existence of pools or implied by well and seismic data. Source rock (predicted or directly measured) should be of high quality.

Maturity: Hydrocarbon expulsion from the source rock is clearly indicated by the existence of pools or implied (e.g., borehole shows, hydrocarbon seeps, and possibly seismic direct hydrocarbon indicators [DHI's]). The source rock is clearly defined and of sufficient volume to source the minimum size prospect assessed within the play.

Migration: A viable migration pathway is clearly supported by the distribution of pools, hydrocarbon shows, and possibly seismic DHI's. The geometry and effectiveness of the migration pathway should be clearly apparent on seismic data.

Timing: Prospects' (or leads') closures should clearly pre-date the main phases of hydrocarbon expulsion.

Score 0.8-0.6

Source rock: Presence of source rock within the play is probable based on well and seismic data or the basin model. Source rock quality (predicted or directly measured) should be high. Slightly leaner source rocks may be considered if it can be demonstrated that the migration pathway is highly efficient.

Maturity: Hydrocarbon expulsion from the source rock is probable based, for example, on the presence of borehole shows, hydrocarbon seeps, and possibly seismic DHI's. The source rock is probably of sufficient volume to source prospects (or leads) of the minimum assessed size.

Migration: A viable migration pathway is probable as implied by the distribution of surrounding hydrocarbon shows, seeps, and possibly seismic data. A probable migration pathway should be apparent on seismic data.

Timing: It should be at least probable that the prospects' (or leads') closures pre-date the main phases of hydrocarbon expulsion.

Score 0.6-0.4

Source rock: Source rock may or may not be present based on well and seismic data or basin modeling. There may be no data to support or deny the presence of high quality source rock.

Maturity: Hydrocarbon expulsion from the source rock is supported by maturation modeling. The basin model and seismic interpretation should give some indication of source rock volumes. The source rock may or may not be of sufficient volume to source the minimum sized prospect (or lead).

Migration: A viable migration pathway may or may not exist.

Timing: The prospects' (or leads') closures may or may not pre-date the main phases of hydrocarbon expulsion.

Score 0.4-0.2

Source rock: Well and seismic data or the basin model indicate that high quality source rocks may be absent.

Maturity: Maturation modeling indicates the possibility that source rock volume is insufficient to source the minimum sized prospect (or lead).

Migration: The distribution (or absence) of hydrocarbon shows and possible seismic DH'Is, or the results of seismic structural mapping, indicate the possibility that the prospects (or leads) do not lie on a viable migration pathway.

Timing: Seismic interpretation and basin modeling indicate the possibility that the prospects' (or leads') closures post-date the main phases of hydrocarbon expulsion.

Score 0.2-0.0

Source rock: Well and seismic data or the basin model indicate that high quality source rocks are probably absent.

Maturity: Maturation modeling indicates the probability that source rock volume is insufficient to source prospects (or leads) of the minimum size assessed.

Migration: The distribution (or absence) of hydrocarbon shows and possible seismic DHI's, or the results of seismic structural mapping, indicate the probability that the prospects (or leads) do not lie on a viable migration pathway.

Timing: Seismic interpretation and basin modeling indicate the probability that throughout the play the prospects' (or leads') closures post-date the main phases of hydrocarbon expulsion.

Reservoir Component

This component assesses the presence of reservoir rock. It also estimates the chance that applicable reservoir parameters exceed specified minimums for porosity, permeability, fracturing, shaliness, cementation, and thickness.

Score 1.0-0.8

Reservoir quality, depositional environment, and diagenesis: Presence of reservoir rock within the play is clearly indicated by pools and wells. The reliability of reservoir presence is confirmed by seismic facies analysis (i.e., there is no evidence of reservoir deterioration between wells and prospects). Reservoir presence may also be supported by seismic attributes. Both wells and seismic data yield a consistent depositional and diagenetic model.

Score 0.8-0.6

Reservoir quality, depositional environment, and diagenesis: Presence of reservoir rock is proven in at least one well in the play, and its presence throughout the play is confirmed by seismic data (facies and/or attributes). It may not be possible to predict reservoir rock from seismic facies analysis; however, a positive indication should come from the depositional and diagenetic model.

Score 0.6-0.4

Reservoir quality, depositional environment, and diagenesis: Presence of reservoir is neither confirmed nor denied by well or seismic data and the associated depositional and diagenetic model. In rank wildcat areas, the chance of reservoir presence will often be the same as risk of reservoir absence.

Score 0.4-0.2

Reservoir quality, depositional environment, and diagenesis: Wells and seismic data indicate possible absence of a reservoir. Seismic facies analysis and the depositional and diagenetic model indicate the possibility of reservoir absence.

Score 0.2-0.0

Reservoir quality, depositional environment, and diagenesis: Wells and seismic data indicate probable absence of a reservoir. Seismic facies analysis and the depositional and diagenetic model indicate the probability of reservoir absence.

Trap Component

This component assesses the existence of closure in the trap (structural, stratigraphic, or combination of both) and considers the existence and quality of seal. The presence of a seal is required when assessing the trap component. The quality of the seal can favorably or adversely affect the assessment of the trap and must be reflected in the overall score of the trap component. The score range used to estimate the adequacy of trap is determined by the most pessimistic range of the trap parameters. For example, if the presence of seal qualifies for the 0.6-0.4 range and this is less than success probability of the closure parameter, then the overall chance of the trap component must be in the 0.6-0.4 range.

Score 1.0-0.8

Closure: Presence of minimum structural or stratigraphic closure within the play is clearly indicated by the existence of pools or implied by well and seismic data. Available well and seismic data allow accurate depth conversion. Closures should be identified from the top reservoir pick, which should be clearly registered on seismic. Stratigraphic closures should be further defined by a reliable base reservoir pick, and wedge-out geometry should be clearly resolved on seismic data.

Seal: Presence of seal is clearly calibrated by wells and seismic data. The integrity of seal is confirmed by the existence of pools or implied by seismic facies analysis; there is no evidence of seal lithofacies deterioration between wells and prospects. Predicted reservoir pressure is not sufficient to break seal (consider capillary entry pressure of seal lithology). There is no evidence of widespread structural breaching such as faults, jointing, or fracture cleavage.

Score 0.8-0.6

Closure: Presence of minimum structural or stratigraphic closure is probable based on seismic coverage and depth conversion. Closures should be identified from the top or near-top reservoir pick. For stratigraphic traps, wedge-out geometry should be clearly apparent on at least some seismic lines.

Seal: Presence of seal is proven in at least one well, and its presence within the play is confirmed by seismic data. It may not be possible to predict seal from seismic facies analysis. Available reservoir pressure data are insufficient to demonstrate a lack of seal integrity. At worst there is only a small risk of structural breaching.

Score 0.6-0.4

Closure: Based on seismic coverage and depth conversion, there is a near equal chance of minimum structural or stratigraphic closure being present or absent within the play. This may be because the mapped seismic horizon is significantly above the target as a result of limited seismic quality.

Seal: Presence of seal is neither confirmed nor denied by well or seismic data. In rank wildcat areas, the chance of seal presence will often be the same as risk of seal absence.

Score 0.4-0.2

Closure: Closures exceeding minimum size are inadequately defined by seismic data.

Seal: Wells and seismic data indicate possible absence of a seal. Reservoir pressure data suggest some risk of seal failure. Structural breaching of the seal is also possible.

Score 0.2-0.0

Closure: Seismic data indicate that closures exceeding minimum size are not present.

Seal: Well, seismic, or reservoir pressure data indicate high risk of seal failure.

Modified from B.A. Duff and D. Hall. 1996. A model-based approach to evaluation of exploration opportunities, *in* A.G. Dore and R. Sinding-Larson, eds., Quantification and prediction of petroleum resources: Norwegian Petroleum Society Special Publication No. 6, p. 183-198.

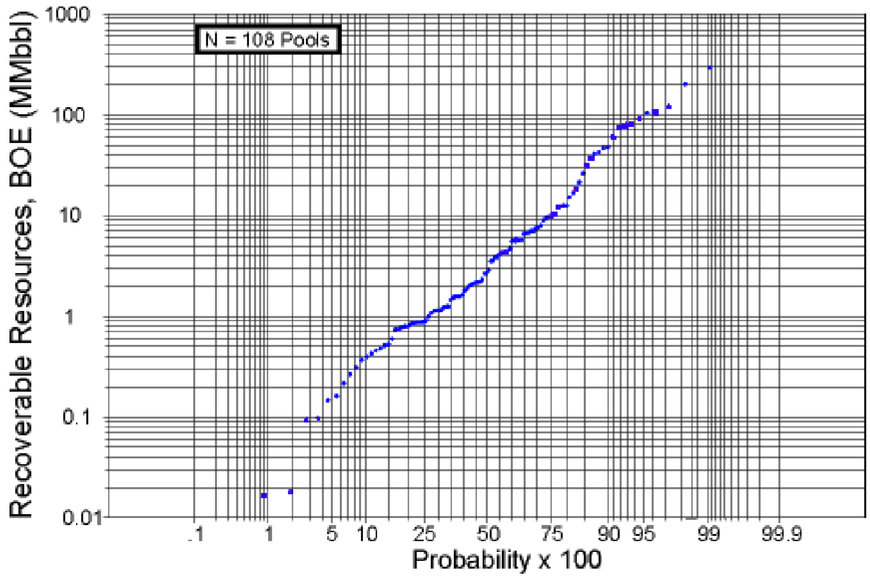

Figure 3. Sample Lognormal Distribution.

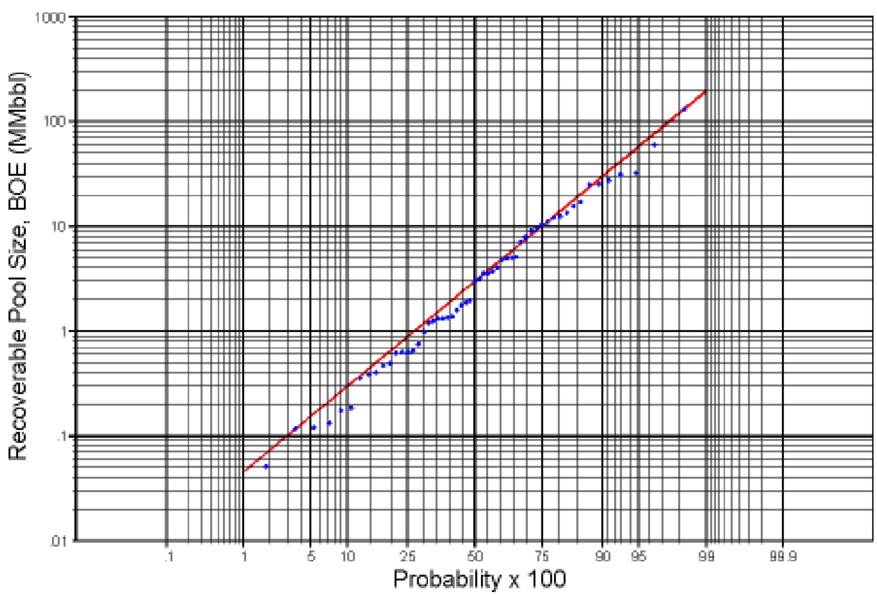

Figure 4. Lognormal Distribution.

1995 National Assessment Play Analysis Worksheet Part 1 (Prior to GRASP)	Name of Play: ______ Chronozone: ______ Depositional style/facies: ______
Play characteristics	
Number of discovered pools in the play	______
Estimated prospective area of play within geologic limit	______ MM acres
Estimated area of play relatively unexplored	______ MM acres
Proved reserves of play	
as of 1/1/95	
Oil	______ MMbo
Gas	______ Bcfg
BOE	______ MMBOE
after reserves appreciation (through 12/2020)	
Oil	______ MMbo
Gas	______ Bcfg
BOE	______ MMBOE
Unproved reserves of play	
as of 1/1/95	
Oil	______ MMbo
Gas	______ Bcfg
BOE	______ MMBOE
after reserves appreciation (through 12/2020)	
Oil	______ MMbo
Gas	______ Bcfg
BOE	______ MMBOE
Types of pools in play	
What is the observed percentage of:	
Oil pools	______ % oil
Gas pools	______ % gas
Mixed pools	______ % mixed
What do you expect the final percentages to be (with additional discoveries)?	
Oil pools	______ % oil
Gas pools	______ % gas
Mixed pools	______ % mixed
Largest discovered pool in play	
Pool name	______
Pool discovery year	______
Pool hydrocarbon pore volume	______ acre-feet
Pool reserves, after appreciation	
Oil	______ MMbo
Gas	Bcfg
BOE	______ MMBOE

Figure 5. Play Worksheet, Part 1 (Prior to GRASP).

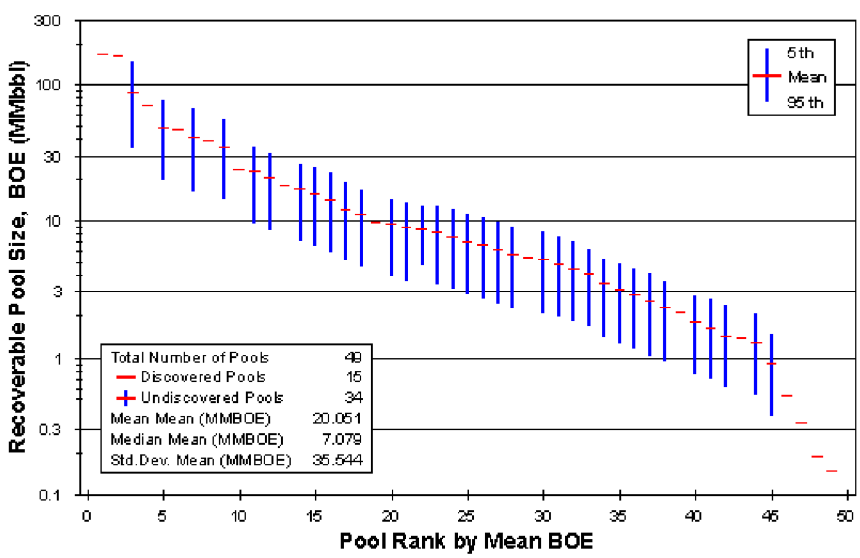

Figure 6. Sample Pool Rank Plot.

1995 National Assessment Play Analysis Worksheet Part 2 (GRASP Input)	Name of Play: ____ Chronozone: ____ Depositional style/facies: ____

Answer the following questions after reviewing and considering the play's:
discovery history, pool size distribution, available geological and geophysical analysis, and exploration status.

Largest pool in play
Has the largest pool in the play been discovered? Yes / No
What is your best estimate of the approximate size, in terms of recoverable reserves after appreciation, of the largest pool remaining to be discovered?
Oil ____ MMbo
Gas ____ Bcfg
BOE ____ MMBOE

Number of pools in play
Using your knowledge of the play and the untested acreage within the limit of the play; how many pools remain to be discovered:
Low estimate ____ pools
(3 chances in 4 that at least this many pools remain to be discovered)
High estimate ____ pools
(1 chance in 4 that at least this many pools remain to be discovered)
Mean estimate ____ pools
(2 chances in 4 that at least this many pools remain to be discovered)

Play analogs
What play(s) is a good analog for this play? ____

Describe how this play differs significantly from its analog(s), e.g. 50 % less area, 25% less volume, more intensely faulted, fewer salt domes, significantly less sand, etc. Attach additional sheets if necessary.

Figure 7. Play Worksheet, Part 2 (GRASP input).

1995 National Assessment Play Analysis Worksheet Part 2 (GRASP Input)	Name of Play: ____ Chronozone: ____ Depositional style/facies: ____

Answer the following questions after reviewing and considering the play's:
discovery history, pool size distribution, available geological and geophysical analysis, and exploration status.

Largest pool in play
Has the largest pool in the play been discovered? Yes / No
What is your best estimate of the approximate size, in terms of recoverable reserves after appreciation, of the largest pool remaining to be discovered?
Oil ____ MMbo
Gas ____ Bcfg
BOE ____ MMBOE

Number of pools in play
Using your knowledge of the play and the untested acreage within the limit of the play; how many pools remain to be discovered:
Low estimate ____ pools
(3 chances in 4 that at least this many pools remain to be discovered)
High estimate ____ pools
(1 chance in 4 that at least this many pools remain to be discovered)
Mean estimate ____ pools
(2 chances in 4 that at least this many pools remain to be discovered)

Play analogs
What play(s) is a good analog for this play? ____

Describe how this play differs significantly from its analog(s), e.g. 50 % less area, 25% less volume, more intensely faulted, fewer salt domes, significantly less sand, etc. Attach additional sheets if necessary.

Figure 8. Play Worksheet, Part 3 (after GRASP).

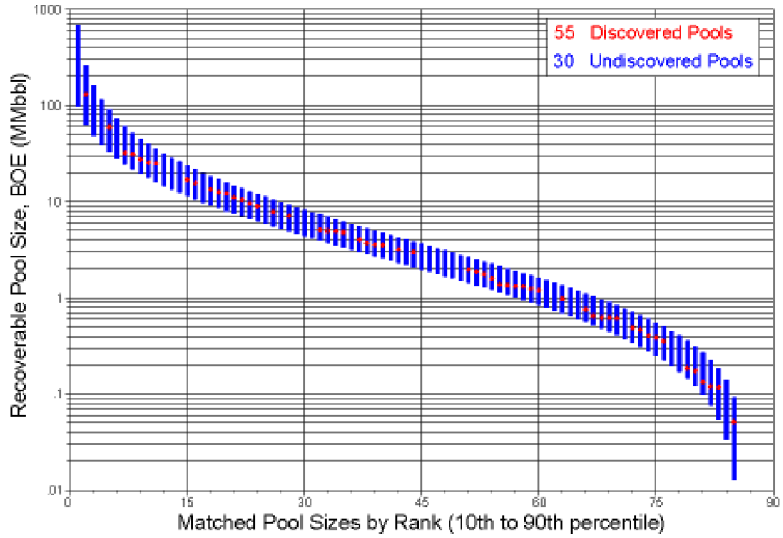

Figure 9. Matched Pool Rank Plot.

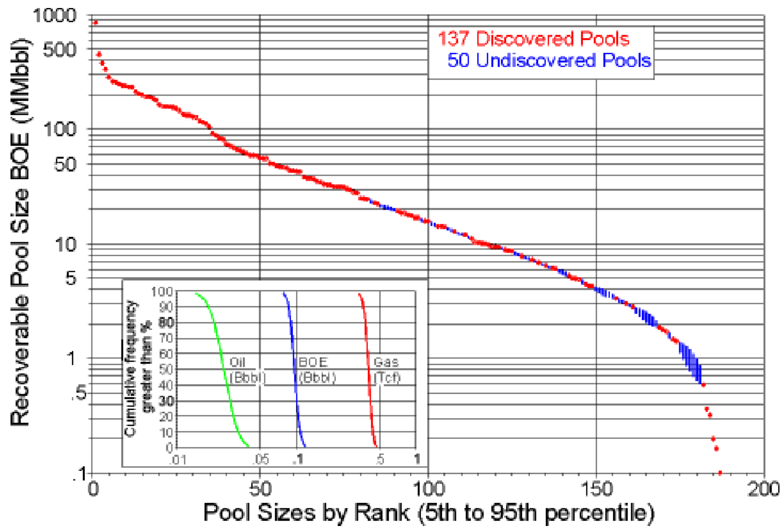

Figure 10. Mature Play Pool Rank Plot.

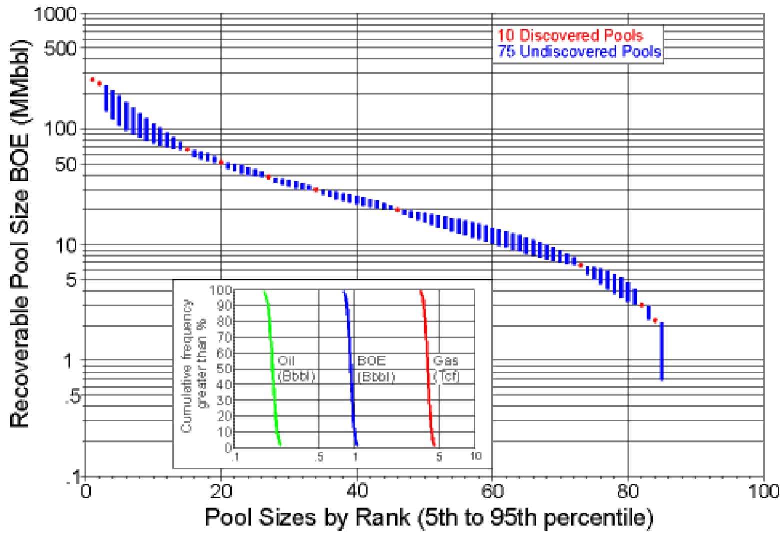

Figure 11. Immature Play Pool Rank Plot.

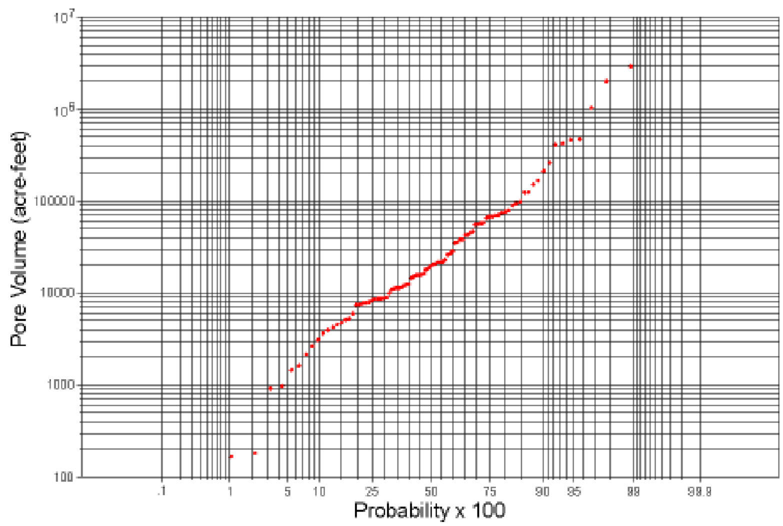

Figure 12. Gulf Coast Analog Pool Size Distribution.

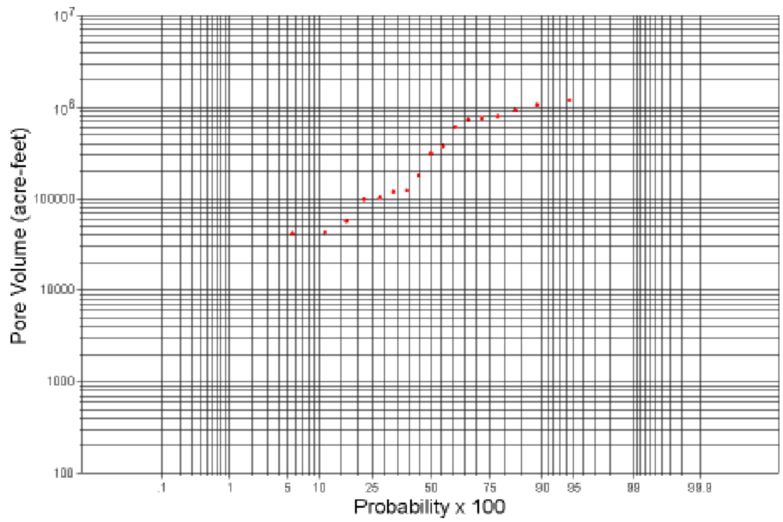

Figure 13. Scotian Shelf Analog Pool Size Distribution.

UNDISCOVERED ECONOMICALLY RECOVERABLE RESOURCES (UERR) GENERAL DISCUSSION

The objective of the economic analysis phase of this assessment was to estimate the portion of the undiscovered conventionally recoverable resources that is expected to be commercially viable in the long term under a specific set of economic conditions. The profitability of a newly discovered field depends on its expected size, oil and gas mix, depth, location, production characteristics, and the point in time at which profitability is measured. Commercial viability or profitability is measured in this study from the two perspectives referred to as full- and half-cycle analysis. The full-cycle analysis does not include pre-lease costs, but does consider all leasehold, geophysical, geologic, and exploration costs incurred subsequent to a decision to explore in determining the economic viability of a prospect. The decision point is whether or not to explore. However, in the exploration process, fields are often discovered that cannot support both exploration and development costs. Some of these fields can be profitably developed once discovered. In a half-cycle analysis, leasehold and exploration costs, as well as delineation costs that are incurred prior to the field development decision, are assumed to be sunk and are not used in the discounted cash flow calculations to determine whether a field is commercially viable. The decision point is whether or not to proceed with development. In neither the full- nor the half-cycle scenario is lease acquisition or other pre-decision point leasehold costs considered in the evaluation. It is assumed in this analysis that the operator is a rational decisionmaker; an investment will not be undertaken unless the full costs of the venture are recovered. Estimates made at different stages in the investment cycle measure the impact of costs yet to be incurred on operational decisions.

The pool rank plots and the marginal probability of hydrocarbons (MPhc) generated by the Geologic Resources ASsessment Program (GRASP) for each play are the key geologic inputs to the economic analysis performed by the Probabilistic Resource ESTimates— Offshore (PRESTO) program. The Gulf of Mexico and Atlantic Regions both contain "stacked plays" (i.e., plays that overlie other plays at different depths) (figure 1). In determining the economic viability of such plays, assessors considered the concurrent exploration, development, and production of possible pools in these plays to determine properly the economic viability of the prospect's resources. If stacked plays were not considered, the estimates of undiscovered economically recoverable resources would be overly

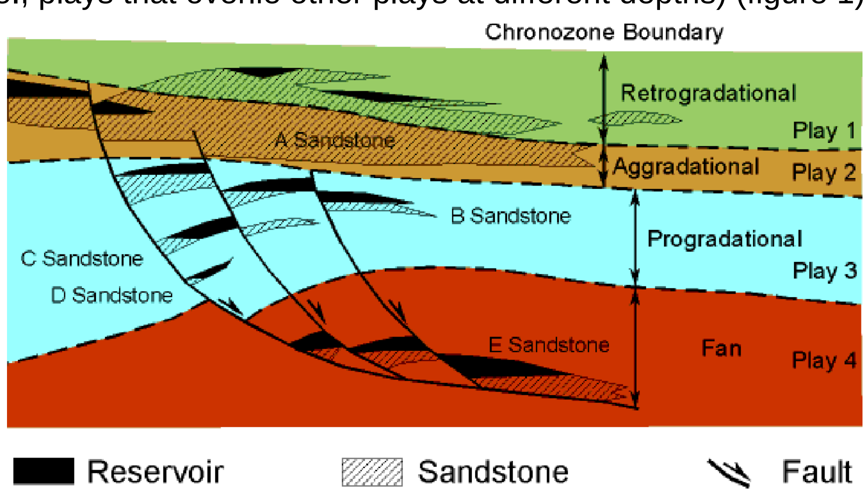

Figure 1. Stacked Plays.

conservative. Therefore, it was necessary to transform the play-based pool size distributions to area-based field size distributions. This was accomplished using the GRASP model from a different perspective— the field.

Exploration and development scenarios— assumptions about the timing and cost of exploration, delineation, development, and transportation activities— were developed specifically for each region, province, planning area, and the combined Gulf of Mexico and Atlantic Continental Margin, by water depth category. These scenarios were based upon logical sequences of events that incorporated past experience, current conditions, and foreseeable development strategies.

Estimates of the undiscovered economically recoverable resources were then derived through a stochastic discounted cash flow simulation process (figure 2), using either a full- or half-cycle approach, for specific product prices using generalized exploration, development, and transportation costs and tariffs with their associated development scheduling scenarios for each relevant area. The basic economic test is performed at the pool (or field) level with subsequent economic hurdles at the area and region levels. Profitability in this assessment was an expected positive after tax net present worth, which was determined by discounting all future cash flows back to the appropriate decision point (to explore or to develop and produce) at a 12-percent discount rate. The half-cycle analysis, which treats lease acquisition, exploration, and delineation costs as sunk, often recognizes the smaller pools that would be economic to develop and produce once found. However, except under rare circumstances, these pools would not typically be exploration targets. Therefore, the expected total economic resource should be somewhere between the comparable full- and half-cycle analysis results.

Estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions and are presented primarily as price-supply curves that describe a functional relationship between economically recoverable resources and product price. The price-supply curves developed in this assessment are marginal-cost curves representing the incremental costs per unit of cumulative output (undiscovered economically recoverable resources). The price-supply curves portray the estimated quantity of undiscovered conventionally recoverable resources that could be profitably produced under a specific set of economic, cost, and technologic assumptions. The curves are unconstrained by alternative sources of hydrocarbons (investment opportunities or market supply and demand) or the effects of time in these analyses. Generally, price and cost (technology) can be considered as equal substitutions for one another. It should be noted that entire resource distributions are generated at each price level, but all of the price-supply curves presented in this report will be the mean case curves.

Figure 3 shows separate curves for oil and gas resources. The two commodity prices are displayed on the y-axes, and a horizontal line drawn from the price axis to the curve yields the quantity of economically recoverable resources at the selected price. The curves represent mean values at any specific price, and it is important that the user realize that the oil and gas prices are not independent. The gas price is dependent on the oilprice, and the two must be used in tandem to determine resource volumes. For example, if a \$30.00/bbl oil price is used to determine the oil resources, the dependent gas price of \$3.52/Mcf must be used to determine the gas resources. Furthermore, the two hydrocarbons frequently occur together, and the individual pool economics are calculated using the coupled pricing.

Two horizontal lines within the graph indicate the critical and marginal prices. Values above the critical price indicate that there was at least one prospect that was simulated as economic at these prices on each trial. Below the marginal price, no prospects were commercially viable. At prices between the critical and the marginal price, a prospect was determined to be economic on some iterations. The two vertical lines indicate the mean estimates of undiscovered conventionally recoverable natural gas and oil resources. As prices increase, the estimate of economically recoverable resources approaches this limit.

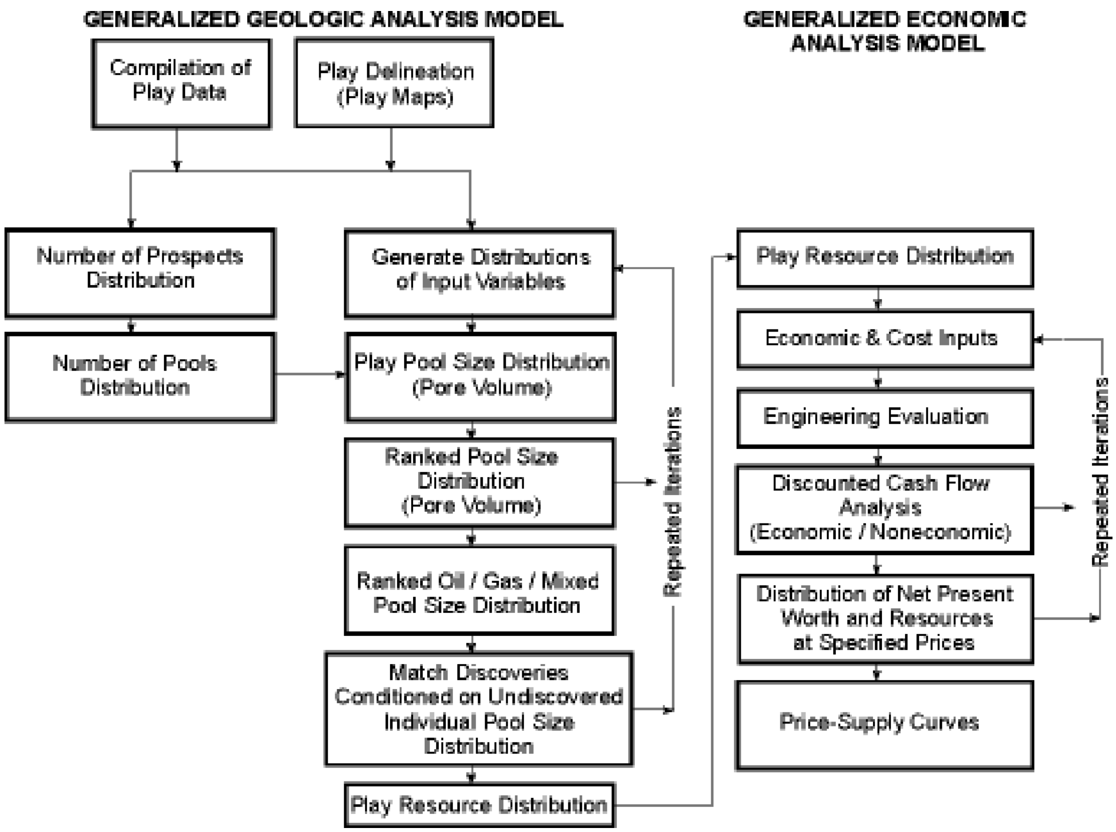

Figure 2. Assessment Process.

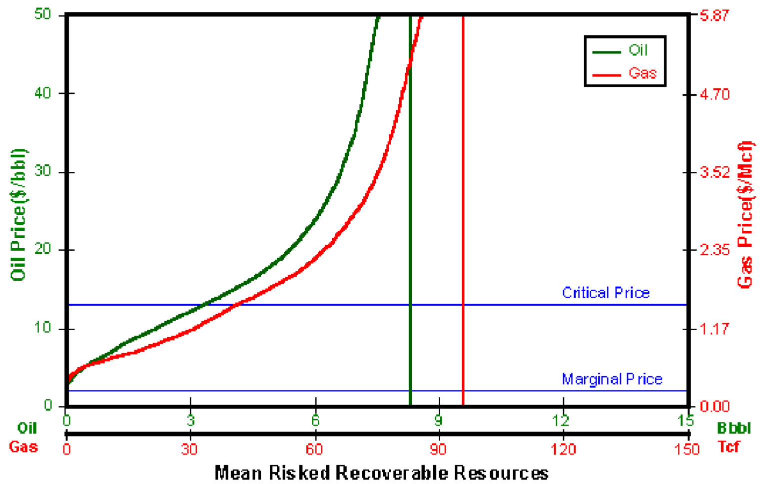

Figure 3. Sample Price-Supply Curve.

UNDISCOVERED ECONOMICALLY RECOVERABLE RESOURCES (UERR) DETAILED DISCUSSION

Since the resource assessment and economic evaluation of recoverable resources must be performed "pre-drill," there is considerable uncertainty as to whether hydrocarbons actually are present in the area and, if so, which of the prospects contain the hydrocarbons and the volume present. Because the productivity of these prospects and their economic viability are also not known until actual drilling occurs, the geologic and economic uncertainties surrounding these evaluations are often enormous. The economic resource evaluation for this assessment was conducted using MMS's Probabilistic Resource Estimates— Offshore (PRESTO) model. PRESTO utilizes a stochastic modeling technique known as Monte Carlo simulation to quantify uncertainty and incorporate subjective judgments in an objective manner. This technique has become a standard in the petroleum and other industries for making decisions under conditions of uncertainty. The technique enables the evaluator to incorporate uncertainty as a range of possible values and specify the distribution type (fixed, normal, lognormal, uniform, loguniform, triangular, and user-defined-free-form) for variables, rather than being restricted to single point estimates. The marginal probability of hydrocarbons (MPhc) is specified at both the play and prospect levels. The model contains mathematical statements that specify the relationships among all variables affecting the outcome. Many iterations or trials are performed to simulate a range of possible outcomes or states of nature. In each iteration, different values are selected from the range of uncertain variables, with each iteration yielding one possible state of nature.

The PRESTO model evolved from a principally geologic assessment model using minimum economic field size cutoffs for economic analyses to a complete discounted cash flow model that analyzes the economics of every pool (or field) in an area and aggregates the economically recoverable resources and various cash flow distributions of each prospect to the area and a higher level (e.g., a basin or region). The program tests the economic viability of potential resource volumes of individual pools, areas, and regions as they may occur in nature. However, the model also incorporates the chance that these hydrocarbon resources may not exist and, if they do exist, may be uneconomic to produce. As with the geologic resource assessment phase of the analysis, the primary problem complicating the economic resource evaluation is insufficient information. Each prospect, area, and region is modeled mathematically. The methodology employed for the engineering and economic evaluation must also consider the relative uncertainty of the available engineering and economic information. The modeling approach used by PRESTO is to simulate the actual drilling of the area under consideration.

Upon completion of the resource assessment phase, in which MMS's Geologic Resources ASsessment Program (GRASP) was used to evaluate the estimates of undiscovered conventionally recoverable resources, distributions of all possible outcomes or physical states of nature (number and size distribution of discovered and undiscovered pools in a play) are imported into PRESTO for economic evaluation (figure 1). The ability to develop and produce all or a portion of the conventionally recoverable resources depends primarily upon (1) the total volume of conventionally recoverable resource, (2) the

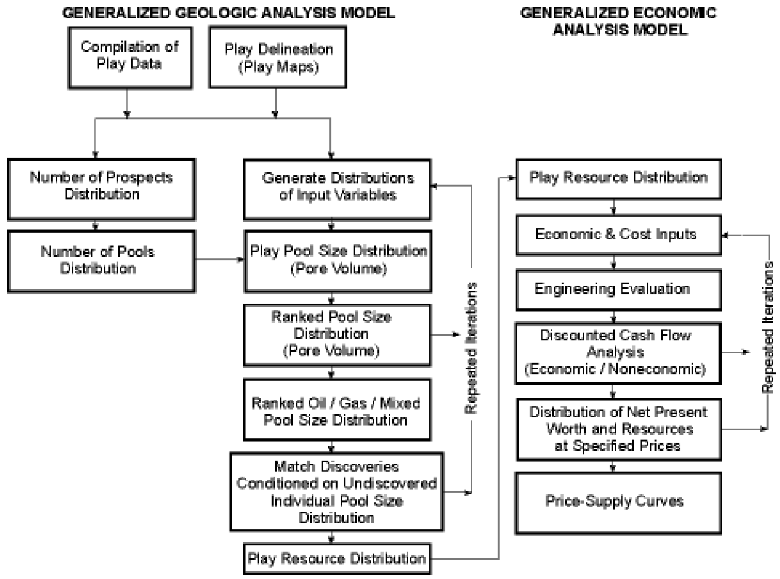

Figure 1. Assessment Process.

extraction cost, and (3) the price obtained. Ideally, an exploratory well may be drilled in each prospect to determine if it is hydrocarbon bearing. If the exploratory well encounters hydrocarbons that are initially assessed to be of a size and characteristic sufficient to warrant additional drilling, further exploration and delineation wells would be drilled to justify the installation and determine the appropriate size of a platform or satellite complex. A development drilling program leading to production will also be determined. If the interrelationships of these factors result in a forecast of real-term profits, the accumulation is developed. The production profile will subsequently size production equipment and pipelines for timely installation and transportation of production to the market. Ultimately, the field would be abandoned when the revenue from production was insufficient to cover the costs of production (operating costs, taxes, and royalties). This phase of the evaluation models 1,000 states of nature derived from the geologic resource assessment phase to determine the economic viability of each potential hydrocarbon accumulation, subarea, and ultimately the planning area. Economically recoverable resources represent only a fraction of the physically recoverable resource. Estimates are derived of the potential volumes of economically recoverable hydrocarbon resources that may be discovered, as well as certain economic measures associated with the production of these resources.

Commercial viability or profitability is measured in this study from the two perspectives referred to as full- and half-cycle analysis. Full-cycle analysis does not include pre-lease costs, but does consider all leasehold, geophysical, geologic, and exploration costs incurred subsequent to a decision to explore in determining the economic viability of a prospect. The decision point is whether or not to explore. However, in the exploration process, fields are often discovered that cannot support both exploration and development costs. Some of these fields can be profitably developed once discovered. In a half-cycle analysis, leasehold and exploration costs, as well as delineation costs that are incurred prior to the field development decision, are assumed to be sunk and are not used in the discounted cash flow calculations to determine whether a field is commercially viable. The decision point is whether or not to proceed with development. In neither the full- nor the half-cycle scenario is lease acquisition or other pre-decision point leasehold costs considered in the evaluation. It is assumed in this analysis that the operator is a rational decisionmaker; an investment will not be undertaken unless the full costs of the venture are recovered. Estimates made at different stages in the investment cycle measure the impact of costs yet to be incurred on operational decisions.

Estimates of the undiscovered economically recoverable resources were derived through a stochastic discounted cash flow simulation process (figure 1), using either a full- or half-cycle approach. The basic economic test is performed at the pool (or field) level with subsequent economic hurdles at the area and region levels. Profitability in this assessment was an expected positive after tax net present worth, which was determined by discounting all future cash flows back to the appropriate decision point (to explore or to develop and produce) at a 12-percent discount rate. The half-cycle analysis, which treats lease acquisition, exploration, and delineation costs as sunk, often recognizes the smaller fields that would be economic to develop and produce once found. However, except under rare circumstances, these fields would not typically be exploration targets. Therefore, the expected total economic resource should be somewhere between the comparable full- and half-cycle analysis.

GEOLOGIC INPUTS

The pool rank plots and the marginal probability of hydrocarbons (MPhc) generated by the Geologic Resources ASsessment Program (GRASP) for each play are the key geologic inputs to the economic analysis performed by the Probabilistic Resource ESTimates— Offshore (PRESTO) program. The Gulf of Mexico and Atlantic Regions both contain "stacked plays" (i.e., plays that overlie other plays at different depths) (table 1 and figure 2). These stacked pools are commercially developed as single fields, and since

Number of Plays	Number of Fields by Field Type		
	Total Fields	**Proved Fields**	**Unproved Fields**
1	343	310	33
2	255	245	10
3	148	144	4
4	92	91	1
5	38	38	0
6	24	24	0
7	14	14	0

Table 1. Distribution of Fields by Number of Plays and Field Type.

fields are the basic entity for any analysis concerning economic viability, it was necessary to transform the play-based pool size distributions to area-based field size distributions. This was accomplished using the GRASP model from a different perspective— the field.

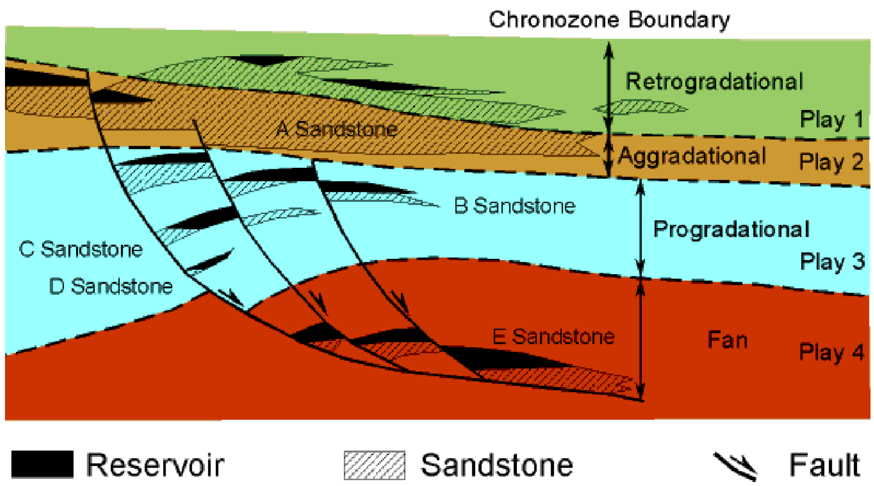

Figure 2. Schematic Cross Section of Typical Field (showing 12 fault-block reservoirs, 7 sandstone-body reservoirs, 4 pools, 4 plays, and 4 depositional styles/facies).

The same theoretical analysis and empirical data that support the lognormal distribution as a reasonable choice for pool size distributions also apply to field size distributions within a basin or province. The identical analyses that were performed at the play and pool level were repeated at the area and field level with the added objective of matching as closely as possible the total resource distribution obtained through pool-level analysis. This process was performed for three water depth ranges (0-200m, 201-900m, and 901-3,000m) because of differences in engineering requirements and economic constraints. (See the *Field Size Distributions* section that follows for the Gulf of Mexico Cenozoic Province field size results.) The results, in terms of field size distributions and MPhc, were then exported to PRESTO for economic analysis.

Field Size Distributions

The GRASP discovery assessment method was used to create ranked field size distributions at the assessment area level in a procedure similar to that used for creating ranked pool size distributions at the play level. These distributions, which consist of discovered fields and predicted undiscovered fields, were developed to be compatible with the combined play-level ranked pool size distributions and are considered to be equivalent—for modeling purposes—to the resource distribution of the assessment area. The mean aggregate volume of resources (both oil and gas) for the fields matches the mean aggregate volume of resources for all plays within the assessment area.

The economic evaluations using the field size distributions were based on the water depth ranges 0-200m, 201-900m, and 901-3,000m. The Gulf of Mexico Cenozoic Province (figure 3) was chosen to demonstrate the field level results because it is the most extensively explored and developed province in the assessment. Figure 4 shows the field rank plot total for this Province, and figures 5, 6, and 7 show the field rank plots by water depth ranges. The mean total endowment of the fields for each of these plots demonstrates a typically lognormal distribution, and the percentage of undiscovered fields progressively increases from shallower to deeper water. Based on mean total endowment, the fields were allocated into the U.S. Geological Survey's field size classes (table 2) (Drew *et. al.*, 1982). Both discovered and undiscovered fields were included in the field size classes (figure 8 shows the field size total and figures 9, 10, and 11 show the field sizes by water depth ranges).

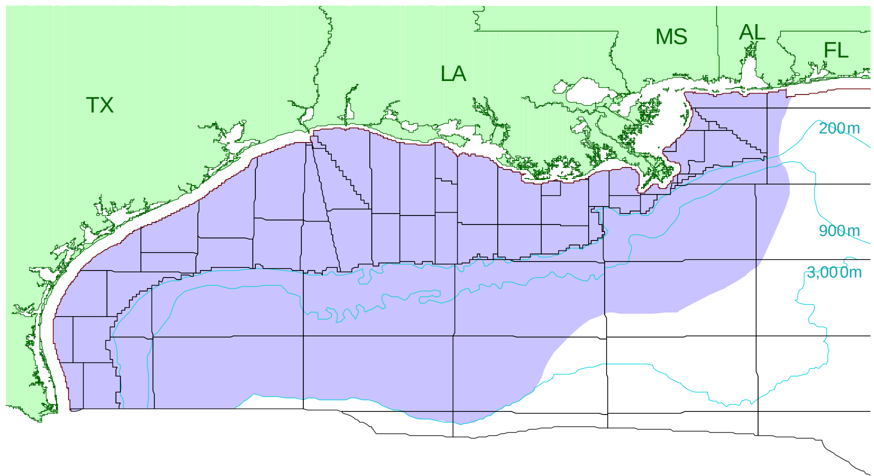

Figure 3. Map of GOM Cenozoic Province (the shaded areas indicate the extent of the assessed plays in the Province).

ENGINEERING AND ECONOMIC INPUTS

In the geologic resource assessment phase of the evaluation, each prospect is stochastically modeled with uncertain geologic variables to determine a physical state of nature. In the engineering and economic resource evaluation, each prospect is drilled and, if hydrocarbons are encountered, developed and produced. Appropriate economic and engineering variables are sampled and the results of this simulated drilling, development, and production scenario are saved as a state of nature. The economic viability of each discovery is tested. If a prospect is profitable, its economically recoverable resources and the net present worths of profits, royalties, and tax payments are aggregated to area-level totals. The area-level economic analysis is performed to determine if sufficient resources will be produced to support the necessary localized transportation infrastructure required to reach major area or regional pipelines before additional aggregations are performed to determine region-level totals. Finally, before cumulative probability distributions at the region level are developed, the results undergo an additional economic viability test related to the transportation of all region-level production to the market. The results from each of the possible outcomes are saved and distributions developed of the estimates of potential quantities of economically recoverable resources, various infrastructure requirements, cash flow streams, and probabilities of occurrence.

Similar to the geologic resource assessment analysis, distributions are developed for all engineering, economic, cost, and timing variables that have an influence on the outcome of an exploration, delineation, development, and production program for each region, province, planning area, and the combined Gulf of Mexico and Atlantic Continental Margin, by water depth category. A PRESTO engineering and economic evaluation requires the inputs described below.

EXPLORATION VARIABLES

Exploration variables are used to determine the drilling depth and the number of exploration and delineation wells:

- number of exploration wells per platform,
- number of exploration wells to condemn a prospect,
- number of exploration wells necessary to condemn an area,
- number of delineation wells necessary to confirm sufficient reserves to justify development,
- water depth for the exploration or delineation wells, and
- drilling depth for the exploration or delineation wells.

DEVELOPMENT VARIABLES

Development variables are used to develop an estimate of the number of development wells:

- number of wells to develop a prospect,
- maximum number of wells per platform or production facility,
- water depth for the development wells, and
- drilling depth for the development wells.

PRODUCTION VARIABLES

Production variables are used to determine the production profile of the wells using a production decline equation:

- gas-to-oil proportion (the proportional volume of gas, including associated and non-associated gas, that can be extracted from the area relative to the volume of crude oil that can be extracted from the area),
- initial production rates,
- initial decline rates,
- fraction of total oil or gas produced before the initial production rates start to decline, and
- hyperbolic decline coefficient (an exponential coefficient used to describe the shape of an oil production decline curve that is defined as a hyperbolic function; zero indicates an exponential decline, and one indicates a harmonic decline).

These well production profiles are subsequently aggregated for each platform or production facility, prospect, area, and region for testing the economic viability at every level.

TRANSPORTATION AND PIPELINE NETWORK VARIABLES

Transportation and pipeline network variables are used to size oil pipelines at the prospect, area, and region levels:

- water depth for the transportation and pipeline network,
- flowline length from a prospect to transport production to the area pipeline,
- area pipeline length necessary to transport production to the regional pipeline infrastructure,
- regional pipeline length necessary to transport production to the market,
- oil and gas tariffs for the area and region, and
- facility capital costs for transportation of production from a region to the

market.

Using the estimated pipeline sizes (calculated by PRESTO based upon the maximum production volume for the prospects, areas, and region) and the input pipeline lengths and tariffs, the model estimates transportation costs for the economic viability analyses. An option is available to use tariffs on a per unit (bbl or Mcf) basis in lieu of actual pipeline costs.

SCHEDULING VARIABLES

Scheduling variables are required for estimates of the timing of exploration, development, production, and transportation activities used in the discounted cash flow analysis:

- delay from the present to drilling of the first exploration well in a prospect (models the delay in exploration for all of the prospects in an area; prospects with high risk are assigned long delays, and prospects with low risk are assigned short delays; thus, the best prospects are drilled first, and the simultaneous drilling of all prospects is prevented),
- time required to drill an exploration or delineation well in a prospect,
- platform and production facility design, fabrication, and installation (DFI) time matrix (sets time delays for installing every platform or production facility in a prospect; the time delays vary with the size of the platform and water depth),
- platform and production facility scheduling matrix (specifies the number of years of delay between installations on a prospect),
- platform and production facility cost fractions matrix (sets the fractions of the platform and production facility DFI costs that will be paid every year during the DFI time period),
- number of development wells matrix (sets the number of development wells to be drilled and completed every year; the number of wells vary with drilling depth and the size of the platform and production facility), and
- time required to obtain, transport, and install production equipment and/or pipelines.

From the scheduling variables, the program first determines when to explore and how long it will take. Then, it decides when to install and pay for each platform and production facility and how many to set each year. Finally, following completion of drilling and installation of the production equipment and pipelines, the program commences development drilling on each platform and production facility and determines the delay to initial production.

COST ESTIMATES

Cost estimates are required for all activities used in the discounted cash flow analysis:

- exploration and delineation well cost matrices (figure 12; these costs vary with drilling depth and water depth),

- platform and production facility cost matrix (figure 13; these costs vary with platform and production facility size and water depth),
- development well cost matrix (figure 14; these costs vary with drilling depth and water depth),
- production equipment cost matrix (these costs vary with peak production rates),
- pipeline cost matrix (figure 15; these costs vary with peak production rate and water depth),
- central facility capital cost matrix for transportation of the production of an area (these costs vary with production volume),
- operating cost matrix (figure 16; these yearly costs are estimated for each well), and
- tangible fractions matrix (these fractions are used by PRESTO to distribute capital costs to tangible and intangible cost categories for tax estimation).

ECONOMIC INPUTS

Economic inputs are used to value production streams and select an appropriate risk-free, after tax rate of return. The estimates of economically recoverable resources were developed using the following economic criteria:

- constant real oil and gas prices (no real price changes),
- 3-percent inflation rate,
- 12-percent discount rate (private, after tax rate of return),
- 35-percent Federal corporate tax rate,
- natural gas prices related to oil prices at 66 percent of the oil energy equivalent price,
- starting oil and gas prices (these criteria are not necessary for the price-supply evaluations that generate the resource estimates for all starting oil prices between $0.00/bbl and $50.00/bbl; but for reporting purposes, two discrete price levels, an $18/bbl scenario [$18.00/bbl and $2.11/Mcf, roughly approximating the current prices at the time of the evaluation], and a $30/bbl scenario [$30.00/bbl and $3.52/Mcf, roughly corresponding to historical high prices] were used; figure 17 and figure 18),
- 12.5- or 16.7-percent royalty rate (The royalty rates used in the economic analysis were those in effect as of the date of the assessment, January 1, 1995. The Deep Water Royalty Relief Act was signed into law on November 28, 1995; therefore, the impact of this legislation on the profitability of eligible fields is not considered in this resource assessment.), and
- the adjustment of the price of crude oil produced from the area compared to an assumed price ($18.00/bbl for 32 degree API crude oil), based on the expected gravity of the oil.

“The term constant price normally does not include inflation since the net present value calculation would use deflation and the result would be the same as not using inflation. However, in an after tax analysis, the effect of depreciation causes write offs of portions of the capital expenses to be delayed. Their nominal value does not increase but the deflation and discount factors cause them to have less present value due to the delay.

When the capital expenses are very large, as in offshore development, this situation can have a significant effect on the net present value." (B. Dickerson, written commun., 1998)

EXPLORATION AND DEVELOPMENT SCENARIO ASSUMPTIONS

Exploration and development scenarios— assumptions about the timing and cost of exploration, delineation, development, and transportation activities— were developed specifically for each region, province, planning area, and the combined Gulf of Mexico and Atlantic Continental Margin, by water depth category. These scenarios were based upon logical sequences of events that incorporated past experience, current conditions, and foreseeable development strategies. Some of the pertinent assumptions that have not been covered in the "Engineering and Economic Inputs" section are the following:

- three water depth categories, each having differences in technologic requirements, are evaluated; 0-200m, 201-900m, and >900m (no resources in water depths exceeding 3,000m are evaluated for this assessment),
- exploratory wells are drilled from jack-ups or semi-submersibles in 0-200m, from semi-submersibles or drill ships in 201-900m, and from drillships in >900m,
- production wells are drilled from the platform (i.e., no predrills and templates),
- platforms are fixed structures in 0-200m, a combination of fixed structures, compliant towers, and tension-leg platforms in 201-900m, and a combination of tension-leg platforms, SPAR, and floating systems in >900m (figure 19),
- production is transported to market via pipelines, and
- platform or structure size ranges from a 2-well caisson (used only in shallow water) to a maximum platform size of 60 wells (the platform size is calculated based upon the number of development wells necessary to develop the prospect fully; if more than 60 wells are required, the program installs additional platforms and sizes them appropriately).

SIMULATION

Estimates of the undiscovered economically recoverable resources are then derived through a stochastic discounted cash flow simulation process (figure 1), using either a full- or half-cycle approach, for specific product prices using generalized exploration, development, and transportation costs and tariffs with their associated development scheduling scenarios for each relevant area by

- subjecting each area's field size distributions to a simulated drilling of the geologic prospects, thus determining which fields and sizes are simulated to be "discovered" on each iteration,
- determining the profitability of each "discovered" field in an area using discounted cash flow analysis,
- developing an aggregate discounted cash flow analysis for the area's "discovered" resources,
- determining if the area's total resources are sufficient to cover shared transportation costs to the regional system,

- determining if the “economic” resources for the area/region will cover the transportation of all products to market,
- judging all resources uneconomic if the appropriate economic test is failed,
- summing the resources that exceed the economic hurdles and then storing the volumes as a distribution of undiscovered economically recoverable resources at that specific price, and
- repeating the process for 1,000 iterations at numerous prices and then generating a distribution curve.

RESULTS

CUMULATIVE PROBABILITY DISTRIBUTIONS AND MARGINAL PROBABILITY

Until exploratory drilling operations actually begin on a prospect area, the presence or absence of economically recoverable hydrocarbons is unknown. To evaluate the potential results of drilling in an area, the assumption is made that recoverable hydrocarbons are present somewhere in the area being assessed. The economic viability of the assumed recoverable hydrocarbons is then tested. Estimates of undiscovered economically recoverable resources conditional on economic success represent the range of possible resources present. However, these conditional estimates do not incorporate the total geologic and marginal economic risks that the area may be devoid of any commercial quantities of oil or gas. Risked (unconditional) estimates of economically recoverable resources incorporate the total economic risk that the area is devoid of commercial hydrocarbon accumulations. The estimates are risked by removing the condition that the area contains commercial hydrocarbons and factoring in the probability that the area does not contain hydrocarbons or, if present, contains them in quantities too small to be economic. Risked estimates of economically recoverable resources consider both the economically recoverable resources calculated for each economic trial and all of the uneconomic (zero resource) trials. PRESTO considers this possibility by calculating the area’s probability of economic success (MPhc,econ), which is the joint probability of recoverable hydrocarbons being present and being present in commercial quantities:

MPhc,econ = (MPhc)(number of economic trials/total number of trials)

Figure 20 shows comparable cumulative probability distributions for an area having economic risk.

As in the geologic assessment, PRESTO presents output distributions from the economic evaluation in percentile tables, which show estimates at every 5th percentile. The mean value is also presented, and it is usually accepted as the best indicator of central tendency.

PRICE-SUPPLY CURVES

Estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions and are presented primarily as price-supply curves that describe a functional relationship between economically recoverable resources and product price. The price-supply curves developed in this assessment are marginal-cost curves representing the incremental costs per unit of cumulative output (undiscovered economically recoverable resources). The price-supply curves portray the estimated quantity of undiscovered conventionally recoverable resources that could be profitably produced under a specific set of economic, cost, and technologic assumptions. The curves are unconstrained by alternative sources of hydrocarbons (investment opportunities or market supply and demand) or the effects of time in these analyses. Generally, price and cost (technology) can be considered as equal substitutions for one another. It should be noted that entire resource distributions are generated at each price level, but all of the price-supply curves presented in this report will be the mean case curves.

Figure 21 shows separate curves for oil and gas resources. The two commodity prices are displayed on the y-axes, and a horizontal line drawn from the price axis to the curve yields the quantity of economically recoverable resources at the selected price. The curves represent mean values at any specific price. It is important that the user realize that the oil and gas prices are not independent. The gas price is dependent on the oil price, and the two must be used in tandem to determine resource volumes. For example, if a \$30.00/bbl oil price is used to determine the oil resouces, the dependent gas price of \$3.52/Mcf must be used to determine the gas resources. Furthermore, the two hydrocarbons frequently occur together, and the individual pool economics are calculated using the coupled pricing.

Two horizontal lines within the graph indicate the critical and marginal prices. Values above the critical price indicate that there was at least one prospect that was simulated as economic at these prices on each trial. Below the marginal price, no prospects were commercially viable. At prices between the critical and the marginal price, a prospect was determined to be economic on some iterations. The two vertical lines indicate the mean estimates of undiscovered conventionally recoverable natural gas and oil resources. As prices increase, the estimate of economically recoverable resources approaches this limit.

The results of the economic analysis are then reviewed by the assessment team for reasonableness and adherence to the geologic model and operational analogs. This step typically results in modifications and refinements to the inputs and, subsequently, further analysis.

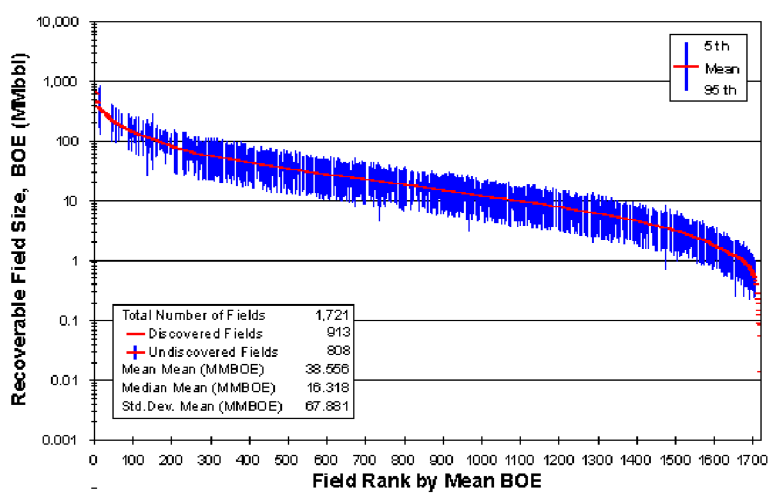

Figure 4. GOM Cenozoic Province Total Field Rank Plot.

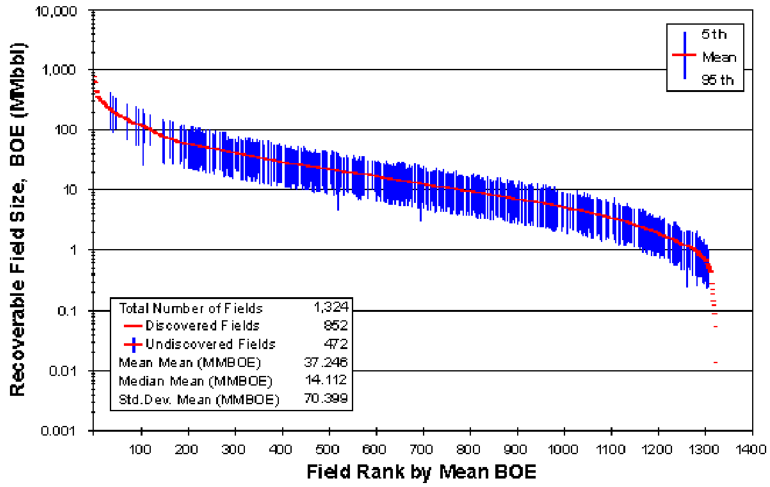

Figure 5. GOM Cenozoic Province 0-200m Field Rank Plot.

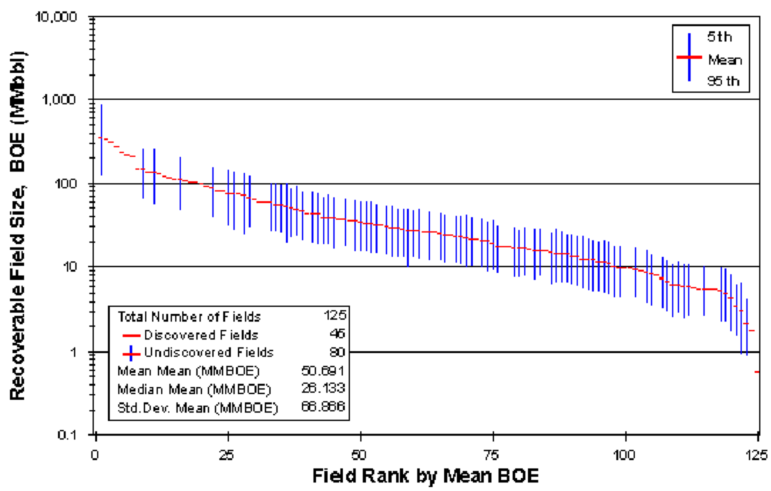

Figure 6. GOM Cenozoic Province 201-900m Field Rank Plot.

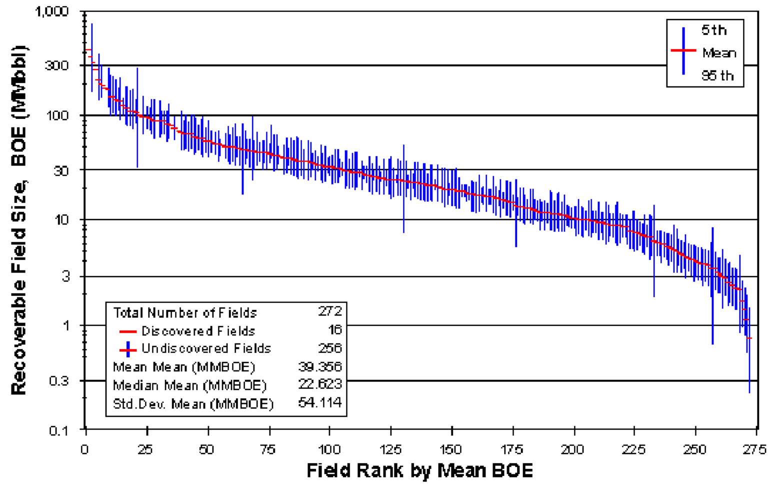

Figure 7. GOM Cenozoic Province 901-3,000m Field Rank Plot.

Size Class	BOE Range (MMbbl)
1	0 - .006
2	.006 - .012
3	.012 - .024
4	.024 - .047
5	.047 - .095
6	.095 - .19
7	.19 - .38
8	.28 - .76
9	.76 - 1.52
10	1.52 - 3.04
11	3.04 - 6.07
12	6.07 - 12.14
13	12.14 - 24.30
14	24.30 - 48.60
15	48.60 - 97.20
16	97.20 - 194.30
17	194.30 - 388.60
18	388.60 - 777.20
19	777.20 - 1,554.40
20	1,554.40 and above

Table 2. USGS Field Size Classes.

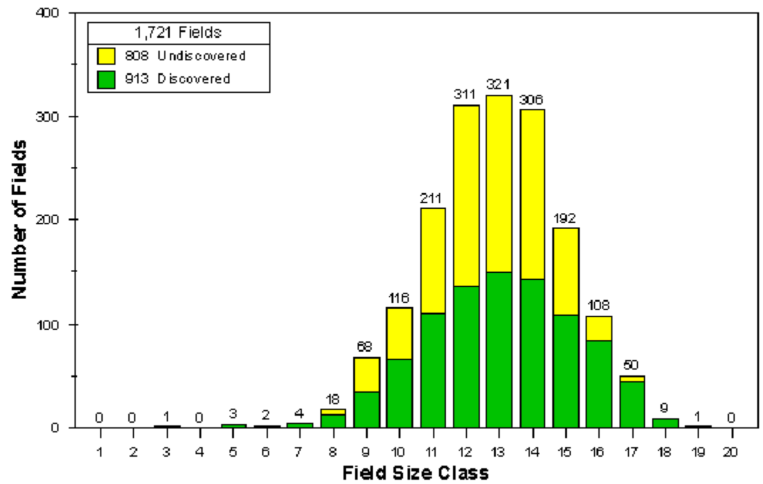

Figure 8. GOM Cenozoic Province Total Field Size Histogram.

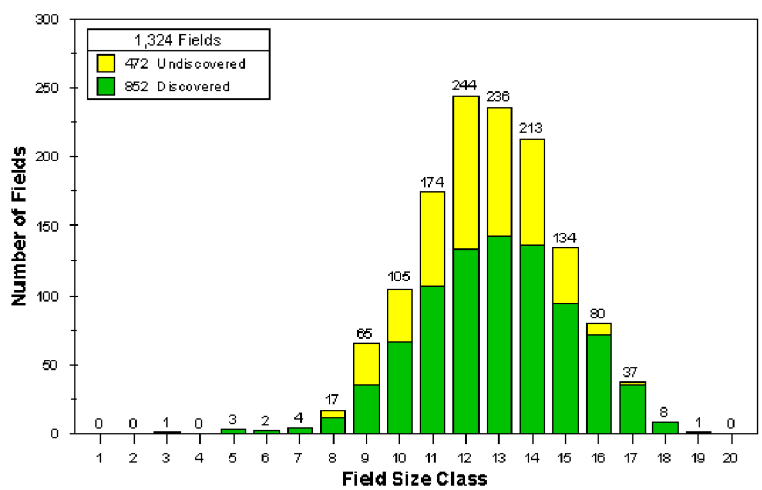

Figure 9. GOM Cenozoic Province 0-200m Field Size Histogram.

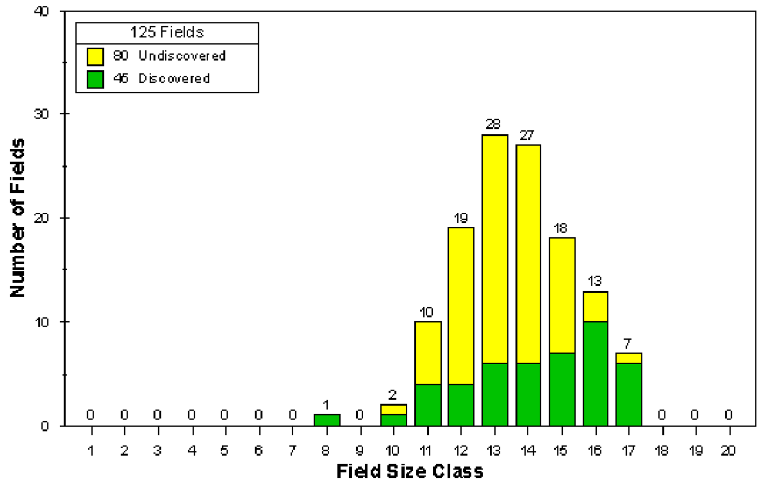

Figure 10. GOM Cenozoic Province 201-900m Field Size Histogram.

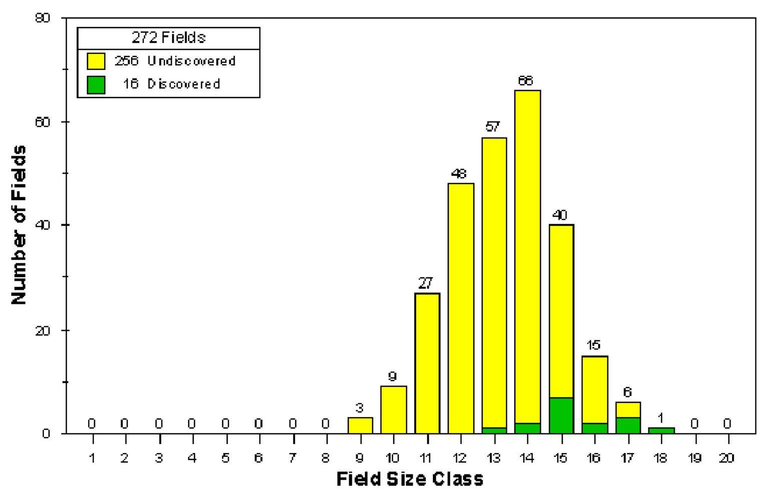

Figure 11. GOM Cenozoic Province 901-3,000m Field Size Histogram.

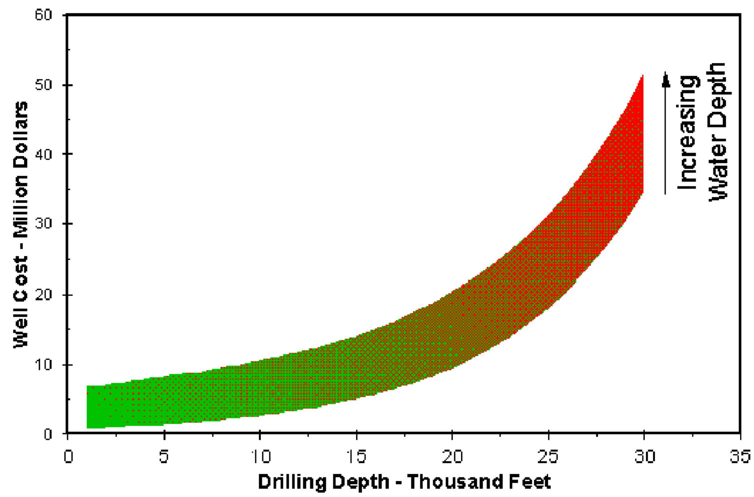

Figure 12. Exploration & Delineation Well Costs.

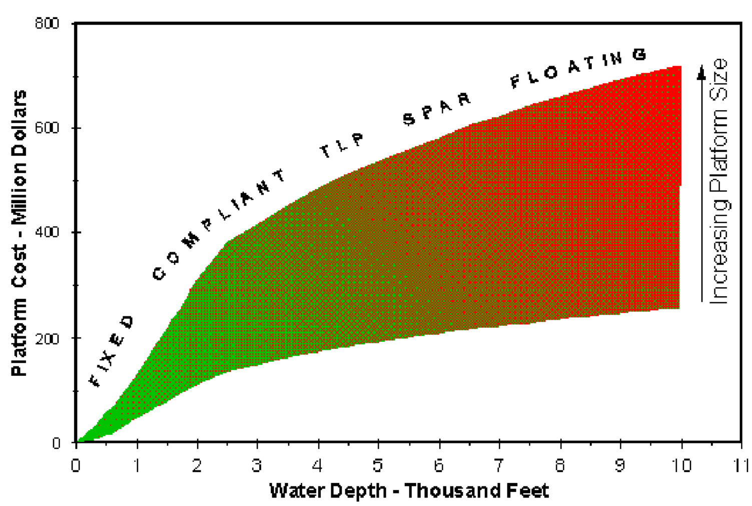

Figure 13. Platform & Production Facility Costs.

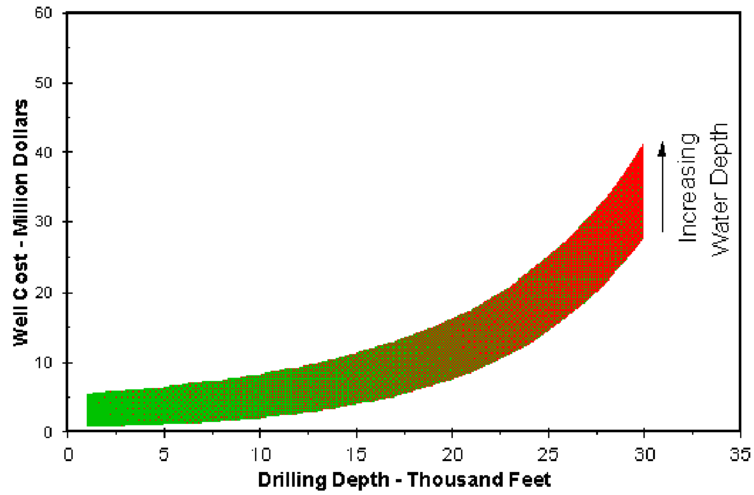

Figure 14. Development Well Costs.

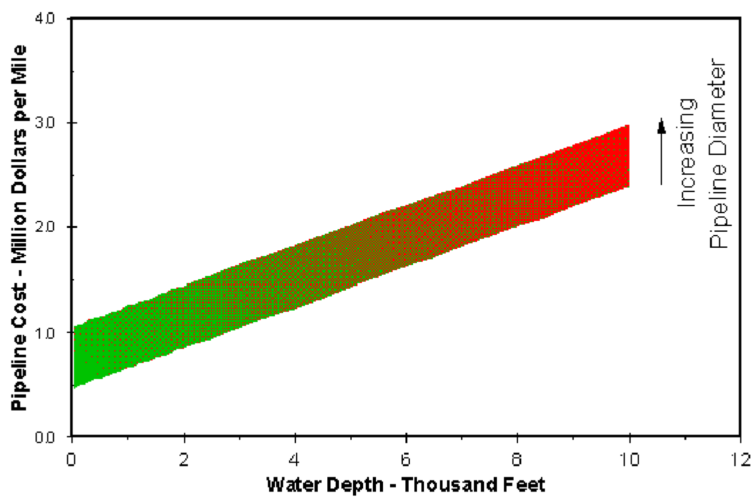

Figure 15. Pipeline Costs.

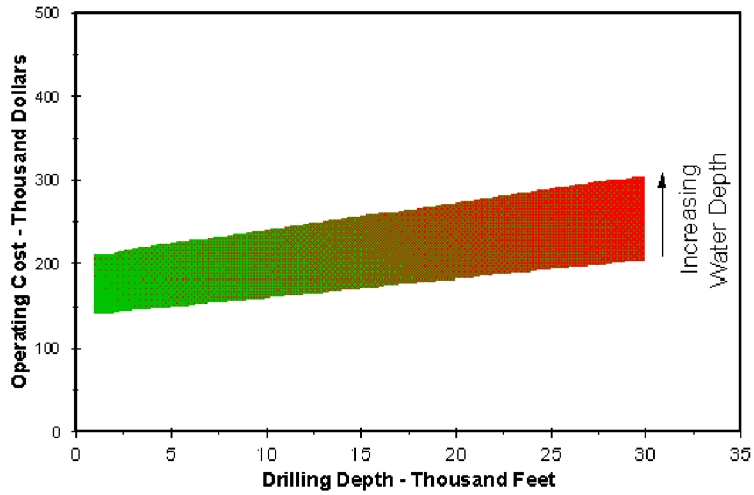

Figure 16. Operating Costs (per well per year).

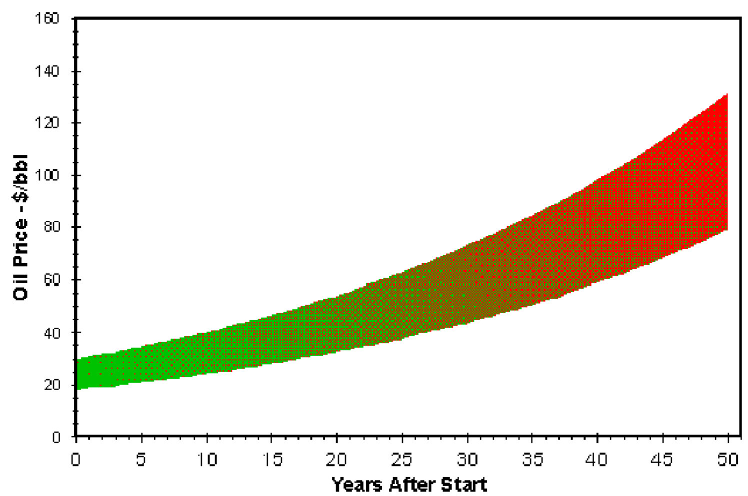

Figure 17. Oil Price Projections.

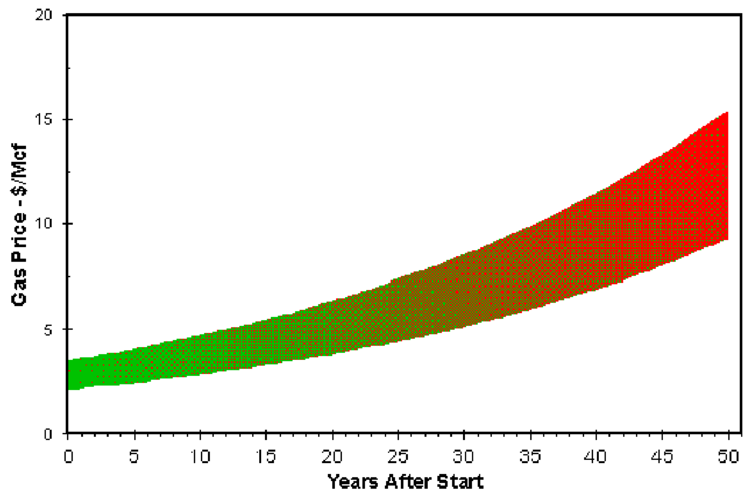

Figure 18. Gas Price Projections.

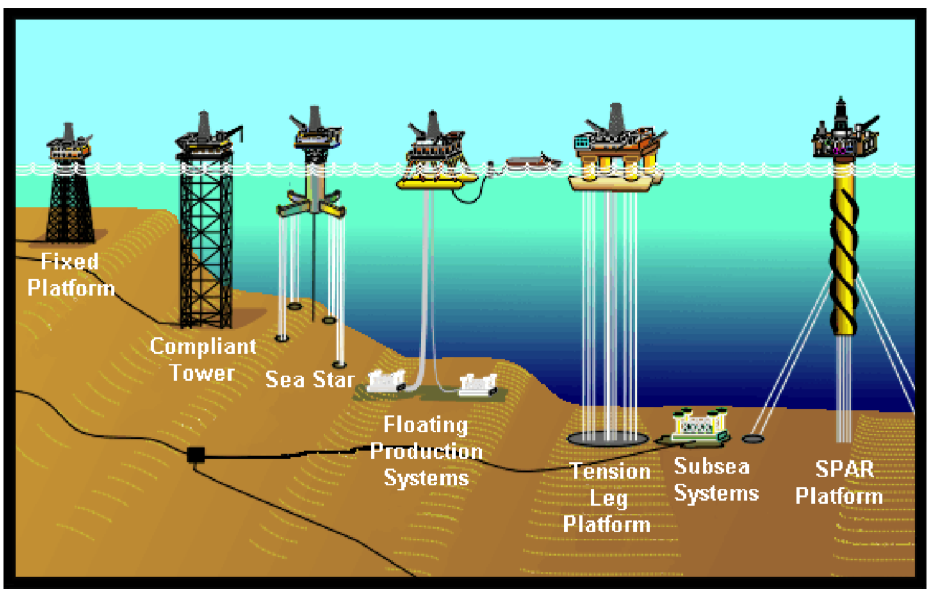

Figure 19. OCS Development Systems.

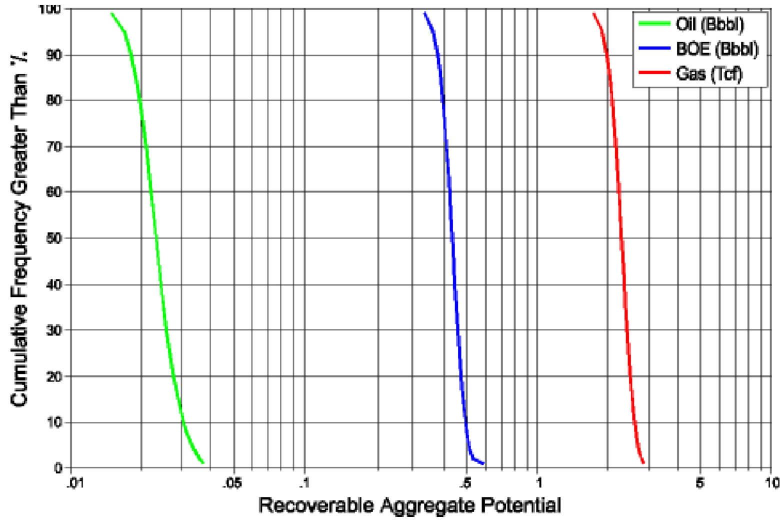

Figure 20. Cumulative Probability Distribution.

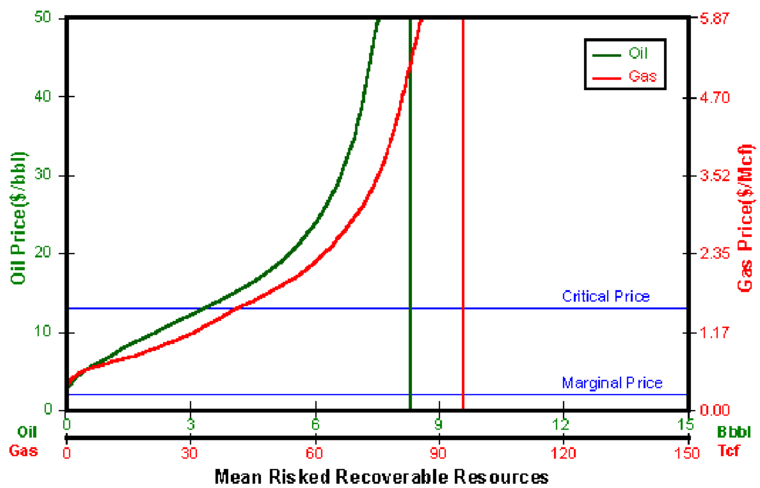

Figure 21. Sample Price-Supply Curve.

ASSESSMENT RESULTS INTRODUCTION

A general discussion of the results of this assessment can be found in these sections. The detailed results of the assessment of undiscovered conventionally recoverable resources at the play, chronozone, series, system, province, region, and the combined Gulf of Mexico and Atlantic Continental Margin levels can be found under the ***Geologic Results*** section. The detailed results of the assessment of undiscovered economically recoverable resources at the planning area, province, region, and the combined Gulf of Mexico and Atlantic Continental Margin levels, by water depth can be found under the ***Economic Results*** section.

RESERVES

PROVED RESERVES

Proved reserves in the 876 proved fields (consisting of 2,114 pools) within the entire Gulf of Mexico Region are estimated to be 11.853 Bbo and 141.891 Tcfg (37.101 BBOE); 157 fields were classified as oil and 719 as gas fields (Melancon *et al*., 1995). Included are 133 fields that are depleted and abandoned. Nearly 100 percent of the proved oil and 99 percent of the proved gas reserves are within the Cenozoic Province. With the exception of the small, abandoned Main Pass 253 field, all of the proved reserves in the Mesozoic Province are in the Upper Jurassic Aggradational (UU A) play (Norphlet Formation). As of January 1, 1995, proved reserves in the OCS portion of the UU A play were estimated to be 1.572 Tcfg and 0.115 MMbbl of condensate (0.280 BBOE). There are no reserves identified in the Atlantic Mesozoic Province.

UNPROVED RESERVES

Unproved reserves are present in 77 active unproved fields in the Gulf of Mexico Region, 48 of which had sufficient levels of economic certainty and hydrocarbon assurance to be evaluated in this assessment. Preliminary estimates of unproved reserves in these 48 fields (consisting of 69 pools) are 0.639 Bbo and 3.603 Tcfg (1.280 BBOE). Approximately 100 percent of the unproved oil and 83 percent of the unproved gas reserves are located within the Cenozoic Province.

RESERVES APPRECIATION

Reserves appreciation is an important consideration in any analysis of future oil and gas supplies. In the Gulf of Mexico OCS, it has routinely exceeded new field discoveries and contributed the bulk of annual additions to proved reserves. As with previous assessments of reserves appreciation, it was implicitly assumed that estimates of proved reserves in recently discovered fields will exhibit the same pattern and relative magnitude of growth as fields in the historical database. This study estimates reserves appreciation through the year 2020 in 924 active (proved and unproved) fields in the Gulf of Mexico OCS as of January 1, 1995, to be 2.507 Bbo and 31.028 Tcfg (8.028 BBOE). This compares favorably to the January 1, 1995, estimates of remaining proved reserves and unproved reserves, which are 3.155 Bbo and 32.861 Tcfg (9.002 BBOE). All but 1.640 Tcfg and 0.002 Bbo (0.294 BBOE) of the appreciation are attributable to fields in the Cenozoic Province. Since there are no proved or unproved reserves in the Atlantic Mesozoic Province, there is no reserves appreciation.

OCS fields were not projected to grow appreciably beyond 50 years after discovery. On balance, the model used in this assessment of reserves appreciation is apt to be conservative. The oldest fields are generally the largest, contribute the bulk of the proved reserves, and are also most likely to experience growth beyond 50 years of age. Although the total volume of hydrocarbons presumed to be available through future reserves growth is substantial, the resources associated with this phenomenon are attainable only in relatively small increments.

TOTAL RESERVES

Total reserves are unevenly distributed in terms of depositional style and age. The distribution of reserves by depositional style/facies in the Gulf of Mexico Cenozoic Province clearly demonstrates this fact (table 1 and figure 1). Historically, progradational sands have been the most prolific producers of oil and gas. Fifty-eight percent of the oil (8.668 Bbbl), 67 percent of the gas (114.878 Tcf), and 64 percent of the BOE (29.109 Bbbl) total reserves occur in progradational sands. The progradational depositional style results in favorable associations of reservoir, source, and seal and is characterized by alternating reservoir-quality sandstones and thick sealing shales. In addition, progradational deposits coincide with areas having large growth faults,

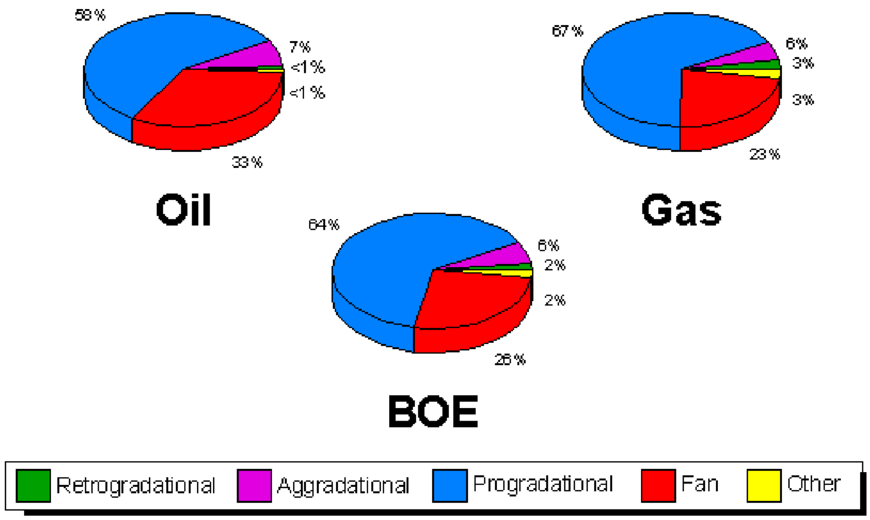

Figure 1. Cenozoic Province Total Reserves by Depositional Style/Facies. The sum of the percentage values may not equal 100 percent due to independent rounding.

	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Cenozoic Province	**14.996**	**172.713**	**45.728**
Retrogradational	0.148	4.668	0.978
Aggradational	1.121	9.603	2.830
Progradational	8.668	114.878	29.109
Fan	4.981	39.185	11.953
Other	0.078	4.378	0.857

Table 1. Cenozoic Province Total Reserves by Depositional Style/Facies.

rollover anticlines, and diapiric salt. All of these factors contribute to the high productivity of these sediments (Seni *et al.*, 1994). Fan deposits rank next in demonstrated prolificness with 33 percent of the oil (4.981 Bbbl), 23 percent of the gas (39.185 Tcf), and 26 percent of the BOE (11.953 Bbbl) total reserves. Reflecting their increasing importance in the reserves base, the fan deposits contain the largest amounts of unproved reserves of oil and gas, with 0.630 Bbbl and 2.924 Tcf (1.150 BBOE). Aggradational deposits contain 7 percent of the oil (1.121 Bbbl), 6 percent of the gas (9.603 Tcf), and 6 percent of the BOE (2.830 Bbbl) total reserves. The remaining 2 percent of the oil (0.226 Bbbl), 4 percent of the gas (9.046 Tcf), and 4 percent of the BOE (1.835 Bbbl) total reserves are within the retrogradational or combination-style deposits.

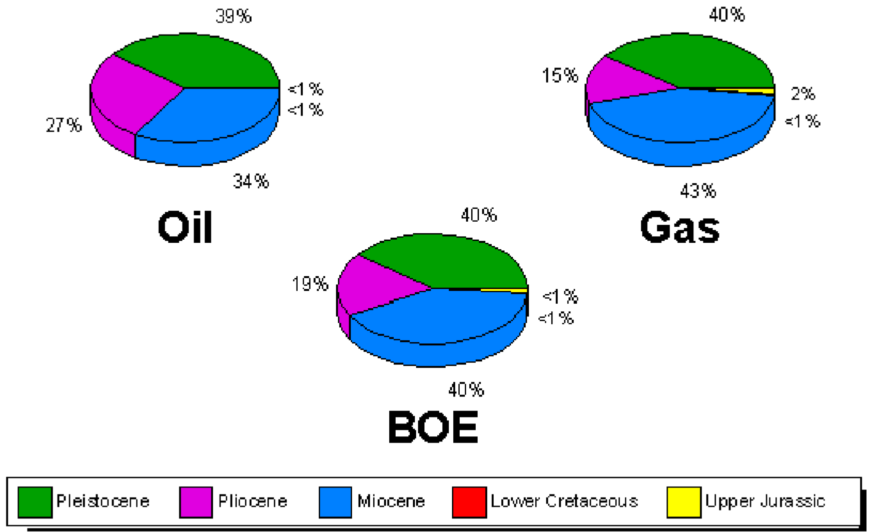

Figure 3. Gulf of Mexico Region Total Reserves by Geologic Age. The sum of the percentage values may not equal 100 percent due to independent rounding.

Reserves have been discovered in the Gulf of Mexico Region in sediments ranging in age from Upper Jurassic to Pleistocene (table 2, figure 2, and figure 3). Miocene age sediments, with 5.083 Bbo and 76.584 Tcfg (18.710 BBOE), and Pleistocene age sediments, with 5.844 Bbo and 70.311 Tcfg (18.355 BBOE), have proven to be the most prolific to date, each containing approximately 40 percent of the Region's total reserves. Pliocene age deposits, with 4.069 Bbo and 25.818 Tcfg (8.663 BBOE), containapproximately 19 percent of the Region's total reserves, and there is a minor but significant amount of gas present in upper Jurassic sediments.

Geologic Time (M.Y.)	Province	System	Series	National Assessment Chronozone	Chronozone	Biozone: Gulf of Mexico	Biozone: Atlantic
~0.01	Cenozoic	Quaternary	Pleistocene	UPL	UPL-4	*Sangamon fauna*	
					UPL-3	*Trimosina* "A" *1st*	
					UPL-2	*Trimosina* "A" *2 nd*	
					UPL-1	*Hyalinea* "B" / *Trimosina* "B"	
				MPL	MPL-2	*Angulogerina* "B" 1 st	
					MPL-1	*Angulogerina* "B" 2 nd	
				LPL	LPL-2	*Lenticulina* 1	
					LPL-1	*Valvulineria* "H"	
~2.8		Tertiary	Pliocene	UP	UP	*Buliminella* 1	
				LP	LP	*Textularia* "X"	
~5.5			Miocene	UM3	UM-3	*Robulus* "E" / *Bigenerina* "A"	
					UM-2	*Cristellaria* "K"	
				UM1	UM-1	*Discorbis* 12	
~10.5				MM9	MM-9	*Bigenerina* 2	
					MM-8	*Textularia* "W"	
				MM7	MM-7	*Bigenerina humblei*	
					MM-6	*Cristellaria* "I"	
					MM-5	*Cibicides opima*	
				MM4	MM-4	*Amphistegina* "B"	
					MM-3	*Robulus* 43	
					MM-2	*Cristellaria* 54 / *Eponides* 14	
					MM-1	*Gyroidina* "K"	
~18.5				LM4	LM-4	*Discorbis* "B"	
					LM-3	*Marginulina* "A"	
				LM2	LM-2	*Siphonina davisi*	
				LM1	LM-1	*Lenticulina hanseni*	
~24.8			Oligocene	O		*Marginulina texana*	
~38.0			Eocene	E			
~55.0			Paleocene	L			
~63.0	Mesozoic	Cretaceous	Upper	UK		*Rotalipora cushmani*	
~97.5			Lower	LK		*Lenticulina washitaensis* *Fossocytheridea lenoirensis* *Cythereis fredericksburgensis* *Dictyoconus walnutensis* *Eocytheropteron trinitiensis* *Orbitolina texana* *Choffatella decipiens* *Schuleridea lacustris*	*Favusella washitaensis* *Muderongia simplex* *Choffatella decipiens* *Polycostella senaria*
~138.0		Jurassic	Upper	UU		*Pseudocyclammina jaccardi*	*Ctenidodinium penneum* *Epistomina uhligi* *Senoniasphaera jurassica* *Pseudocyclammina jaccardi*
~163.0			Middle	MU			*Gonyaulacysta pectinigera* *Gonyaulacysta pachyderma*
~183.0			Lower	LU			
~205.0		Triassic	Upper	UTR			

(Modified from Melancon, et al., 1995)

Figure 2. National Assessment Chronostratigraphic Chart.

	OIL (Bbbl)	GAS (Tcf)	BOE (Bbbl)
GULF of MEXICO REGION	**14.999**	**176.522**	**46.409**
Pleistocene	5.844	70.311	18.355
Pliocene	4.069	25.818	8.663
Miocene	5.083	76.584	18.710
Oligocene/Eocene	0.000	0.000	0.000
Paleocene	na	na	na
Upper Cretaceous	0.000	0.000	0.000
Lower Cretaceous	0.003	0.436	0.080
Upper Jurassic	<0.001	3.373	0.600
Middle Jurassic	na	na	na
Lower Jurassic	na	na	na
Upper Triassic	na	na	na

Table 2. Gulf of Mexico Region Total Reserves by Geologic Age.

UNDISCOVERED CONVENTIONALLY RECOVERABLE RESOURCES (UCRR) RESULTS

GULF OF MEXICO AND ATLANTIC CONTINENTAL MARGIN

The Gulf of Mexico and Atlantic Continental Margin is estimated to contain undiscovered conventionally recoverable resources (UCRR) of 10.615 Bbo and 123.140 Tcfg (32.526 BBOE), at mean levels. Total UCRR volumes, ranging from the 95th to the 5th percentile, are 8.017 to 13.689 Bbo and 104.286 to 144.011 Tcfg (27.402 to 38.217 BBOE) (table 1 and figure 1). The Gulf of Mexico Region is projected to contain almost 80 percent of the mean oil and gas resources.

	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Continental Margin (MPhc = 1.00)				
95th percentile	-	8.017	104.286	27.402
Mean	2,475	10.615	123.140	32.526
5th percentile	-	13.689	144.011	38.217
Gulf of Mexico Region (Mphc = 1.00)				
95th percentile	-	6.038	82.323	21.218
Mean	1,973	8.344	95.661	25.366
5th percentile	-	11.138	110.286	29.990
Cenozoic Province (MPhc = 1.00)				
95th percentile	-	4.428	74.766	18.199
Mean	1,794	6.291	87.553	21.870
5th percentile	-	8.584	101.639	25.977
Mesozoic Province (MPhc = 1.00)				
95th percentile	-	1.360	7.106	2.678
Mean	179	2.053	8.108	3.495
5th percentile	-	2.933	9.194	4.455
Atlantic Region (MPhc = 1.00)				
95th percentile	-	1.267	15.855	4.475
Mean	502	2.271	27.480	7.161
5th percentile	-	3.667	43.372	10.684

Table 1. Undiscovered Conventionally Recoverable Resources.

GULF OF MEXICO REGION

The Gulf of Mexico Region plays were assessed in 14 chronozones in the Cenozoic Province (the Oligocene and Eocene chronozones were assessed as one chronozone) and 3 chronozones in the Mesozoic Province. The mean-level assessment of UCRR for the Gulf of Mexico Region is 8.344 Bbo and 95.661 Tcfg (25.366 BBOE). The resource estimates range from 6.038 to 11.138 Bbo and 82.323 to 110.286 Tcfg (21.218 to 29.990 BBOE) (table 1). The Cenozoic Province is forecast, at mean levels, to contain 75 percent of the undiscovered oil and 92 percent of the undiscovered gas resources in the Region.

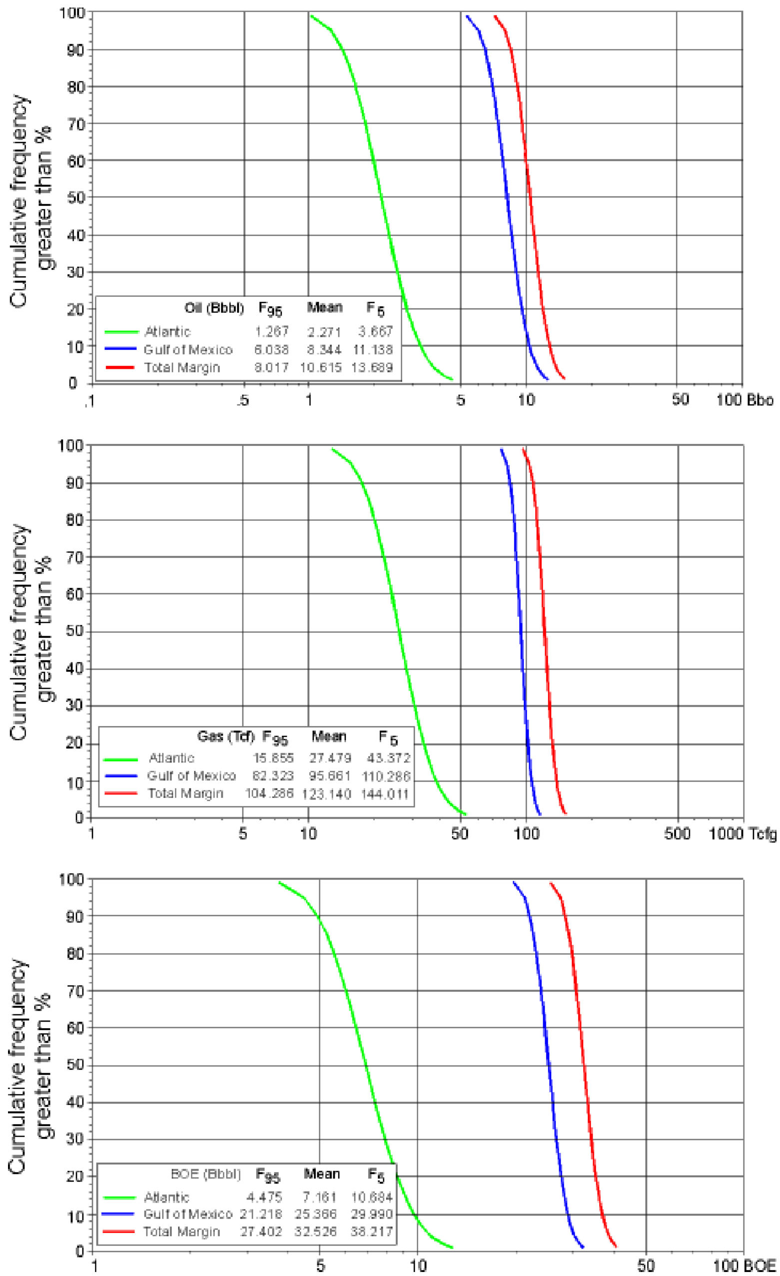

Figure 1. Gulf of Mexico and Atlantic Margin Undiscovered Conventionally Recoverable Resources.

GULF OF MEXICO CENOZOIC PROVINCE

The Gulf of Mexico Cenozoic Province plays are projected to contain UCRR mean-level estimates of 6.291 Bbo and 87.553 Tcfg (21.870 BBOE). The ranges are 4.428 to 8.584 Bbo and 74.766 to 101.639 Tcfg (18.199 to 25.977 BBOE), with the greatest amount of UCRR anticipated to occur in the fan plays (table 1 and figure 2). The mean values for fan deposits are 4.723 Bbo and 61.645 Tcfg (15.692 BBOE), and the corresponding 95th- and 5th-percentile values range from 3.942 to 5.594 Bbo and 52.390 to 71.869 Tcfg (13.594 to 17.982 BBOE). Second to the fans are the progradational sands, with mean values for undiscovered resources of 0.673 Bbo and 16.651 Tcfg (3.636 BBOE). The range of values are 0.502 to 0.876 Bbo and 14.699 to 18.760 Tcfg (3.205 to 4.101 BBOE). Contrasted with the distribution of proved reserves, the fan deposits are expected to contain 75 and 70 percent, respectively, of the undiscovered conventionally recoverable oil and gas resources, and the more thoroughly explored progradational plays only 11 and 19 percent, respectively. Fan deposits are less explored, occurring in deeper water or at deeper drilling depths on the shelf. Successful play and prospect models capable of significantly reducing the uncertainty and risk associated with these targets have only recently become widely available.

The Pleistocene Series contains the greatest amount of mean undiscovered oil resources, 2.648 Bbbl (42% of the Cenozoic Province total), and the Miocene Series contains the greatest potential for mean-level gas, 41.486 Tcf (47% of the Province total). The corresponding 95th and 5th percentiles for the Pleistocene are 2.064 and 3.326 Bbo, and for the Miocene are 35.278 and 48.341 Tcfg (figure 3).

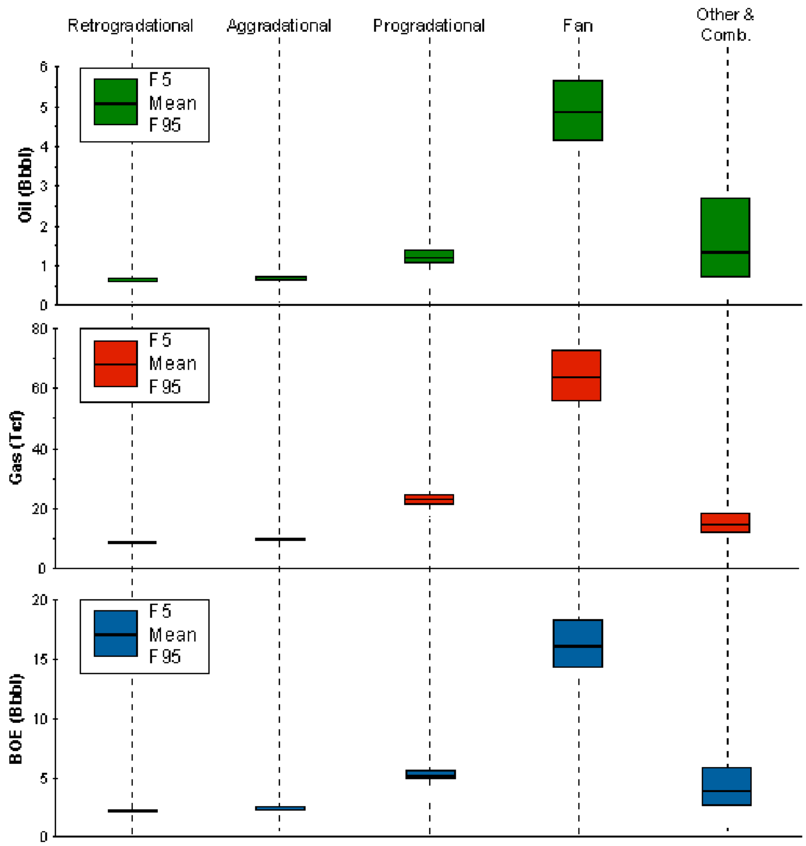

Figure 2. Cenozoic Province Undiscovered Conventionally Recoverable Resources by Depositional Style/Facies.

GULF OF MEXICO MESOZOIC PROVINCE

The Gulf of Mexico Mesozoic Province plays are projected to contain UCRR mean-level estimates of 2.053 Bbo and 8.108 Tcfg (3.495 BBOE) (table 1). The Cretaceous System represents 46 percent and the Jurassic System 54 percent of that total, based on BOE. Carbonate rocks are expected to contain 44 percent and clastic rocks 56 percent of the mean BOE undiscovered resources (figure 4). Areas of potential discoveries extend from the Mississippi, Alabama, and Florida State-Federal boundaries through the Tampa and South Florida Basins to the United States-Cuba International Boundary.

The greatest amount of UCRR is expected to occur in upper Jurassic clastic sediments of the Norphlet Formation. These resources are mainly gas, with mean-level estimates of 7.121 Tcfg and 0.591 Bbo (1.858 BBOE), representing 88 percent of the Province's gas and 29 percent of its oil. Second in magnitude to the upper Jurassic clastic undiscovered resources are lower Cretaceous carbonates, which briefly produced from the Main Pass 253 field. These resources are chiefly oil, with mean-level estimates of 1.351 Bbo and 0.759 Tcfg (1.485 BBOE), representing 9 percent of the Province's gas and 66 percent of its oil.

Lower Cretaceous age sediments have the greatest potential for oil, 1.388 Bbbl, and upper Jurassic sediments have the greatest potential for gas, 7.169 Tcf. These mean-level estimates represent 68 percent of the UCRR for oil and 88 percent for gas. The respective 95th- and 5th-percentile estimates for the lower Cretaceous are 0.921 to 1.980 Bbo, and for the upper Jurassic are 6.490 to 7.890 Tcfg (figure 3).

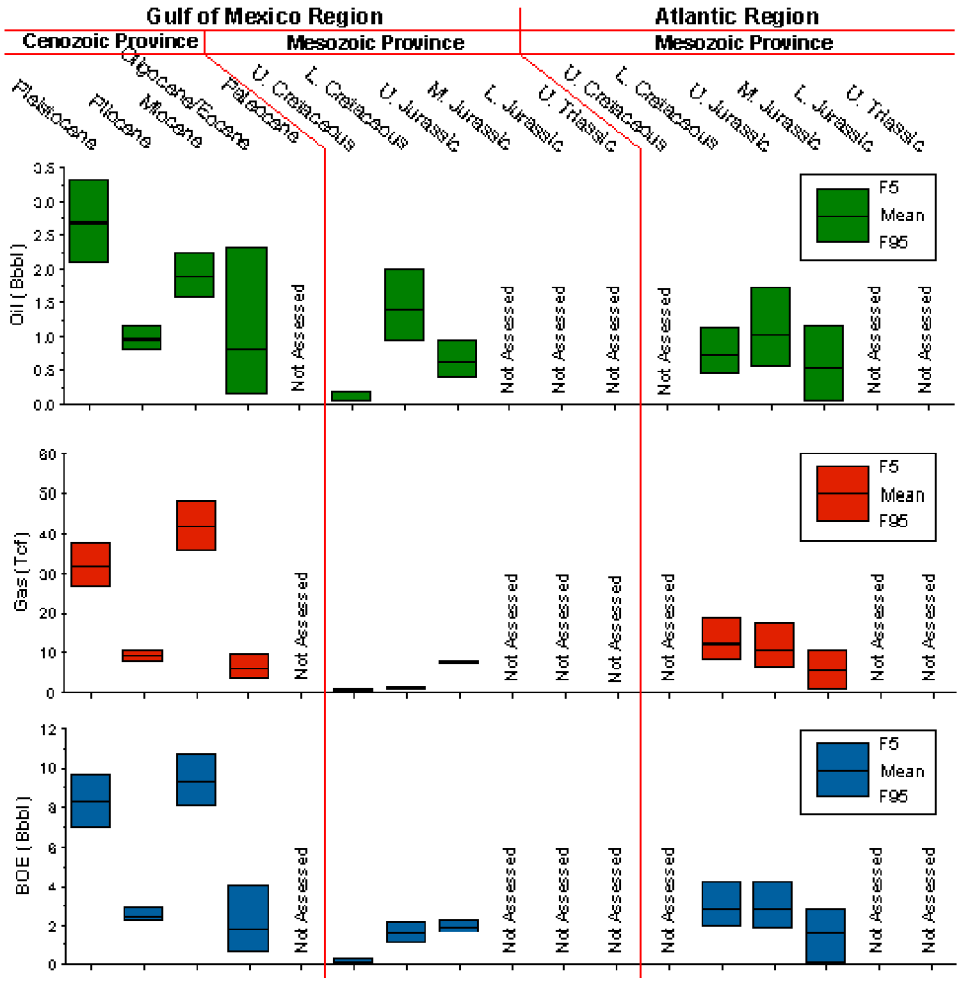

Figure 3. Gulf of Mexico and Atlantic Margin Undiscovered Conventionally Recoverable Resources by Geologic Age.

ATLANTIC REGION

The Atlantic Region plays were assessed in a single geologic province, the Atlantic Mesozoic Province, which is projected to have UCRR mean-level estimates of 2.271 Bbo and 27.480 Tcfg (7.161 BBOE). Sixty-eight percent of these total undiscovered resources is gas (table 1). The Cretaceous System contains 39 percent and the Jurassic System 61 percent of the total undiscovered resources, based on BOE. Ninety-one percent of the Region's mean BOE undiscovered resources is estimated to occur in carbonate rocks and 9 percent in clastic rocks (figure 4).

The greatest amount of UCRR is expected to occur in lower Cretaceous clastic sediments with 0.722 Bbo and 11.767 Tcfg (2.816 BBOE) at mean levels. This represents 32 and 43 percent of the Region's undiscovered conventionally recoverable resources for oil and gas, respectively. Values range from 0.431 to 1.143 Bbo and 7.840 to 18.813 Tcfg (1.985 to 4.190 BBOE). Second in magnitude to the lower Cretaceous clastic resources are upper Jurassic clastic sediments, containing mainly gas, with 8.953 Tcfg and 0.822 Bbo (2.415 BBOE) at mean levels. These estimates comprise 36 percent of the Region's undiscovered conventionally recoverable oil resources and 33 percent of the gas resources. Values range from 0.545 to 1.153 Bbo and 6.401 to 13.270 Tcfg (1.832 to 3.273 BBOE).

Upper Jurassic reservoirs have the greatest potential for oil, 1.020 Bbbl, while lower Cretaceous reservoirs have the greatest potential for gas, 11.767 Tcf, both at mean levels. These values represent 45 percent of the Region's UCRR for oil and 43 percent for gas. The Upper Jurassic Series values range from 0.527 to 1.733 Bbo, and the Lower Cretaceous Series values range from 7.840 to 18.813 Tcfg (figure 3).

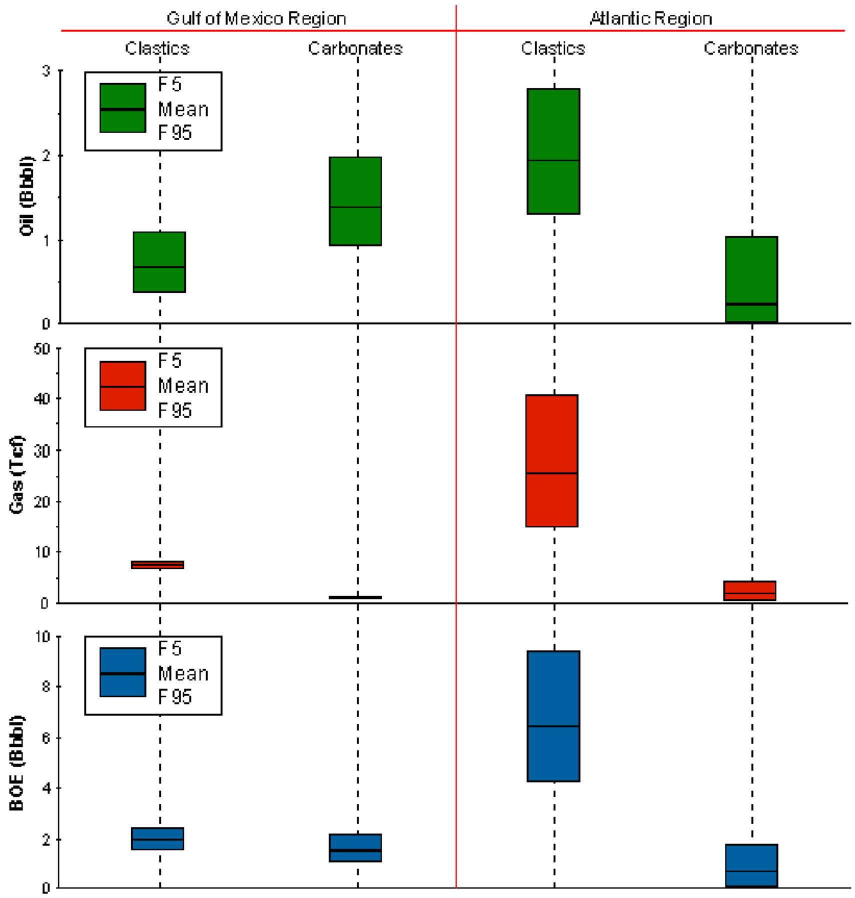

Figure 4. Mesozoic Provinces Undiscovered Conventionally Recoverable Resources by Lithology.

UNDISCOVERED ECONOMICALLY RECOVERABLE RESOURCES

Commercial viability or profitability is measured in this study from the two perspectives referred to as full- and half-cycle analysis. The full-cycle analysis does not include pre-lease costs, but does consider all leasehold, geophysical, geologic, and exploration costs incurred subsequent to a decision to explore in determining the economic viability of a prospect. The decision point is whether or not to explore. In a half-cycle analysis, leasehold and exploration costs, as well as delineation costs that are incurred prior to the field development decision, are assumed to be sunk and are not used in the discounted cash flow calculations to determine whether a field is commercially viable. The decision point is whether or not to proceed with development. In neither the full- nor the half-cycle scenario is lease acquisition or other pre-decision point leasehold costs considered in the evaluation.

Results of the assessment of undiscovered economically recoverable resources (UERR) were generated as price-supply curves (see the discussion of the methodology involved in the ***General Text, Methodology, UERR (Economically Recoverable)*** sections). But for reporting purposes, the mean results of the economic analysis are reported at two discrete price levels: (1) an $18/bbl scenario ($18.00/bbl and $2.11/Mcf, roughly approximating the current prices at the time of the assessment) and (2) a $30/bbl scenario ($30.00/bbl and $3.52/Mcf, roughly corresponding to historical high prices).

GULF OF MEXICO AND ATLANTIC CONTINENTAL MARGIN

For the Gulf of Mexico and Atlantic Continental Margin, the full-cycle, $18/bbl scenario projects, at mean levels, UERR of 5.350 Bbo and 63.295 Tcfg (16.613 BBOE), representing about half of the estimate of undiscovered conventionally recoverable oil and gas resources. These estimates increase in the $30/bbl scenario to 7.672 Bbo and 85.684 Tcfg (22.918 BBOE). Half-cycle considerations only modestly increase the mean estimates to 5.784 Bbo and 68.462 Tcfg (17.966 BBOE) in the $18/bbl scenario and 8.077 Bbo and 89.895 Tcfg (24.072 BBOE) in the $30/bbl scenario (table 1).

Approximately 92 percent of the mean BOE economically recoverable resources in the full-cycle, $18/bbl scenario is projected to occur in the Gulf of Mexico Region. In the full-cycle, $30/bbl scenario, the relatively higher cost resources in the Atlantic Region become economic, and the Gulf of Mexico contribution decreases slightly to 87 percent.

GULF OF MEXICO REGION

The Gulf of Mexico Region estimates of UERR can be seen in table 1. Figure 1 shows the mean full-cycle price-supply curve for the Gulf of Mexico Region. The vertical lines represent the mean estimate of undiscovered conventionally recoverable oil (8.344 Bbbl) and gas (95.661 Tcf). Over the range of historical oil and gas prices, the estimates of economically recoverable resources rapidly approach the estimate of undiscovered conventionally recoverable oil and gas. Using the full-cycle, $18/bbl scenario, 59 percent of the undiscovered conventionally recoverable oil and 61 percent of the gas are economic. This increases to about 80 percent for both oil and gas in the full-cycle, $30/bbl scenario. More than 1.705 Bbo and 20.363 Tcfg of the undiscovered conventionally recoverable

		$18/bbl Scenario				$30/bbl Scenario			
		MPhc	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	MPhc	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Continental Margin									
	95th percentile	-	4.364	57.252	14.551	-	6.632	79.526	20.783
Full-cycle	Mean	1.00	5.350	63.295	16.613	1.00	7.672	85.684	22.918
	5th percentile	-	7.094	70.695	19.674	-	9.367	92.942	25.905
	95th percentile	-	4.791	62.301	15.876	-	7.019	83.936	21.954
Half-cycle	Mean	1.00	5.784	68.462	17.966	1.00	8.077	89.895	24.072
	5th percentile	-	7.374	76.883	21.055	-	9.892	97.023	27.156
Gulf of Mexico Region									
	95th percentile	-	4.016	53.737	13.577	-	5.697	71.606	18.439
Full-cycle	Mean	1.00	4.941	57.941	15.251	1.00	6.639	75.298	20.038
	5th percentile	-	6.627	62.162	17.688	-	8.241	79.251	22.343
	95th percentile	-	4.350	58.428	14.747	-	5.963	74.379	19.197
Half-cycle	Mean	1.00	5.306	62.300	16.391	1.00	6.865	78.100	20.762
	5th percentile	-	6.967	66.495	18.799	-	8.485	81.964	23.069
Atlantic Region									
	95th percentile	-	0.00	0.00	0.00	-	0.587	5.855	1.628
Full-cycle	Mean	0.92	0.368	5.203	1.294	1.00	1.063	10.479	2.927
	5th percentile	-	0.808	11.688	2.888	-	1.644	16.444	4.570
	95th percentile	-	0.125	1.154	0.331	-	0.788	7.242	2.076
Half-cycle	Mean	0.97	0.452	5.989	1.518	1.00	1.234	11.966	3.363
	5th percentile	-	0.910	12.404	3.118	-	1.854	17.661	4.997

Table 1. Undiscovered Economically Recoverable Resources.

resources require prices above historical highs to be recovered profitably.

Figure 2 illustrates the mean half-cycle price-supply curve for the Gulf of Mexico Region. In the $18/bbl scenario, 65 percent of the undiscovered conventionally recoverable resources is economic. This increases to 82 percent in the $30/bbl scenario. The percent increase in UERR from the full- to the half-cycle analysis is relatively small, ranging from approximately 4 percent to about 7.5 percent. The smallest increase occurs in well-explored,

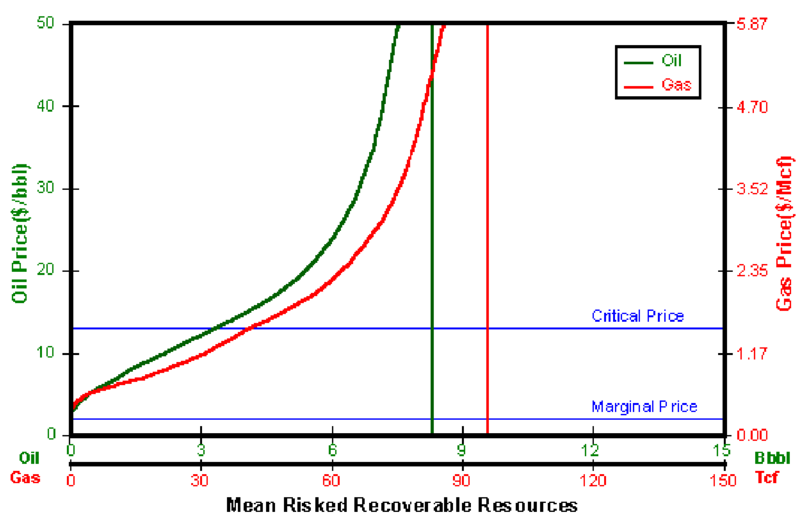

Figure 1. Gulf of Mexico Region Full-Cycle Price-Supply Curve.

mature areas (i.e., shallow-water central Gulf of Mexico), where the necessary exploration and delineation costs compared to development costs may be minimal for the marginal pool size. The largest increases occur in frontier areas, where a more extensive exploration and delineation program is required to justify development. There is less of a difference between the full- and half-cycle analyses in the $30/bbl scenario than in the $18/bbl scenario because the size of the marginal pool in the $30/bbl scenario is not affected by removing consideration of exploration and delineation costs to the same extent as in the lower price scenario. The smaller the marginal pool size, the greater the number of potentially economic pools at each price scenario.

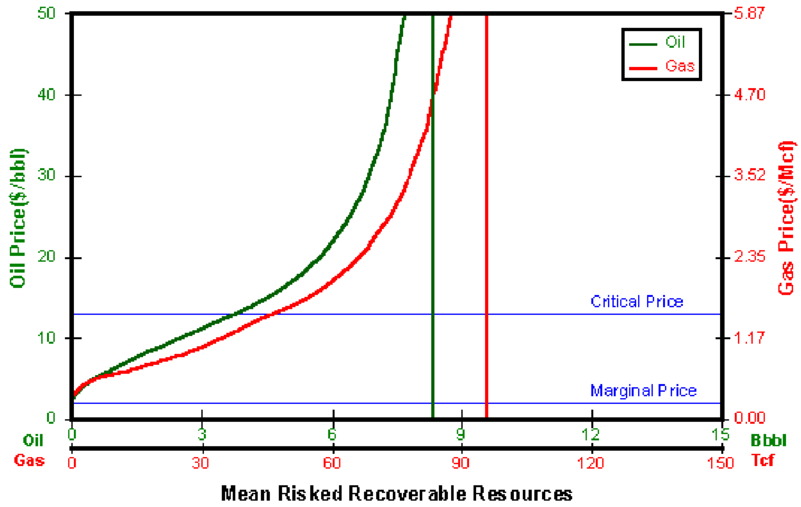

Figure 2. Gulf of Mexico Region Half-Cycle Price-Supply Curve.

ATLANTIC REGION

The Atlantic Region estimates of UERR paint a significantly different picture than the Gulf of Mexico Region results. The full-cycle price-supply curve for the Atlantic Region (figure 3) is much steeper than the comparable Gulf of Mexico Region curve (figure 1). Over the range of historical oil and gas prices, the estimates of economically recoverable resources do not approach the mean estimates of undiscovered conventionally recoverable oil and gas resources. The marginal price in the Atlantic is $5.20/bbl and $0.60/Mcf, similar to the critical price in the Gulf of Mexico. The critical price in the Atlantic Region is significantly higher, $25.00/bbl and $2.95/Mcf. This dramatically illustrates the impact of a lack of regional transportation infrastructure and the relatively low potential in the lower cost, shallow-water nearshore areas. The mean results of the economic analysis at the two

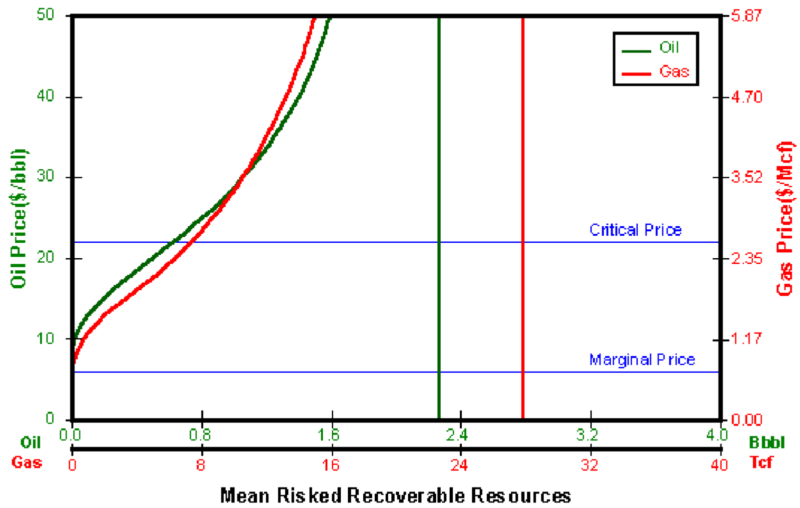

Figure 3. Atlantic Region Full-Cycle Price-Supply Curve.

discrete price levels are shown in table 1. In the $18/bbl scenario, only 16 percent of the undiscovered conventionally recoverable oil (0.368 Bbbl) and 19 percent of the gas (5.203 Tcf) are economic. This increases to 47 and 38 percent (1.063 Bbo and 10.479 Tcfg), respectively, in the $30/bbl scenario.

Figure 4 shows the mean half-cycle price-supply curve for the Atlantic Region. The marginal price in the Atlantic is $4.90/bbl and $0.60/Mcf. The critical price is significantly higher, $22.95/bbl and $2.70/Mcf. In the half-cycle, $18/bbl scenario, the mean estimates of UERR increase by 0.084 Bbo and 0.786 Tcfg over the full-cycle analysis. In the half-cycle, $18/bbl scenario, 20 percent of the undiscovered conventionally recoverable oil (0.452 Bbbl) and 22 percent of the gas (5.989 Tcf) are economic. This increases to 54 and 44 percent (1.234 Bbo and 11.966 Tcfg), respectively, in the $30/bbl scenario.

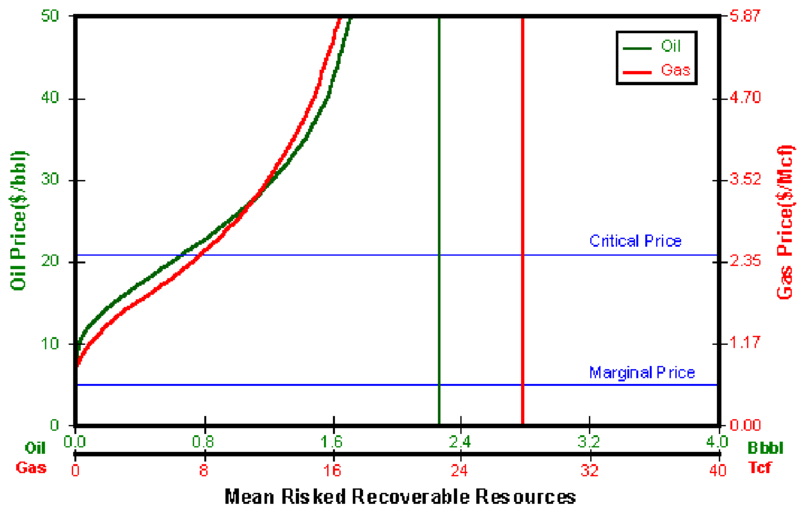

Figure 4. Atlantic Region Half-Cycle Price-Supply Curve.

The percent increase in UERR from the mean full- to half-cycle analysis is much larger than in the Gulf of Mexico Region and ranges from just over 15 percent to almost 17 percent. This is the result of the Atlantic Region being a frontier area requiring a much more extensive, time consuming, and expensive exploration and delineation program than the Gulf of Mexico. As such, the removal of the exploration and delineation scenarios with their associated costs and timing has a much greater impact on the marginal pool size in the Atlantic than it does in the Gulf of Mexico Region.

TOTAL ENDOWMENT

GULF OF MEXICO AND ATLANTIC CONTINENTAL MARGIN

The Gulf of Mexico and Atlantic Continental Margin total endowment ranges from 23.016 to 28.688 Bbo and 280.808 to 320.533 Tcfg (73.811 to 84.626 BBOE), at the 95th and 5th percentiles, respectively, with mean estimates of 25.614 Bbo and 299.662 Tcfg (78.935 BBOE) (table 1). Ninety-one percent of this mean BOE total endowment is attributable to Gulf of Mexico Region. Moreover, the Gulf of Mexico Cenozoic Province is by far the most prolific of the three geologic provinces assessed, containing 86 percent of the mean BOE total endowment (figure 1). Of the depositional styles/facies addressed in this study, the progradational (41%) and fan (35%) deposits account for the largest portion of the Margin's mean BOE total endowment (figure 2).

Marginal Probability = 1.00	**Number of Pools**	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Reserves				
Original proved	2,114	11.853	141.891	37.101
Cumulative production	--	9.338	112.633	29.379
Remaining proved	--	2.516	29.258	7.722
Unproved	69	0.639	3.603	1.280
Appreciation (P&U)	--	2.507	31.028	8.028
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	8.017	104.286	27.402
Mean	2,475	10.615	123.140	32.526
5th percentile	--	13.689	144.011	38.217
Total Endowment				
95th percentile	--	23.016	280.808	73.811
Mean	4,658	25.614	299.662	78.935
5th percentile	--	28.688	320.533	84.626

Table 1. Gulf of Mexico and Atlantic Margin Total Endowment.

GULF OF MEXICO REGION

The Gulf of Mexico Region total endowment ranges from 21.037 to 26.137 Bbo and 258.845 to 286.808 Tcfg (67.627 to 76.399 BBOE), at the 95th and 5th percentiles, respectively, with mean estimates of 23.343 Bbo and 272.183 Tcfg (71.775 BBOE). The total endowment distribution by resource category can be seen in table 2. Sixty-five percent of the mean BOE total endowment is in the various reserves categories, with approximately 52 percent consisting of proved reserves. After 50 years of exploration and development, nearly half of the mean BOE total endowment is represented by reserves appreciation and undiscovered conventionally recoverable resources. In the full-cycle analysis, 86 percent of the mean BOE total endowment is economic in the $18/bbl scenario, and nearly 93 percent is economic in the $30/bbl scenario. These values increase slightly in the half-cycle analysis to 87 percent in the $18/bbl scenario and 94 percent in the $30/bbl scenario.

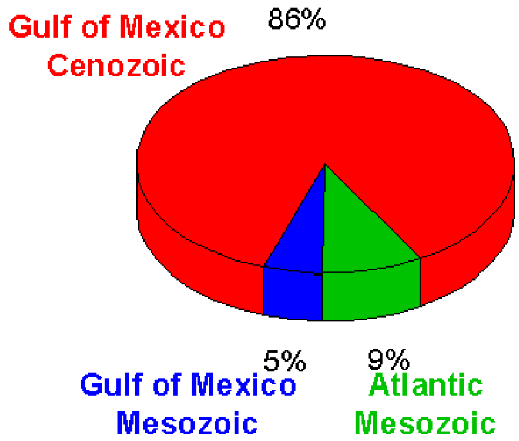

Figure 1. Gulf of Mexico and Atlantic Margin Mean Total Endowment by Geologic Age.

Figure 3 and figure 4 show the distribution of the Region's total endowment by geologic age. Within the Gulf of Mexico Cenozoic Province, the Pleistocene Series is projected to ultimately contain the largest mean oil endowment, 8.492 Bbbl, and the Miocene Series is projected to contain the largest mean gas endowment, 118.070 Tcf. Within the Gulf of Mexico Mesozoic Province, the Lower Cretaceous Series is anticipated to

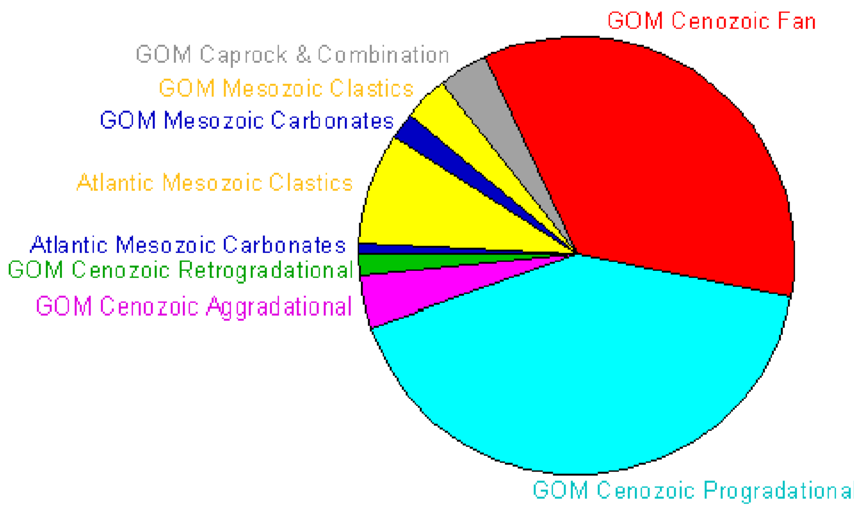

Figure 2. Gulf of Mexico and Atlantic Margin Mean Total Endowment by Depositional Style/Facies.

contain the largest mean oil endowment, 1.391 Bbbl, and the Upper Jurassic Series is projected to contain the largest mean gas endowment, 10.542 Tcf. Figure 5 and figure 6 show the distribution of the Region's total endowment by depositional style/facies. Within the Gulf of Mexico Cenozoic Province, the fan pools are projected to ultimately contain the largest mean oil endowment, 9.704 Bbbl, and the progradational pools are projected to contain the largest mean gas endowment, 131.529 Tcf. Within the Gulf of Mexico Mesozoic Province, carbonate pools are anticipated to ultimately contain the largest mean oil endowment, 1.382 Bbbl, and the clastic pools are projected to contain the largest mean gas endowment, 10.674 Tcf.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	2,114	11.853	141.891	37.101
Cumulative production	--	9.338	112.633	29.379
Remaining proved	--	2.516	29.258	7.722
Unproved	69	0.639	3.603	1.280
Appreciation (P&U)	--	2.507	31.028	8.028
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	6.038	82.323	21.218
Mean	1,973	8.344	95.661	25.366
5th percentile	--	11.138	110.286	29.990
Total Endowment				
95th percentile	--	21.037	258.845	67.627
Mean	4,156	23.343	272.183	71.775
5th percentile	--	26.137	286.808	76.399

Table 2. Gulf of Mexico Region Total Endowment.

ATLANTIC REGION

In the Atlantic Region, the total endowment equals the undiscovered conventionally recoverable resources (because there are no reserves) and ranges from 1.267 to 3.667 Bbo and 15.855 to 43.372 Tcfg (4.475 to 10.684 BBOE), with mean estimates of 2.271 Bbo and 27.480 Tcfg (7.161 BBOE) (table 3). In the Atlantic Region, the Upper Jurassic Series is assessed as having the largest mean oil endowment, 1.020 Bbbl, and the Lower Cretaceous Series is assessed as having the largest mean gas endowment, 11.767 Tcf (figure 3 and figure 4). In the Atlantic Region, clastic deposits are assessed as having the largest oil and gas resource potential, with mean levels of 1.943 Bbbl and 25.612 Tcf (figure 5 and figure 6).

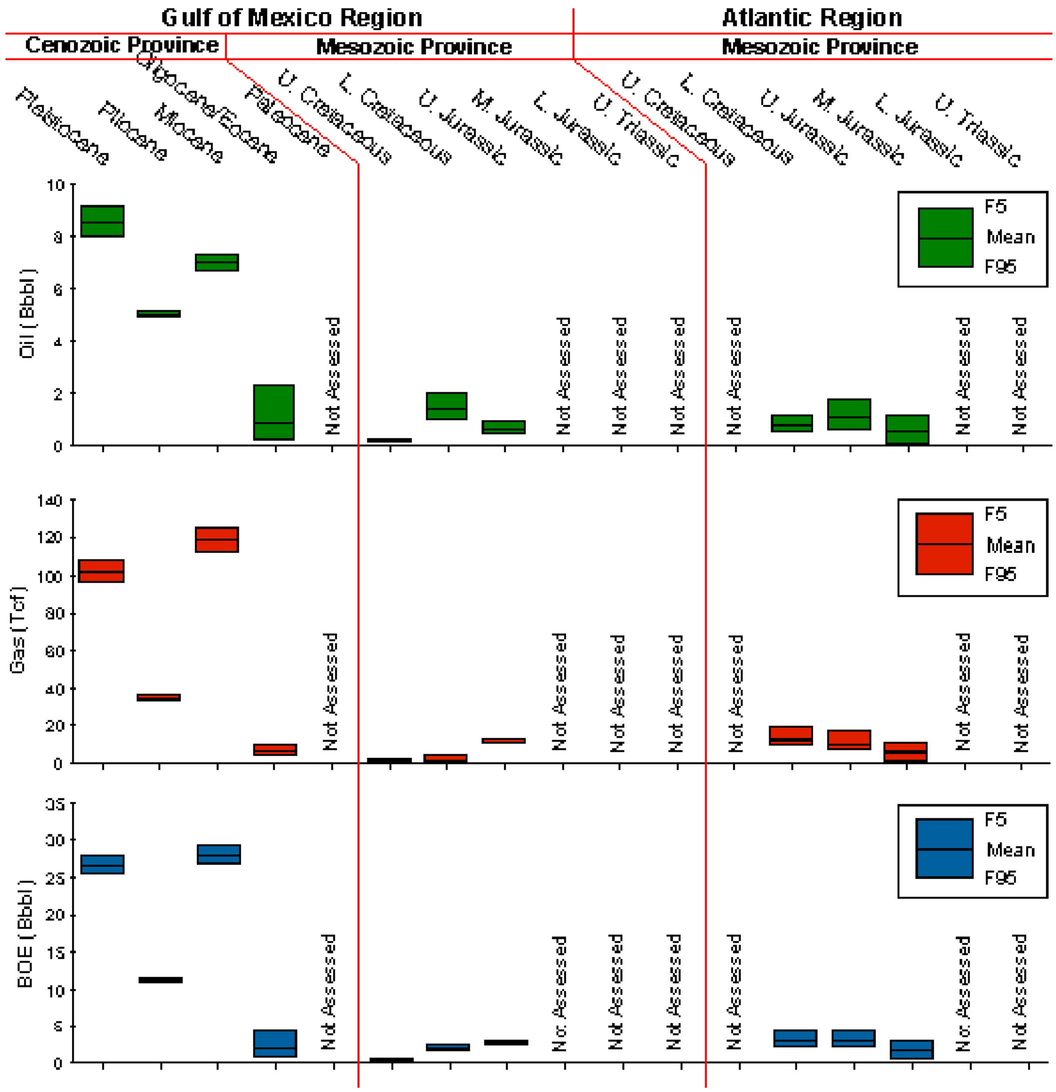

Figure 3. Gulf of Mexico and Atlantic Margin Total Endowment Range by Geologic Age.

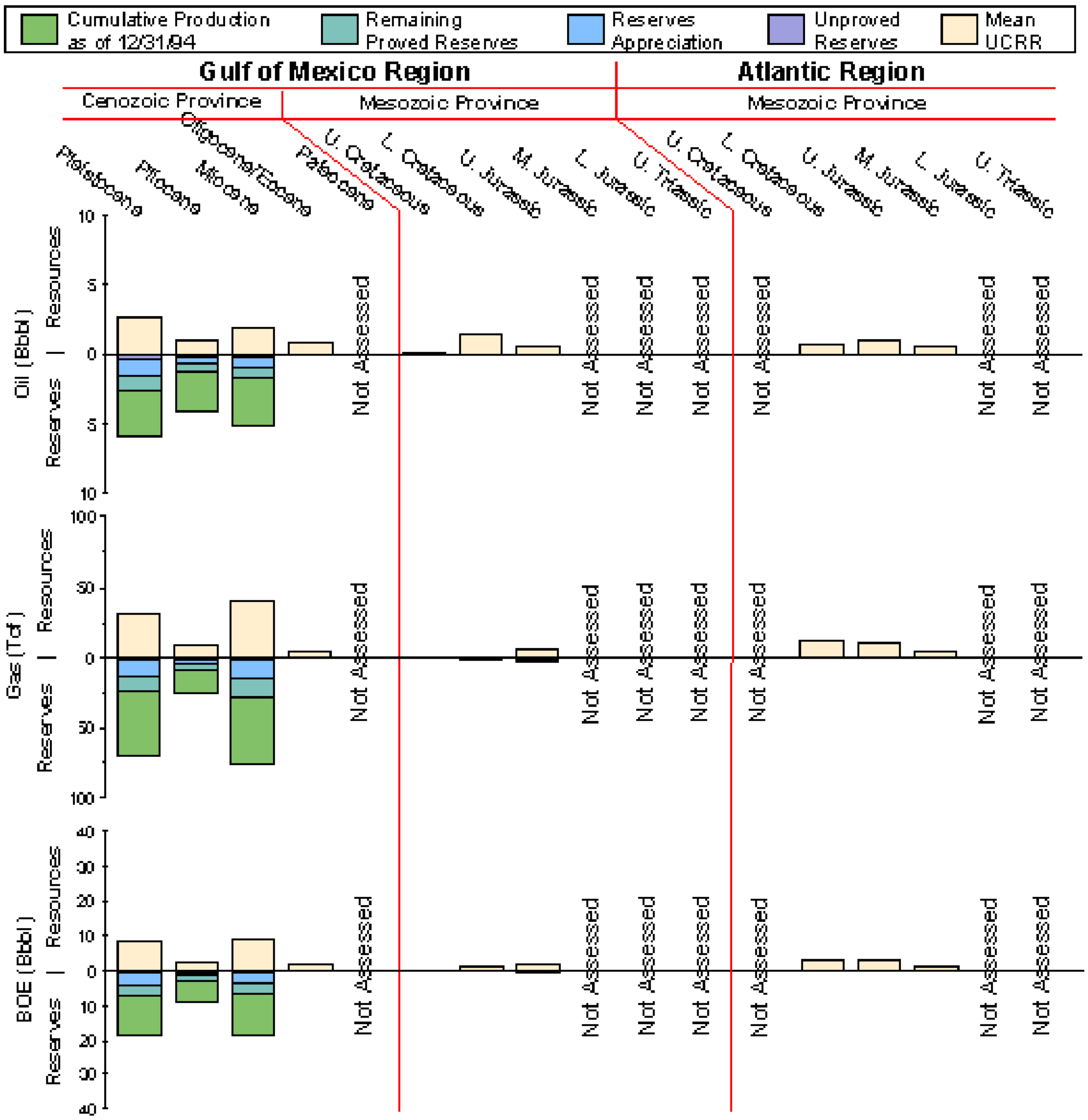

Figure 4. Gulf of Mexico and Atlantic Margin Mean Total Endowment by Geologic Age.

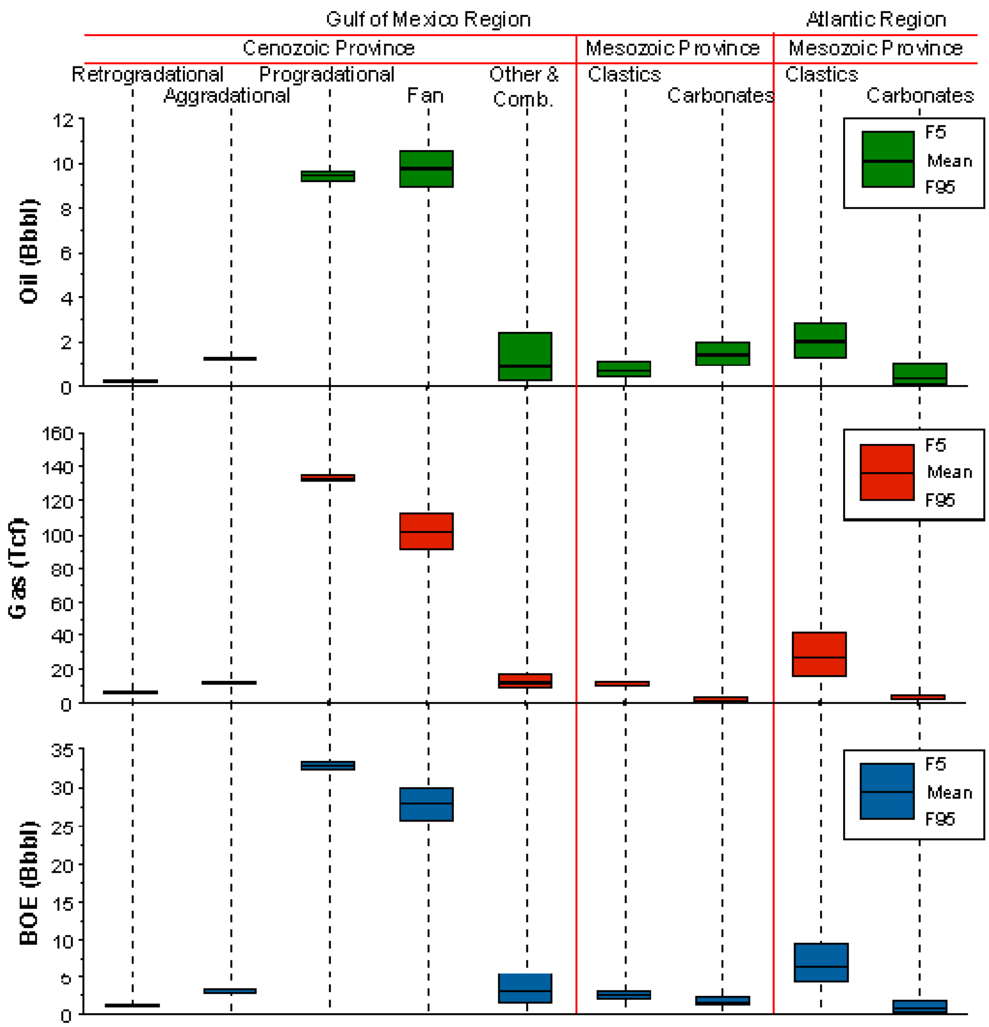

Figure 5. Gulf of Mexico and Atlantic Margin Total Endowment Range by Depositional Style/Facies.

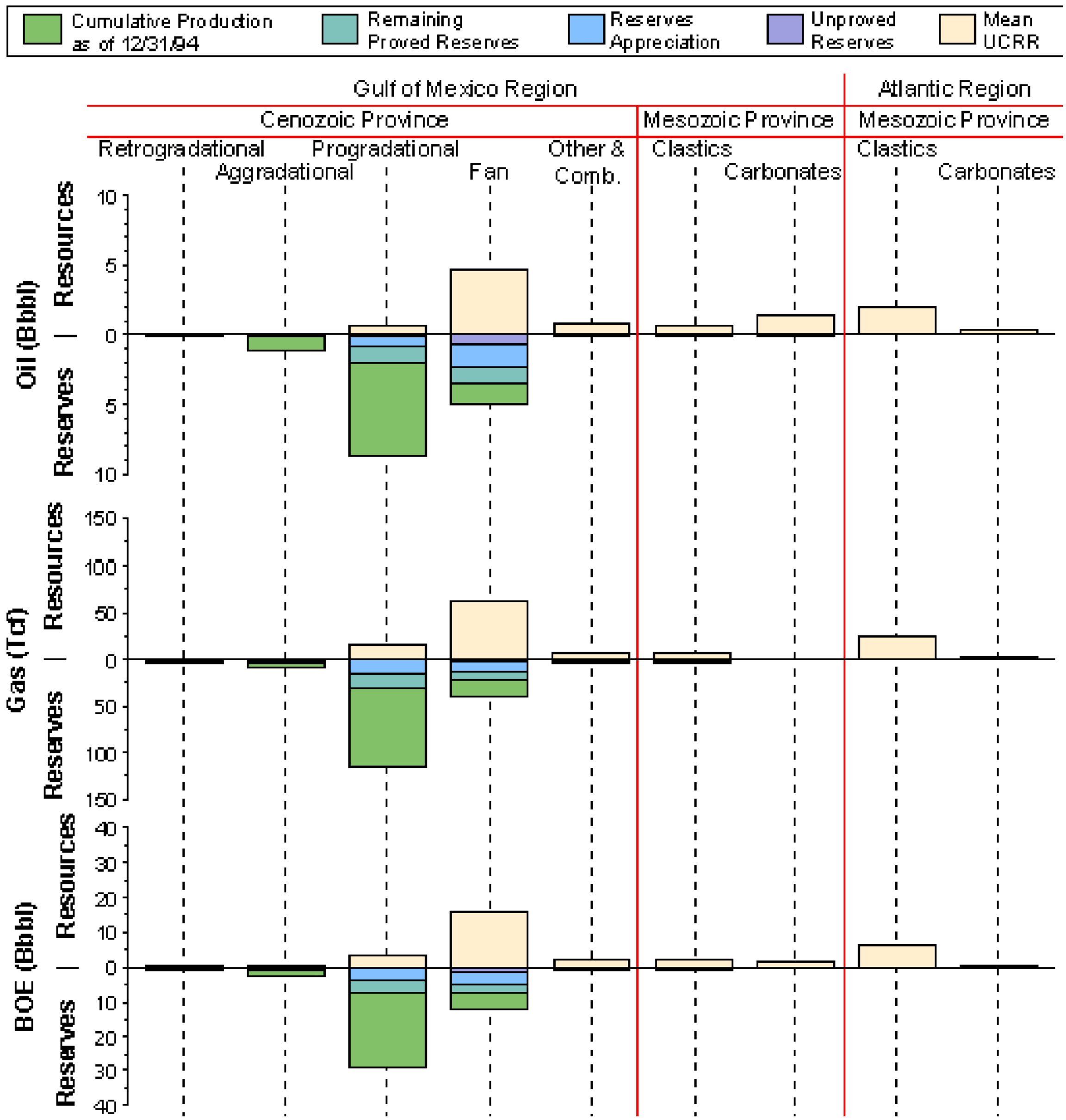

Figure 6. Gulf of Mexico and Atlantic Margin Mean Total Endowment by Depositional Style/Facies.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	0	0.000	0.000	0.000
Cumulative production	-	0.000	0.000	0.000
Remaining proved	-	0.000	0.000	0.000
Unproved	0	0.000	0.000	0.000
Appreciation (P&U)	-	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources				
95th percentile	-	1.267	15.855	4.475
Mean	502	2.271	27.480	7.161
5th percentile	-	3.667	43.372	10.684
Total Endowment				
95th percentile	-	1.267	15.855	4.475
Mean	502	2.271	27.480	7.161
5th percentile	-	3.667	43.372	10.684

Table 3. Atlantic Region Total Endowment.

COMPARISONS INTRODUCTION

Resource assessment is an imprecise science. Uncertainty abounds! There is little in the way of laws and hard-and-fast rules to guide an assessment. The art of the resource assessment employs a multi-faceted analytical procedure. Results are not generally repeatable by different assessors, each using different methodologies, within what most observers would view as reasonable margins of error. There is no single definitive assessment procedure appropriate to all situations and demonstrated to be "correct."

If a reviewer is determined to compare petroleum estimates from different assessments, then to do so properly it is first necessary to ascertain whether the assessments encompass the same things. They should be identical in terms of

- commodities assessed,
- categories of resources assessed,
- areas assessed,
- statistical data reported (e.g., ranges and probabilities), and
- technologic and economic conditions incorporated.

It is intuitively obvious that the last item may be the most troublesome to deal with since these conditions are rarely explicitly stated or easily measured. Irrespective of modifications in methodology, changes in basic geologic knowledge, economic conditions, and technology make it difficult to compare estimates over time.

Some reviewers of assessments of the same area made by different assessors using different techniques have postulated a relationship between the relative magnitude of the assessment and the methodology employed. Miller (1986) generalized that play analysis methods and those using pool size distributions provide more conservative estimates, and volumetric yield methods produce the more optimistic assessments. The assessments presented in this section were developed using varied techniques.

COMPARISON WITH RESULTS FOR OTHER OCS REGIONS

In an attempt to place this resource assessment of the Gulf of Mexico and Atlantic Continental Margin in a national perspective, the total endowment of the entire United States OCS by region (Alaska, Atlantic, Gulf of Mexico, and Pacific) was examined (table 1 and figure 1). Please note that comparisons are made using two decimal places in the resource numbers. The Gulf of Mexico Region is second to the Alaska Region in terms of the potential quantities of undiscovered conventionally recoverable petroleum resources. However, in the Gulf of Mexico Region, the various categories of reserves, with 46.41 BBOE, approach the mean total endowment of the Alaska Region. The mean total endowment of the Gulf of Mexico Region is greater than that of the other three Regions combined, 71.78 versus 71.09 BBOE. In addition, the Gulf of Mexico Region has a larger percentage of both mean total endowment, 84 percent, and mean undiscovered conventionally recoverable resources, 60 percent, that is economically recoverable (full-cycle, $18/bbl scenario). The Atlantic Region, with a mean total endowment of 7.16 BBOE, ranks last of the four OCS Regions.

	Billion Barrels of Oil Equivalent			
	Alaska	**Atlantic**	**GOM**	**Pacific**
Reserves				
Cumulative production	0.00	0.00	29.38	0.81
Remaining proved & Unproved	0.50	0.00	9.00	1.80
Appreciation (P&U)	0.00	0.00	8.03	0.00
Undiscovered Economically Recoverable Resources				
Mean at $18/bbl	3.95	1.29	15.25	6.78
Mean at >$18/bbl	42.77	5.87	10.12	7.32
Total Endowment				
Mean	47.22	7.16	71.78	16.71

Table 1. Total Endowment of the OCS Regions by Resource Category (Mean Full-Cycle Analysis). Alaska and Pacific data from Minerals Management Service (1996).

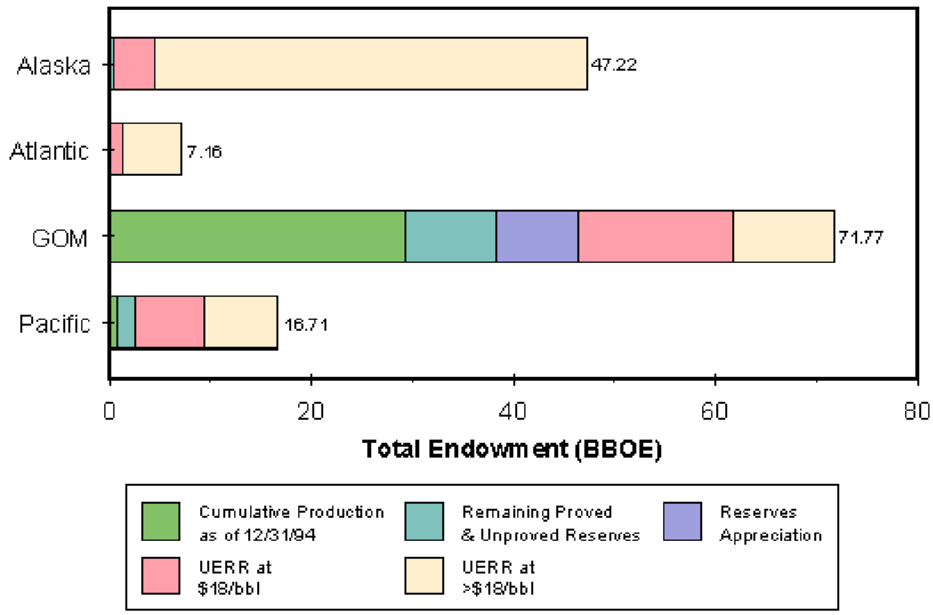

Figure 1. Total Endowment of the OCS Regions by Resource Category (Mean Full-Cycle Analysis).

MMS 1987 VERSUS 1995 ASSESSMENT RESULTS

Although the results of this assessment are not directly comparable with previous assessments, comparisons will inevitably be made. This section highlights some of the key differences between this assessment and MMS's previous comprehensive assessment (Cooke and Dellagiarino, 1990) which incorporated data as of January 1987. Table 1 shows the estimates that are most appropriate for comparison from the two assessments. Both assessments present estimates of undiscovered conventionally recoverable resources (UCRR) and undiscovered economically recoverable resources (UERR) under two scenarios. Please note that all comparisons are made using two decimal places in the resource numbers.

	Gulf of Mexico Region (Including Florida Straits)			Atlantic Region (Excluding Florida Straits)		
	Oil	Gas	BOE	Oil	Gas	BOE
Cumulative Production						
1987	6.93	75.18	20.31	0	0	0
1995	9.34	112.63	29.38	0	0	0
Remaining Proved Reserves						
1987	3.88	45.82	12.03	0	0	0
1995	2.52	29.26	7.72	0	0	0
Reserves Appreciation						
1987	0.50	5.75	1.52	0	0	0
1995	2.51	31.03	8.03	0	0	0
Unproved Reserves						
1987	0.07	1.24	0.29	0	0	0
1995	0.64	3.60	1.28	0	0	0
Mean Risked UCRR						
1987	9.65	103.72	28.11	0.88	16.65	3.84
1995	8.34	95.66	25.37	2.27	27.48	7.16
Mean Risked UERR						
1987 Primary Case	5.70	64.44	17.17	0.19	4.40	0.97
1995 $18/bbl Scenario	5.31	62.30	16.39	0.45	5.99	1.52
1987 Alternative Case	7.09	78.68	21.09	0.33	6.81	1.54
1995 $30/bbl Scenario	6.87	78.10	20.76	1.23	11.97	3.36
Mean Hydrocarbon Endowment						
1987	21.03	231.71	62.26	0.88	16.65	3.84
1995	23.34	272.18	71.78	2.27	27.48	7.16

Table 1. Comparison of the Results of MMS'S 1987 and 1995 Resource Assessments. Oil is reported in Bbbl, gas is reported in Tcf, BOE is reported in Bbbl. 1995 UERR is half-Cycle results.

This assessment differs most importantly from the 1987 assessment specifically because the 1987 assessment's technique involved a projection from the largest undiscovered fields "identified" in the economic assessment to the smallest assessed size. These "identified" undiscovered fields were developed from a summation of prospects approach. Another significant difference is the 1995 assessment included discovered appreciated pools as an integral part of the methodology. There are other major differences in resource assessment methodologies employed in the economic evaluations, such as use of internal discounted cash flow analysis (1995) versus exogenously determined minimum economic field sizes (1987) and the incorporation of significant changes in economic assumptions, exploration and development costs, and exploitation scenarios, all of which significantly impacted the results. There are notable differences in economic parameters (table 2) embodied in the $18/bbl scenario for the 1995 assessment and the primary case of the prior MMS assessment. The economic factors having the greatest impact on the 1995 results compared with 1987 results were the assumption of no real price change and the considerably higher discount rate used in this assessment. Both of these changes resulted in significant downward pressure on the estimate of volumes of undiscovered economically recoverable hydrocarbon resources in the 1995 assessment.

Economic Parameter	1987	1995
Time periods	period 1, 3 years period 2, remaining years	period 1, life of evaluation
Starting oil price	\$18.00/bbl \$30.00/bbl	\$18.00/bbl \$30.00/bbl
Starting gas price	\$1.80/Mcf \$3.00/Mcf	\$2.11/Mcf \$3.52/Mcf
Real oil price growth rates	period 1, -4%, -3%, -2% period 2, 3%, 4%, 5%	constant, 0%
Real gas price growth rates	period 1, -3%, -2%, -1% period 2, 4.5%, 5.5%, 6.5%	constant, 0%
Inflation	Period 1, 4% Period 2, 7%	constant, 3%
After tax rate of return	triangular, 6%, 8%, 10%	constant, 12%
Scenario	half-cycle	full-cycle half-cycle
Analysis method	non-price-supply	price-supply

Table 2. Significant Differences in Economic Parameters between 1987 and 1995 Resource Assessments.

Gulf of Mexico Region

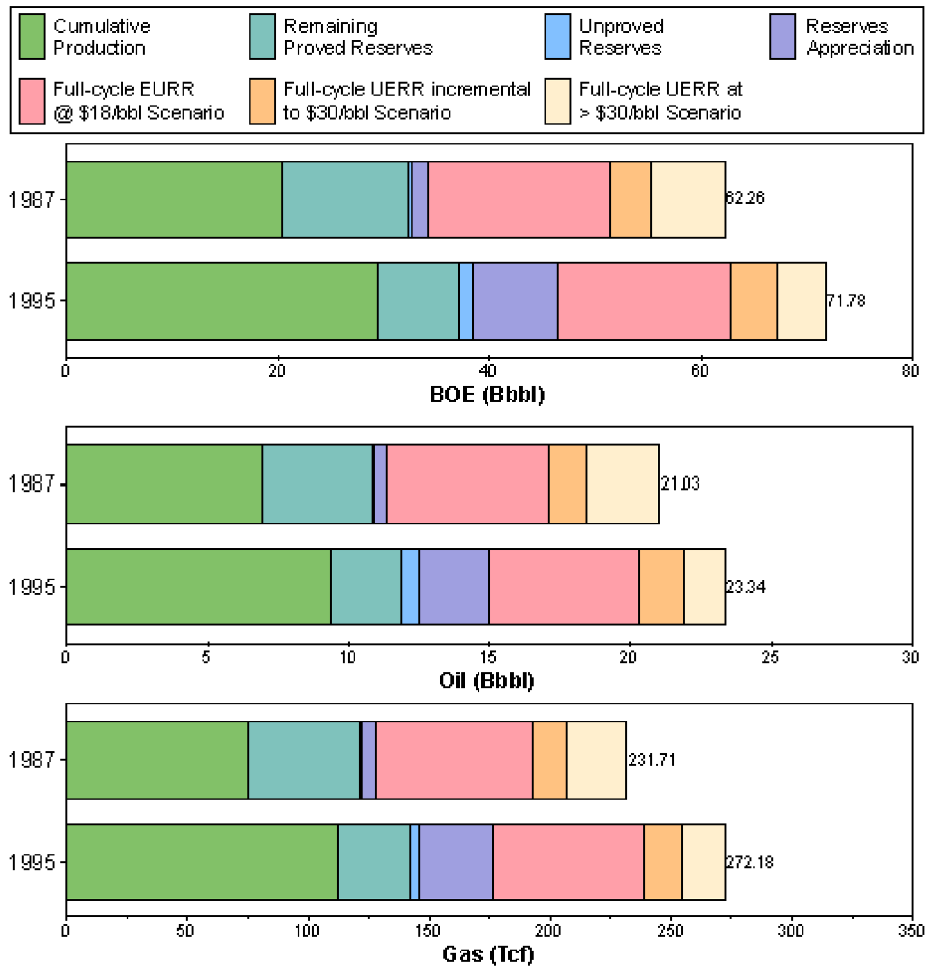

Figure 1. Gulf of Mexico Region Comparison of 1987 and 1995 Resource Assessment.

Figure 1 is a comparison of the mean results from the two assessments for the Gulf of Mexico Region. Undiscovered conventionally recoverable resources were referred to as the undiscovered resource base in the 1987 assessment. Comparing the risked mean estimates from the 1987 primary case to the 1995 half-cycle, $18/bbl scenario, the total endowment increased by 2.31 Bbo and 40.51 Tcfg (9.53 BBOE). An additional 2.41 Bbo and 37.45 Tcfg (9.07 BBOE) were produced between the assessments, and remaining proved reserves decreased by 1.36 Bbo and 16.56 Tcfg (4.31 BBOE). This represents an overall increase of 1.05 Bbo and 20.89 Tcfg (4.76 BBOE) in the estimates of proved reserves. Estimates of reserves appreciation in 1987 were developed by direct subjective assessment. The more rigorous approach of the 1995 assessment resulted in a substantial increase of 2.01 Bbo and 25.28 Tcfg (6.51 BBOE) in future resources attributable to this phenomenon. Estimates of unproved reserves increased by 0.57 Bbo and 2.40 Tcfg (1.00 BBOE) from the 1987 assessment.

The 1995 estimate of the potential mean volumes of UCRR decreased by 1.31 Bbo and 8.06 Tcfg (2.74 BBOE) from the 1987 assessment. Mean estimates of UERR decreased by 0.39 Bbo and 2.14 Tcfg (0.78 BBOE) in the $18/bbl scenario and 0.22 Bbo and 0.58 Tcfg (0.33 BBOE) in the $30/bbl scenario. In the 1987 assessment, 645 of the existing 729 fields were studied and had estimates of reserves reported. In the 1995 assessment, 924 of the 1,096 fields (876 proved, 77 unproved, and 143 expired with no production) were studied and had estimates of reserves reported. The additional 279 proved and unproved fields considered in this assessment contain an estimated 1.62 Bbo and 23.29 Tcfg (5.76 BBOE) of proved and unproved reserves. These reserves represent resources that can be presumed to have moved from the undiscovered resource base of 1987. If this adjustment is made to the 1987 assessment, the 1995 mean estimates of UCRR then represent an increase of 0.31 Bbo and 15.23 Tcfg (3.02 BBOE) over the comparable 1987 estimates.

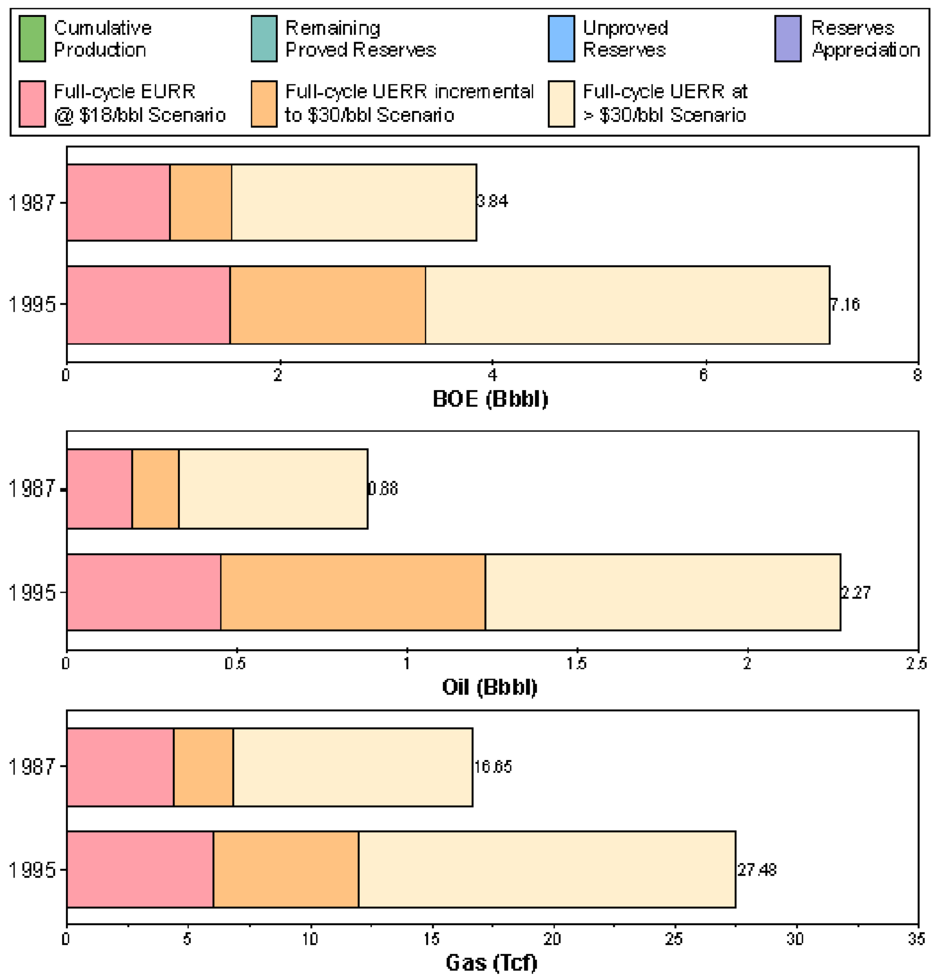

Figure 2. Atlantic Region Comparison of 1987 and 1995 Resource Assessment.

ATLANTIC REGION

Figure 2 is a comparison of the mean results from the two assessments for the Atlantic Region. The 1995 mean estimates of UCRR increased by 1.39 Bbo and 10.83 Tcfg (3.32 BBOE), a 158 and 65 percent increase, respectively, for oil and gas. This is primarily the result of a fundamental difference in the assessed prospectiveness of the Region's plays. Some of the increase is attributable to more fully developed analogs; however, it is also attributable to the different methodologies employed. An example of the methodological impact is the reliance on identified prospects in 1987. These prospects, which were the basis for the assessment of both UCRR and UERR, were economically truncated in each of the different cost regimes. The use in the 1995 assessment of complete pool size distributions based on geologic analogs and mapped prospects resulted in a fuller consideration of the possible numbers and sizes of undiscovered pools. This change has contributed to a higher assessment of UCRR in the 1995 study. Contrasting the 1987 and 1995 assessments of UERR for the Atlantic Region, the potential volumes of mean economic resources increased by 0.26 Bbo and 1.59 Tcfg (0.55 BBOE) in the $18/bbl scenario and 0.90 Bbo and 5.16 Tcfg (1.82 BBOE) in the $30/bbl scenario.

SELECTED PREVIOUS ASSESSMENTS

Estimates of the potential quantities of undiscovered hydrocarbon resources have been made periodically by numerous organizations, companies, government agencies, and individuals. Many of these have been published. Most of these assessments, however, have dealt with the entire United States and provide little additional regional detail, beyond possibly breaking out the lower 48 states onshore/offshore and Alaska onshore/offshore. Table 1, along with figures 1 and 2, compare 23 selected estimates of undiscovered resources, all of which were represented as the economically recoverable portion of their conventional resources (at least as pertains to the OCS). Please note that all comparisons are made using one decimal place in the resource numbers. Although the method of analysis differs in each study, most present the estimates under a range of economic assumptions, generally expressed as moderate and high-price scenarios. Some present results under different technologic advancement assumptions. An attempt was made to select cases as similar as possible to allow for some reasonable degree of comparison. The most complete series of estimates are the assessments of gas resources published biennially by the Potential Gas Committee (PGC) from 1971 to 1995.

The overall range of the estimates of undiscovered economically recoverable resources has been expansive. During the 25-year interval represented, estimates of undiscovered economically recoverable resources for the Gulf of Mexico Region ranged from 1.3 to 30.0 Bbo and 25.2 to 240.0 Tcfg. In the Atlantic Region, the range was from 0.2 to 15.0 Bbo and 4.4 to 82.5 Tcfg. The high estimates in both Regions were by the U.S. Geological Survey (1974). The general tendency over time is a declining trend in the estimates.

Methodological approaches used by the various individuals and organizations vary from simple Delphi and volumetric yield approaches to geologic analogy, to statistical techniques, such as finding rates and discovery process models, to summation of prospects and play assessment approaches using discounted cash flow analysis. It is often difficult to determine in each assessment what is measured with respect to conventional/unconventional resources. The estimates presented all appear to have no time limit, although they assume discovery and recovery under the economic and technologic trends prevailing at the time of the assessment.

The degree to which variations among the reported assessments are attributable to different perceptions of the magnitude and distribution of the resource base is impossible to determine. What is certain, however, is that the estimates have a time dimension that impacted the degree of basic geologic knowledge available to the assessors, as well as their technologic and economic perceptions. In the case of the Gulf of Mexico Region, an example of the changing information base available to the assessor is the additional 665 fields with proved and unproved reserves of 4.4 Bbo and 69.5 Tcfg discovered during the period covered by the estimates.

Table 1. Comparison of Selected Estimates of Reserves and Undiscovered Economically Recoverable Resources.

Source	Effective Date	Cumulative Production		Remaining Proved		Reserves Appreciation		Unproved		Mean Undiscovered Economically Recoverable Resources		Comments
		Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)	Oil (Bbbl)	Gas (Tcf)	
Gulf of Mexico Region												
PGC	12/70	*	*	*	*	*	38.0	*	*	*	153.0	1,2,13,18
PGC	12/72	*	*	*	*	*	57.0	*	*	*	127.0	1,2,13,18
USGS	3/74	*	*	*	*	*	*	*	*	30.0	240.0	1,14,20
Mobil (Moody)	74	*	*	*	*	*	*	*	*	14.0	69.0	1,19
USGS Circ. 725	12/74	4.1	32.1	2.3	35.3	2.4	27.0	*	*	6.3	50.0	1,5,6,20
Nehring	12/75	*	*	7.8	91.1	1.9	11.0	*	*	1.3	25.2	1,7,15,17
PGC	12/76	*	*	*	*	*	51.0	*	*	*	100.0	1,2,13,18
PGC	12/78	*	*	*	*	*	45.0	*	*	*	102.0	1,2,13,18
USGS Circ. 860	12/79	5.6	49.7	1.7	35.6	1.0	26.7	*	*	8.1	71.8	1,5,6,22
PGC	12/80	*	*	*	*	*	34.0	*	*	*	90.0	1,2,13,21
PGC	12/82	*	*	*	*	*	33.0	*	*	*	82.0	1,2,13,21
MMS (Cooke)	7/84	5.9	62.5	3.4	43.7	*	*	*	*	6.0	59.8	4,12,23
PGC	12/84	*	*	*	*	*	32.0	*	*	*	77.9	1,2,13,21
PGC	12/86	*	*	*	*	*	25.5	*	*	*	79.1	1,2,13,21
MMS (Cooke)	1/87	6.9	75.2	3.9	45.8	0.5	5.8	0.1	1.2	5.7	64.4	4,9,12,16,23
PGC	12/88	*	*	*	*	*	26.5	*	*	*	102.4	1,2,13,21
MMS (Cooke)	1/90	7.8	88.9	3.0	40.2	0.5	5.8	*	*	6.4	64.9	4,9,12,16,23
NPC	12/90	*	80.3	*	33.4	*	64.7	*	*	*	114.5	1,8
PGC	12/90	*	*	*	*	*	23.0	*	*	*	95.8	1,2,13,21
AAPG (Gunn)	12/91	*	*	*	*	*	*	*	*	3.8	*	1,11,23
PGC	12/92	*	*	*	*	*	20.1	*	*	*	92.1	1,2,13,21
PGC	12/94	*	*	*	*	*	17.2	*	*	*	100.5	1,2,13,23
MMS	1/95	9.3	112.6	2.5	29.3	2.5	31.0	0.6	3.6	5.3	62.3	4,13,12,23
Atlantic Region												
PGC	12/70	*	*	*	*	*	*	*	*	*	36.0	1,3,13,18
PGC	12/72	*	*	*	*	*	*	*	*	*	35.0	1,3,13,18
USGS	3/74	*	*	*	*	*	*	*	*	15.0	82.5	1,14,20
Mobil (Moody)	74	*	*	*	*	*	*	*	*	6.0	31.0	1,19
USGS Circ. 725	12/74	*	*	*	*	*	*	*	*	3.3	10.0	1,6,20
Nehring	12/75	*	*	*	*	*	*	*	*	0.2	6.0	1,7,15,17
PGC	12/76	*	*	*	*	*	*	*	*	*	36.0	1,3,13,18
PGC	12/78	*	*	*	*	*	*	*	*	*	53.0	1,3,13,18
USGS Circ. 860	12/79	*	*	*	*	*	*	*	*	6.2	23.7	1,6,22
PGC	12/80	*	*	*	*	*	*	*	*	*	*	1,3,13,21
PGC	12/82	*	*	*	*	*	*	*	*	*	16.0	1,3,13,21
MMS (Cooke)	7/84	*	*	*	*	*	*	*	*	0.7	12.2	5,12,23
PGC	12/84	*	*	*	*	*	*	*	*	*	13.2	1,3,13,21
PGC	12/86	*	*	*	*	*	*	*	*	*	13.2	1,3,13,21
MMS (Cooke)	1/87	*	*	*	*	*	*	*	*	0.2	4.4	5,9,12,16,23
PGC	12/88	*	*	*	*	*	*	*	*	*	15.5	1,3,13,21
MMS (Cooke)	1/90	*	*	*	*	*	*	*	*	0.2	4.4	5,9,12,16,23
NPC	12/90	*	*	*	*	*	*	*	*	*	17.0	1,8
PGC	12/90	*	*	*	*	*	*	*	*	*	15.5	1,3,13,21
AAPG (Gunn)	12/91	*	*	*	*	*	*	*	*	0.6	*	1,11,21
PGC	12/92	*	*	*	*	*	*	*	*	*	15.5	1,3,13,21
PGC	12/94	*	*	*	*	*	*	*	*	*	15.2	1,3,13,23
MMS	1/95	*	*	*	*	*	*	*	*	0.5	6.0	5,13,12,23

*Not reported or not assessed
1. Includes state waters
2. Includes west Florida shelf
3. Excludes west Florida shelf
4. Includes Florida Straits planning area
5. Excludes Florida Straits planning area
6. Includes NGL with oil
7. Cumulative production includes remaining reserves
8. Current technology case
9. Primary case
10. Base case
11. $20/bbl case
12. Half-cycle evaluation
13. Most likely values
14. Mid-point of reported range
15. Appreciaiton is F50 estimate
16. Appreciation is mean estimate
17. Sum of F50 values
18. 0-1500 feet water depth
19. 0-6000 feet water depth
20. 0-200 meters water depth
21. 0-1000 meters water depth
22. 0-2500 meters water depth
23. No water depth limit reported

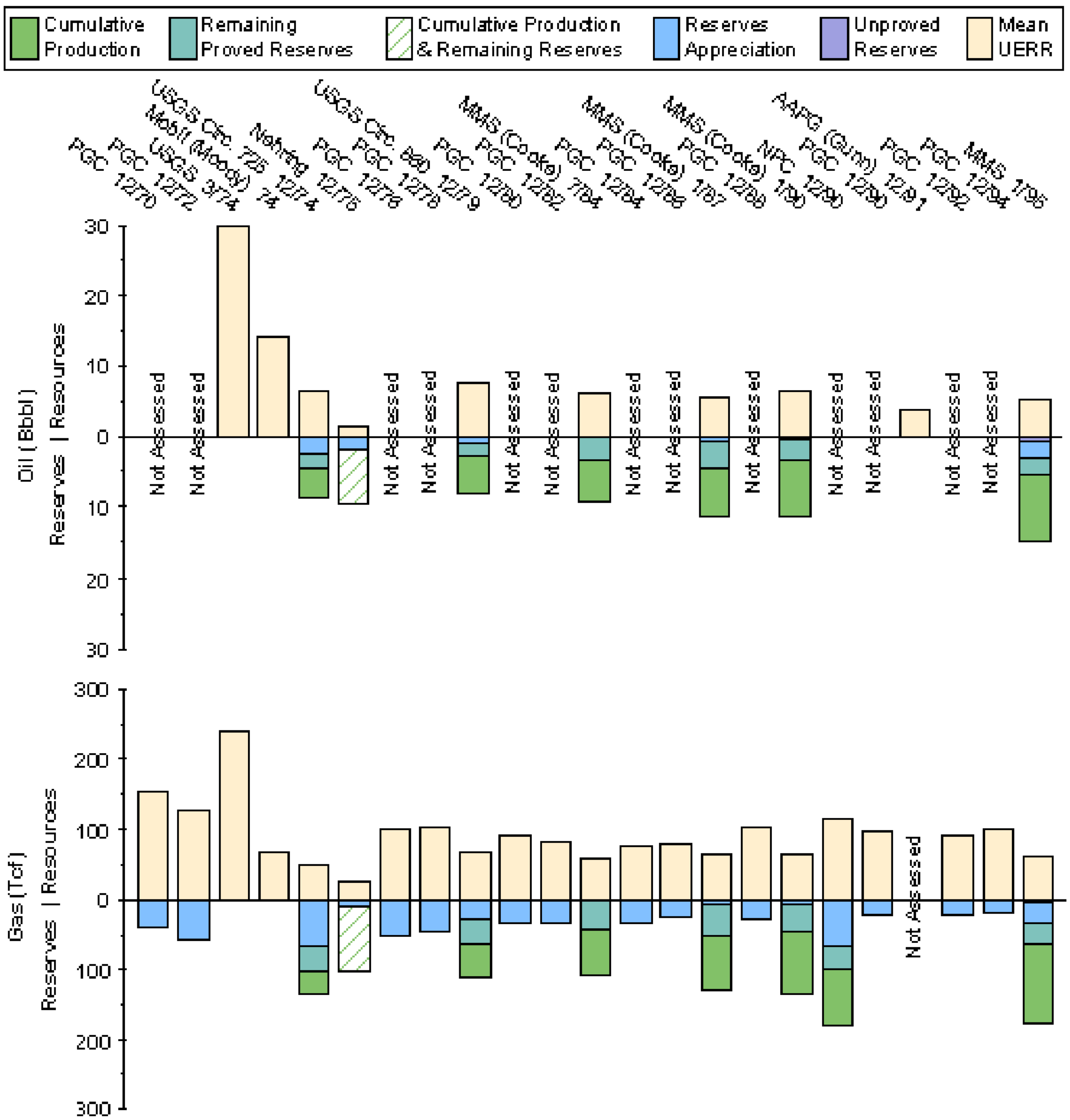

Figure 1. Gulf of Mexico Region Comparison of Selected Estimates of Economically Recoverable Resources.

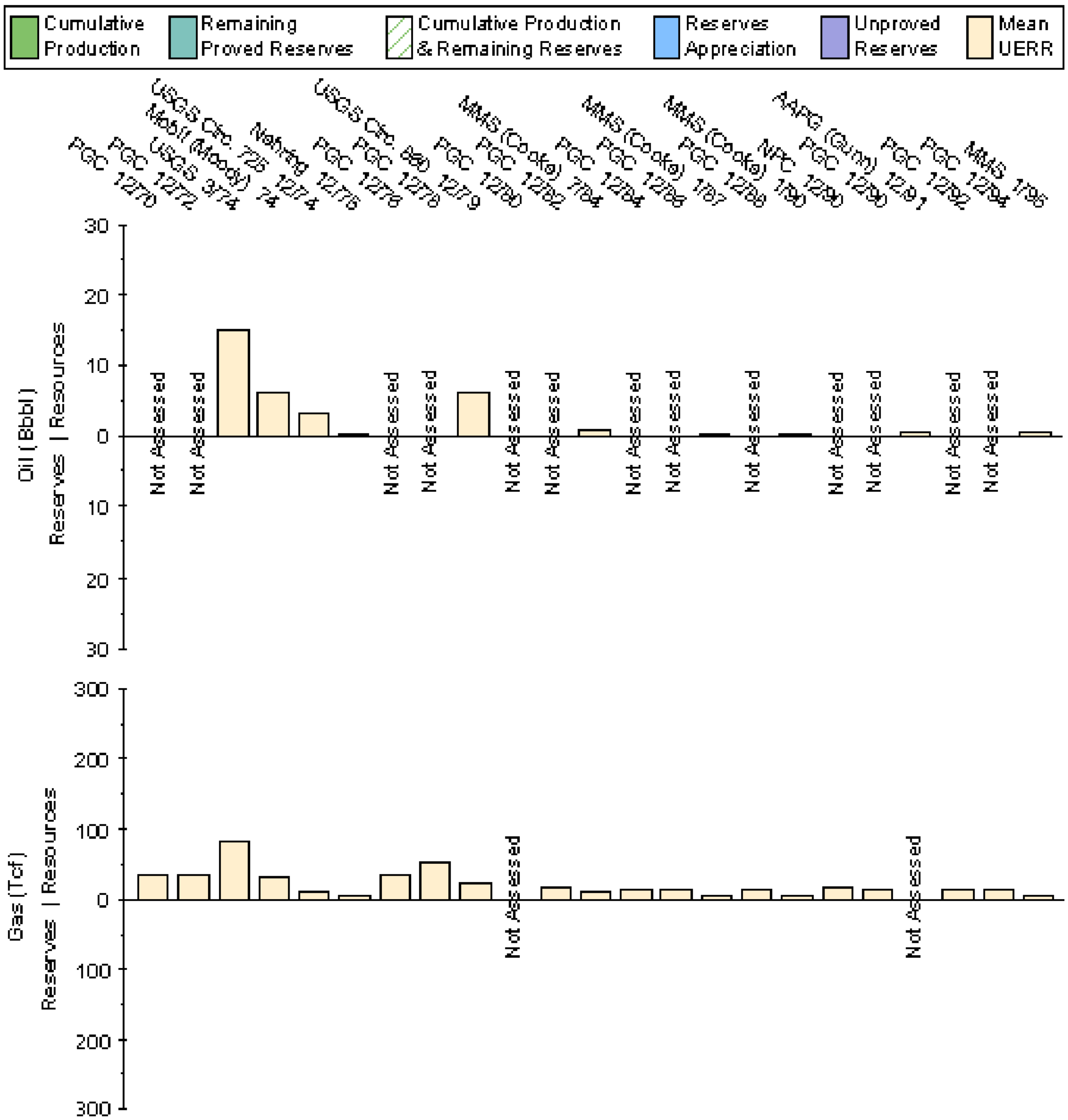

Figure 2. Atlantic Region Comparison of Selected Estimates of Economically Recoverable Resources.

CONCLUSIONS

Prior to 1995 there were 876 fields with proved reserves in the Gulf of Mexico OCS. Included in this number were 133 fields that were depleted and abandoned. Cumulative production was 9.338 Bbo and 112.633 Tcfg (29.379 BBOE), and remaining proved reserves totaled 2.516 Bbo and 29.258 Tcfg (7.722 BBOE); thus, 79 percent of the current estimate of proved reserves in these fields have been produced. Reserves appreciation curves constructed from historical Gulf of Mexico offshore fields indicate that, on average, the estimate of proved reserves in a newly discovered OCS field is anticipated to increase by a factor of 3.8 over the field's life. In active fields discovered prior to January 1, 1995, reserves appreciation to the year 2020 is estimated to be 2.507 Bbo and 31.028 Tcfg (8.028 BBOE), a quantity of resources that exceeds the estimate of remaining proved reserves at the same point in time. Only a single noncommercial structure/discovery exists in the Atlantic Region.

The mean estimates of undiscovered conventionally recoverable resources (UCRR) beneath the Gulf of Mexico and Atlantic Continental Margin are 10.615 Bbo and 123.140 Tcfg (32.526 BBOE). Nearly 78 percent of these resources are projected to be in the Gulf of Mexico. Assuming existing and reasonably foreseeable technology, an estimated 13.679 to 19.351 Bbo and 168.175 to 207.900 Tcfg (44.432 to 55.247 BBOE) of remaining conventionally recoverable resources exist within the study area. Approximately 86 percent of these remaining resources (mean BOE) are believed to be located in the Gulf of Mexico Region.

The results of the economic analysis must be viewed in the long term. Full-cycle economic analysis estimates the expected profitability at the time of the exploration decision. Half-cycle analysis considers exploration and delineation as sunk costs; the decision point is whether or not to proceed with development. In mature, well-developed areas, half-cycle analysis generally results in modest increases in the estimate of undiscovered economically recoverable resources (UERR) over the equivalent full-cycle analysis (e.g., 4 to 8% in the Gulf of Mexico Region). In frontier areas such as the Atlantic Region, the difference can be more significant, ranging between 15 and 17 percent. The basic presentation of the results of the economic analysis is in the form of price-supply curves.

The full-cycle, $18/bbl scenario projects, at mean levels, UERR of 5.350 Bbo and 63.295 Tcfg (16.613 BBOE) for the Gulf of Mexico and Atlantic Continental Margin. This represents about half of the estimates of UCRR for the Margin. The estimates of UERR increase in the $30/bbl scenario to 7.672 Bbo and 85.684 Tcfg (22.918 BBOE). Approximately 92 percent of the estimates of UERR in the full-cycle, $18/bbl scenario is projected to occur in the Gulf of Mexico Region. As higher cost Atlantic OCS resources become economic in the full-cycle, $30/bbl scenario, this decreases slightly to 87 percent.

In the Gulf of Mexico Region full-cycle, $18/bbl scenario, 59 percent (4.941 Bbbl) of the mean undiscovered conventionally recoverable oil and 61 percent (57.941 Tcf) of the gas are economic. This increases to approximately 80 percent (6.639 Bbbl and 75.298 Tcf) for both oil and gas in the $30/bbl scenario. Results for the Atlantic Region are markedly different. In the $18/bbl scenario, only 16 percent (0.368 Bbbl) of the mean undiscovered conventionally recoverable oil and 19 percent (5.203 Tcf) of the gas are economic. This increases to 47 percent (1.063 Bbo) and 38 percent (10.479 Tcfg), respectively, in the $30/bbl scenario.

The mean estimates of total endowment for the Gulf of Mexico and Atlantic Continental Margin are 25.614 Bbo and 299.662 Tcfg (78.935 BBOE). The Gulf of Mexico Region's mean total endowment is 23.343 Bbo and 272.183 Tcfg (71.775 BBOE). Sixty-five percent of this BOE total endowment is in the various reserves categories, with approximately 52 percent occurring as proved reserves. After nearly 50 years of exploration and development, nearly half of the mean BOE total endowment is represented by future reserves appreciation and UCRR. In the full-cycle, $18/bbl scenario, 86 percent of the mean BOE total endowment is economic. This increases to nearly 93 percent in the $30/bbl scenario. The Atlantic Region's total endowment equals its undiscovered conventionally recoverable resources, with mean estimates of 2.271 Bbo and 27.480 Tcfg (7.161 BBOE).

From a National perspective, comparing the four Federal Regions (Alaska, Atlantic, Gulf of Mexico, and Pacific), the Gulf of Mexico Region is second to the Alaska Region in terms of the potential quantities of UCRR. In the Gulf of Mexico Region, the volumes of conventionally recoverable resources represented by the various categories of reserves, 46.409 BBOE, approach the mean total endowment of the Alaska Region. The mean total endowment of the Gulf of Mexico Region is greater than that of the other three Regions combined, 71.775 versus 71.09 BBOE. The Gulf of Mexico Region also has a larger percentage of both mean total endowment, 84 percent, and mean UCRR, 60 percent, estimated to be economically recoverable at near current oil and gas prices and specified economic conditions. The Atlantic Region, with a mean total endowment of 7.161 BBOE, ranks last of the four OCS Regions.

Summary Table 1. Play classification and total endowment of the Gulf of Mexico and Atlantic Continental Margin plays.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding. This table diverges from the August 1996 (OCS Report MMS 96-0047) table in that it uses different rounding, a different reserves appreciation equation, and includes reserves appreciation for unproved reserves.

		Play Classification (E=Established, F=Frontier, C=Conceptual, T=Total)												Total Endowment (Reserves + Resources)									
		Assessed				Non-assessed				Total				No.	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	No.	E	F	C	T	E	F	C	T	E	F	C	T	Pools	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
GOM & Atlantic Margin		50	10	2	62	2	0	8	10	52	10	10	72	4,658	23.016	25.614	28.688	280.808	299.662	320.533	73.811	78.935	84.626
Gulf of Mexico Region		50	5	2	57	2	0	2	4	52	5	4	61	4,156	21.037	23.343	26.137	258.845	272.183	286.808	67.627	71.775	76.399
Cenozoic Province		48	1	1	50	2	0	0	2	50	1	1	52	3,966	19.424	21.287	23.580	247.479	260.266	274.352	63.927	67.598	71.705
Quaternary System		9	0	0	9	2	0	0	2	11	0	0	11	1,446	7.908	8.492	9.170	96.427	101.871	107.979	25.299	26.618	28.086
Pleistocene Series		9	0	0	9	2	0	0	2	11	0	0	11	1,446	7.908	8.492	9.170	96.427	101.871	107.979	25.299	26.618	28.086
UPL Chronozone		3	0	0	3	1	0	0	1	4	0	0	4	395	2.123	2.497	2.952	29.421	30.924	32.565	7.435	8.000	8.632
UPL A Play	1	1	0	0	1	0	0	0	0	1	0	0	1	69	0.112	0.118	0.127	3.183	3.217	3.253	0.681	0.690	0.701
UPL P Play	2	1	0	0	1	0	0	0	0	1	0	0	1	185	0.626	0.689	0.772	16.136	16.484	16.845	3.527	3.623	3.731
UPL F Play	3	1	0	0	1	0	0	0	0	1	0	0	1	140	1.367	1.648	2.070	10.050	11.217	12.650	3.248	3.644	4.240
UPL C Play	4	0	0	0	0	1	0	0	1	1	0	0	1	1	0.042	0.042	0.042	0.006	0.006	0.006	0.043	0.043	0.043
MPL Chronozone		3	0	0	3	1	0	0	1	4	0	0	4	404	1.223	1.271	1.325	18.133	19.035	20.123	4.472	4.658	4.874
MPL A Play	5	1	0	0	1	0	0	0	0	1	0	0	1	66	0.019	0.020	0.022	0.940	0.972	1.008	0.188	0.194	0.201
MPL P Play	6	1	0	0	1	0	0	0	0	1	0	0	1	187	0.842	0.852	0.864	13.559	14.044	14.621	3.261	3.351	3.451
MPL F Play	7	1	0	0	1	0	0	0	0	1	0	0	1	150	0.361	0.399	0.445	3.596	4.018	4.775	1.018	1.113	1.260
MPL C Play	8	0	0	0	0	1	0	0	1	1	0	0	1	1	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
LPL Chronozone		3	0	0	3	0	0	0	0	3	0	0	3	647	4.461	4.724	5.034	47.970	51.913	56.536	13.131	13.961	14.913
LPL A Play	9	1	0	0	1	0	0	0	0	1	0	0	1	87	0.332	0.345	0.364	2.043	2.097	2.158	0.700	0.719	0.742
LPL P Play	10	1	0	0	1	0	0	0	0	1	0	0	1	280	1.663	1.728	1.808	22.644	23.131	23.656	5.725	5.844	5.978
LPL F Play	11	1	0	0	1	0	0	0	0	1	0	0	1	280	2.436	2.651	2.908	23.113	26.684	31.051	6.863	7.399	8.279
Tertiary System		39	1	1	41	0	0	0	0	39	1	1	41	2,520	11.350	12.795	14.726	149.184	158.396	168.674	38.158	40.980	44.227
Pliocene Series		6	0	0	6	0	0	0	0	6	0	0	6	684	4.857	5.030	5.224	33.270	34.740	36.380	10.856	11.211	11.601
UP Chronozone		3	0	0	3	0	0	0	0	3	0	0	3	371	2.402	2.469	2.544	19.046	19.419	19.818	5.815	5.925	6.043
UP A Play	12	1	0	0	1	0	0	0	0	1	0	0	1	42	0.144	0.149	0.154	1.018	1.051	1.082	0.328	0.336	0.345
UP P Play	13	1	0	0	1	0	0	0	0	1	0	0	1	171	1.007	1.029	1.054	9.838	9.948	10.060	2.767	2.799	2.835
UP F Play	14	1	0	0	1	0	0	0	0	1	0	0	1	158	1.239	1.291	1.346	8.118	8.419	8.733	2.700	2.789	2.882
LP Chronozone		3	0	0	3	0	0	0	0	3	0	0	3	313	2.433	2.561	2.711	14.095	15.321	16.756	5.002	5.287	5.611
LP A Play	15	1	0	0	1	0	0	0	0	1	0	0	1	43	0.506	0.511	0.519	1.441	1.503	1.567	0.764	0.778	0.795
LP P Play	16	1	0	0	1	0	0	0	0	1	0	0	1	170	1.420	1.446	1.476	8.443	8.581	8.730	2.933	2.974	3.019
LP F Play	17	1	0	0	1	0	0	0	0	1	0	0	1	100	0.500	0.603	0.737	4.369	5.237	6.621	1.318	1.535	1.832
Miocene Series		33	0	0	33	0	0	0	0	33	0	0	33	1,796	6.642	6.963	7.323	111.862	118.070	124.925	26.691	27.972	29.375
UM3 Chronozone		6	0	0	6	0	0	0	0	6	0	0	6	397	3.445	3.549	3.671	19.666	20.367	21.142	6.975	7.174	7.394
UM3 R1 Play	18	1	0	0	1	0	0	0	0	1	0	0	1	8	<0.001	<0.001	<0.001	0.057	0.065	0.074	0.010	0.012	0.013
UM3 R2 Play	19	1	0	0	1	0	0	0	0	1	0	0	1	31	0.095	0.102	0.112	0.703	0.744	0.786	0.222	0.235	0.249
UM3 A Play	20	1	0	0	1	0	0	0	0	1	0	0	1	12	0.019	0.019	0.019	0.303	0.311	0.322	0.072	0.074	0.076
UM3 AP Play	21	1	0	0	1	0	0	0	0	1	0	0	1	30	<0.001	<0.001	<0.001	0.388	0.394	0.401	0.069	0.070	0.071
UM3 P Play	22	1	0	0	1	0	0	0	0	1	0	0	1	195	2.429	2.438	2.450	12.511	12.628	12.760	4.659	4.685	4.715
UM3 F Play	23	1	0	0	1	0	0	0	0	1	0	0	1	121	0.896	0.990	1.103	5.599	6.226	6.881	1.924	2.098	2.298
UM1 Chronozone		4	0	0	4	0	0	0	0	4	0	0	4	278	1.076	1.152	1.239	16.660	17.245	17.889	4.068	4.220	4.386
UM1 A Play	24	1	0	0	1	0	0	0	0	1	0	0	1	4	<0.001	<0.001	0.001	0.134	0.141	0.151	0.024	0.025	0.027
UM1 AP Play	25	1	0	0	1	0	0	0	0	1	0	0	1	40	0.026	0.026	0.026	0.988	1.002	1.017	0.202	0.204	0.207
UM1 P Play	26	1	0	0	1	0	0	0	0	1	0	0	1	124	0.586	0.597	0.612	9.850	9.926	10.008	2.343	2.363	2.387
UM1 F Play	27	1	0	0	1	0	0	0	0	1	0	0	1	110	0.460	0.529	0.608	5.649	6.176	6.770	1.489	1.627	1.784
MM9 Chronozone		5	0	0	5	0	0	0	0	5	0	0	5	220	0.896	0.998	1.123	13.578	14.461	15.444	3.363	3.571	3.802
MM9 RAP Play	28	1	0	0	1	0	0	0	0	1	0	0	1	18	<0.001	<0.001	<0.001	0.144	0.148	0.152	0.026	0.027	0.028
MM9 A Play	29	1	0	0	1	0	0	0	0	1	0	0	1	6	<0.001	<0.001	<0.001	0.047	0.057	0.070	0.009	0.011	0.013
MM9 AP Play	30	1	0	0	1	0	0	0	0	1	0	0	1	6	<0.001	<0.001	<0.001	0.141	0.153	0.166	0.025	0.027	0.029
MM9 P Play	31	1	0	0	1	0	0	0	0	1	0	0	1	85	0.138	0.150	0.174	6.982	7.198	7.414	1.386	1.430	1.478
MM9 F Play	32	1	0	0	1	0	0	0	0	1	0	0	1	105	0.756	0.847	0.963	6.175	6.906	7.763	1.896	2.076	2.282
MM7 Chronozone		6	0	0	6	0	0	0	0	6	0	0	6	307	0.481	0.570	0.677	23.436	27.096	31.592	4.691	5.392	6.239
MM7 R Play	33	1	0	0	1	0	0	0	0	1	0	0	1	40	0.030	0.033	0.035	2.474	2.525	2.580	0.472	0.482	0.493
MM7 RAPF Play	34	1	0	0	1	0	0	0	0	1	0	0	1	37	0.012	0.014	0.018	3.643	4.255	5.040	0.661	0.771	0.913
MM7 A Play	35	1	0	0	1	0	0	0	0	1	0	0	1	20	0.001	0.002	0.003	0.220	0.276	0.343	0.041	0.051	0.064
MM7 P1 Play	36	1	0	0	1	0	0	0	0	1	0	0	1	100	0.175	0.183	0.195	9.885	10.095	10.329	1.938	1.980	2.027
MM7 P2 Play	37	1	0	0	1	0	0	0	0	1	0	0	1	20	0.004	0.008	0.018	0.964	1.238	1.759	0.178	0.228	0.325
MM7 F Play	38	1	0	0	1	0	0	0	0	1	0	0	1	90	0.264	0.330	0.421	6.534	8.707	12.310	1.462	1.880	2.562
MM4 Chronozone		4	0	0	4	0	0	0	0	4	0	0	4	271	0.402	0.431	0.462	16.177	16.685	17.226	3.292	3.400	3.514
MM4 R Play	39	1	0	0	1	0	0	0	0	1	0	0	1	55	0.034	0.037	0.041	1.468	1.529	1.596	0.297	0.309	0.323
MM4 A Play	40	1	0	0	1	0	0	0	0	1	0	0	1	22	0.015	0.015	0.016	0.616	0.627	0.639	0.126	0.127	0.130
MM4 P Play	41	1	0	0	1	0	0	0	0	1	0	0	1	109	0.121	0.126	0.134	9.005	9.154	9.315	1.727	1.756	1.787
MM4 F Play	42	1	0	0	1	0	0	0	0	1	0	0	1	85	0.229	0.252	0.276	4.982	5.375	5.774	1.122	1.208	1.295
LM4 Chronozone		4	0	0	4	0	0	0	0	4	0	0	4	181	0.108	0.144	0.191	8.078	9.163	10.435	1.553	1.775	2.036
LM4 R Play	43	1	0	0	1	0	0	0	0	1	0	0	1	23	0.002	0.002	0.002	0.595	0.617	0.642	0.107	0.111	0.116
LM4 A Play	44	1	0	0	1	0	0	0	0	1	0	0	1	19	0.001	0.002	0.004	0.609	0.628	0.648	0.110	0.114	0.119
LM4 P Play	45	1	0	0	1	0	0	0	0	1	0	0	1	59	0.046	0.050	0.055	4.275	4.457	4.663	0.807	0.843	0.881
LM4 F Play	46	1	0	0	1	0	0	0	0	1	0	0	1	80	0.056	0.090	0.133	2.514	3.461	4.609	0.541	0.706	0.946
LM2 Chronozone		2	0	0	2	0	0	0	0	2	0	0	2	83	0.062	0.069	0.079	7.087	7.493	7.944	1.326	1.402	1.487
LM2 P Play	47	1	0	0	1	0	0	0	0	1	0	0	1	39	0.034	0.039	0.045	4.151	4.356	4.593	0.776	0.815	0.858
LM2 F Play	48	1	0	0	1	0	0	0	0	1	0	0	1	44	0.025	0.029	0.034	2.873	3.137	3.431	0.536	0.587	0.642
LM1 Chronozone		2	0	0	2	0	0	0	0	2	0	0	2	59	0.042	0.049	0.059	5.165	5.557	5.995	0.964	1.038	1.121
LM1 P Play	49	1	0	0	1	0	0	0	0	1	0	0	1	10	0.003	0.004	0.006	0.260	0.291	0.331	0.050	0.056	0.064
LM1 F Play	50	1	0	0	1	0	0	0	0	1	0	0	1	49	0.038	0.045	0.054	4.893	5.267	5.685	0.907	0.982	1.057

Summary Table 1. Play classification and total endowment of the Gulf of Mexico and Atlantic Continental Margin plays.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding. This table diverges from the August 1996 (OCS Report MMS 96-0047) table in that it uses different rounding, a different reserves appreciation equation, and includes reserves appreciation for unproved reserves.

		Play Classification (E=Established, F=Frontier, C=Conceptual, T=Total)												Total Endowment (Reserves + Resources)									
		Assessed				Non-assessed				Total				No.	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	No.	E	F	C	T	E	F	C	T	E	F	C	T	Pools	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
Oligocene/Eocene Series		0	1	1	2	0	0	0	0	0	1	1	2	40	0.126	0.803	2.327	2.844	5.586	9.576	0.558	1.797	4.032
O/E Chronozone		0	1	1	2	0	0	0	0	0	1	1	2	40	0.126	0.803	2.327	2.844	5.586	9.576	0.558	1.797	4.032
O F Play	51	0	1	0	1	0	0	0	0	0	1	0	1	30	0.026	0.043	0.078	1.976	3.249	5.471	0.380	0.621	1.040
OE X Play	52	0	0	1	1	0	0	0	0	0	0	1	1	10	0.181	0.760	2.206	1.030	2.337	4.571	0.396	1.176	2.968
Paleocene Series		0	0	0	0	0	0	0	0	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
L Chronozone		0	0	0	0	0	0	0	0	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Mesozoic Province		2	4	1	7	0	0	2	2	2	4	3	9	190	1.363	2.056	2.936	10.915	11.917	13.003	3.359	4.176	5.136
Cretaceous System		1	3	1	5	0	0	0	0	1	3	1	5	144	0.908	1.436	2.124	0.955	1.375	1.961	1.106	1.680	2.423
Upper Cretaceous Series		0	1	0	1	0	0	0	0	0	1	0	1	5	0.000	0.045	0.190	0.000	0.070	0.257	0.000	0.057	0.226
UK Chronozone		0	1	0	1	0	0	0	0	0	1	0	1	5	0.000	0.045	0.190	0.000	0.070	0.257	0.000	0.057	0.226
UK CL Play	53	0	1	0	1	0	0	0	0	0	1	0	1	5	0.000	0.045	0.190	0.000	0.070	0.257	0.000	0.057	0.226
Lower Cretaceous Series		1	2	1	4	0	0	0	0	1	2	1	4	139	0.924	1.391	1.983	0.966	1.305	1.756	1.122	1.622	2.251
LK Chronozone		1	2	1	4	0	0	0	0	1	2	1	4	139	0.924	1.391	1.983	0.966	1.305	1.756	1.122	1.622	2.251
LK CL Play	54	0	1	0	1	0	0	0	0	0	1	0	1	20	0.000	0.037	0.093	0.000	0.110	0.244	0.000	0.057	0.133
LK CB Play	55	1	0	0	1	0	0	0	0	1	0	0	1	28	0.199	0.348	0.565	0.868	1.122	1.450	0.374	0.547	0.780
LK SUN Play	56	0	1	0	1	0	0	0	0	0	1	0	1	33	0.295	0.419	0.609	0.022	0.031	0.045	0.298	0.425	0.617
LK SFB Play	57	0	0	1	1	0	0	0	0	0	0	1	1	58	0.400	0.587	0.881	0.029	0.042	0.065	0.405	0.593	0.893
Jurassic System		1	1	0	2	0	0	2	2	1	1	2	4	46	0.375	0.620	0.947	9.863	10.542	11.263	2.161	2.496	2.873
Upper Jurassic Series		1	1	0	2	0	0	1	1	1	1	1	3	46	0.375	0.620	0.947	9.863	10.542	11.263	2.161	2.496	2.873
UU Chronozone		1	1	0	2	0	0	1	1	1	1	1	3	46	0.375	0.620	0.947	9.863	10.542	11.263	2.161	2.496	2.873
UU A Play	58	1	0	0	1	0	0	0	0	1	0	0	1	41	0.360	0.591	0.856	9.843	10.494	11.181	2.165	2.458	2.788
UU SMK Play	59	0	1	0	1	0	0	0	0	0	1	0	1	5	0.003	0.029	0.101	0.011	0.048	0.122	0.006	0.038	0.121
UU-LK TZ Play	60	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Middle Jurassic Series		0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
MU Chronozone		0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
MU-UU FBCL Play	61	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lower Jurassic Series		0	0	0	0	0	0	0	0	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
LU Chronozone		0	0	0	0	0	0	0	0	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Triassic System		0	0	0	0	0	0	0	0	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Upper Triassic Series		0	0	0	0	0	0	0	0	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
UTR Chronozone		0	0	0	0	0	0	0	0	0	0	0	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Atlantic Region		0	5	0	5	0	0	6	6	0	5	6	11	502	1.267	2.271	3.667	15.855	27.480	43.372	4.475	7.161	10.684
Mesozoic Province		0	5	0	5	0	0	6	6	0	5	6	11	502	1.267	2.271	3.667	15.855	27.480	43.372	4.475	7.161	10.684
Cretaceous System		0	1	0	1	0	0	1	1	0	1	1	2	120	0.431	0.722	1.143	7.840	11.767	18.813	1.985	2.816	4.190
Upper Cretaceous Series		0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AUK Chronozone		0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AUK CL Play	62	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lower Cretaceous Series		0	1	0	1	0	0	0	0	0	1	0	1	120	0.431	0.722	1.143	7.840	11.767	18.813	1.985	2.816	4.190
ALK Chronozone		0	1	0	1	0	0	0	0	0	1	0	1	120	0.431	0.722	1.143	7.840	11.767	18.813	1.985	2.816	4.190
ALK CL Play	63	0	1	0	1	0	0	0	0	0	1	0	1	120	0.431	0.722	1.143	7.840	11.767	18.813	1.985	2.816	4.190
Jurassic System		0	4	0	4	0	0	3	3	0	4	3	7	382	0.762	1.549	2.714	9.040	15.712	24.847	2.584	4.345	6.716
Upper Jurassic Series		0	2	0	2	0	0	2	2	0	2	2	4	235	0.527	1.020	1.733	6.135	10.210	15.667	1.791	2.837	4.201
AUU Chronozone		0	2	0	2	0	0	2	2	0	2	2	4	235	0.527	1.020	1.733	6.135	10.210	15.667	1.791	2.837	4.201
AUU CL Play	64	0	1	0	1	0	0	0	0	0	1	0	1	200	0.545	0.822	1.153	6.401	8.953	13.270	1.832	2.415	3.273
AUU CB Play	65	0	1	0	1	0	0	0	0	0	1	0	1	35	0.000	0.198	0.435	0.000	1.257	3.152	0.000	0.422	0.945
AUU-UK BFF Play	66	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AUU-LK TZ Play	67	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Middle Jurassic Series		0	2	0	2	0	0	0	0	0	2	0	2	147	0.000	0.529	1.163	0.000	5.502	10.426	0.000	1.508	2.830
AMU Chronozone		0	2	0	2	0	0	0	0	0	2	0	2	147	0.000	0.529	1.163	0.000	5.502	10.426	0.000	1.508	2.830
AMU CL Play	68	0	1	0	1	0	0	0	0	0	1	0	1	120	0.000	0.399	0.645	0.000	4.891	8.455	0.000	1.269	2.020
AMU CB Play	69	0	1	0	1	0	0	0	0	0	1	0	1	27	0.000	0.130	0.413	0.000	0.611	1.633	0.000	0.239	0.688
Lower Jurassic Series		0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ALU Chronozone		0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AU-K DIA Play	70	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Triassic System		0	0	0	0	0	0	2	2	0	0	2	2	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Upper Triassic Series		0	0	0	0	0	0	2	2	0	0	2	2	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AUTR Chronozone		0	0	0	0	0	0	2	2	0	0	2	2	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ATR-LU CLR Play	71	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ATR-LU CBR Play	72	0	0	0	0	0	0	1	1	0	0	1	1	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Summary Table 2. Reserves and undiscovered conventionally recoverable resources of the Gulf of Mexico and Atlantic Continental Margin plays.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding. This table diverges from the August 1996 (OCS Report MMS 96-0047) table in that it uses different rounding, a different reserves appreciation equation, and includes reserves appreciation for unproved reserves.

		Reserves																			Risked Undiscovered Conventionally Recoverable Resources										
		Proved				Cum. Production			Remaining Proved			Unproved				Appreciation (P&U)														
		No.	Oil	Gas	BOE	Oil	Gas	BOE	Oil	Gas	BOE	No.	Oil	Gas	BOE	Oil	Gas	BOE	MPhc	No.	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)			
	No.	Pools	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)	Pools	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)		Undisc Pools	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5	
GOM & Atlantic Margin		2,114	11.853	141.891	37.101	9.338	112.633	29.379	2.516	29.258	7.722	69	0.639	3.603	1.280	2.507	31.028	8.028	1.00	2,475	8.017	10.615	13.689	104.286	123.140	144.011	27.402	32.526	38.217	
Gulf of Mexico Region		2,114	11.853	141.891	37.101	9.338	112.633	29.379	2.516	29.258	7.722	69	0.639	3.603	1.280	2.507	31.028	8.028	1.00	1,973	6.038	8.344	11.138	82.323	95.661	110.286	21.218	25.366	29.990	
Cenozoic Province		2,105	11.853	140.318	36.821	9.337	112.434	29.344	2.516	27.884	7.477	67	0.638	3.006	1.172	2.505	29.389	7.735	1.00	1,794	4.428	6.291	8.584	74.766	87.553	101.639	18.199	21.870	25.977	
Quaternary System		828	4.317	57.136	14.483	3.259	46.084	11.459	1.058	11.051	3.024	36	0.323	1.088	0.517	1.204	12.088	3.355	1.00	582	2.064	2.648	3.326	26.116	31.560	37.668	6.944	8.263	9.731	
Pleistocene Series		828	4.317	57.136	14.483	3.259	46.084	11.459	1.058	11.051	3.024	36	0.323	1.088	0.517	1.204	12.088	3.355	1.00	582	2.064	2.648	3.326	26.116	31.560	37.668	6.944	8.263	9.731	
UPL Chronozone		223	0.744	16.069	3.604	0.398	12.842	2.683	0.347	3.227	0.921	10	0.100	0.199	0.135	0.317	3.339	0.911	1.00	162	0.962	1.336	1.791	9.813	11.316	12.957	2.785	3.350	3.982	
UPL A Play	1	57	0.094	2.602	0.557	0.075	1.915	0.416	0.019	0.688	0.141	0	0	0	0	0.014	0.470	0.098	1.00	12	0.003	0.009	0.018	0.111	0.145	0.181	0.026	0.035	0.046	
UPL P Play	2	134	0.425	11.685	2.504	0.208	9.895	1.968	0.217	1.790	0.536	1	<0.001	0.016	0.003	0.135	2.060	0.502	1.00	50	0.066	0.129	0.212	2.375	2.723	3.084	0.518	0.614	0.722	
UPL F Play	3	31	0.185	1.776	0.502	0.092	1.029	0.275	0.094	0.747	0.227	9	0.100	0.183	0.132	0.165	0.809	0.309	1.00	100	0.917	1.198	1.620	7.281	8.448	9.881	2.305	2.701	3.297	
UPL C Play	4	1	0.040	0.006	0.041	0.023	0.003	0.024	0.017	0.003	0.017	0	0	0	0	0.002	<0.001	0.002	1.00	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
MPL Chronozone		226	0.845	13.057	3.169	0.667	10.779	2.585	0.178	2.278	0.584	9	0.013	0.139	0.037	0.179	2.508	0.625	1.00	169	0.186	0.234	0.288	2.429	3.331	4.419	0.641	0.827	1.043	
MPL A Play	5	52	0.018	0.704	0.143	0.012	0.534	0.107	0.006	0.170	0.036	0	0	0	0	<0.001	0.152	0.027	1.00	14	0.001	0.002	0.004	0.084	0.116	0.152	0.017	0.023	0.030	
MPL P Play	6	136	0.711	11.213	2.706	0.601	9.812	2.347	0.110	1.401	0.359	1	<0.001	0.001	0.001	0.112	1.759	0.425	1.00	50	0.019	0.029	0.041	0.586	1.071	1.648	0.130	0.220	0.320	
MPL F Play	7	37	0.116	1.140	0.319	0.054	0.433	0.131	0.062	0.707	0.188	8	0.012	0.138	0.037	0.067	0.597	0.173	1.00	105	0.165	0.203	0.249	1.722	2.144	2.901	0.489	0.584	0.731	
MPL C Play	8	1	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	0.000	0.000	0.000	0	0	0	0	<0.001	<0.001	<0.001	1.00	0	NA	NA	NA	NA	NA	NA	NA	NA	NA	
LPL Chronozone		379	2.727	28.009	7.711	2.194	22.463	6.191	0.533	5.546	1.519	17	0.211	0.749	0.344	0.709	6.241	1.819	1.00	251	0.815	1.078	1.388	12.970	16.913	21.536	3.257	4.087	5.039	
LPL A Play	9	67	0.320	1.560	0.598	0.291	1.335	0.529	0.029	0.225	0.069	0	0	0	0	0.002	0.240	0.045	1.00	20	0.010	0.023	0.042	0.243	0.297	0.358	0.057	0.076	0.099	
LPL P Play	10	203	1.366	16.473	4.297	1.212	13.969	3.698	0.154	2.504	0.600	4	0.007	0.047	0.015	0.136	2.350	0.555	1.00	73	0.153	0.218	0.298	3.775	4.262	4.787	0.857	0.976	1.110	
LPL F Play	11	109	1.040	9.977	2.816	0.691	7.159	1.965	0.350	2.818	0.851	13	0.204	0.702	0.329	0.570	3.651	1.220	1.00	158	0.622	0.837	1.094	8.783	12.354	16.721	2.499	3.035	3.915	
Tertiary System		1,277	7.537	83.183	22.338	6.078	66.350	17.884	1.458	16.833	4.453	31	0.314	1.918	0.656	1.301	17.300	4.379	1.00	1,212	2.198	3.643	5.574	46.782	55.994	66.272	10.785	13.607	16.854	
Pliocene Series		387	3.412	21.715	7.276	2.757	17.354	5.845	0.655	4.361	1.431	13	0.131	0.554	0.229	0.526	3.548	1.158	1.00	284	0.788	0.961	1.155	7.452	8.922	10.562	2.193	2.548	2.938	
UP Chronozone		208	1.576	12.834	3.860	1.222	10.176	3.032	0.354	2.658	0.827	9	0.126	0.525	0.220	0.360	2.429	0.792	1.00	154	0.340	0.407	0.482	3.258	3.631	4.030	0.943	1.053	1.171	
UP A Play	12	34	0.135	0.885	0.292	0.122	0.773	0.259	0.013	0.112	0.033	0	0	0	0	0.003	0.075	0.017	1.00	8	0.006	0.011	0.016	0.058	0.091	0.122	0.019	0.027	0.036	
UP P Play	13	130	0.889	8.296	2.365	0.754	6.882	1.979	0.135	1.414	0.387	0	0	0	0	0.073	0.932	0.239	1.00	41	0.045	0.067	0.092	0.611	0.721	0.833	0.163	0.195	0.231	
UP F Play	14	44	0.552	3.654	1.202	0.346	2.521	0.794	0.206	1.132	0.408	9	0.126	0.525	0.220	0.283	1.422	0.536	1.00	105	0.277	0.329	0.384	2.518	2.819	3.133	0.742	0.831	0.924	
LP Chronozone		179	1.836	8.881	3.417	1.535	7.179	2.813	0.301	1.702	0.604	4	0.004	0.030	0.010	0.166	1.119	0.365	1.00	130	0.426	0.554	0.704	4.065	5.291	6.726	1.210	1.495	1.819	
LP A Play	15	28	0.483	1.205	0.697	0.453	1.085	0.646	0.029	0.121	0.051	0	0	0	0	0.015	0.065	0.027	1.00	15	0.008	0.013	0.021	0.171	0.233	0.297	0.040	0.054	0.071	
LP P Play	16	130	1.240	6.843	2.457	1.045	5.523	2.028	0.195	1.320	0.430	1	<0.001	0.002	<0.001	0.109	0.810	0.253	1.00	39	0.072	0.098	0.128	0.787	0.925	1.074	0.222	0.263	0.308	
LP F Play	17	21	0.114	0.832	0.262	0.037	0.571	0.139	0.077	0.262	0.123	3	0.004	0.028	0.009	0.042	0.244	0.086	1.00	76	0.340	0.443	0.577	3.265	4.133	5.517	0.961	1.178	1.475	
Miocene Series		890	4.124	61.468	15.062	3.321	48.996	12.039	0.803	12.472	3.022	18	0.184	1.364	0.426	0.775	13.752	3.222	1.00	888	1.559	1.880	2.240	35.278	41.486	48.341	7.981	9.262	10.665	
UM3 Chronozone		240	2.610	12.822	4.891	2.220	10.288	4.050	0.390	2.534	0.841	9	0.105	0.422	0.180	0.383	2.452	0.819	1.00	148	0.348	0.452	0.574	3.970	4.671	5.446	1.085	1.284	1.504	
UM3 R1 Play	18	3	<0.001	0.027	0.005	<0.001	0.025	0.005	<0.001	0.002	<0.001	0	0	0	0	<0.001	0.006	0.001	1.00	5	<0.001	<0.001	<0.001	0.024	0.032	0.041	0.004	0.006	0.007	
UM3 R2 Play	19	24	0.083	0.557	0.182	0.069	0.461	0.151	0.014	0.096	0.031	0	0	0	0	0.003	0.056	0.013	1.00	7	0.009	0.016	0.026	0.090	0.131	0.173	0.027	0.040	0.054	
UM3 A Play	20	9	0.018	0.241	0.061	0.016	0.180	0.048	0.003	0.061	0.013	0	0	0	0	0.001	0.054	0.010	1.00	3	<0.001	<0.001	<0.001	0.008	0.016	0.027	0.001	0.003	0.005	
UM3 AP Play	21	15	<0.001	0.192	0.034	<0.001	0.047	0.008	<0.001	0.145	0.026	2	<0.001	0.008	0.001	<0.001	0.155	0.028	1.00	13	<0.001	<0.001	<0.001	0.033	0.039	0.046	0.006	0.007	0.008	
UM3 P Play	22	165	2.284	10.906	4.225	2.056	9.087	3.673	0.228	1.819	0.552	0	0	0	0	0.127	1.203	0.341	1.00	30	0.018	0.027	0.039	0.401	0.518	0.650	0.093	0.119	0.149	
UM3 F Play	23	24	0.224	0.898	0.384	0.079	0.487	0.166	0.145	0.411	0.218	7	0.105	0.415	0.179	0.253	0.978	0.427	1.00	90	0.315	0.409	0.522	3.308	3.935	4.590	0.935	1.109	1.309	
UM1 Chronozone		150	0.675	10.591	2.559	0.512	8.572	2.037	0.163	2.019	0.522	5	0.013	0.646	0.128	0.102	1.921	0.443	1.00	123	0.286	0.362	0.449	3.502	4.087	4.731	0.937	1.089	1.255	
UM1 A Play	24	1	<0.001	0.094	0.017	<0.001	0.036	0.006	<0.001	0.058	0.010	0	0	0	0	<0.001	0.025	0.005	1.00	3	<0.001	<0.001	0.001	0.015	0.022	0.032	0.003	0.004	0.006	
UM1 AP Play	25	24	0.017	0.579	0.120	<0.001	0.323	0.057	0.017	0.257	0.062	1	<0.001	0.005	0.001	0.009	0.350	0.071	1.00	15	<0.001	<0.001	<0.001	0.054	0.068	0.083	0.010	0.012	0.015	
UM1 P Play	26	103	0.535	8.772	2.096	0.475	7.623	1.831	0.060	1.149	0.265	1	<0.001	0.003	0.001	0.037	0.792	0.178	1.00	20	0.014	0.025	0.040	0.283	0.359	0.441	0.069	0.089	0.113	
UM1 F Play	27	22	0.123	1.146	0.327	0.037	0.590	0.142	0.085	0.556	0.184	3	0.013	0.638	0.127	0.056	0.754	0.190	1.00	85	0.268	0.337	0.416	3.111	3.638	4.232	0.846	0.984	1.141	
MM9 Chronozone		94	0.391	6.926	1.624	0.225	5.313	1.171	0.166	1.614	0.453	4	0.065	0.295	0.118	0.201	1.708	0.505	1.00	122	0.238	0.340	0.465	4.649	5.532	6.515	1.116	1.324	1.555	
MM9 RAP Play	28	11	<0.001	0.097	0.017	<0.001	0.063	0.011	<0.001	0.034	0.006	0	0	0	0	<0.001	0.033	0.006	1.00	7	<0.001	<0.001	<0.001	0.014	0.018	0.022	0.002	0.003	0.004	
MM9 A Play	29	2	<0.001	0.021	0.004	<0.001	0.019	0.003	<0.001	0.002	<0.001	0	0	0	0	<0.001	0.006	0.001	1.00	4	<0.001	<0.001	<0.001	0.021	0.031	0.044	0.004	0.006	0.008	
MM9 AP Play	30	3	<0.001	0.082	0.015	<0.001	0.020	0.003	<0.001	0.062	0.011	0	0	0	0	<0.001	0.039	0.007	1.00	3	<0.001	<0.001	<0.001	0.020	0.032	0.045	0.004	0.006	0.008	
MM9 P Play	31	63	0.102	5.468	1.075	0.085	4.847	0.947	0.017	0.621	0.127	0	0	0	0	0.026	0.643	0.141	1.00	22	0.010	0.022	0.046	0.870	1.086	1.302	0.171	0.215	0.263	
MM9 F Play	32	15	0.289	1.259	0.513	0.140	0.364	0.205	0.149	0.895	0.308	4	0.065	0.295	0.118	0.175	0.987	0.351	1.00	86	0.226	0.317	0.433	3.634	4.365	5.222	0.914	1.094	1.300	
MM7 Chronozone		126	0.180	12.601	2.422	0.149	10.884	2.086	0.031	1.717	0.336	0	0	0	0	0.042	2.038	0.405	1.00	181	0.259	0.348	0.455	8.797	12.457	16.953	1.864	2.565	3.412	
MM7 R Play	33	23	0.024	1.912	0.364	0.020	1.721	0.326	0.004	0.191	0.038	0	0	0	0	0.004	0.325	0.062	1.00	17	0.002	0.005	0.007	0.237	0.288	0.343	0.046	0.056	0.067	
MM7 RAPF Play	34	22	0.008	2.245	0.407	0.005	1.696	0.307	0.002	0.549	0.100	0	0	0	0	0.002	0.588	0.107	1.00	15	0.002	0.004	0.008	0.810	1.422	2.207	0.147	0.257	0.399	
MM7 A Play	35	7	<0.001	0.074	0.013	<0.001	0.062	0.011	<0.001	0.011	0.002	0	0	0	0	<0.001	0.026	0.005	1.00	13	0.001	0.002	0.003	0.121	0.177	0.244	0.023	0.033	0.046	
MM7 P1 Play	36	61	0.138	8.021	1.565	0.118	7.192	1.398	0.020	0.829	0.167	0	0	0	0	0.027	0.833	0.175	1.00	39	0.011	0.019	0.031	1.031	1.241	1.475	0.198	0.240	0.287	
MM7 P2 Play	37	6	0.001	0.171	0.031	<0.001	0.076	0.014	<0.001	0.095	0.017	0	0	0	0	0.001	0.206	0.038	1.00	14	0.002	0.006	0.016	0.587	0.861	1.382	0.109	0.159	0.256	
MM7 F Play	38	7	0.010	0.178	0.042	0.005	0.137	0.029	0.005	0.041	0.012	0	0	0	0	0.008	0.061	0.019	1.00	83	0.246	0.312	0.403	6.295	8.468	12.071	1.402	1.820	2.502	
MM4 Chronozone		147	0.176	9.242	1.821	0.143	7.372	1.455	0.033	1.870	0.366	0	0	0	0	0.028	2.286	0.435	1.00	124	0.197	0.226	0.257	4.650	5.158	5.699	1.036	1.144	1.258	
MM4 R Play	39	40	0.030	1.086	0.223	0.026	0.920	0.190	0.004	0.166	0.034	0	0	0	0	0.002	0.196	0.037	1.00	15	0.002	0.005	0.009	0.186	0.247	0.314	0.037	0.049	0.063	

Summary Table 2. Reserves and undiscovered conventionally recoverable resources of the Gulf of Mexico and Atlantic Continental Margin plays.
Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding. This table diverges from the August 1996 (OCS Report MMS 96-0047) table in that it uses different rounding, a different reserves appreciation equation, and includes reserves appreciation for unproved reserves.

		Reserves																		Risked Undiscovered Conventionally Recoverable Resources										
		Proved				Cum. Production			Remaining Proved			Unproved				Appreciation (P&U)													
		No.	Oil	Gas	BOE	Oil	Gas	BOE	Oil	Gas	BOE	No.	Oil	Gas	BOE	Oil	Gas	BOE	MPhc	No. Undisc	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	No.	Pools	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)	Pools	(Bbbl)	(Tcf)	(Bbbl)	(Bbbl)	(Tcf)	(Bbbl)		Pools	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
MM4 A Play	40	18	0.015	0.525	0.108	0.010	0.444	0.089	0.005	0.081	0.019	0	0	0	0	0.001	0.073	0.013	1.00	4	<0.001	<0.001	0.001	0.018	0.029	0.041	0.004	0.005	0.008
MM4 P Play	41	79	0.098	6.525	1.259	0.083	5.136	0.997	0.015	1.389	0.262	0	0	0	0	0.017	1.806	0.339	1.00	30	0.006	0.011	0.019	0.674	0.823	0.984	0.129	0.158	0.189
MM4 F Play	42	10	0.034	1.105	0.231	0.024	0.871	0.179	0.010	0.234	0.051	0	0	0	0	0.008	0.211	0.046	1.00	75	0.187	0.210	0.234	3.666	4.059	4.458	0.846	0.932	1.019
LM4 Chronozone		69	0.036	3.227	0.610	0.030	2.377	0.453	0.006	0.849	0.157	0	0	0	0	0.007	1.255	0.231	1.00	112	0.065	0.101	0.148	3.596	4.681	5.953	0.712	0.934	1.195
LM4 R Play	43	15	0.001	0.306	0.055	0.001	0.161	0.029	<0.001	0.145	0.026	0	0	0	0	0.001	0.197	0.036	1.00	8	<0.001	<0.001	<0.001	0.092	0.114	0.139	0.016	0.020	0.025
LM4 A Play	44	11	0.001	0.325	0.059	<0.001	0.154	0.028	<0.001	0.171	0.031	0	0	0	0	<0.001	0.180	0.033	1.00	8	<0.001	0.001	0.003	0.103	0.122	0.142	0.019	0.023	0.028
LM4 P Play	45	41	0.034	2.586	0.494	0.029	2.054	0.395	0.005	0.531	0.099	0	0	0	0	0.006	0.872	0.161	1.00	18	0.006	0.010	0.015	0.817	0.999	1.205	0.152	0.188	0.226
LM4 F Play	46	2	<0.001	0.010	0.002	<0.001	0.008	0.002	<0.001	0.002	<0.001	0	0	0	0	<0.001	0.006	0.001	1.00	78	0.056	0.090	0.133	2.499	3.446	4.594	0.538	0.703	0.943
LM2 Chronozone		44	0.038	3.628	0.683	0.030	2.440	0.464	0.008	1.187	0.219	0	0	0	0	0.006	1.337	0.244	1.00	39	0.018	0.025	0.035	2.122	2.528	2.979	0.399	0.475	0.560
LM2 P Play	47	29	0.025	2.258	0.427	0.020	1.424	0.273	0.005	0.834	0.154	0	0	0	0	0.005	1.116	0.203	1.00	10	0.005	0.010	0.016	0.777	0.982	1.219	0.146	0.185	0.228
LM2 F Play	48	15	0.013	1.370	0.257	0.010	1.017	0.191	0.003	0.353	0.065	0	0	0	0	0.001	0.221	0.041	1.00	29	0.011	0.015	0.020	1.282	1.546	1.840	0.239	0.290	0.345
LM1 Chronozone		20	0.018	2.431	0.451	0.012	1.748	0.323	0.006	0.682	0.128	0	0	0	0	0.005	0.757	0.140	1.00	39	0.018	0.025	0.035	1.978	2.370	2.808	0.373	0.447	0.530
LM1 P Play	49	5	0.002	0.168	0.032	0.001	0.035	0.007	0.002	0.134	0.026	0	0	0	0	0.001	0.041	0.008	1.00	5	<0.001	0.001	0.003	0.050	0.081	0.121	0.010	0.016	0.024
LM1 F Play	50	15	0.016	2.262	0.419	0.012	1.714	0.316	0.005	0.548	0.102	0	0	0	0	0.005	0.715	0.132	1.00	34	0.017	0.024	0.033	1.915	2.289	2.707	0.356	0.431	0.506
Oligocene/Eocene Series		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	40	0.126	0.803	2.327	2.844	5.586	9.576	0.558	1.797	4.032
O/E Chronozone		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	40	0.126	0.803	2.327	2.844	5.586	9.576	0.558	1.797	4.032
O F Play	51	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	30	0.026	0.043	0.078	1.976	3.249	5.471	0.380	0.621	1.040
OE X Play	52	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	10	0.181	0.760	2.206	1.030	2.337	4.571	0.396	1.176	2.968
Paleocene Series		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
L Chronozone		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Mesozoic Province		9	<0.001	1.572	0.280	<0.001	0.198	0.035	<0.001	1.374	0.245	2	0.001	0.597	0.107	0.002	1.640	0.294	1.00	179	1.360	2.053	2.933	7.106	8.108	9.194	2.678	3.495	4.455
Cretaceous System		1	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	0.000	0.000	0.000	1	0.001	0.150	0.028	0.002	0.285	0.052	1.00	142	0.905	1.433	2.121	0.519	0.939	1.525	1.026	1.600	2.343
Upper Cretaceous Series		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.56	5	0.000	0.045	0.190	0.000	0.070	0.257	0.000	0.057	0.226
UK Chronozone		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.56	5	0.000	0.045	0.190	0.000	0.070	0.257	0.000	0.057	0.226
UK CL Play	53	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.56	5	0.000	0.045	0.190	0.000	0.070	0.257	0.000	0.057	0.226
Lower Cretaceous Series		1	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	0.000	0.000	0.000	1	0.001	0.150	0.028	0.002	0.285	0.052	1.00	137	0.921	1.388	1.980	0.530	0.869	1.320	1.042	1.542	2.171
LK Chronozone		1	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	0.000	0.000	0.000	1	0.001	0.150	0.028	0.002	0.285	0.052	1.00	137	0.921	1.388	1.980	0.530	0.869	1.320	1.042	1.542	2.171
LK CL Play	54	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.65	20	0.000	0.037	0.093	0.000	0.110	0.244	0.000	0.057	0.133
LK CB Play	55	1	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	0.000	0.000	0.000	1	0.001	0.150	0.028	0.002	0.285	0.052	1.00	26	0.196	0.345	0.562	0.432	0.686	1.014	0.294	0.467	0.700
LK SUN Play	56	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	33	0.295	0.419	0.609	0.022	0.031	0.045	0.298	0.425	0.617
LK SFB Play	57	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	58	0.400	0.587	0.881	0.029	0.042	0.065	0.405	0.593	0.893
Jurassic System		8	<0.001	1.572	0.280	<0.001	0.198	0.035	<0.001	1.374	0.245	1	<0.001	0.446	0.079	<0.001	1.355	0.241	1.00	37	0.375	0.620	0.947	6.490	7.169	7.890	1.561	1.896	2.273
Upper Jurassic Series		8	<0.001	1.572	0.280	<0.001	0.198	0.035	<0.001	1.374	0.245	1	<0.001	0.446	0.079	<0.001	1.355	0.241	1.00	37	0.375	0.620	0.947	6.490	7.169	7.890	1.561	1.896	2.273
UU Chronozone		8	<0.001	1.572	0.280	<0.001	0.198	0.035	<0.001	1.374	0.245	1	<0.001	0.446	0.079	<0.001	1.355	0.241	1.00	37	0.375	0.620	0.947	6.490	7.169	7.890	1.561	1.896	2.273
UU A Play	58	8	<0.001	1.572	0.280	<0.001	0.198	0.035	<0.001	1.374	0.245	1	<0.001	0.446	0.079	<0.001	1.355	0.241	1.00	32	0.360	0.591	0.856	6.470	7.121	7.808	1.565	1.858	2.188
UU SMK Play	59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	5	0.003	0.029	0.101	0.011	0.048	0.122	0.006	0.038	0.121
UU-LK TZ Play	60	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Middle Jurassic Series		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
MU Chronozone		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
MU-UU FBCL Play	61	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lower Jurassic Series		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
LU Chronozone		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Triassic System		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Upper Triassic Series		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
UTR Chronozone		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Atlantic Region		0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000	1.00	502	1.267	2.271	3.667	15.855	27.480	43.372	4.475	7.161	10.684
Mesozoic Province		0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000	1.00	502	1.267	2.271	3.667	15.855	27.480	43.372	4.475	7.161	10.684
Cretaceous System		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	120	0.431	0.722	1.143	7.840	11.767	18.813	1.985	2.816	4.190
Upper Cretaceous Series		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AUK Chronozone		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AUK CL Play	62	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Lower Cretaceous Series		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	120	0.431	0.722	1.143	7.840	11.767	18.813	1.985	2.816	4.190
ALK Chronozone		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	120	0.431	0.722	1.143	7.840	11.767	18.813	1.985	2.816	4.190
ALK CL Play	63	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	120	0.431	0.722	1.143	7.840	11.767	18.813	1.985	2.816	4.190
Jurassic System		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	382	0.762	1.549	2.714	9.040	15.712	24.847	2.584	4.345	6.716
Upper Jurassic Series		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	235	0.527	1.020	1.733	6.135	10.210	15.667	1.791	2.837	4.201
AUU Chronozone		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	235	0.527	1.020	1.733	6.135	10.210	15.667	1.791	2.837	4.201

Summary Table 2. Reserves and undiscovered conventionally recoverable resources of the Gulf of Mexico and Atlantic Continental Margin plays.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding. This table diverges from the August 1996 (OCS Report MMS 96-0047) table in that it uses different rounding, a different reserves appreciation equation, and includes reserves appreciation for unproved reserves.

		Reserves																	Risked Undiscovered Conventionally Recoverable Resources										
		Proved				Cum. Production			Remaining Proved			Unproved				Appreciation (P&U)				No.	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	No.	No. Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	No. Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	MPhc	Undisc Pools	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
AUU CL Play	64	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1.00	200	0.545	0.822	1.153	6.401	8.953	13.270	1.832	2.415	3.273
AUU CB Play	65	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.85	35	0.000	0.198	0.435	0.000	1.257	3.152	0.000	0.422	0.945
AUU-UK BFF Play	66	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AUU-LK TZ Play	67	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Middle Jurassic Series		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.93	147	0.000	0.529	1.163	0.000	5.502	10.426	0.000	1.508	2.830
AMU Chronozone		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.93	147	0.000	0.529	1.163	0.000	5.502	10.426	0.000	1.508	2.830
AMU CL Play	68	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.90	120	0.000	0.399	0.645	0.000	4.891	8.455	0.000	1.269	2.020
AMU CB Play	69	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.65	27	0.000	0.130	0.413	0.000	0.611	1.633	0.000	0.239	0.688
Lower Jurassic Series		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ALU Chronozone		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AU-K DIA Play	70	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Triassic System		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Upper Triassic Series		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
AUTR Chronozone		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ATR-LU CLR Play	71	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
ATR-LU CBR Play	72	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Summary Table 3. Reserves and cumulative production of the Gulf of Mexico and Atlantic Continental Margin aggregated by water depth ranges and depostional style/facies.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding. This table diverges from the August 1996 (OCS Report MMS 96-0047) table in that it uses different rounding, a different reserves appreciation equation, and includes reserves appreciation for unproved reserves.

	Reserves																
	Proved				Cum. Production			Remaining Proved			Unproved				Appreciation (P&U)		
	No. Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	No. Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
GOM & Atlantic Margin	2,114	11.853	141.891	37.101	9.338	112.633	29.379	2.516	29.258	7.722	69	0.639	3.603	1.280	2.507	31.028	8.028
0 - 200m WD	2,056	10.534	136.232	34.775	8.938	110.943	28.678	1.597	25.289	6.096	19	0.033	0.761	0.168	1.172	25.375	5.687
200 - 900m WD	55	1.043	4.753	1.889	0.400	1.689	0.701	0.643	3.064	1.188	29	0.281	0.874	0.437	0.778	3.044	1.320
> 900m WD	3	0.276	0.905	0.437	0.000	0.000	0.000	0.276	0.905	0.437	21	0.324	1.969	0.675	0.557	2.609	1.022
Gulf of Mexico Region	2,114	11.853	141.891	37.101	9.338	112.633	29.379	2.516	29.258	7.722	69	0.639	3.603	1.280	2.507	31.028	8.028
0 - 200m WD	2,056	10.534	136.232	34.775	8.938	110.943	28.678	1.597	25.289	6.096	19	0.033	0.761	0.168	1.172	25.375	5.687
200 - 900m WD	55	1.043	4.753	1.889	0.400	1.689	0.701	0.643	3.064	1.188	29	0.281	0.874	0.437	0.778	3.044	1.320
> 900m WD	3	0.276	0.905	0.437	0.000	0.000	0.000	0.276	0.905	0.437	21	0.324	1.969	0.675	0.557	2.609	1.022
Cenozoic Province	2,105	11.853	140.318	36.821	9.337	112.434	29.344	2.516	27.884	7.477	67	0.638	3.006	1.172	2.505	29.389	7.735
0 - 200m WD	2,047	10.534	134.660	34.495	8.938	110.745	28.643	1.597	23.914	5.852	17	0.032	0.164	0.061	1.170	23.735	5.394
200 - 900m WD	55	1.043	4.753	1.889	0.400	1.689	0.701	0.643	3.064	1.188	29	0.281	0.874	0.437	0.778	3.044	1.320
> 900m WD	3	0.276	0.905	0.437	0.000	0.000	0.000	0.276	0.905	0.437	21	0.324	1.969	0.675	0.557	2.609	1.022
Cenozoic Province	2,105	11.853	140.318	36.821	9.337	112.434	29.344	2.516	27.884	7.477	67	0.638	3.006	1.172	2.505	29.389	7.735
Retrogradational	105	0.138	3.889	0.830	0.115	3.289	0.701	0.022	0.600	0.129	0	0.000	0.000	0.000	0.010	0.779	0.149
Aggradational	286	1.084	8.236	2.550	0.980	6.538	2.143	0.104	1.699	0.406	0	0.000	0.000	0.000	0.037	1.366	0.280
Progradational	1,285	7.849	99.385	25.534	6.687	83.554	21.554	1.163	15.831	3.980	8	0.008	0.070	0.020	0.811	15.423	3.556
Fan	352	2.717	25.607	7.274	1.527	16.902	4.534	1.190	8.704	2.739	56	0.630	2.924	1.150	1.634	10.655	3.530
Other	77	0.065	3.201	0.634	0.029	2.151	0.412	0.036	1.050	0.223	3	<0.001	0.012	0.002	0.013	1.165	0.220
Mesozoic Province	9	<0.001	1.572	0.280	<0.001	0.198	0.035	<0.001	1.374	0.245	2	0.001	0.597	0.107	0.002	1.640	0.294
0 - 200m WD	9	<0.001	1.572	0.280	<0.001	0.198	0.035	<0.001	1.374	0.245	2	0.001	0.597	0.107	0.002	1.640	0.294
200 - 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
> 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
Mesozoic Province	9	<0.001	1.572	0.280	<0.001	0.198	0.035	<0.001	1.374	0.245	2	0.001	0.597	0.107	0.002	1.640	0.294
Clastics	8	<0.001	1.572	0.280	<0.001	0.198	0.035	<0.001	1.374	0.245	1	<0.001	0.446	0.079	<0.001	1.355	0.241
Carbonates	1	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	0.000	0.000	0.000	1	0.001	0.150	0.028	0.002	0.285	0.052
Western Planning Area	485	0.596	25.449	5.125	0.353	18.756	3.691	0.243	6.693	1.434	14	0.160	0.865	0.314	0.430	10.233	2.251
0 - 200m WD	466	0.380	23.961	4.643	0.299	18.232	3.543	0.080	5.730	1.100	1	0.016	0.031	0.021	0.104	8.515	1.619
200 - 900m WD	19	0.217	1.487	0.481	0.054	0.524	0.147	0.163	0.963	0.334	11	0.063	0.437	0.141	0.237	1.304	0.469
> 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2	0.081	0.396	0.151	0.089	0.414	0.163
Central Planning Area	1,629	11.257	116.442	31.976	8.984	93.877	25.688	2.273	22.565	6.288	52	0.478	2.209	0.871	2.077	20.264	5.683
0 - 200m WD	1,590	10.155	112.271	30.132	8.638	92.712	25.135	1.516	19.559	4.997	16	0.017	0.278	0.066	1.068	16.477	4.000
200 - 900m WD	36	0.826	3.266	1.408	0.346	1.165	0.553	0.481	2.101	0.854	18	0.218	0.436	0.295	0.541	1.741	0.851
> 900m WD	3	0.276	0.905	0.437	0.000	0.000	0.000	0.276	0.905	0.437	18	0.244	1.494	0.510	0.468	2.046	0.832
Eastern Planning Area	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	3	<0.001	0.530	0.094	<0.001	0.531	0.095
0 - 200m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	2	<0.001	0.451	0.080	<0.001	0.383	0.068
200 - 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
> 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	1	<0.001	0.078	0.014	<0.001	0.148	0.026
Straits of FL Planning Area	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
0 - 200m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
200 - 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
> 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
Atlantic Region	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
0 - 200m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
200 - 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
> 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
Mesozoic Province	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
0 - 200m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
200 - 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
> 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
Mesozoic Province	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
Clastics	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
Carbonates	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
North Atlantic Planning Area	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
0 - 200m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
200 - 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
> 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
Mid-Atlantic Planning Area	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
0 - 200m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
200 - 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
> 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
South Atlantic Planning Area	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
0 - 200m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
200 - 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000
> 900m WD	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0	0.000	0.000	0.000	0.000	0.000	0.000

Summary Table 4. Total endowment and undiscovered conventionally recoverable resources of the Gulf of Mexico and Atlantic Continental Margin aggregated by water depth ranges and depostional style/facies.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding. This table diverges from the August 1996 (OCS Report MMS 96-0047) table in that it uses different rounding, a different reserves appreciation equation, and includes reserves appreciation for unproved reserves.

	Total Endowment (Reserves + Resources)										Risked Undiscovered Conventionally Recoverable Resources								
	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)			MPhc	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5		F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
GOM & Atlantic Margin	23.016	25.614	28.688	280.808	299.662	320.533	73.811	78.935	84.626	1.00	8.017	10.615	13.689	104.286	123.140	144.011	27.402	32.526	38.217
0 - 200m WD	15.620	16.032	16.316	216.283	219.683	226.222	54.105	55.121	56.569	1.00	3.881	4.292	4.576	53.916	57.315	63.854	13.474	14.491	15.938
200 - 900m WD	3.532	3.851	4.378	25.515	27.383	29.503	8.072	8.723	9.628	1.00	1.430	1.749	2.276	16.843	18.712	20.831	4.427	5.078	5.983
> 900m WD	4.997	5.729	7.564	50.461	53.352	56.646	13.976	15.222	17.643	1.00	3.839	4.571	6.406	44.978	47.868	51.163	11.842	13.088	15.510
Gulf of Mexico Region	21.037	23.343	26.137	258.845	272.183	286.808	67.627	71.775	76.399	1.00	6.038	8.344	11.138	82.323	95.661	110.286	21.218	25.366	29.990
0 - 200m WD	15.035	15.452	15.918	210.304	211.699	213.089	52.456	53.120	53.834	1.00	3.296	3.712	4.178	47.936	49.331	50.721	11.825	12.490	13.203
200 - 900m WD	2.927	3.135	3.457	17.776	18.879	20.299	6.090	6.494	7.069	1.00	0.825	1.033	1.355	9.105	10.208	11.628	2.445	2.849	3.424
> 900m WD	4.112	4.751	6.524	39.636	41.996	44.903	11.165	12.224	14.514	1.00	2.955	3.593	5.367	34.152	36.513	39.420	9.032	10.090	12.381
Cenozoic Province	19.424	21.287	23.580	247.479	260.266	274.352	63.927	67.598	71.705	1.00	4.428	6.291	8.584	74.766	87.553	101.639	18.199	21.870	25.977
0 - 200m WD	13.484	13.671	13.869	198.689	200.317	202.176	48.838	49.314	49.843	1.00	1.747	1.934	2.132	40.131	41.759	43.618	8.888	9.365	9.893
200 - 900m WD	2.847	3.013	3.276	17.608	18.743	20.365	5.980	6.348	6.900	1.00	0.744	0.911	1.174	8.937	10.072	11.693	2.334	2.703	3.255
> 900m WD	3.985	4.557	6.236	38.898	41.642	45.096	10.906	11.967	14.261	1.00	2.828	3.400	5.079	33.414	36.159	39.613	8.773	9.834	12.127
Cenozoic Province	19.424	21.287	23.580	247.479	260.266	274.352	63.927	67.598	71.705	1.00	4.428	6.291	8.584	74.766	87.553	101.639	18.199	21.870	25.977
Retrogradational	0.164	0.175	0.189	5.348	5.480	5.628	1.119	1.149	1.183	1.00	0.016	0.027	0.041	0.680	0.812	0.960	0.141	0.171	0.205
Aggradational	1.157	1.183	1.217	10.676	10.883	11.114	3.067	3.120	3.179	1.00	0.036	0.062	0.096	1.073	1.280	1.511	0.237	0.290	0.349
Progradational	9.170	9.341	9.544	129.577	131.529	133.638	32.314	32.745	33.210	1.00	0.502	0.673	0.876	14.699	16.651	18.760	3.205	3.636	4.101
Fan	8.923	9.704	10.575	91.575	100.830	111.054	25.547	27.645	29.935	1.00	3.942	4.723	5.594	52.390	61.645	71.869	13.594	15.692	17.982
Other	0.206	0.885	2.413	8.372	11.542	15.954	1.587	2.939	5.262	1.00	0.128	0.807	2.335	3.994	7.164	11.576	0.730	2.082	4.405
Mesozoic Province	1.363	2.056	2.936	10.915	11.917	13.003	3.359	4.176	5.136	1.00	1.360	2.053	2.933	7.106	8.108	9.194	2.678	3.495	4.455
0 - 200m WD	1.407	1.780	2.250	10.966	11.376	11.859	3.358	3.804	4.360	1.00	1.404	1.777	2.247	7.157	7.567	8.050	2.678	3.123	3.679
200 - 900m WD	0.071	0.117	0.190	0.091	0.139	0.225	0.087	0.142	0.230	1.00	0.071	0.117	0.190	0.091	0.139	0.225	0.087	0.142	0.230
> 900m WD	0.087	0.191	0.371	0.223	0.359	0.529	0.127	0.255	0.465	1.00	0.087	0.191	0.371	0.223	0.359	0.529	0.127	0.255	0.465
Mesozoic Province	1.363	2.056	2.936	10.915	11.917	13.003	3.359	4.176	5.136	1.00	1.360	2.053	2.933	7.106	8.108	9.194	2.678	3.495	4.455
Clastics	0.374	0.674	1.090	9.864	10.674	11.545	2.150	2.573	3.061	1.00	0.374	0.674	1.090	6.491	7.301	8.172	1.550	1.973	2.461
Carbonates	0.911	1.382	1.984	0.947	1.243	1.627	1.105	1.603	2.230	1.00	0.908	1.379	1.981	0.511	0.807	1.191	1.025	1.523	2.150
Western Planning Area	3.364	3.956	5.646	71.784	74.607	77.696	16.137	17.231	19.471	1.00	2.178	2.769	4.460	35.238	38.061	41.149	8.448	9.542	11.781
0 - 200m WD	1.139	1.228	1.350	50.441	51.827	53.322	10.114	10.450	10.838	1.00	0.639	0.728	0.851	17.933	19.320	20.815	3.830	4.166	4.554
200 - 900m WD	0.750	0.824	0.933	6.253	6.729	7.256	1.862	2.021	2.225	1.00	0.233	0.307	0.417	3.025	3.501	4.028	0.771	0.930	1.133
> 900m WD	1.298	1.900	3.510	14.085	16.034	18.724	3.804	4.754	6.841	1.00	1.128	1.731	3.340	13.274	15.223	17.913	3.490	4.439	6.527
Central Planning Area	17.130	17.363	17.622	187.090	188.893	190.976	50.420	50.973	51.604	1.00	3.317	3.550	3.809	48.175	49.978	52.061	11.889	12.443	13.073
0 - 200m WD	12.454	12.581	12.763	151.436	152.591	153.564	39.400	39.733	40.088	1.00	1.215	1.342	1.524	22.410	23.565	24.538	5.202	5.535	5.890
200 - 900m WD	2.036	2.189	2.459	11.103	12.024	13.777	4.012	4.329	4.911	1.00	0.451	0.604	0.874	5.660	6.581	8.334	1.458	1.775	2.357
> 900m WD	2.516	2.593	2.665	23.211	24.286	25.467	6.646	6.914	7.197	1.00	1.528	1.605	1.678	18.766	19.840	21.021	4.868	5.135	5.418
Eastern Planning Area	1.575	1.986	2.452	8.527	9.042	9.782	3.092	3.594	4.192	1.00	1.575	1.985	2.451	7.466	7.981	8.722	2.903	3.406	4.003
0 - 200m WD	1.269	1.630	2.086	6.951	7.273	7.559	2.506	2.925	3.431	1.00	1.269	1.630	2.086	6.117	6.439	6.725	2.357	2.776	3.283
200 - 900m WD	0.064	0.109	0.180	0.092	0.138	0.229	0.080	0.133	0.220	1.00	0.064	0.109	0.180	0.092	0.138	0.229	0.080	0.133	0.220
> 900m WD	0.151	0.249	0.391	1.164	1.634	2.474	0.358	0.540	0.831	1.00	0.151	0.249	0.391	0.938	1.408	2.247	0.318	0.500	0.791
Straits of FL Planning Area	0.022	0.031	0.044	0.014	0.019	0.025	0.025	0.034	0.048	1.00	0.022	0.031	0.044	0.014	0.019	0.025	0.025	0.034	0.048
0 - 200m WD	0.009	0.013	0.019	0.001	0.001	0.001	0.009	0.013	0.019	1.00	0.009	0.013	0.019	0.001	0.001	0.001	0.009	0.013	0.019
200 - 900m WD	0.006	0.009	0.013	<0.001	0.001	0.001	0.006	0.009	0.013	1.00	0.006	0.009	0.013	<0.001	0.001	0.001	0.006	0.009	0.013
> 900m WD	0.004	0.010	0.019	0.011	0.018	0.026	0.006	0.013	0.023	1.00	0.004	0.010	0.019	0.011	0.018	0.026	0.006	0.013	0.023
Atlantic Region	1.267	2.271	3.667	15.855	27.480	43.372	4.475	7.161	10.684	1.00	1.267	2.271	3.667	15.855	27.480	43.372	4.475	7.161	10.684
0 - 200m WD	0.418	0.576	0.669	4.790	8.004	14.557	1.271	2.000	3.259	1.00	0.418	0.576	0.669	4.790	8.004	14.557	1.271	2.000	3.259
200 - 900m WD	0.524	0.722	0.995	6.994	8.512	10.519	1.769	2.236	2.867	1.00	0.524	0.722	0.995	6.994	8.512	10.519	1.769	2.236	2.867
> 900m WD	0.753	0.983	1.385	9.695	11.353	13.485	2.478	3.003	3.784	1.00	0.753	0.983	1.385	9.695	11.353	13.485	2.478	3.003	3.784
Mesozoic Province	1.267	2.271	3.667	15.855	27.480	43.372	4.475	7.161	10.684	1.00	1.267	2.271	3.667	15.855	27.480	43.372	4.475	7.161	10.684
0 - 200m WD	0.418	0.576	0.669	4.790	8.004	14.557	1.271	2.000	3.259	1.00	0.418	0.576	0.669	4.790	8.004	14.557	1.271	2.000	3.259
200 - 900m WD	0.524	0.722	0.995	6.994	8.512	10.519	1.769	2.236	2.867	1.00	0.524	0.722	0.995	6.994	8.512	10.519	1.769	2.236	2.867
> 900m WD	0.753	0.983	1.385	9.695	11.353	13.485	2.478	3.003	3.784	1.00	0.753	0.983	1.385	9.695	11.353	13.485	2.478	3.003	3.784
Mesozoic Province	1.267	2.271	3.667	15.855	27.480	43.372	4.475	7.161	10.684	1.00	1.267	2.271	3.667	15.855	27.480	43.372	4.475	7.161	10.684
Clastics	1.282	1.943	2.784	14.697	25.612	40.575	4.231	6.500	9.413	1.00	1.282	1.943	2.784	14.697	25.612	40.575	4.231	6.500	9.413
Carbonates	0.000	0.329	1.037	0.000	1.868	4.351	0.000	0.661	1.782	0.90	0.000	0.329	1.037	0.000	1.868	4.351	0.000	0.661	1.782
North Atlantic Planning Area	0.596	0.693	0.806	7.523	8.812	10.910	1.935	2.261	2.747	1.00	0.596	0.693	0.806	7.523	8.812	10.910	1.935	2.261	2.747
0 - 200m WD	0.138	0.190	0.221	1.581	2.641	4.804	0.419	0.660	1.075	1.00	0.138	0.190	0.221	1.581	2.641	4.804	0.419	0.660	1.075
200 - 900m WD	0.149	0.194	0.257	2.093	2.549	3.053	0.522	0.647	0.801	1.00	0.149	0.194	0.257	2.093	2.549	3.053	0.522	0.647	0.801
> 900m WD	0.238	0.309	0.407	3.153	3.651	4.364	0.799	0.958	1.184	1.00	0.238	0.309	0.407	3.153	3.651	4.364	0.799	0.958	1.184
Mid-Atlantic Planning Area	0.666	0.796	1.004	8.144	9.588	11.624	2.116	2.502	3.072	1.00	0.666	0.796	1.004	8.144	9.588	11.624	2.116	2.502	3.072
0 - 200m WD	0.142	0.196	0.227	1.629	2.721	4.949	0.432	0.680	1.108	1.00	0.142	0.196	0.227	1.629	2.721	4.949	0.432	0.680	1.108
200 - 900m WD	0.168	0.226	0.293	2.316	2.783	3.415	0.580	0.722	0.901	1.00	0.168	0.226	0.293	2.316	2.783	3.415	0.580	0.722	0.901
> 900m WD	0.271	0.376	0.588	3.482	4.110	5.011	0.891	1.107	1.479	1.00	0.271	0.376	0.588	3.482	4.110	5.011	0.891	1.107	1.479
South Atlantic Planning Area	0.676	0.789	1.029	7.822	9.396	11.643	2.068	2.461	3.101	1.00	0.676	0.789	1.029	7.822	9.396	11.643	2.068	2.461	3.101
0 - 200m WD	0.138	0.190	0.221	1.581	2.641	4.804	0.419	0.660	1.075	1.00	0.138	0.190	0.221	1.581	2.641	4.804	0.419	0.660	1.075
200 - 900m WD	0.198	0.302	0.521	2.532	3.184	4.164	0.649	0.868	1.262	1.00	0.198	0.302	0.521	2.532	3.184	4.164	0.649	0.868	1.262
> 900m WD	0.235	0.299	0.390	3.101	3.592	4.249	0.786	0.938	1.146	1.00	0.235	0.299	0.390	3.101	3.592	4.249	0.786	0.938	1.146

Summary Table 5. $18/bbl scenario undiscovered economically recoverable resources of the Gulf of Mexico and Atlantic Continental Margin aggregated by water depth ranges and depostional style/facies.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding. This table diverges from the August 1996 (OCS Report MMS 96-0047) table in that it uses different rounding, a different reserves appreciation equation, and includes reserves appreciation for unproved reserves.

	Full-Cycle @ $18.00/bbl and $2.11/Mcf Risked Undiscovered Economically Recoverable Resources										Half-Cycle @ $18.00/bbl and $2.11/Mcf Risked Undiscovered Economically Recoverable Resources									
	MPhc	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)			MPhc	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
		F95	Mean	F5	F95	Mean	F5	F95	Mean	F5		F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
GOM & Atlantic Margin	1.00	4.364	5.350	7.094	57.252	63.295	70.695	14.551	16.613	19.674	1.00	4.791	5.784	7.374	62.301	68.462	76.883	15.876	17.966	21.055
0 - 200m WD	1.00	2.651	3.043	3.385	40.514	45.512	52.431	9.860	11.142	12.714	1.00	2.769	3.209	3.551	43.237	48.100	54.919	10.462	11.768	13.323
200 - 900m WD	1.00	0.485	0.782	1.294	3.961	5.633	8.650	1.190	1.784	2.833	1.00	0.536	0.849	1.353	4.451	6.319	9.979	1.328	1.973	3.129
> 900m WD	1.00	0.808	1.497	3.196	8.859	12.140	15.620	2.384	3.657	5.975	1.00	1.039	1.708	3.388	10.611	13.992	17.220	2.927	4.198	6.452
Gulf of Mexico Region	1.00	4.016	4.941	6.627	53.737	57.941	62.162	13.577	15.251	17.688	1.00	4.350	5.306	6.967	58.428	62.300	66.495	14.747	16.391	18.799
0 - 200m WD	1.00	2.374	2.771	3.186	38.807	40.722	42.653	9.279	10.017	10.775	1.00	2.497	2.901	3.322	41.085	42.859	44.855	9.808	10.527	11.304
200 - 900m WD	1.00	0.476	0.701	1.030	3.859	5.200	6.817	1.162	1.626	2.243	1.00	0.513	0.736	1.056	4.381	5.633	7.383	1.292	1.739	2.369
> 900m WD	1.00	0.830	1.477	3.170	8.627	12.053	15.275	2.365	3.621	5.888	1.00	1.008	1.670	3.360	10.665	13.822	16.857	2.906	4.130	6.360
Cenozoic Province	1.00	3.005	3.794	5.338	48.764	53.028	56.780	11.682	13.230	15.441	1.00	3.253	4.053	5.632	52.603	56.600	60.148	12.613	14.125	16.334
0 - 200m WD	1.00	1.600	1.759	1.982	33.984	35.818	37.656	7.647	8.132	8.682	1.00	1.623	1.792	2.006	35.346	37.144	38.995	7.913	8.401	8.944
200 - 900m WD	1.00	0.454	0.635	0.902	3.843	5.169	6.942	1.138	1.554	2.138	1.00	0.489	0.665	0.935	4.175	5.584	7.335	1.232	1.659	2.240
> 900m WD	1.00	0.738	1.406	3.069	8.743	12.016	15.715	2.294	3.544	5.865	1.00	0.931	1.603	3.231	10.608	13.810	17.570	2.818	4.060	6.358
Cenozoic Province	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Retrogradational	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Aggradational	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Progradational	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fan	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Mesozoic Province	1.00	0.759	1.154	1.672	3.921	4.969	5.892	1.457	2.038	2.720	1.00	0.835	1.266	1.796	4.982	5.792	6.612	1.721	2.297	2.972
0 - 200m WD	1.00	0.727	1.021	1.497	3.606	4.874	5.889	1.369	1.889	2.545	1.00	0.749	1.111	1.602	4.861	5.687	6.442	1.614	2.123	2.748
200 - 900m WD	0.88	0.000	0.061	0.140	0.000	0.048	0.137	0.000	0.070	0.164	0.92	0.000	0.066	0.143	0.000	0.053	0.136	0.000	0.075	0.167
> 900m WD	0.40	0.000	0.077	0.300	0.000	0.054	0.223	0.000	0.086	0.340	0.47	0.000	0.086	0.304	0.000	0.060	0.214	0.000	0.097	0.342
Mesozoic Province	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Clastics	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Carbonates	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Western Planning Area	1.00	1.053	1.734	3.260	20.110	22.897	26.386	4.632	5.808	7.955	1.00	1.262	1.900	3.418	22.012	24.920	28.234	5.179	6.334	8.442
0 - 200m WD	1.00	0.530	0.630	0.742	14.162	15.564	17.219	3.050	3.399	3.806	1.00	0.551	0.650	0.764	14.866	16.258	17.837	3.196	3.542	3.938
200 - 900m WD	1.00	0.122	0.204	0.313	1.082	1.796	2.580	0.314	0.523	0.772	1.00	0.146	0.222	0.352	1.276	2.048	2.692	0.373	0.586	0.831
> 900m WD	1.00	0.276	0.916	2.535	3.053	5.508	8.496	0.820	1.896	4.046	1.00	0.396	1.052	2.686	4.434	6.677	9.578	1.185	2.240	4.390
Central Planning Area	1.00	1.857	2.115	2.428	27.572	30.216	32.718	6.763	7.492	8.250	1.00	1.945	2.216	2.557	29.416	31.904	34.306	7.179	7.893	8.661
0 - 200m WD	1.00	1.095	1.212	1.406	19.453	20.713	21.695	4.557	4.898	5.267	1.00	1.117	1.236	1.434	20.350	21.570	22.531	4.738	5.074	5.443
200 - 900m WD	1.00	0.281	0.431	0.692	2.214	3.382	5.200	0.675	1.032	1.617	1.00	0.285	0.445	0.693	2.484	3.565	5.450	0.727	1.079	1.663
> 900m WD	1.00	0.352	0.477	0.601	4.186	6.190	8.195	1.097	1.578	2.060	1.00	0.424	0.538	0.667	4.848	6.816	8.759	1.286	1.751	2.226
Eastern Planning Area	1.00	0.676	1.071	1.508	3.492	4.476	5.601	1.298	1.868	2.504	1.00	0.763	1.170	1.640	4.337	5.220	6.283	1.535	2.099	2.758
0 - 200m WD	1.00	0.599	0.909	1.358	3.272	4.177	4.764	1.181	1.652	2.206	1.00	0.656	1.002	1.457	4.182	4.839	5.300	1.400	1.863	2.400
200 - 900m WD	0.88	0.000	0.059	0.137	0.000	0.047	0.134	0.000	0.067	0.161	0.92	0.000	0.064	0.139	0.000	0.053	0.145	0.000	0.073	0.164
> 900m WD	0.51	0.000	0.080	0.232	0.000	0.322	1.502	0.000	0.138	0.499	0.61	0.000	0.093	0.254	0.000	0.382	1.524	0.000	0.161	0.525
Straits of FL Planning Area	0.67	0.000	0.008	0.022	0.000	0.003	0.009	0.000	0.009	0.024	0.75	0.000	0.009	0.024	0.000	0.003	0.010	0.000	0.010	0.025
0 - 200m WD	0.45	0.000	0.003	0.009	0.000	<0.001	<0.001	0.000	0.003	0.009	0.51	0.000	0.003	0.010	0.000	<0.001	<0.001	0.000	0.003	0.010
200 - 900m WD	0.45	0.000	0.002	0.006	0.000	<0.001	<0.001	0.000	0.002	0.006	0.51	0.000	0.002	0.007	0.000	<0.001	<0.001	0.000	0.002	0.007
> 900m WD	0.39	0.000	0.004	0.015	0.000	0.003	0.011	0.000	0.004	0.017	0.47	0.000	0.004	0.015	0.000	0.003	0.011	0.000	0.005	0.017
Atlantic Region	0.92	0.000	0.368	0.808	0.000	5.203	11.688	0.000	1.294	2.888	0.97	0.125	0.452	0.910	1.154	5.989	12.404	0.331	1.518	3.118
0 - 200m WD	0.90	0.000	0.274	0.427	0.000	4.810	12.027	0.000	1.129	2.567	0.94	0.037	0.313	0.447	0.378	5.279	12.398	0.105	1.252	2.653
200 - 900m WD	0.22	0.000	0.083	0.449	0.000	0.375	2.933	0.000	0.150	0.971	0.31	0.000	0.118	0.519	0.000	0.652	3.629	0.000	0.234	1.165
> 900m WD	0.05	0.000	0.026	0.146	0.000	0.104	0.656	0.000	0.045	0.262	0.08	0.000	0.040	0.311	0.000	0.157	1.381	0.000	0.068	0.557
Mesozoic Province	0.92	0.000	0.368	0.808	0.000	5.203	11.688	0.000	1.294	2.888	0.97	0.125	0.452	0.910	1.154	5.989	12.404	0.331	1.518	3.118
0 - 200m WD	0.90	0.000	0.274	0.427	0.000	4.810	12.027	0.000	1.129	2.567	0.94	0.037	0.313	0.447	0.378	5.279	12.398	0.105	1.252	2.653
200 - 900m WD	0.22	0.000	0.083	0.449	0.000	0.375	2.933	0.000	0.150	0.971	0.31	0.000	0.118	0.519	0.000	0.652	3.629	0.000	0.234	1.165
> 900m WD	0.05	0.000	0.026	0.146	0.000	0.104	0.656	0.000	0.045	0.262	0.08	0.000	0.040	0.311	0.000	0.157	1.381	0.000	0.068	0.557
Mesozoic Province	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Clastics	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Carbonates	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
North Atlantic Planning Area	0.91	0.000	0.113	0.219	0.000	1.707	3.871	0.000	0.417	0.908	0.95	0.024	0.139	0.274	0.250	1.937	4.171	0.069	0.484	1.017
0 - 200m WD	0.91	0.000	0.099	0.157	0.000	1.626	3.942	0.000	0.388	0.859	0.95	0.024	0.112	0.164	0.230	1.784	4.061	0.065	0.430	0.886
200 - 900m WD	0.10	0.000	0.012	0.120	0.000	0.092	0.873	0.000	0.028	0.276	0.16	0.000	0.020	0.144	0.000	0.155	1.075	0.000	0.047	0.335
> 900m WD	0.05	0.000	0.007	0.037	0.000	0.026	0.165	0.000	0.011	0.066	0.08	0.000	0.010	0.082	0.000	0.040	0.334	0.000	0.017	0.142
Mid-Atlantic Planning Area	0.94	0.016	0.132	0.263	0.081	1.795	4.143	0.031	0.451	1.000	0.97	0.045	0.160	0.349	0.456	2.068	4.166	0.126	0.528	1.090
0 - 200m WD	0.91	0.000	0.102	0.162	0.000	1.675	4.061	0.000	0.400	0.885	0.95	0.024	0.116	0.169	0.237	1.838	4.184	0.067	0.443	0.913
200 - 900m WD	0.21	0.000	0.021	0.140	0.000	0.103	0.824	0.000	0.039	0.286	0.29	0.000	0.032	0.152	0.000	0.190	1.231	0.000	0.066	0.371
> 900m WD	0.04	0.000	0.011	0.036	0.000	0.044	0.199	0.000	0.019	0.071	0.07	0.000	0.021	0.157	0.000	0.073	0.638	0.000	0.034	0.271
South Atlantic Planning Area	0.94	0.021	0.152	0.323	0.124	1.826	4.364	0.043	0.477	1.099	0.97	0.048	0.183	0.413	0.506	2.086	4.542	0.138	0.554	1.221
0 - 200m WD	0.91	0.000	0.099	0.157	0.000	1.626	3.942	0.000	0.388	0.859	0.95	0.024	0.112	0.164	0.230	1.784	4.061	0.065	0.430	0.886
200 - 900m WD	0.22	0.000	0.052	0.280	0.000	0.203	1.199	0.000	0.088	0.494	0.31	0.000	0.066	0.302	0.000	0.303	1.463	0.000	0.120	0.562
> 900m WD	0.05	0.000	0.005	0.029	0.000	0.021	0.135	0.000	0.009	0.053	0.08	0.000	0.008	0.066	0.000	0.033	0.272	0.000	0.014	0.115

Summary Table 6. $30/bbl scenario undiscovered economically recoverable resources of the Gulf of Mexico and Atlantic Continental Margin aggregated by water depth ranges and depostional style/facies.

Note: Summation of individual resource values may differ from total values due to independent computer runs and rounding. This table diverges from the August 1996 (OCS Report MMS 96-0047) table in that it uses different rounding, a different reserves appreciation equation, and includes reserves appreciation for unproved reserves.

	Full-Cycle @ $30.00/bbl and $3.52/Mcf Risked Undiscovered Economically Recoverable Resources										Half-Cycle @ $30.00/bbl and $3.52/Mcf Risked Undiscovered Economically Recoverable Resources									
	MPhc	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)			MPhc	Oil (Bbbl)			Gas (Tcf)			BOE (Bbbl)		
		F95	Mean	F5	F95	Mean	F5	F95	Mean	F5		F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
GOM & Atlantic Margin	1.00	6.632	7.672	9.367	79.526	85.684	92.942	20.783	22.918	25.905	1.00	7.019	8.077	9.892	83.936	89.895	97.023	21.954	24.072	27.156
0 - 200m WD	1.00	3.429	3.857	4.218	49.936	53.379	59.400	12.315	13.355	14.788	1.00	3.527	3.924	4.277	50.646	54.133	60.227	12.539	13.556	14.994
200 - 900m WD	1.00	0.817	1.272	1.826	7.400	10.283	12.844	2.134	3.102	4.112	1.00	0.997	1.349	1.869	8.758	11.245	13.726	2.556	3.350	4.312
> 900m WD	1.00	1.802	2.569	4.385	18.749	22.078	25.626	5.138	6.498	8.945	1.00	1.984	2.822	4.641	20.819	24.603	28.461	5.689	7.200	9.705
Gulf of Mexico Region	1.00	5.697	6.639	8.241	71.606	75.298	79.251	18.439	20.038	22.343	1.00	5.963	6.865	8.485	74.379	78.100	81.964	19.197	20.762	23.069
0 - 200m WD	1.00	2.980	3.368	3.856	45.136	46.745	48.159	11.012	11.686	12.425	1.00	3.018	3.423	3.905	45.852	47.318	48.730	11.177	11.843	12.575
200 - 900m WD	1.00	0.651	0.870	1.196	5.993	7.244	8.747	1.718	2.159	2.752	1.00	0.672	0.892	1.205	6.358	7.602	9.166	1.803	2.245	2.836
> 900m WD	1.00	1.731	2.398	4.158	18.492	21.216	24.342	5.021	6.173	8.490	1.00	1.873	2.545	4.303	20.385	23.056	26.086	5.500	6.648	8.944
Cenozoic Province	1.00	4.175	4.927	6.539	64.580	68.220	71.732	15.666	17.066	19.302	1.00	4.374	5.096	6.704	67.102	70.826	74.216	16.314	17.699	19.909
0 - 200m WD	1.00	1.717	1.876	2.061	38.128	39.868	41.827	8.502	8.970	9.503	1.00	1.715	1.884	2.075	38.606	40.284	42.166	8.584	9.053	9.577
200 - 900m WD	1.00	0.609	0.772	1.045	5.863	7.163	8.790	1.652	2.047	2.609	1.00	0.620	0.792	1.070	6.329	7.518	9.114	1.746	2.130	2.692
> 900m WD	1.00	1.646	2.273	3.908	18.115	21.132	24.862	4.870	6.033	8.331	1.00	1.810	2.416	4.064	20.020	22.975	26.616	5.372	6.504	8.799
Cenozoic Province	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Retrogradational	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Aggradational	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Progradational	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Fan	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Other	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Mesozoic Province	1.00	1.259	1.706	2.225	6.530	7.024	7.477	2.421	2.956	3.555	1.00	1.318	1.766	2.278	6.682	7.202	7.585	2.507	3.047	3.628
0 - 200m WD	1.00	1.104	1.496	1.971	6.505	6.864	7.302	2.262	2.717	3.270	1.00	1.164	1.543	2.017	6.660	7.027	7.464	2.349	2.794	3.345
200 - 900m WD	1.00	0.041	0.092	0.165	0.017	0.071	0.163	0.044	0.104	0.194	1.00	0.044	0.094	0.168	0.027	0.077	0.159	0.049	0.108	0.196
> 900m WD	0.74	0.000	0.118	0.318	0.000	0.089	0.233	0.000	0.134	0.360	0.81	0.000	0.127	0.321	0.000	0.100	0.267	0.000	0.145	0.368
Mesozoic Province	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Clastics	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Carbonates	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Western Planning Area	1.00	1.543	2.156	3.825	26.106	28.891	32.189	6.188	7.297	9.553	1.00	1.653	2.259	3.916	27.652	30.517	33.796	6.574	7.689	9.930
0 - 200m WD	1.00	0.620	0.703	0.826	16.839	18.269	19.727	3.616	3.954	4.336	1.00	0.620	0.707	0.829	17.138	18.529	19.995	3.669	4.004	4.387
200 - 900m WD	1.00	0.175	0.253	0.400	1.829	2.502	2.922	0.500	0.699	0.920	1.00	0.184	0.264	0.391	2.086	2.693	3.227	0.555	0.743	0.965
> 900m WD	1.00	0.590	1.198	2.817	5.915	8.126	10.992	1.643	2.644	4.773	1.00	0.678	1.288	2.903	7.148	9.316	12.175	1.950	2.946	5.069
Central Planning Area	1.00	2.636	2.863	3.164	37.436	39.758	41.988	9.297	9.937	10.635	1.00	2.695	2.925	3.224	38.400	40.673	42.914	9.527	10.162	10.860
0 - 200m WD	1.00	1.158	1.295	1.488	21.517	22.618	23.565	4.986	5.320	5.681	1.00	1.168	1.302	1.487	21.705	22.808	23.789	5.030	5.361	5.720
200 - 900m WD	1.00	0.357	0.520	0.780	3.669	4.683	6.571	1.010	1.353	1.950	1.00	0.362	0.529	0.800	3.830	4.846	6.654	1.044	1.391	1.984
> 900m WD	1.00	0.946	1.051	1.148	11.059	12.509	14.118	2.914	3.276	3.660	1.00	1.006	1.094	1.186	11.587	13.078	14.725	3.068	3.421	3.806
Eastern Planning Area	1.00	1.196	1.597	2.072	5.691	6.509	7.346	2.208	2.756	3.379	1.00	1.243	1.658	2.130	6.012	6.747	7.618	2.312	2.858	3.485
0 - 200m WD	1.00	0.996	1.356	1.820	5.464	5.838	6.109	1.969	2.395	2.907	1.00	1.041	1.403	1.870	5.617	5.968	6.272	2.040	2.465	2.986
200 - 900m WD	1.00	0.034	0.086	0.160	0.013	0.070	0.154	0.036	0.098	0.187	1.00	0.040	0.088	0.160	0.024	0.077	0.167	0.044	0.102	0.190
> 900m WD	0.91	0.000	0.147	0.301	0.000	0.594	1.667	0.000	0.253	0.598	0.95	0.023	0.162	0.301	0.033	0.682	1.790	0.029	0.284	0.620
Straits of FL Planning Area	1.00	0.009	0.020	0.034	0.001	0.005	0.010	0.010	0.021	0.036	1.00	0.010	0.021	0.034	0.002	0.006	0.011	0.010	0.022	0.036
0 - 200m WD	1.00	0.004	0.008	0.014	<0.001	<0.001	0.001	0.004	0.008	0.015	1.00	0.004	0.009	0.015	<0.001	<0.001	0.001	0.004	0.009	0.015
200 - 900m WD	1.00	0.002	0.006	0.010	<0.001	<0.001	<0.001	0.002	0.006	0.010	1.00	0.003	0.006	0.010	<0.001	<0.001	<0.001	0.003	0.006	0.010
> 900m WD	0.74	0.000	0.006	0.016	0.000	0.004	0.011	0.000	0.007	0.018	0.80	0.000	0.006	0.016	0.000	0.005	0.013	0.000	0.007	0.018
Atlantic Region	1.00	0.587	1.063	1.644	5.855	10.479	16.444	1.628	2.927	4.570	1.00	0.788	1.234	1.854	7.242	11.966	17.661	2.076	3.363	4.997
0 - 200m WD	1.00	0.338	0.486	0.578	3.361	6.653	13.179	0.936	1.669	2.923	1.00	0.346	0.499	0.586	3.600	6.848	13.395	0.987	1.718	2.970
200 - 900m WD	0.95	0.044	0.408	0.740	0.209	3.047	5.276	0.081	0.950	1.679	0.98	0.225	0.463	0.809	1.514	3.622	5.648	0.495	1.108	1.814
> 900m WD	0.42	0.000	0.173	0.638	0.000	0.798	3.572	0.000	0.315	1.273	0.63	0.000	0.277	0.759	0.000	1.505	4.446	0.000	0.545	1.551
Mesozoic Province	1.00	0.587	1.063	1.644	5.855	10.479	16.444	1.628	2.927	4.570	1.00	0.788	1.234	1.854	7.242	11.966	17.661	2.076	3.363	4.997
0 - 200m WD	1.00	0.338	0.486	0.578	3.361	6.653	13.179	0.936	1.669	2.923	1.00	0.346	0.499	0.586	3.600	6.848	13.395	0.987	1.718	2.970
200 - 900m WD	0.95	0.044	0.408	0.740	0.209	3.047	5.276	0.081	0.950	1.679	0.98	0.225	0.463	0.809	1.514	3.622	5.648	0.495	1.108	1.814
> 900m WD	0.42	0.000	0.173	0.638	0.000	0.798	3.572	0.000	0.315	1.273	0.63	0.000	0.277	0.759	0.000	1.505	4.446	0.000	0.545	1.551
Mesozoic Province	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Clastics	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Carbonates	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
North Atlantic Planning Area	1.00	0.202	0.322	0.440	1.884	3.328	5.555	0.538	0.914	1.428	1.00	0.237	0.373	0.519	2.182	3.767	6.031	0.626	1.043	1.592
0 - 200m WD	1.00	0.112	0.164	0.194	1.123	2.200	4.350	0.312	0.555	0.968	1.00	0.115	0.167	0.191	1.195	2.263	4.444	0.328	0.570	0.982
200 - 900m WD	0.90	0.000	0.107	0.186	0.000	0.905	1.519	0.000	0.268	0.457	0.96	0.054	0.122	0.193	0.390	1.079	1.658	0.124	0.314	0.489
> 900m WD	0.42	0.000	0.050	0.196	0.000	0.238	1.063	0.000	0.092	0.385	0.63	0.000	0.083	0.223	0.000	0.467	1.402	0.000	0.166	0.472
Mid-Atlantic Planning Area	1.00	0.207	0.369	0.580	1.971	3.566	5.796	0.557	1.003	1.611	1.00	0.256	0.424	0.655	2.426	4.066	6.269	0.688	1.148	1.770
0 - 200m WD	1.00	0.116	0.169	0.199	1.157	2.267	4.482	0.322	0.572	0.997	1.00	0.119	0.173	0.197	1.231	2.332	4.579	0.338	0.587	1.011
200 - 900m WD	0.94	0.006	0.126	0.217	0.022	0.978	1.663	0.010	0.300	0.513	0.98	0.077	0.144	0.227	0.454	1.173	1.853	0.157	0.352	0.557
> 900m WD	0.40	0.000	0.077	0.309	0.000	0.313	1.298	0.000	0.132	0.540	0.61	0.000	0.114	0.340	0.000	0.561	1.713	0.000	0.214	0.645
South Atlantic Planning Area	1.00	0.210	0.384	0.620	1.997	3.578	5.971	0.565	1.020	1.683	1.00	0.268	0.440	0.675	2.437	4.078	6.425	0.702	1.165	1.818
0 - 200m WD	1.00	0.112	0.164	0.194	1.123	2.200	4.350	0.312	0.555	0.968	1.00	0.115	0.167	0.191	1.195	2.263	4.444	0.328	0.570	0.982
200 - 900m WD	0.95	0.035	0.176	0.425	0.143	1.161	2.143	0.061	0.382	0.806	0.98	0.081	0.196	0.447	0.593	1.367	2.344	0.187	0.440	0.864
> 900m WD	0.42	0.000	0.045	0.191	0.000	0.223	1.000	0.000	0.085	0.369	0.63	0.000	0.078	0.209	0.000	0.448	1.343	0.000	0.158	0.448

GLOSSARY

Aggradational: See "*depositional style.*"

Allocthonous: Formed elsewhere than at its present location.

Alluvial deposits: A general description of all sediments deposited on land by streams.

Annual growth factor (AGF): See "*growth factor*."

Appreciation: Analogous to *reserves appreciation*. See "*reserves*."

Assessment: The estimation of potential amounts of conventionally recoverable hydrocarbon resources.

Associated gas: See "*gas, natural*."

Basin: An area in which a thick sequence (typically thicknesses of 1 kilometer or greater) of sedimentary rocks is preserved.

Barrels of oil equivalent (BOE): The sum of gas resources, expressed in terms of their energy equivalence to oil, plus the oil volume. The conversion factor of 5,620 standard cubic feet of gas equals 1 BOE is based on the average heating values of domestic hydrocarbons.

Bias: A systematic distortion of a statistical result. This differs from a random error, which is symmetrically dispersed around the results and therefore, on average, balances the error.

Block: A numbered area on an OCS map, varying in size, but typically 5,000 to 5,760 acres (approximately 9 square miles). Each block has a specific identifying number, area, and latitude and longitude coordinates that can be located on a map.

Carbonate: See "*sediment*."

Chance: See "*probability*" or "*risk*."

Chronozone: A body of rock formed during the same span of time. In this report, boundaries are defined by biostratigraphic and correlative seismic markers.

Clastic: See "*sediment*."

Compliant tower: See "*development systems*."

Conceptual play: See “*play*.”

Condensate: Hydrocarbons, associated with saturated gas, that are present in the gaseous state at reservoir conditions, but produced as liquid hydrocarbons at the surface.

Continental margin: The composite continental rise, continental slope, and continental shelf as a single entity. The term, as used in this report, applies only to the portion of the margin whose mineral estate is under Federal jurisdiction; geographically synonymous with Outer Continental Shelf (OCS).

Continental rise: The base of the continental slope, which in places is marked by a more gently dipping surface that leads seaward to the ocean floor.

Continental shelf: The shallow, gradually sloping zone extending from the shoreline to a depth at which there is a marked steep descent to the ocean bottom.

Continental slope: The portion of the continental margin extending seaward from the continental shelf to the continental rise or ocean floor.

Conventionally recoverable: Producible by natural pressure, pumping, or secondary recovery methods such as gas or water injection.

Conventionally recoverable resources: See “*resources*.”

Critical price: See “*price-supply curves*.”

Cumulative growth factor (CGF): See “*growth factor*.”

Cumulative probability distributions: A distribution showing the probability of a given amount or more occurring. These distributions include the values for the resource estimates presented throughout this report: a low estimate having a 95-percent probability (19 in 20 chance) of at least that amount (F95), a high estimate having a 5-percent probability (1 in 20 chance) of at least that amount (F5), and a mean (μ) estimate representing the average of all possible values. Values of the fractiles are not additive. These distributions are often referred to as S-curves.

Cumulative production: The sum of all produced volumes of hydrocarbons prior to a specified point in time.

Delineation: The drilling of additional wells after a discovery in order to more accurately determine the extent and quality of a prospect prior to a development decision.

Dependency, geologic: An estimate that reflects the relative degree of commonality among plays with respect to factors controlling the occurrence of hydrocarbons at the play level: charge, reservoir, and trap. Dependencies reflect the degree of coexistence among plays. Values for dependency can range from one, in which case each play would not exist if the other(s) did not exist, to zero, in which case the existence of each play is totally independent from all others.

Depositional style: Large-scale patterns of basin fill. Depositional styles are discerned by relative proportions of sandstone and shale, electric log patterns, ecozone information, and parasequence stacking patterns. Four patterns (retrogradational, aggradational, progradational, and fan) were utilized herein to provide a framework for classifying and predicting reservoir trends, distribution, and quality in the northern Gulf of Mexico.

Retrogradational: Characterized by well log patterns showing backstepping packages of thin, commonly fining-upward sandstones separated by thicker shale units. Represents the reworking of sediments by major marine transgressions.

Aggradational: Characterized by well log patterns showing thick, blocky, stacked sandstones separated by thinner shale units. Represents sediment buildup in continental to shallow marine shelf environments.

Progradational: Characterized by well log patterns showing commonly coarsening-upward packages of thin to thick sandstones separated by subequally thick shale units. Represents a major regressive episode in which sediments outbuild onto both the shelf and slope.

Fan: Characterized by well log patterns showing thin to thick, commonly fining-upward sandstones, which are blocky at the base and can be stacked or singular. These sandstones are overlain by thick marine shales. Represents channel-levee complexes and fan lobes deposited basinward of the shelf edge.

Deterministic: A process in which future states can be forecast exactly from knowledge of the present state and rules governing the process. It contains no random or uncertain components.

Development: Activities following exploration, including the installation of production facilities and the drilling and completion of wells for production.

Development systems: Basic options used in constructing OCS permanent production facilities.

Compliant tower (CT): An offshore facility consisting of a narrow, flexible tower and a piled foundation that can support a conventional deck for drilling and production operations. Unlike the fixed platform, the compliant tower withstands large lateral forces by sustaining significant lateral deflections and is usually used in water depths between 1,500 and 3,000 feet.

Fixed platform (FP): An offshore facility consisting of a jacket (a tall vertical section made of tubular steel members supported by piles driven into the seabed) with a deck placed on top, providing space for crew quarters, drilling rigs, and production facilities. The fixed platform is economically feasible for installation in water depths up to about 1,650 feet.

Floating production system (FPS): An offshore facility consisting of a semi-submersible which is equipped with drilling and production equipment. It is anchored in place with wire rope and chain or can be dynamically positioned using rotating thrusters. Wellheads are located on the ocean floor and are connected to the surface deck with production risers designed to accommodate platform motion. Floating production systems can be used in water depths ranging from 600 to 6,000 feet.

SeaStar tension leg platform (SStar): An offshore facility consisting of a floating mini-tension leg platform of relatively low cost developed for production of smaller deepwater reserves which would be uneconomic to produce using more conventional deepwater production systems. It can also be used as a utility, satellite, or early production platform for larger deepwater discoveries. SeaStar platforms can be used in water depths ranging from 600 to 3,500 feet.

SPAR platform (SPAR): An offshore facility consisting of a large diameter vertical cylinder supporting a deck. It has a typical fixed platform topside (surface deck with drilling and production equipment), three types of risers (drilling, production, and export), and a hull which is moored using a taut catenary system of 6 to 20 lines anchored into the sea floor. SPAR's are presently used in water depths up to 3,000 feet, although existing technology can extend this to about 10,000 feet.

Subsea system (SS): An offshore facility ranging from single subsea wells producing to a nearby platform, floating production system, or tension leg platform to multiple wells producing through a manifold and pipeline system to a distant production facility. These systems are now used in water depths up to 7,000 feet, although existing technology can extend this to about 10,000 feet.

Tension leg platform (TLP): An offshore facility consisting of a floating structure held in place by vertical, tensioned tendons connected to the sea floor by pile-secured templates. Tensioned tendons provide for use of the tension leg platform in a broad water depth range and for limited vertical motion.

Tension leg platforms can be used in water depths up to about 6,000 feet.

Discounted cash flow analysis: An analysis of future anticipated expenditures and revenues associated with a project discounted back to time zero (usually the present) at a rate typically representing the average opportunity cost or cost of capital of the investor or a desired rate of return.

Dissolved gas: See "*gas, natural*."

Economic analysis: An assessment performed in order to estimate the portion of the undiscovered conventionally recoverable resources in an area that is expected to be commercially viable in the long term under a specific set of economic conditions.

Full-cycle analysis: Full-cycle analysis considers all leasehold (excluding lease acquisition), geophysical, geologic, and exploration costs in determining the economic viability of a prospect. The decision point is whether or not to explore.

Half-cycle analysis: Half-cycle analysis considers all leasehold and exploration costs, as well as delineation costs, that are incurred prior to the field development decision to be sunk; these costs are not utilized in the discounted cash flow calculations to determine whether a field is commercially profitable. The decision point is whether or not to develop and produce the field.

Economic risk: See "*risk*."

Economically recoverable resources: See "*resources*."

Established play: See "*play*."

Evaporite: See "*sediment*."

Exploration: The process of searching for minerals prior to development. Exploration activities include geophysical surveys, drilling to locate hydrocarbon reservoirs, and the drilling of delineation wells to determine the extent and quality of an existing discovery prior to a development decision.

Facies: The aspects, appearance, and characteristics of a rock unit, usually reflecting the conditions of origin.

Fan: See "*depositional style.*"

Field: A producible accumulation of hydrocarbons consisting of a single pool or multiple pools related to the same geologic structure and/or stratigraphic condition. In general usage this term refers to a commercial accumulation.

Marginal field: A field containing quantities of hydrocarbon reserves that are barely profitable to develop.

Fixed platform: See “*development systems*.”

Floating production system: See “*development systems*.”

Fluvial deposits: A general description of all sediments deposited in water by streams.

Formation: A mappable sedimentary rock unit of distinctive lithology.

Frequency: The number of times an indicated event occurs within a specified interval.

Frontier play: See “*play*.”

Full-cycle analysis: See “*economic analysis*.”

Gas, natural: A mixture of gaseous hydrocarbons (typically methane with lesser amounts of ethane, propane, butane, pentane, and possibly some nonhydrocarbon gases).

Associated gas: The volume of natural gas that occurs in crude oil reservoirs as free gas (gas cap).

Dissolved gas: The volume of natural gas that occurs as gas in solution with crude oil reservoirs.

Nonassociated gas: The volume of natural gas that occurs in reservoirs and is not in contact with significant quantities of crude oil.

Geologic risk: See “*risk*.”

Growth factor: A function which can be used to calculate an estimate of a field’s size at a future date. Growth factors reflect technology, market, and economic conditions existing over the period spanned by the estimates.

Annual growth factor (AGF): The function which represents the ratio of the size of a field of a specific age as estimated in a subsequent year.

Cumulative growth factor (CGF): The function which represents the ratio of the size of a field a specific number of years after discovery to the initial estimate of its size in the year of discovery.

Half-cycle analysis: See "*economic analysis*."

Hydrocarbon limit: See "*play limit*."

Hydrocarbon maturation: The process by which organic material trapped in source rocks is transformed naturally by heat and pressure through time and depth of burial into oil and/or gas.

Hydrocarbons: Any of a large class of organic compounds containing primarily carbon and hydrogen. Hydrocarbons include crude oil and natural gas.

Lacustrine deposits: A general description for all sediments deposited in lakes.

Lithology: The description of rocks, especially sedimentary clastics, on the basis of such characteristics as color, structures, mineralogic composition, and grain size.

Lognormal distribution: A statistical distribution which, when plotted logarithmically, has the appearance of a normal Gaussian-distribution curve. Lognormal pool or field distributions are highly skewed, having very few large values and very many low values.

Margin: See "*continental margin*."

Marginal field: See "*field*."

Marginal price: See "*price-supply curves*."

Marginal probability (MP): A probability value that depends only on a single condition where one or more other conditions exist.

Marginal probability of hydrocarbons (MPhc): An estimate, expressed as a decimal fraction, of the chance that an oil or natural gas accumulation exists in the area under consideration. The area under consideration is typically a geologic entity, such as a pool, prospect, play, basin, or province; or a large geographic area such as a planning area or region. All estimates presented in this report reflect the probability that an area may be devoid of hydrocarbons or, in the case of estimates of economically recoverable resources, that commercial accumulations may not be present.

Mean (μ): A statistical measure of central tendency; the average or expected value, calculated by summing all values and dividing by the number of values.

Model: A geologic hypothesis expressed in mathematical form.

Monte Carlo simulation: A method of approximating solutions of problems by iterative sampling from simulated random or pseudo-random processes.

Nonassociated gas: See "*gas, natural*."

Oil, crude: A mixture of hydrocarbons that exists naturally in the liquid phase in subsurface reservoirs.

Original proved reserves: Analogous to *proved reserves*. See "*reserves*."

Outer Continental Shelf (OCS): The continental margin, including the shelf, slope, and rise, beyond the line that marks the boundary of state ownership; that part of the seabed under Federal jurisdiction.

Planning area: A subdivision of an offshore area used as the initial basis for considering blocks to be offered for lease in the Department of the Interior's areawide offshore oil and gas leasing program.

Play: A group of known and/or postulated pools that share common geologic, geographic, and temporal properties, such as history of hydrocarbon generation, migration, reservoir development, and entrapment.

Conceptual play: A play which is hypothesized by the analysts based on the subsurface geophysical data and regional geologic knowledge of the area. It is still a hypothesis, and the play concept has not been verified.

Established play: A play in which hydrocarbons have been discovered in one or more pools for which reserves have been estimated.

Frontier play: A play in which exploration activities are at an early stage. Some wells have already been drilled to verify the play concept.

Play limit: The geographic boundary of a play encompassing areas where hydrocarbon accumulations are known to exist, or where limited data indicate they may exist. Play components critical to the existence of these accumulations include hydrocarbon fill, reservoir, and trap.

Hydrocarbon limit: A subset of the play limit where hydrocarbon accumulations have been encountered, including field reserves.

Reserves limit: A subset of the hydrocarbon limit where proved and unproved reserves have been assessed for this project.

Pool: A discovered or undiscovered hydrocarbon accumulation, typically within a single stratigraphic interval. As utilized in this assessment, it is the aggregation of all reservoirs within a field that occur in the same play.

Pool rank plot: A graphical representation of the discovered and undiscovered pools sorted by relative size at a specific level (i.e., play, chronozone, series, system, province, or planning area).

Price-supply curves: A plot portraying volumes of undiscovered economically recoverable resources at various oil and gas prices. As prices increase (or costs decrease) the amount of economically recoverable resources approaches the estimate of the undiscovered conventionally recoverable resources.

Critical price: The minimum value at which at least one prospect is profitable under the specified economic and technologic conditions. Above the critical price, there is always an economic prospect(s).

Marginal price: The minimum value at which at least one prospect might be profitable under the specified economic and technologic conditions. Below the marginal price, there is never an economic prospect(s).

Probability: A means of expressing an outcome on a numerical scale that ranges from impossibility to absolute certainty. The chance that a specified event will occur.

Progradational: See "*depositional style.*"

Prospect: A geologic feature having the potential for trapping and accumulating hydrocarbons; a pool(s) or potential field.

Proved reserves: See "*reserves*."

Province: A large area unified geologically by means of a single dominant structural element or a number of contiguous elements.

Random: Occurring or observed without bias, so the appearance of any value within the range of the variable is determined only by chance.

Random variable: A variable whose particular values cannot be predicted, but whose behavior is governed by a probability distribution.

Recoverable resources: See "*resources*."

Region: A very large expanse of acreage usually characterized or set apart by some aspect such as a political division or area of similar geography. In this report, the regions are groupings of planning areas.

Remaining proved reserves: See "*reserves*."

Reserves: The quantities of hydrocarbon resources which are anticipated to be recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty.

Proved reserves: The quantities of hydrocarbons which can be estimated with reasonable certainty to be commercially recoverable from known accumulations and under current economic conditions, operating methods, and government regulations. Current economic conditions include prices and costs prevailing at the time of the estimate. Estimates of proved reserves equal cumulative production plus remaining proved reserves and do not include reserves appreciation.

Remaining proved reserves: The quantities of proved reserves currently estimated to be recoverable. Estimates of remaining proved reserves equal proved reserves minus cumulative production.

Reserves appreciation: The observed incremental increase through time in the estimates of reserves (proved and unproved [P & U]) of an oil and/or gas field. It is that part of the known resources over and above proved and unproved reserves that will be added to existing fields through extension, revision, improved recovery, and the addition of new reservoirs. Also referred to as reserves growth or field growth.

Total reserves: All hydrocarbon resources within known fields that can be profitably produced using current technology under existing economic conditions. Estimates of total reserves equal cumulative production plus remaining proved reserves plus unproved reserves plus reserves appreciation.

Unproved reserves: Reserve estimates based on geologic and engineering information similar to that used in developing estimates of proved reserves, but technical, contractual, economic, or regulatory uncertainty precludes such reserves being classified as proved.

Reserves limit: See "*play limit*."

Reservoir: A subsurface, porous, permeable rock body in which an isolated accumulation of oil and/or gas is stored.

Resource assessment: The estimation of potential amounts of recoverable resources. The focus is normally on conventionally recoverable hydrocarbons.

Resources: Concentrations in the earth's crust of naturally occurring liquid or gaseous hydrocarbons that can conceivably be discovered and recovered. Normal use encompasses both discovered and undiscovered resources.

Recoverable resources: The volume of hydrocarbons that is potentially recoverable, regardless of the size, accessibility, recovery technique, or economics of the postulated accumulations.

Conventionally recoverable resources: The volume of hydrocarbons that may be produced from a wellbore as a consequence of natural pressure, artificial lift, pressure maintenance (gas or water injection), or other secondary recovery methods. They do not include quantities of hydrocarbon resources that could be recovered by enhanced recovery techniques, gas in geopressured brines, natural gas hydrates (clathrates), or oil and gas that may be present in insufficient quantities or quality (low permeability "tight" reservoirs) to be produced via conventional recovery techniques.

Remaining conventionally recoverable resources: The volume of conventionally recoverable resources that has not yet been produced and includes remaining proved reserves, unproved reserves, reserves appreciation, and undiscovered conventionally recoverable resources.

Economically recoverable resources: The volume of conventionally recoverable resources that is potentially recoverable at a profit after considering the costs of production and the product prices.

Undiscovered resources: Resources postulated, on the basis of geologic knowledge and theory, to exist outside of known fields or accumulations. Included also are resources from undiscovered pools within known fields to the extent that they occur within separate plays.

Undiscovered conventionally recoverable resources (UCRR): Resources in undiscovered accumulations analogous to those in existing fields producible with current recovery technology and efficiency, but without any consideration of economic viability. These accumulations are of sufficient size and quality to be amenable to conventional primary and secondary recovery techniques. Undiscovered conventionally recoverable resources are primarily located outside of known fields.

Undiscovered economically recoverable resources (UERR): The portion of the undiscovered conventionally recoverable resources that is economically recoverable under imposed economic and technologic conditions.

Retrogradational: See "*depositional style.*"

Risk: The chance or probability that a particular event will not occur; the complement of marginal probability or success.

Economic risk: The chance that no commercial accumulation of hydrocarbons will exist in the area under consideration (e.g., prospect, play, or area). The chance that an area may not contain hydrocarbons or the volume present may be noncommercial is incorporated in the economic risk.

Geologic risk: The chance that recoverable hydrocarbons will not exist in the area under consideration (e.g., zone, prospect, play, or area). The commercial viability of an accumulation is not a consideration.

Sandstone-body reservoir: The aggregation of all fault-block portions of an originally continuous sandstone body.

Seal: Impervious rocks that form a barrier to migrating hydrocarbons above, below, and/or lateral to the reservoir rock.

SeaStar tension leg platform: See "*development systems*."

Sediment: Solid material, both mineral and organic, that is in suspension, is being transported, or has been moved from its site of origin by air, water, or ice and has come to rest on the earth's surface, either above or below sea level.

Carbonate: A sediment consisting chiefly of carbonate, commonly calcium carbonate, that precipitates from an aqueous solution originating as a chemical process, or more commonly, as a biological process (e.g., reef building).

Clastic: A sediment that originates in another form, but the effects of erosion and transportation have redeposited the sediment away from its site of origin.

Evaporite: A nonclastic sediment that results from the complete evaporation of seawater or brines (e.g., halite, aragonite, and anhydrite).

Series: A time-stratigraphic unit of rock classed next in rank below system, and above chronozone, based on a clearly designated stratigraphic interval.

Skewness: Asymmetry in a frequency distribution.

Source rock: A sedimentary rock, commonly a shale or limestone, whose organic matter has been transformed naturally by heat and pressure through time and depth of burial into oil and/or gas. This transformation is referred to as generation or maturation.

SPAR platform: See "*development systems*."

Standard deviation (σ): A measure of the amount of dispersion in a set of data; the square root of the variance.

Stochastic: A process in which each observation possesses a random variable.

Stratigraphic trap: See "*trap*."

Structural trap: See "*trap*."

Subsea system: See "*development systems*."

Sunk costs: Capital costs already incurred and not considered in an evaluation. They will not affect the future profitability of a project measured at a point in time subsequent to their expenditure.

System: A major time-stratigraphic rock unit of world-wide significance, representing the fundamental unit of time-stratigraphic classification. In this assessment it is classed next in rank below province, and above series.

Tension leg platform: See "*development systems*."

Total endowment: All conventionally recoverable hydrocarbon resources of an area. Estimates of total endowment equal undiscovered conventionally recoverable resources plus cumulative production plus remaining proved reserves plus unproved reserves plus reserves appreciation.

Total reserves: See "*reserves*."

Trap: A barrier to hydrocarbon migration that allows oil and gas to accumulate in a reservoir.

Stratigraphic trap: A trap that results from changes in the lithologic character of a rock.

Structural trap: A trap that results from folding, faulting, or other deformation of a rock.

Uncertainty: Imprecision in estimating the value (or range of values) for a variable.

Unconformity: A surface of erosion or nondeposition, usually the former, that separates younger strata from older rocks.

Undiscovered conventionally recoverable resources (UCRR): See "*resources*."

Undiscovered economically recoverable resources (UERR): See "*resources*."

Undiscovered resources: See "*resources*."

Unproved reserves: See "*reserves*."

Variance (σ^2): A measure of the amount of dispersion in a set of data. The variance is equal to the mean of the squared differences of the data values from the mean of the data, or the mean of the squares of the data from the square of the mean.

UNIT ABBREVIATIONS

Bbbl	billion barrels
bbl	barrels
Bbo	billion barrels of oil
BBOE	billion barrels of oil equivalent
BOE	barrels of oil equivalent
Bcfg	billion cubic feet of gas
bopd	barrels of oil per day
cf	cubic feet
m	meters
Mbo	thousand barrels of oil
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
MMbbl	million barrels
MMbo	million barrels of oil
MMBOE	million barrels of oil equivalent
MMcf	million cubic feet
MMcfd	million cubic feet per day
MMcfg	million cubic feet of gas
scf	standard cubic feet
stb	stock tank barrels
Tcf	trillion cubic feet
Tcfg	trillion cubic feet of gas

ACRONYMS AND SYMBOLS

AAPG	American Association of Petroleum Geologists
AGA	American Gas Association
AGF	annual growth factor
API	American Petroleum Institute
CDP	common depth point
CGF	cumulative growth factor
COST	Continental Offshore Stratigraphic Test
CPA	Canadian Petroleum Association
DFI	design, fabricate, and installation
DOE	U.S. Department of Energy
EIA	Energy Information Administration
F5	5th percentile, a 5-percent probability (1 in 20 chance) of there being more than that amount
F95	95th percentile, a 95-percent probability (19 in 20 chance) of there being more than that amount
FASPAG	Fast Appraisal System for Petroleum AGgregation
FVF	formation volume factor
GOM	Gulf of Mexico
GOR	gas-oil ratio
GRASP	Geologic Resources ASsessment Program
MMS	Minerals Management Service
MPhc	marginal probability of hydrocarbons
MPhc,econ	marginal probability of economically recoverable hydrocarbons
μ	mu (a statistical measure of central tendency) is one of the two standard descriptive parameters of a lognormal distribution; it represents the mean of the log-transformed data
N	total number of discovered and undiscovered pools
NPC	National Petroleum Council
OCS	Outer Continental Shelf
OGIFF	Oil and Gas Integrated Field File
PETRIMES	PETroleum Resources Information Management and Evaluation System suite of programs
PGC	Potential Gas Committee
PRESTO	Probabilistic Resource ESTimates— Offshore program
PROP	proportion of net pay oil
PRU	post-rift unconformity
PVT	pressure, volume, and temperature
RECG	recoverable gas
RECO	recoverable oil
RPVT	reservoir pressure, volume, and temperature

σ^2	sigma squared (a measure of the amount of dispersion in a set of data) is one of the two standard descriptive parameters of a lognormal distribution; it represents the variance of the log-transformed data
SP	spontaneous potential
STP	standard temperature and pressure
UCRR	undiscovered conventionally recoverable resources
UERR	undiscovered economically recoverable resources
U.S.	United States
USGS	U.S. Geological Survey

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Minerals Management Service
Gulf of Mexico OCS Region
Public Information Office (MS 5034)
1201 Elmwood Park Blvd.
New Orleans, LA 70123-2394
(504) 736-2519 or 1-800-200-GULF
GulfPublicInfo@mms.gov

The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places;
and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Royalty Management Program** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.

Minerals Management Service
Gulf of Mexico OCS Region

Managing America's offshore energy resources

Protecting America's coastal and marine environments