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

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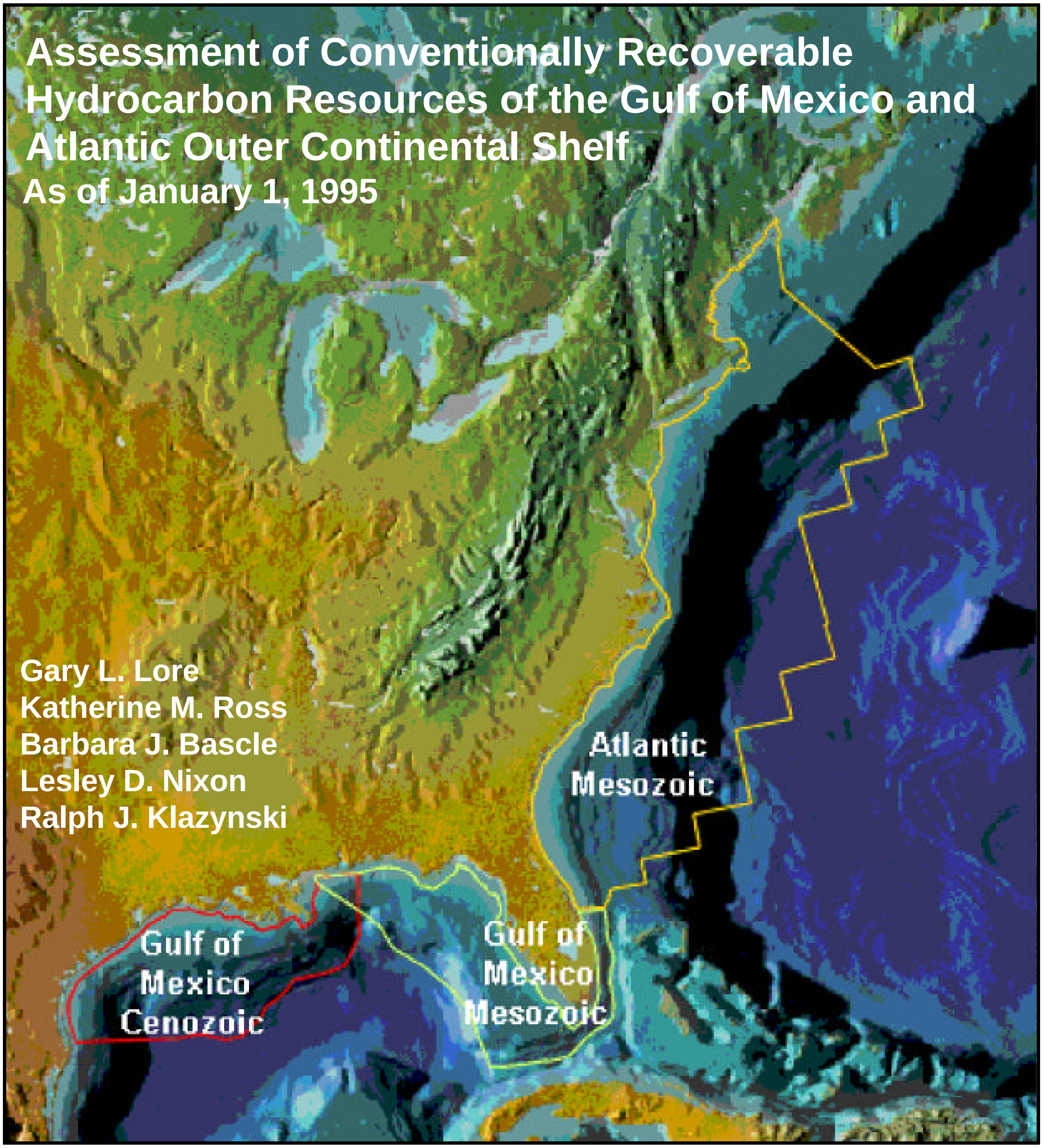

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SUMMARY

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

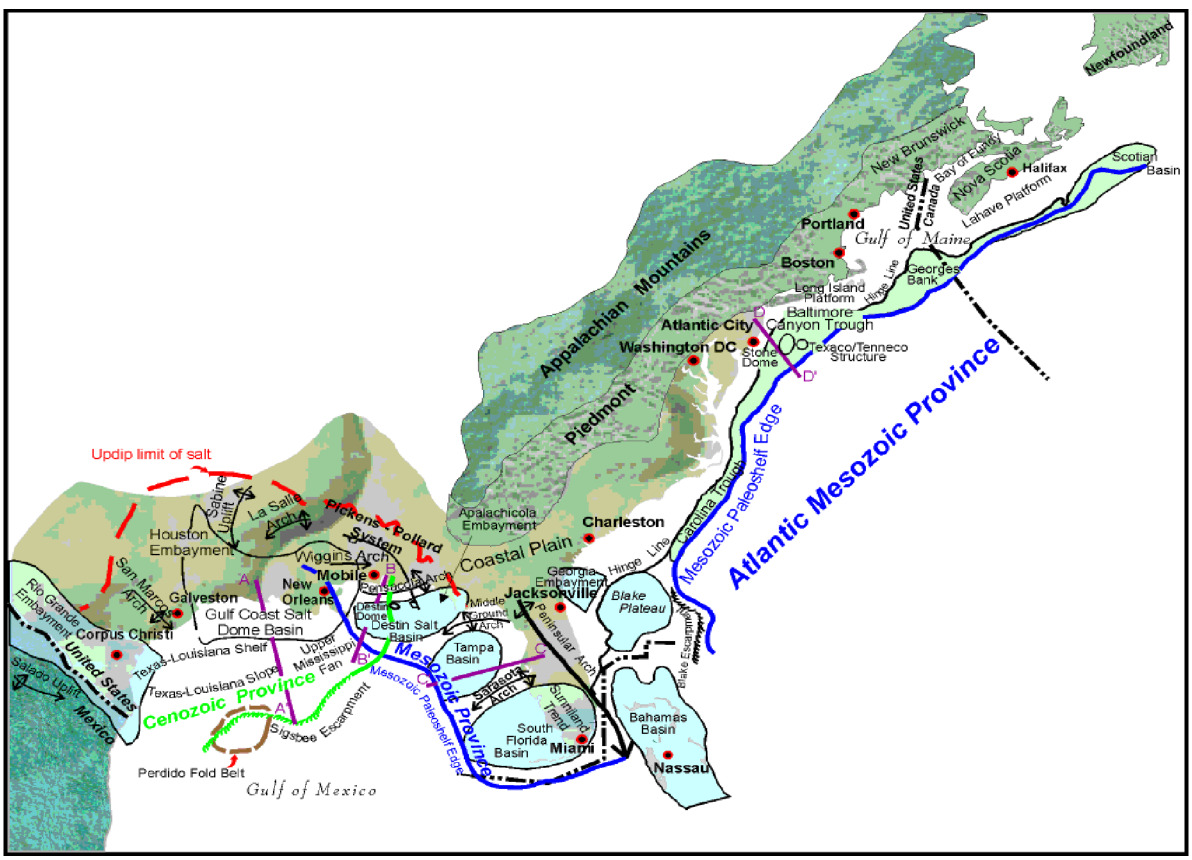


Figure 1. Physiographic Map of the Gulf of Mexico and Atlantic Continental Margin.

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.

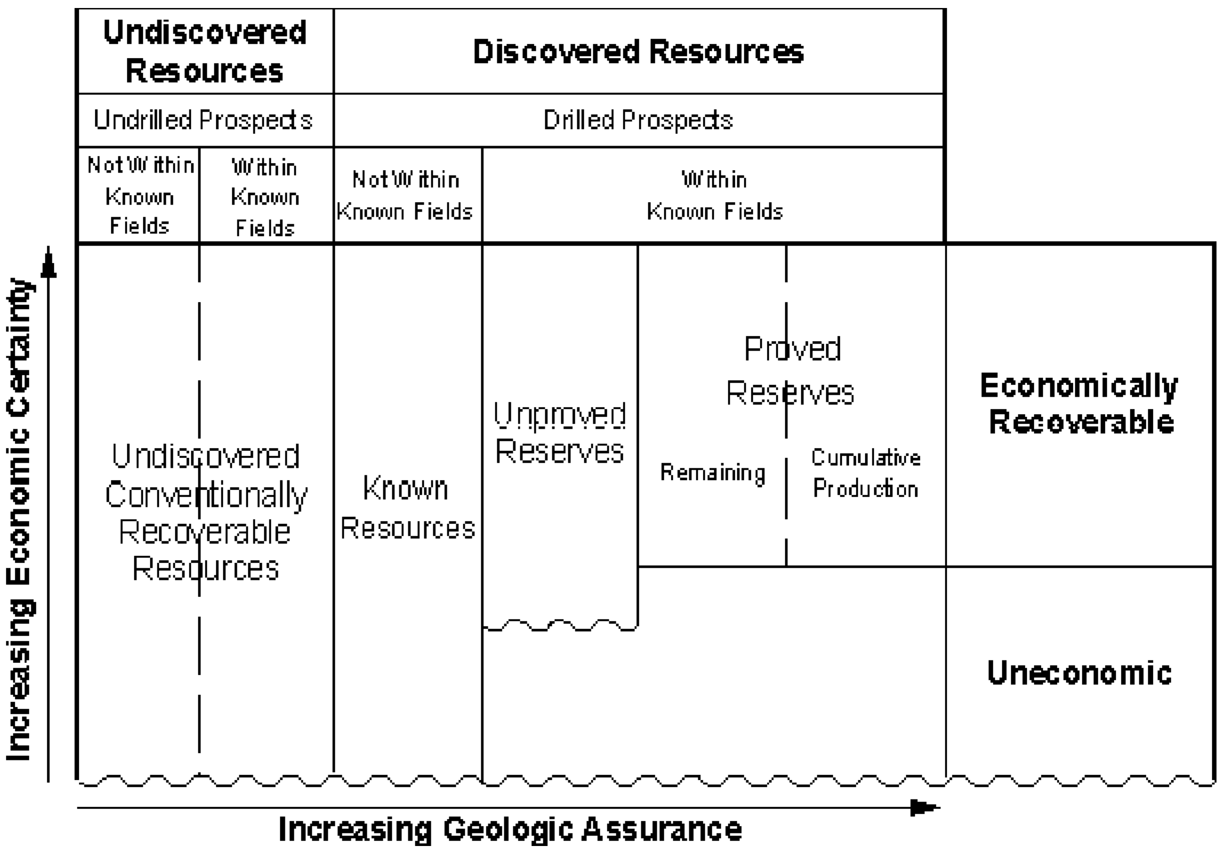
Energy is the lifeblood of the world's economy. In 1994, oil and gas resources were the major contributor to the world energy supply, 38 and 22 percent, respectively (MacKenzie, 1996). Worldwide reliance on petroleum resources as the principal fuel to satisfy future energy demand is likely to continue 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

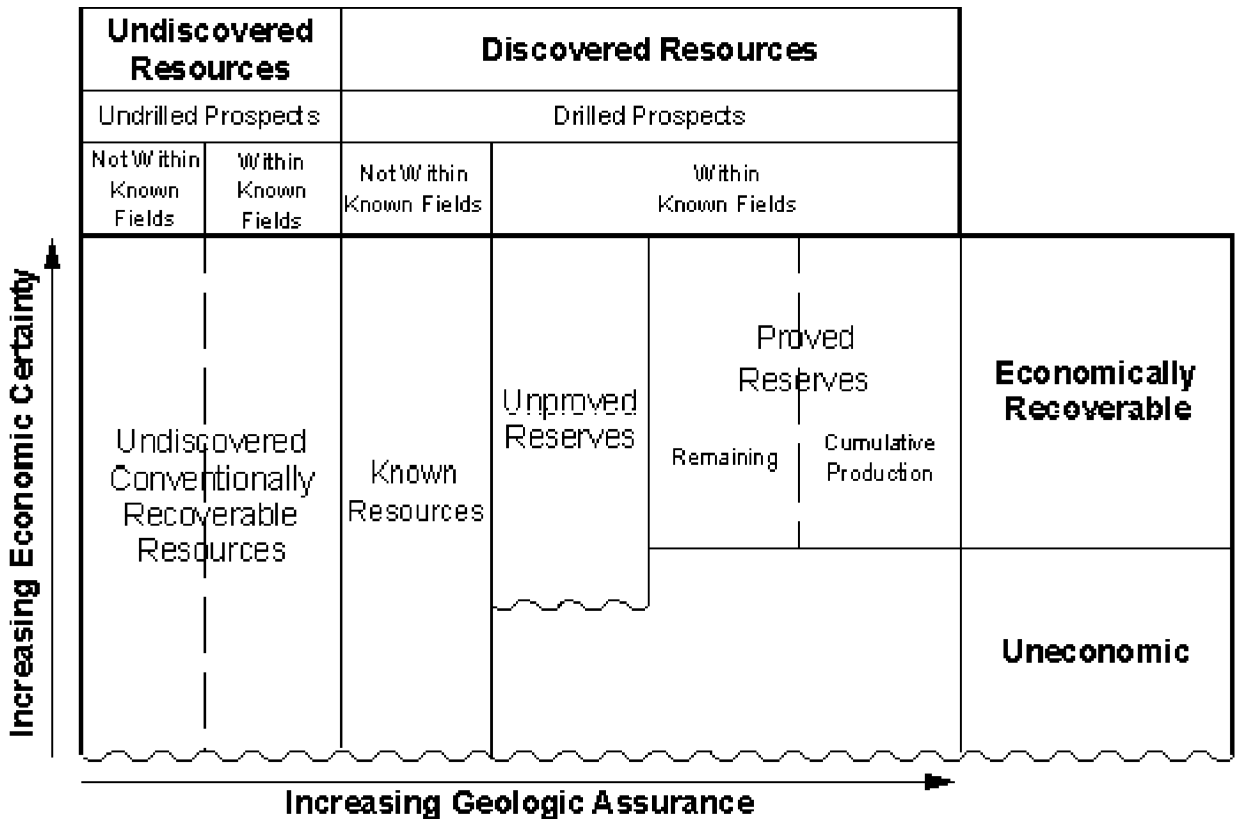
Previous MMS assessments presented estimates of undiscovered conventionally recoverable oil and gas resources as cumulative distributions of the quantities of resources expected in a particular area. Knowledge of both the total amount of undiscovered conventionally recoverable oil and gas resources and 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

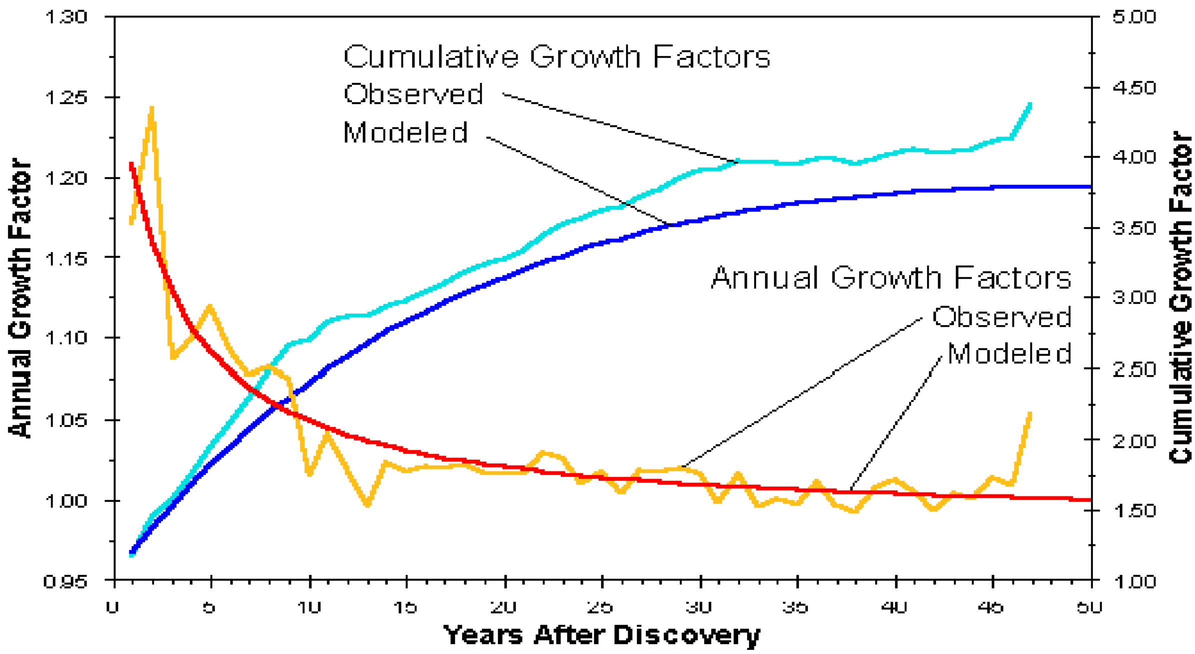


Figure 1. Observed and Modeled Annual and Cumulative Growth Factors.

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.

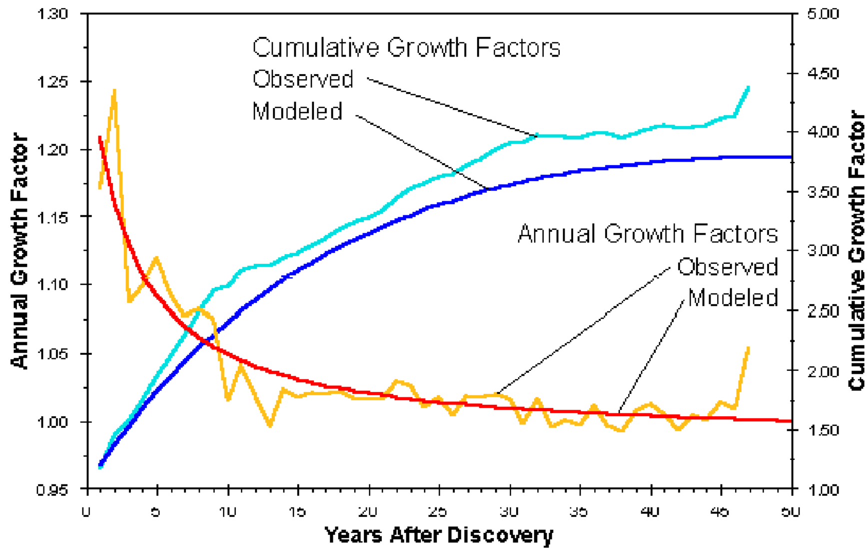


Figure 1. Observed and Modeled Annual and Cumulative Growth Factors.

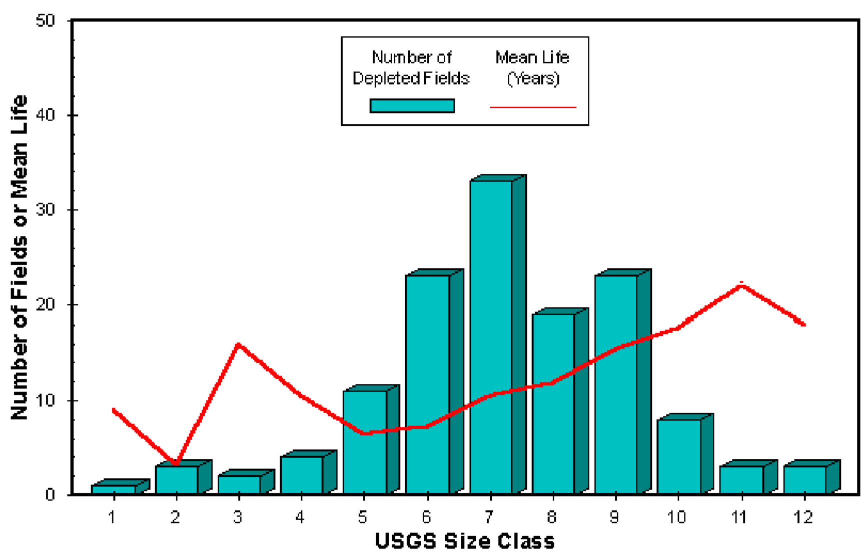


Figure 2. Abandoned Fields by USGS Size Class.

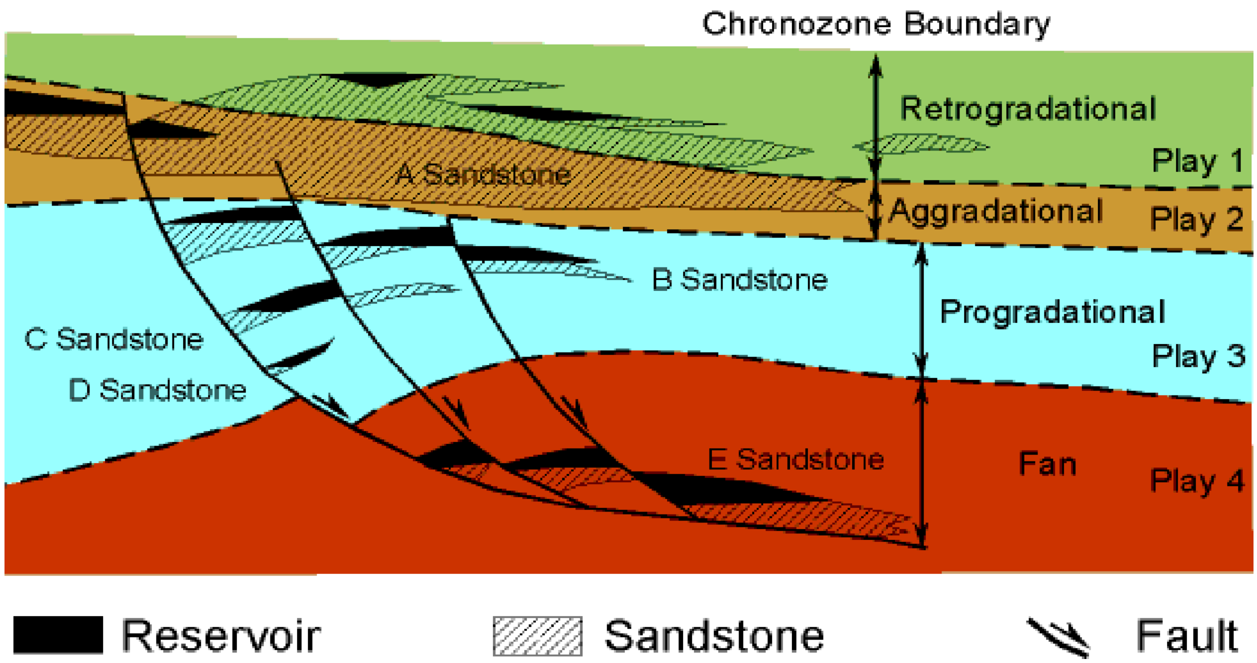
The MMS historical series of field-level estimates of proved reserves is included as a database file (94resgrw.dbf).

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.

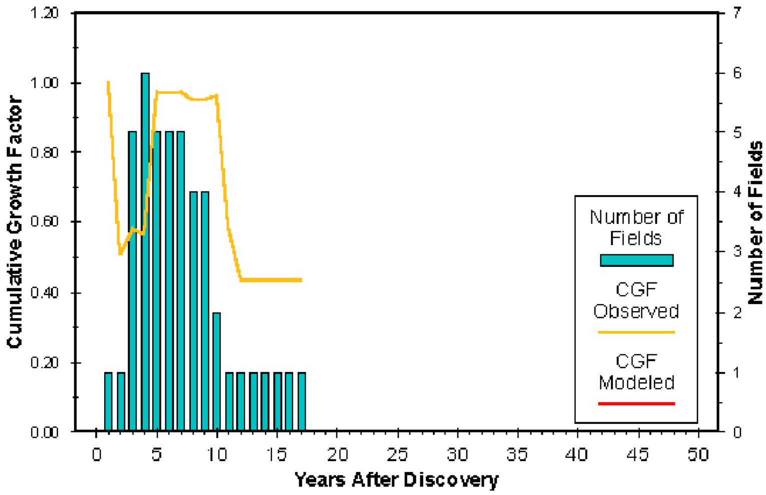


Figure 4. Retrogradational Play Family Cumulative Growth Factors (CGF).

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

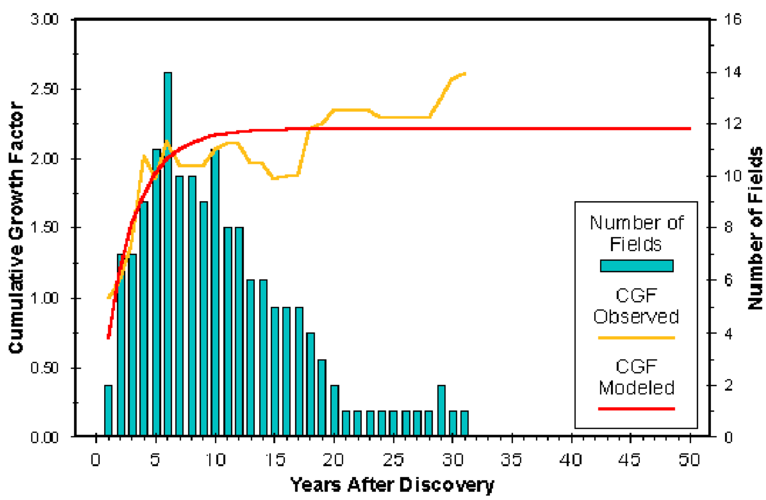


Figure 5. Aggradational Play Family Cumulative Growth Factors (CGF).

(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.

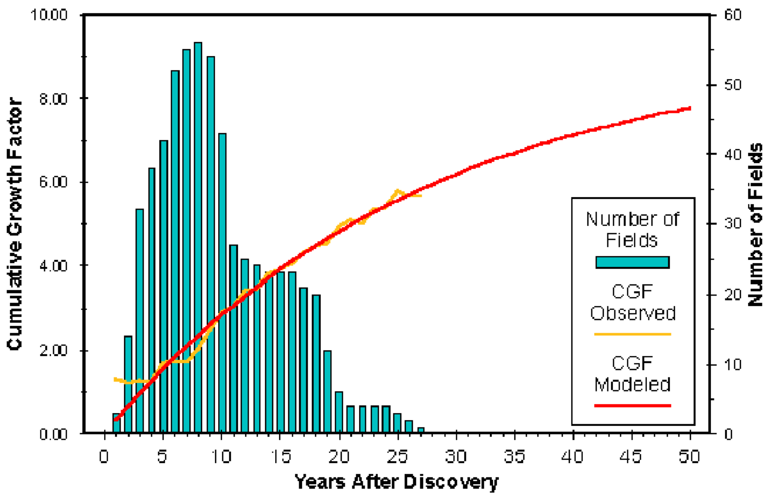


Figure 6. Fan Play Family Cumulative Growth Factors (CGF).

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

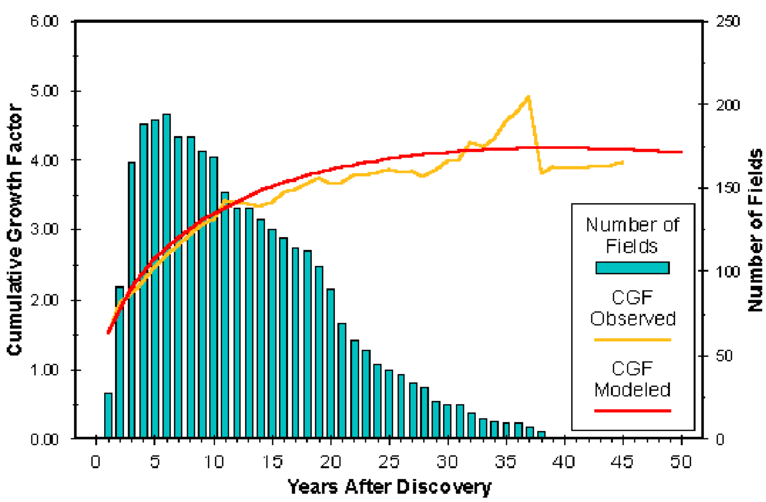


Figure 7. Progradationall Play Family Cumulative Growth Factors (CGF).

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

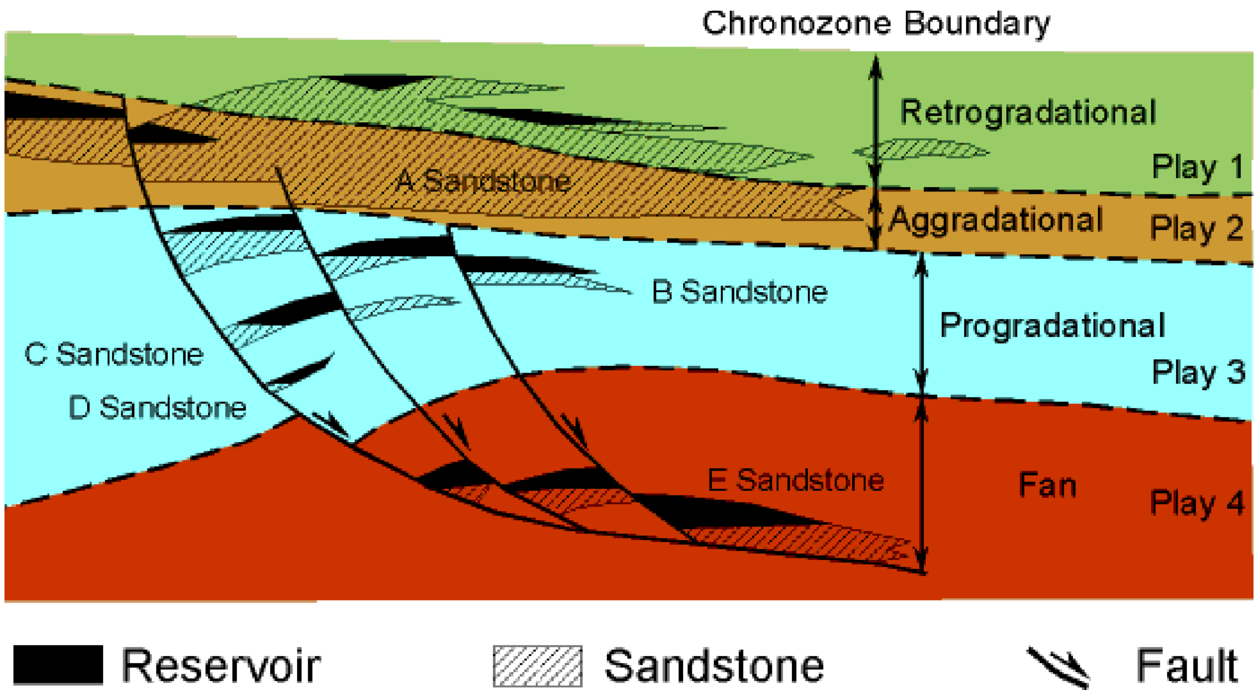
PLAY DELINEATION PROCEDURES GENERAL DISCUSSION

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.

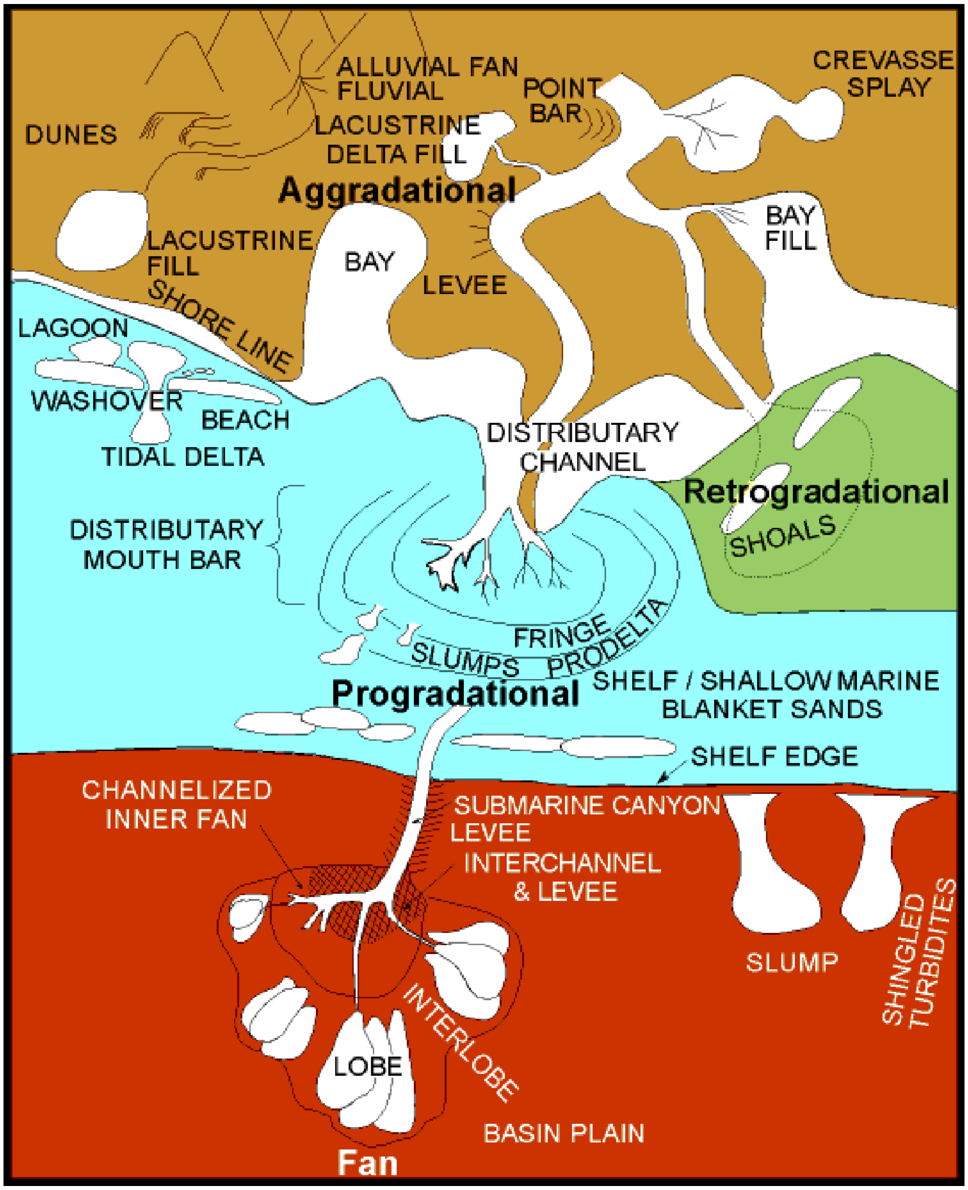
Since a single field mayproduce hydrocarbos from several reservoirs that vary in geologic age, depositional environment, lithology, and many other attributes used to characterize a play, it may be represented in more than one play. Because most existing offshore fields are associated with growth-fault 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*
~139.0		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.



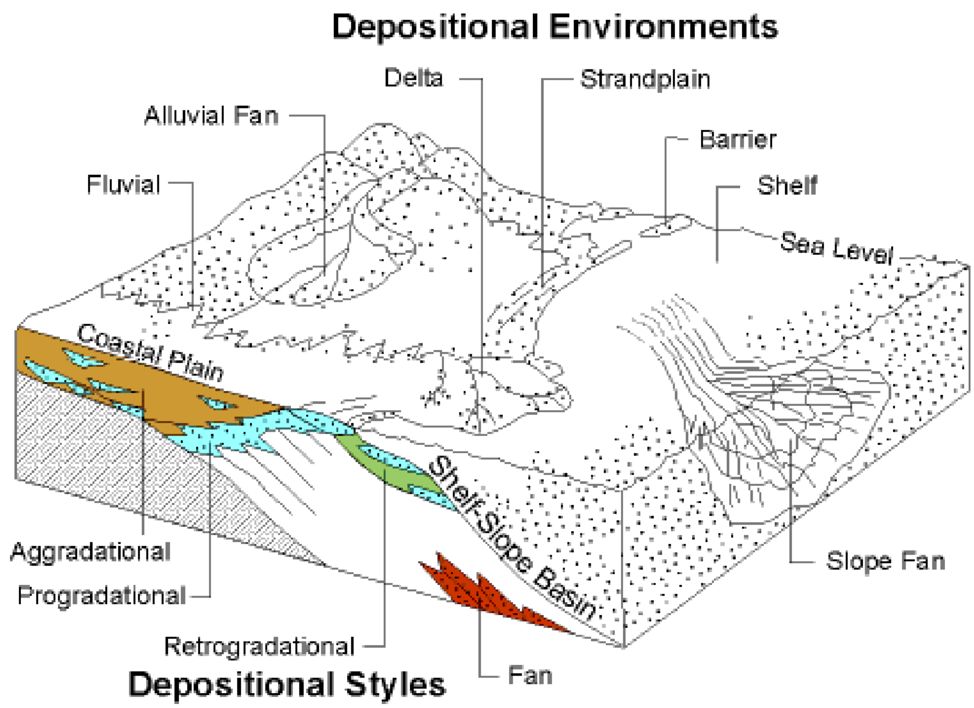
(Modified from Seni *et al.*, 1997)

Figure 3. Model for Deltaic Deposition.

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.

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

Geologic Time (M.Y.)	Province	System	Series	National Assessment Chronozone	Chronozone	Biozone: Gulf of Mexico	Biozone: Atlantic
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				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			
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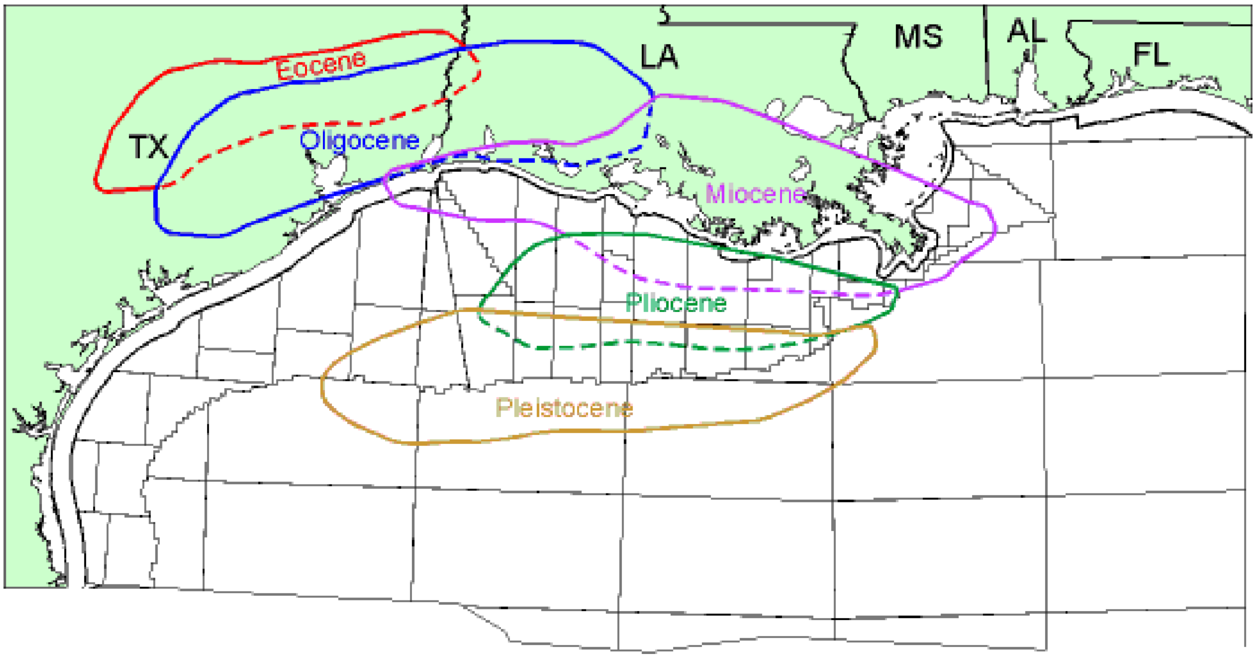
~138.0		Jurassic	Upper	UU		*Pseudocyclammina jaccardi*	*Ctenidodinium penneum* *Epistomina uhligi* *Senoniasphaera jurassica* *Pseudocyclammina jaccardi*
~163.0			Middle	MU			*Gonyaulacysta pectinigera* *Gonyaulacysta pachyderma*
~183.0			Lower	LU			
~206.0		Triassic	Upper	UTR			

(Modified from Melancon, et al., 1995)

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.

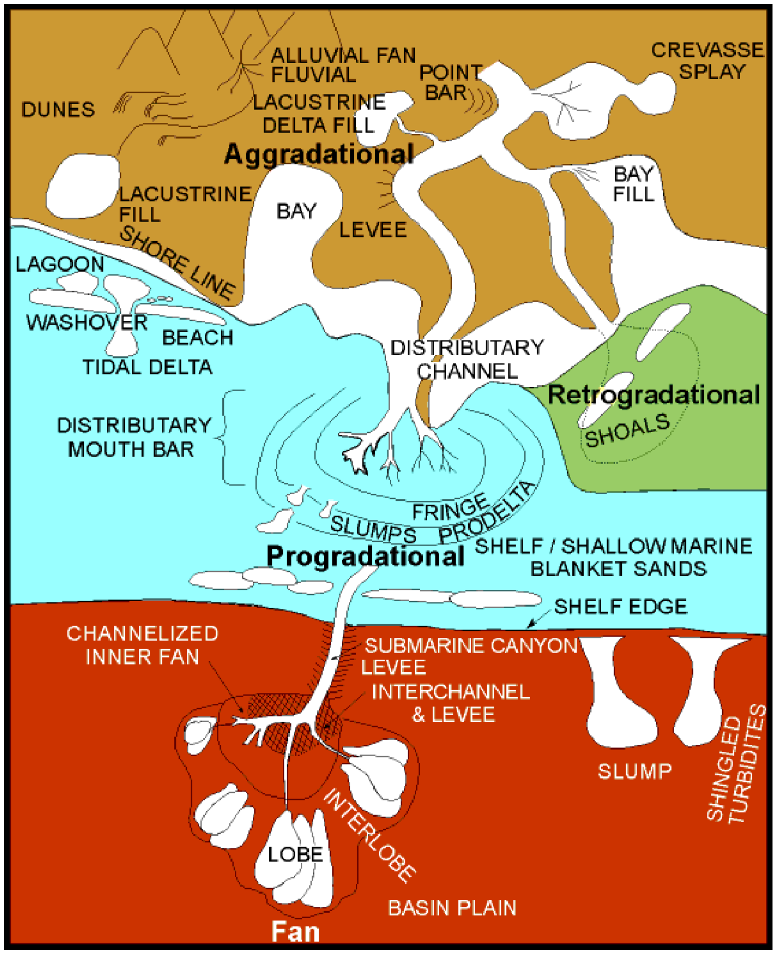


Figure 3. Model for Deltaic Deposition.

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.

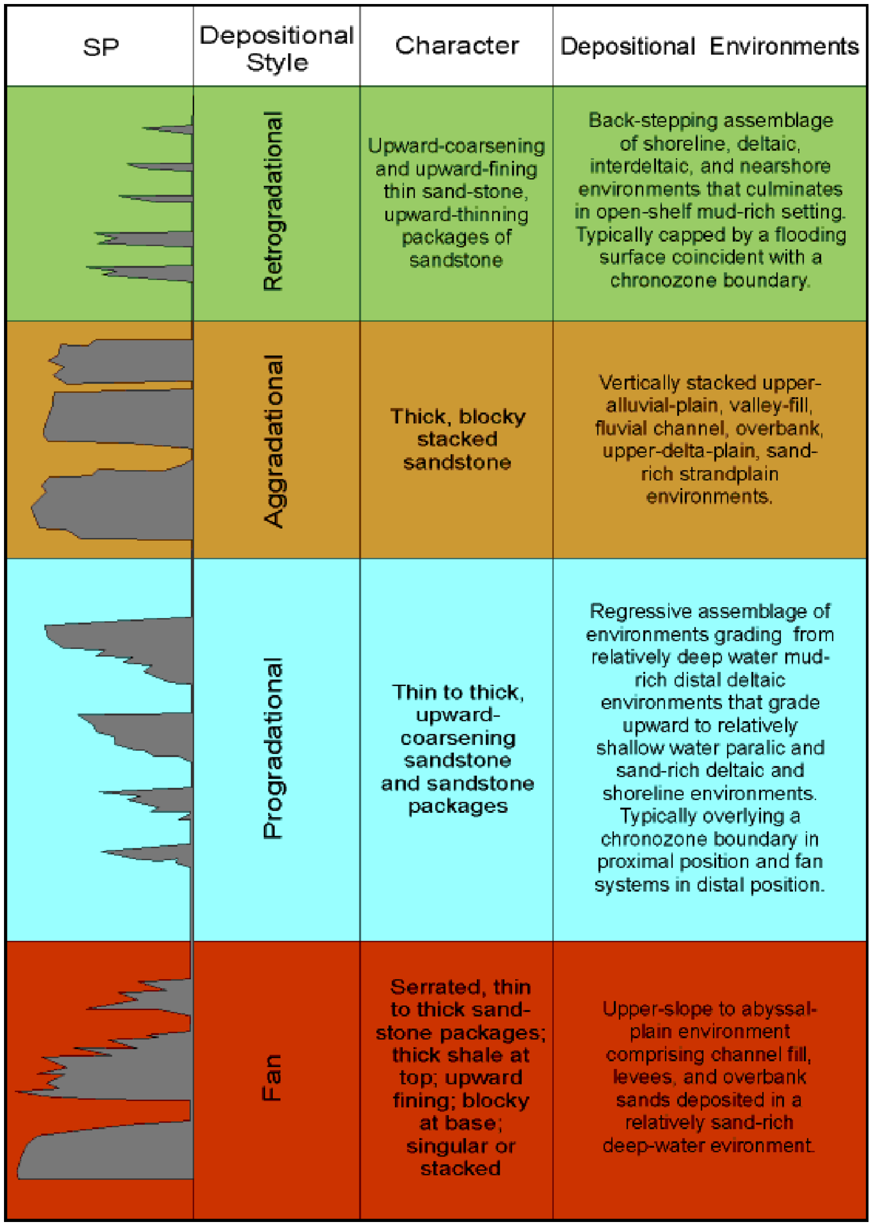


Figure 4. Representative Electric Log Characteristics by Depositional Style.

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

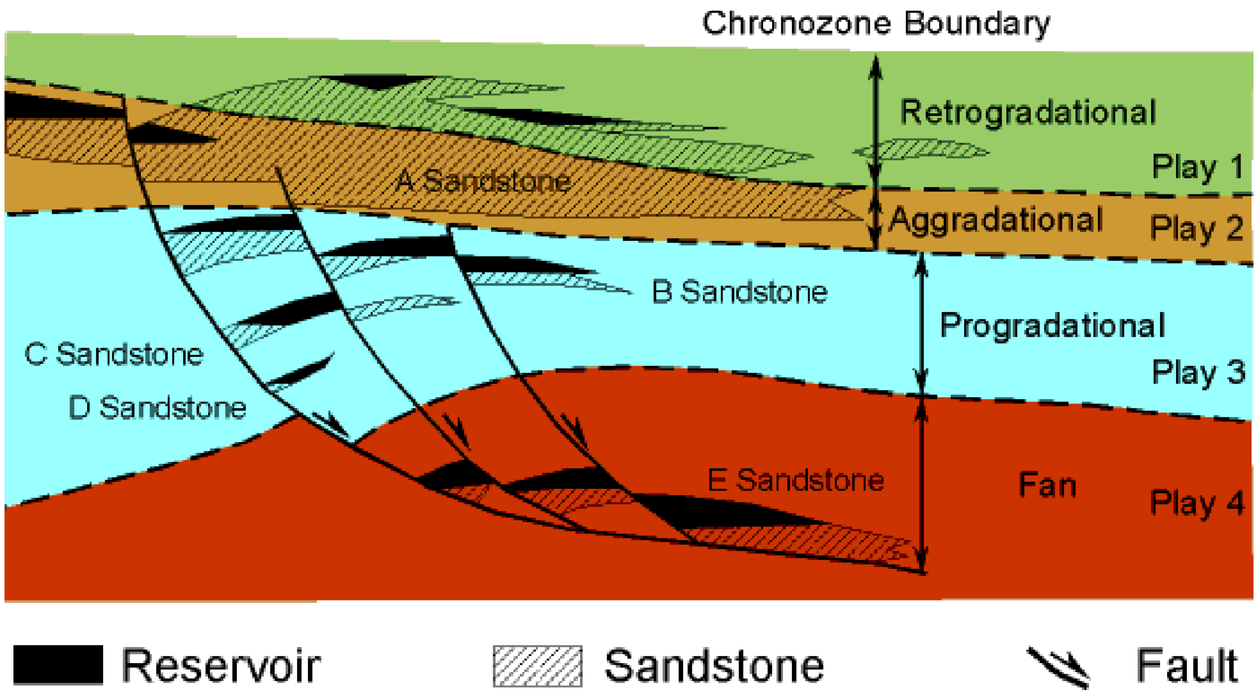
Structural control over the distribution of reservoirs and plays can be identified in local areas, such as along the Corsair Fault System and locally over salt structures. However, the extent of subregional hydrocarbon plays in the Province depends principally on the distribution of depositional facies 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).

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. Figure 5 shows a generalized cross section of a typical field that illustrates this organizational framework.

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.

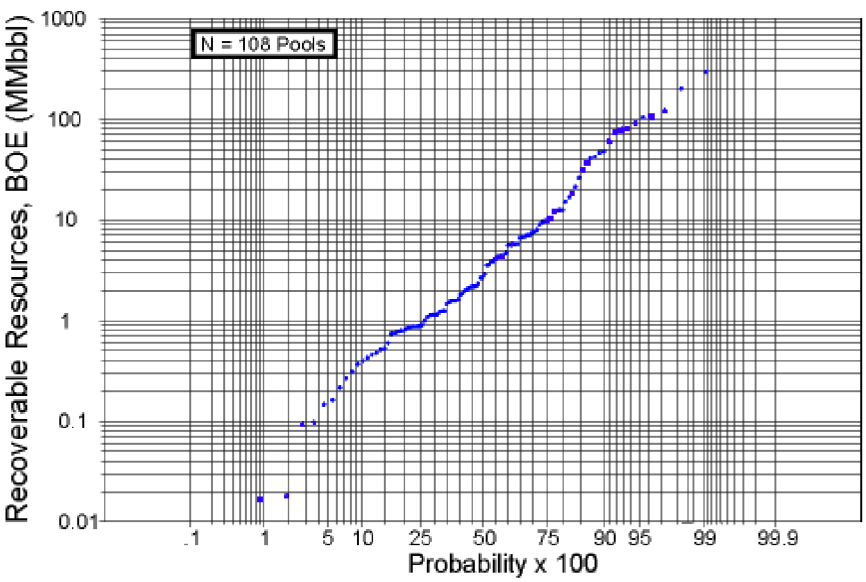


Figure 1. Sample Lognormal Distribution.

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.

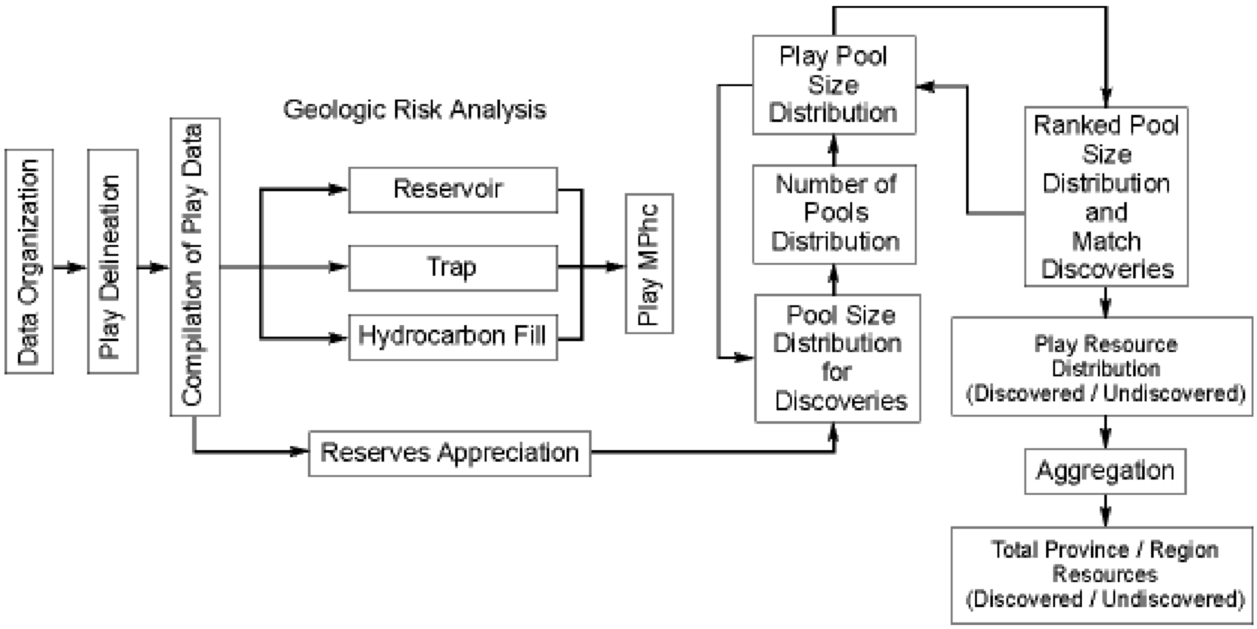


Figure 2. UCRR Process.

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).

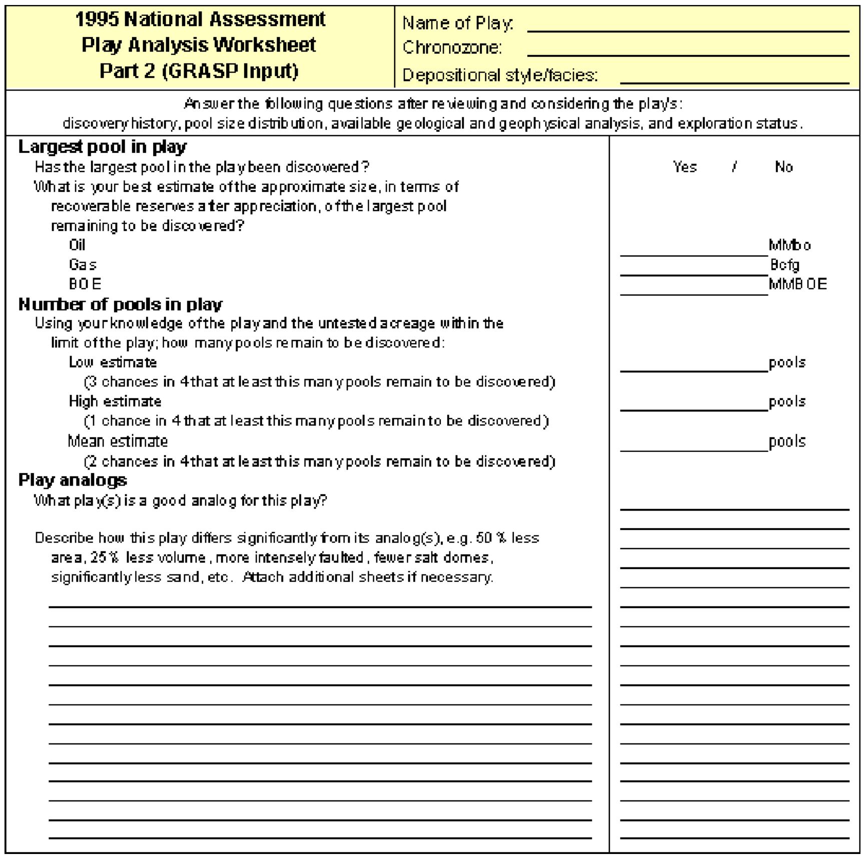
The matching process requires a careful consideration of all available information pertaining to the play: petroleum geology, discovery history, play maturity, etc. (figure 4). Typically this is accomplished by responding to questions such as

- 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?

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.


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).

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

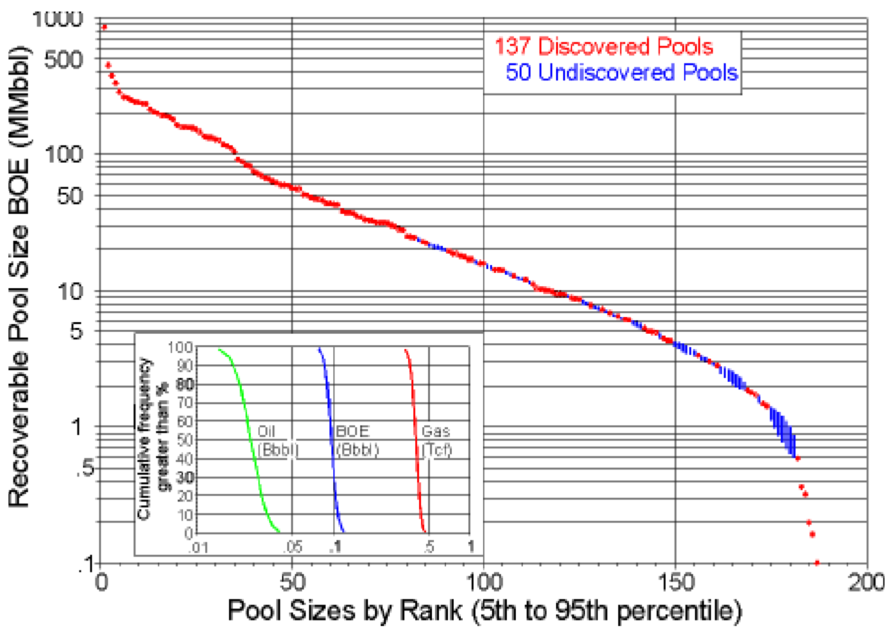


Figure 6. Mature Play Pool Rank Plot.

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.

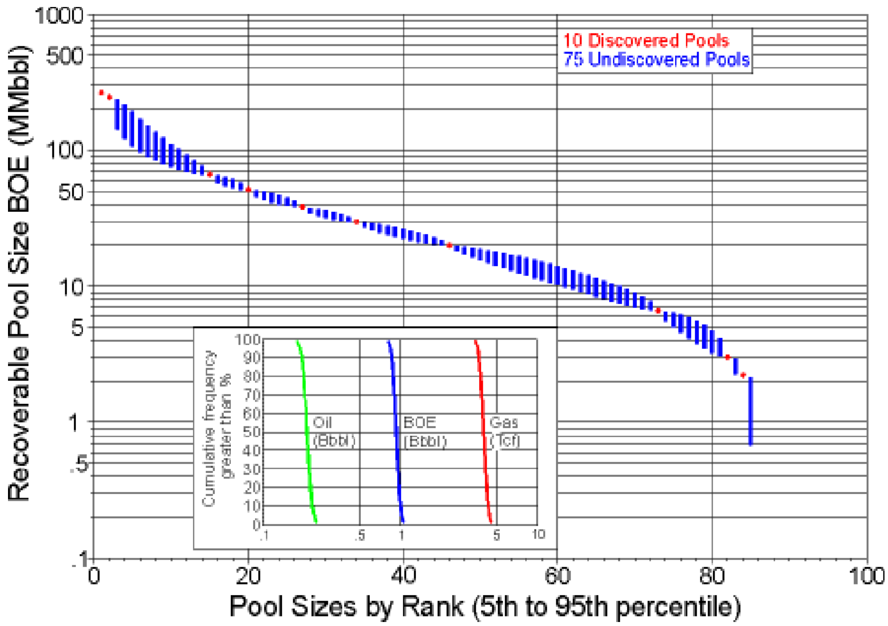


Figure 7. Immature Play Pool Rank Plot.

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

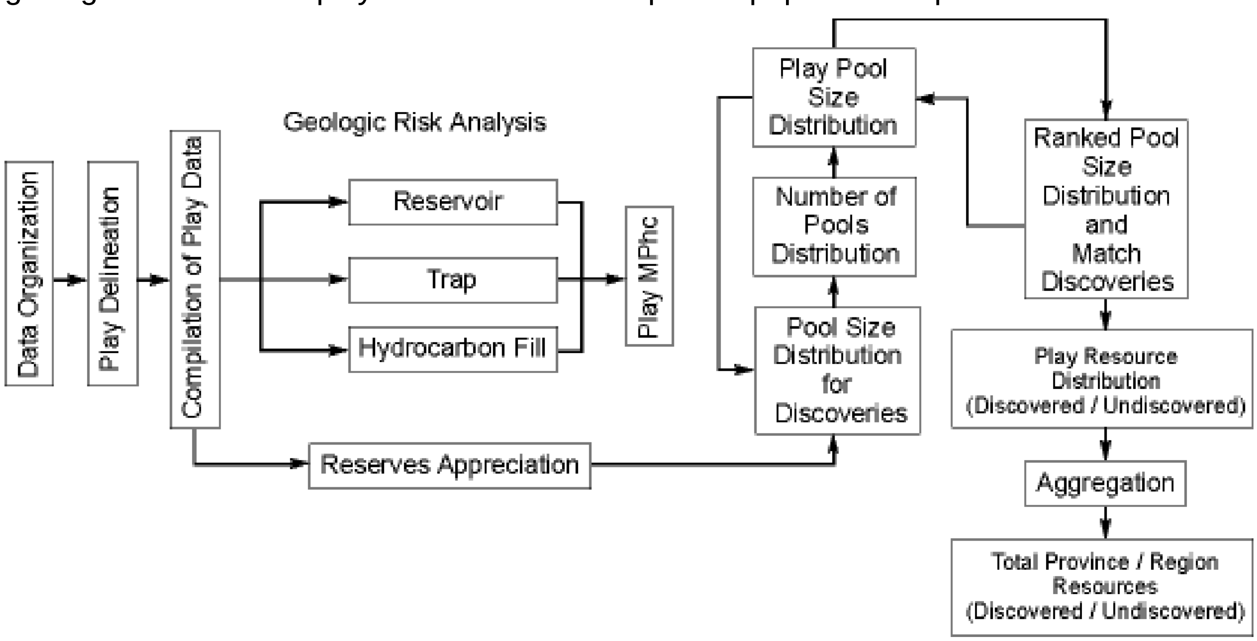


Figure 1. UCRR Process.

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.

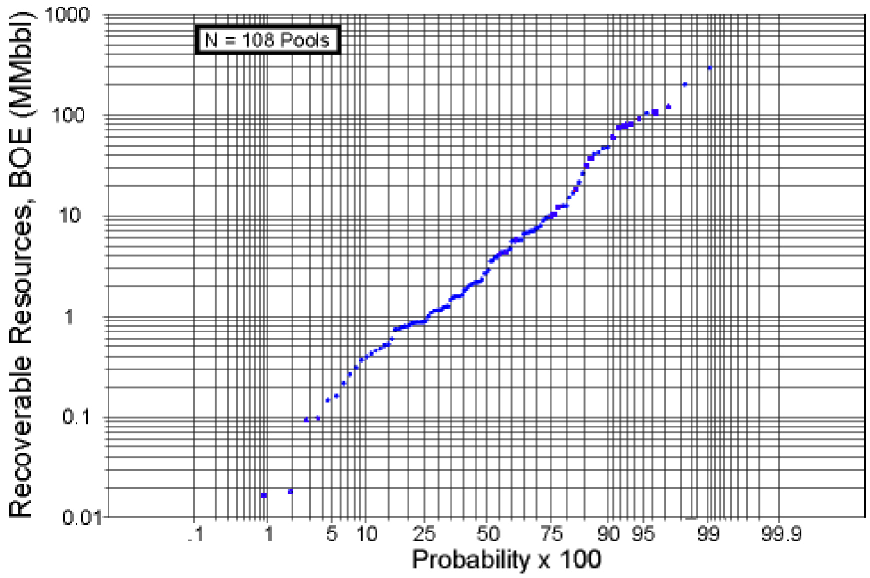


Figure 3. Sample Lognormal Distribution.

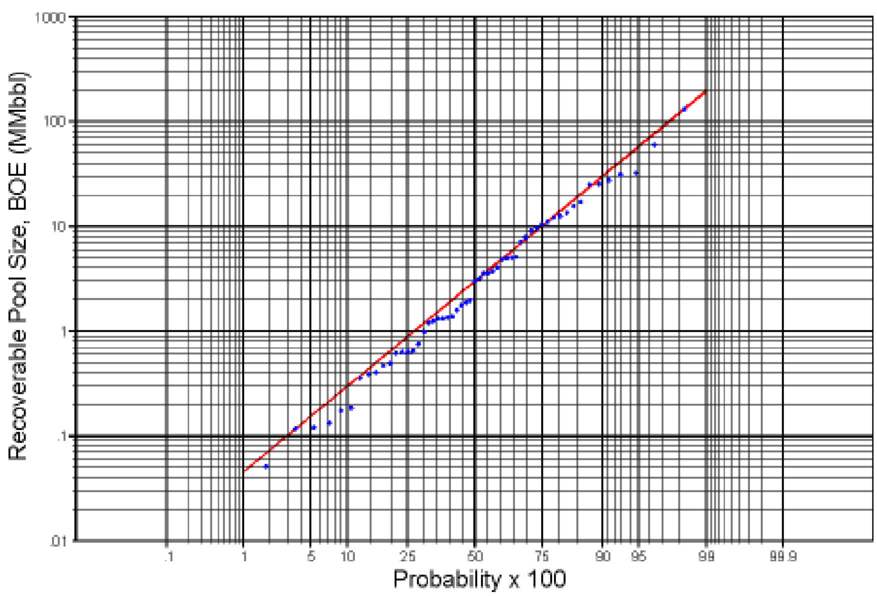


Figure 4. Lognormal Distribution.

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).

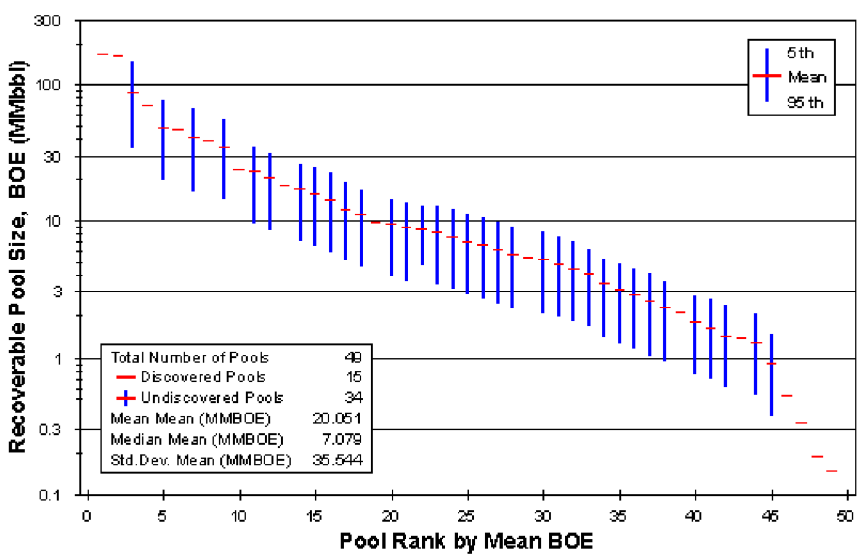


Figure 6. Sample Pool Rank Plot.

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).

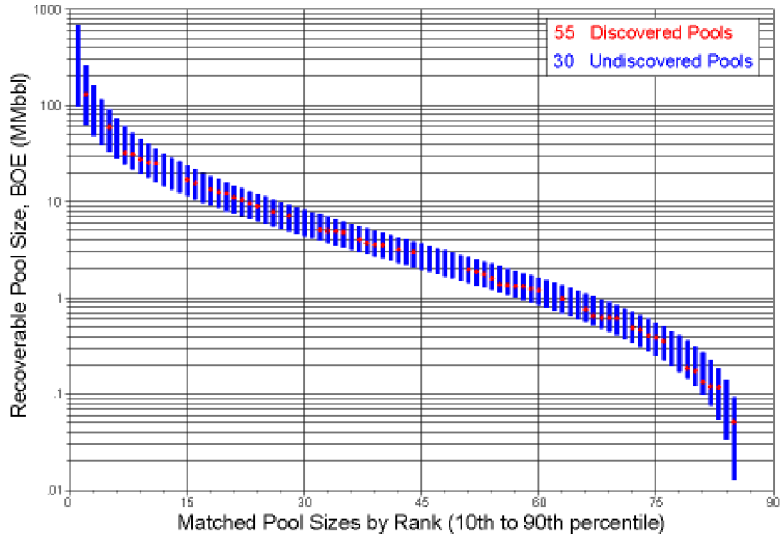


Figure 9. Matched Pool Rank Plot.

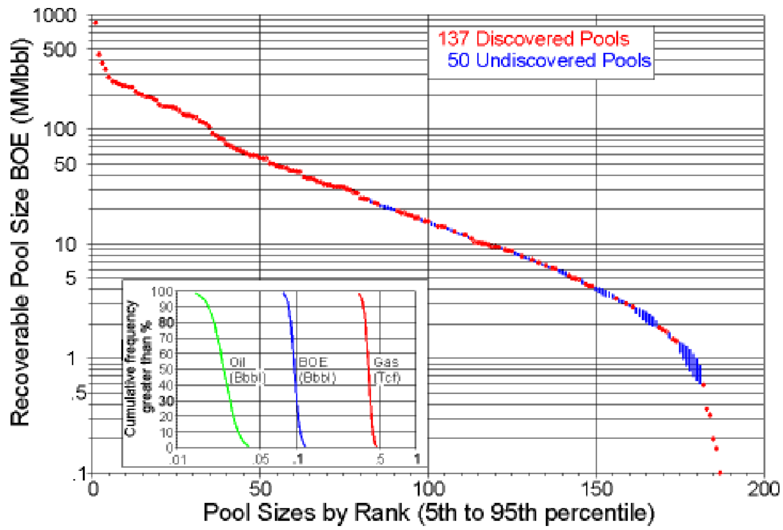


Figure 10. Mature Play Pool Rank Plot.

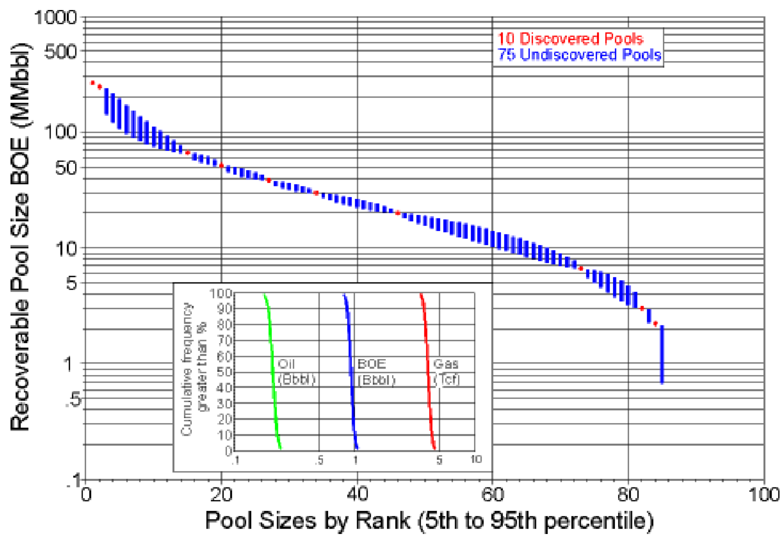


Figure 11. Immature Play Pool Rank Plot.

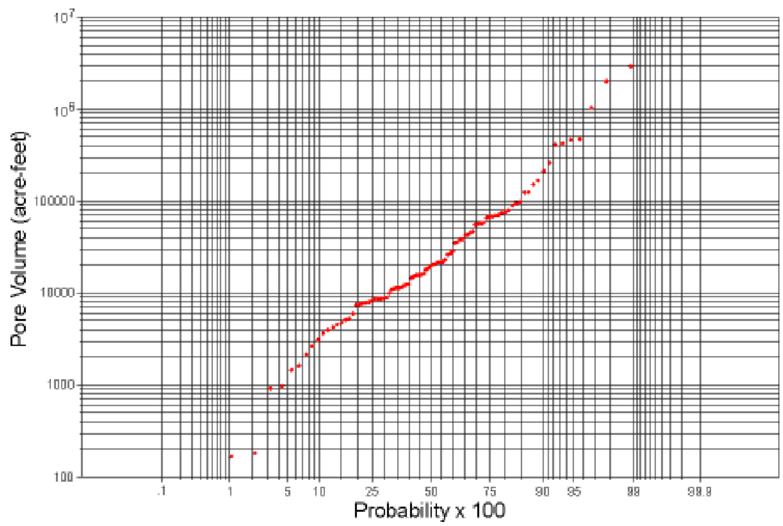


Figure 12. Gulf Coast Analog Pool Size Distribution.

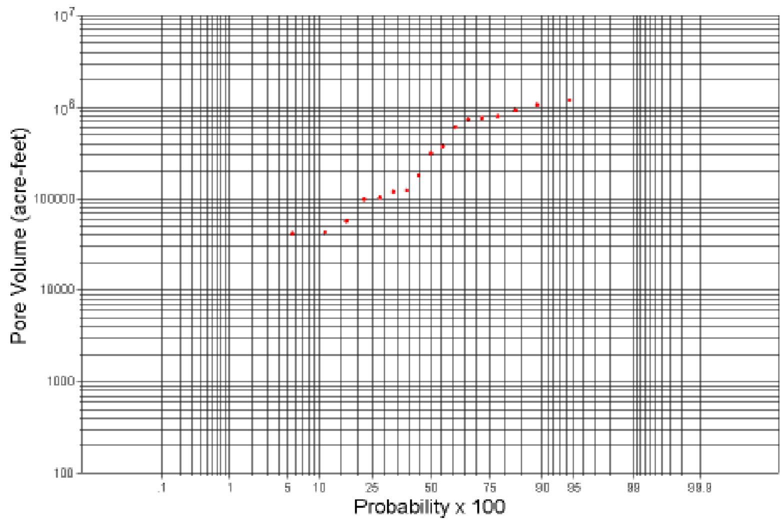


Figure 13. Scotian Shelf Analog Pool Size Distribution.

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

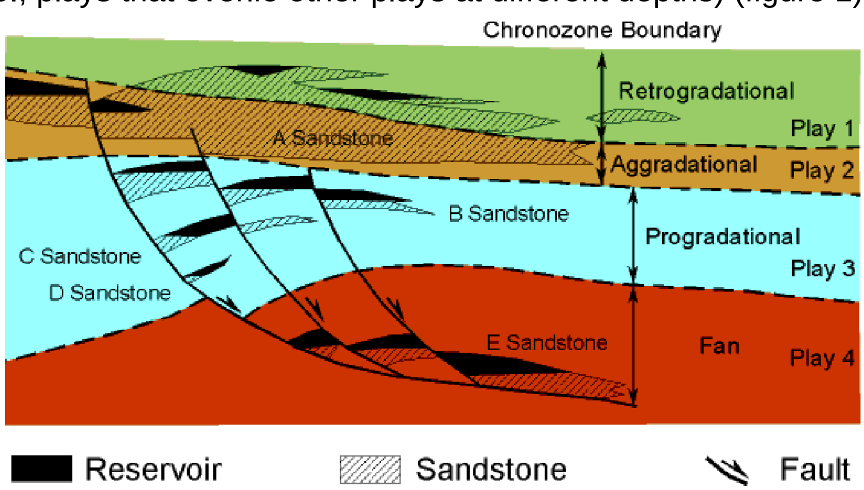


Figure 1. Stacked Plays.

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.

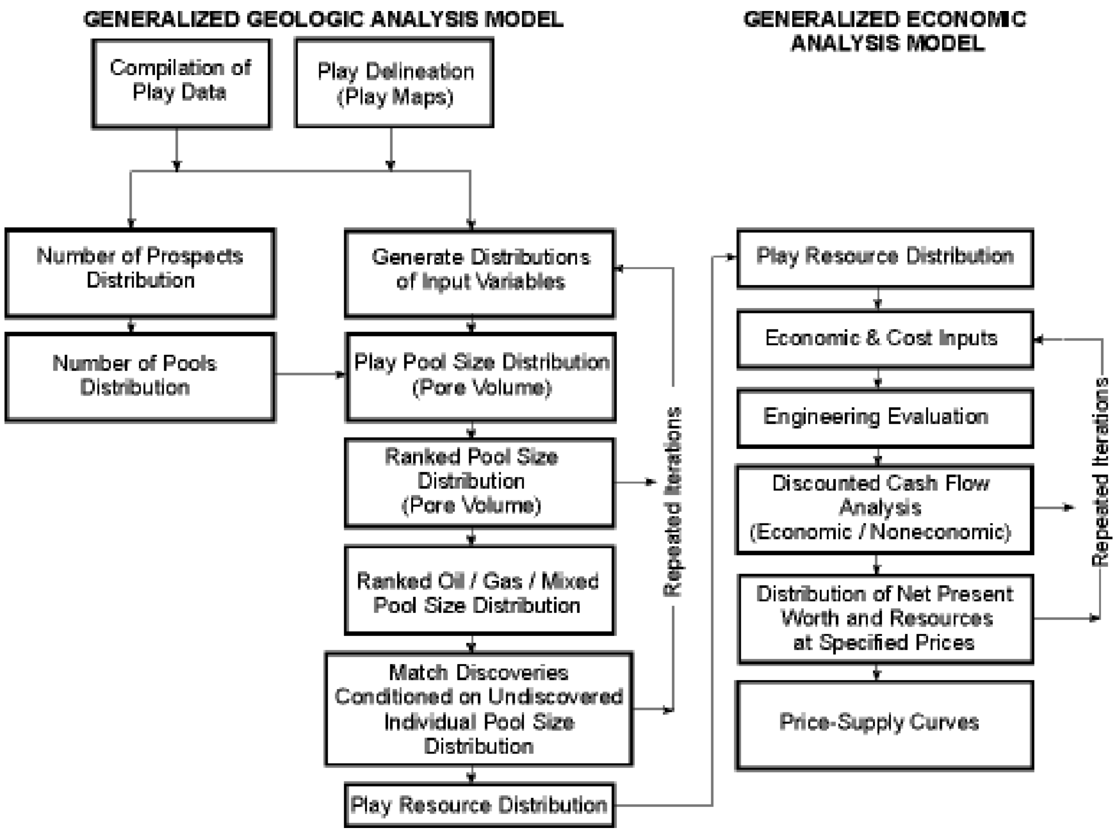


Figure 2. Assessment Process.

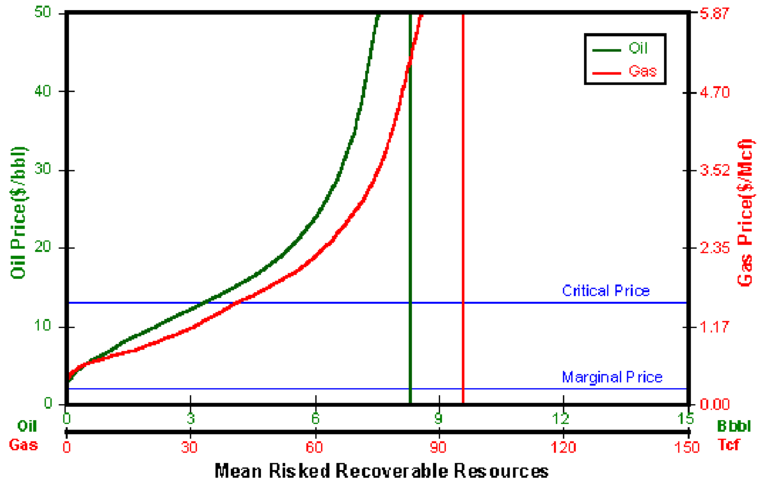


Figure 3. Sample Price-Supply Curve.

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 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.

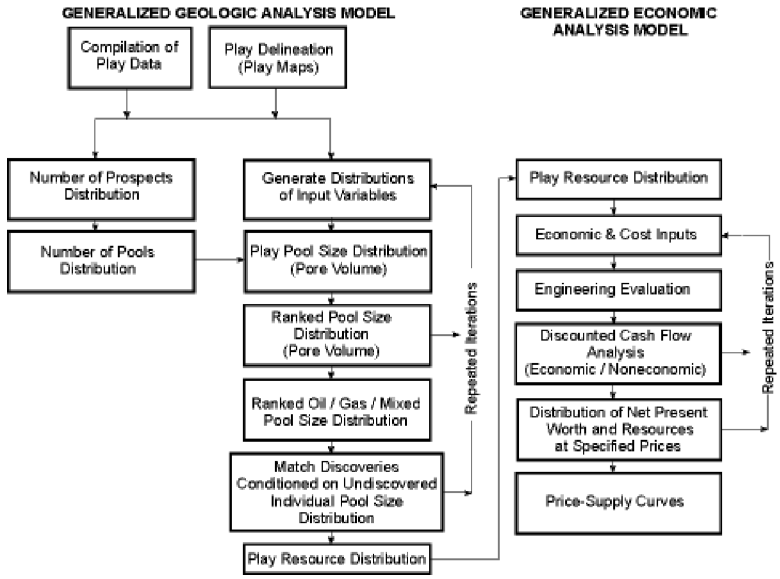


Figure 1. Assessment Process.

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.

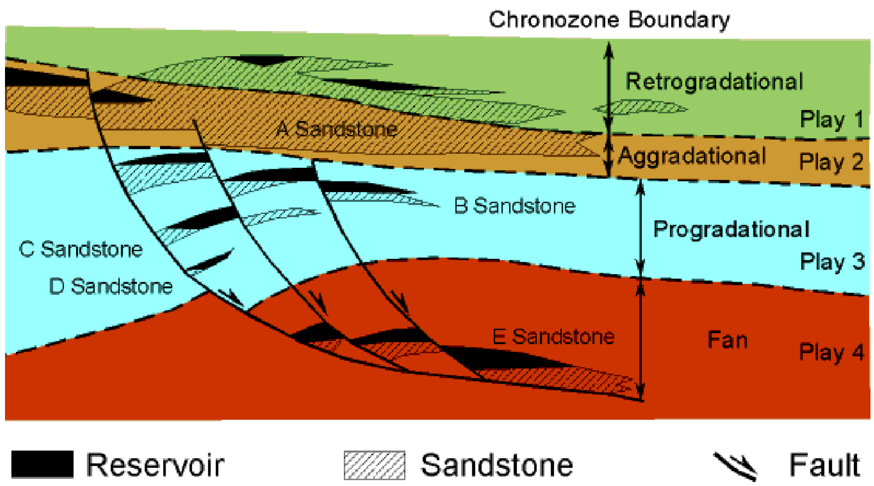
GEOLOGIC INPUTS

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.



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

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).

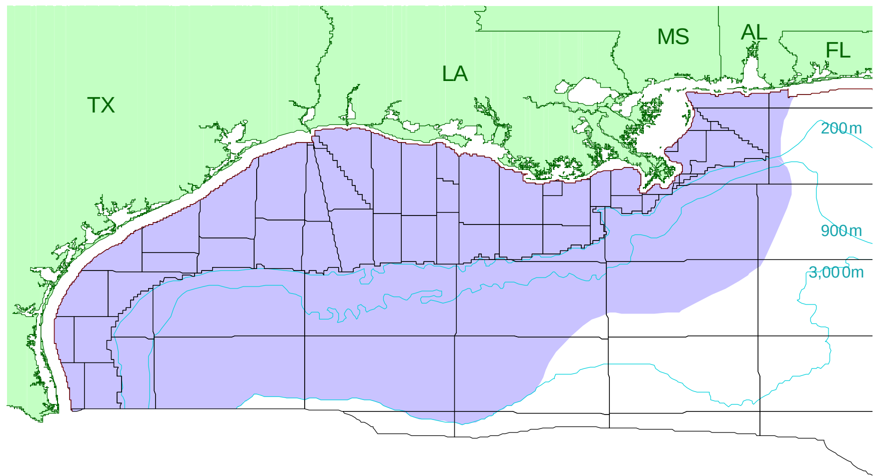


Figure 3. Map of GOM Cenozoic Province (the shaded areas indicate the extent of the assessed plays in the Province).

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.

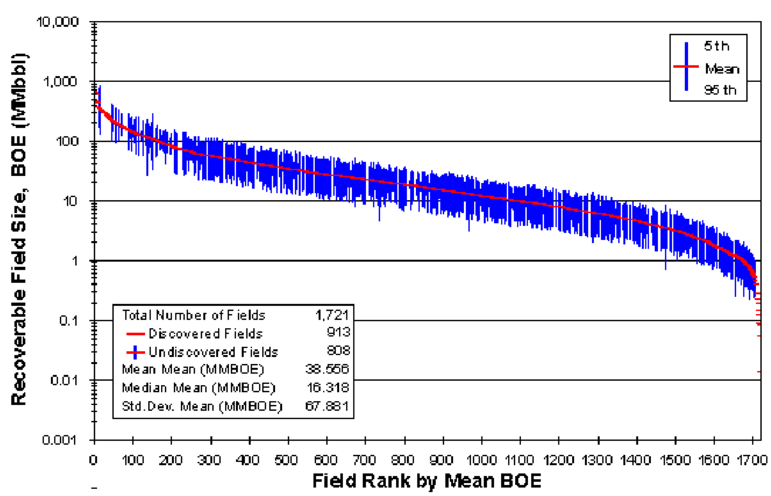


Figure 4. GOM Cenozoic Province Total Field Rank Plot.

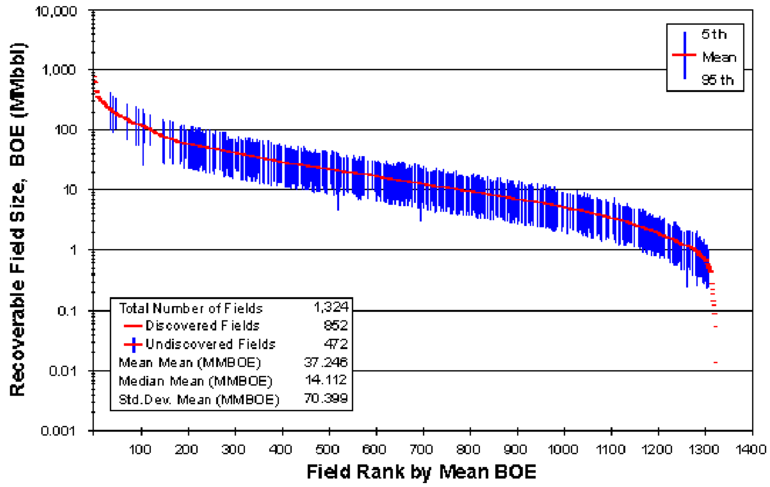


Figure 5. GOM Cenozoic Province 0-200m Field Rank Plot.

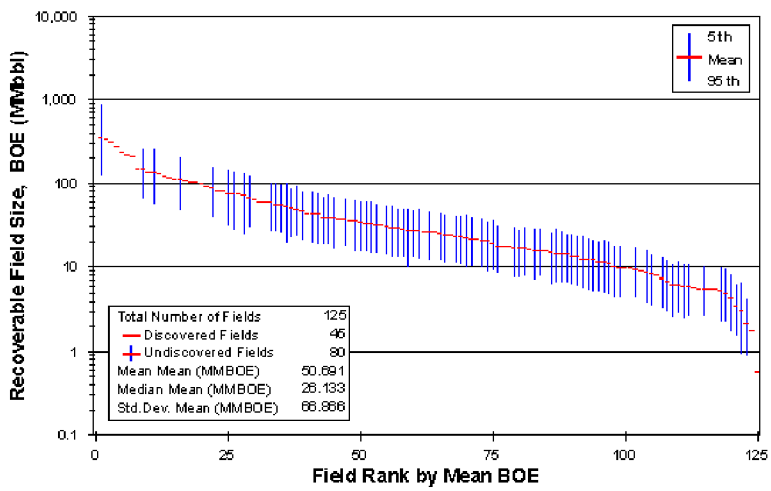


Figure 6. GOM Cenozoic Province 201-900m Field Rank Plot.

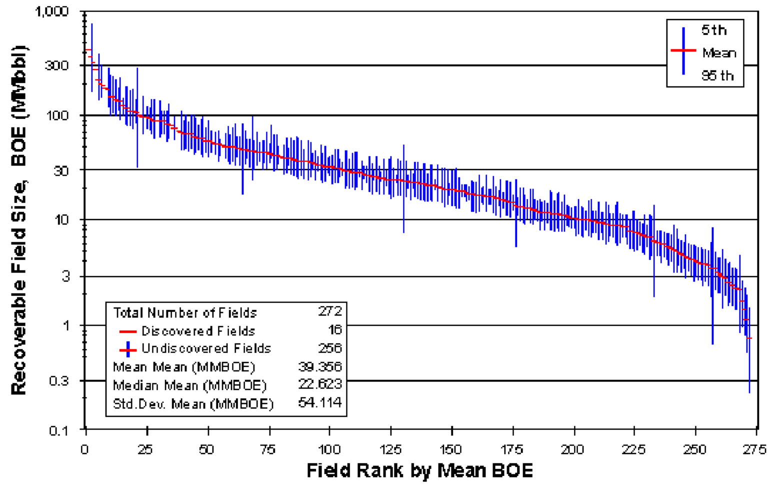


Figure 7. GOM Cenozoic Province 901-3,000m Field Rank Plot.

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.

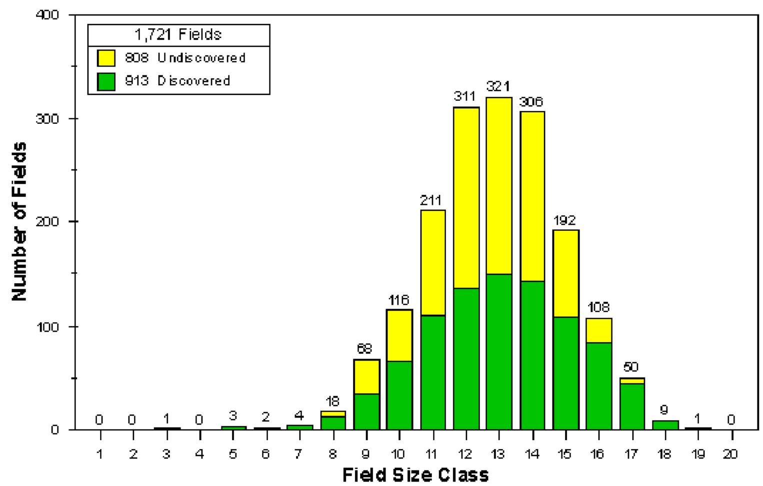


Figure 8. GOM Cenozoic Province Total Field Size Histogram.

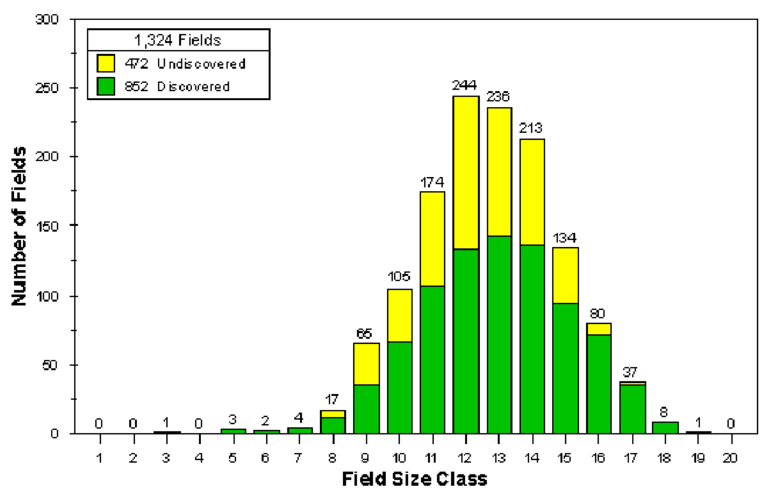


Figure 9. GOM Cenozoic Province 0-200m Field Size Histogram.

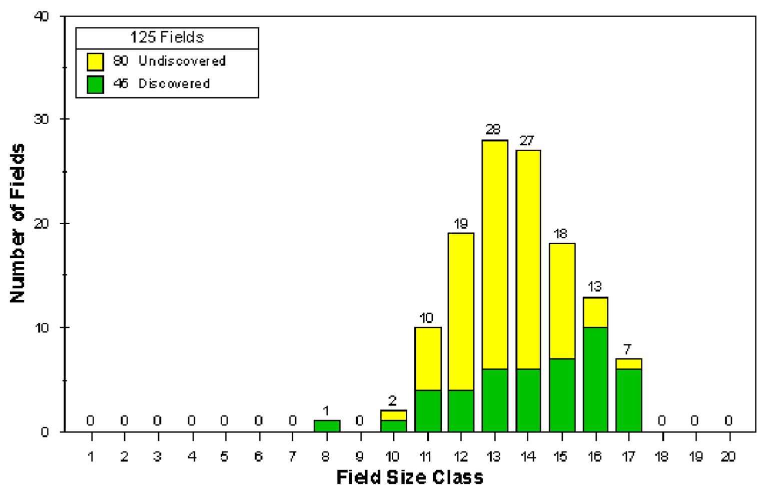


Figure 10. GOM Cenozoic Province 201-900m Field Size Histogram.

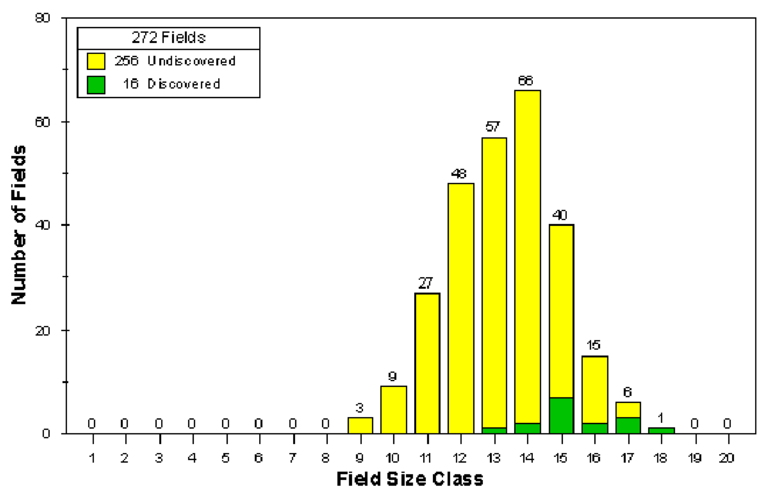


Figure 11. GOM Cenozoic Province 901-3,000m Field Size Histogram.

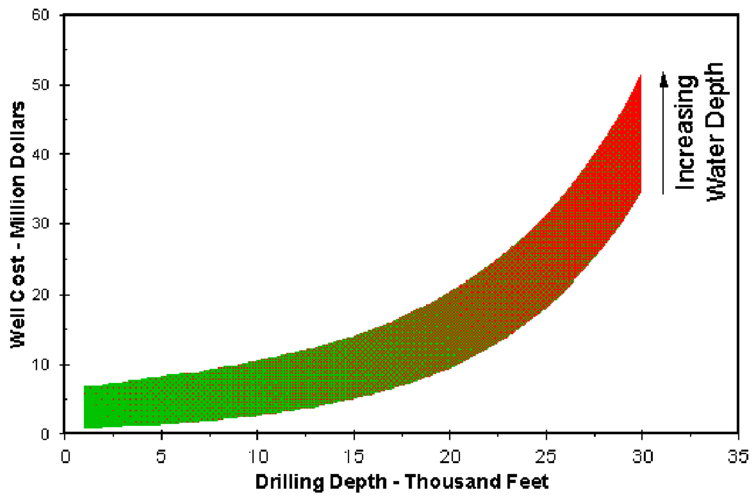


Figure 12. Exploration & Delineation Well Costs.

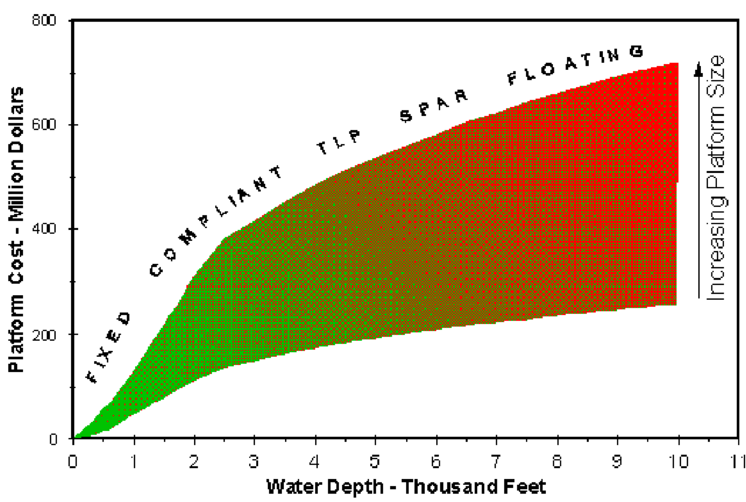


Figure 13. Platform & Production Facility Costs.

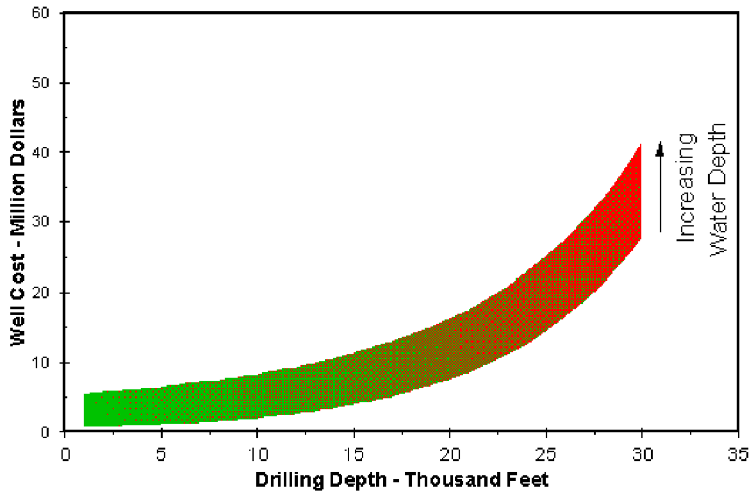


Figure 14. Development Well Costs.

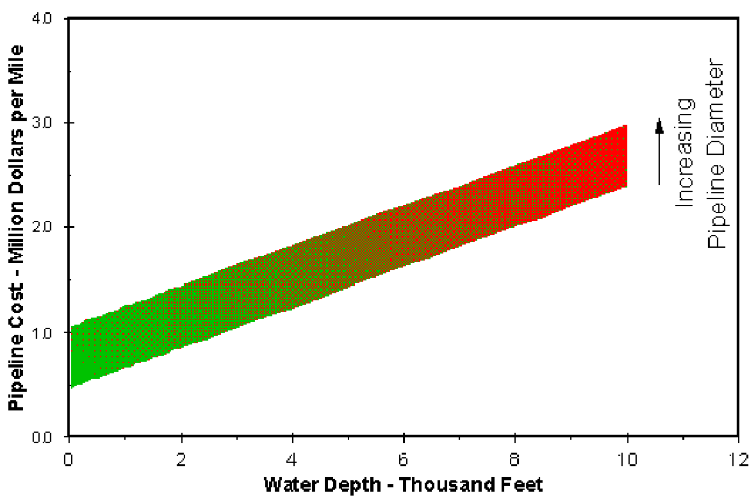


Figure 15. Pipeline Costs.

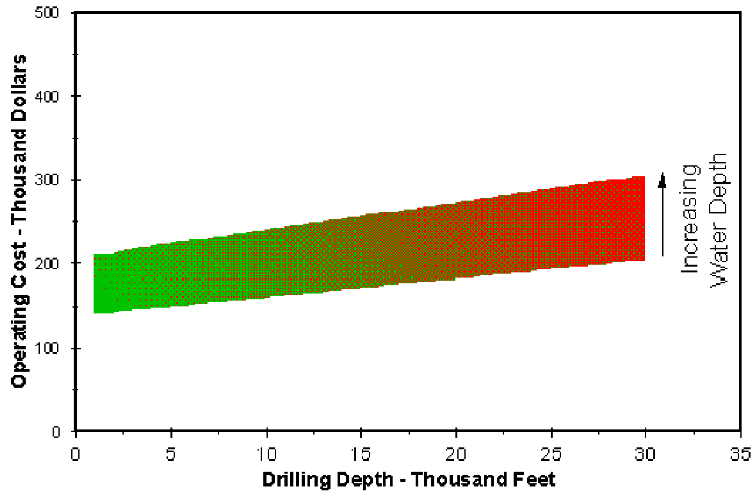


Figure 16. Operating Costs (per well per year).

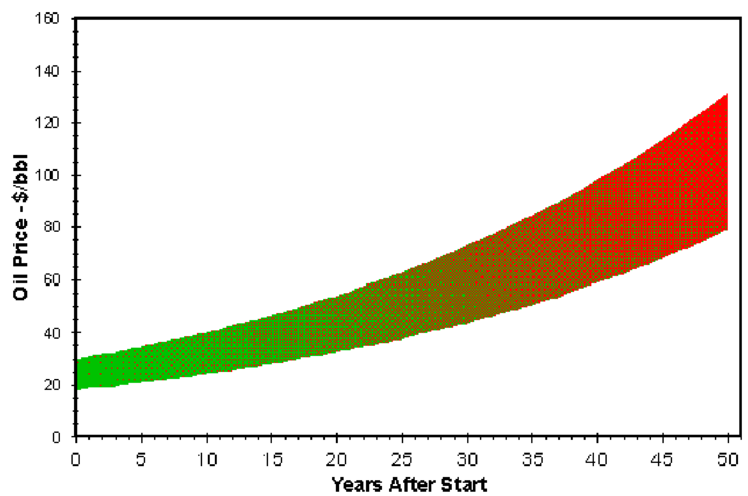


Figure 17. Oil Price Projections.

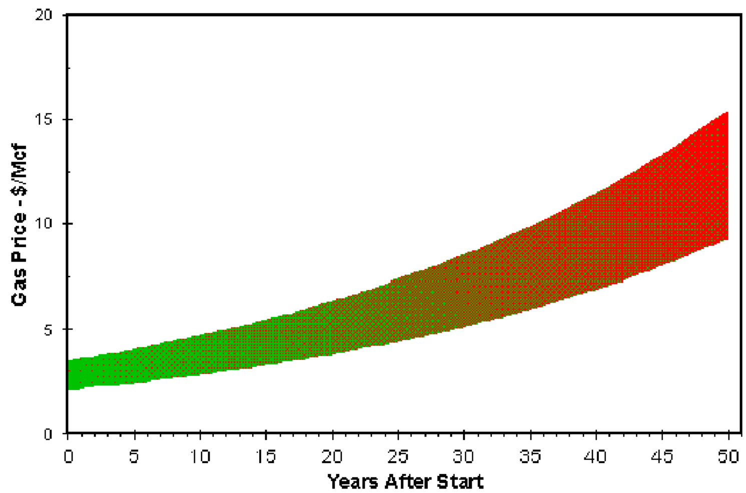


Figure 18. Gas Price Projections.

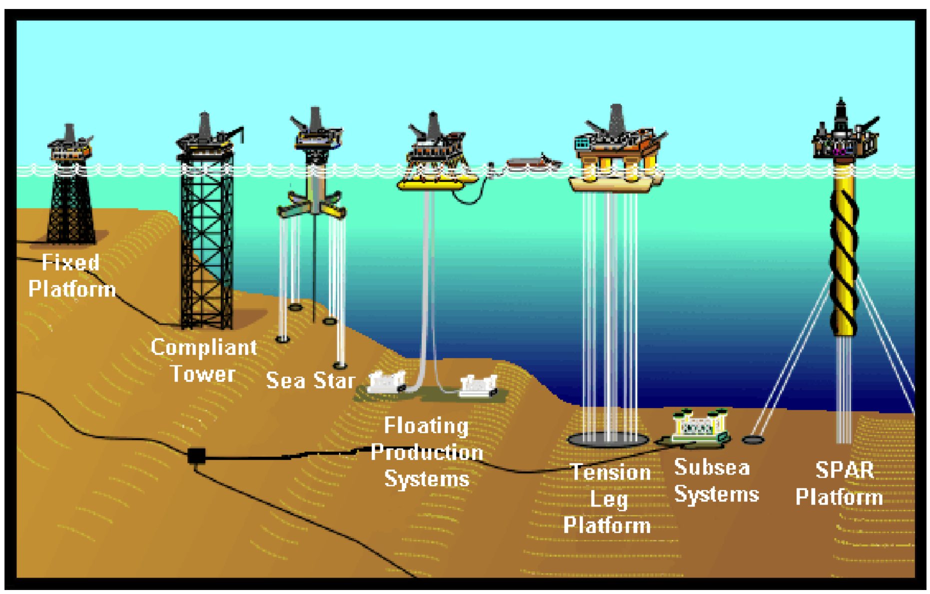


Figure 19. OCS Development Systems.

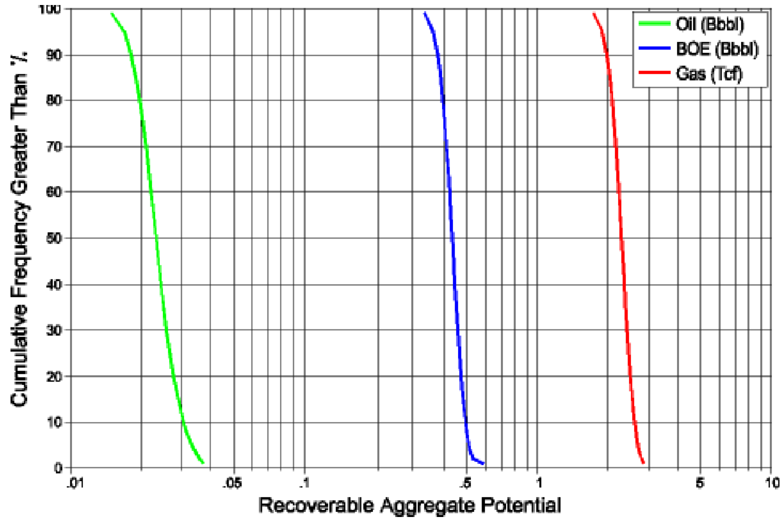


Figure 20. Cumulative Probability Distribution.

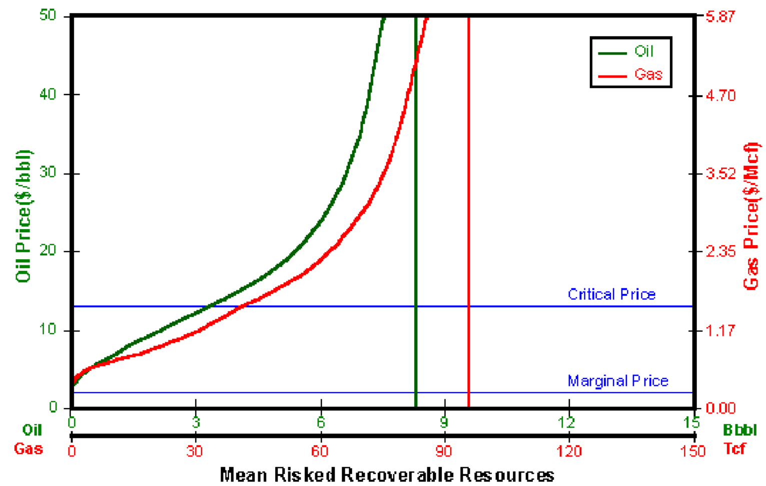


Figure 21. Sample Price-Supply Curve.

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,

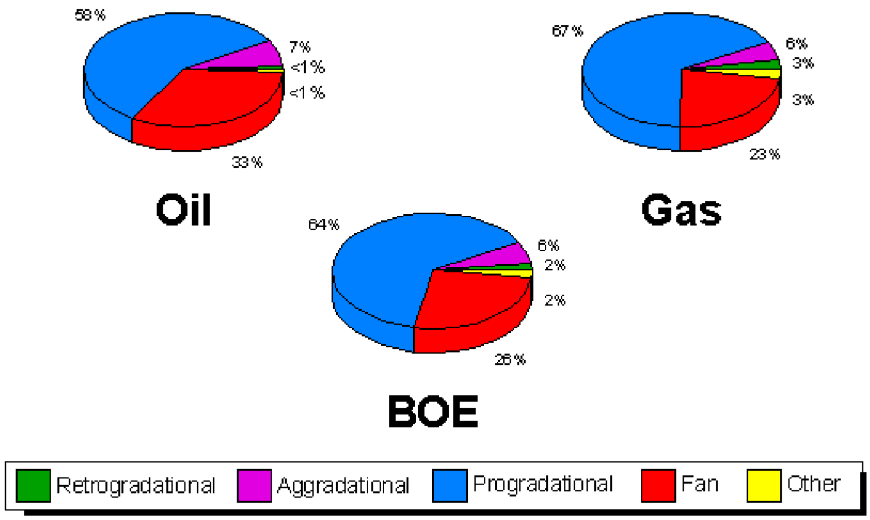


Figure 1. Cenozoic Province Total Reserves by Depositional Style/Facies. The sum of the percentage values may not equal 100 percent due to independent rounding.

	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.

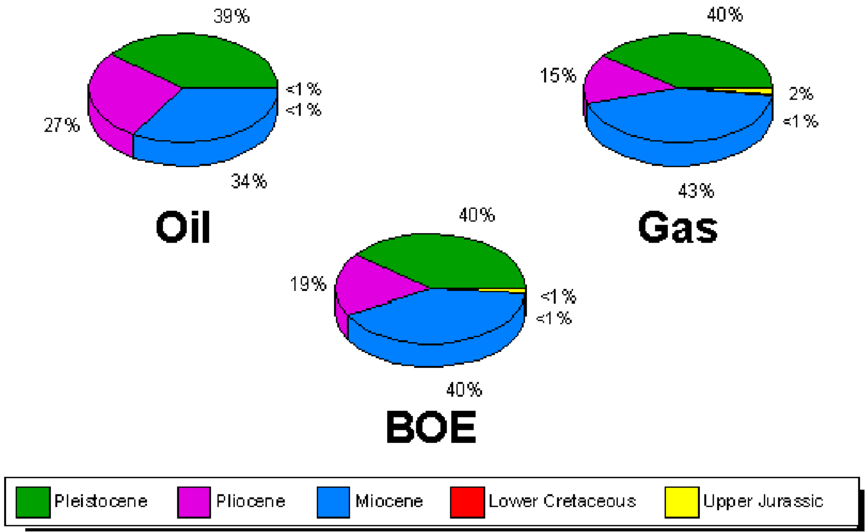


Figure 3. Gulf of Mexico Region Total Reserves by Geologic Age. The sum of the percentage values may not equal 100 percent due to independent rounding.

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.

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 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*
~139.0		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.

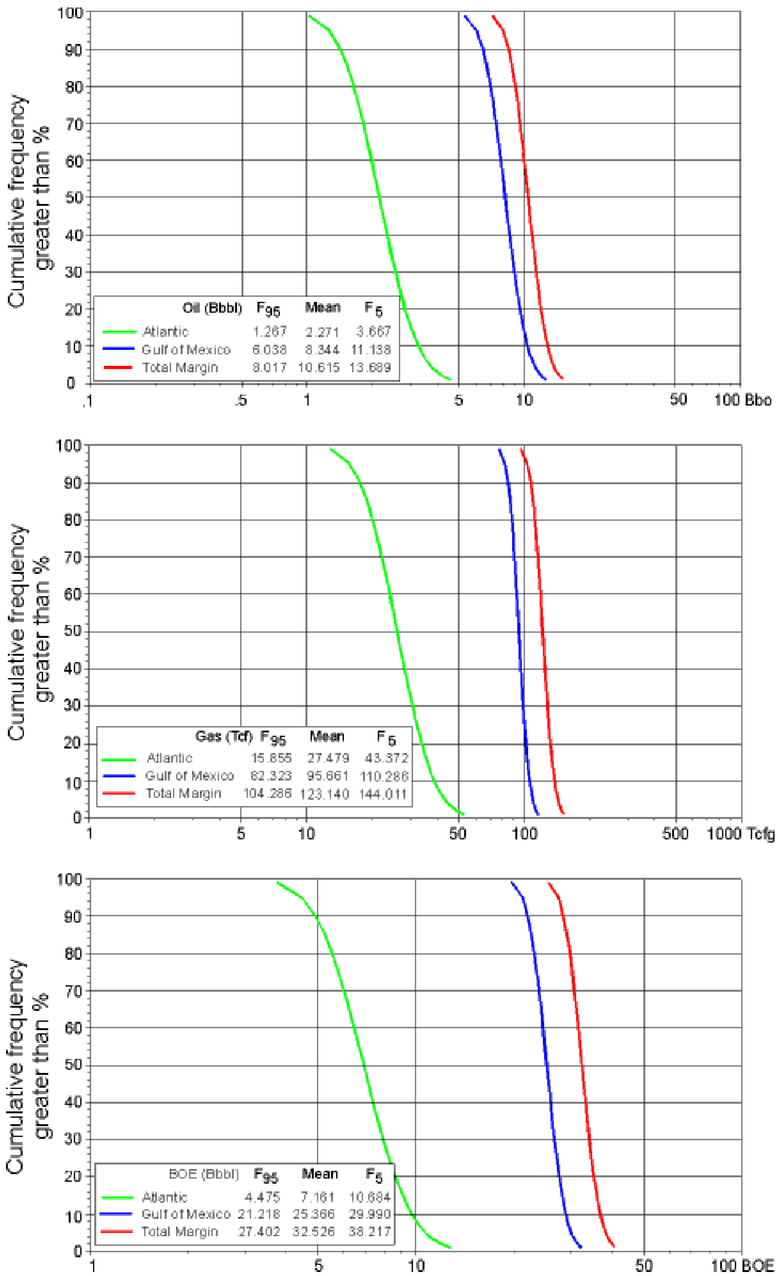


Figure 1. Gulf of Mexico and Atlantic Margin Undiscovered Conventionally Recoverable Resources.

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).

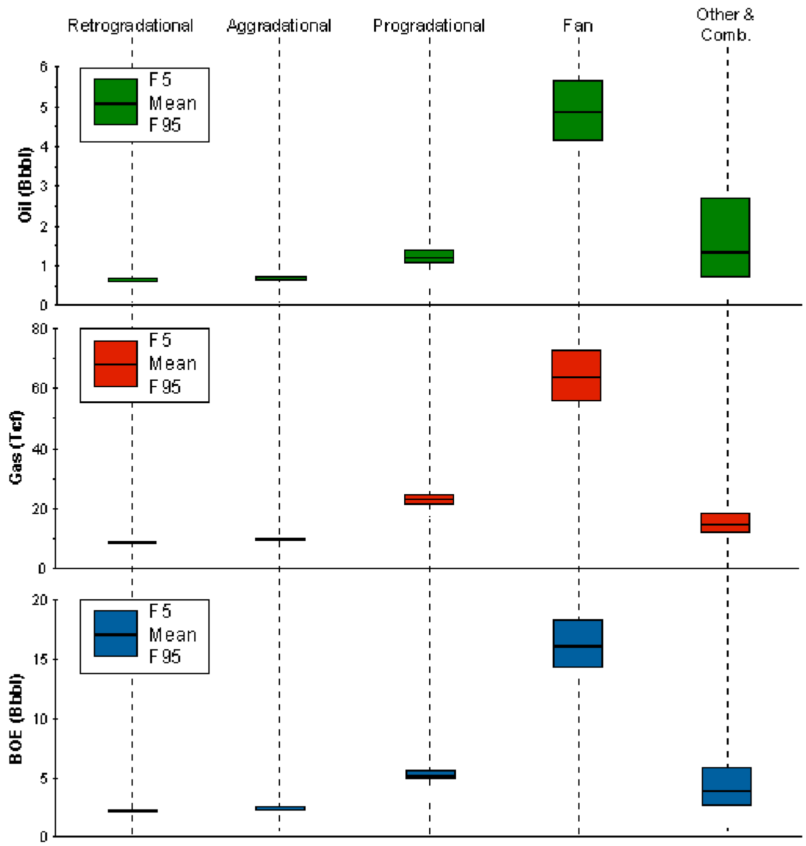


Figure 2. Cenozoic Province Undiscovered Conventionally Recoverable Resources by Depositional Style/Facies.

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).

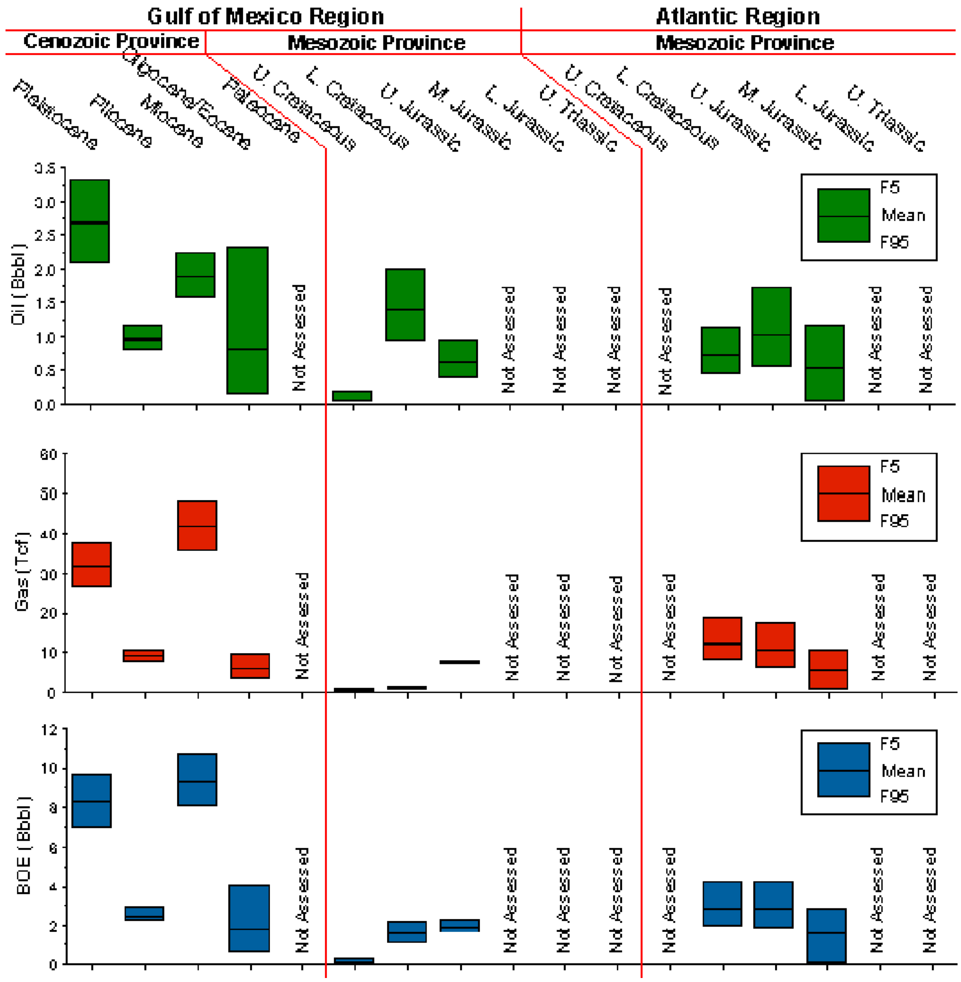


Figure 3. Gulf of Mexico and Atlantic Margin Undiscovered Conventionally Recoverable Resources by Geologic Age.

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).

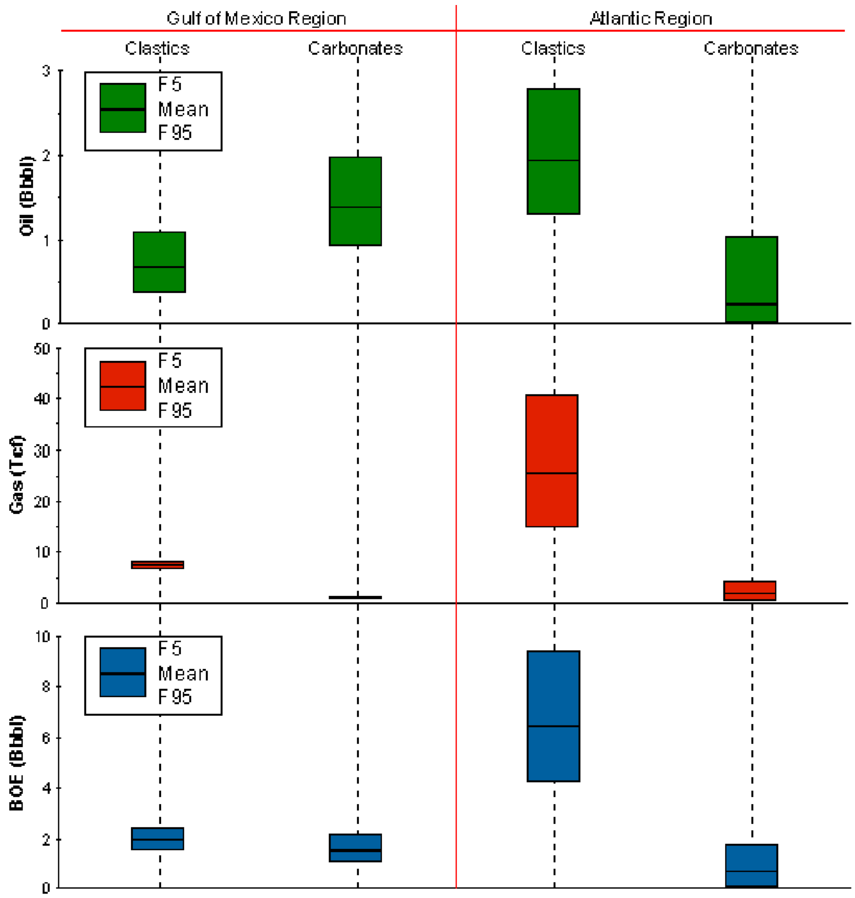


Figure 4. Mesozoic Provinces Undiscovered Conventionally Recoverable Resources by Lithology.

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,

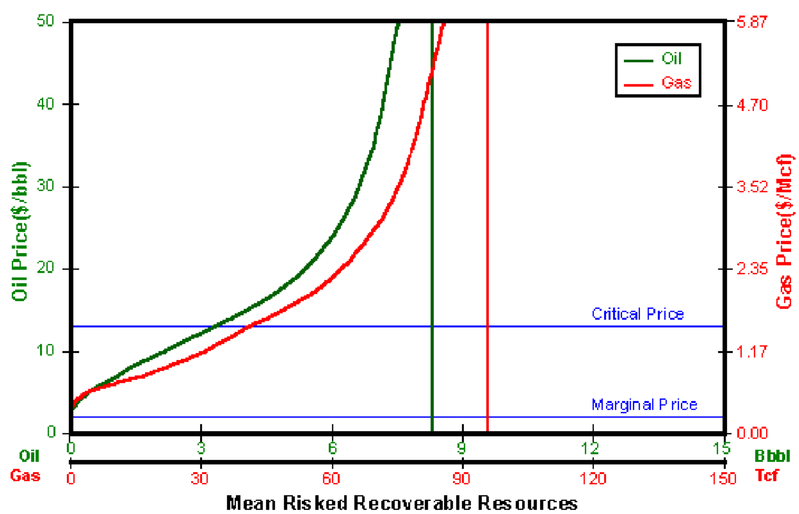


Figure 1. Gulf of Mexico Region Full-Cycle Price-Supply Curve.

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.

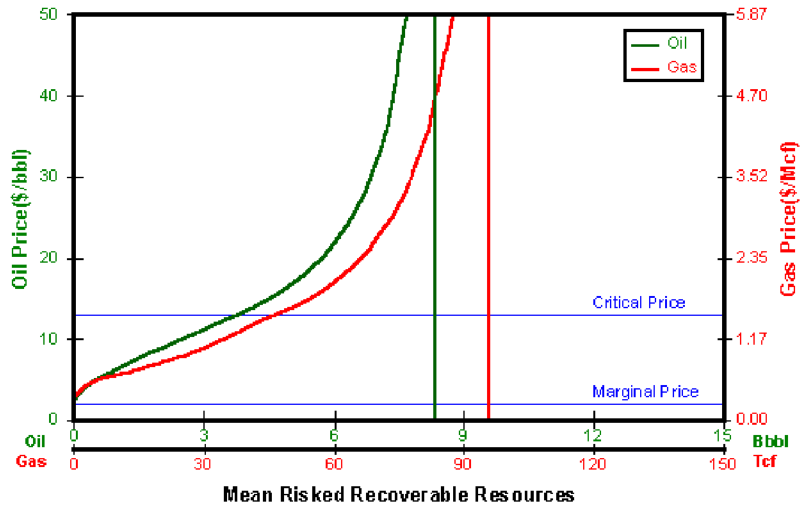


Figure 2. Gulf of Mexico Region Half-Cycle Price-Supply Curve.

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

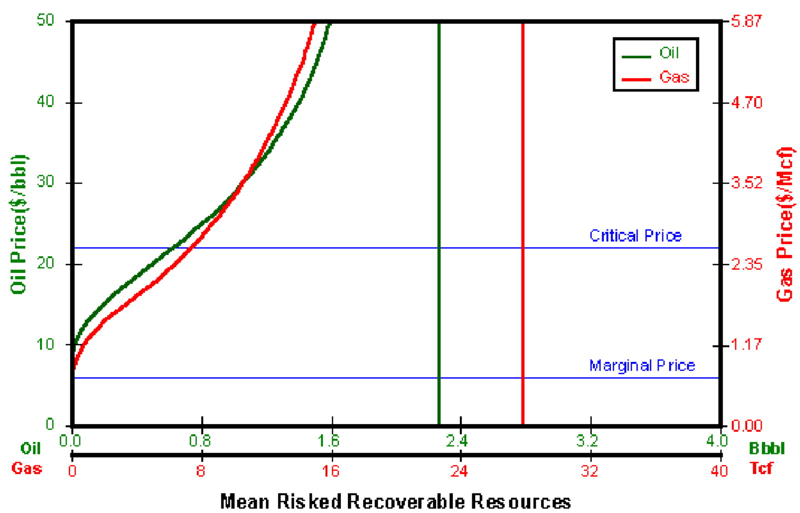


Figure 3. Atlantic Region Full-Cycle Price-Supply Curve.

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.

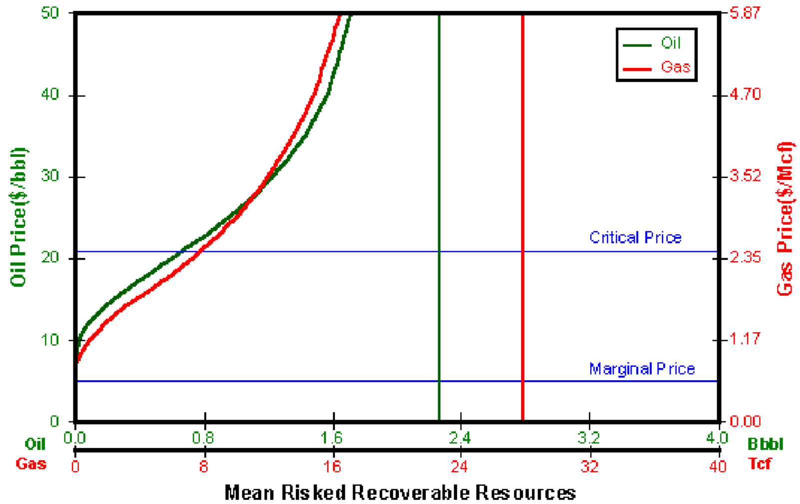


Figure 4. Atlantic Region Half-Cycle Price-Supply Curve.

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.

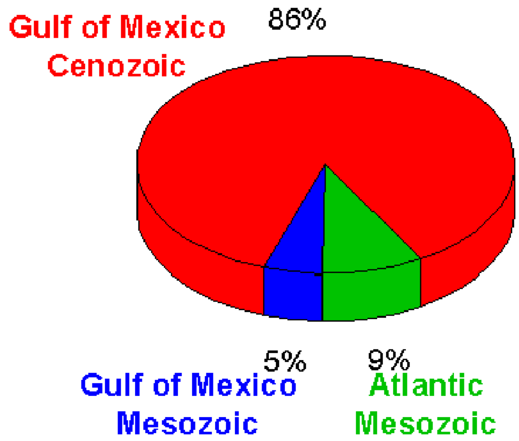


Figure 1. Gulf of Mexico and Atlantic Margin Mean Total Endowment by Geologic Age.

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

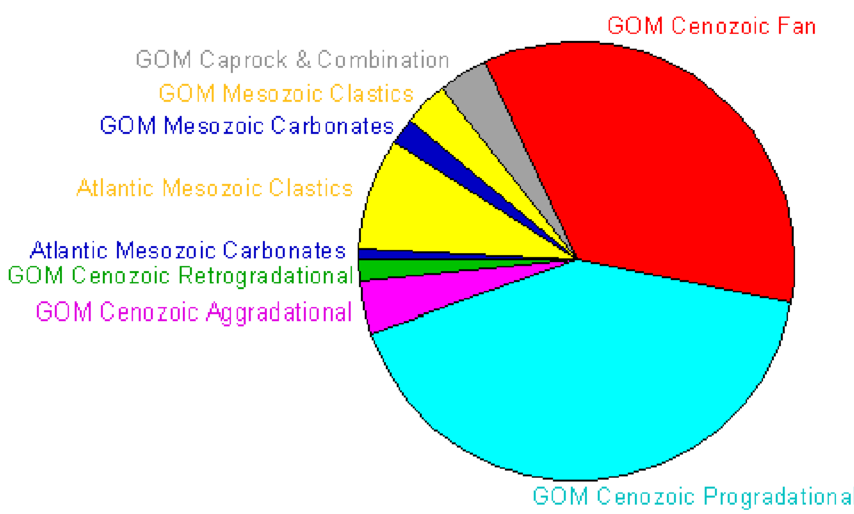


Figure 2. Gulf of Mexico and Atlantic Margin Mean Total Endowment by Depositional Style/Facies.

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).

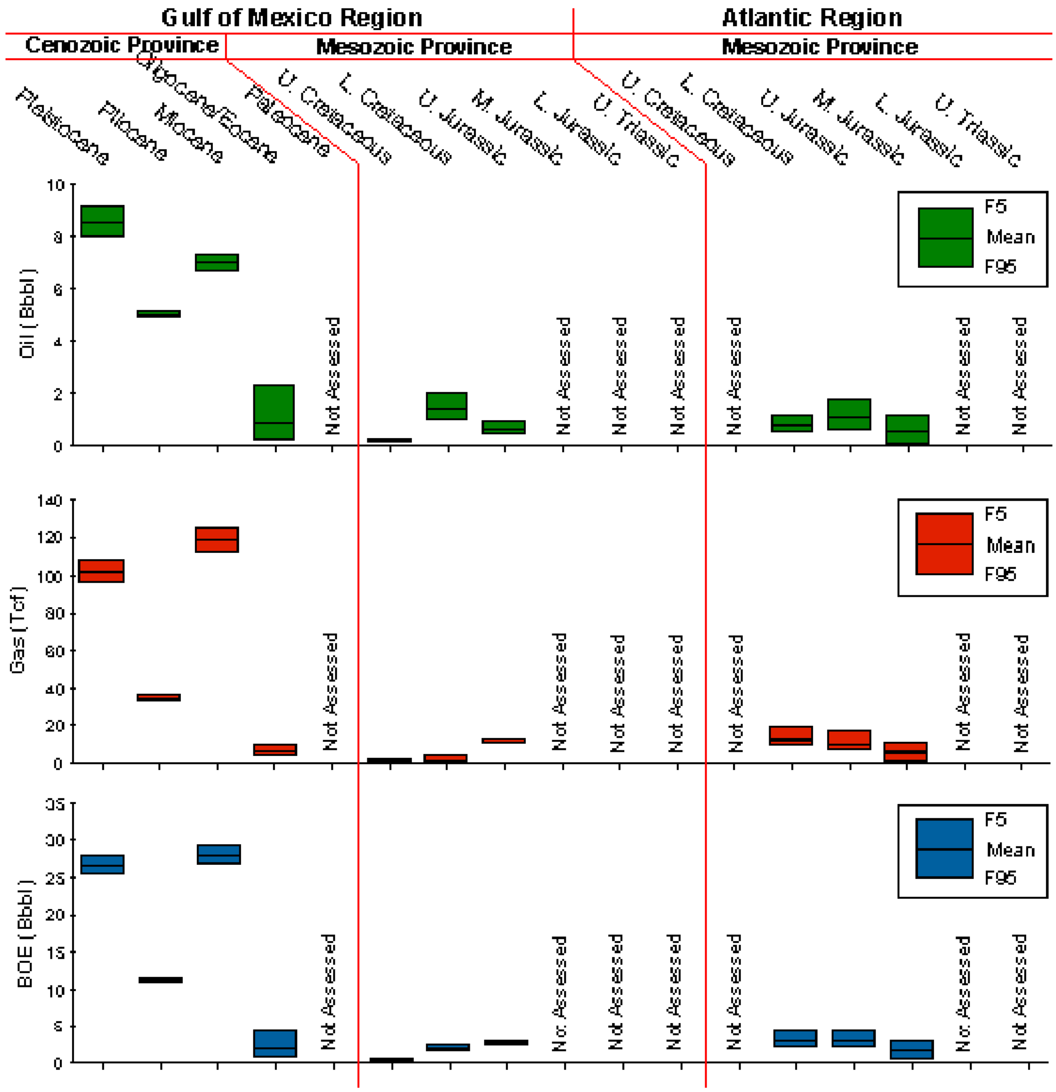


Figure 3. Gulf of Mexico and Atlantic Margin Total Endowment Range by Geologic Age.

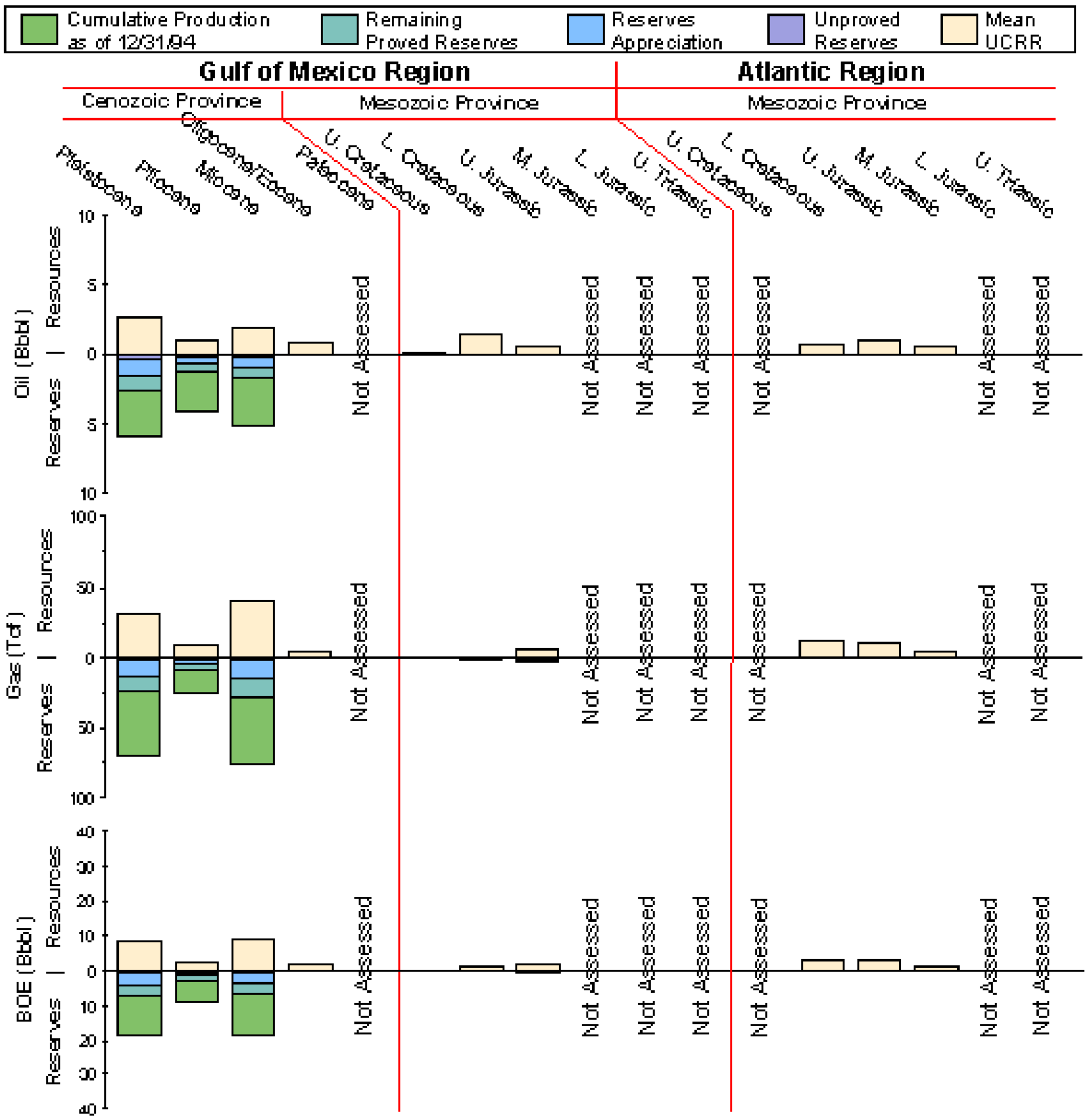


Figure 4. Gulf of Mexico and Atlantic Margin Mean Total Endowment by Geologic Age.

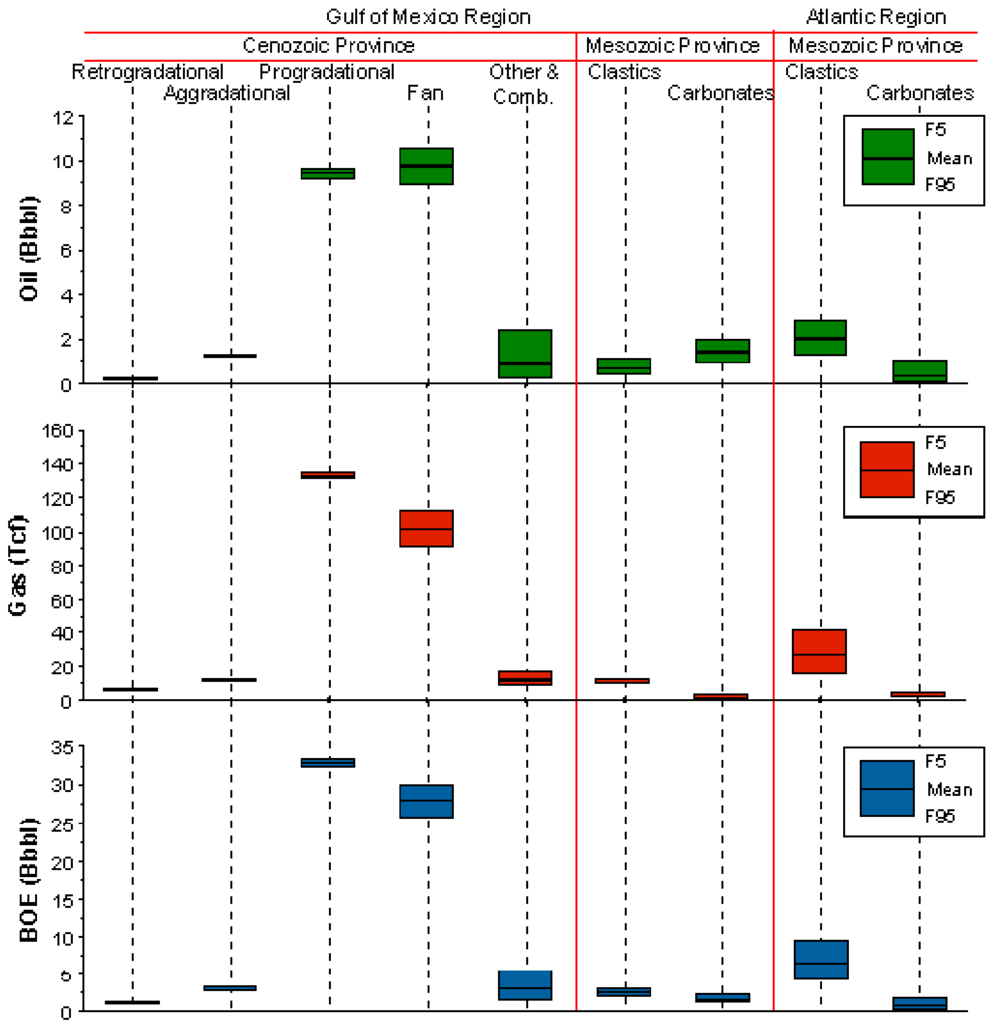


Figure 5. Gulf of Mexico and Atlantic Margin Total Endowment Range by Depositional Style/Facies.

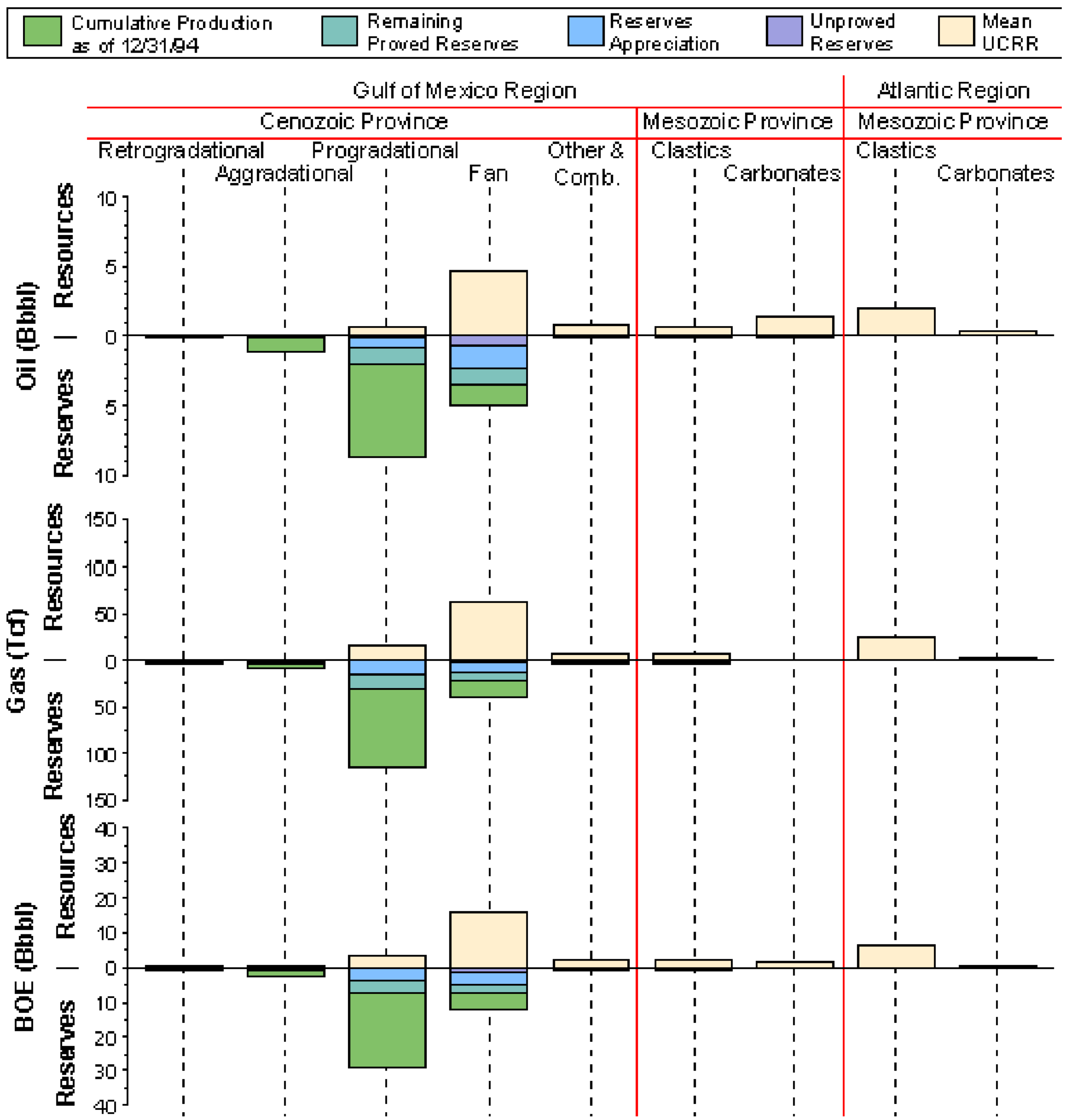


Figure 6. Gulf of Mexico and Atlantic Margin Mean Total Endowment by Depositional Style/Facies.

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).

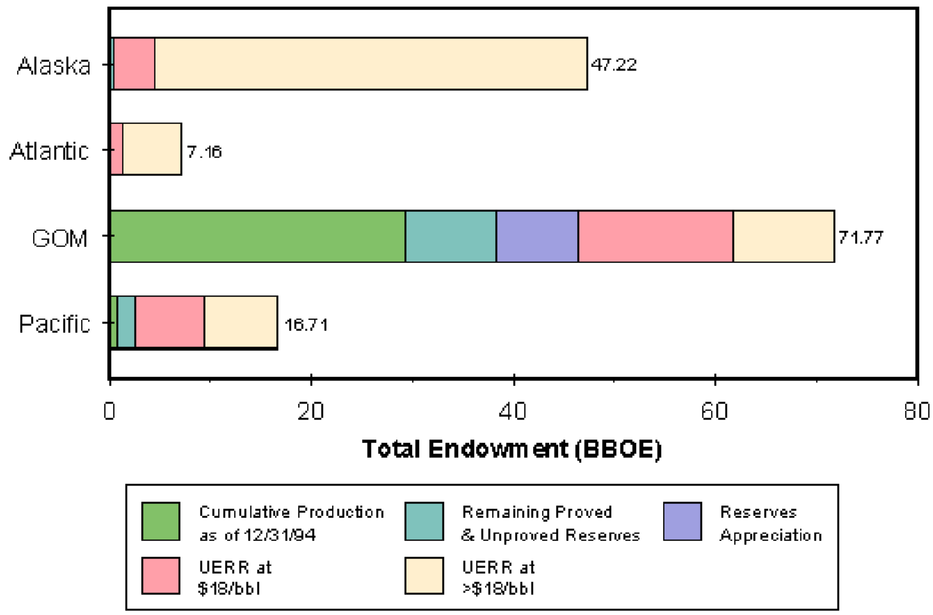


Figure 1. Total Endowment of the OCS Regions by Resource Category (Mean Full-Cycle Analysis).

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 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.

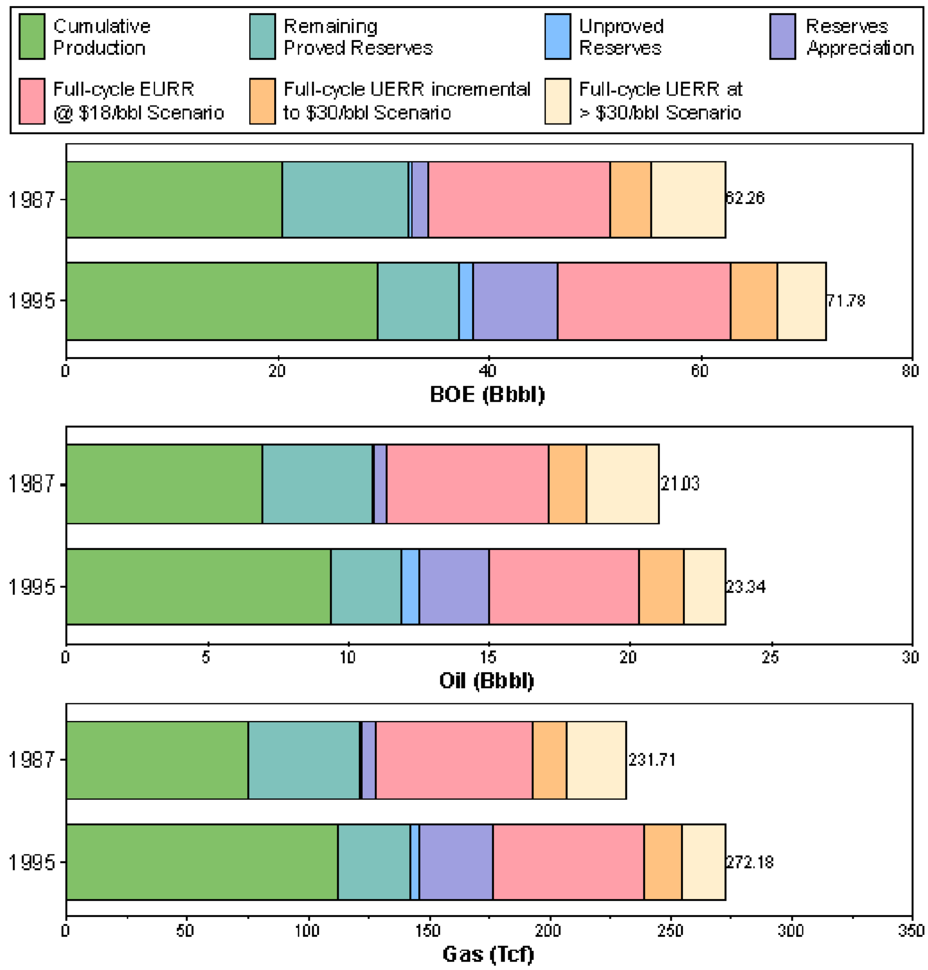


Figure 1. Gulf of Mexico Region Comparison of 1987 and 1995 Resource Assessment.

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.

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.

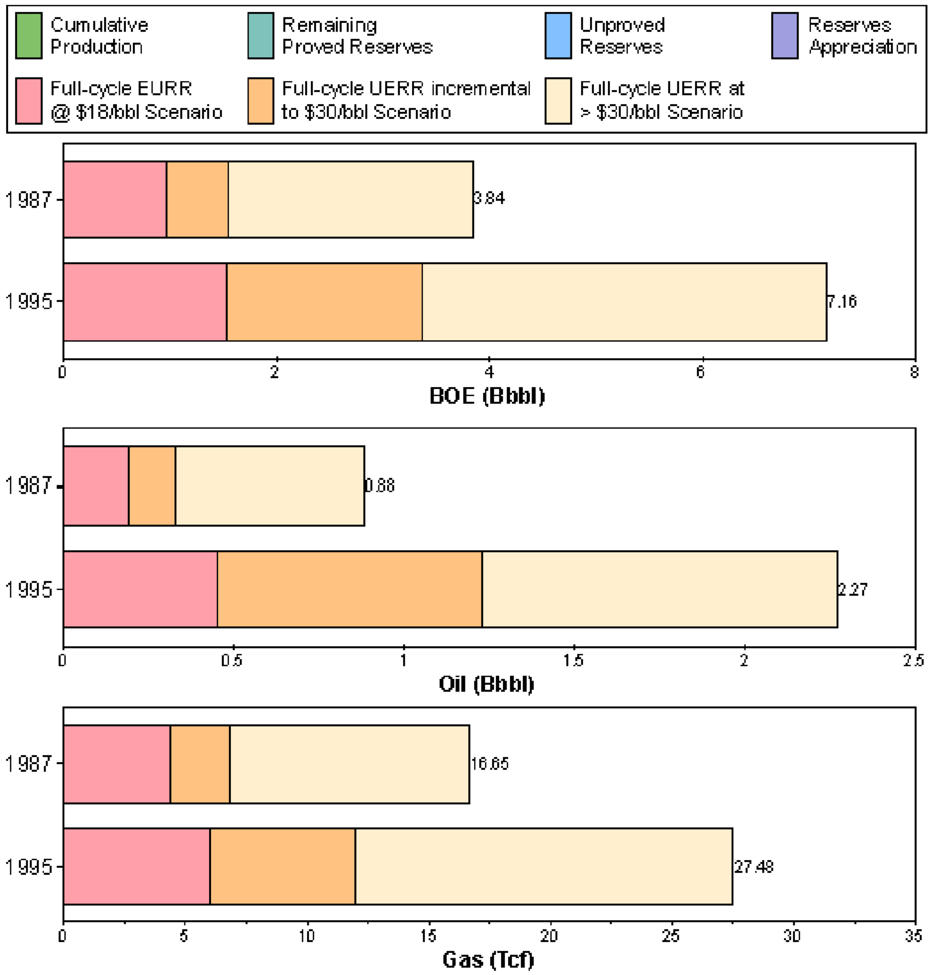


Figure 2. Atlantic Region Comparison of 1987 and 1995 Resource Assessment.

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

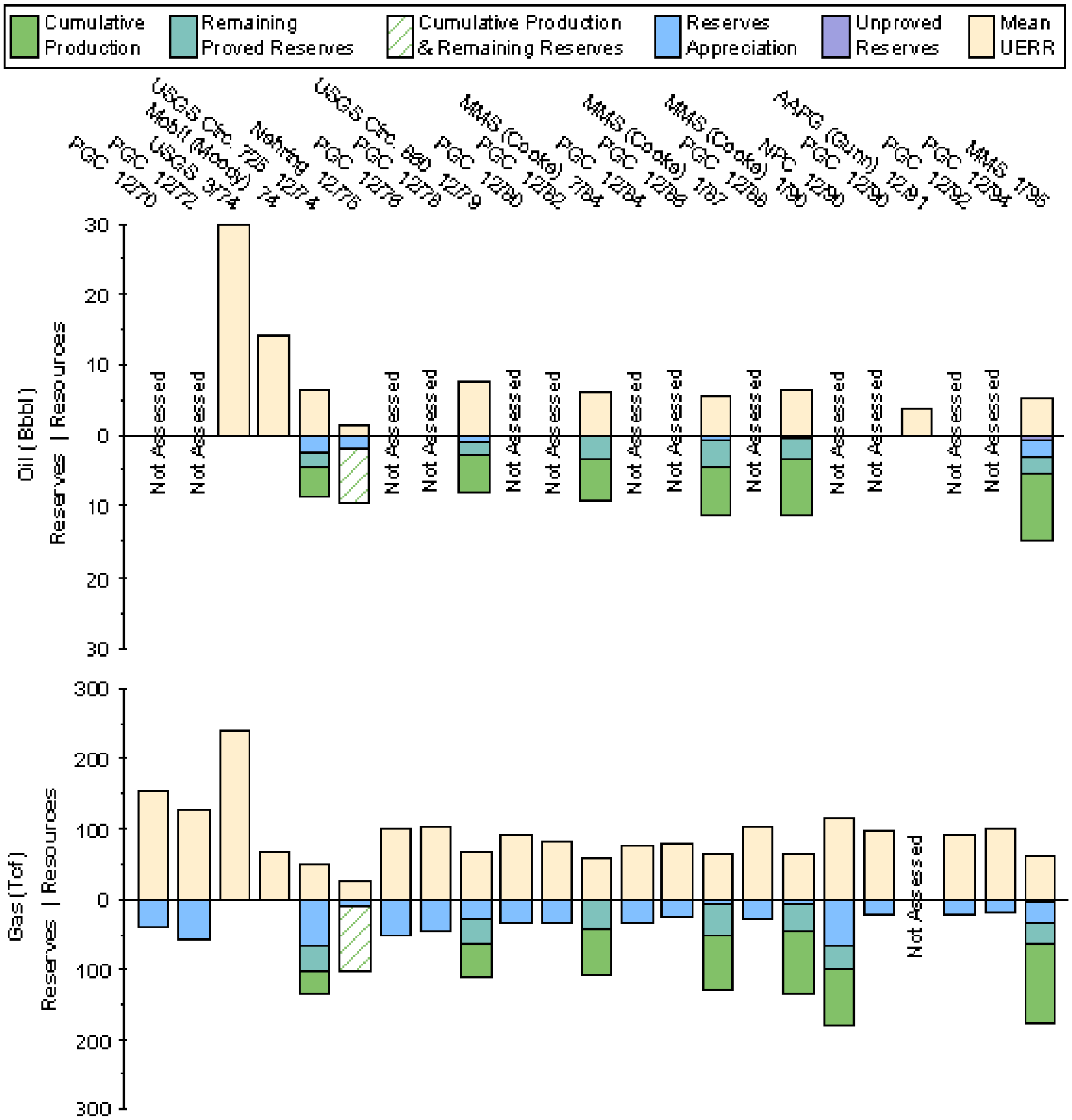


Figure 1. Gulf of Mexico Region Comparison of Selected Estimates of Economically Recoverable Resources.

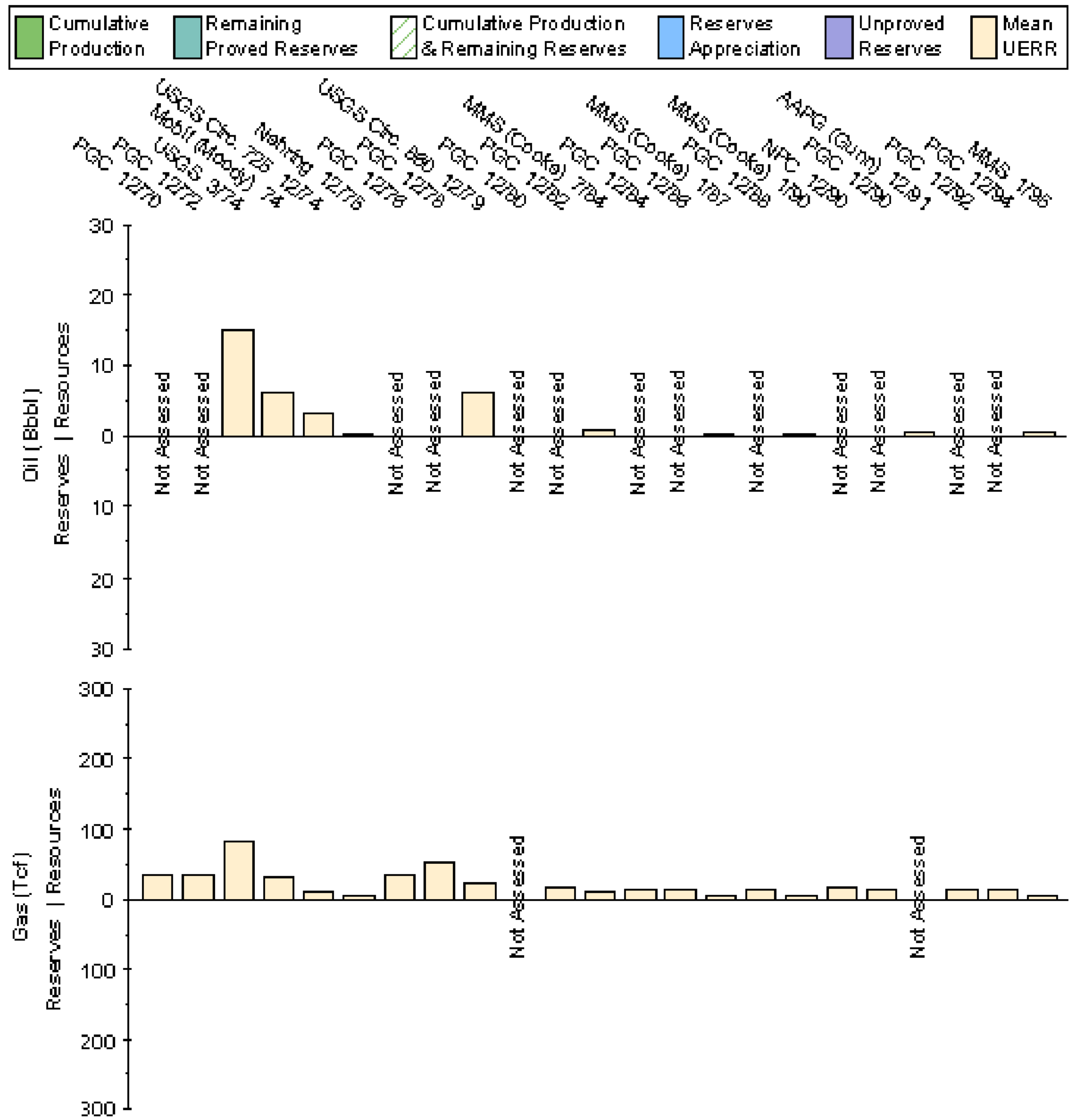


Figure 2. Atlantic Region Comparison of Selected Estimates of Economically Recoverable Resources.

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 (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
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)												
																			MPhc	No. Undisc	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)		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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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

OCS Report
MMS 99-0034

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

As of January 1, 1995

Gary L. Lore
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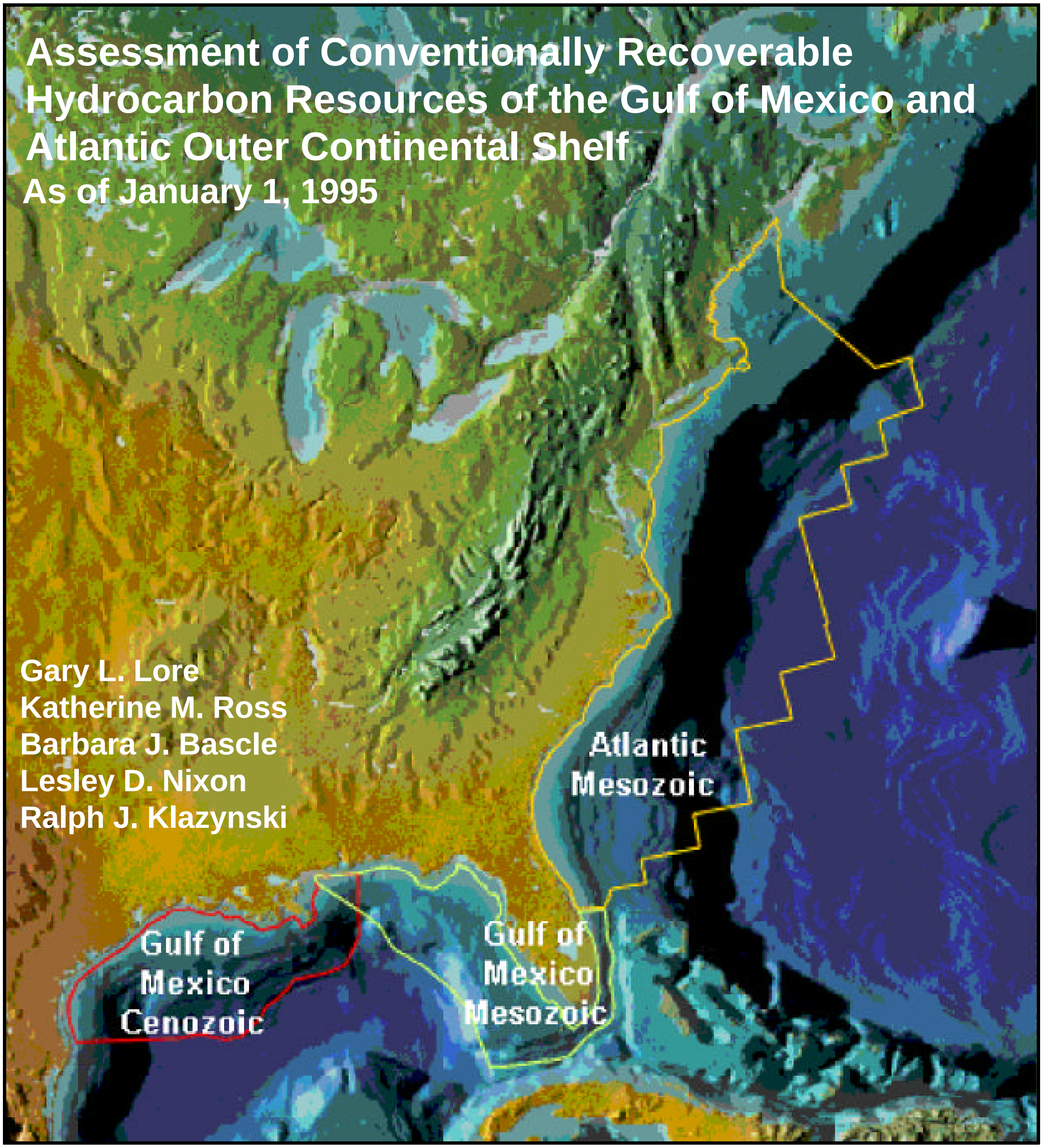

U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Regional Office
Office of Resource Evaluation

New Orleans
June 1999

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GULF OF MEXICO AND ATLANTIC CONTINENTAL MARGIN

MARGIN DESCRIPTION

The petroleum accumulations of the Gulf of Mexico and Atlantic Continental Margin are within the offshore portion of the Gulf of Mexico Basin and the western Atlantic Shelf. This Continental Margin consists of two regions and three provinces (figure 1). The Gulf of Mexico Region contains the Gulf of Mexico Cenozoic and Mesozoic Provinces and extends from offshore Texas to the Florida Peninsular Arch and the U.S.-International Maritime Boundary. The Atlantic Region consists of a Mesozoic Province extending from the U.S.-Canadian offshore boundary to the Florida Peninsular Arch. Figure 2 illustrates the overall extent of the 72 plays identified within the Gulf of Mexico and Atlantic Continental Margin.

The Gulf of Mexico and Atlantic Regions comprise a passive marine margin that originated during late Triassic and early Jurassic time with the breakup of Pangea when Africa/South America separated from North America. Initial sedimentary deposits were Triassic to lower Jurassic lacustrine and red bed clastics. Continental highlands provided the sediments deposited on the Atlantic Shelf and the northern and northeastern Gulf of

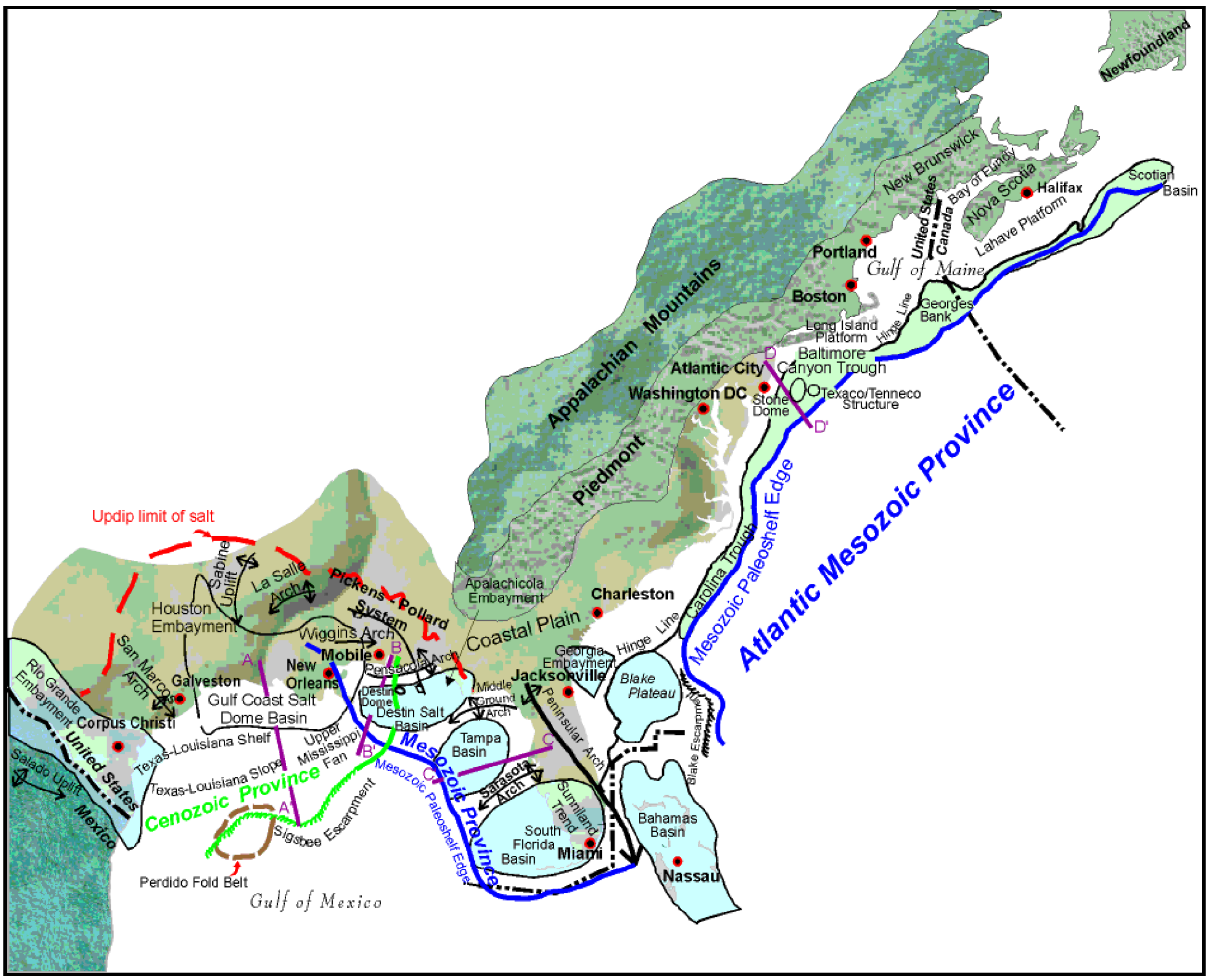


Figure 1. Physiographic map.

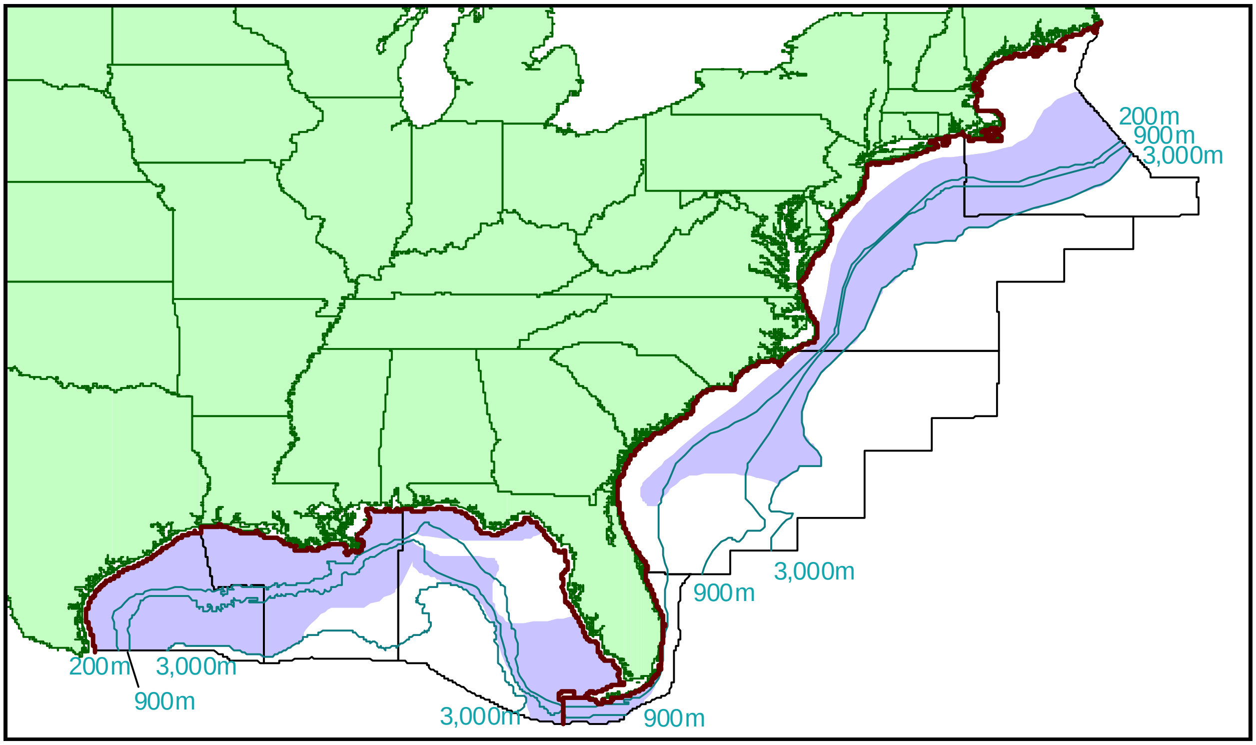


Figure 2. Map of assessed margin.

Mexico Basin during the middle to late Jurassic. While continentally derived sediments dominated deposition in the Atlantic through the late Jurassic, in the Gulf of Mexico, massive evaporites and carbonates were beginning to form. During Cretaceous time, in both the Atlantic and eastern Gulf of Mexico, a large stable carbonate platform developed with extensive reef systems growing along the shelf-edge margin. Clastic deposition became dominant in the lower Cretaceous in the Atlantic, and in the middle Miocene in the eastern Gulf of Mexico. In the central and western Gulf of Mexico, clastic deposition dominated the entire Cenozoic Era.

ASSESSMENT RESULTS

The mean total endowment for the Gulf of Mexico and Atlantic Continental Margin is estimated at 25.614 Bbo and 299.662 Tcfg (78.935 BBOE) (table 1). Thirty-seven percent of this BOE mean total endowment has been produced, all from the Gulf of Mexico Region.

Assessment results indicate that undiscovered resources may occur in as many as 2,475 pools. These undiscovered resources are estimated to have a range of 8.017 to 13.689 Bbo and 104.286 to 144.011 Tcfg at the

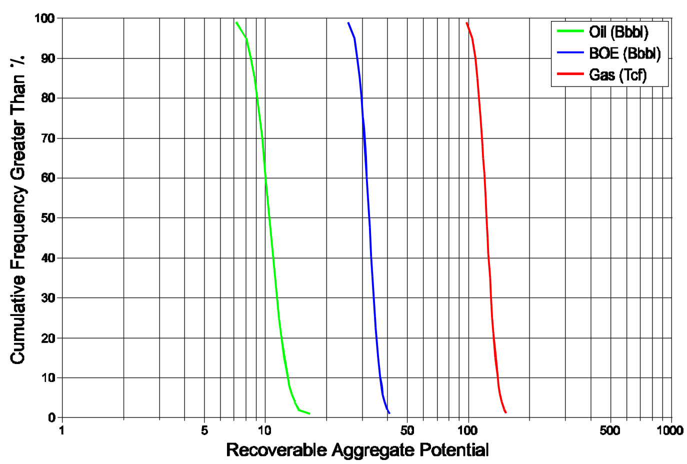


Figure 3. Cumulative probability distribution.

95th and 5th percentiles, respectively (figure 3). The majority, 78 percent, of these undiscovered resources are projected to occur in the Gulf of Mexico Region.

Table 1. Assessment results.

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

GULF OF MEXICO REGION

REGION DESCRIPTION

The Gulf of Mexico Region comprises a passive marine basin that continued to subside as the North American continent rose. As the basin subsided, it was filled with a thick Mesozoic and Cenozoic sequence of sediments. These two distinct sedimentary environments provide the basis for the two provinces in the Gulf of Mexico Region, the Cenozoic Province and the Mesozoic Province (figure 1). The Region includes the submerged Federal lands offshore Texas, Louisiana, Mississippi, Alabama, and Florida and extends from the U.S.-Mexico International Boundary in the west to the U.S.-Cuba International Boundary in the southeast. Figure 2 shows the overall extent of the assessed plays within the Region.

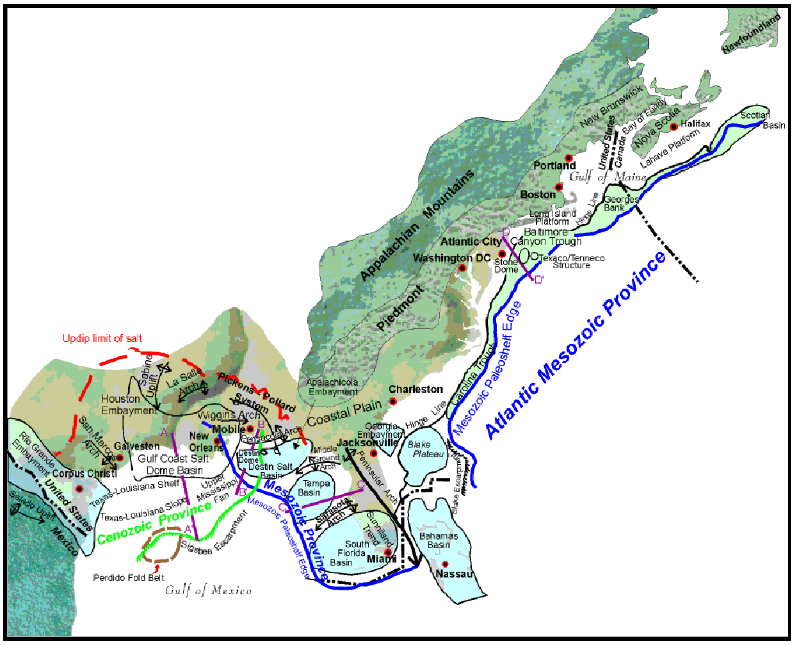


Figure 1. Physiographic map.

The Gulf of Mexico Region originated as a basin that formed during the Jurassic

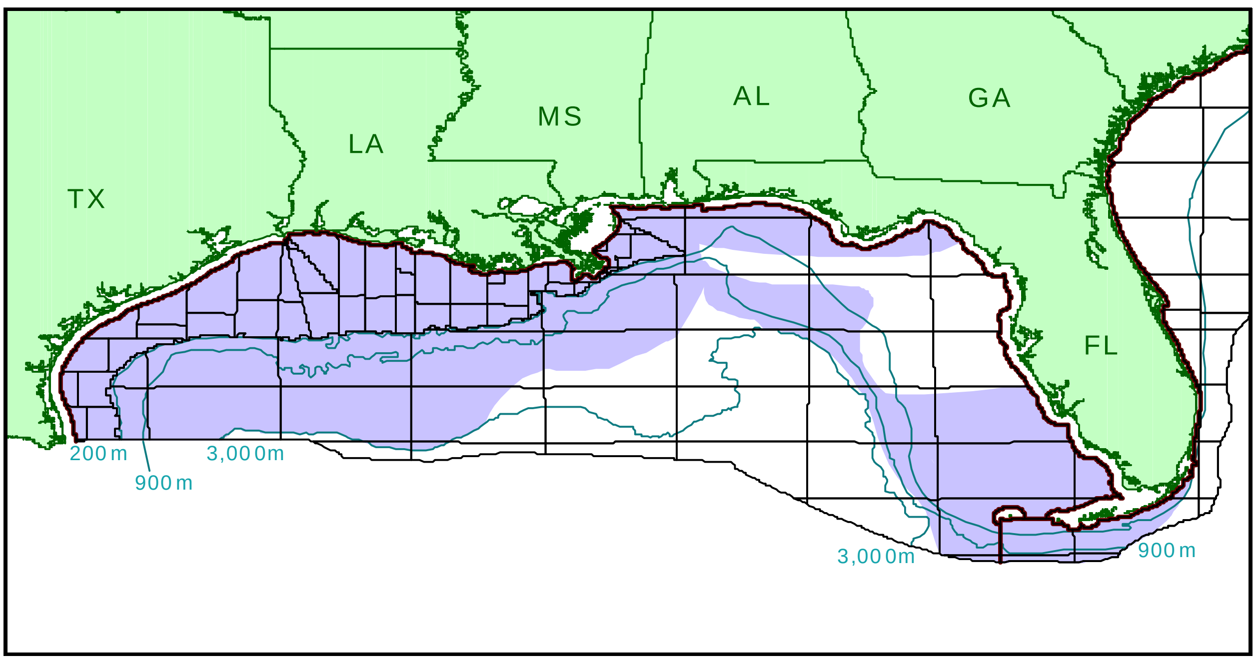


Figure 2. Map of assessed region.

Period with the breakup of Pangea when Africa/South America separated from North America. As the rifting of the basin continued, a series of shallow seas formed that were periodically separated from open ocean waters during the early Jurassic. Cycles of seawater influx and evaporation precipitated massive accumulations of salt. Subsequent loading of the salt by large volumes of Mesozoic and Cenozoic sediments deformed the salt and created many of the structures within the Region that are favorable for the entrapment of hydrocarbons.

During the late Jurassic, the basin was exposed to the open sea, changing the depositional environment to shallow marine. In these shallow seas, broad carbonate banks grew around the margins of the basin during the Cretaceous. In the eastern Gulf of Mexico, carbonates and evaporites continued to dominate the depositional setting until the middle Miocene, when Cenozoic clastic influx became significant enough to prograde onto and, subsequently, across the Cretaceous carbonate platform. These carbonates and evaporites, interbedded with clastic deposits, define the Gulf of Mexico Mesozoic Province (figure 1).

Uplift of the North American continent and the subsequent Laramide Orogeny provided the source for large amounts of clastic deltaic sediments that were deposited in the central and western areas of the Gulf of Mexico Basin from the late Cretaceous through the Tertiary. During the Quaternary, periods of continental glaciation provided an increased clastic sediment load to the central and western basin areas. This resulted in the present-day Texas and Louisiana shelf and slope that are characterized by massive amounts of clastic materials that were predominantly deposited during the Cenozoic Era. These clastic sediments define the Gulf of Mexico Cenozoic Province (figure 1).

DISCOVERIES

Initially, exploration in the Gulf of Mexico Region targeted oil, but recent discoveris have tended to be prodominately natural gas in many plays. As of January 1, 1995, there were 876 proved fields, of which 157 were classified as oil and 719 as gas. Included in this number are 133 fields that were depleted and abandoned. In addition, there were 48 unproved fields that were deemed economically viable to be used in this assessment. The Gulf of Mexico Region contains total reserves of 14.999 Bbo and 176.522 Tcfg (46.409 BBOE), of which 9.338 Bbo and 112.633 Tcfg (29.379 BBOE) have been produced. The Region contains 8,856 producible sands in 2,183 pools (table 1). The first reserves in the Region were discovered in 1947 (figure 3). Even though the number of discoveries peaked in the mid- to late 1980's, only about 20 percent of the total reserves were added in this same time period.

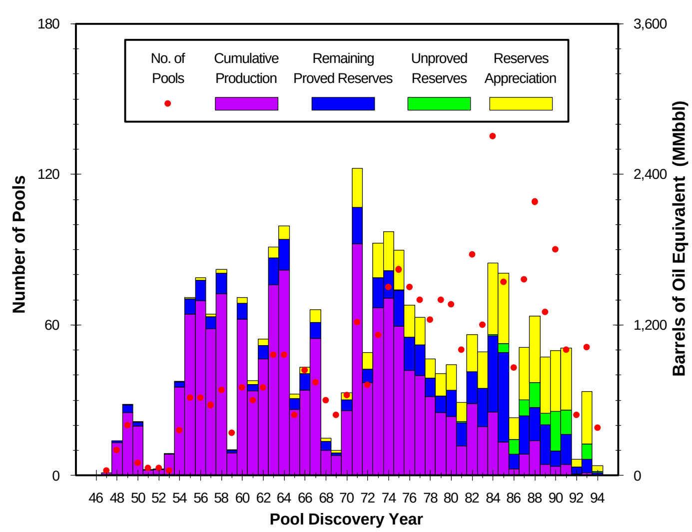


Figure 3. Exploration history graph.

ASSESSMENT RESULTS

Table 1. Characteristics of the discovered pools.

2,183 Pools (8,856 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	9	222	7,500
Subsea depth (feet)	950	7,892	22,600
Number of sands per pool	1	4	45
Porosity	10%	29%	39%
Water saturation	7%	28%	66%

In the Cenozoic Province, Paleocene and Eocene sediments (except for the conceptual Perdido Fold Belt [O/E X] play) were not evaluated because the existence of reservoir-quality sands in the Federal offshore is highly unlikely. In fact, much uncertainty abounds as to whether reservoir-quality sediments are present in Tertiary deposits beyond the Sigsbee Escarpment. Because of a lack of well data and a limited amount of seismic data available beyond the Sigsbee Escarpment, the 3,000 meter water depth, which approximates the southern limit of the Sigsbee Escarpment, was used as the geographical cutoff for the assessment of the Cenozoic Province.

In the Mesozoic Province, the dominantly evaporitic sediments of the Upper Triassic Series, the Lower Jurassic Series, and the Middle Jurassic Series were not considered to be of reservoir quality. Sediment type and lack of any onshore analogs provided the basis for condemning these deposits. As with the Cenozoic sediments, Mesozoic sediments beyond the 3,000 meter water depth were not assessed.

Sixty-one individual plays within the Gulf of Mexico have been identified, of which 57 were assessed. Of the four plays identified but not assessed, two are established and two are conceptual. The Middle Pleistocene Caprock (MPL C) play and the Upper Pleistocene Caprock (UPL C) play are both established, but are unique and of such limited occurrence that additional discoveries are unlikely. Two conceptual plays, the Upper Jurassic to Lower Cretaceous Transition Zone (UU-LK TZ) play and the Middle Jurassic to Upper Jurassic Florida Basal Clastic (MU-UU FBCL) play were not assessed. The Transition Zone play was evaluated to lack source rock potential, and the Florida Basal Clastic play was evaluated to have poor reservoir potential.

From the assessed plays in the Gulf of Mexico Region— 48 established, 1 frontier, and 1 conceptual in the Cenozoic Province, and 2 established, 4 frontier, and 1 conceptual in the Mesozoic Province— the mean total endowment is estimated at 23.343 Bbo and 272.183 Tcfg (71.775 BBOE) (table 2). Forty-one percent of this BOE mean total endowment has been produced.

The 95th- and 5th-percentile estimates of undiscovered resources in the Gulf of Mexico Region are 6.038 to 11.138 Bbo and 82.323 to 110.286 Tcfg, respectively (figure

4). At mean levels, undiscovered resources are estimated at 8.344 Bbo and 95.661 Tcfg (25.366 BBOE). These undiscovered resources may occur in as many as 1,973 pools. Seventy-five percent of these undiscovered oil resources and 92 percent of these undiscovered gas resources are projected to occur in the Cenozoic Province.

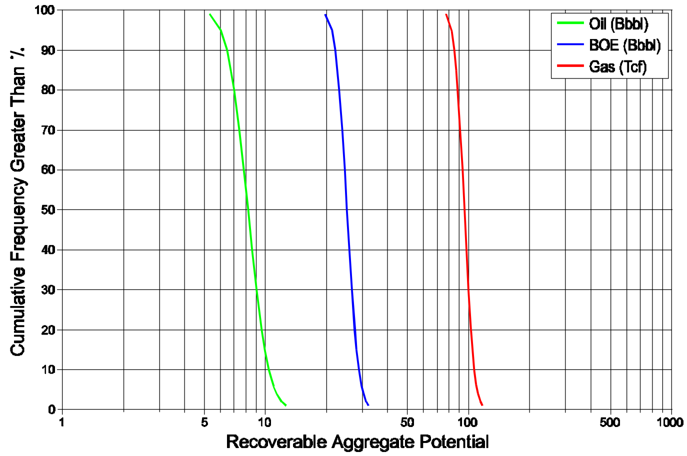


Figure 4. Cumulative probability distribution.

Table 2. Assessment results.

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

ATLANTIC REGION

The Atlantic Region contains only one assessed province, the Atlantic Mesozoic Province. Well data indicate that Cenozoic sediments in the Atlantic Region have poor reservoir and source rock characteristics. Therefore, the Cenozoic section is not considered prospective for hydrocarbons and is not assessed [see Atlantic Mesozoic Province].

GULF OF MEXICO CENOZOIC PROVINCE

PROVINCE DESCRIPTION

The Cenozoic Province covers an area from the U.S.-Mexico International Boundary to the Federal waters offshore the Florida panhandle (figure 1). The sedimentary section attains a thickness upwards of 50,000 feet, and water depths range from approximately 10 to over 10,000 feet. Figure 2 illustrates the overall extent of the plays assessed within the Cenozoic Province.

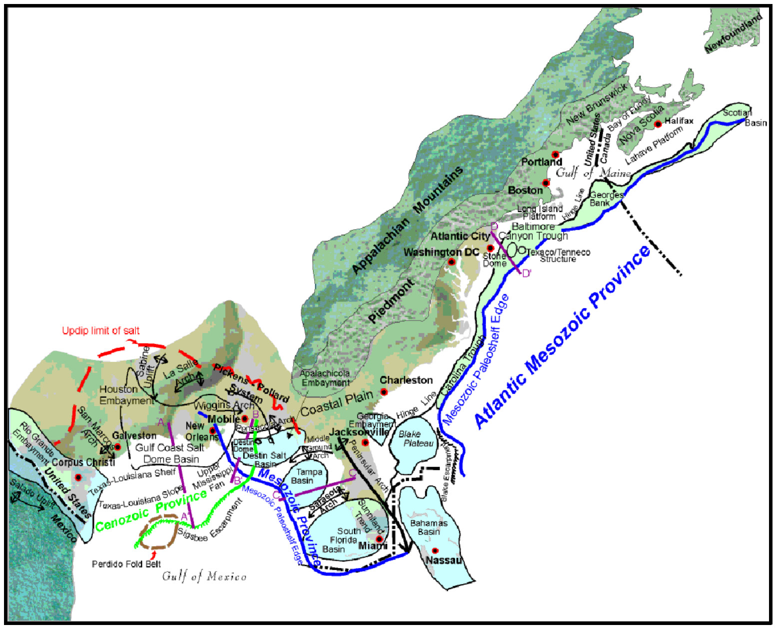


Figure 1. Physiographic map.

A general uplift of the North American continent and the subsequent Laramide Orogeny during late Cretaceous and early Tertiary time provided vast amounts of clastic sediment that were transported into the northwestern Gulf of Mexico. As the basin subsided, these large volumes of sediment were deposited as successively younger wedges of off-lapping strata. The supply of sediment, being out of phase with the load-induced subsidence, created multiple transgressive and regressive depositional environments. During periods when subsidence was rapid and sediment supply was limited, retrogradational deposits developed. When basin subsidence was minimal and the sediment load was sufficient, aggradational sediments were deposited. A very large volume of clastics, related to mountain building during the Tertiary and later due to continental glaciation during the Quaternary, was supplied to the basin. As a result, basin subsidence was overwhelmed and the Gulf of Mexico margin prograded seaward, with sediments spilling across the outer shelf and upper slope as fan systems.

This basic deltaic depositional model was the foundation for play delineation within the Cenozoic Province (figure 3 and figure 4). The major flooding events of the Cenozoic and detailed paleontological analysis provided the basis for the Cenozoic chronostratigraphic chart (figure 5).

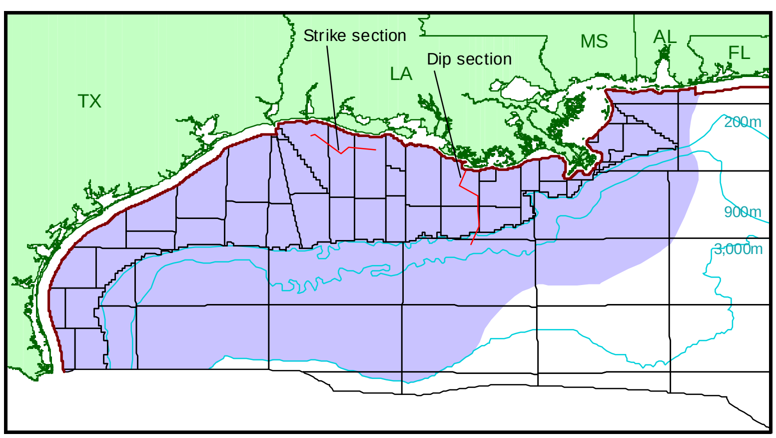


Figure 2. Map of assessed province.

Chronostratigraphy, coupled with the distinct depositional styles and environments of this model—retrogradational, aggradational, progradational, and fans— recognized by a combination of electric log curve characteristics, ecozone data, and seismic character, are the principal basis for play delineation in the Cenozoic Province (Seni *et al*., 1994, 1995, 1997; Lore and Batchelder, 1995; Hunt and Burgess, 1995; Hentz *et al*., 1997).

A strike and a dip cross section, exhibiting chronozones and depositional styles, have been prepared for the Cenozoic Province. The strike section (see figure 2 for location) extends from the West Cameron to Vermilion Areas and is representative of the chronostratigraphy and depositional styles found on the shelf (this cross section is too large to be presented in text format, but is available for viewing in the interactive report). Not surprisingly, aggradational and progradational deposits dominate. In general, aggradational deposits are relatively poor in hydrocarbons, perhaps as a result of the paucity of seals in this sand-rich environment. The progradational sediments are the most productive, probably due to their overall thickness, the interbedding of sands and shales typical of these sediments, and the association with structures and faulting that occur along the shelf margin. The dip section (see figure 2 for location) extends from the Ship Shoal Area on the shelf to the Green Canyon Area in deepwater (this cross section is too large to be presented in text format, but is available for viewing in the interactive report). This dip section illustrates the progradation of successively younger Cenozoic sediments into the Gulf of Mexico Basin. The localized thickening and thinning of sediments deposited in mini-basins controlled by

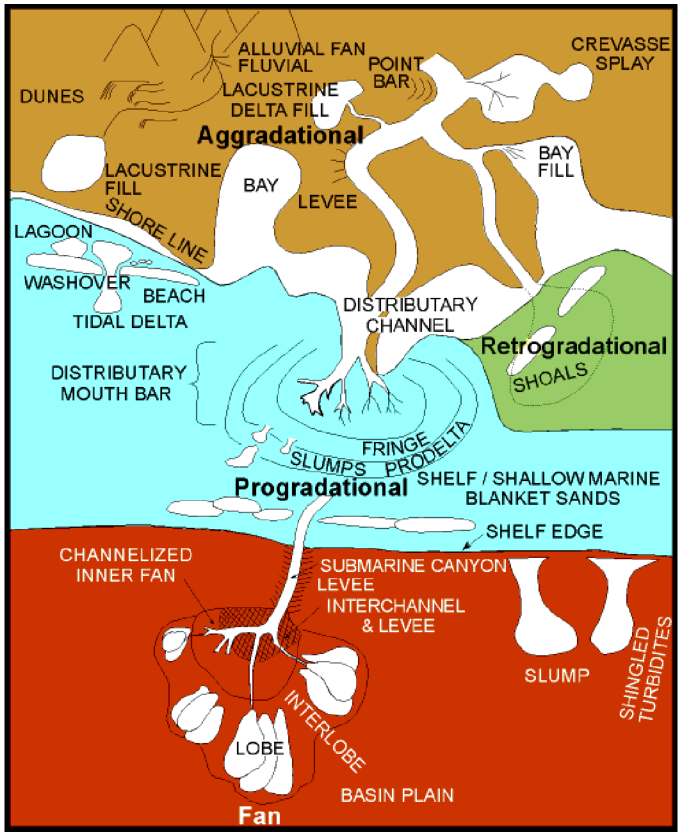


Figure 3. Model for deltaic deposition.

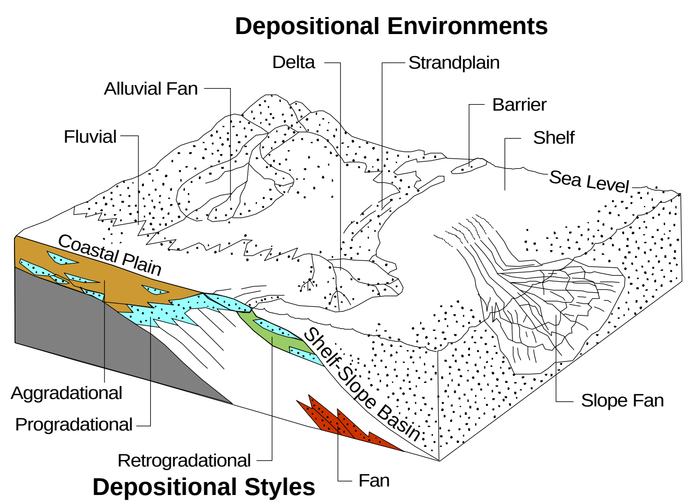


Figure 4. Siliciclastic depositional environments (Modified from Seni *et al*., 1997).

National Assessment Chronostratigraphy

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 5. Chronostratigraphic chart.

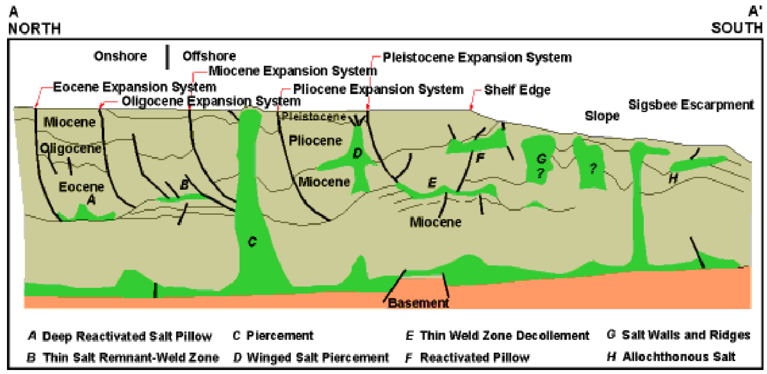


Figure 6. Cross section A-A' (Modified from Brooks, 1993).

salt tectonics is characteristic of the deepwater areas, as shown in the OCS G05889 No. 1 well in the Green Canyon 65 field ("Bullwinkle").

During the Jurassic Period, massive amounts of salt precipitated as the Gulf of Mexico Basin was periodically separated from open ocean waters. Subsequent loading of the salt by large volumes of Mesozoic and Cenozoic sediments deformed the salt. Until relatively recently, almost all Gulf of Mexico salt structures were thought to be piercement-type structures connected to the original salt deposits. With recent developments in the collection and analysis of seismic data, the salt in the Gulf of Mexico is recognized to exist in a series of salt provinces, each having a distinct style of salt emplacement (figure 6; see figure 1 for location). Salt in the form of diapirs penetrated the late Miocene sediments, then flowed downdip due to the influence of gravity and pressure, resulting in large sheets of salt that deformed owing to subsequent sediment loading. The recognition that salt exists as lenses, winged salt piercements, and allochthonous sheets has led to the exploration of those sediments that lie below the salt. In 1993, the "Mahogany" prospect offshore Louisiana confirmed that the sediments that lie below salt can contain hydrocarbons in economic quantities.

DISCOVERIES

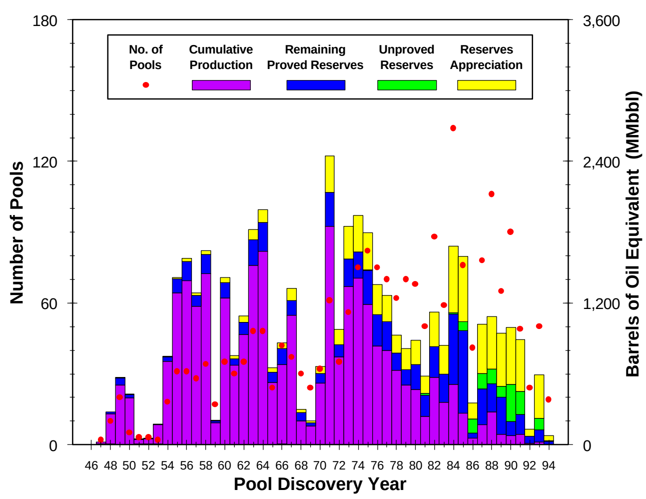


Figure 7. Exploration history graph.

Since the first Federal oil and gas lease sale in 1954, there have been 71 lease offerings within the Cenozoic Province, resulting in over 11,000 leases encompassing approximately 57 million acres. In the more than 50 years of petroleum exploration in the Gulf of Mexico, over 31,000 boreholes have been drilled in the Federal waters of this Province. Since 1976, nearly 5.4 million line-miles of seismic data have been collected by industry in the area.

The Cenozoic Province contains total reserves of 14.996 Bbo and 172.713 Tcfg (45.728 BBOE), of which 9.337 Bbo and 112.434 Tcfg (29.344 BBOE) have been produced. The first reserves were discovered in the Province in 1947 (figure 7), and 914 proved and unproved fields have been discovered. The Province contains 8,845 producible sands in 2,172 pools (table 1), and 2,105 of these pools contain proved reserves (table 2).

Table 1. Characteristics of the discovered pools.

2,172 Pools (8,845 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	9	223	7,500
Subsea depth (feet)	950	7,831	19,216
Number of sands per pool	1	4	45
Porosity	14%	29%	39%
Water saturation	7%	28%	66%

ASSESSMENT RESULTS

In the Cenozoic Province, Paleocene and Eocene sediments (except for the conceptual Perdido Fold Belt [O/E X] play) were not evaluated because the existence of reservoir-quality sands in the Federal offshore is highly unlikely. Because of a lack of well data and a limited amount of seismic data available beyond the Sigsbee Escarpment, the 3,000 meter water depth, which approximates the southern limit of the Sigsbee Escarpment, was used as the geographical cutoff for the assessment of the Cenozoic Province.

Fifty-two individual plays within the Gulf of Mexico Cenozoic Province have been identified. Fifty were assessed and two were unassessed, the Middle Pleistocene Caprock (MPL C) play and the Upper Pleistocene Caprock (UPL C) play. Both Caprock plays are established, but are unique and of such limited occurrence that additional discoveries are unlikely.

From the 50 assessed plays— 48 established, 1 frontier, and 1 conceptual— in the Gulf of Mexico Cenozoic Province, the mean total endowment is estimated at 21.287 Bbo and 260.266 Tcfg (67.598 BBOE) (table 2). Forty-three percent of this BOE mean total endowment has been produced.

The 95th- and 5th-percentile estimates of undiscovered resources in the Cenozoic Province are 4.428 to 8.584 Bbo and 74.766 to 101.639 Tcfg, respectively (figure 8). At mean levels, undiscovered resources are 6.291 Bbo and 87.553 Tcfg (21.870 BBOE). These undiscovered resources may occur in as many as 1,794 pools (figure 9).

The potential for significant additional discoveries on the shelf and slope of the central and western Gulf of Mexico is excellent, despite almost 50 years of extensive drilling in this area. The potential that does exist in the area,

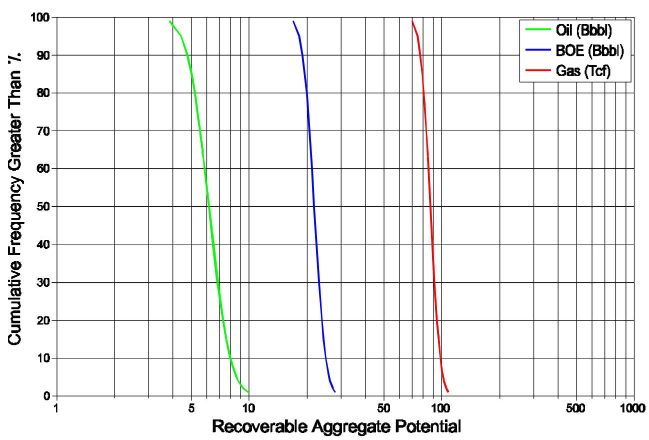


Figure 8. Cumulative probability distribution.

however, is primarily dependent upon deeper drilling or discoveries being made in deepwater or subsalt, with the greatest part of the hydrocarbon potential of the Province, (72 percent in the mean case), occurring in deepwater fan deposits.

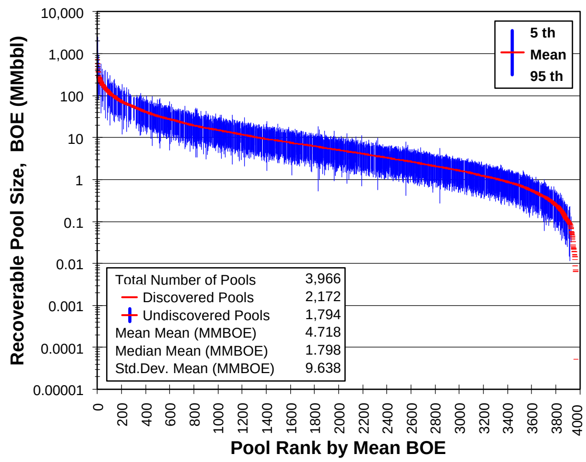


Figure 9. Pool rank plot.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	2,105	11.853	140.318	36.821
Cumulative production	--	9.337	112.434	29.344
Remaining proved	--	2.516	27.884	7.477
Unproved	67	0.638	3.006	1.172
Appreciation (P & U)	--	2.505	29.389	7.735
Undiscovered Conventionally Recoverable Resources				
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
Total Endowment				
95th percentile	--	19.424	247.479	63.927
Mean	3,966	21.287	260.266	67.598
5th percentile	--	23.580	274.352	71.705

GULF OF MEXICO MESOZOIC PROVINCE

PROVINCE DESCRIPTION

The eastern portion of the Gulf of Mexico, a passive margin underlain by Mesozoic and Cenozoic sediments, extends from the Florida Peninsula Arch in the east and southeast, through the South Florida Basin, northwestward approximately to Mobile Bay, and provides an exploration frontier covering 76 million acres (119,000 square miles) (figure 1). The sedimentary section attains a thickness exceeding 30,000 feet in the South Florida Basin and eastern portion of the Gulf of Mexico Basin, and water depths range from approximately 10 to over 10,000 feet. Areas of potential discoveries within the Mesozoic section of the eastern Gulf of Mexico extend from the Louisiana-Mississippi border and the Alabama and Florida State-Federal boundaries, through the Tampa and South Florida Basins to the U.S.-Cuba International Boundary. Figure 2 illustrates the overall extent of the plays assessed within the Mesozoic Province.

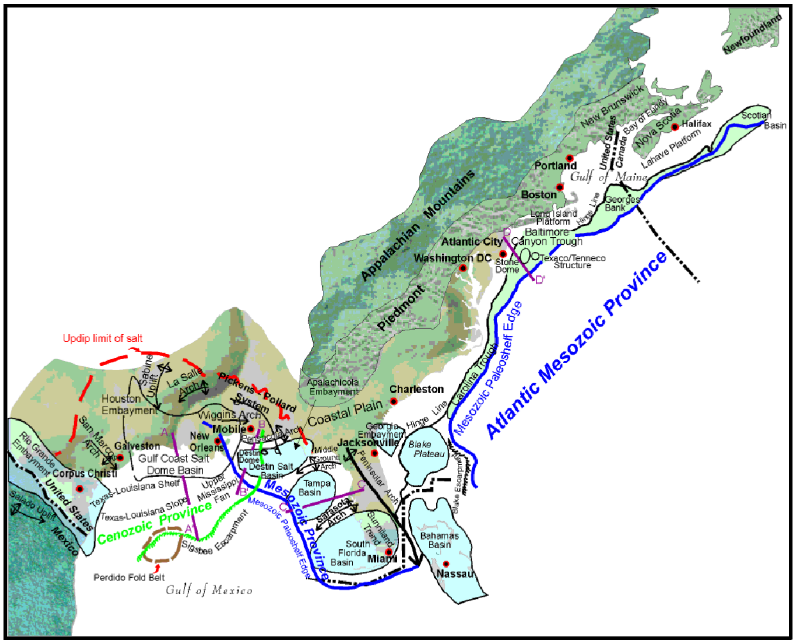


Figure 1. Physiographic map.

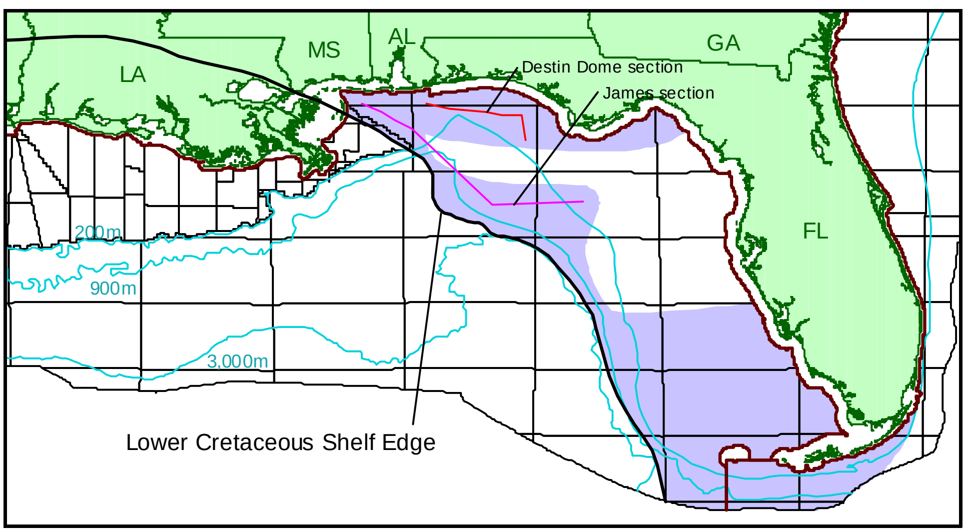


Figure 2. Map of assessed province.

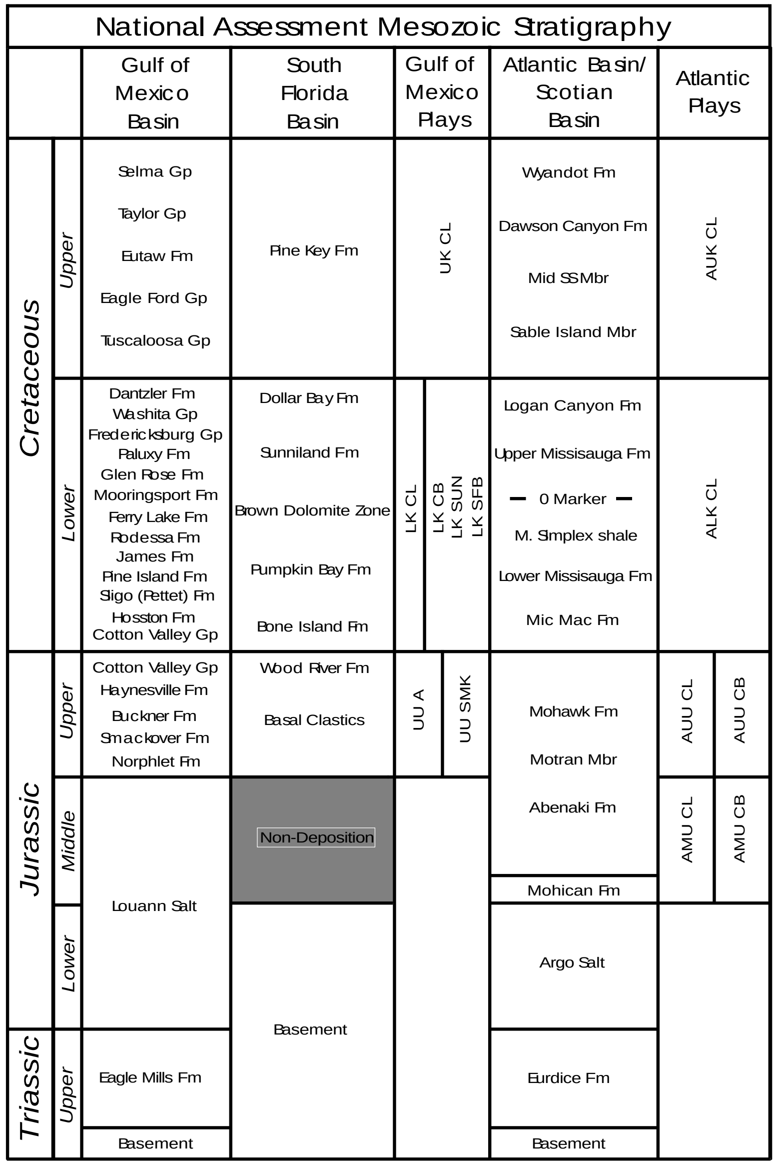
Detailed paleontological analysis provided the basis for the Mesozoic chronostratigraphic chart (figure 3). The geologic history of the northern Gulf of Mexico during the Mesozoic began with the breakup of the Pangean supercontinent about 200

National Assessment Chronostratigraphy							
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 3. Chronostratigraphic chart.

million years ago. A series of late Triassic-early Jurassic rift basins formed as grabens in what is now onshore Georgia, Florida, Mississippi, Alabama, Louisiana, and Texas, as well as the central Gulf of Mexico. The Wiggins Arch and parts of the Sarasota Arch represent Paleozoic remnants left behind during the rifting stage (figure 1). The grabens were active depocenters receiving alluvial, fluvial, delta plain, lacustrine, and marine deposits similar to those found along the Atlantic margin. Marine incursions resulted in the deposition of thick shallow-water salt deposits in the Gulf of Mexico. The upper Jurassic is characterized by a series of clastic and carbonate regressive sequences, resulting in a seaward progradation of the shelf. As the shelf prograded, a shelf-edge reef complex developed in the early Cretaceous and continued growing through the late Cretaceous, resulting in deposition of a thick sequence of carbonate rocks that interfinger with clastics in the back-reef area. Figure 5 illustrates the stratigraphic and lithologic relationships of the formations overlying the Louann Salt from the onshore to the Federal OCS (see figure 1 for location and figure 4 for stratigraphy). The maximum thicknesses attained by the upper Jurassic sediments exceed 5,000 feet, the lower Cretaceous 10,000 feet, and the upper Cretaceous 5,000 feet.



Rock unit positions do not imply age relationships between basins.

Figure 4. Stratigraphic column.

Three prospective chronozones have been identified in the Gulf of Mexico Mesozoic Province: upper Jurassic (UU), lower Cretaceous (LK), and upper Cretaceous (UK). Potential traps are related to folded structures, faults (normal and growth), and permeability pinchouts against nonporous shales, evaporites, and carbonates. The Destin Dome section (see figure 2 for location and figure 4 for stratigraphy) shows the sequence of Mesozoic clastics and carbonates and their characteristic log signatures in the Federal OCS area (this cross section is too large to be presented in text format, but is available for viewing in the interactive report). These regionally extensive sediments exhibit thinning over the Destin Dome, indicative of the area's upwarping during the Cretaceous.

Of the upper Jurassic formations present in the area and shown in figure 5 and on the Destin Dome section, the Norphlet is the primary exploration target in Federal waters.

Exploration targets for the Cretaceous differ depending on the geologic setting. In the Viosca Knoll and Destin Dome Areas, the Lower Cretaceous James Formation is the principal target (see figure 2 for location and figure 4 for stratigraphy) (this cross section is too large to be presented in text format, but is available for viewing in the interactive report). In offshore Florida, the Sunniland Formation, or its stratigraphic equivalent, and the Brown Dolomite Zone of the Lehigh Acres Formation have the greatest reservoir potential. These formations and their stratigraphic relationships are illustrated in Figure 6 (see figure 1 for location and figure 4 for stratigraphy).

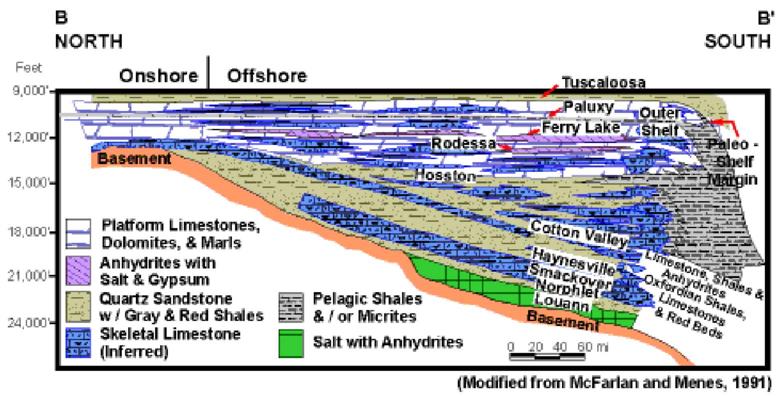


Figure 5. Cross section B-B'.

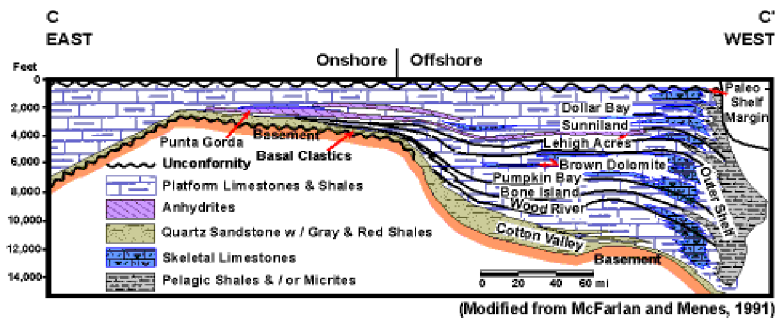


Figure 6. Cross sectionC-C'.

Discoveries

Federal oil and gas lease sales have been held for the Mesozoic Province since 1959. Nearly 500 leases encompassing 2.5 million acres have been awarded. Approximately 125 wells targeting or penetrating the Mesozoic section have been drilled with approximately 27 finding commercially recoverable hydrocarbons (the Mesozoic well database [wellmeso.dbf] is presented in the CD-ROM DataFiles directory). The remaining offshore wells are dry or have encountered subeconomic quantities of hydrocarbons.

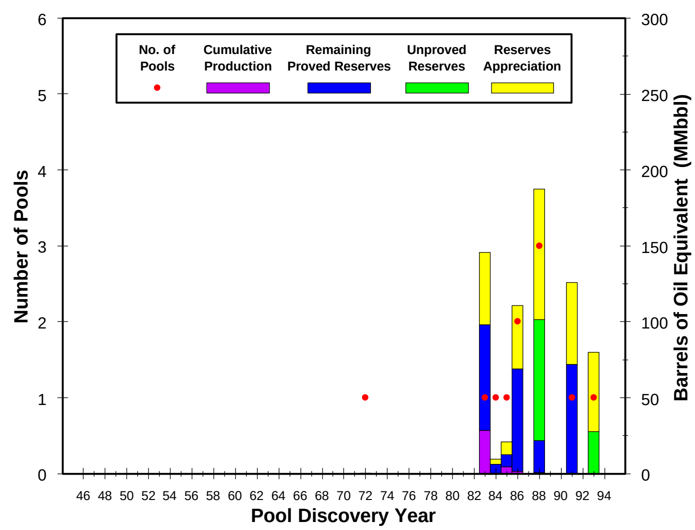


Figure 7. Exploration history graph.

The Mesozoic Province contains total reserves of 0.003 Bbo and 3.809 Tcfg (0.681 BBOE), of which less than 0.001 Bbo and 0.198 Tcfg (0.035 BBOE) have been produced. The first reserves were discovered in the Province in 1972 (figure 7). The Province contains 11 producible sands in 11 pools (table 1), and nine of these pools contain proved reserves (table 2).

Table 2. Characteristics of the discovered pools.

11 Pools (11 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	37	89	288
Subsea depth (feet)	8,700	19,974	22,600
Number of sands per pool	1	1	1
Porosity	10%	13%	20%
Water saturation	19%	31%	52%

Table 1. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	9	<0.001	1.572	0.280
Cumulative production	--	<0.001	0.198	0.035
Remaining proved	--	<0.001	1.374	0.245
Unproved	2	0.001	0.597	0.107
Appreciation (P & U)	--	0.002	1.640	0.294
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	1.360	7.106	2.678
Mean	179	2.053	8.108	3.495
5th percentile	--	2.933	9.194	4.455
Total Endowment				
95th percentile	--	1.363	10.915	3.359
Mean	190	2.056	11.917	4.176
5th percentile	--	2.936	13.003	5.136

ASSESSMENT RESULTS

Potential Mesozoic reservoirs are postulated within the Mississippi fan and Perdido foldbelts and other large structures of the deepwater central and western Gulf of Mexico. The existence of these reservoirs below Cenozoic sediments is highly speculative. These potential plays were not assessed at this time due to their low probability of existence and the high degree of uncertainty concerning their reservoir characteristics and the actual occurrence of hydrocarbon accumulations.

The dominantly evaporitic sediments of the Upper Triassic Series, the Lower Jurassic Series, and the Middle Jurassic Series were not considered to be of reservoir quality. Sediment type and lack of any onshore analogs provided the basis for condemning these deposits. As with the Cenozoic sediments, Mesozoic sediments beyond the 3,000 meter water depth were not assessed.

Nine individual plays within the Gulf of Mexico Mesozoic Province have been identified, two of which are established, four are frontier, and three are conceptual. Seven were assessed and two, the conceptual Middle Jurassic to Upper Jurassic Florida Basal Clastic (MU-UU FBCL) play and the conceptual Upper Jurassic to Lower Cretaceous Transition Zone (UU-LK TZ) play, were unassessed due to poor reservoir potential and a lack of source rock potential, respectively.

The mean total endowment for the seven assessed plays in the Mesozoic Province is estimated at 2.056 Bbo and 11.917 Tcfg (4.176 BBOE) (table 2). Less than 1 percent of this BOE mean total endowment has been produced.

The 95th- and 5th-percentile estimates of undiscovered resources in the Mesozoic Province are 1.360 to 2.933 Bbo and 7.106 to 9.194 Tcfg, respectively (figure 8). These undiscovered resources may occur in as many as 179 pools (figure 9).

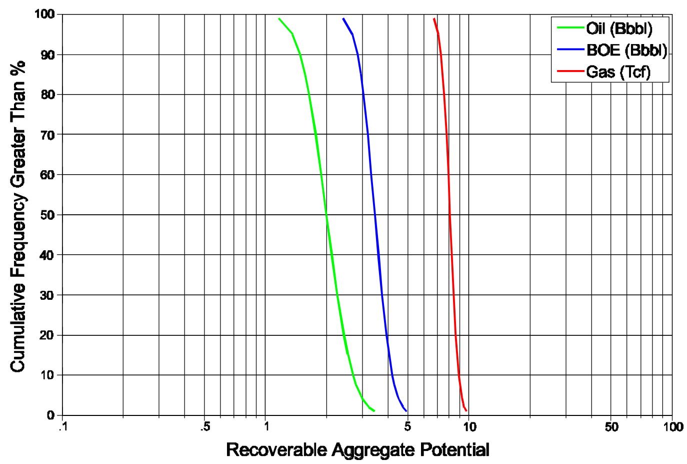


Figure 8. Cumulative probability distribution.

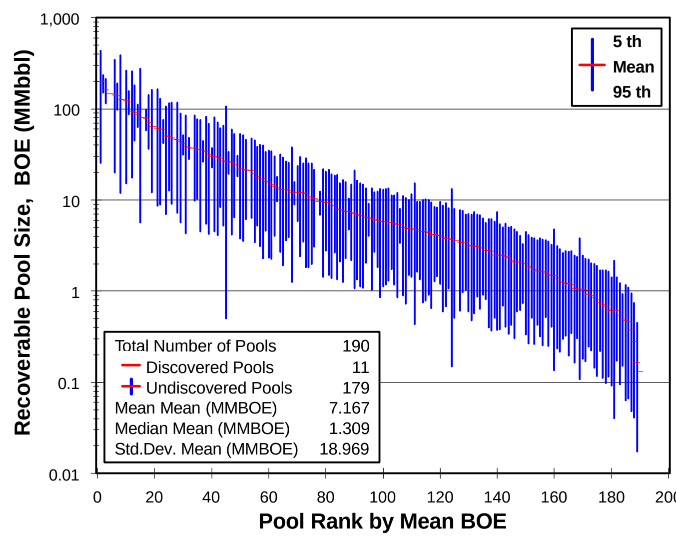


Figure 9. Pool rank plot.

ATLANTIC MESOZOIC PROVINCE

PROVINCE DESCRIPTION

The Atlantic OCS is a passive margin, underlain by Mesozoic and Cenozoic sediments, extending from the U.S.-Canadian offshore border to the Florida Peninsular Arch (figure 1). The margin encompasses an area of approximately 135 million acres (211,000 square miles). In the northern and central portions of the Province, the sediments underlying the shelf are siliciclastic, derived from erosion of the Appalachian Mountain System, and platform and reefal carbonates immediately seaward of the terrigenous detritus. Carbonate rocks predominate in the southern portion of the Atlantic OCS. The sedimentary section attains thicknesses exceeding 40,000 feet, and water depths range from approximately 80 to more than 10,000 feet. Figure 2 illustrates the overall extent of the assessed plays within the Atlantic Mesozoic Province.

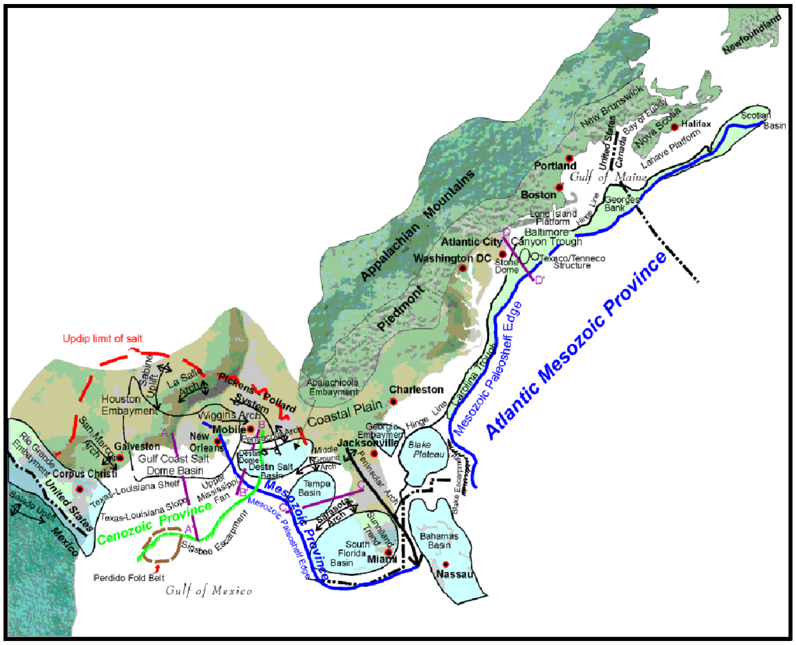


Figure 1. Physiographic map.

Late Triassic continental rifting initiated a system of faults paralleling the Appalachian Mountains and extending from southeast Newfoundland to southeast Georgia and then westward into Texas. These faults developed into rift basins filled with nonmarine red bed and lacustrine deposits. The easternmost band of these rifts functioned as southwestward extensions of the Tethys Seaway, accommodating marine sediments, including evaporites. A regional post rift unconformity (PRU) overlies the rift sedimentary sequence under the shelf. The PRU represents a 20-million-year hiatus and

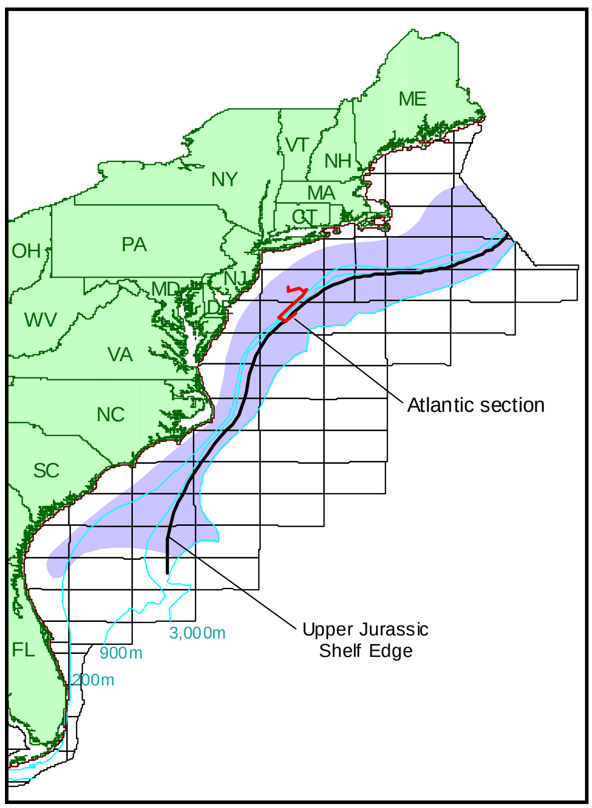


Figure 2. Map of assessed province.

National Assessment Chronostratigraphy

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		*Discorbis* Zone	
~38.0			Eocene	E			
~55.0			Paleocene	L			
~63.0	Mesozoic	Cretaceous	Upper	UK		*Globotruncana elevata* *Rotalipora cushmani*	*Globotruncana mayaroensis* *Marthasterites furcatus* *Rotalipora cushmani*
~97.5			Lower	LK		*Lenticulina washitaensis* *Fossocytheridea lenoirensis* *Cythereis fredericksburgensis* *Dictyoconus walnutensis* *Eocytheropteron trinitiensis* *Orbitolina texana* *Choffatella decipiens* *Schuleridea lacustris* *Schuleridea acuminata*	*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 3. Chronostratigraphic chart.

is overlain by the middle Jurassic to recent sediments. As evident from seismic data, the postrift sequence is structurally uncomplicated; growth faults, which appear to sole out into deep strata, and their associated rollover structures follow the northeast-southwest regional structural grain. Jurassic sediments include siliciclastic basin infill and platform carbonates. The maximum thickness attained by the middle Jurassic sediments exceeds 10,000 feet, the upper Jurassic 6,000 feet, the lower and upper Cretaceous 5,000 feet each, and the Cenozoic 3,000 feet. Detailed paleontological analysis provided the basis for the Mesozoic chronostratigraphic chart (figure 3). Three prospective chronozones have been identified in the Atlantic Mesozoic Province: middle Jurassic (AMU), upper Jurassic (AUU), and lower Cretaceous (ALK). Figure 4 and figure 5 illustrate the stratigraphic relationships of the Mesozoic sediments of the Atlantic OCS area (see figure 1 for location of figure 4).

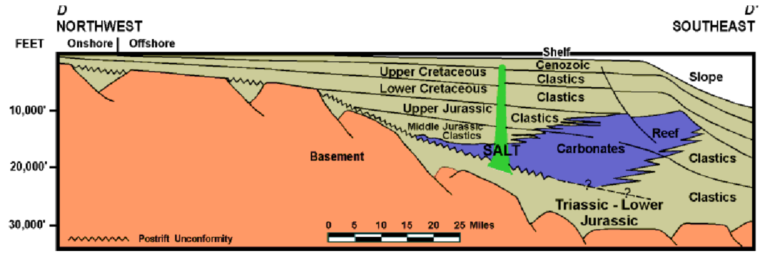


Figure 4. Cross section D-D'.

National Assessment Mesozoic Stratigraphy

		Gulf of Mexico Basin	South Florida Basin	Gulf of Mexico Plays	Atlantic Basin/ Scotian Basin	Atlantic Plays
Cretaceous	Upper	Selma Gp Taylor Gp Eutaw Fm Eagle Ford Gp Tuscaloosa Gp	Pine Key Fm	UK CL	Wyandot Fm Dawson Canyon Fm Mid SS Mbr Sable Island Mbr	AUK CL
Cretaceous	Lower	Dantzler Fm Washita Gp Fredericksburg Gp Paluxy Fm Glen Rose Fm Mooringsport Fm Ferry Lake Fm Rodessa Fm James Fm Pine Island Fm Sligo (Pettet) Fm Hosston Fm Cotton Valley Gp	Dollar Bay Fm Sunniland Fm Brown Dolomite Zone Pumpkin Bay Fm Bone Island Fm	LK CL LK CB LK SUN LK SFB	Logan Canyon Fm Upper Missisauga Fm — 0 Marker — M. Simplex shale Lower Missisauga Fm Mic Mac Fm	ALK CL
Jurassic	Upper	Cotton Valley Gp Haynesville Fm Buckner Fm Smackover Fm Norphlet Fm	Wood River Fm Basal Clastics	UU A UU SMK	Mohawk Fm Motran Mbr	AUU CL AUU CB
Jurassic	Middle	Louann Salt	Non-Deposition		Abenaki Fm Mohican Fm	AMU CL AMU CB
Jurassic	Lower	Louann Salt	Basement		Argo Salt	
Triassic	Upper	Eagle Mills Fm Basement	Basement		Eurdice Fm Basement	

Rock unit positions do not imply age relationships between basins.

Figure 5. Stratigraphic column.

DISCOVERIES

In 1976, the first U.S. Atlantic offshore lease sale was held, Mid-Atlantic Sale 40, in the Baltimore Canyon Trough area. Successful bids were submitted for 93 leases, which included both the Great Stone Dome and the Hudson Canyon 598-642 (Texaco/Tenneco) structures. The former prospect was tested by seven exploration wells, which were all dry, and the latter by eight wells, five of which had significant but subeconomic hydrocarbon flows, mostly natural gas, from lower Cretaceous siliciclastics (the Mesozoic well database [wellmeso.dbf] is presented in the CD-ROM DataFiles directory). The Atlantic Mesozoic Province cross section (see figure 2 for location) is a regional cross section showing wells drilled on the Great Stone Dome and the Texaco/Tenneco structure (this cross section is too large to be presented in text format, but is available for viewing in the interactive report).

A total of nine Atlantic OCS sales have occurred in the North, Mid-, and South Atlantic Planning Areas. Fifty-one wells were drilled, five of which were Continental Offshore Stratigraphic Test (COST) wells sited off-structure by industry consortiums in the 1970's to gain stratigraphic data. Most of the exploration wells were drilled on paleoshelf anticlinal structures, targeting siliciclastic reservoirs. However, three wells (Shell Wilmington Canyon 372-1, 586-1, and 587-1) tested the upper Jurassic-lower Cretaceous shelf-edge reef, backreef, and carbonate platform offshore New Jersey. One well (Shell Baltimore Rise 93-1) near the shelf edge penetrated a thick lower Cretaceous deltaic sequence offshore Maryland. Excluding the Texaco/Tenneco structure, all wells were dry or contained only minor shows. Altogether, 433 Federal leases have been issued in the Atlantic Region for petroleum exploration. As of January 1, 1995, 53 leases (all in the Mid- and South Atlantic Planning Areas) remain active under Suspensions of Operation.

Assessment Results

Eleven individual plays within the Atlantic Mesozoic Province have been identified, of which 5 are assessed frontier plays and 6 are unassessed conceptual plays. The mean total endowment, which equals the mean undiscovered resources, for the Atlantic Mesozoic Province is estimated at 2.271 Bbo and 27.480 Tcfg (7.161 BBOE) (table 1). The 95th- and 5th-percentile estimates of undiscovered resources in the Province are 1.267 to 3.667 Bbo and 15.855 to 43.372 Tcfg (figure 6). These undiscovered resources may occur in as many as 502 pools (figure 7).

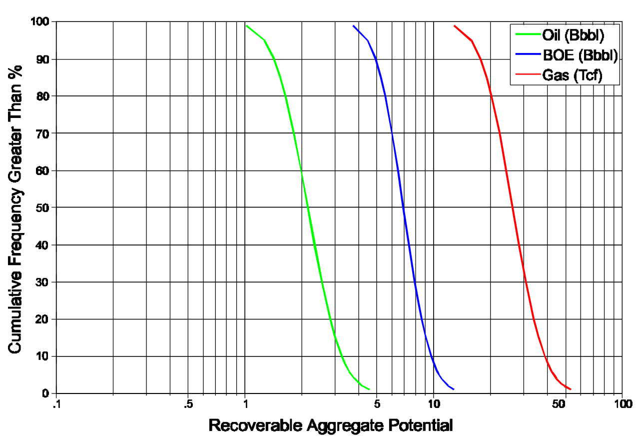


Figure 6. Cumulative probability distribution.

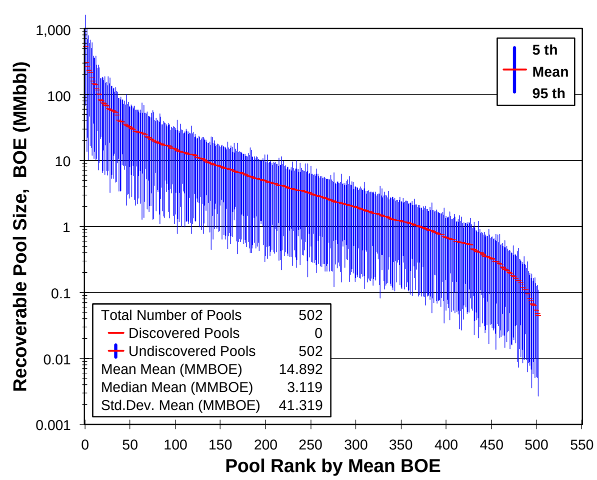


Figure 7. Pool rank plot.

Table 1. Assessment results.

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

QUATERNARY SYSTEM

The Quaternary System contains only one series [see Pleistocene Series].

TERTIARY SYSTEM

SYSTEM DESCRIPTION

The Tertiary System comprises the Oligocene/Eocene, Miocene, and Pliocene Series of the Gulf of Mexico Cenozoic Province. Thirty-nine established plays, one frontier play, and one conceptual play were identified and assessed by either their depositional style (retrogradational, aggradational, progradational, or fan) or their structural style for the Tertiary System. Figure 1 illustrates the overall extent of these plays.

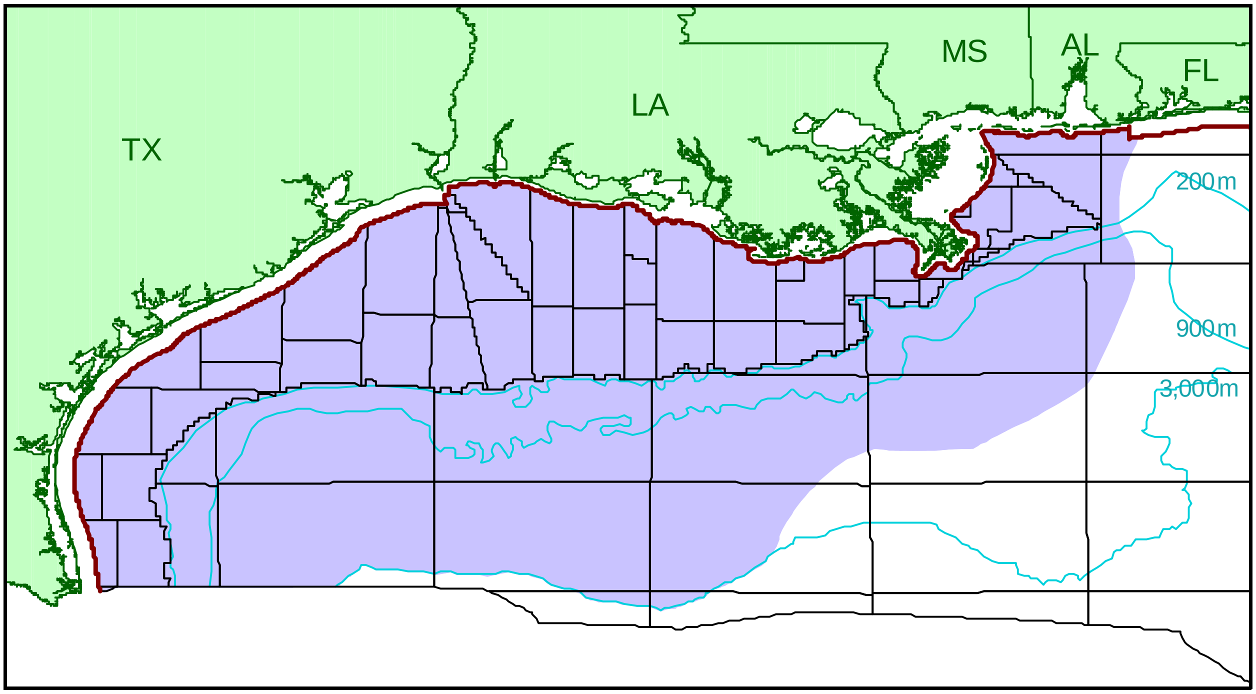


Figure 1. Map of assessed system.

DISCOVERIES

The Tertiary System contains 1,308 discovered pools (table 1). Though the number of discoveries per year peaked in the 1980's, over 70 percent of the total reserves for the Tertiary System were added prior to that decade (figure 2). In addition, almost 90 percent of the cumulative production for the Tertiary System has been from discoveries made prior to 1980.

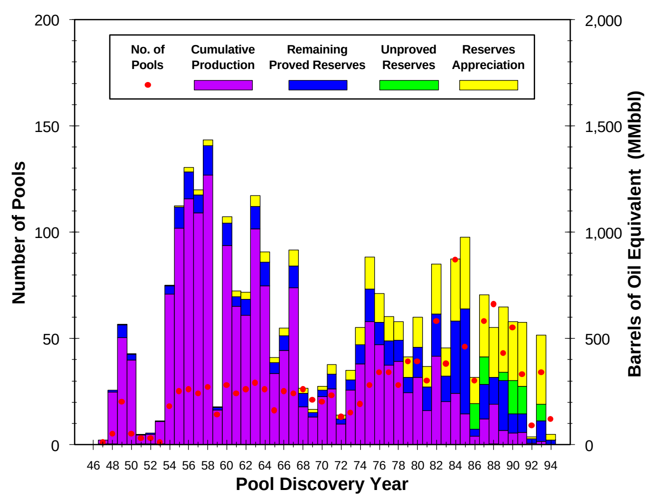


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

1,308 Pools (5,114 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	9	173	7,500
Subsea depth (feet)	1,500	8,938	19,216
Number of sands per pool	1	4	45
Porosity	14%	28%	39%
Water saturation	9%	29%	66%

Assessment Results

The Tertiary System contains 2,520 pools (1,308 discovered pools plus 1,212 undiscovered pools), with a mean total endowment of 12.795 Bbo and 158.396 Tcfg (40.980 BBOE) (table 2 and figure 3). Undiscovered resources have a range of 2.198 to 5.574 Bbo and 46.782 to 66.272 Tcfg at the 95th and 5th percentiles, respectively (figure 4). At mean levels, the undiscovered resources in the Tertiary System are estimated at 3.643 Bbo and 55.994 Tcfg (13.607 BBOE).

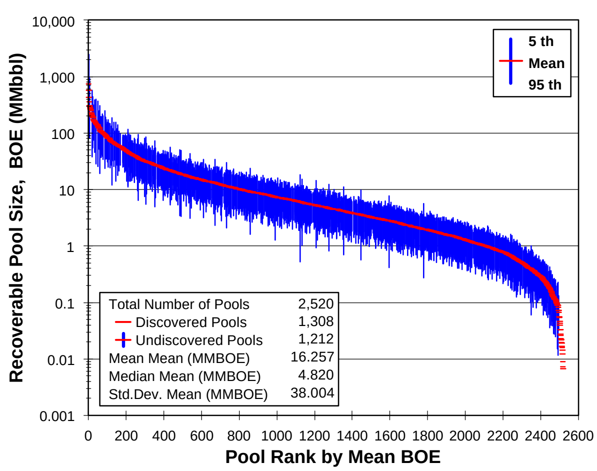


Figure 3. Pool rank plot.

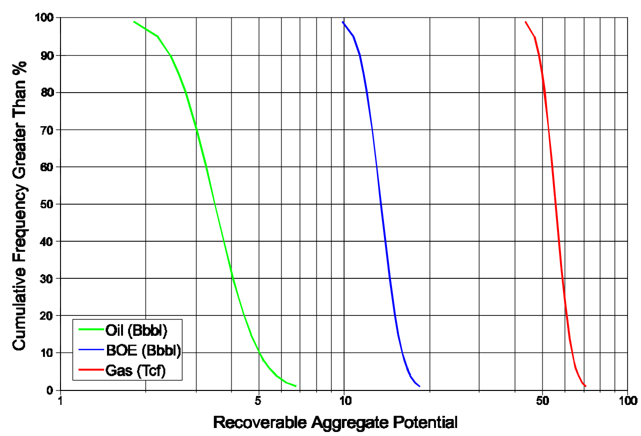


Figure 4. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	1,277	7.537	83.183	22.338
Cumulative production	--	6.078	66.350	17.884
Remaining proved	--	1.458	16.833	4.453
Unproved	31	0.314	1.918	0.656
Appreciation (P & U)	--	1.301	17.300	4.379
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	2.198	46.782	10.785
Mean	1,212	3.643	55.994	13.607
5th percentile	--	5.574	66.272	16.854
Total Endowment				
95th percentile	--	11.350	149.184	38.158
Mean	2,520	12.795	158.396	40.980
5th percentile	--	14.726	168.674	44.227

Cretaceous System

System Description

The Cretaceous System comprises the Lower Cretaceous and the Upper Cretaceous Series in the Gulf of Mexico Mesozoic Province. Five plays were identified and assessed in the Cretaceous System, one established play, three frontier plays, and one conceptual play. Figure 1 illustrates the overall extent of these plays.

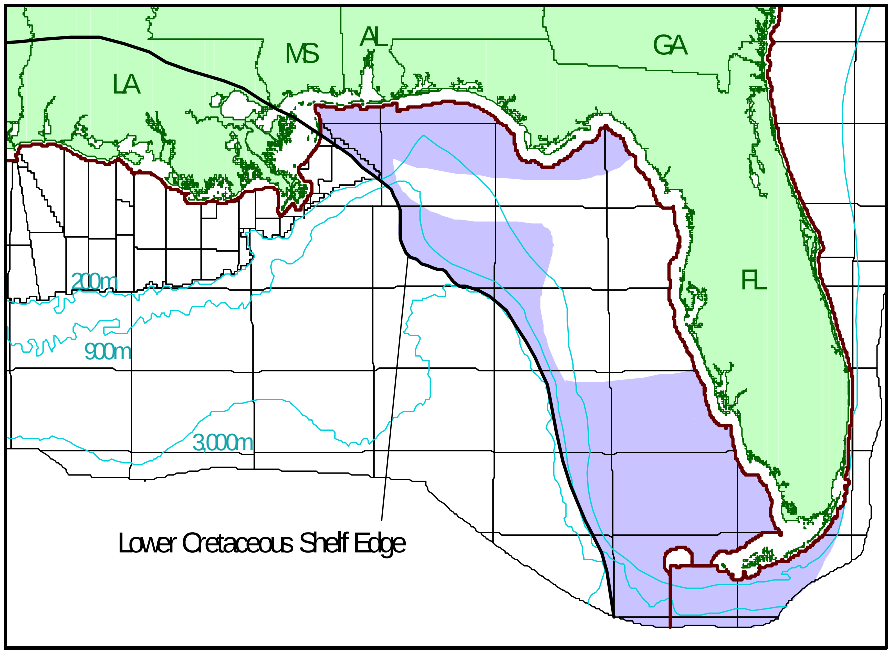


Figure 1. Map of assessed system.

Discoveries

Of the five plays in the System, the Lower Cretaceous Shelf-Margin Carbonate (LK CB) play is the only play that has discovered pools, with two (table 1 and figure 2).

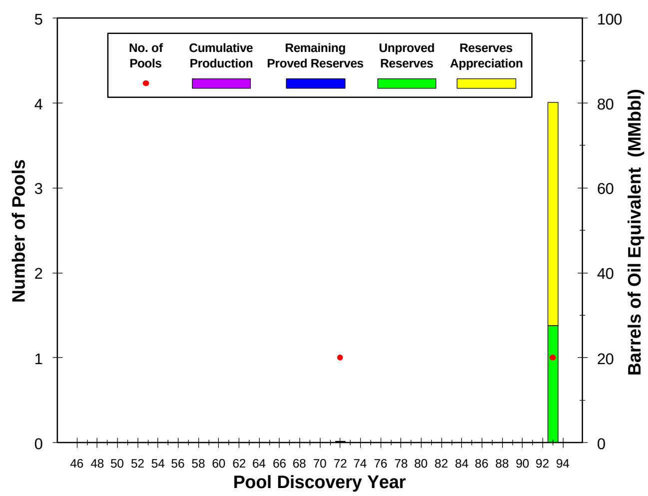


Figure 2. Exploration history graph.

Assessment Results

The Cretaceous System contains 144 pools (2 discovered pools plus 142 undiscovered pools), with a mean total endowment of 1.436 Bbo and 1.375 Tcfg (1.680 BBOE) (table 2 and figure 3).

Table 1. Characteristics of the discovered pools.

2 Pools (2 Reservoirs)	Minimum	Mean	Maximum
Water depth (feet)	120	204	288
Subsea depth (feet)	8,700	11,500	14,300
Number of reservoirs per pool	1	1	1
Porosity	10%	15%	20%
Water saturation	26%	29%	32%

Undiscovered resources have a range of 0.905 to 2.121 Bbo and 0.519 to 1.525 Tcfg at the 95th and 5th percentiles, respectively (figure 4). At mean levels, the undiscovered resources in the Cretaceous System are estimated at 1.433 Bbo and 0.939 Tcfg (1.600 BBOE).

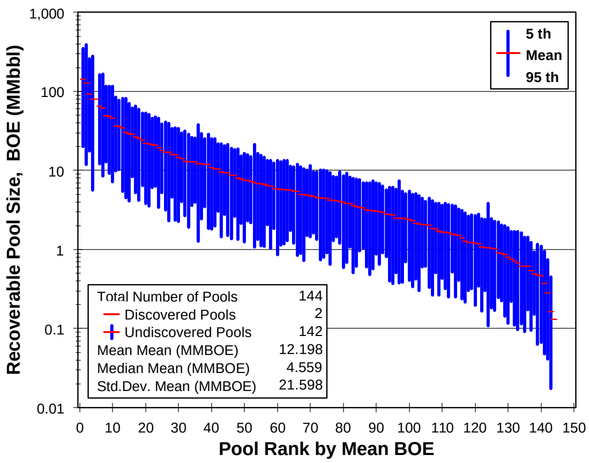


Figure 3. Pool rank plot.

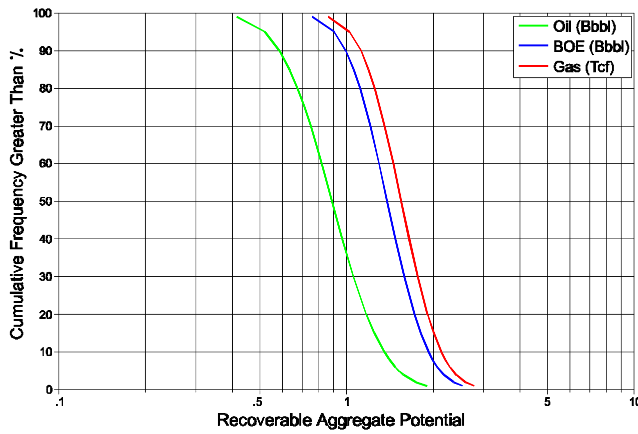


Figure 4. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	1	<0.001	<0.001	<0.001
Cumulative production	--	<0.001	<0.001	<0.001
Remaining proved	--	0.000	0.000	0.000
Unproved	1	0.001	0.150	0.028
Appreciation (P & U)	--	0.002	0.285	0.052
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.905	0.519	1.026
Mean	142	1.433	0.939	1.600
5th percentile	--	2.121	1.525	2.343
Total Endowment				
95th percentile	--	0.908	0.955	1.106
Mean	144	1.436	1.375	1.680
5th percentile	--	2.124	1.961	2.423

JURASSIC SYSTEM

The Jurassic System comprises the Lower, Middle, and Upper Jurassic Series. However, only the Upper Jurassic Series contains assessed plays. The Upper Jurassic Series contains only one chronozone [see Upper Jurassic (UU) Chronozone].

TRIASSIC SYSTEM

The Triassic System comprises the Upper Triassic Series, which contains only one chronozone [see Upper Triassic (UTR) chronozone].

ATLANTIC CRETACEOUS SYSTEM

The Atlantic Cretaceous System comprises the Lower and Upper Cretaceous Series. However, only the Atlantic Lower Cretaceous Series contains a chronozone with an assessed play [see Atlantic Lower Cretaceous Clastic (ALK CL) play].

ATLANTIC JURASSIC SYSTEM

SYSTEM DESCRIPTION

The Atlantic Jurassic System comprises the Lower, Middle, and Upper Jurassic Series. Four frontier and three conceptual plays are identified within the Atlantic Jurassic System. However, only the four frontier plays are assessed. The three conceptual plays were not assessed due to poor source rock potential and lack of known hydrocarbons in structurally analogous areas. Figure 1 illustrates the overall extent of the assessed plays in the Atlantic Jurassic System.

DISCOVERIES

No pools in the Atlantic Jurassic System have as yet been discovered in the Federal OCS area.

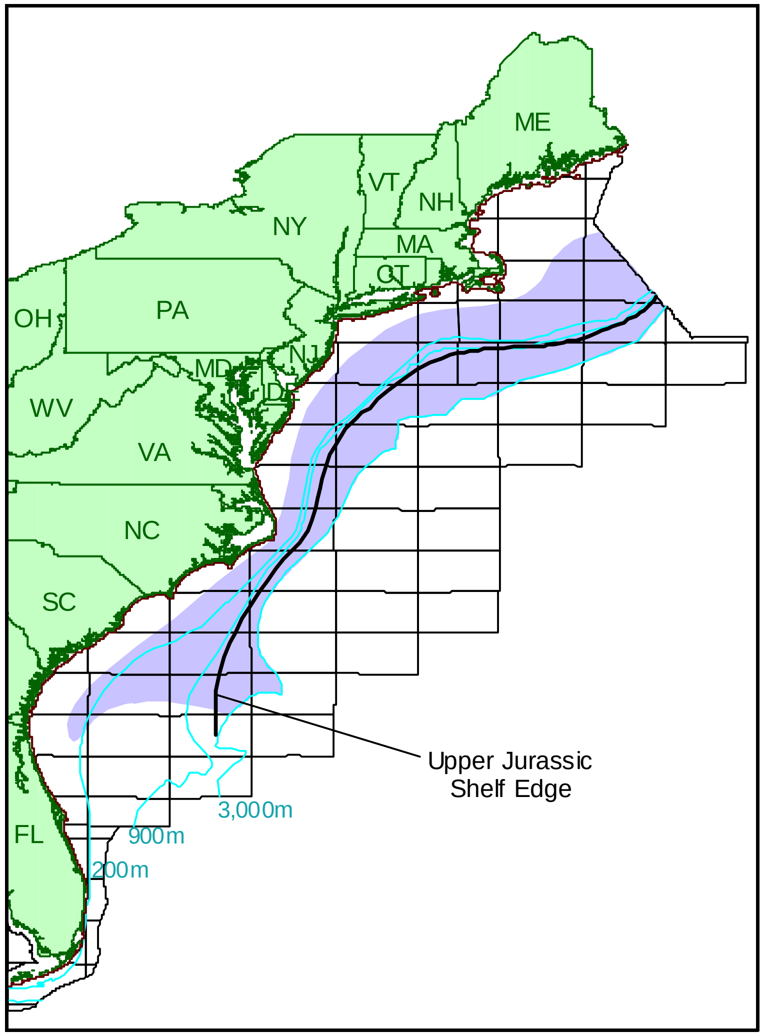


Figure 1. Map of assessed system.

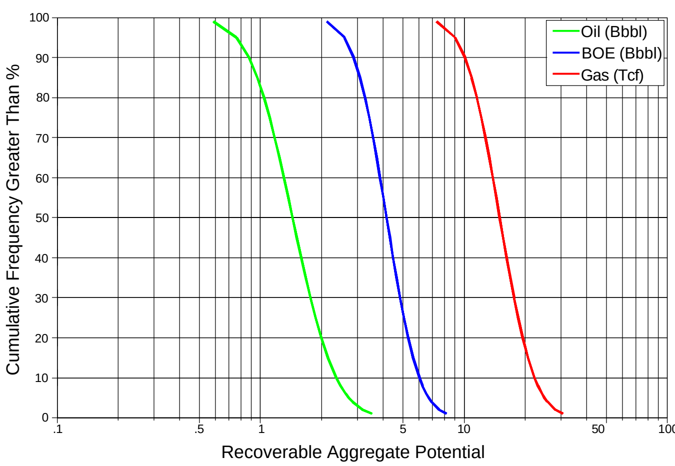


Figure 2. Cumulative probability distribution.

ASSESSMENT RESULTS

Undiscovered resources for the Atlantic Jurassic System have a range of 0.762 to 2.714 Bbo and 9.040 to 24.847 Tcfg at the 95th and 5th percentiles, respectively (figure 2 and table 1). At mean levels, the undiscovered resources are estimated at 1.549 Bbo and 15.712 Tcfg (4.345 BBOE). These undiscovered resources may occur in as many as 382 pools (figure 3).

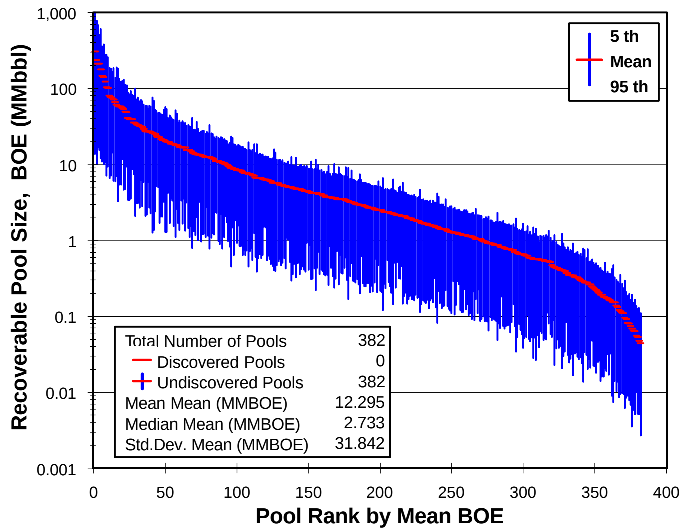


Figure 3. Pool rank plot.

Table 1. Assessment results.

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	--	0.762	9.040	2.584
Mean	382	1.549	15.712	4.345
5th percentile	--	2.714	24.847	6.716
Total Endowment				
95th percentile	--	0.762	9.040	2.584
Mean	382	1.549	15.712	4.345
5th percentile	--	2.714	24.847	6.716

ATLANTIC TRIASSIC SYSTEM

The Atlantic Triassic System comprises the Atlantic Upper Triassic Series, which contains only one chronozone [see Atlantic Upper Triassic (AUTR) chronozone].

PLEISTOCENE SERIES

SERIES DESCRIPTION

The Pleistocene Series comprises the lower Pleistocene (LPL), middle Pleistocene (MPL), and upper Pleistocene (UPL) chronozones. Nine established plays were identified by their retrogradational, aggradational, progradational, or fan depositional styles and assessed. In addition, two unassessed plays— the Middle Pleistocene Caprock (MPL C) play and the Upper Pleistocene Caprock (UPL C) play— that contain reserves are included in the Pleistocene Series. Both Caprock plays are established, but are unique and of such limited occurrence that additional discoveries are unlikely. Figure 1 illustrates the overall extent of the plays in the Pleistocene Series.

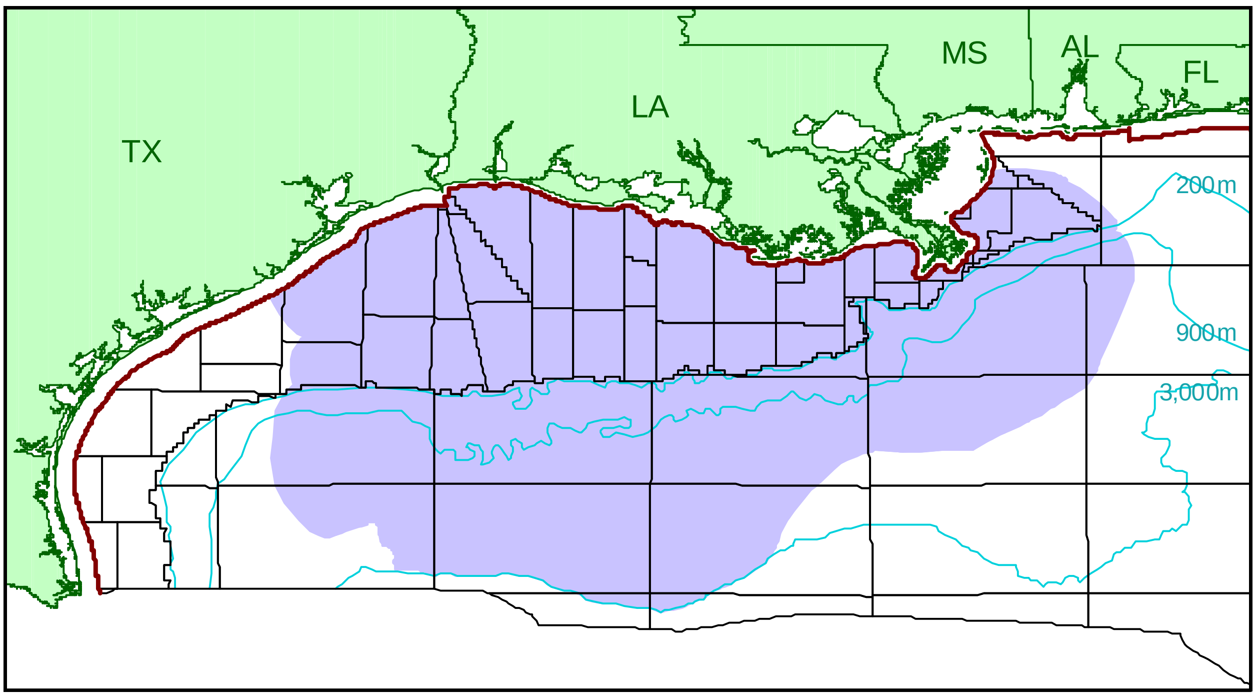


Figure 1. Map of assessed series.

DISCOVERIES

The Pleistocene Series contains 864 discovered pools, with the earliest discovery dating back to 1947 (table 1 and figure 2). The number of pool discoveries per year substantially increased after 1970. Discoveries made from 1971 through 1977 account for over 40 percent of the total reserves and over 50 percent of the cumulative production for the Pleistocene Series.

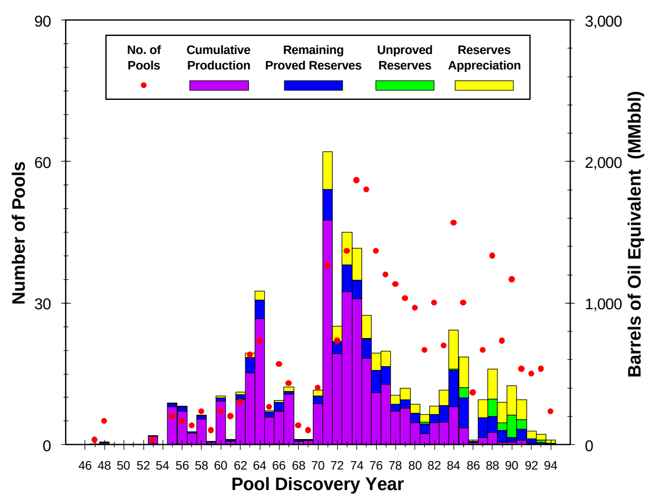


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

864 Pools (3,731 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	12	298	6,950
Subsea depth (feet)	950	6,154	16,950
Number of sands per pool	1	4	42
Porosity	17%	30%	38%
Water saturation	7%	26%	62%

ASSESSMENT RESULTS

The Pleistocene Series contains 1,446 pools (864 discovered pools plus 582 undiscovered pools), with a mean total endowment of 8.492 Bbo and 101.871 Tcfg (26.618 BBOE) (table 2 and figure 3). This is the second largest of the 11 Gulf of Mexico Region Series, based on BOE.

The Pleistocene Series also contains the second largest amount of BOE mean undiscovered resources of the 11 Series, with 2.648 Bbo and 31.560 Tcfg (8.263 BBOE). These undiscovered resources have a range of 2.064 to 3.326 Bbo and 26.116 to 37.668 Tcfg at the 95th and 5th percentiles, respectively (figure 4).

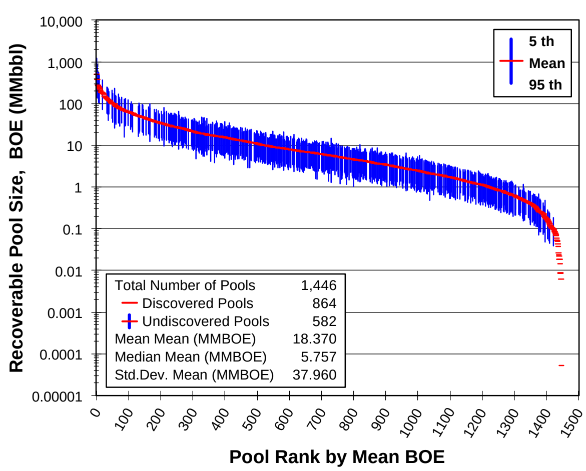


Figure 3. Pool rank plot.

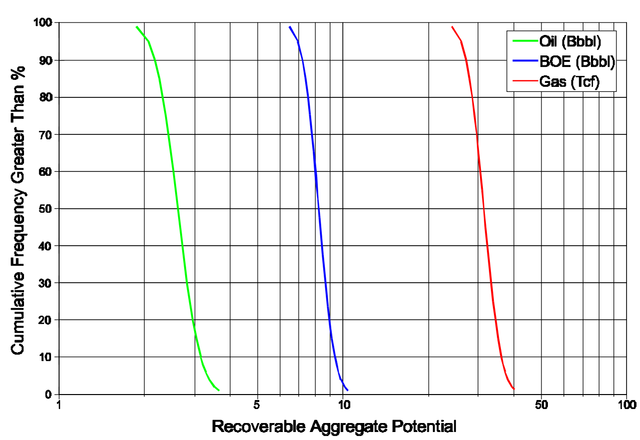


Figure 4. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	828	4.317	57.136	14.483
Cumulative production	--	3.259	46.084	11.459
Remaining proved	--	1.058	11.051	3.024
Unproved	36	0.323	1.088	0.517
Appreciation (P & U)	--	1.204	12.088	3.355
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	2.064	26.116	6.944
Mean	582	2.648	31.560	8.263
5th percentile	--	3.326	37.668	9.731
Total Endowment				
95th percentile	--	7.908	96.427	25.299
Mean	1,446	8.492	101.871	26.618
5th percentile	--	9.170	107.979	28.086

Pliocene Series

Series Description

The Pliocene Series comprises the lower Pliocene (LP) and upper Pliocene (UP) chronozones. Six established plays were identified for the Pliocene Series by their retrogradational, aggradational, progradational, or fan depositional style and assessed. Figure 1 illustrates the overall extent of these plays.

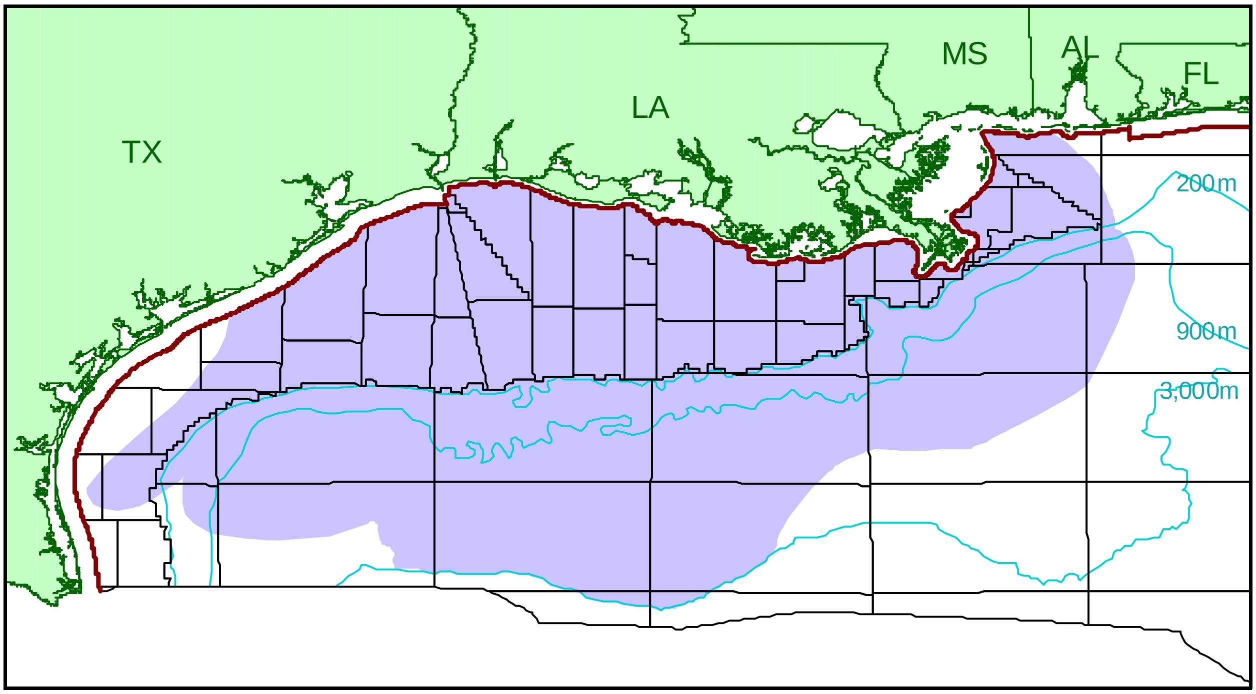


Figure 1. Map of assessed series.

Discoveries

The Pliocene Series contains 400 discovered pools, with the earliest discovery dating back to 1948 (table 1 and figure 2). Over 75 percent of the cumulative production and 60 percent of the total reserves for the Pliocene Series are associated with pools discovered prior to 1970. However, 57 percent of the total number of pools in the Pliocene Series were discovered in 1970 or later and are indicative of the smaller size of these more recent discoveries.

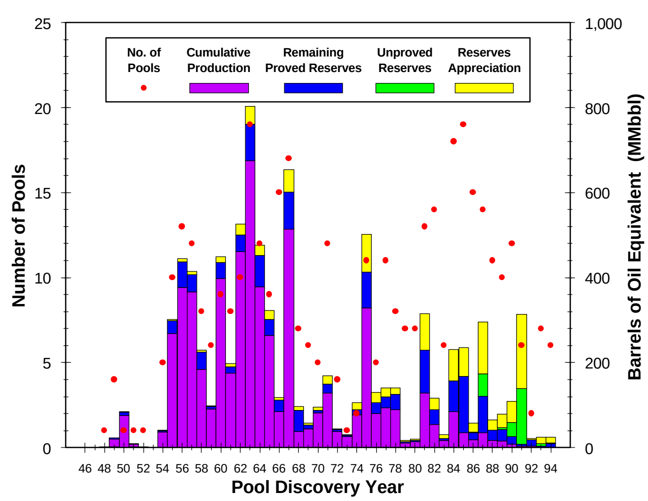


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

400 Pools (1,815 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	12	232	7,500
Subsea depth (feet)	1,889	8,956	19,216
Number of sands per pool	1	5	36
Porosity	21%	29%	37%
Water saturation	12%	28%	61%

ASSESSMENT RESULTS

The Pliocene Series contains 684 pools (400 discovered pools plus 284 undiscovered pools), with a mean total endowment of 5.030 Bbo and 34.740 Tcfg (11.211 BBOE) (table 2 and figure 3). This is the third largest of the 11 Gulf of Mexico Region Series.

The Pliocene Series also contains the third largest amount of BOE mean undiscovered resources of the 11 Series, with 0.961 Bbo and 8.922 Tcfg (2.548 BBOE). These undiscovered resources have a range of 0.788 to 1.155 Bbo and 7.452 to 10.562 Tcfg at the 95th and 5th percentiles, respectively (figure 4).

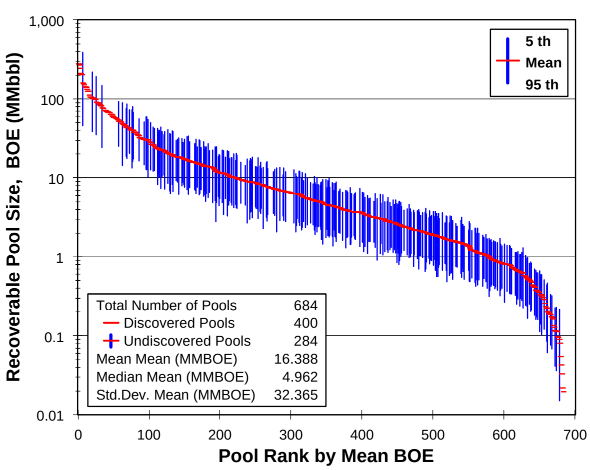


Figure 3. Pool rank plot.

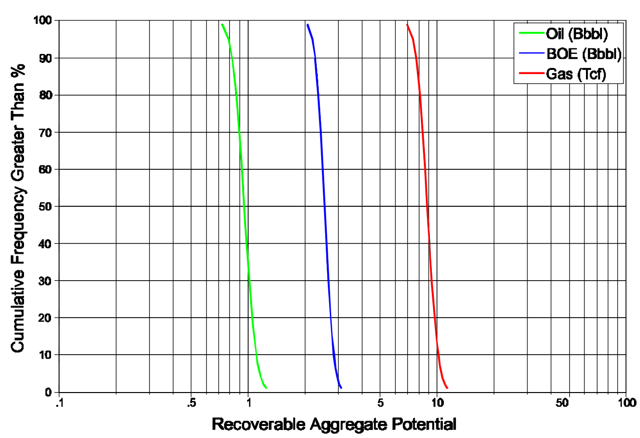


Figure 4. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	387	3.412	21.715	7.276
Cumulative production	--	2.757	17.354	5.845
Remaining proved	--	0.655	4.361	1.431
Unproved	13	0.131	0.554	0.229
Appreciation (P & U)	--	0.526	3.548	1.158
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.788	7.452	2.193
Mean	284	0.961	8.922	2.548
5th percentile	--	1.155	10.562	2.938
Total Endowment				
95th percentile	--	4.857	33.270	10.856
Mean	684	5.030	34.740	11.211
5th percentile	--	5.224	36.380	11.601

Miocene Series

Series Description

The Miocene Series comprises the lower lower Miocene (LM1), middle lower Miocene (LM2), upper lower Miocene (LM4), lower middle Miocene (MM4), middle middle Miocene (MM7), upper middle Miocene (MM9), lower upper Miocene (UM1), and upper upper Miocene (UM3) chronozones. Thirty-three established plays were identified by either their depositional style (retrogradational, aggradational, progradational, or fan) or by their structural style ("Corsair" or "Seagull") within the Miocene Series. Figure 1 illustrates the overall extent of these assessed plays.

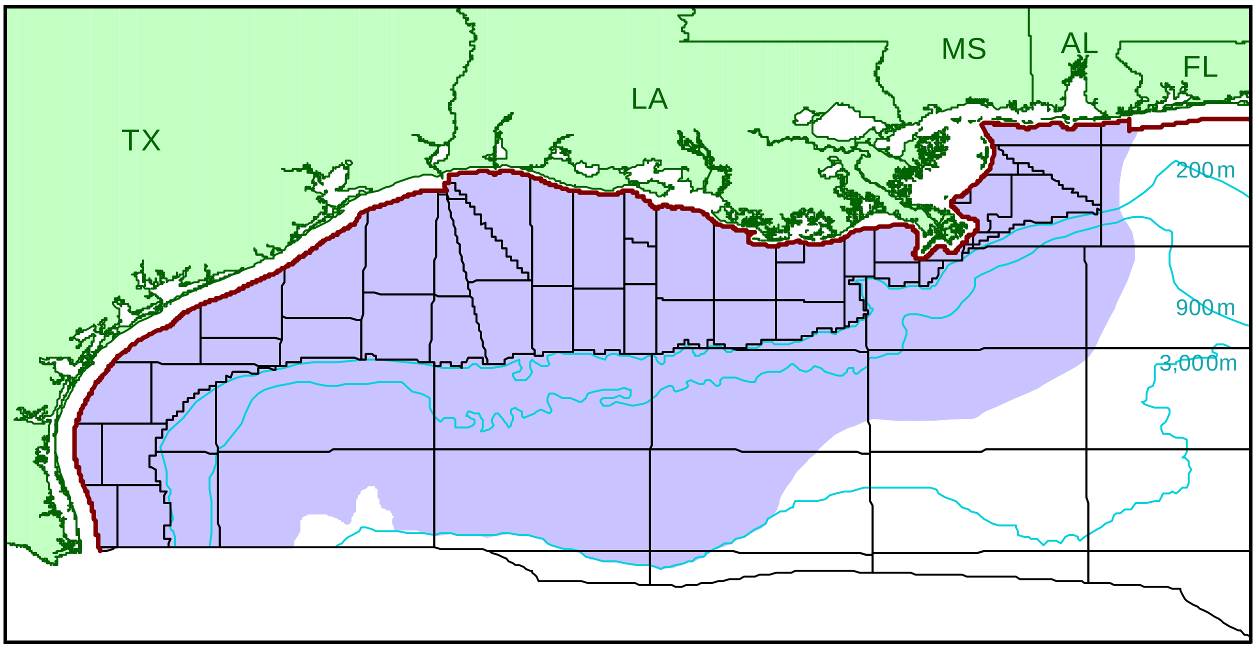


Figure 1. Map of assessed series.

Discoveries

The Miocene Series contains 908 discovered pools, with the earliest discovery dating back to 1947 (table 1 and figure 2). The number of discoveries per year substantially increased after 1975, with over 60 percent of the pool discoveries in the Miocene Series occurring after 1975. However, the post-1975 discoveries added only 43 percent of the total reserves to the Miocene Series and are indicative of the smaller size of these

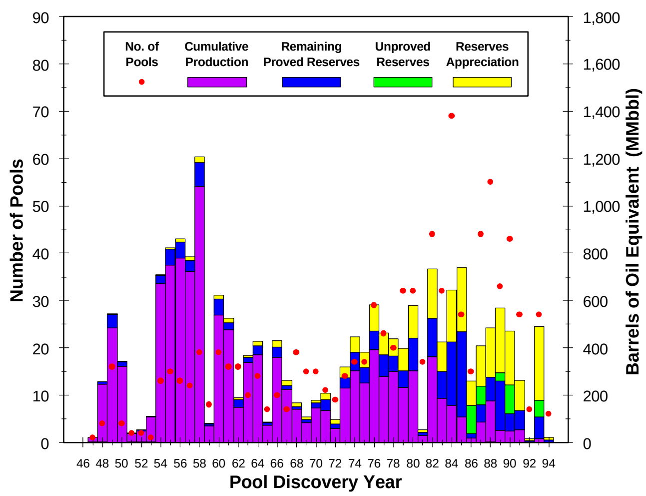


Figure 2. Exploration history graph.

more recent discoveries.

Table 1. Characteristics of the discovered pools.

908 Pools (3,299 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	9	147	7,500
Subsea depth (feet)	1,500	8,930	18,800
Number of sands per pool	1	4	45
Porosity	14%	28%	39%
Water saturation	9%	29%	66%

ASSESSMENT RESULTS

The Miocene Series contains 1,796 pools (908 discovered pools plus 888 undiscovered pools), with a mean total endowment of 6.963 Bbo and 118.070 Tcfg (27.972 BBOE) (table 2 and figure 3). This is the largest of the 11 Gulf of Mexico Region Series, based on BOE.

The Miocene Series also contains the largest amount of BOE mean undiscovered resources of the 11 Series, with 1.880 Bbo and 41.486 Tcfg (9.262 BBOE). These undiscovered resources have a range of 1.559 to 2.240 Bbo and 35.278 to 48.341 Tcfg at the 95th and 5th percentiles, respectively (figure 4).

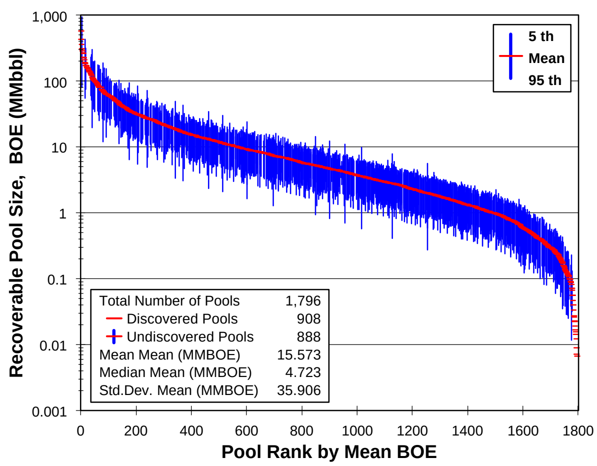


Figure 3. Pool rank plot.

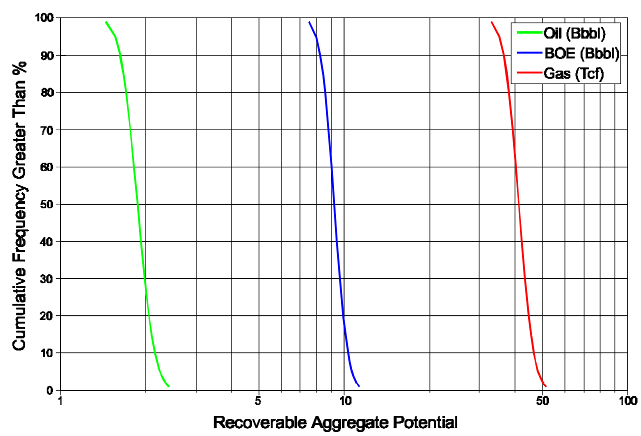


Figure 4. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	890	4.124	61.468	15.062
Cumulative production	--	3.321	48.996	12.039
Remaining proved	--	0.803	12.472	3.022
Unproved	18	0.184	1.364	0.426
Appreciation (P & U)	--	0.775	13.752	3.222
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	1.559	35.278	7.981
Mean	888	1.880	41.486	9.262
5th percentile	--	2.240	48.341	10.665
Total Endowment				
95th percentile	--	6.642	111.862	26.691
Mean	1,796	6.963	118.070	27.972
5th percentile	--	7.323	124.925	29.375

OLIGOCENE/EOCENE SERIES

The Oligocene/Eocene Series contains only one combined chronozone [see Oligocene/Eocene (O/E) chronozone].

PALEOCENE SERIES

The Paleocene Series contains only one chronozone [see Paleocene (L) chronozone].

UPPER CRETACEOUS SERIES

The Upper Cretaceous Series contains only one chronozone, which contains only one play [see Upper Cretaceous Clastic (UK CL) play].

LOWER CRETACEOUS SERIES

The Lower Cretaceous Series contains only one chronozone [see Lower Cretaceous (LK) chronozone].

UPPER JURASSIC SERIES

The Upper Jurassic Series contains only one chronozone [see Upper Jurassic (UU) chronozone].

MIDDLE JURASSIC SERIES

The Middle Jurassic Series contains only one chronozone, which contains only one play [see Middle Jurassic to Upper Jurassic Florida Basal Clastic (MU-UU FBCL) play].

LOWER JURASSIC SERIES

The Lower Jurassic Series contains only one chronozone [see Lower Jurassic (LU) chronozone].

UPPER TRIASSIC SERIES

The Upper Triassic Series contains only one chronozone [see Upper Triassic (UTR) chronozone].

ATLANTIC UPPER CRETACEOUS SERIES

The Atlantic Upper Cretaceous Series contains only one chronozone, which contains only one play [see Atlantic Upper Cretaceous Clastic (AUK CL) play].

ATLANTIC LOWER CRETACEOUS SERIES

The Atlantic Lower Cretaceous Series contains only one chronozone, which contains only one play [see Atlantic Lower Cretaceous Clastic (ALK CL) play].

ATLANTIC UPPER JURASSIC SERIES

The Atlantic Upper Jurassic Series contains only one chronozone [see Atlantic Upper Jurassic (AUU) chronozone].

ATLANTIC MIDDLE JURASSIC SERIES

The Atlantic Middle Jurassic Series contains only one chronozone [see Atlantic Middle Jurassic (AMU) chronozone].

ATLANTIC LOWER JURASSIC SERIES

The Atlantic Lower Jurassic Series contains only one chronozone, which contains only one play [see Atlantic Jurassic to Cretaceous Diapir (AU-K DIA) play].

ATLANTIC UPPER TRIASSIC SERIES

The Atlantic Upper Triassic Series contains only one chronozone [see Atlantic Upper Triassic (AUTR) chronozone].

UPPER PLEISTOCENE (UPL) CHRONOZONE

CHRONOZONE DESCRIPTION

The Upper Pleistocene (UPL) chronozone corresponds to the *Hyalinea* "B," *Trimosina* "A" 2nd occurrence, and *Trimosina* "A" 1st occurrence biozones, and Sangamon fauna. The UPL section reflects delta systems prograding onto the continental shelf and fan deposition on the continental slope of the Gulf of Mexico Basin. Depositional styles present in the UPL chronozone include aggradational, progradational, and fan, each of which defines a play: the Upper Pleistocene Aggradational (UPL A) play, the Upper Pleistocene Progradational (UPL P) play, and the Upper Pleistocene Fan (UPL F) play. Another play identified in the chronozone, the Upper Pleistocene Caprock (UPL C) play, was not assessed because it contains only one field and is of such limited occurrence that additional discoveries are unlikely. Retrogradational sands associated with marine transgressions also occur locally in the play areas at the top of the progradational and aggradational deposits. Because these retrogradational sands are discontinuous over any significant distance, they are included as part of the underlying deposits.

The potential for sand development within the UPL chronozone extends from the nearshore Brazos to the deepwater Alaminos Canyon Areas northeastward to the Main Pass, Viosca Knoll, and western Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). Updip, UPL sands continue onshore, except in the eastern Texas and western Louisiana areas where the chronozone's sediments are so shallow that they are no longer logged or where they can no longer be correlated. To the west and northeast, potential for sand development within the UPL chronozone is limited by a lack of sediment influx at the edges of the UPL depocenter. The downdip limit extends at least as far as the Sigsbee Escarpment as indicated by UPL sand development in the OCS

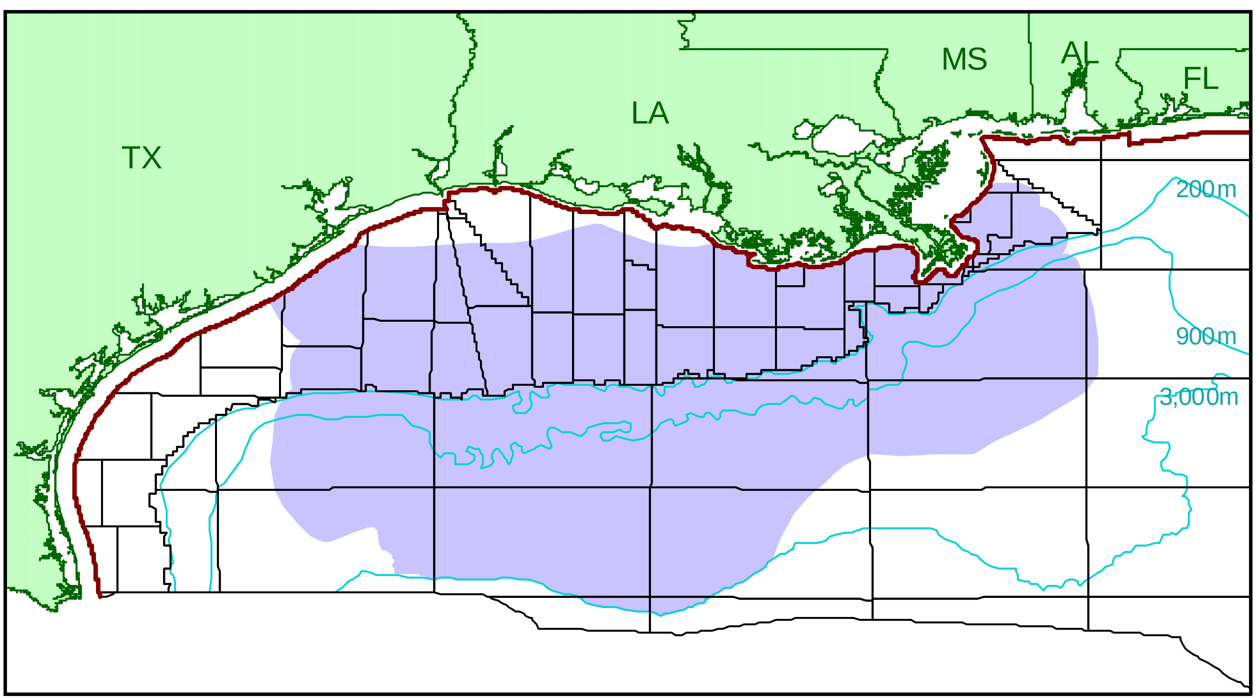


Figure 1. Map of assessed chronozone.

G11643-1 well in Keathley Canyon block 255 and by correlation of chronozone tops to seismic data.

No significant lateral shift in the Louisiana depocenter is observed from the underlying middle Pleistocene (MPL) chronozone to the UPL chronozone. The aggradational and progradational sediments of the UPL chronozone extend farther basinward than do those sediments of the MPL chronozone, indicative of delta progradation.

Major structural features in the UPL chronozone are salt diapirs, anticlines, and growth faults. Other structures include normal faults, shale diapirs, and stratigraphic pinch-outs.

DISCOVERIES

The UPL chronozone contains 233 discovered pools in four plays (table 1). Significant amounts of hydrocarbons were recently identified in the UPL chronozone in the Garden Banks 387 field ("Cooper"). Total reserves in the chronozone are 1.161 Bbo and 19.608 Tcfg (4.650 BBOE), of which 0.398 Bbo and 12.842 Tcfg (2.683 BBOE) have been produced. The largest number of discoveries in the UPL chronozone occurred when 25 pools were added in 1974 (figure 2). However, the maximum yearly total reserves of 794.753 MMBOE were added in 1973 with the discovery of 18 pools.

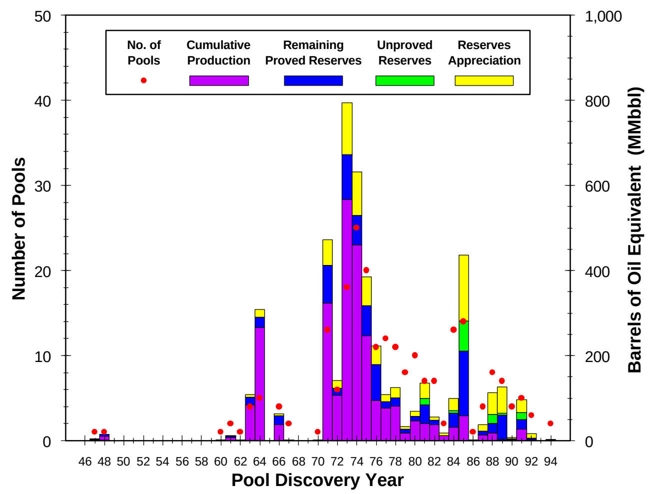


Figure 2. Exploration history graph.

Of the four plays in the UPL chronozone, the UPL P play contains the most total reserves in 135 pools, with 0.560 Bbo and 13.761 Tcfg (3.009 BBOE).

Table 1. Characteristics of the discovered pools.

233 Pools (870 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	18	325	3,180
Subsea depth (feet)	950	4,311	12,757
Number of sands per pool	1	4	27
Porosity	23%	31%	38%
Water saturation	10%	26%	47%

ASSESSMENT RESULTS

The UPL chronozone contains 395 pools (discovered plus undiscovered), with a mean total endowment estimated at 2.497 Bbo and 30.924 Tcfg (8.000 BBOE) (table 2). This is the second largest BOE mean total endowment of all 21 chronozones in the Gulf of Mexico Region.

Assessment results indicate that undiscovered resources may occur in as many as 162 pools, which contain a range of 0.962 to 1.791 Bbo and 9.813 to 12.957 Tcfg at the 95th and 5th percentiles, respectively (figure 3). At mean levels, 1.336 Bbo and 11.316 Tcfg (3.350 BBOE) are projected. These undiscovered resources represent 42 percent of the UPL chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the largest in the chronozone (figure 4). Additionally, when compared with the other Gulf of Mexico chronozones, the UPL chronozone is projected to contain the second largest amount of mean undiscovered oil and the third largest amount of mean undiscovered gas.

Of the four UPL plays, the UPL F play is projected to contain the greatest

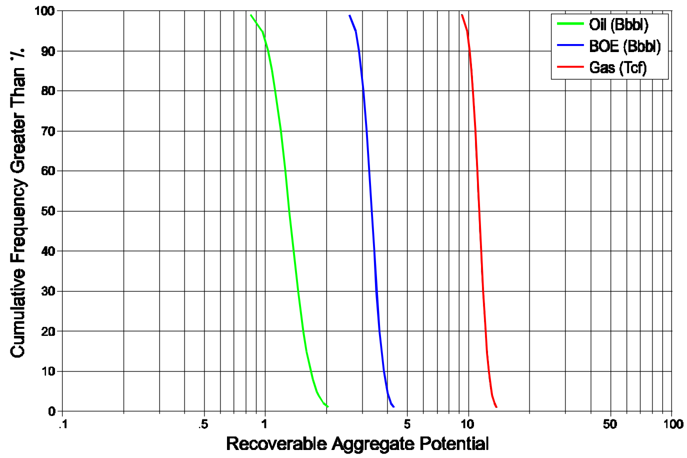


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	223	0.744	16.069	3.604
Cumulative production	--	0.398	12.842	2.683
Remaining proved	--	0.347	3.227	0.921
Unproved	10	0.100	0.199	0.135
Appreciation (P & U)	--	0.317	3.339	0.911
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.962	9.813	2.785
Mean	162	1.336	11.316	3.350
5th percentile	--	1.791	12.957	3.982
Total Endowment				
95th percentile	--	2.123	29.421	7.435
Mean	395	2.497	30.924	8.000
5th percentile	--	2.952	32.565	8.632

exploration potential, with mean undiscovered resources estimated at 1.198 Bbo and 8.448 Tcfg (2.701 BBOE) remaining to be found in 100 pools. These undiscovered resources in the UPL F play represent 34 percent of the BOE mean total endowment for the UPL chronozone. This high percentage, the potential for numerous discoveries within a large unexplored area, the potential for excellent-quality UPL sand development in deepwater areas, and prolific existing fan production make the UPL F play an attractive exploration target in UPL strata.

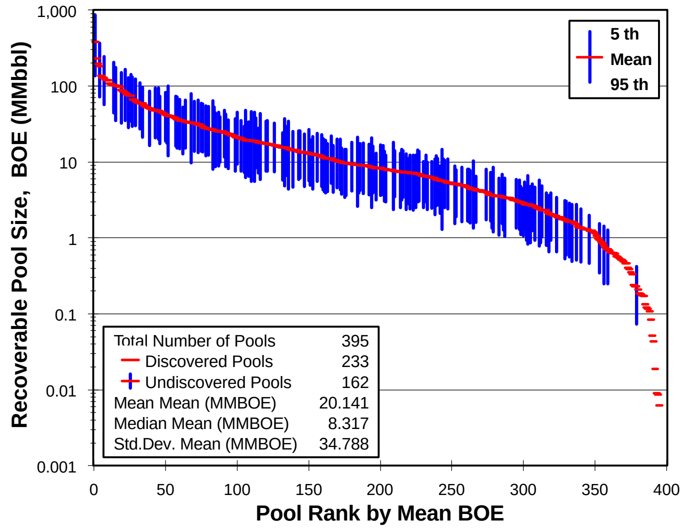


Figure 4. Pool rank plot.

UPPER PLEISTOCENE AGGRADATIONAL (UPL A) PLAY

PLAY DESCRIPTION

The established Upper Pleistocene Aggradational (UPL A) play occurs within the *Hyalinea* "B," *Trimosina* "A" 2nd occurrence, and *Trimosina* "A" 1st occurrence biozones, and Sangamon fauna. This play extends from the northeastern Brazos Area offshore Texas northeastward into the Chandeleur and Main Pass Areas east of the present-day Mississippi River Delta (figure 1).

The updip limit of the play extends onshore into Texas in the Brazos and Galveston Areas and into Louisiana from the Ship Shoal to Chandeleur Areas. Otherwise, the updip limit for the UPL A play occurs where the play is so shallow that it is no longer logged or where it can no longer be correlated. To the northeast and west, the play is limited by a lack of sediment influx at the edges of the UPL depocenter. Downdip, the play grades into the shelf deposits of the Upper Pleistocene Progradational (UPL P) play.

The UPL A play extends farther basinward than does the Middle Pleistocene Aggradational (MPL A) play. This basinward shift reflects the prograding nature of the delta systems through time.

PLAY CHARACTERISTICS

The productive UPL A play consists of delta plain and shallow marine shelf deposits that formed as distributary channels, channel/levee complexes, barrier and distributary mouth bars, delta front and fringe sands, and shelf slumps. In addition, retrogradational sands locally cap the UPL A play. Because these retrogradational, reworked sands are so discontinuous, they are included as part of the UPL A play. Anticlines, salt diapirs, and growth faults are the major structural features in the play. Normal faults and shale diapirs

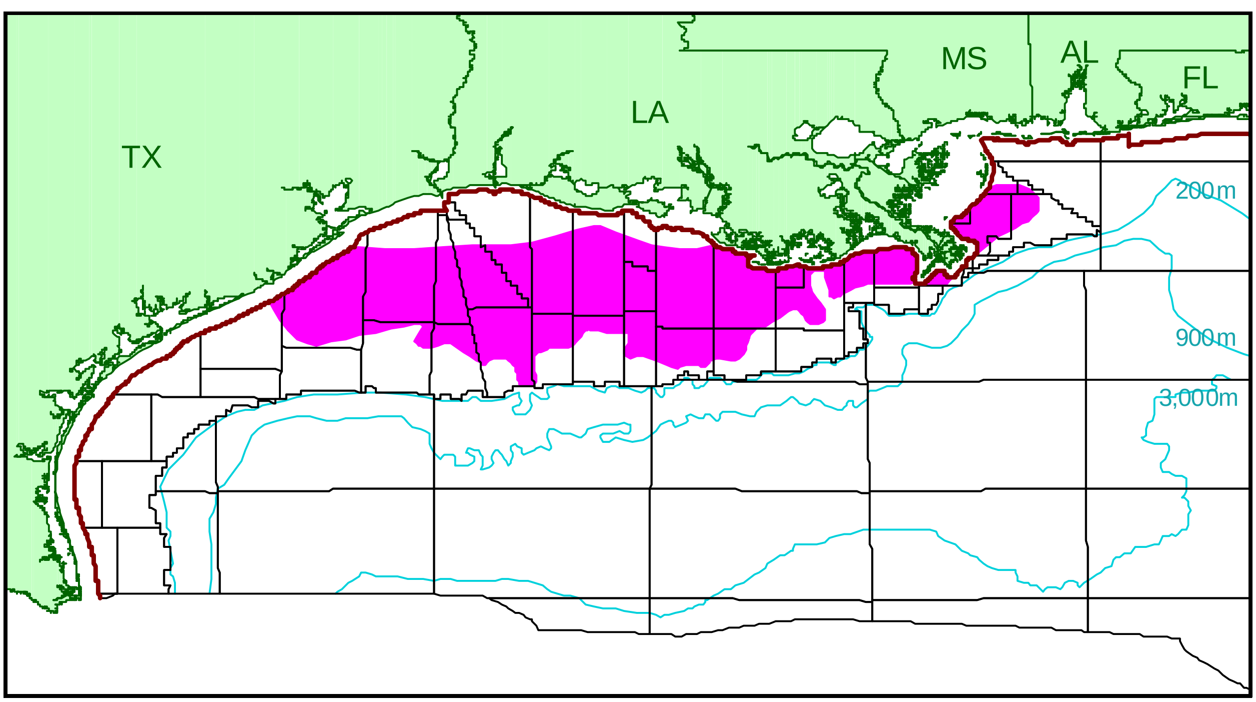


Figure 1. Map of assessed play.

also occur, but less frequently. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive aggradational depositional environments, structures, or seals.

Eugene Island 266 is the type field. Conoco's BT (Apache's 2000) and CP sands and Apache's 2600 sand represent the UPL A play in this field.

DISCOVERIES

The UPL A gas play contains total reserves of 0.109 Bbo and 3.072 Tcfg (0.655 BBOE), of which 0.075 Bbo and 1.915 Tcfg (0.416 BBOE) have been produced. The play contains 175 producible sands in 57 pools (table 1). The first reserves discovered in the play occurred in the Ship Shoal 32 field in 1947 (figure 2). Discoveries were minimal until the 1970's. The maximum yearly total reserves of 197.660 MMBOE were added in 1971 with the discovery of four pools, including the largest pool in the play in the Eugene Island 330 field. Over 85 percent of the play's cumulative production and 80 percent of its total reserves come from pools discovered before 1980. The most recent discoveries, prior to this study's cutoff date of January 1, 1995, were in 1992.

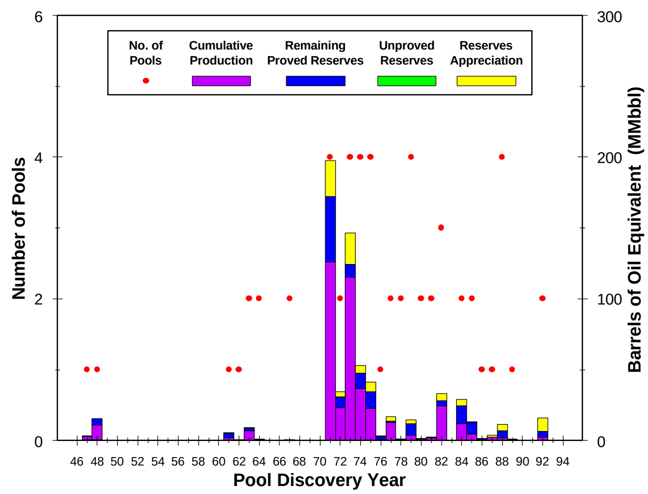


Figure 2. Exploration history graph.

The 57 discovered pools range in size from 0.009 to 135.695 MMBOE. These pools contain 255 reservoirs, of which 204 are nonassociated gas, 39 are undersaturated oil, and 12 are saturated oil.

Of the 11 aggradational plays in the Gulf of Mexico Cenozoic Province, the UPL A play contains the second largest amount of total reserves at 23 percent and has produced the third largest amount of hydrocarbons at 19 percent, based on BOE.

Table 1. Characteristics of the discovered pools.

57 Pools (175 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	18	168	374
Subsea depth (feet)	1,285	2,579	4,675
Number of sands per pool	1	3	15
Porosity	24%	32%	38%
Water saturation	10%	25%	46%

Assessment Results

The marginal probability of hydrocarbons for the UPL A play is 1.00. The play contains a mean total endowment of 0.118 Bbo and 3.217 Tcfg (0.690 BBOE) (table 2). Sixty percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.003 to 0.018 Bbo and 0.111 to 0.181 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.009 Bbo and 0.145 Tcfg (0.035 BBOE). These undiscovered resources may occur in as many as 12 pools. The largest undiscovered pool, with a mean size of 6.176 MMBOE, is modeled as the twentieth largest pool in the play (figure 4). For all the undiscovered pools in the UPL A play, the mean mean size is 2.919 MMBOE, which is smaller than the 11.499 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 10.007 MMBOE.

The UPL A play is well explored. All of the undiscovered pools are modeled to have

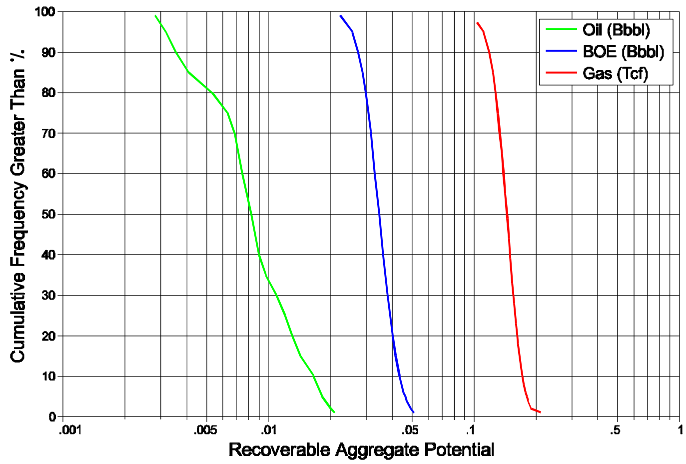


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	57	0.094	2.602	0.557
Cumulative production	--	0.075	1.915	0.416
Remaining proved	--	0.019	0.688	0.141
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.014	0.470	0.098
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.003	0.111	0.026
Mean	12	0.009	0.145	0.035
5th percentile	--	0.018	0.181	0.046
Total Endowment				
95th percentile	--	0.112	3.183	0.681
Mean	69	0.118	3.217	0.690
5th percentile	--	0.127	3.253	0.701

a mean size less than 10 MMBOE, and they contribute only 5 percent to the play's BOE mean total endowment.

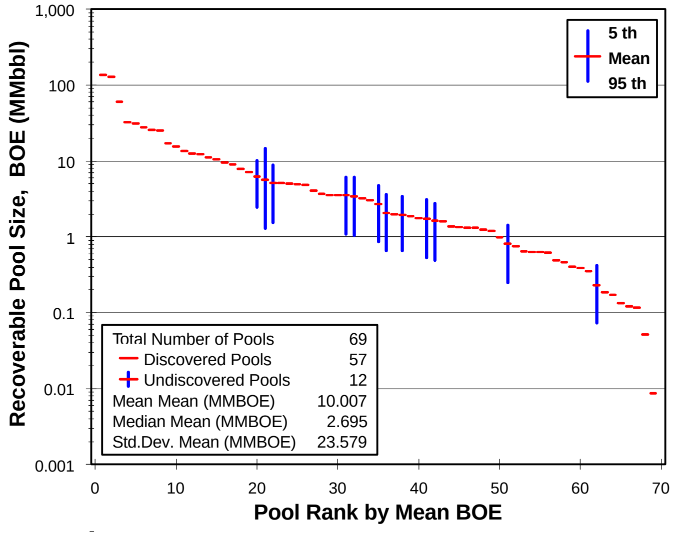


Figure 4. Pool rank plot.

UPPER PLEISTOCENE PROGRADATIONAL (UPL P) PLAY

PLAY DESCRIPTION

The Upper Pleistocene Progradational (UPL P) play is one of the largest established plays in the Gulf of Mexico Region. The play occurs within the *Hyalinea* "B," *Trimosina* "A" 2nd occurrence, and *Trimosina* "A" 1st occurrence biozones, and Sangamon fauna. This play extends from the Galveston Area offshore Texas northeastward into the Main Pass and Viosca Knoll Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the play ends where the progradational deposits grade into the nearshore deposits of the Upper Pleistocene Aggradational (UPL A) play. The UPL P play also extends onshore into Louisiana near the Mississippi River Delta. To the northeast and west, the UPL P play is limited by a lack of sediment influx at the edges of the UPL depocenter. Downdip, the play grades into the deposits of the Upper Pleistocene Fan (UPL F) play.

The UPL P play extends farther basinward than does the Middle Pleistocene Progradational (MPL P) play. This basinward shift reflects the prograding nature of the delta systems through time.

PLAY CHARACTERISTICS

The productive UPL P play consists of progradational deltaic sediments deposited in delta fringe, shelf blanket, distributary mouth bar, distributary channel, and crevasse splay environments. In addition, retrogradational locally cap the UPL P play. Because these retrogradational, reworked sands are so discontinuous, they are included as part of the UPL P play. Major structural features in the play include salt diapirs, anticlines, and growth faults. Normal fault, shale diapirs, and stratigraphic pinch-outs also occur. Seals

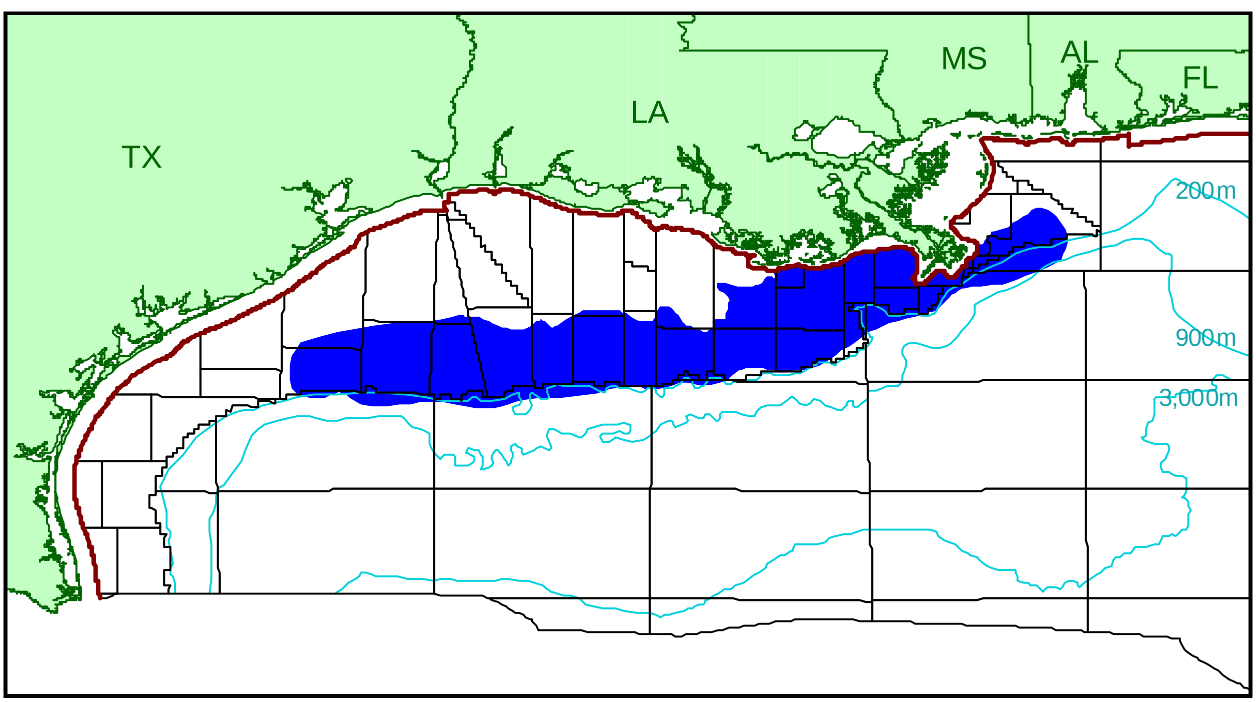


Figure 1. Map of assessed play.

are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive progradational depositional environments, structures, or seals.

Eugene Island 361 is the type field, and Chevron USA Inc.'s 3200, 3400, 3700, 3900, 4000, and 4100 sands represent the UPL P play in this field.

DISCOVERIES

The UPL P gas play contains total reserves of 0.560 Bbo and 13.761 Tcfg (3.009 BBOE), of which 0.208 Bbo and 9.895 Tcfg (1.968 BBOE) have been produced. The play contains 543 producible sands in 135 pools, and 134 of these pools contain proved reserves (table 1). The first reserves discovered in the play occurred in the Grand Isle 43 field in 1960 (figure 2). Discoveries peaked in the mid-1970's. The maximum yearly total reserves of 648.225 MMBOE were added in 1973 with the discovery of 14 pools. However, the largest pool in the play was found in 1964 in the Eugene Island 292 field. Over 75 percent of the play's total reserves and 85 percent of its cumulative production have come from pools discovered in 1975 and earlier. On a BOE basis, 11 percent of the play's cumulative production is oil, but remaining total reserves indicate that future production may increase to 34 percent oil. Seven pools have been discovered in the 1990's, the most recent, prior to this study's cutoff date of January 1, 1995, in 1994.

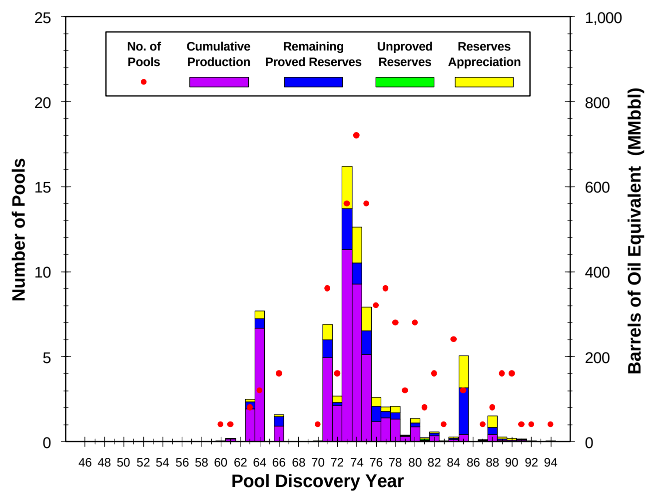


Figure 2. Exploration history graph.

The 135 discovered pools range in size from 0.006 to 230.275 MMBOE. These pools contain 1,015 reservoirs, of which 754 are nonassociated gas, 185 are undersaturated oil, and 76 are saturated oil.

Table 1. Characteristics of the discovered pools.

135 Pools (543 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	40	249	948
Subsea depth (feet)	950	4,110	9,090
Number of sands per pool	1	4	22
Porosity	23%	31%	38%
Water saturation	13%	25%	47%

Of the 61 Gulf of Mexico plays, the UPL P play contains the fifth largest amount of total reserves and has produced the sixth largest amount of hydrocarbons, based on BOE. In fact, the play contains the third-most gas total reserves at 8 percent and has produced the second-most gas at 9 percent.

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the UPL P play is 1.00. This play is the fifth largest in the Gulf of Mexico, based on a mean total endowment of 0.689 Bbo and 16.484 Tcfg (3.623 BBOE) (table 2). Fifty-four percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.066 to 0.212 Bbo and 2.375 to 3.084 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.129 Bbo and 2.723 Tcfg (0.614 BBOE). These undiscovered resources may occur in as many as 50 pools. The

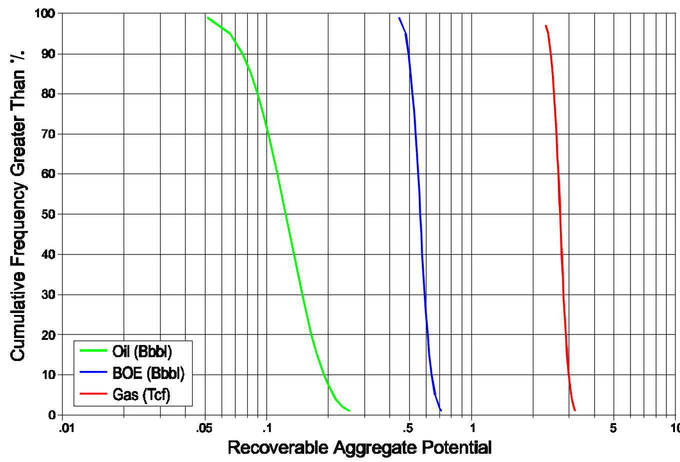


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	134	0.425	11.685	2.504
Cumulative production	--	0.208	9.895	1.968
Remaining proved	--	0.217	1.790	0.536
Unproved	1	<0.001	0.016	0.003
Appreciation (P & U)	--	0.135	2.060	0.502
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.066	2.375	0.518
Mean	50	0.129	2.723	0.614
5th percentile	--	0.212	3.084	0.722
Total Endowment				
95th percentile	--	0.626	16.136	3.527
Mean	185	0.689	16.484	3.623
5th percentile	--	0.772	16.845	3.731

largest undiscovered pool, with a mean size of 50.725 MMBOE, is modeled as the eighteenth largest pool in the play (figure 4). For all the undiscovered pools in the UPL P play, the mean mean size is 12.270 MMBOE, which is smaller than the 22.286 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 19.579 MMBOE.

Of the 14 Gulf of Mexico progradational plays, the UPL P play is projected to contain the second largest amounts of mean undiscovered oil and gas at 19 percent and 16 percent, respectively.

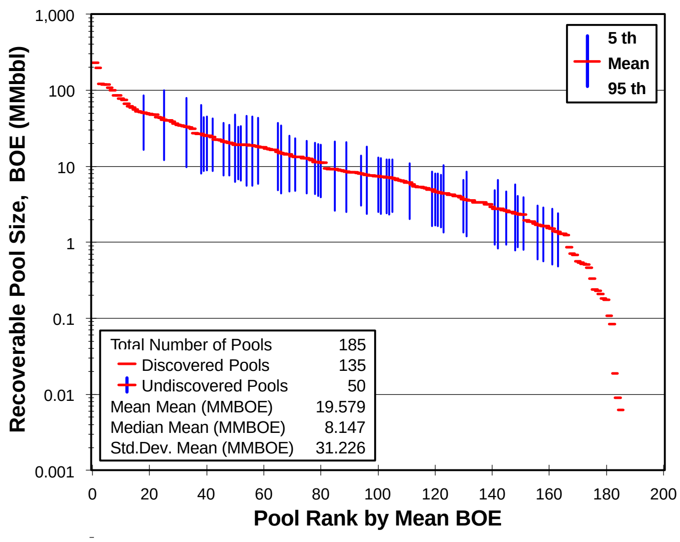


Figure 4. Pool rank plot.

The UPL P play is well explored with the largest pools modeled as already discovered. The undiscovered resources are projected to account for 17 percent of the play's BOE mean total endowment.

UPPER PLEISTOCENE FAN (UPL F) PLAY

PLAY DESCRIPTION

The established Upper Pleistocene Fan (UPL F) play occurs within the *Hyalinea* "B," *Trimosina* "A" 2nd occurrence, and *Trimosina* "A" 1st occurrence biozones, and Sangamon fauna. This play encompasses an area from the southern Galveston, East Breaks, and Alaminos Canyon Areas northeastward to the southern Viosca Knoll and western Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1).

The play ends updip where turbidite sand deposits grade into the deposits of the Upper Pleistocene Progradational (UPL P) play. To the northeast and west, the UPL F play is limited by a lack of sediment influx at the edges of the UPL depocenter. The southern extension of the play's potential to at least the Sigsbee Escarpment is supported by good, reservoir-quality UPL sands in the OCS G11643-1 well in Keathley Canyon block 255 and by correlation of chronozone tops to seismic data.

The UPL shelf/slope break occurs slightly farther basinward than the middle Pleistocene (MPL) shelf/slope break, reflecting the prograding nature of the delta systems through time.

PLAY CHARACTERISTICS

The productive UPL F play consists of deepwater turbidites deposited in fan systems as channel fill, fan lobes, and fringe sheet sediments on the UPL slope between salt highs. Salt diapirs, anticlines, and growth faults are the dominant structural features in this play. Normal faults and shale diapirs also occur, but less frequently. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying

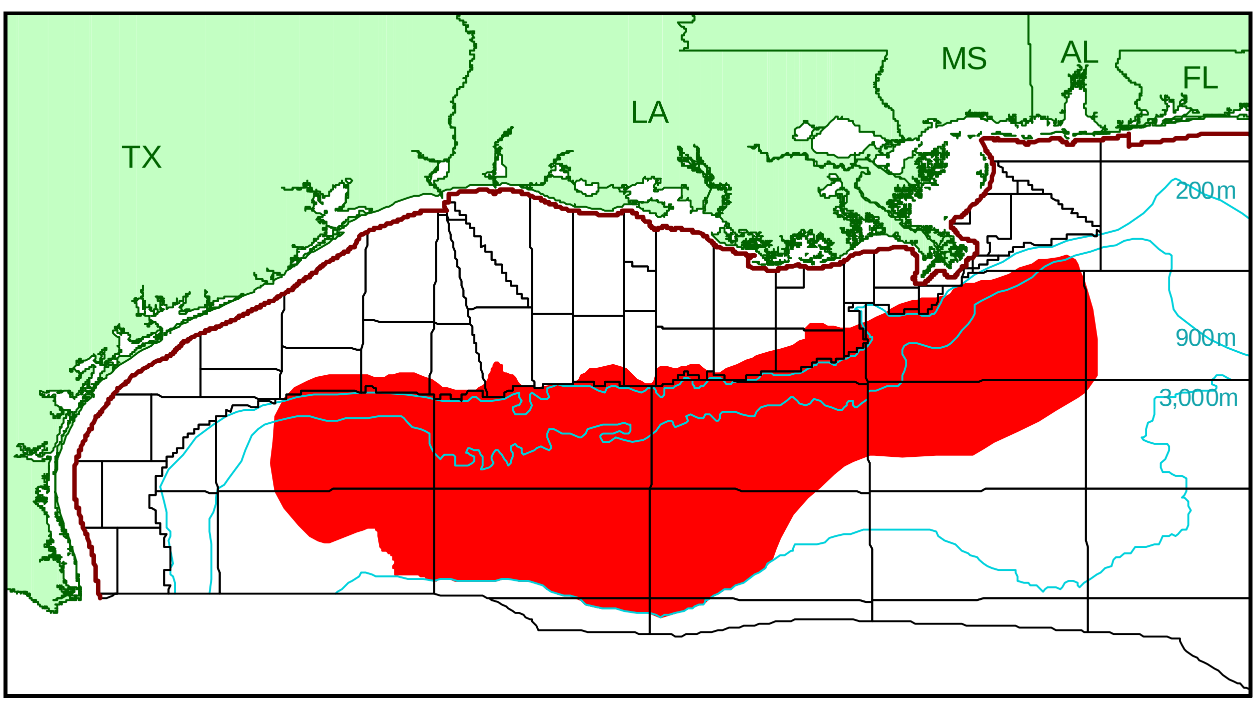


Figure 1. Map of assessed play.

shales). Future discoveries are not limited to the aforementioned productive fan depositional environments, structures, or seals.

Green Canyon 6 is the type field, and Texaco Exploration and Production's I3, I4L, TA1, TA2, TA3U, TA3L, TA4, TA6, and TA7 sands represent the UPL F play in this field.

DISCOVERIES

The UPL F mixed oil and gas play contains total reserves of 0.450 Bbo and 2.769 Tcfg (0.943 BBOE), of which 0.092 Bbo and 1.029 Tcfg (0.275 BBOE) have been produced. The play contains 151 producible sands in 40 pools, and 31 of these pools contain proved reserves (table 1). The first reserves discovered in the play occurred in the High Island 571A field in 1974 (figure 2). The maximum yearly total reserves of 221.549 MMBOE were added in 1985 when nine pools were discovered. Seventy-five percent of the play's total reserves and 96 percent of its cumulative production have come from pools discovered in 1985 and earlier. However, the largest discovered pool in the play was found in 1989 in the Garden Banks 387 field ("Cooper"), and is indicative of the play's deepwater potential. On a BOE basis, 33 percent of the play's cumulative production is oil, but remaining total reserves indicate that future production may increase to 54 percent oil. Four pools have been discovered in the 1990's, the most recent, prior to this study's cutoff date of January 1, 1995, in 1994.

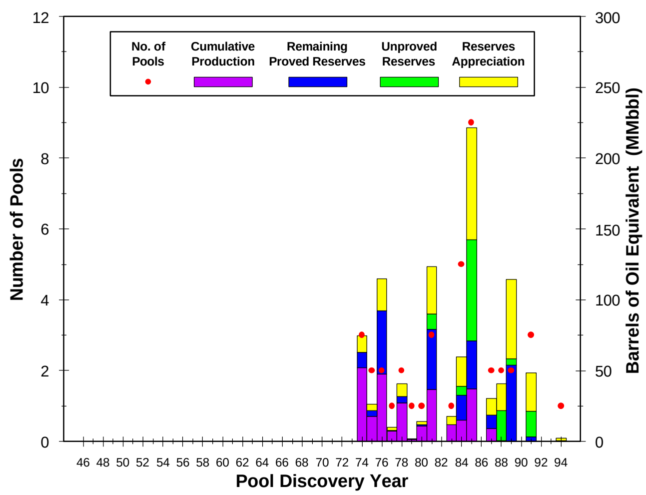


Figure 2. Exploration history graph.

The 40 discovered pools range in size from 0.576 to 105.454 MMBOE. These pools contain 279 reservoirs, of which 123 are nonassociated gas, 132 are undersaturated oil, and 24 are saturated oil.

Table 1. Characteristics of the discovered pools.

40 Pools (151 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	164	809	3,180
Subsea depth (feet)	3,944	7,525	12,757
Number of sands per pool	1	4	27
Porosity	24%	31%	35%
Water saturation	17%	28%	43%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the UPL F play is 1.00. This play is the fourth largest in the Gulf of Mexico Region, based on a mean total endowment of 1.648 Bbo and 11.217 Tcfg (3.644 BBOE) (table 2). Eight percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.917 to 1.620 Bbo and 7.281 to 9.881 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 1.198 Bbo and 8.448 Tcfg (2.701 BBOE). These undiscovered resources may occur in as many as 100 pools. The largest undiscovered pool, with a mean size of 379.920 MMBOE, is modeled as the largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 2, 3, 6, and 7 on the pool rank plot. For all the undiscovered pools in the UPL F play, the mean mean size is 27.005 MMBOE, which is larger than the 23.566 MMBOE mean size of the discovered pools. The mean mean size for all pools, including

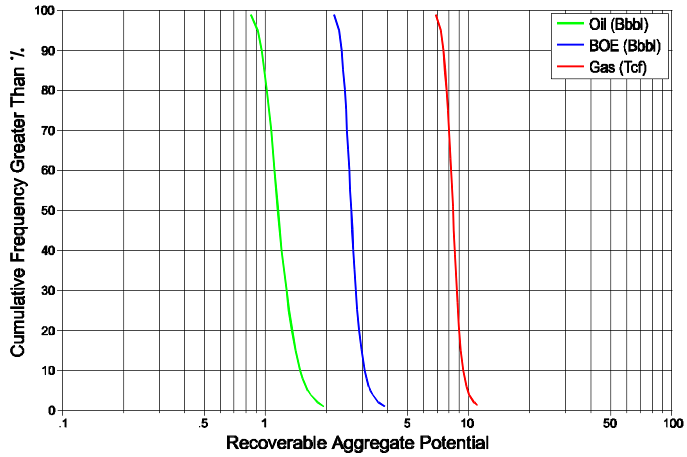


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	31	0.185	1.776	0.502
Cumulative production	--	0.092	1.029	0.275
Remaining proved	--	0.094	0.747	0.227
Unproved	9	0.100	0.183	0.132
Appreciation (P & U)	--	0.165	0.809	0.309
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.917	7.281	2.305
Mean	100	1.198	8.448	2.701
5th percentile	--	1.620	9.881	3.297
Total Endowment				
95th percentile	--	1.367	10.050	3.248
Mean	140	1.648	11.217	3.644
5th percentile	--	2.070	12.650	4.240

both discovered and undiscovered, is 26.022 MMBOE.

Of the 61 Gulf of Mexico plays, the UPL F play is projected to contain the largest amount of mean undiscovered oil (14%) and the third largest amount of mean undiscovered gas (9%). Additionally, of the 15 Gulf of Mexico fan plays, the UPL F play is the second largest, with 12 percent of the BOE mean total endowment.

A large unexplored area and good potential for sand development in UPL sediments support the numerous discoveries modeled for the UPL F play. Undiscovered resources are projected to add 74 percent to the play's BOE mean total endowment. Potential for discoveries occurs downdip of existing fields, especially in water depths greater than 1,000 feet.

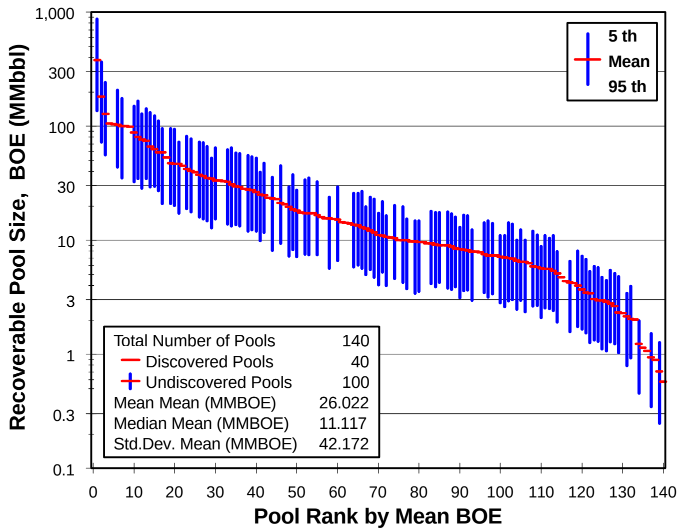


Figure 4. Pool rank plot.

UPPER PLEISTOCENE CAPROCK (UPL C) PLAY

PLAY DESCRIPTION

The established Upper Pleistocene Caprock (UPL C) play consists of the Main Pass 299 field (figure 1).

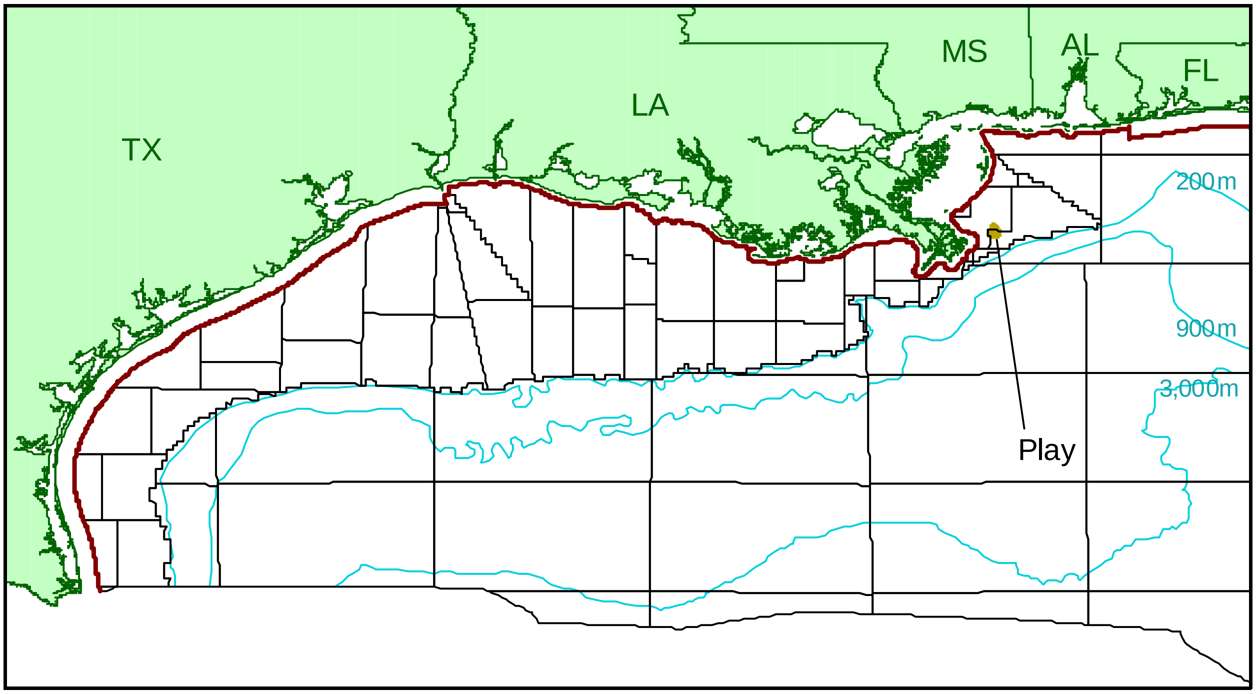


Figure 1. Map of play.

PLAY CHARACTERISTICS

The structure at the Main Pass 299 field is a salt diapir. Overlying impermeable layers of the caprock seal the hydrocarbons in this play. The UPL C play's reservoir is a vugular limestone. This caprock limestone is a product of diagenesis, and its age is unknown. Therefore, for mapping purposes, the caprock is correlated to the surrounding UPL sediments.

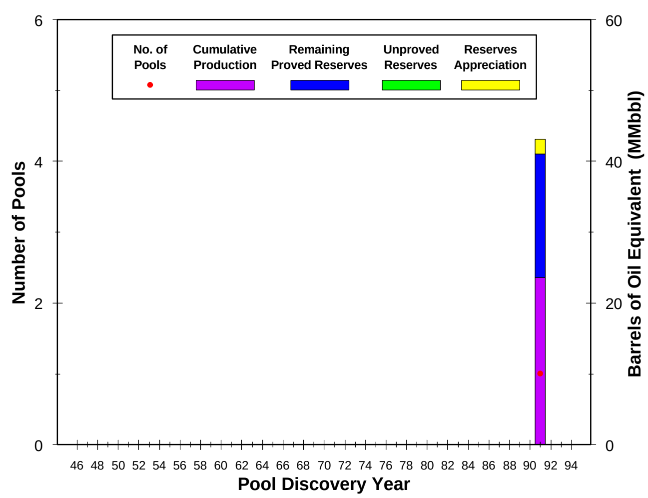


Figure 2. Exploration history graph.

DISCOVERIES

The UPL C oil play contains total reserves of 0.042 Bbo and 0.006 Tcfg

(0.043 BBOE), of which 0.023 Bbo and 0.003 Tcfg (0.024 BBOE) have been produced. The play consists of one reservoir in one pool (table 1). The play's reserves were discovered in 1991 in Freeport-McMoRan Inc.'s CAPROCK reservoir (figure 2).

Table 1. Characteristics of the discovered pools.

1 Pool (1 Reservoir)	Minimum	Mean	Maximum
Water depth (feet)	--	209	--
Subsea depth (feet)	--	1,500	--
Number of reservoirs per pool	--	1	--
Porosity	--	35%	--
Water saturation	--	30%	--

ASSESSMENT RESULTS

Though hydrocarbons often occur in caprock sequences, production from them in the Gulf of Mexico is rare. Because the UPL C play is unlikely to contribute significant new resources to the UPL chronozone, it was not evaluated for this National Assessment. However, the estimates for reserves and production can be found in table 2.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	1	0.040	0.006	0.041
Cumulative production	--	0.023	0.003	0.024
Remaining proved	--	0.017	0.003	0.017
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.002	<0.001	0.002
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	na	na	na
Mean	na	na	na	na
5th percentile	--	na	na	na
Total Endowment				
95th percentile	--	na	na	na
Mean	na	na	na	na
5th percentile	--	na	na	na

MIDDLE PLEISTOCENE (MPL) CHRONOZONE

CHRONOZONE DESCRIPTION

The Middle Pleistocene (MPL) chronozone corresponds to the *Angulogerina* "B" biozone. The MPL section reflects delta systems prograding onto the continental shelf and fan deposition on the continental slope of the Gulf of Mexico Basin. Depositional styles present in the MPL chronozone include aggradational, progradational, and fan, each of which defines a play: the Middle Pleistocene Aggradational (MPL A) play, the Middle Pleistocene Progradational (MPL P) play, and the Middle Pleistocene Fan (MPL F) play. Another play identified in the chronozone, the Middle Pleistocene Caprock (MPL C) play, was not assessed because it contains only one field and is of such limited occurrence that additional discoveries are unlikely. Retrogradational sands associated with marine transgressions also occur locally in the play areas at the top of the progradational and aggradational deposits. Because these retrogradational sands are discontinuous over any significant distance, they are included as part of the underlying deposits.

The potential for sand development within the MPL chronozone extends from the Galveston, East Breaks, and Alaminos Canyon Areas northeastward to the Main Pass, Viosca Knoll, and western Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). Updip, MPL sands continue onshore into Louisiana and Texas, except in eastern Texas and western Louisiana where the chronozone's sediments are so shallow that they are no longer logged or where they can no longer be correlated. To the west and northeast, potential for sand development within the MPL chronozone is limited by a lack of sediment influx at the edges of the MPL depocenter. The downdip limit extends at least as far as the Sigsbee Escarpment as indicated by MPL sand development in the OCS G12662-1 well in Garden Banks block 568 and by correlation of chronozone tops to seismic data.

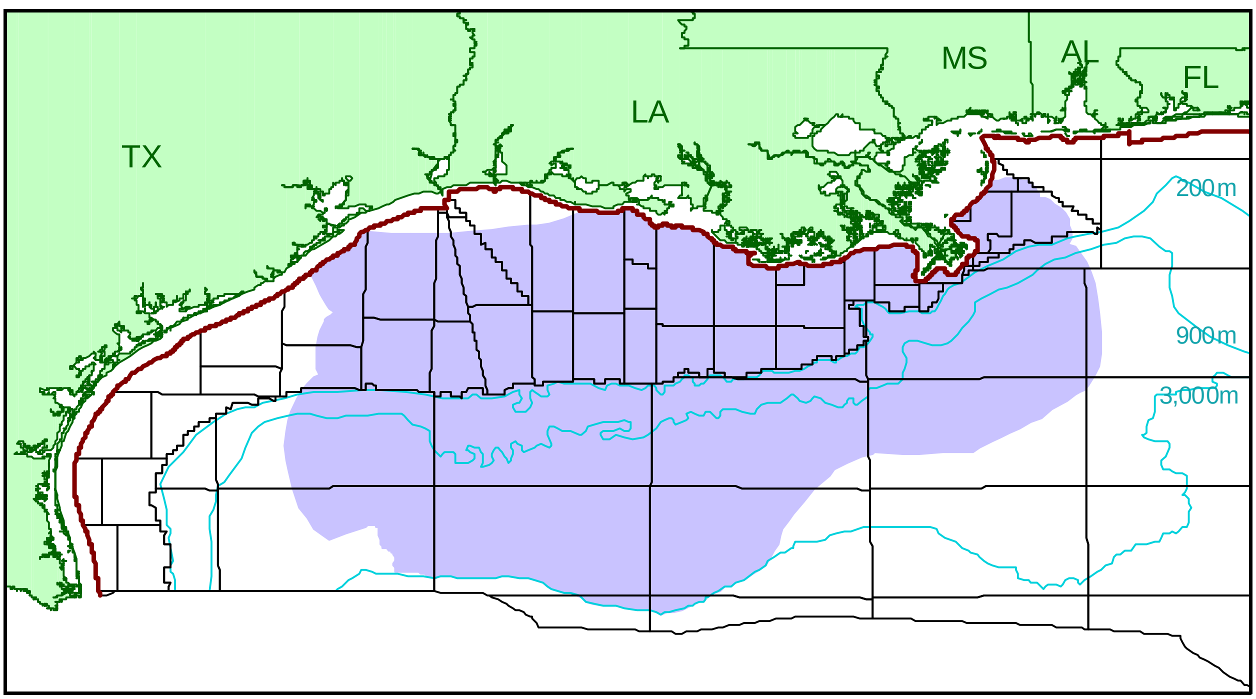


Figure 1. Map of assessed chronozone.

No significant lateral shift in the Louisiana depocenter is observed from the underlying lower Pleistocene (LPL) chronozone to the MPL chronozone. However, the updip extent of the progradational sediments in the LPL chronozone is located much farther to the north, creating a broader shelf than was present in MPL time. The shelf/slope break of the underlying LPL chronozone was also located farther to the north, resulting in MPL shelf sediments prograding out over underlying LPL fan deposits. A large sea level drop occurred during the overlying upper Pleistocene (UPL) chronozone and led to localized erosion of the upper MPL section. In places, the entire MPL section was removed.

Major structural features in the MPL chronozone include salt diapirs, anticlines, growth faults, and normal faults. Other structures include shale diapirs, stratigraphic pinch-outs, and salt ridges.

Discoveries

The MPL chronozone contains 235 discovered pools in four plays (table 1). Total reserves in the chronozone are 1.037 Bbo and 15.704 Tcfg (3.831 BBOE), of which 0.667 Bbo and 10.779 Tcfg (2.585 BBOE) have been produced. The largest number of discoveries in the MPL chronozone occurred when 19 pools were added in 1974 (figure 2). However, the maximum yearly total reserves of 974.245 MMBOE were added in 1971 with the discovery of 14 pools.

Of the four plays in the MPL chronozone, the MPL P play contains the most total reserves in 137 pools, with 0.823 Bbo and 12.973 Tcfg (3.131 BBOE).

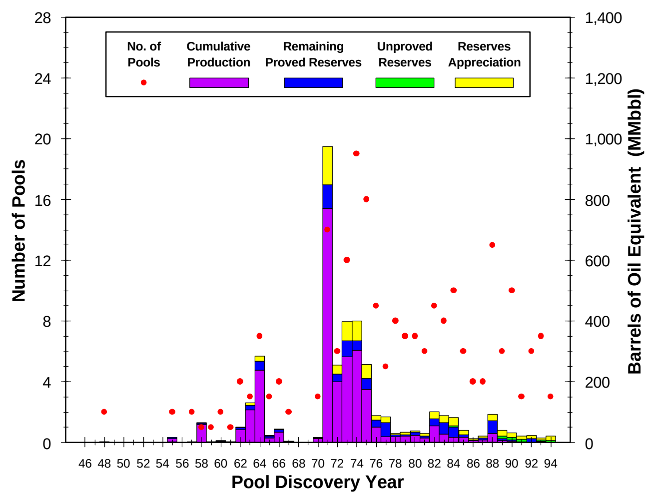


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

235 Pools (846 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	13	276	2,896
Subsea depth (feet)	2,125	5,730	15,034
Number of sands per pool	1	4	26
Porosity	21%	31%	37%
Water saturation	15%	27%	62%

ASSESSMENT RESULTS

The MPL chronozone contains 404 pools (discovered plus undiscovered), with a mean total endowment estimated at 1.271 Bbo and 19.035 Tcfg (4.658 BBOE) (table 2).

Assessment results indicate that undiscovered resources may occur in as many as 169 pools, which contain a range of 0.186 to 0.288 Bbo and 2.429 to 4.419 Tcfg at the 95th and 5th percentiles, respectively (figure 3). At mean levels, 0.234 Bbo and 3.331 Tcfg (0.827 BBOE) are projected. These undiscovered resources represent 18 percent of the MPL chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the fifth largest in the chronozone (figure 4).

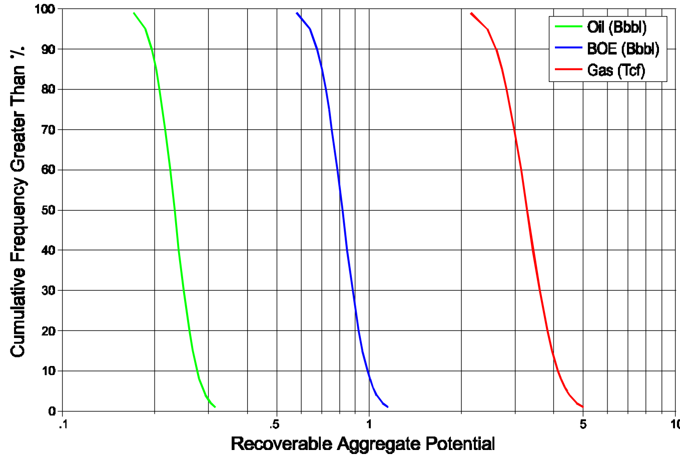


Figure 3. Cumulative probability distribution.

Of the four MPL plays, the MPL F play is projected to contain the greatest exploration potential, with mean undiscovered resources estimated at 0.203 Bbo and 2.144 Tcfg (0.584 BBOE) remaining to be found in 105 pools. These undiscovered resources in the MPL F play represent 13 percent of the BOE mean total endowment for the MPL

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	226	0.845	13.057	3.169
Cumulative production	--	0.667	10.779	2.585
Remaining proved	--	0.178	2.278	0.584
Unproved	9	0.013	0.139	0.037
Appreciation (P & U)	--	0.179	2.508	0.625
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.186	2.429	0.641
Mean	169	0.234	3.331	0.827
5th percentile	--	0.288	4.419	1.043
Total Endowment				
95th percentile	--	1.223	18.133	4.472
Mean	404	1.271	19.035	4.658
5th percentile	--	1.325	20.123	4.874

chronozone. This percentage and the potential for numerous discoveries within a large unexplored area make the MPL F play an attractive exploration target in MPL strata.

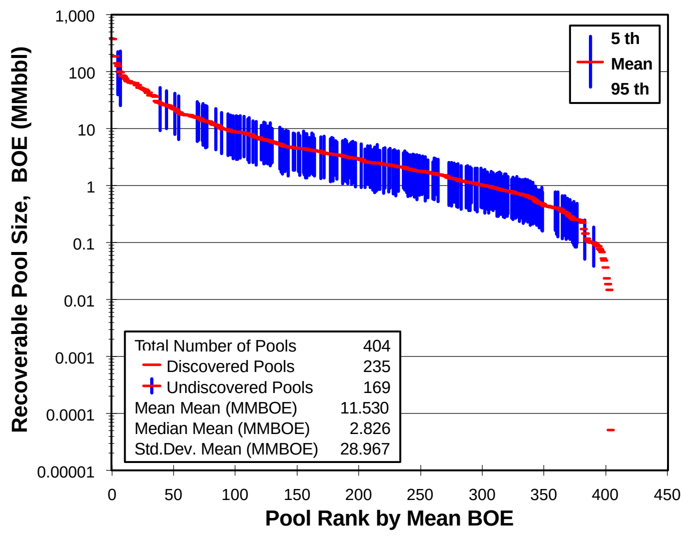


Figure 4. Pool rank plot.

MIDDLE PLEISTOCENE AGGRADATIONAL (MPL A) PLAY

PLAY DESCRIPTION

The established Middle Pleistocene Aggradational (MPL A) play occurs at the *Angulogerina* "B" biozone. This play extends from the Galveston Area offshore Texas to the Chandeleur/Viosca Knoll border east of the present-day Mississippi River Delta (figure 1).

Updip, the play continues onshore, except in the northern High Island, West Cameron, and East Cameron Areas where the play is so shallow that it is no longer logged or where it can no longer be correlated. To the northeast and west, the play is bounded by a lack of sediment influx at the edges of the MPL depocenter. Downdip, the play grades into the sediments of the Middle Pleistocene Progradational (MPL P) play.

The sediments in this play were supplied by ancient delta systems located in the Louisiana area. No significant lateral shift in depocenter is observed in the offshore area from the underlying lower Pleistocene (LPL) chronozone to the MPL chronozone.

PLAY CHARACTERISTICS

The productive MPL A play consists of delta plain and shallow marine shelf deposits that formed as channels, delta front and fringe sands, distributary mouth bars, crevasse splays, and shelf slumps. In addition, retrogradational sands locally cap the MPL A play. Because these retrogradational, reworked sands are so discontinuous, they are included as part of the MPL A play. Major structural features in this play include salt diapirs, growth faults, and anticlines. Normal faults and stratigraphic pinch-outs occur less commonly. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs,

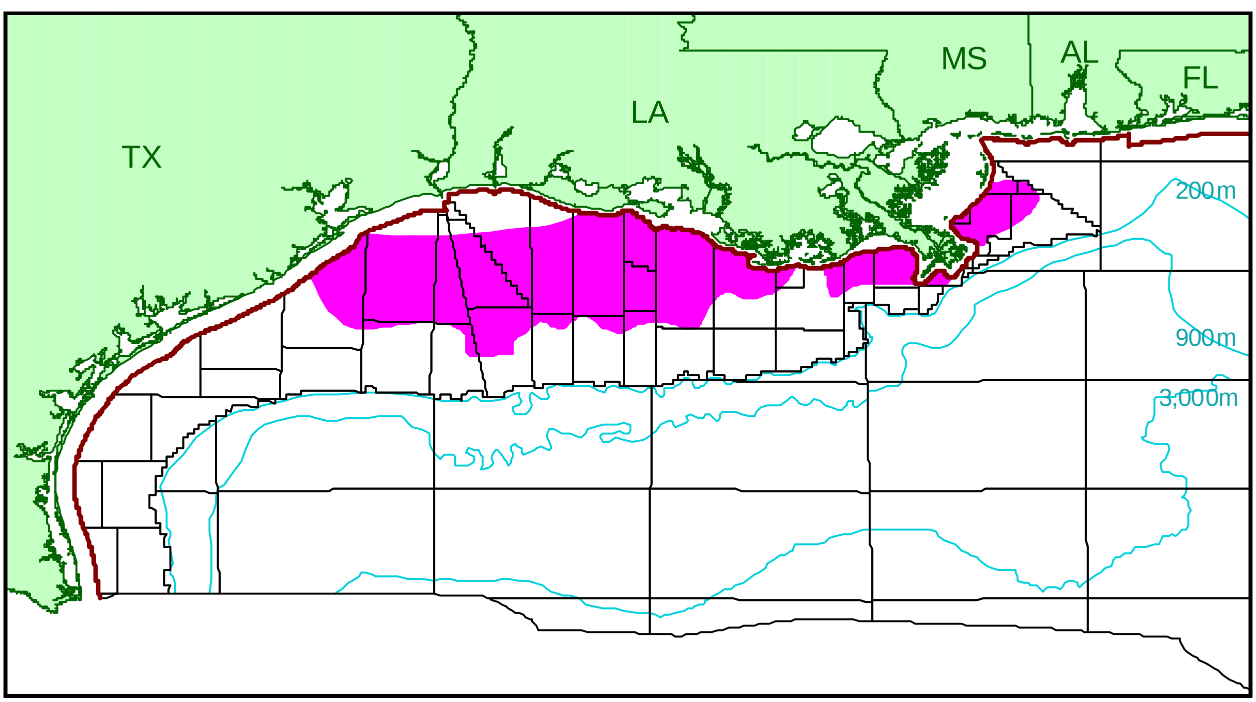


Figure 1. Map of assessed play.

overlying shales). Future discoveries are not limited to the aforementioned productive aggradational depositional environments, structures, or seals.

East Cameron 245 is the type field, and Pennzoil Exploration and Production's 3100, 3200, 3300, 3500, 3800, and 3900 sands represent the MPL A play in this field.

DISCOVERIES

The MPL A play is predominantly a gas play, with total reserves of 0.018 Bbo and 0.856 Tcfg (0.171 BBOE), of which 0.012 Bbo and 0.534 Tcfg (0.107 BBOE) have been produced. The play contains 84 producible sands in 52 pools (table 1). The first reserves in the play were discovered in the Ship Shoal 32 field in 1948 (figure 2). The maximum yearly total reserves were added in 1963 with the discovery of the largest pool in the play in the East Cameron 245 field. Pool discoveries were sparse until the mid-1970's when pools began to be discovered at an average rate of about two per year. The most recent discoveries, prior to this study's cutoff date of January 1, 1995, were in 1993.

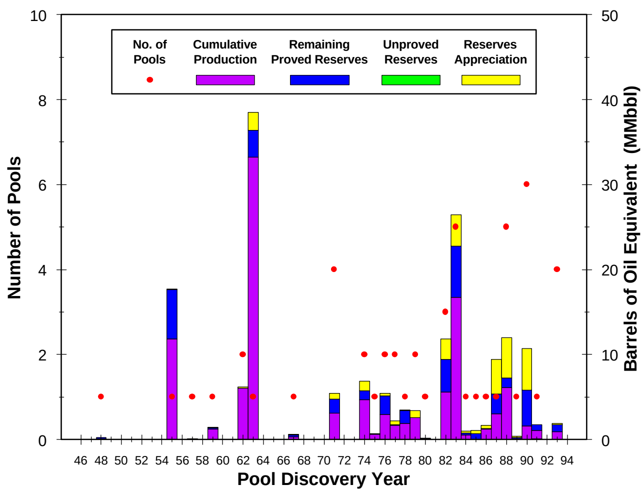


Figure 2. Exploration history graph.

The 52 discovered pools range in size from 0.053 to 38.489 MMBOE. These pools contain 97 reservoirs, of which 88 are nonassociated gas and 9 are undersaturated oil.

Table 1. Characteristics of the discovered pools.

52 Pools (84 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	13	92	211
Subsea depth (feet)	2,125	3,726	6,260
Number of sands per pool	1	2	5
Porosity	26%	32%	37%
Water saturation	16%	25%	52%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the MPL A play is 1.00. The play contains a mean total endowment of 0.020 Bbo and 0.972 Tcfg (0.194 BBOE) (table 2). Fifty-five percent of this BOE mean total endowment has been produced.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	52	0.018	0.704	0.143
Cumulative production	--	0.012	0.534	0.107
Remaining proved	--	0.006	0.170	0.036
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.152	0.027
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.001	0.084	0.017
Mean	14	0.002	0.116	0.023
5th percentile	--	0.004	0.152	0.030
Total Endowment				
95th percentile	--	0.019	0.940	0.188
Mean	66	0.020	0.972	0.194
5th percentile	--	0.022	1.008	0.201

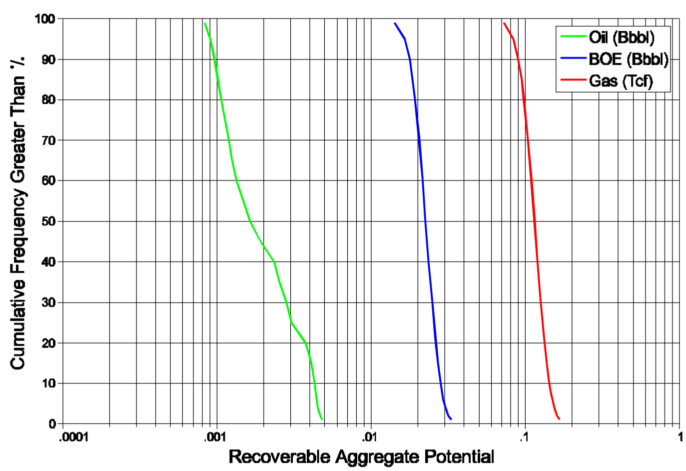


Figure 3. Cumulative probability distribution.

Assessment results indicate that undiscovered resources have a range of 0.001 to 0.004 Bbo and 0.084 to 0.152 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.002 Bbo and 0.116 Tcfg (0.023 BBOE). These undiscovered resources may occur in as many as 14 pools. The largest undiscovered pool, with a mean size of 6.359 MMBOE, is modeled as the seventh largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 10, 22, 24, and 30 on the pool rank plot. For all the undiscovered pools in the MPL A play, the mean mean size is 1.631 MMBOE, which is smaller than the 3.281 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 2.931 MMBOE.

The MPL A play is well explored. Relative to the discovered pools, the undiscovered pools are expected to be small to moderate in size. These undiscovered resources are projected to contribute only 12 percent to the play's BOE mean total endowment.

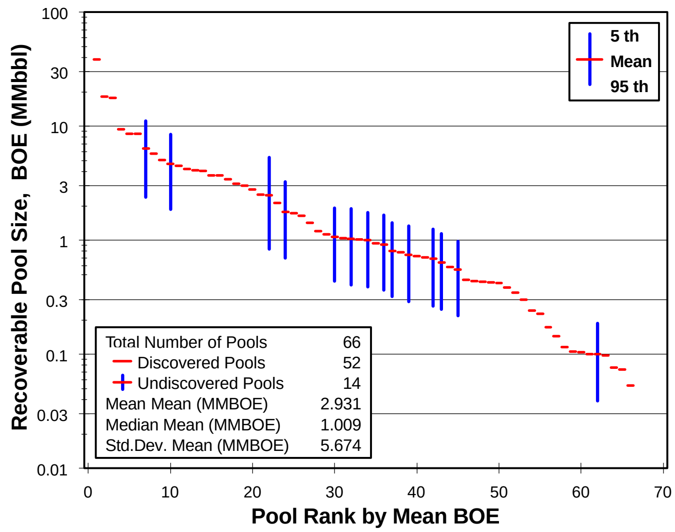


Figure 4. Pool rank plot.

MIDDLE PLEISTOCENE PROGRADATIONAL (MPL P) PLAY

PLAY DESCRIPTION

The Middle Pleistocene Progradational (MPL P) play is one of the largest established plays in the Gulf of Mexico Region. The MPL P play occurs at the *Angulogerina* "B" biozone and extends from the Galveston Area offshore Texas to the Main Pass and Viosca Knoll Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the play grades into the nearshore sediments of the Middle Pleistocene Aggradational (MPL A) play. The MPL P play also extends onshore into Louisiana near the Mississippi River Delta. To the northeast and west, the play is bounded by a lack of sediment influx at the edges of the MPL depocenter. Downdip, the play grades into the deposits of the Middle Pleistocene Fan (MPL F) play.

The sediments in this play were supplied by ancient delta systems located in the Louisiana area. No significant lateral shift in depocenter is observed in the offshore area from the underlying lower Pleistocene (LPL) chronozone to the MPL chronozone. The progradational sequence of the MPL chronozone is located farther downdip than that of the LPL chronozone. Therefore, the MPL P play occurs stratigraphically above both the LPL progradational and fan deposits.

PLAY CHARACTERISTICS

The productive MPL P play consists of progradational deltaic sediments deposited in delta front and fringe, channel, crevasse splay, shelf blanket, and shelf and upper slope slump environments. In addition, retrogradational sands locally cap the MPL P play. Because these retrogradational, reworked sands are so discontinuous, they are included as part of the MPL P play. Salt diapirs, anticlines, growth faults, and normal faults are the

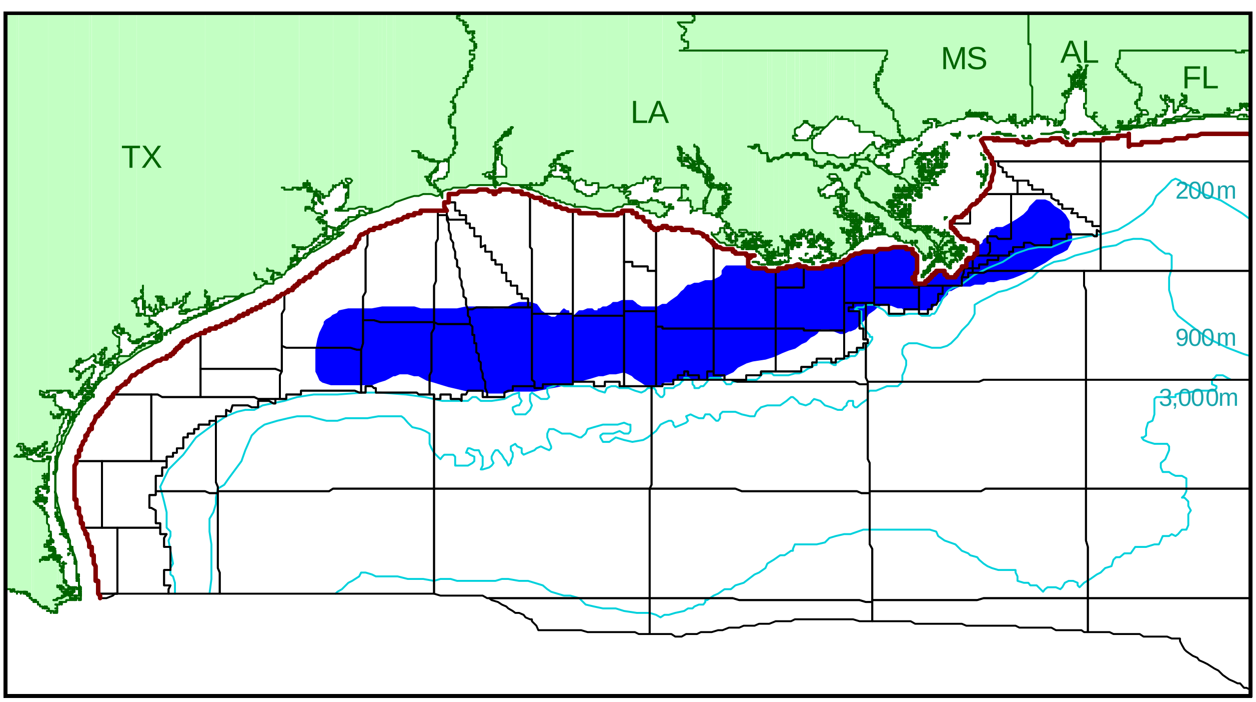


Figure 1. Map of assessed play.

dominant structural features in the play. Shale diapirs and stratigraphic pinch-outs occur less frequently. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive progradational depositional environments, structures, or seals.

Vermilion 340 is the type field, and Shell Offshore Inc.'s D6, E, G, G4, G6, H, I, J, L, L2, N, N2, and O sands represent the MPL P play in this field.

DISCOVERIES

The MPL P play is predominantly a gas play, with total reserves of 0.823 Bbo and 12.973 Tcfg (3.131 BBOE), of which 0.601 Bbo and 9.812 Tcfg (2.347 BBOE) have been produced. The play contains 653 producible sands in 137 pools, and 136 of these pools contain proved reserves (table 1). The first reserves in the play were discovered in the South Timbalier 34 field in 1948 (figure 2). Almost half of the pools were discovered from 1970 to 1976. The maximum yearly total reserves of 968.777 MMBOE were added in 1971 with the discovery of 10 pools, including the largest pool in the play in the Eugene Island 330 field. Pool discoveries prior to 1976 account for over 90 percent of both the play's cumulative production and total reserves. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1994.

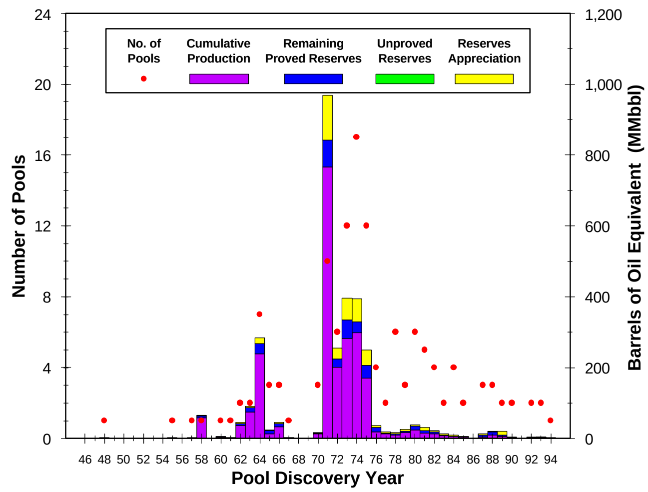


Figure 2. Exploration history graph.

The 137 discovered pools range in size from 0.015 to 379.565 MMBOE. These pools contain 1,322 reservoirs, of which 854 are nonassociated gas, 329 are undersaturated oil, and 139 are saturated oil.

Of the 61 Gulf of Mexico plays, the MPL P play contains the fourth largest amount of total reserves and has produced the third largest amount of hydrocarbons, based on

Table 1. Characteristics of the discovered pools.

137 Pools (653 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	31	186	320
Subsea depth (feet)	3,016	5,585	11,055
Number of sands per pool	1	5	26
Porosity	21%	30%	35%
Water saturation	16%	27%	62%

BOE. In fact, this play has produced the third largest amount of gas at 9 percent. Of the 14 Gulf of Mexico progradational plays, the MPL P play is the third largest, based on BOE total reserves, with 11 percent of the total.

Assessment Results

The marginal probability of hydrocarbons for the MPL P play is 1.00. This play is the sixth largest in the Gulf of Mexico, based on a mean total endowment of 0.852 Bbo and 14.044 Tcfg (3.351 BBOE) (table 2). Seventy percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.019 to 0.041 Bbo and 0.586 to 1.648 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.029 Bbo and 1.071 Tcfg (0.220 BBOE). These undiscovered resources may occur in as many as 50 pools. The largest undiscovered pool, with a mean size of 127.500 MMBOE, is modeled as the fifth

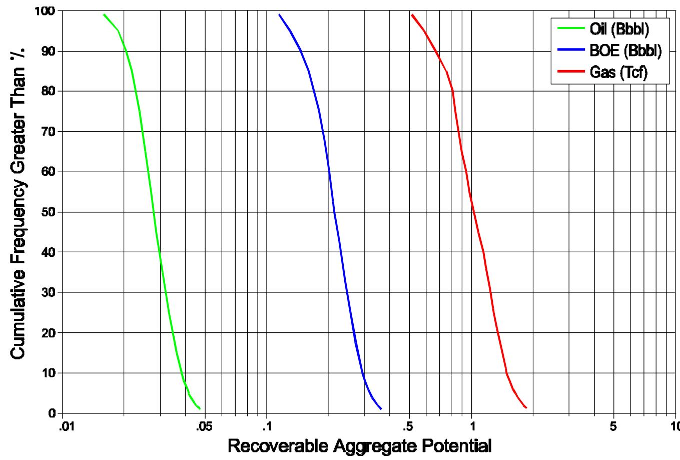


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	136	0.711	11.213	2.706
Cumulative production	--	0.601	9.812	2.347
Remaining proved	--	0.110	1.401	0.359
Unproved	1	<0.001	0.001	0.001
Appreciation (P & U)	--	0.112	1.759	0.425
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.019	0.586	0.130
Mean	50	0.029	1.071	0.220
5th percentile	--	0.041	1.648	0.320
Total Endowment				
95th percentile	--	0.842	13.559	3.261
Mean	187	0.852	14.044	3.351
5th percentile	--	0.864	14.621	3.451

largest pool in the play (figure 4). For all the undiscovered pools in the MPL P play, the mean mean size is 4.397 MMBOE, which is substantially less than the 22.856 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 17.921 MMBOE.

The MPL P play is well explored, and except for the fifth largest pool in the play, the largest pools are modeled as already discovered. Relative to the discovered pools, most of the undiscovered pools are small in size and are expected to contribute only 7 percent to the play's BOE mean total endowment.

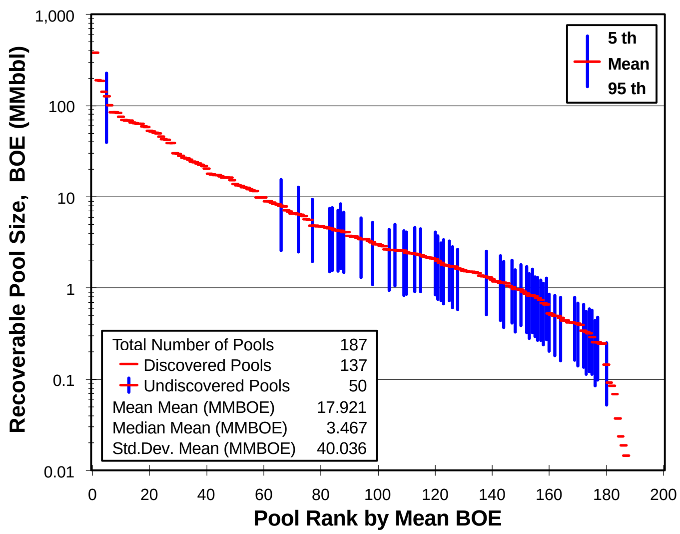


Figure 4. Pool rank plot.

Middle Pleistocene Fan (MPL F) Play

Play Description

The established Middle Pleistocene Fan (MPL F) play occurs at the *Angulogerina* “B” biozone. This play extends from the southern Galveston, East Breaks, and Alaminos Canyon Areas to the Viosca Knoll and western Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1).

The play is bounded updip by the shelf/slope break associated with the *Angulogerina* “B” biozone and grades into the sediments of the Middle Pleistocene Progradational (MPL P) play. To the northeast and west, the play is bounded by a lack of sediment influx at the edges of the MPL depocenter. The southern extension of the play’s potential to at least the Sigsbee Escarpment is supported by MPL reservoir-quality sands in the OCS G12662-1 well in Garden Banks block 568 and by chronozone tops correlated to seismic data.

The sediments in this play were mainly supplied by ancient delta systems located in the Louisiana area. No significant lateral shift in depocenter is observed in the offshore area from the underlying lower Pleistocene (LPL) chronozone to the MPL chronozone. The MPL shelf/slope break occurs farther basinward than the LPL shelf/slope break, indicative of the prograding nature of the delta systems with time.

Play Characteristics

The productive MPL F play consists of deepwater turbidites deposited in fan systems as channel fill, overbank deposits, fan lobes, and fringe sheet sediments on the MPL slope between salt highs. The play’s major structural features are salt diapirs and anticlines. Growth faults, normal faults, and shale diapirs also occur, but less commonly.

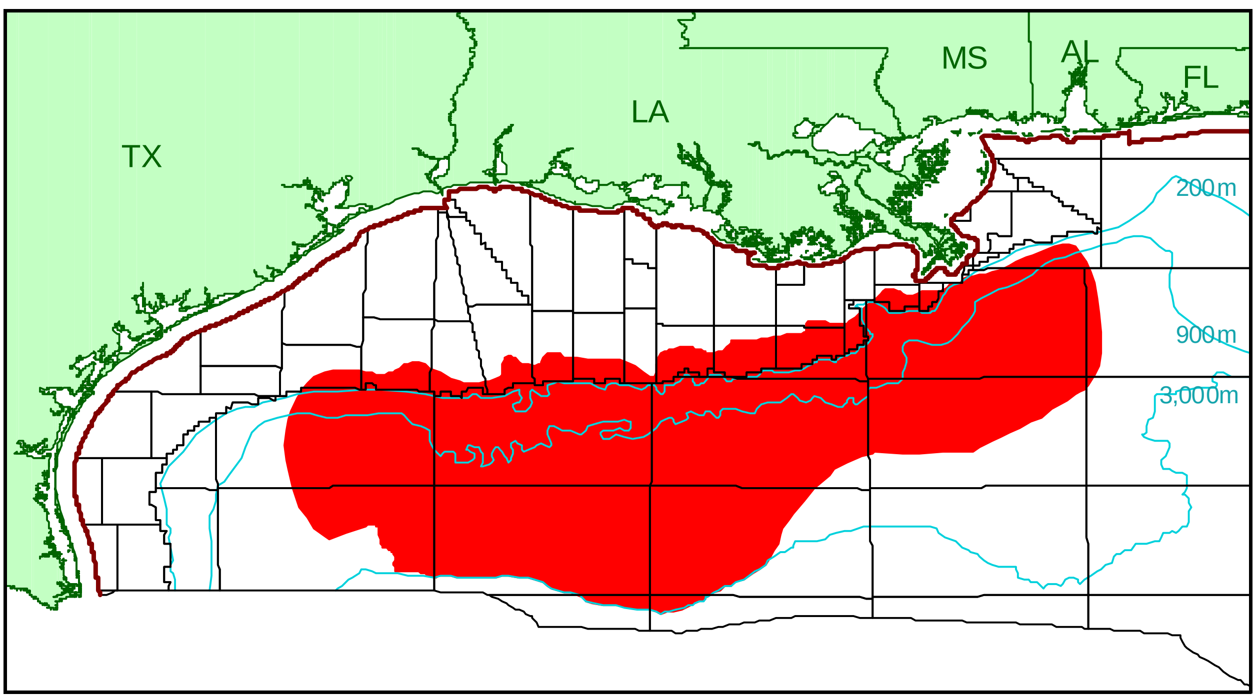


Figure 1. Map of assessed play.

Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive fan depositional environments, structures, or seals.

Green Canyon 65 (“Bullwinkle”) is the type field, and Shell Offshore Inc.’s H and I sand series represent the MPL F play in this field.

DISCOVERIES

The MPL F mixed oil and gas play contains total reserves of 0.196 Bbo and 1.874 Tcfg (0.529 BBOE), of which 0.054 Bbo and 0.433 Tcfg (0.131 BBOE) have been produced. The play contains 108 producible sands in 45 pools, and 37 of these pools contain proved reserves (table 1). The first reserves in the play were discovered in the West Delta 133 field in 1966 (figure 2). The maximum yearly total reserves of 72.893 MMBOE were added in 1984 with the discovery of five pools. However, the largest discovered pool in the play in the Mississippi Canyon 354 field (“Zinc”) was found in 1977. Sixty-six percent of the play’s cumulative production is from pools discovered in 1983 or earlier. In comparison, two-thirds of the play’s pools have been discovered since 1983, including seven pools that are in water depths greater than 1,000 feet. The most recent discoveries, prior to this study’s cutoff date of January 1, 1995, were in 1994.

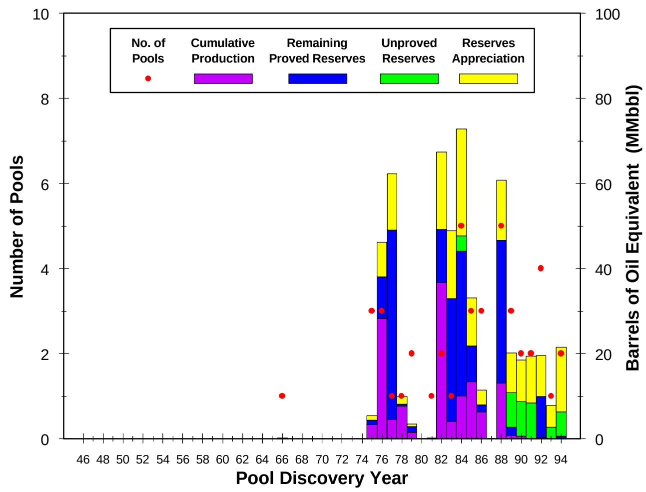


Figure 2. Exploration history graph.

The 45 discovered pools range in size from 0.049 to 62.368 MMBOE. These pools contain 136 reservoirs, of which 59 are nonassociated gas, 63 are undersaturated oil, and 14 are saturated oil.

Table 1. Characteristics of the discovered pools.

45 Pools (108 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	165	768	2,896
Subsea depth (feet)	4,525	8,525	15,034
Number of sands per pool	1	2	11
Porosity	22%	30%	36%
Water saturation	15%	29%	48%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the MPL F play is 1.00. The play contains a mean total endowment of 0.399 Bbo and 4.018 Tcfg (1.113 BBOE) (table 2). Twelve percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.165 to 0.249 Bbo and 1.722 to 2.901 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.203 Bbo and 2.144 Tcfg (0.584 BBOE). These undiscovered resources may occur in as many as 105 pools. The largest undiscovered pool, with a mean size of 97.668 MMBOE, is modeled as the largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 8, 10, 12, and 13 on the pool rank plot. For all the undiscovered pools in the MPL F play, the mean mean size is 5.566 MMBOE, which is smaller than the 11.758 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and

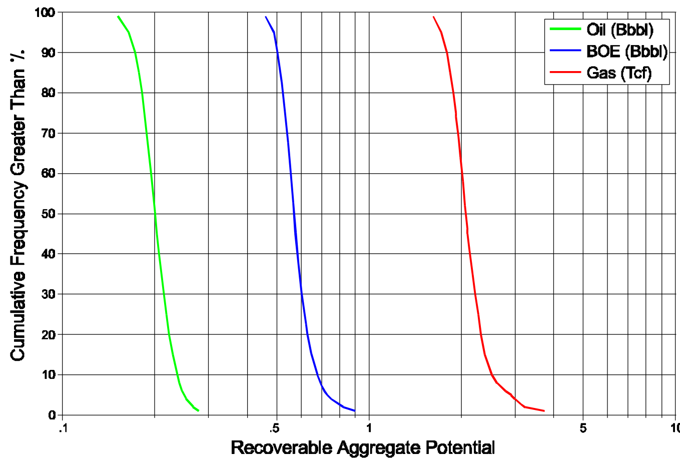


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	37	0.116	1.140	0.319
Cumulative production	--	0.054	0.433	0.131
Remaining proved	--	0.062	0.707	0.188
Unproved	8	0.012	0.138	0.037
Appreciation (P & U)	--	0.067	0.597	0.173
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.165	1.722	0.489
Mean	105	0.203	2.144	0.584
5th percentile	--	0.249	2.901	0.731
Total Endowment				
95th percentile	--	0.361	3.596	1.018
Mean	150	0.399	4.018	1.113
5th percentile	--	0.445	4.775	1.260

undiscovered, is 7.424 MMBOE.

Because of its large unexplored area and known areas of good sand development, the MPL F play is expected to contain numerous undiscovered pools, which account for over half of the play's mean total endowment. Potential for discoveries occurs downdip of existing fields, especially in water depths greater than 1,000 feet.

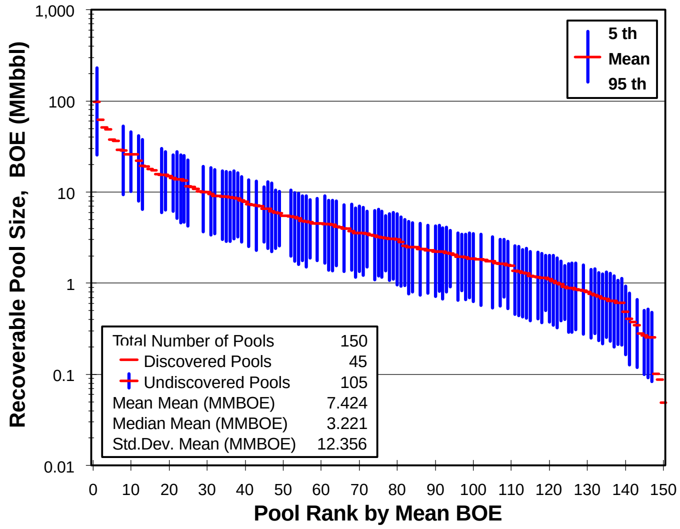


Figure 4. Pool rank plot.

MIDDLE PLEISTOCENE CAPROCK (MPL C) PLAY

PLAY DESCRIPTION

The established Middle Pleistocene Caprock (MPL C) play consists of the South Timbalier 86 field (figure 1).

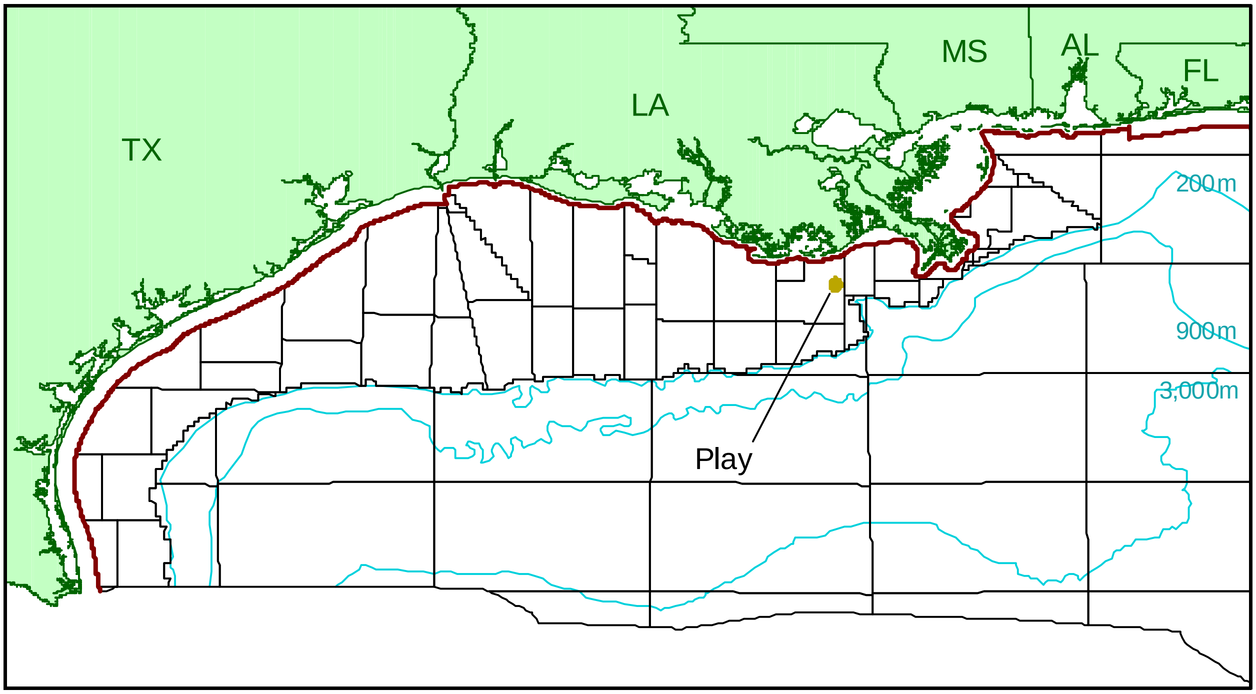


Figure 1. Map of play.

PLAY CHARACTERISTICS

The structure at the South Timbalier 86 field is a salt diapir. Overlying impermeable layers of the caprock seal the hydrocarbons in this play. The MPL C play's reservoir is crystalline limestone. This caprock limestone is a product of diagenesis, and its age is unknown. Therefore, for mapping purposes, the caprock is correlated to the surrounding MPL sediments.

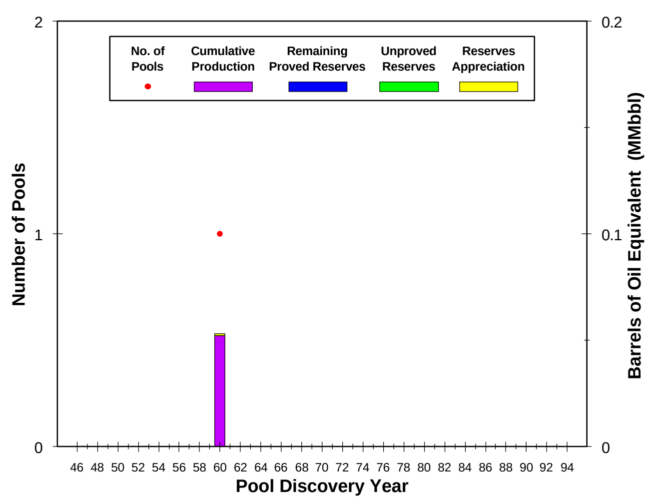


Figure 2. Exploration history graph.

DISCOVERIES

The MPL C oil play contains proved reserves of 0.039 MMbo and 0.072 Bcfg (0.052 MMBOE), of which all have been produced. The play consists of one reservoir in one pool (table 1). The play's reserves were discovered in 1960 in Murphy Exploration and Production's ZONE 3 reservoir (figure 2).

Table 1. Characteristics of the discovered pools.

1 Pool (1 Reservoir)	Minimum	Mean	Maximum
Water depth (feet)	--	94	--
Subsea depth (feet)	--	4,070	--
Number of reservoirs per pool	--	1	--
Porosity	--	29%	--
Water saturation	--	24%	--

ASSESSMENT RESULTS

Though hydrocarbons often occur in caprock sequences, production from them in the Gulf of Mexico is rare. Because the MPL C play is unlikely to contribute significant new resources to the MPL chronozone, it was not evaluated for this National Assessment. However, the estimates for reserves and production can be found in table 2.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	1	<0.001	<0.001	<0.001
Cumulative production	--	<0.001	<0.001	<0.001
Remaining proved	--	0.000	0.000	0.000
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	<0.001	<0.001
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	na	na	na
Mean	na	na	na	na
5th percentile	--	na	na	na
Total Endowment				
95th percentile	--	na	na	na
Mean	na	na	na	na
5th percentile	--	na	na	na

LOWER PLEISTOCENE (LPL) CHRONOZONE

CHRONOZONE DESCRIPTION

The Lower Pleistocene (LPL) chronozone corresponds to the *Valvulineria* "H" and *Lenticulina* 1 biozones. The LPL section reflects delta systems prograding onto the continental shelf and fan deposition on the continental slope of the Gulf of Mexico Basin. Depositional styles present in the LPL chronozone include aggradational, progradational, and fan, each of which defines a play: the Lower Pleistocene Aggradational (LPL A) play, the Lower Pleistocene Progradational (LPL P) play, and the Lower Pleistocene Fan (LPL F) play. Retrogradational sands associated with marine transgressions also occur locally in the play areas at the top of the progradational and aggradational deposits. However, because these retrogradational sands are discontinuous over any significant distance, they are included as part of the underlying deposits.

The potential for sand development within the LPL chronozone extends from the Galveston, East Breaks, and Alaminos Canyon Areas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). Updip, LPL sands continue onshore into Louisiana and eastern Texas. Sand potential is limited to the west and northeast due to a lack of sediment influx at the edges of the LPL depocenter. The downdip limit extends at least as far as the Sigsbee Escarpment as indicated by LPL sand development in the OCS G11643-1 well in Keathley Canyon block 255 and by chronozone tops correlated to seismic data.

Productive and established sand locations in the LPL chronozone are a result of an ancient depocenter in the Louisiana area. During LPL time, as in upper Pliocene (UP) time, the Texas depocenter no longer received significant amounts of sand-rich sediments. When compared with underlying productive UP sediments, the productive LPL sediments

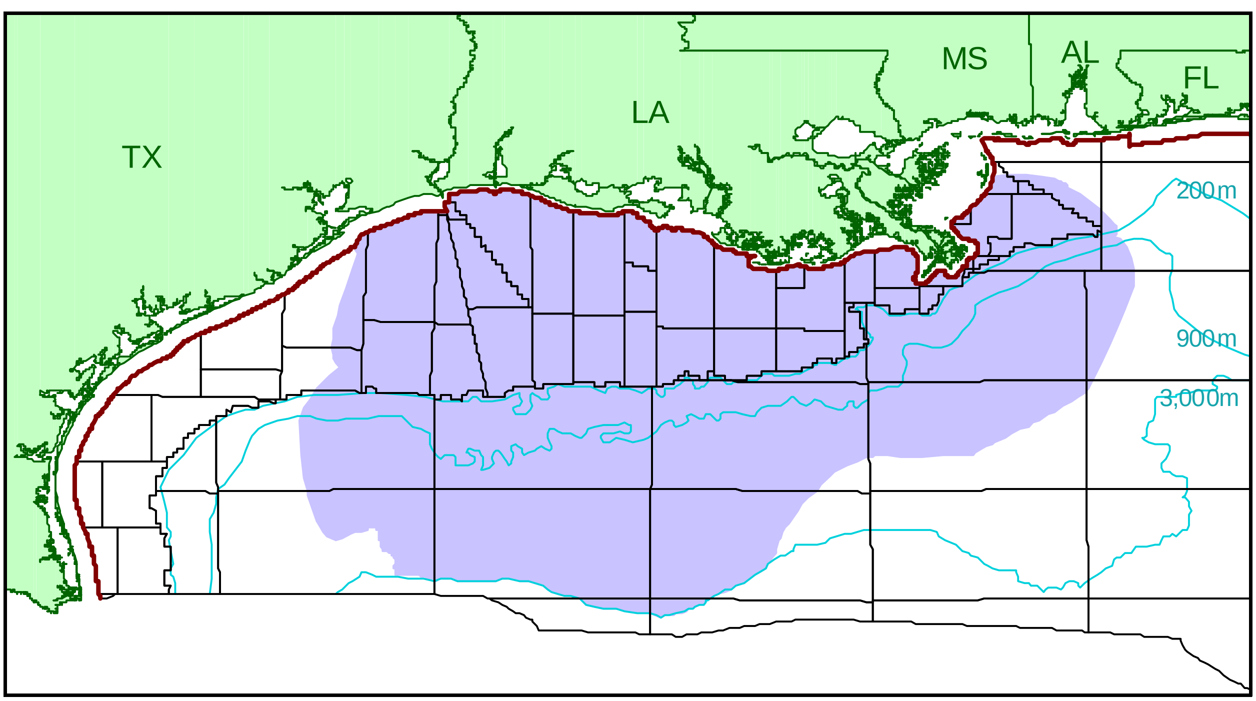


Figure 1. Map of assessed chronozone.

shifted considerably westward, with LPL sediments deposited as far west as the Galveston and East Breaks Areas. In addition, as is typical of prograding delta systems, the sediments of LPL time occur considerably more basinward as compared with the sediments of UP time.

Major structural features in the LPL chronozone include salt diapirs, anticlines, growth faults, and normal faults. Less common structures include stratigraphic pinch-outs, shale diapirs, salt ridges, and unconformities.

Discoveries

The LPL chronozone contains 396 discovered pools in three plays (table 1). Significant amounts of hydrocarbons were recently identified in the LPL chronozone in the East Breaks 945 field ("Diana"), the Garden Banks 426 field ("Auger"), and the Green Canyon 205 field ("Genesis"). Of the 21 chronozones in the Gulf of Mexico Region, the LPL chronozone contains the largest amount of total reserves, with 3.646 Bbo and 35.000 Tcfg (9.874 BBOE), of which 2.194 Bbo and 22.463 Tcfg (6.191 BBOE) have been produced. The largest number of discoveries in the LPL chronozone occurred when 24 pools added the maximum yearly total reserves of 625.645 MMBOE in 1984 (figure 2).

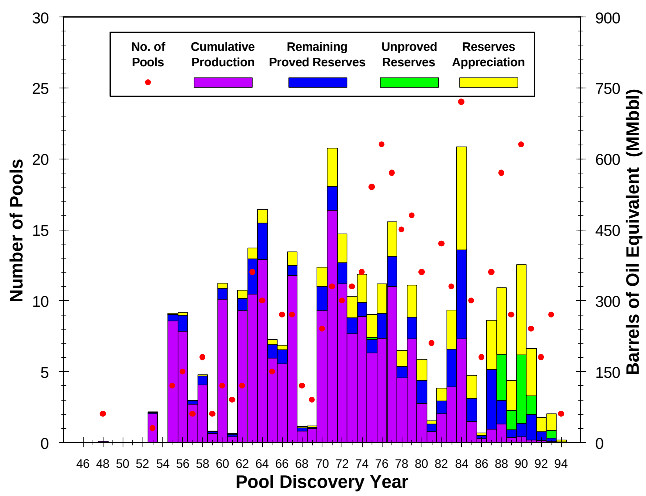


Figure 2. Exploration history graph.

Of the three plays in the LPL chronozone, the LPL P play contains the most total reserves in 207 pools, with 1.510 Bbo and 18.869 Tcfg (4.868 BBOE).

Table 1. Characteristics of the discovered pools.

396 Pools (2,015 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	12	294	6,950
Subsea depth (feet)	1,625	7,490	16,950
Number of sands per pool	1	5	42
Porosity	17%	30%	36%
Water saturation	7%	26%	54%

ASSESSMENT RESULTS

The LPL chronozone contains 647 pools (discovered plus undiscovered), with a mean total endowment estimated at 4.724 Bbo and 51.913 Tcfg (13.961 BBOE) (table 2). This is the largest mean total endowment of all the chronozones in the Gulf of Mexico.

Assessment results indicate that undiscovered resources may occur in as many as 251 pools, which contain a range of 0.815 to 1.388 Bbo and 12.970 to 21.536 Tcfg at the 95th and 5th percentiles, respectively (figure 3). At mean levels, 1.078 Bbo and 16.913 Tcfg (4.087 BBOE) are projected. These undiscovered resources represent 29 percent of the LPL chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the largest in the chronozone (figure 4). Additionally, when compared with the other Gulf of Mexico chronozones, the LPL chronozone is projected to contain the largest amount of mean undiscovered gas and the third largest amount of mean undiscovered oil.

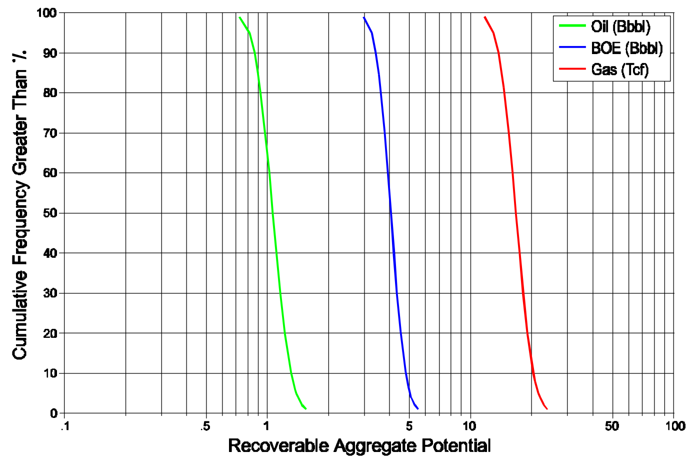


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	379	2.727	28.009	7.711
Cumulative production	--	2.194	22.463	6.191
Remaining proved	--	0.533	5.546	1.519
Unproved	17	0.211	0.749	0.344
Appreciation (P & U)	--	0.709	6.241	1.819
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.815	12.970	3.257
Mean	251	1.078	16.913	4.087
5th percentile	--	1.388	21.536	5.039
Total Endowment				
95th percentile	--	4.461	47.970	13.131
Mean	647	4.724	51.913	13.961
5th percentile	--	5.034	56.536	14.913

Of the three LPL plays, the LPL F play is projected to contain the greatest exploration potential, with mean undiscovered resources estimated at 0.837 Bbo and 12.354 Tcfg (3.035 BBOE) remaining to be found in 158 pools. These undiscovered resources in the LPL F play represent 22 percent of the BOE mean total endowment for the LPL chronozone. This percentage, the potential for numerous discoveries within a large unexplored area, the potential for good LPL reservoir sand development in deepwater areas, and prolific existing fan production make the LPL F play an attractive exploration target in LPL strata.

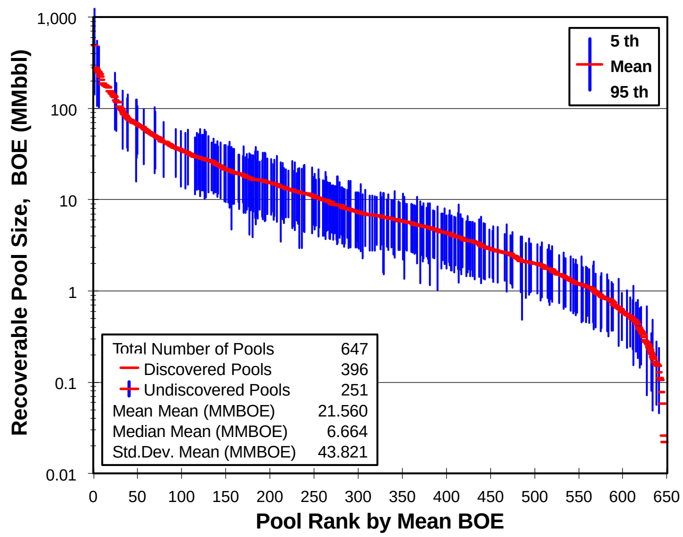


Figure 4. Pool rank plot.

LOWER PLEISTOCENE AGGRADATIONAL (LPL A) PLAY

PLAY DESCRIPTION

The established Lower Pleistocene Aggradational (LPL A) play occurs within the *Valvulineria* "H" and *Lenticulina* 1 biozones. This play extends from the northeastern portion of the Galveston Area offshore Texas to the Viosca Knoll Area east of the present-day Mississippi River Delta (figure 1).

Updip, the play continues onshore into Louisiana and eastern Texas. The play does not extend farther to the west or northeast because of an apparent lack of shelfal source sands at the edges of the LPL depocenter. Downdip, the play grades into the sediments of the Lower Pleistocene Progradational (LPL P) play.

The sediments in the LPL A play were mainly supplied by ancient delta systems located in the Louisiana area. No significant lateral shift in depocenter is observed in the offshore area from the underlying upper Pliocene (UP) chronozone to the LPL chronozone. The downdip limit of the aggradational deposits is located considerably more basinward in LPL time compared to that of UP time, indicative of the prograding nature of the delta systems with time.

PLAY CHARACTERISTICS

The productive LPL A play consists of channel and stacked channel, delta front and fringe, distributary mouth bar, crevasse splay, and shelf slump deposits. In addition, retrogradational sands locally cap the LPL A play. Because these retrogradational, reworked sands are so discontinuous, they are included as part of the LPL A play. Salt diapirs, anticlines, growth faults, and normal faults are the play's dominant stuctural features. Less common structures include salt ridges, shale diapirs, and stratigraphic

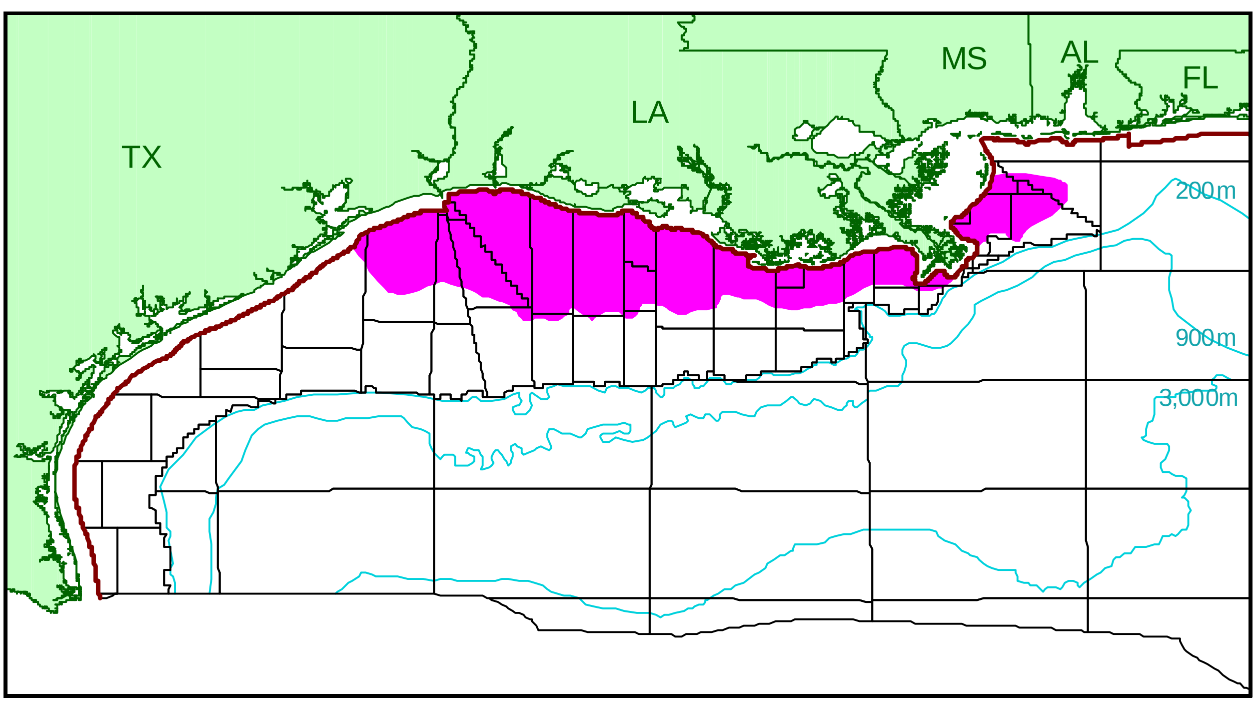


Figure 1. Map of assessed play.

pinch-outs. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive aggradational depositional environments, structures, or seals.

Eugene Island 126 is the type field, and Mobil Oil Exploration & Production's C1, C2, C3, C4, C5, C6, C7, C9, C11, C12, C13, D1, D2, D3, E1, E2, F1, and F2 sands represent the LPL A play in this field.

DISCOVERIES

The LPL A mixed oil and gas play contains total reserves of 0.322 Bbo and 1.800 Tcfg (0.643 BBOE), of which 0.291 Bbo and 1.335 Tcfg (0.529 BBOE) have been produced. The play contains 224 producible sands in 67 pools (table 1). The first reserves in the play were discovered in the Eugene Island 45 field in 1948 (figure 2). The maximum yearly total reserves of 203.096 MMBOE were added in 1955 when three pools were discovered, including the largest pool in the play in the West Delta 30 field. On a BOE basis, 45 percent of the play's cumulative production is gas, but remaining total reserves indicate that future production may increase to 73 percent gas. Forty-five percent of the play's pools have been discovered since 1979. However, 81 percent of the play's cumulative production and 74 percent of its total reserves come from pools discovered prior to 1970, indicative of the large size of some of these early discoveries. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1994.

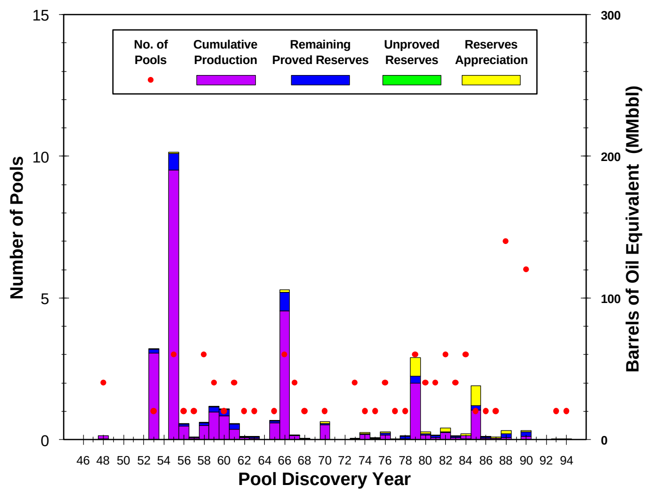


Figure 2. Exploration history graph.

The 67 discovered pools range in size from 0.078 to 153.640 MMBOE. These pools contain 395 reservoirs, of which 185 are nonassociated gas, 191 are undersaturated oil, and 19 are saturated oil.

Table 1. Characteristics of the discovered pools.

67 Pools (224 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	12	78	202
Subsea depth (feet)	1,625	4,847	6,847
Number of sands per pool	1	3	21
Porosity	22%	31%	36%
Water saturation	13%	26%	54%

Of the 11 aggradational plays in the Gulf of Mexico Cenozoic Province, the LPL A play has produced the second largest amount of hydrocarbons at 25 percent and contains the third largest amount of total reserves at 23 percent, based on BOE.

Assessment Results

The marginal probability of hydrocarbons for the LPL A play is 1.00. This play is the second largest aggradational play in the Gulf of Mexico Cenozoic Province, based on a mean total endowment of 0.345 Bbo and 2.097 Tcfg (0.719 BBOE) (table 2). Seventy-four percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.010 to 0.042 Bbo and 0.243 to 0.358 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.023 Bbo and 0.297 Tcfg (0.076 BBOE). These undiscovered resources may occur in as many as 20 pools. The largest undiscovered pool, with a mean size of

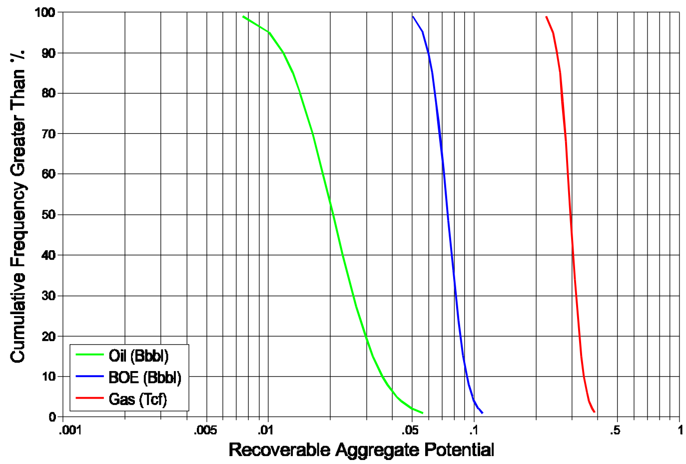


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	67	0.320	1.560	0.598
Cumulative production	--	0.291	1.335	0.529
Remaining proved	--	0.029	0.225	0.069
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.002	0.240	0.045
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.010	0.243	0.057
Mean	20	0.023	0.297	0.076
5th percentile	--	0.042	0.358	0.099
Total Endowment				
95th percentile	--	0.332	2.043	0.700
Mean	87	0.345	2.097	0.719
5th percentile	--	0.364	2.158	0.742

16.617 MMBOE, is modeled as the ninth largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 17, 18, 20, and 21 on the pool rank plot. For all the undiscovered pools in the LPL A play, the mean mean size is 3.770 MMBOE, which is smaller than the 9.592 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 8.254 MMBOE.

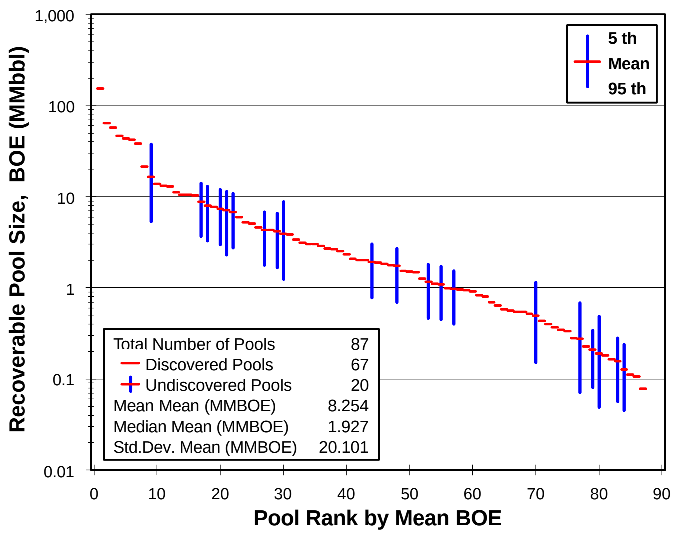


Figure 4. Pool rank plot.

Of the 11 Gulf of Mexico Cenozoic Province aggradational plays, the LPL A play is projected to contain the largest amounts of mean undiscovered oil and gas, at 38 percent and 23 percent, respectively.

The LPL A play is well explored. All of the undiscovered pools are modeled to have a mean size less than 20 MMBOE and to contribute only 11 percent to the play's BOE mean total endowment. Thus, this play is believed to have limited exploration potential for large resources.

LOWER PLEISTOCENE PROGRADATIONAL (LPL P) PLAY

PLAY DESCRIPTION

The Lower Pleistocene Progradational (LPL P) play is one of the largest established plays in the Gulf of Mexico Region. The play occurs within the *Valvulineria* "H" and *Lenticulina* 1 biozones and extends from the Galveston Area offshore Texas to the Destin Dome Area east of the present-day Mississippi River Delta (figure 1).

Updip, the play grades into the sediments of the Lower Pleistocene Aggradational (LPL A) play. The LPL P play also extends onshore in some areas near the Mississippi River Delta. The play does not extend farther to the west or northeast because of an apparent lack of shelfal source sands at the edges of the LPL depocenter. Downdip, the play grades into the deposits of the Lower Pleistocene Fan (LPL F) play.

The sediments in the LPL P play were mainly supplied by ancient delta systems located in the Louisiana area. No significant lateral shift in depocenter is observed in the offshore area from the underlying upper Pliocene (UP) chronozone to the LPL chronozone. The LPL progradational sequence is located farther basinward compared with the UP progradational sequence, which demonstrates the prograding nature of the delta systems with time.

PLAY CHARACTERISTICS

The productive LPL P play consists of progradational deltaic sediments deposited in delta front and fringe, channel and stacked channel, crevasse splay, shelf blanket, and shelf and upper slope slump environments. In addition, retrogradational sands locally cap the LPL P play. Because these retrogradational, reworked sands are so discontinuous, they are included as part of the LPL P play. Salt diapirs, anticlines, normal faults, and

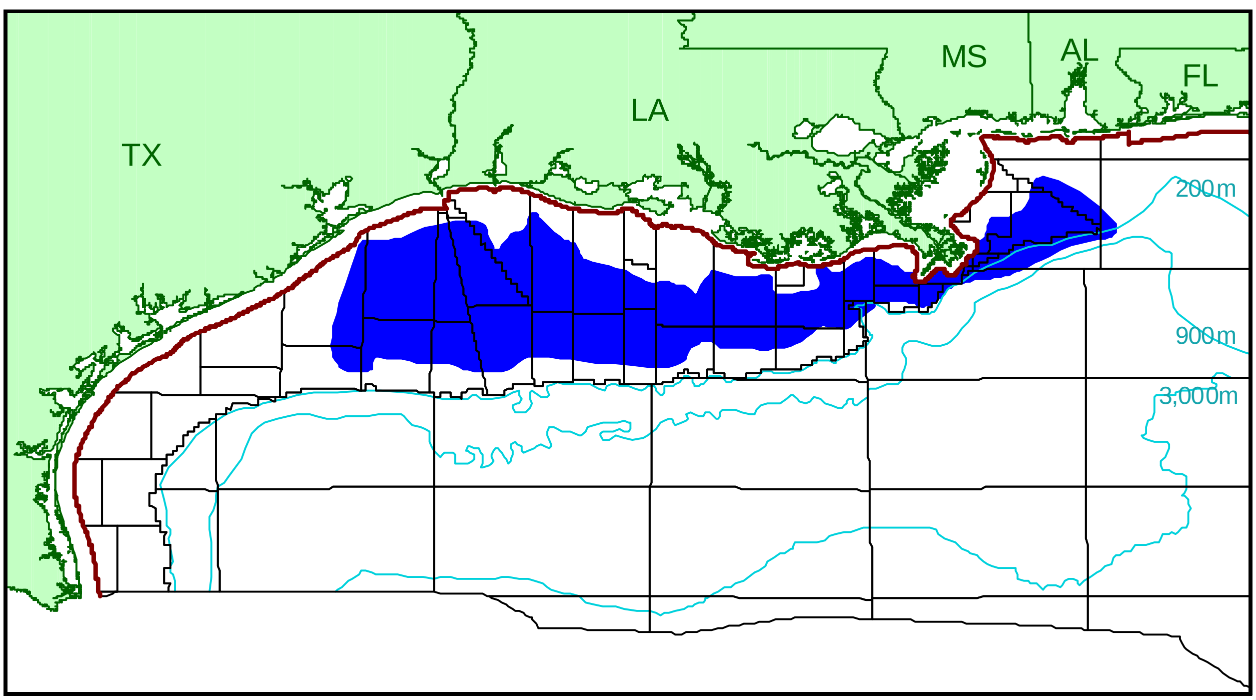


Figure 1. Map of assessed play.

growth faults are the dominant structural features in the play. Less commonly, stratigraphic pinch-outs and shale diapirs occur. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive progradational depositional environments, structures, or seals.

Vermilion 265 is the type field. Exxon Corporation's C5, C10, C25, C40, C50, D10 (equals Texaco Exploration and Production's I SEG500), D20, D40, D50, D60, D70 (equals Texaco Exploration and Production's JF), and D75 sands represent the LPL P play in this field.

DISCOVERIES

The LPL P play is predominantly a gas play, with total reserves of 1.510 Bbo and 18.869 Tcfg (4.868 BBOE), of which 1.212 Bbo and 13.969 Tcfg (3.698 BBOE) have been produced. The play contains 1,234 producible sands in 207 pools, and 203 of these pools contain proved reserves (table 1). The first LPL P reserves were discovered in the Ship Shoal 154 field in 1955 (figure 2). The maximum yearly total reserves of 484.902 MMBOE were added in 1964 with the discovery of eight pools. However, the largest pool in the play was discovered in 1962 in the South Timbalier 172 field. Discoveries in 1975 and earlier account for 88 percent of the cumulative production and 81 percent of the total reserves in the LPL P play. Throughout the play's history, pool discoveries have averaged about five per year. The most recent discoveries, prior to this study's cutoff date of January 1, 1995, occurred in 1993.

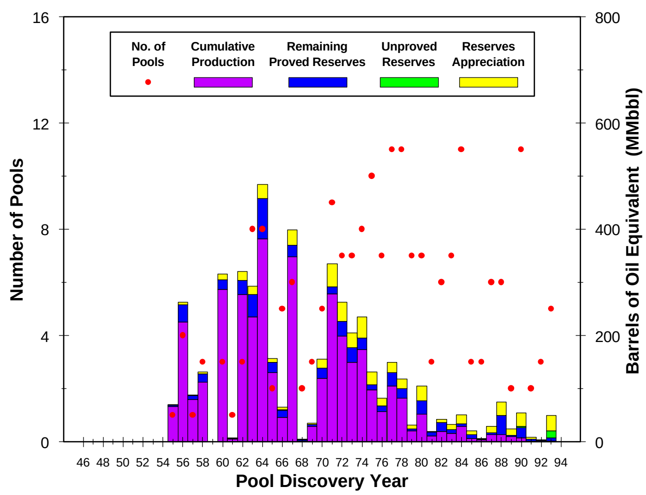


Figure 2. Exploration history graph.

The 207 discovered pools range in size from 0.059 to 278.575 MMBOE. These

Table 1. Characteristics of the discovered pools.

207 Pools (1,234 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	40	150	516
Subsea depth (feet)	2,550	7,030	13,473
Number of sands per pool	1	6	42
Porosity	17%	30%	36%
Water saturation	7%	26%	48%

pools contain 2,630 reservoirs, of which 1,445 are nonassociated gas, 975 are undersaturated oil, and 210 are saturated oil.

Of the 61 Gulf of Mexico plays, the LPL P play is the largest based on BOE total reserves. It contains the largest amount of gas total reserves (11%) and the third largest amount of oil total reserves (10%). The play has also produced the largest amount of gas (12%) and the second largest amount of oil (13%). Additionally, the play is the largest of the 14 Gulf of Mexico progradational plays, containing 17 percent of the BOE total reserves.

Assessment Results

The marginal probability of hydrocarbons for the LPL P play is 1.00. This play is the second largest in the Gulf of Mexico, based on a mean total endowment of 1.728 Bbo and 23.131 Tcfg (5.844 BBOE) (table 2). Sixty-three percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.153 to 0.298 Bbo and 3.775 to 4.787 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.218 Bbo and 4.262 Tcfg

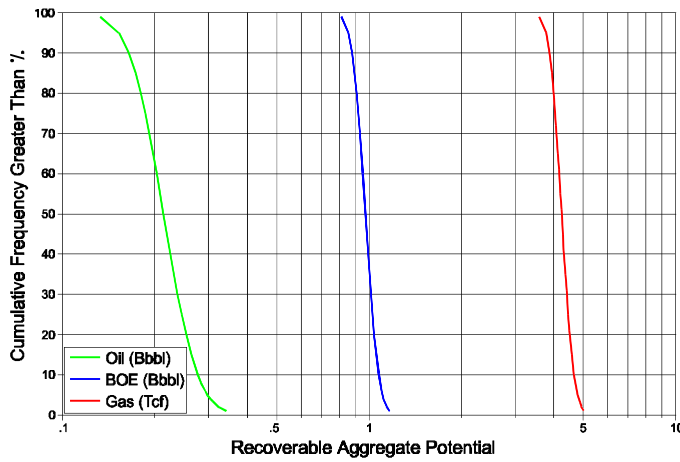


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	203	1.366	16.473	4.297
Cumulative production	--	1.212	13.969	3.698
Remaining proved	--	0.154	2.504	0.600
Unproved	4	0.007	0.047	0.015
Appreciation (P & U)	--	0.136	2.350	0.555
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.153	3.775	0.857
Mean	73	0.218	4.262	0.976
5th percentile	--	0.298	4.787	1.110
Total Endowment				
95th percentile	--	1.663	22.644	5.725
Mean	280	1.728	23.131	5.844
5th percentile	--	1.808	23.656	5.978

(0.976 BBOE). These undiscovered resources may occur in as many as 73 pools. The largest undiscovered pool, with a mean size of 91.737 MMBOE, is modeled as the thirteenth largest pool in the play (figure 4). For all the undiscovered pools in the LPL P play, the mean mean size is 13.344 MMBOE, which is smaller than the 23.515 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 20.863 MMBOE.

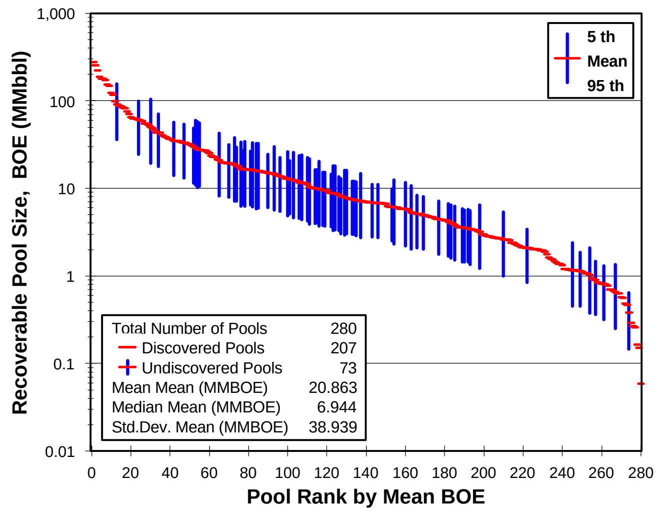


Figure 4. Pool rank plot.

Of all 61 Gulf of Mexico plays, the LPL P play is projected to contain the sixth largest amount of mean undiscovered gas resources at 4 percent. Of the 14 Gulf of Mexico progradational plays, the LPL P play is projected to contain the largest amounts of mean undiscovered oil and gas resources, at 32 percent and 26 percent, respectively.

The LPL P play is well explored with large amounts of total reserves. Relative to the discovered pools, most of the undiscovered pools are of moderate size. However, the LPL P play has the largest undiscovered resources of all the progradational plays in the Gulf of Mexico. These undiscovered resources contribute 17 percent to the play's BOE mean total endowment.

LOWER PLEISTOCENE FAN (LPL F) PLAY

PLAY DESCRIPTION

The Lower Pleistocene Fan (LPL F) play is one of the largest established plays in the Gulf of Mexico Region. The play occurs within the *Lenticulina* 1 and *Valvulineria* "H" biozones and extends from the Galveston, East Breaks, and Alaminos Canyon Areas to the western edges of the Desoto Canyon and Destin Dome Areas east of the present-day Mississippi River Delta (figure 1).

The play is bounded updip by the shelf/slope break associated with the *Lenticulina* 1 biozone and grades into the sediments of the Lower Pleistocene Progradational (LPL P) play. The LPL F play does not extend farther to the west because of an apparent lack of shelfal source sands in offshore Texas during LPL time. To the northeast, the play is limited by a lack of clastic influx at the edge of the LPL depocenter. The southern extension of the play's potential to at least the Sigsbee Escarpment is supported by LPL reservoir-quality sands in the OCS G11643-1 well in Keathley Canyon block 255 and by chronozone tops correlated to seismic data.

The sediments in the LPL F play were supplied mainly by ancient delta systems located in the Louisiana area. The shelf/slope break of the LPL chronozone occurs farther basinward as compared to that of the upper Pliocene (UP) chronozone, indicative of prograding delta systems.

PLAY CHARACTERISTICS

The productive LPL F play consists of deepwater turbidites deposited in fan systems as channel fill, overbank deposits, fan lobes, and fringe sheet sediments on the LPL slope between salt highs. Salt diapirs and anticlines dominate the play's structural features.

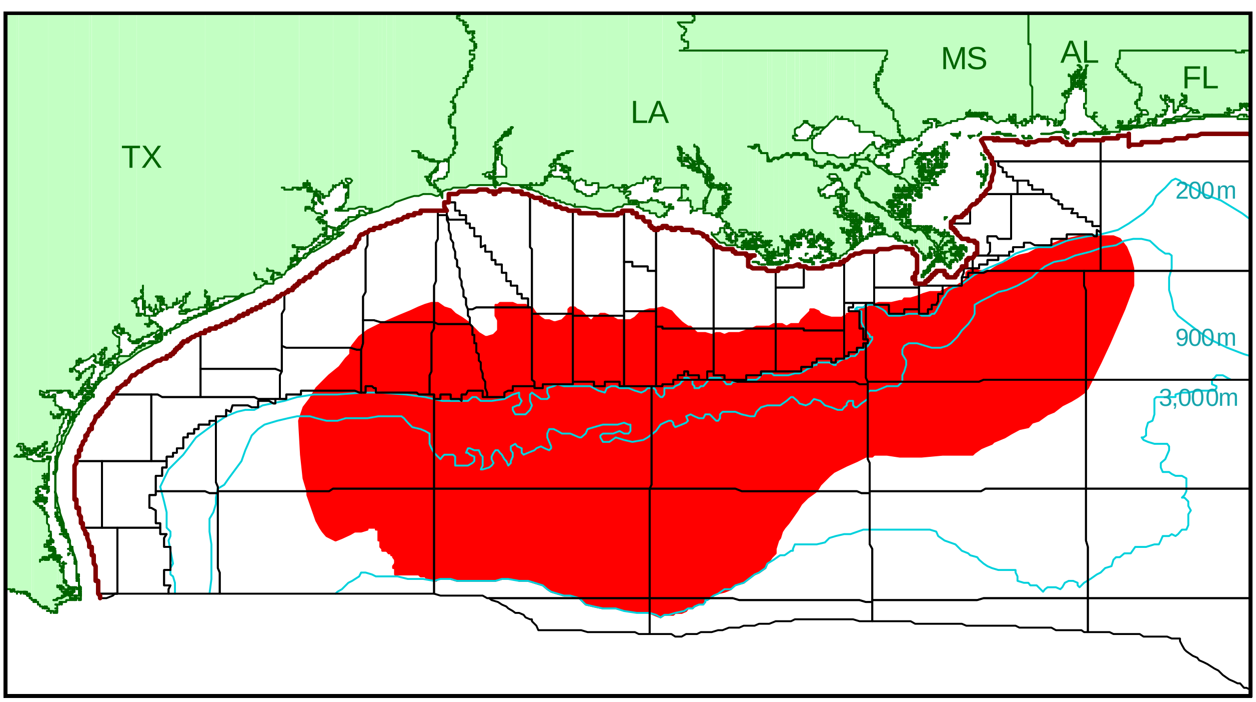


Figure 1. Map of assessed play.

Less commonly, growth faults, normal faults, stratigraphic pinch-outs, unconformities, salt ridges, and shale diapirs occur. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive fan depositional environments, structures, or seals.

High Island 467A is the type field, and Forcenergy Gas Exploration Inc.'s GO, GI, HIK, HP, ID, IP, JA, JD, JF, JG, and JM sands represent the LPL F play in this field.

DISCOVERIES

The LPL F mixed oil and gas play contains total reserves of 1.814 Bbo and 14.330 Tcfg (4.364 BBOE), of which 0.691 Bbo and 7.159 Tcfg (1.965 BBOE) have been produced. The play contains 557 producible sands in 122 pools, (table 1), and 109 of these pools contain proved reserves. The first reserves in the play were discovered in the South Marsh Island 79 field in 1963 (figure 2). Pool discoveries peaked in 1976 at 12 and have averaged about four per year throughout the play's history. Substantial reserves have been added almost every year since the initial discovery, with a maximum of 570.799 MMBOE found in 1984 in 10 pools. However, the largest discovered pool in the play was found in 1990 in the East Breaks 945 field (“Diana”). In 1987 and 1988, significant discoveries were made in the Garden Banks 426 field ("Auger") and in the Green Canyon 205 field (“Genesis”), respectively. The most recent discovery, prior to this study’s cutoff date of January 1, 1995, was in 1994.

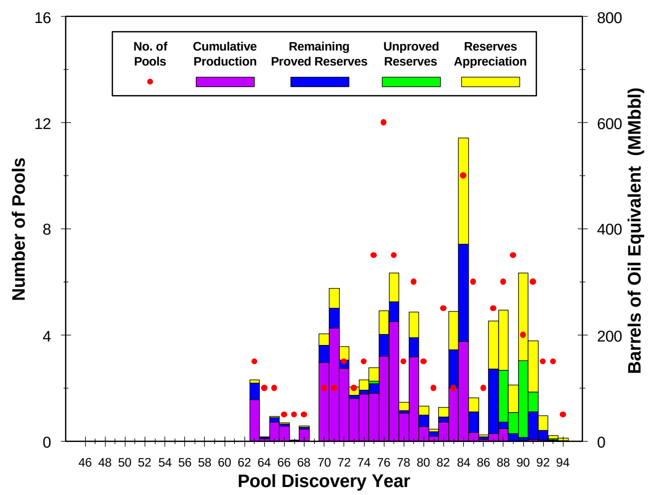


Figure 2. Exploration history graph.

Ninety-six percent of the cumulative production from this play has occurred from pools discovered prior to 1985, while 65 percent of the remaining total reserves is

Table 1. Characteristics of the discovered pools.

122 Pools (557 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	95	658	6,950
Subsea depth (feet)	5,668	9,722	16,950
Number of sands per pool	1	5	26
Porosity	20%	30%	36%
Water saturation	16%	26%	50%

estimated to be in pools discovered in 1984 or later. Deepwater, unproved pools, plus their reserves appreciation, account for most of these remaining total reserves discovered since 1984. On a BOE basis, 35 percent of the play's cumulative production is oil, but remaining total reserves indicate that future production may increase to almost 50 percent oil.

The 122 discovered pools range in size from 0.022 to 277.882 MMBOE. These pools contain 1,034 reservoirs, of which 540 are nonassociated gas, 397 are undersaturated oil, and 97 are saturated oil.

Of the 61 plays in the Gulf of Mexico, the LPL F play is the third largest, based on BOE total reserves. It contains the second largest amounts of both oil and gas total reserves, at 12 percent and 8 percent, respectively. The play also ranks seventh for BOE cumulative production (7%). Of the 15 fan plays, the LPL F play is the largest, containing 37 percent of the BOE total reserves and accounting for 43 percent of the BOE production.

Assessment Results

The marginal probability of hydrocarbons for the LPL F play is 1.00. This play is the largest in the Gulf of Mexico, based on a mean total endowment of 2.651 Bbo and 26.684 Tcfg (7.399 BBOE) (table 2). Twenty-seven percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.622 to 1.094 Bbo and 8.783 to 16.721 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.837 Bbo and 12.354 Tcfg (3.035

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	109	1.040	9.977	2.816
Cumulative production	--	0.691	7.159	1.965
Remaining proved	--	0.350	2.818	0.851
Unproved	13	0.204	0.702	0.329
Appreciation (P & U)	--	0.570	3.651	1.220
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.622	8.783	2.499
Mean	158	0.837	12.354	3.035
5th percentile	--	1.094	16.721	3.915
Total Endowment				
95th percentile	--	2.436	23.113	6.863
Mean	280	2.651	26.684	7.399
5th percentile	--	2.908	31.051	8.279

BBOE). These undiscovered resources may occur in as many as 158 pools. The largest undiscovered pool, with a mean size of 494.930 MMBOE, is modeled as the largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 3, 4, 14, and 15 on the pool rank plot. For all the undiscovered pools in the LPL F play, the mean mean size is 19.148 MMBOE, which is substantially smaller than the 35.770 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 26.390 MMBOE.

Of all 61 Gulf of Mexico plays, the LPL F play is projected to contain the largest amount of mean undiscovered gas and the second largest amount of mean undiscovered oil, or 12 percent of the BOE mean undiscovered resources. Additionally, the play contains 17 percent of the BOE mean undiscovered resources for the 15 Gulf of Mexico fan plays.

Due to a large unexplored area and known areas of good LPL sand development, the LPL F play is expected to contain numerous undiscovered pools, which account for 41 percent of the play's BOE mean total endowment. The greatest exploration potential exists downdip of discovered fields, especially in areas of present-day water depths greater than 1,000 feet.

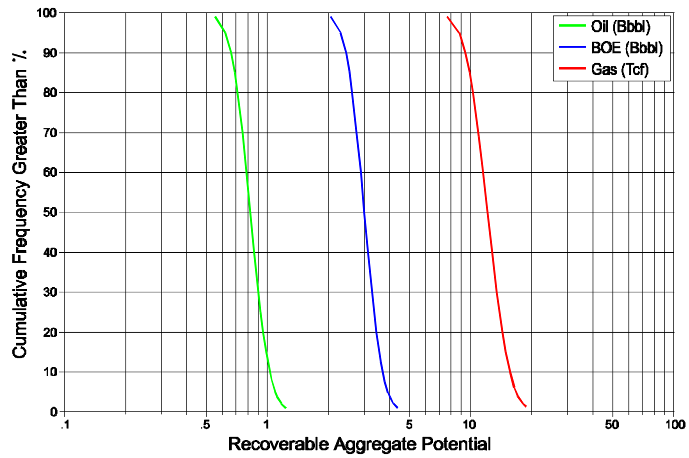


Figure 3. Cumulative probability distribution.

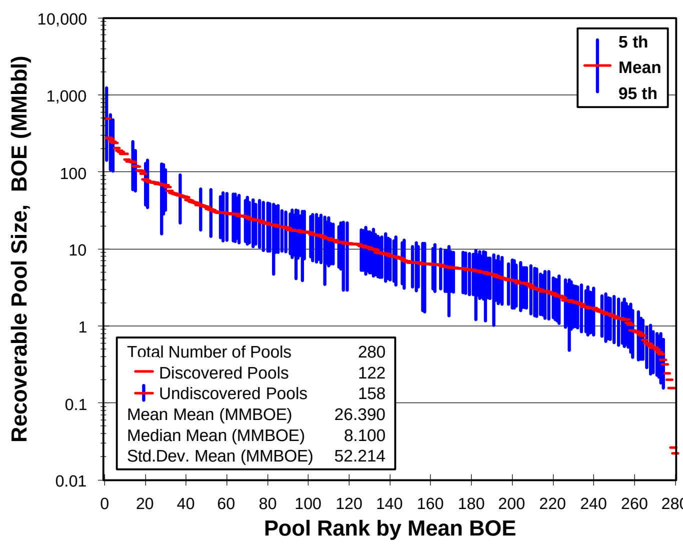


Figure 4. Pool rank plot.

UPPER PLIOCENE (UP) CHRONOZONE

CHRONOZONE DESCRIPTION

The Upper Pliocene (UP) chronozone corresponds to the *Buliminella* 1 biozone. The UP section reflects delta systems prograding onto the continental shelf and fan deposition on the continental slope of the Gulf of Mexico Basin. Depositional styles present in the UP chronozone include aggradational, progradational, and fan, each of which defines a play: the Upper Pliocene Aggradational (UP A) play, the Upper Pliocene Progradational (UP P) play, and the Upper Pliocene Fan (UP F) play. Retrogradational sands associated with marine transgressions also occur locally in the play areas at the top of the progradational and aggradational deposits. However, because these retrogradational sands are discontinuous over any significant distance, they are included as part of the underlying deposits.

The potential for sand development within the UP chronozone extends from the nearshore Galveston to the deepwater Port Isabel and Corpus Christi Areas northeastward to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). Updip, UP sands continue onshore into Louisiana and eastern Texas. Sand potential is limited to the west and northeast due to a lack of sediment influx at the edges of the UP depocenter. The downdip limit extends at least as far as the Sigsbee Escarpment as indicated by UP sand development in the OCS G12662-1 well in Garden Banks block 568 and by chronozone tops correlated to seismic data.

Productive and established sand locations in Miocene plays are a result of two ancient depocenters, one in the Texas area and the other in the Louisiana area. In UP time, sand deposition was greatly diminished in the Texas depocenter when compared with deposition during lower Pliocene (LP) time. Thus, other than in the eastern Galveston and

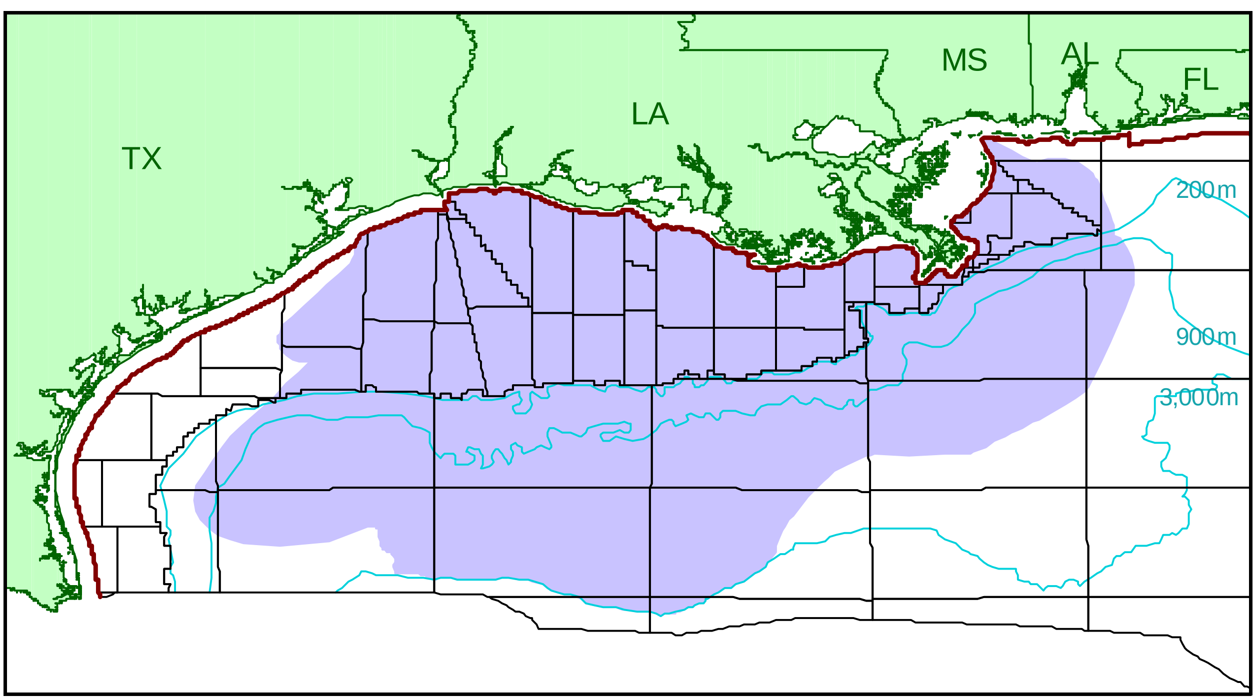


Figure 1. Map of assessed chronozone.

High Island Areas, few sands are found in the UP chronozone in offshore Texas.

In the Louisiana area, the UP shelf edge is observed farther offshore than that of the underlying LP chronozone due to the seaward progradation of deltaic deposits from the ancestral Mississippi River.

Major structural features in the UP chronozone include salt diapirs, anticlines, normal faults, and growth faults. Stratigraphic pinch-outs, salt ridges, and shale diapirs occur much less frequently.

DISCOVERIES

The UP chronozone contains 217 discovered pools in three plays (table 1). Significant amounts of hydrocarbons were recently identified in the UP chronozone in the Garden Banks 260 field ("Antioch"). Of the 21 chronozones in the Gulf of Mexico Region, the UP chronozone contains the third largest amount of total reserves, with 2.062 Bbo and 15.788 Tcfg (4.872 BBOE), of which 1.222 Bbo and 10.176 Tcfg (3.032 BBOE) have been produced. The largest number of discoveries in the UP chronozone occurred when 13 pools were added in 1984 (figure 2). However, the maximum yearly total reserves of 647.757 MMBOE were added in 1963 with the discovery of 10 pools.

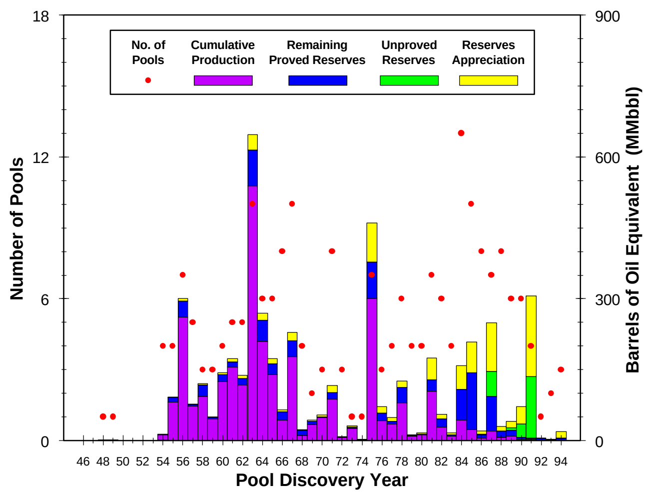


Figure 2. Exploration history graph.

Of the three plays in the UP chronozone, the UP P play contains the most total reserves in 130 pools, with 0.962 Bbo and 9.227 Tcfg (2.604 BBOE).

Table 1. Characteristics of the discovered pools.

217 Pools (969 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	13	299	7,500
Subsea depth (feet)	1,971	8,805	19,216
Number of sands per pool	1	4	36
Porosity	21%	29%	36%
Water saturation	16%	27%	51%

Assessment Results

The UP chronozone contains 371 pools (discovered plus undiscovered), with a mean total endowment estimated at 2.469 Bbo and 19.419 Tcfg (5.925 BBOE) (table 2).

Assessment results indicate that undiscovered resources may occur in as many as 154 pools, which contain a range of 0.340 to 0.482 Bbo and 3.258 to 4.030 Tcfg at the 95th and 5th percentiles, respectively (figure 3). At mean levels, 0.407 Bbo and 3.631 Tcfg (1.053 BBOE) are projected. These undiscovered resources represent 18 percent of the UP chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the thirty-ninth largest in the chronozone (figure 4).

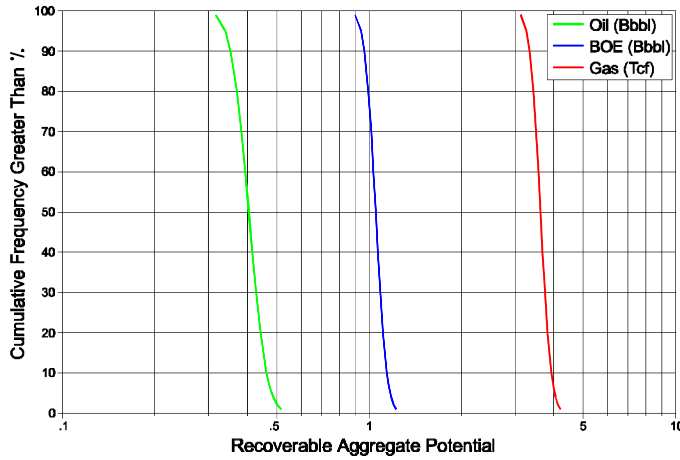


Figure 3. Cumulative probability distribution.

Of the three UP plays, the UP F play is projected to contain the greatest exploration potential, with mean undiscovered resources estimated at 0.329 Bbo and 2.819 Tcfg (0.831 BBOE) in 105 pools. These undiscovered resources in the UP F play represent 14 percent of the BOE mean total endowment for the UP chronozone. Drilling results in

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	208	1.576	12.834	3.860
Cumulative production	--	1.222	10.176	3.032
Remaining proved	--	0.354	2.658	0.827
Unproved	9	0.126	0.525	0.220
Appreciation (P & U)	--	0.360	2.429	0.792
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.340	3.258	0.943
Mean	154	0.407	3.631	1.053
5th percentile	--	0.482	4.030	1.171
Total Endowment				
95th percentile	--	2.402	19.046	5.815
Mean	371	2.469	19.419	5.925
5th percentile	--	2.544	19.818	6.043

Garden Banks block 568 support strongly developed UP reservoir-quality sands in deepwater. This, coupled with the potential for numerous discoveries within a large unexplored area and prolific existing fan production, makes the UP F play an attractive exploration target in UP strata.

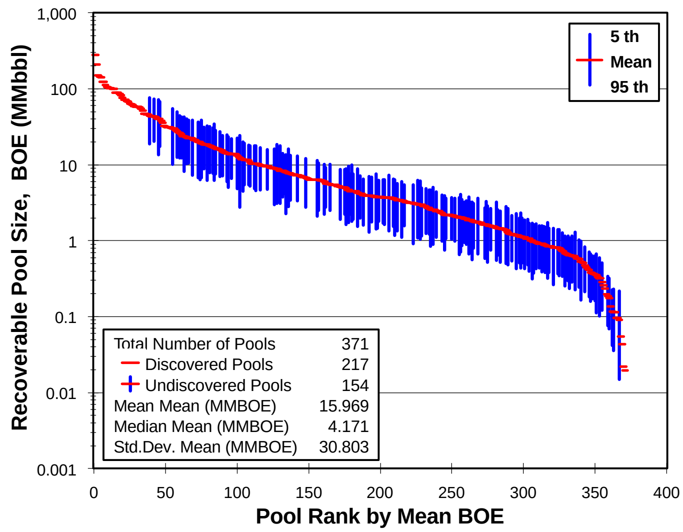


Figure 4. Pool rank plot.

UPPER PLIOCENE AGGRADATIONAL (UP A) PLAY

PLAY DESCRIPTION

The established Upper Pliocene Aggradational (UP A) play occurs at the *Buliminella* 1 biozone. This play extends from the Galveston Area offshore Texas to the Viosca Knoll and Mobile Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the play continues onshore into Louisiana and eastern Texas. Aggradational sand deposition ends to the west in the High Island Area and to the east in the Viosca Knoll and Mobile Areas at the edges of the UP depocenter. Downdip, the play grades into the sediments of the Upper Pliocene Progradational (UP P) play.

The downdip extent of the aggradational sequence in the UP chronozone is located farther basinward than that of the lower Pliocene (LP) chronozone, indicative of progradation by the ancient delta systems.

PLAY CHARACTERISTICS

The productive UP A play consists of delta plain and shallow marine shelf deposits that formed as channels, point bars, distributary mouth bars, crevasse splays, beaches, barrier islands, and nearshore bars. In addition, retrogradational sands locally cap the UP A play. Because these retrogradational, reworked sands are so discontinuous, they are included as part of the UP A play. Salt diapirs, anticlines, growth faults, and normal faults are the major structural features in the play. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive aggradational depositional environments, structures, or seals.

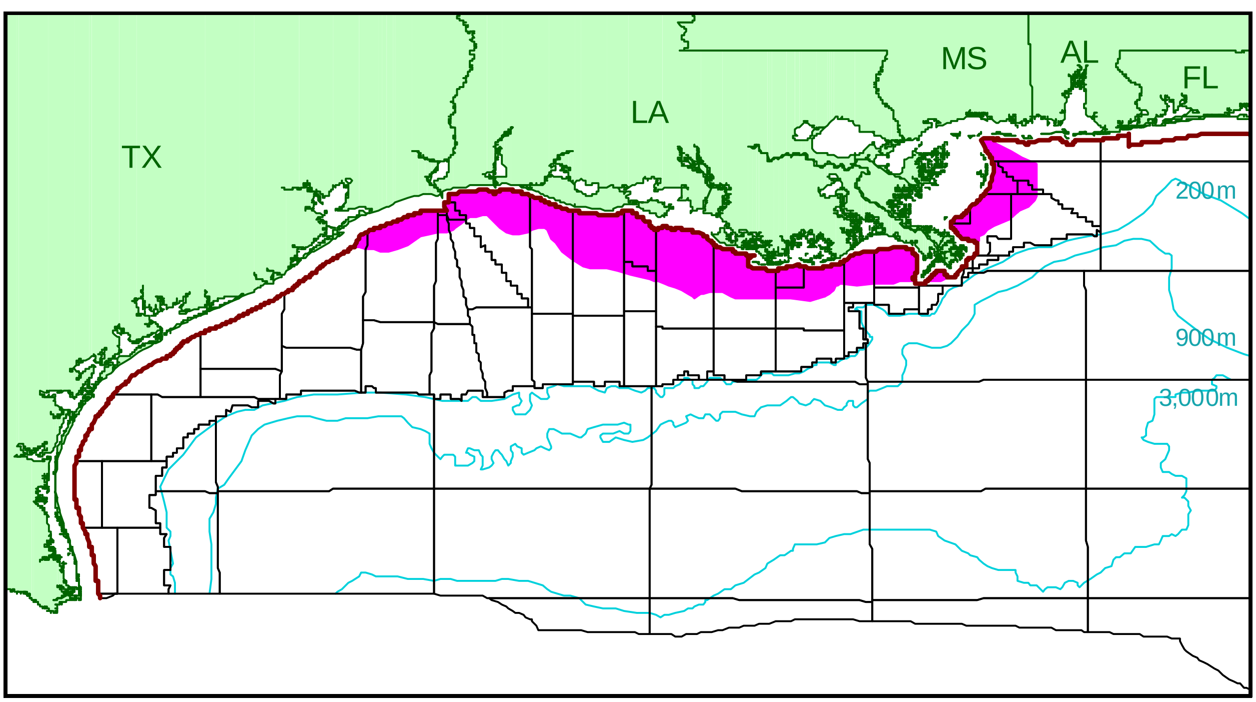


Figure 1. Map of assessed play.

South Pelto 23 is the type field, and Stone Petroleum Corporation's 8400, 8500, 8700, 9000, and 9300 sands represent the UP A play in this field.

DISCOVERIES

The UP A mixed oil and gas play contains total reserves of 0.138 Bbo and 0.960 Tcfg (0.309 BBOE), of which 0.122 Bbo and 0.773 Tcfg (0.259 BBOE) have been produced. The play contains 132 producible sands in 34 pools (table 1). The first reserves in the play were discovered in the Grand Isle 16 field in 1948 (figure 2). The most active period of discoveries lasted from 1954 to 1963, during which 18 pools and over 85 percent of the play's total reserves were found. The maximum yearly total reserves of 88.229 MMBOE were added in 1955 with the discovery of three pools. However, the largest pool in the play was discovered in 1956 in the Main Pass 41 field. On a BOE basis, 53 percent of the play's cumulative production is gas, but remaining total reserves indicate that future production may increase to 67 percent gas. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1994.

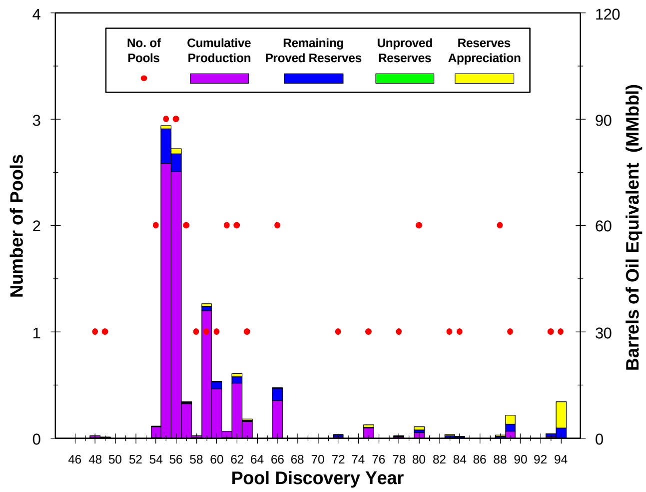


Figure 2. Exploration history graph.

The 34 discovered pools range in size from 0.019 to 63.714 MMBOE. These pools contain 301 reservoirs, of which 75 are nonassociated gas, 201 are undersaturated oil, and 25 are saturated oil.

Table 1. Characteristics of the discovered pools.

34 Pools (132 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	13	58	179
Subsea depth (feet)	1,971	6,449	12,100
Number of sands per pool	1	4	21
Porosity	25%	30%	36%
Water saturation	16%	27%	50%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the UP A play is 1.00. The play contains a mean total endowment of 0.149 Bbo and 1.051 Tcfg (0.336 BBOE) (table 2). Seventy-seven percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.006 to 0.016 Bbo and 0.058 to 0.122 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.011 Bbo and 0.091 Tcfg (0.027 BBOE). These undiscovered resources may occur in as many as eight pools. The largest undiscovered pool, with a mean size of 8.064 MMBOE, is modeled as the eleventh largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 13, 16, 22, and 24 on the pool rank plot. For all the undiscovered pools in the UP A play, the mean mean size is 3.403 MMBOE, which is smaller than the 9.094 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 8.010 MMBOE.

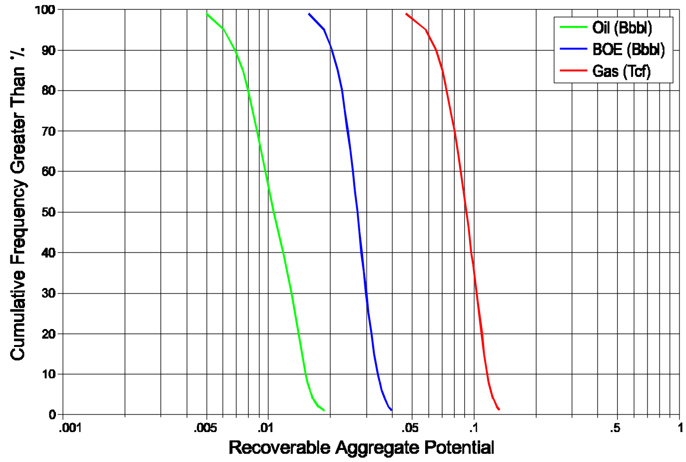


Figure 3. Cumulative probability distribution.

Of the 11 aggradational plays in the Gulf of Mexico Cenozoic Province, the UP A play is projected to contain the third largest amount of mean undiscovered oil resources at 18 percent.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	34	0.135	0.885	0.292
Cumulative production	--	0.122	0.773	0.259
Remaining proved	--	0.013	0.112	0.033
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.003	0.075	0.017
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.006	0.058	0.019
Mean	8	0.011	0.091	0.027
5th percentile	--	0.016	0.122	0.036
Total Endowment				
95th percentile	--	0.144	1.018	0.328
Mean	42	0.149	1.051	0.336
5th percentile	--	0.154	1.082	0.345

Many wells have tested this shallow-water play, leaving only limited interfield exploration potential. On the pool rank plot, the eight undiscovered pools are placed near the moderate and small discovered pool sizes and are estimated to add only 8 percent to the play's BOE mean total endowment.

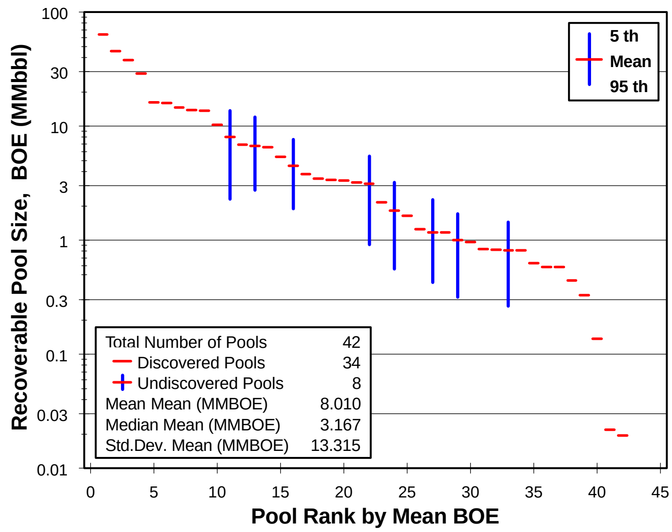


Figure 4. Pool rank plot.

UPPER PLIOCENE PROGRADATIONAL (UP P) PLAY

PLAY DESCRIPTION

The Upper Pliocene Progradational (UP P) play is one of the largest established plays in the Gulf of Mexico Region. The play occurs at the *Buliminella* 1 biozone and extends from the Galveston Area offshore Texas to the western edge of the Destin Dome Area east of the present-day Mississippi River Delta (figure 1).

Updip, the play grades into the deposits of the Upper Pliocene Aggradational (UP A) play. To the northeast and southwest, the UP P play is limited by a marked decrease of sediment influx at the edges of the UP depocenter. Downdip, the play grades into the deposits of the Upper Pliocene Fan (UP F) play.

The ancestral Mississippi River Delta System, located in the present-day offshore Louisiana and easternmost Texas areas, was the dominant depocenter during UP time. East of the Viosca Knoll Area and West of the Galveston Area, UP sediments were deposited at the edges of the depocenter. These sediments are considered nonprospective as they are thin and very shallow in depth.

The updip boundary of the lower Pliocene (LP) progradational deposits occurs either onshore or just slightly offshore. By UP time, the delta systems had migrated basinward so that the updip boundary of the progradational deposits is primarily in Federal waters.

PLAY CHARACTERISTICS

The productive UP P play consists of progradational deltaic sediments deposited in delta front, delta fringe, and shelf blanket environments. In addition, retrogradational sands locally cap the UP P play. Because these retrogradational, reworked sands are so

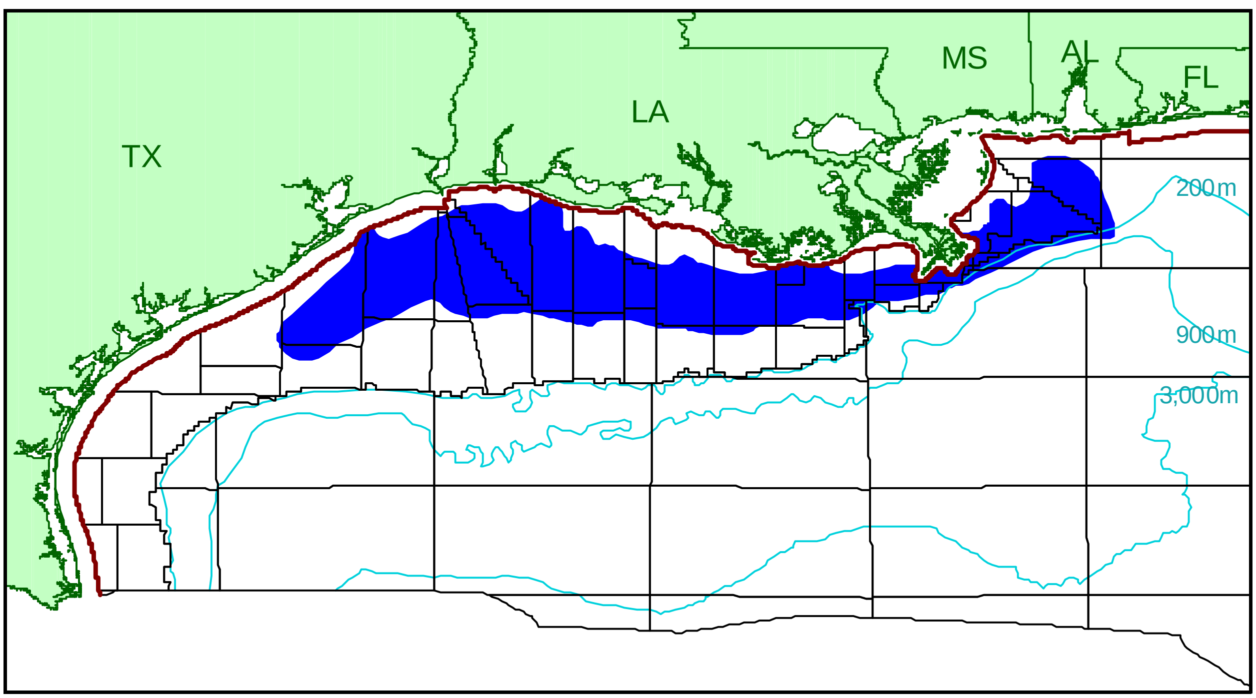


Figure 1. Map of assessed play.

discontinuous, they are included as part of the UP P play. Salt diapirs, normal faults, and anticlines are the dominant structural features in this play. Growth faults, stratigraphic pinch-outs, salt ridges, and shale diapirs also occur. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive progradational depositional environments, structures, or seals.

Ship Shoal 181 is the type field, and Chevron USA Inc.'s D10, D11, E2, E3, E5, E7, and E9 sands represent the UP F play in this field.

Discoveries

The UP P mixed oil and gas play contains total reserves of 0.962 Bbo and 9.227 Tcfg (2.604 BBOE), of which 0.754 Bbo and 6.882 Tcfg (1.979 BBOE) have been produced. The play contains 641 producible sands in 130 pools (table 1). The first reserves in the play were discovered in the South Timbalier 52 field in 1954 (figure 2). The maximum yearly total reserves of 531.386 MMBOE were added in 1963 with the discovery of eight pools. However, the largest pool in the play was discovered in 1956 in the South Timbalier 135 field. Over 75 percent of the play's cumulative production and over 70 percent of the play's total reserves are from pools discovered in the 1960's or earlier. An average of three to four pools were discovered each year from 1954 to 1992. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1994.

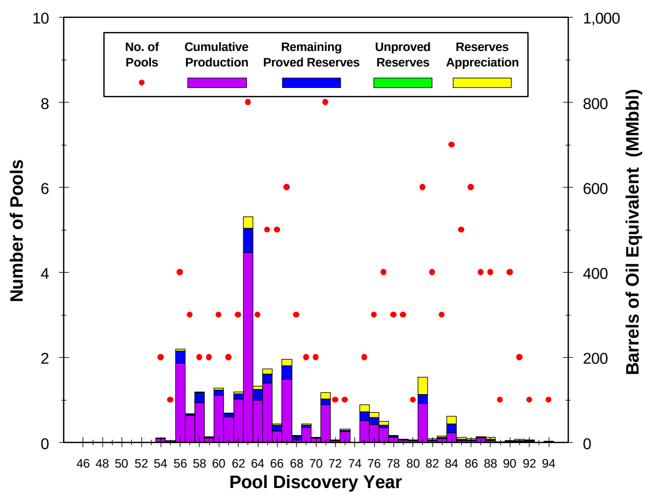


Figure 2. Exploration history graph.

The 130 discovered pools range in size from 0.043 to 150.190 MMBOE. These pools contain 1,661 reservoirs, of which 783 are nonassociated gas, 726 are undersaturated oil, and 152 are saturated oil.

Table 1. Characteristics of the discovered pools.

130 Pools (641 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	22	127	516
Subsea depth (feet)	2,260	8,207	15,148
Number of sands per pool	1	5	36
Porosity	22%	29%	36%
Water saturation	16%	27%	45%

Of the 61 Gulf of Mexico plays, the UP P play contains the seventh largest amount of total reserves (6%) and has produced the fifth largest amount of hydrocarbons (7%), based on BOE.

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the UP P play is 1.00. This play is the eighth largest in the Gulf of Mexico, based on a mean total endowment of 1.029 Bbo and 9.948 Tcfg (2.799 BBOE) (table 2). Seventy-one percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.045 to 0.092 Bbo and 0.611 to 0.833 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.067 Bbo and 0.721 Tcfg (0.195 BBOE). These undiscovered resources may occur in as many as 41 pools. The largest undiscovered pool, with a mean size of

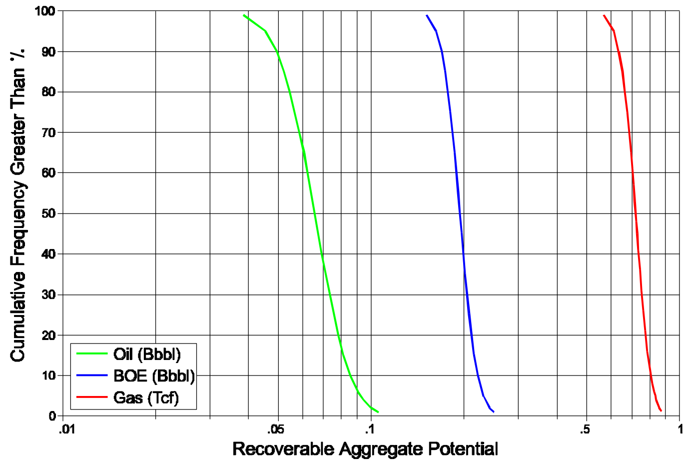


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	130	0.889	8.296	2.365
Cumulative production	--	0.754	6.882	1.979
Remaining proved	--	0.135	1.414	0.387
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.073	0.932	0.239
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.045	0.611	0.163
Mean	41	0.067	0.721	0.195
5th percentile	--	0.092	0.833	0.231
Total Endowment				
95th percentile	--	1.007	9.838	2.767
Mean	171	1.029	9.948	2.799
5th percentile	--	1.054	10.060	2.835

19.143 MMBOE, is modeled as the thirty-fifth largest pool in the play (figure 4). For all the undiscovered pools in the UP P play, the mean mean size is 4.748 MMBOE, which is substantially smaller than the 20.031 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 16.367 MMBOE.

The UP P play is well explored, with limited potential for discoveries between and downdip of discovered pools. Undiscovered pools are modeled as moderate to small in size and are expected to contribute only 7 percent to the play's BOE mean total endowment.

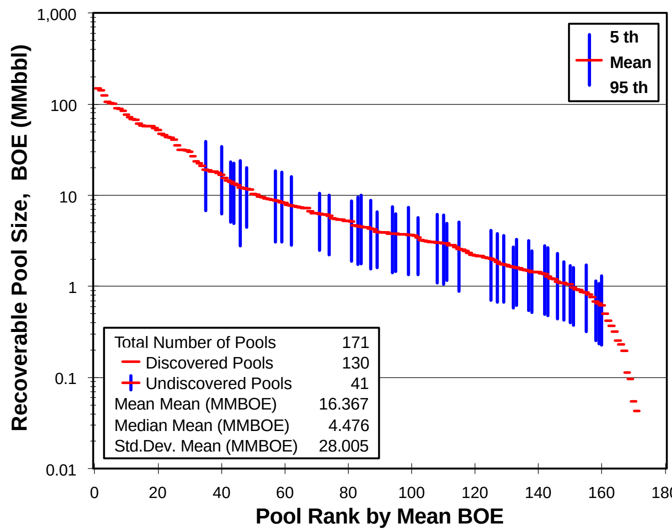


Figure 4. Pool rank plot.

UPPER PLIOCENE FAN (UP F) PLAY

PLAY DESCRIPTION

The Upper Pliocene Fan (UP F) play is one of the largest established plays in the Gulf of Mexico Region. The play occurs at the *Buliminella* 1 biozone and extends from the Corpus Christi and Port Isabel Areas to the western edge of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1).

Updip and to the northeast, the play is bounded by the shelf/slope break associated with the *Buliminella* 1 biozone and grades into the deposits of the Upper Pliocene Progradational (UP P) play. To the southwest, the play is limited by a marked decrease in sediment influx at the edge of the UP depocenter. The southern extension of the play's potential to at least the Sigsbee Escarpment is supported by good reservoir-quality UP sands in the OCS G12662-1 well in Garden Banks block 568.

The ancestral Mississippi River Delta System, located in the present-day offshore Louisiana and easternmost Texas areas, was the dominant depocenter during UP time. The active delta systems present in Texas during the Miocene no longer provided significant clastic influx to the present-day Texas offshore area.

PLAY CHARACTERISTICS

The productive UP F play consists of deepwater turbidite sands deposited in fan systems as channel fill, fan lobes, and fringe sheet sediments on the UP slope between salt highs. Salt diapirs, anticlines, and normal faults are the dominant structural features in this play. Growth faults and salt ridges occur less commonly. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future

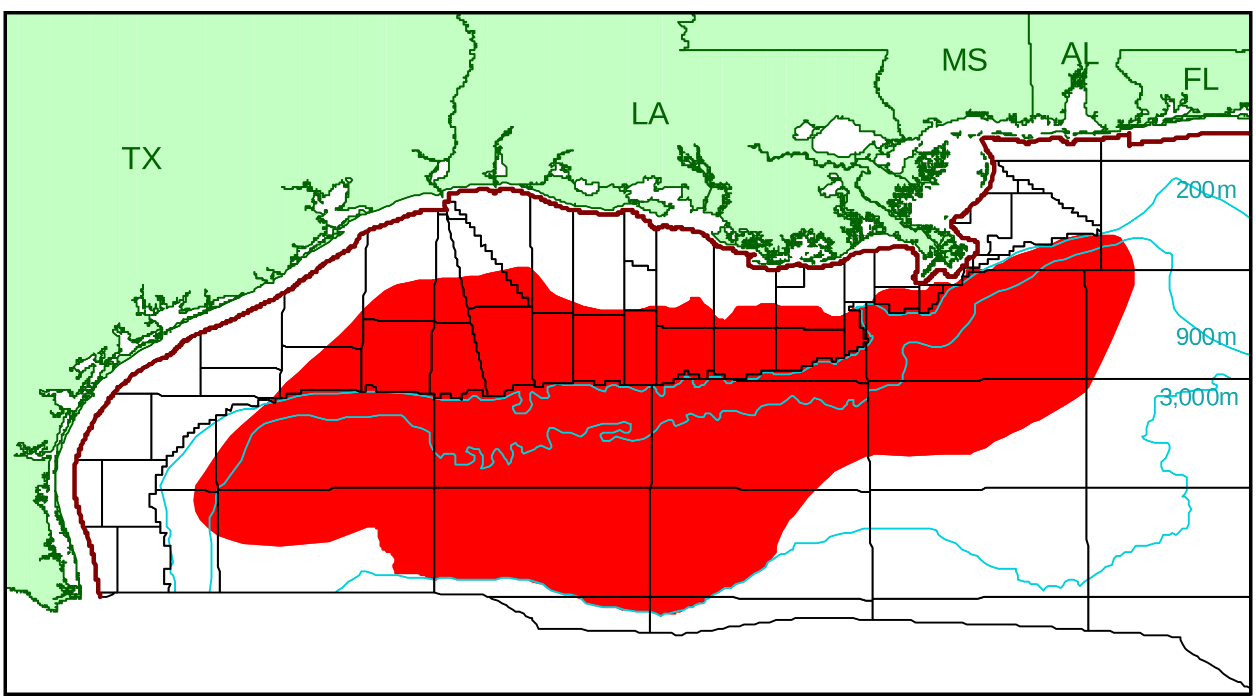


Figure 1. Map of assessed play.

discoveries are not limited to the aforementioned productive fan depositional environments, structures, or seals.

South Pass 89 is the type field. Marathon Oil Co.'s T10, STRAY, U1, U5, US1 and US2 sands and Exxon Corporation's P3, Z10, and Z20 sands represent the UP F play in this field.

DISCOVERIES

The UP F mixed oil and gas play contains total reserves of 0.962 Bbo and 5.600 Tcfg (1.958 BBOE), of which 0.346 Bbo and 2.521 Tcfg (0.794 BBOE) have been produced. The play contains 196 producible sands in 53 pools, and 44 of these pools contain proved reserves (table 1). The first reserves in the play were discovered in the Ship Shoal 208 field in 1961 (figure 2). The maximum yearly total reserves of 367.105 MMBOE were added in 1975 when four pools were discovered, including the largest pool in the play in the Mississippi Canyon 194 field ("Cognac"). Forty-four percent of the play's total reserves were discovered in 22 pools in 1985 or later; half of these pools are in water depths greater than 1,000 feet. A significant discovery was made in 1991 in the Garden Banks 260 field ("Antioch"). The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1994.

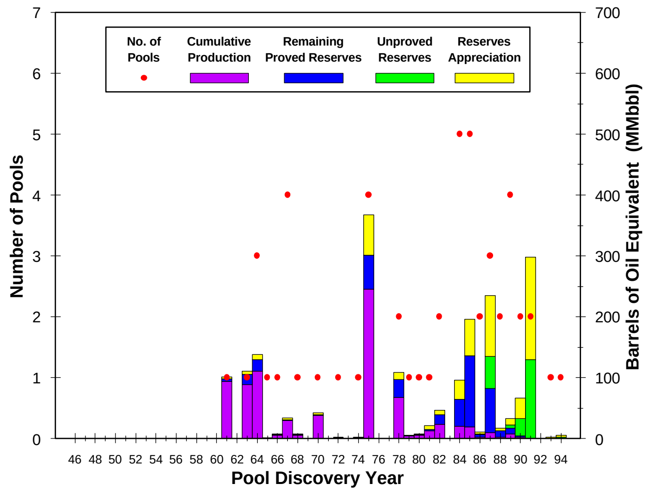


Figure 2. Exploration history graph.

The 53 discovered pools range in size from 0.095 to 281.112 MMBOE. These pools contain 335 reservoirs, of which 139 are nonassociated gas, 159 are undersaturated oil, and 37 are saturated oil.

Of the 61 Gulf of Mexico plays, the UP F play contains the ninth largest amount of BOE total reserves at 4 percent. Of the 15 Gulf of Mexico fan plays, the UP F play is the second largest, based on BOE total reserves (16%) and BOE cumulative production (18%).

Table 1. Characteristics of the discovered pools.

53 Pools (196 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	71	877	7,500
Subsea depth (feet)	6,137	11,785	19,216
Number of sands per pool	1	4	17
Porosity	21%	29%	34%
Water saturation	16%	26%	51%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the UP F play is 1.00. This play is the ninth largest in the Gulf of Mexico, based on a mean total endowment of 1.291 Bbo and 8.419 Tcfg (2.789 BBOE) (table 2). Twenty-eight percent of this BOE mean total endowment has been produced.

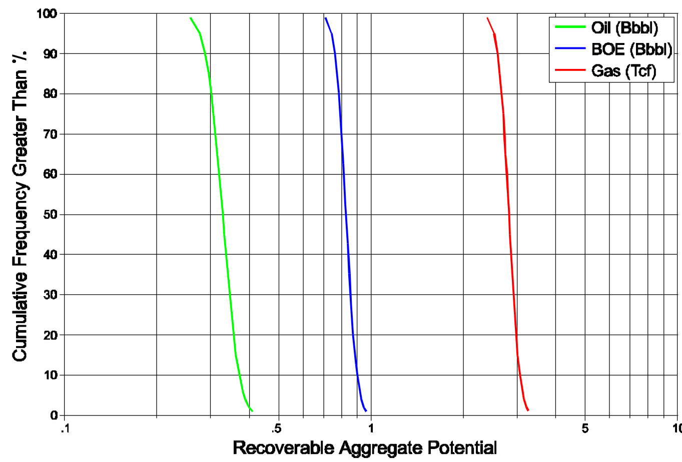


Figure 3. Cumulative probability distribution.

Assessment results indicate that undiscovered resources have a range of 0.277 to 0.384 Bbo and 2.518 to 3.133 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.329 Bbo and 2.819 Tcfg (0.831 BBOE). These undiscovered resources may occur in as many as 105 pools. The largest undiscovered pool, with a mean size of 44.022 MMBOE, is modeled as the fifteenth largest pool in the play (figure 4). The model results place the next four undiscovered pools in positions 16, 18, 19, and 23 on the pool rank plot. For all the undiscovered pools in the UP F play, the mean mean size is 7.915 MMBOE, which is substantially smaller than the 36.949 MMBOE mean size of the discovered pools. The mean mean size for all pools,

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	44	0.552	3.654	1.202
Cumulative production	--	0.346	2.521	0.794
Remaining proved	--	0.206	1.132	0.408
Unproved	9	0.126	0.525	0.220
Appreciation (P & U)	--	0.283	1.422	0.536
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.277	2.518	0.742
Mean	105	0.329	2.819	0.831
5th percentile	--	0.384	3.133	0.924
Total Endowment				
95th percentile	--	1.239	8.118	2.700
Mean	158	1.291	8.419	2.789
5th percentile	--	1.346	8.733	2.882

including both discovered and undiscovered, is 17.654 MMBOE.

Of the 15 Gulf of Mexico fan plays, the UP F play is the third largest, with 9 percent of the BOE mean total endowment.

Because of the large unexplored area and occurrence of good reservoir-quality sands in deepwater areas, numerous undiscovered pools are modeled for the UP F play. Undiscovered resources are expected to add 30 percent to the play's BOE mean total endowment. Hydrocarbon potential exists downdip of the discovered fields, especially in water depths greater than 1,000 feet.

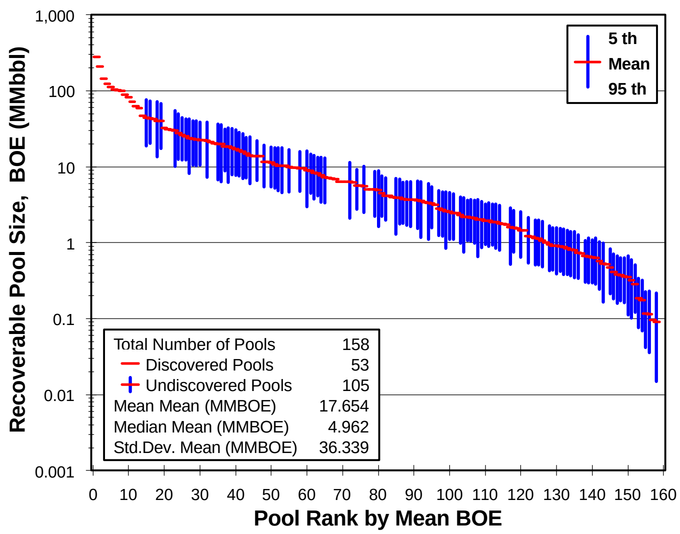


Figure 4. Pool rank plot.

LOWER PLIOCENE (LP) CHRONOZONE

CHRONOZONE DESCRIPTION

The Lower Pliocene (LP) chronozone corresponds to the *Textularia* "X" biozone. The LP section reflects delta systems prograding onto the continental shelf and fan deposition on the continental slope of the Gulf of Mexico Basin. Depositional styles present in the LP chronozone include aggradational, progradational, and fan, each of which defines a play: the Lower Pliocene Aggradational (LP A) play, the Lower Pliocene Progradational (LP P) play, and the Lower Pliocene Fan (LP F) play. Retrogradational sands associated with marine transgressions also occur locally in the play areas at the top of the progradational and aggradational deposits. Because these retrogradational sands are discontinuous over any significant distance, they are included as part of these underlying deposits.

The potential for sand development within the LP chronozone extends from the North Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). Updip, LP sands continue onshore into Texas and Louisiana or shale out. Lower Pliocene sand potential is limited to the west and northeast by a lack of sediment influx at the edges of the LP depocenter. The downdip limit extends at least as far as the Sigsbee Escarpment as indicated by LP sand development in the OCS G12662-1 well in Garden Banks block 568 and by correlation of chronozone tops to seismic data.

The influx of sand-rich sediments, which existed during the underlying upper upper Miocene (UM3) chronozone in the offshore Texas area, was reduced significantly in LP time. As a result, only a few poorly developed progradational sands have been identified southwest of the Galveston Area. The predominant delta system that fed the LP

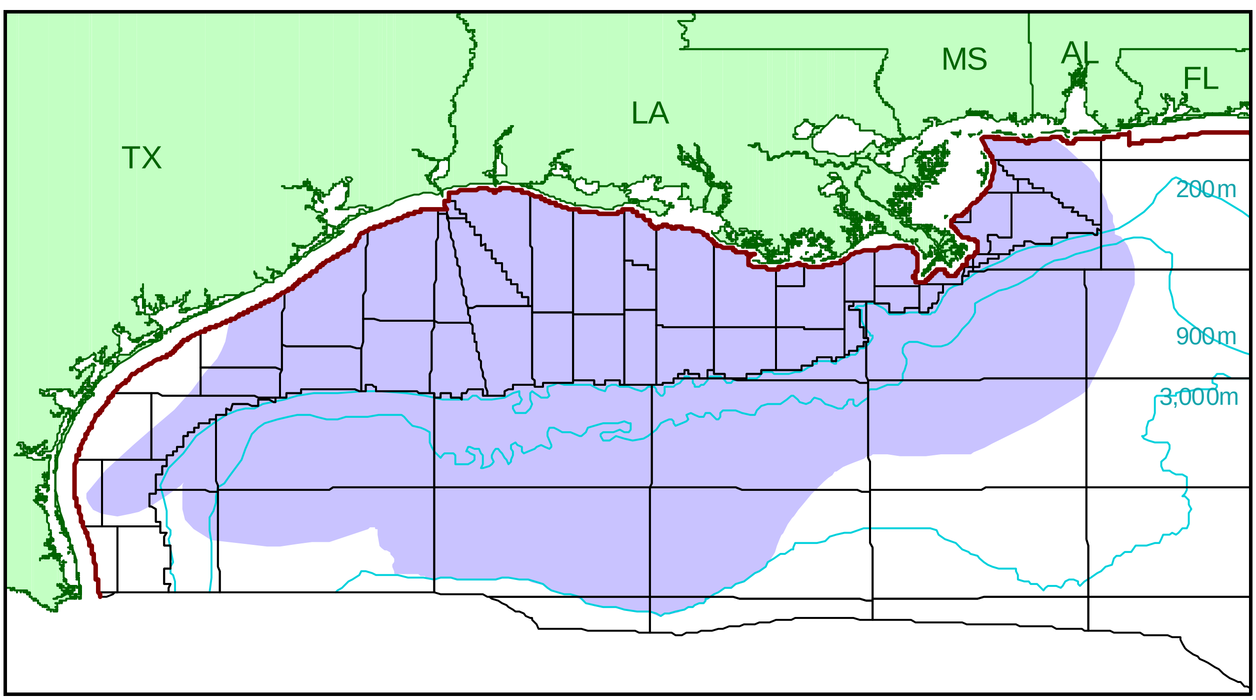


Figure 1. Map of assessed chronozone.

depocenter was centered in the Louisiana area. The shelf edge showed a relative shift basinward from that of the UM3 chronozone.

Major structural features in the LP chronozone include salt diapirs, anticlines, normal faults, and growth faults. Other structures include stratigraphic pinch-outs and shale diapirs.

Discoveries

The LP chronozone contains 183 discovered pools in three plays (table 1). Total reserves in the chronozone are 2.007 Bbo and 10.030 Tcfg (3.792 BBOE), of which 1.535 Bbo and condensate and 7.179 Tcfg (2.813 BBOE) have been produced. The largest number of discoveries in the LP chronozone occurred when nine pools were added in both 1963 and 1985 (figure 2). However, the maximum yearly total reserves of 426.203 MMBOE were added in 1967 with the discovery of seven pools.

Of the three plays in the LP chronozone, the LP P play contains the most total reserves in 131 pools, with 1.348 Bbo and 7.656 Tcfg (2.711 BBOE).

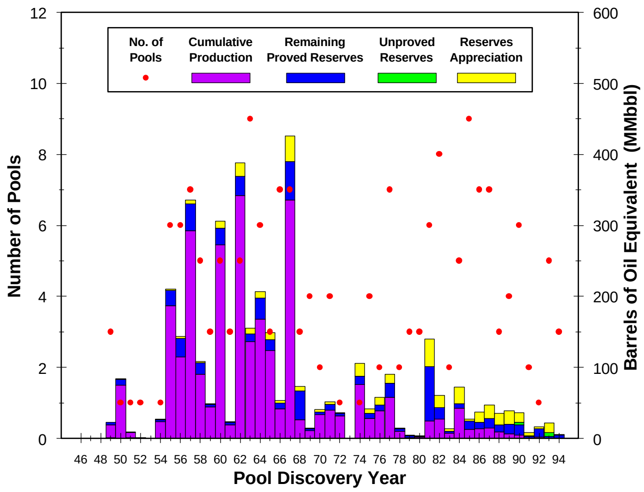


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

183 Pools (846 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	12	152	3,236
Subsea depth (feet)	1,889	9,134	17,109
Number of sands per pool	1	5	25
Porosity	21%	29%	37%
Water saturation	12%	29%	61%

Assessment Results

The LP chronozone contains 313 pools (discovered plus undiscovered), with a mean total endowment estimated at 2.561 Bbo and 15.321 Tcfg (5.287 BBOE) (table 2).

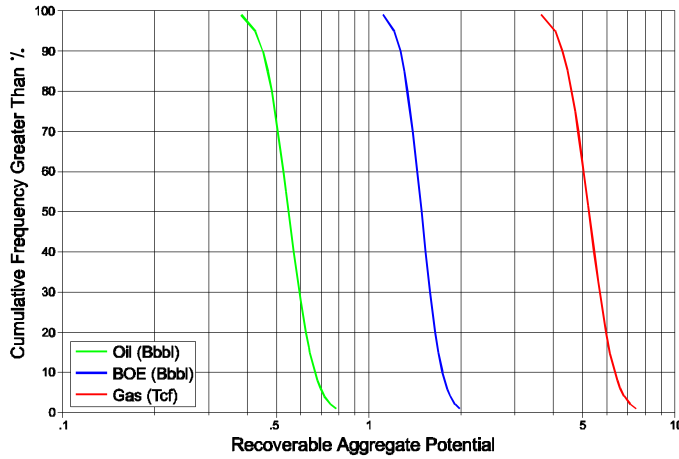


Figure 3. Cumulative probability distribution.

Assessment results indicate that undiscovered resources may occur in as many as 130 pools, which contain a range of 0.426 to 0.704 Bbo and 4.065 to 6.726 Tcfg at the 95th and 5th percentiles, respectively (figure 3). At mean levels, 0.554 Bbo and 5.291 Tcfg (1.495 BBOE) are projected. These undiscovered resources represent 28 percent of the LP chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the fifth largest in the chronozone (figure 4).

Of the three LP plays, the LP F play is projected to contain the greatest exploration potential, with mean undiscovered resources estimated at 0.443 Bbo and 4.133 Tcfg (1.178 BBOE) remaining to be found in 76 pools. These undiscovered resources in the LP F play represent 22 percent of the BOE mean total endowment for the LP chronozone.

Table 2. Assessment results.

Marginal Probability = 1.00	**Number of Pools**	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Reserves				
Original proved	179	1.836	8.881	3.417
Cumulative production	--	1.535	7.179	2.813
Remaining proved	--	0.301	1.702	0.604
Unproved	4	0.004	0.030	0.010
Appreciation (P & U)	--	0.166	1.119	0.365
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.426	4.065	1.210
Mean	130	0.554	5.291	1.495
5th percentile	--	0.704	6.726	1.819
Total Endowment				
95th percentile	--	2.433	14.095	5.002
Mean	313	2.561	15.321	5.287
5th percentile	--	2.711	16.756	5.611

This percentage, the potential for numerous discoveries within a large unexplored area, and the potential for good-quality LP sand development in deepwater areas make the LP F play an attractive exploration target in LP strata.

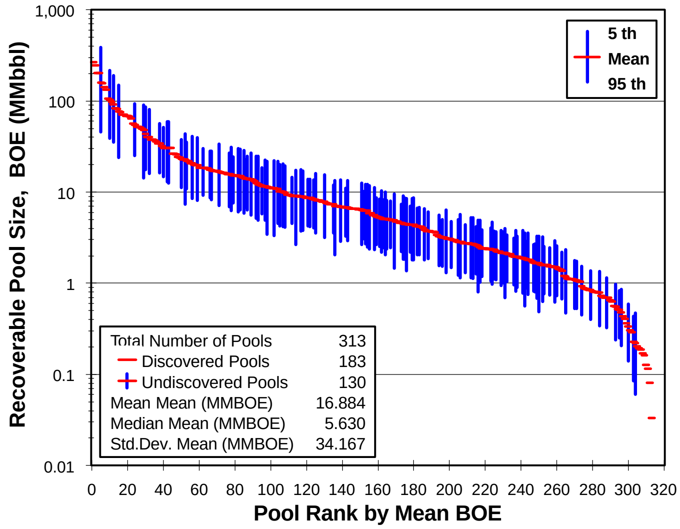


Figure 4. Pool rank plot.

LOWER PLIOCENE AGGRADATIONAL (LP A) PLAY

PLAY DESCRIPTION

The established Lower Pliocene Aggradational (LP A) play occurs at the *Textularia* "X" biozone. This play extends from the Brazos Area offshore Texas eastward into the Mobile Area east of the present-day Mississippi River Delta (figure 1).

Updip, the play continues onshore into Texas and Louisiana. To the west and northeast, the play is limited by a marked decrease in sediment influx at the edges of the LP depocenter. Downdip, the play grades into the sediments of the Lower Pliocene Progradational (LP P) play.

The underlying Upper Upper Miocene Aggradational (UM3 A) play is very extensive in the offshore Texas area. Lower Pliocene aggradational deposits have not been identified in the offshore Texas west of the Brazos Area. The depocenter present in the offshore Texas area during UM3 time no longer received significant amounts of sand-rich sediments during LP time. The LP sediments reflect the depocenter shift to the ancestral Mississippi River Delta System.

PLAY CHARACTERISTICS

The productive LP A play consists of fluvial and distributary channels, barrier and distributary mouth bars, delta fringe sands, and shelf slumps. In addition, retrogradational sands locally cap the LP A play. Because these retrogradational, reworked sands are so discontinuous, they are included as part of the LP A play. Anticlines, growth faults, salt diapirs, and normal faults are the dominant structural features in the play. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying

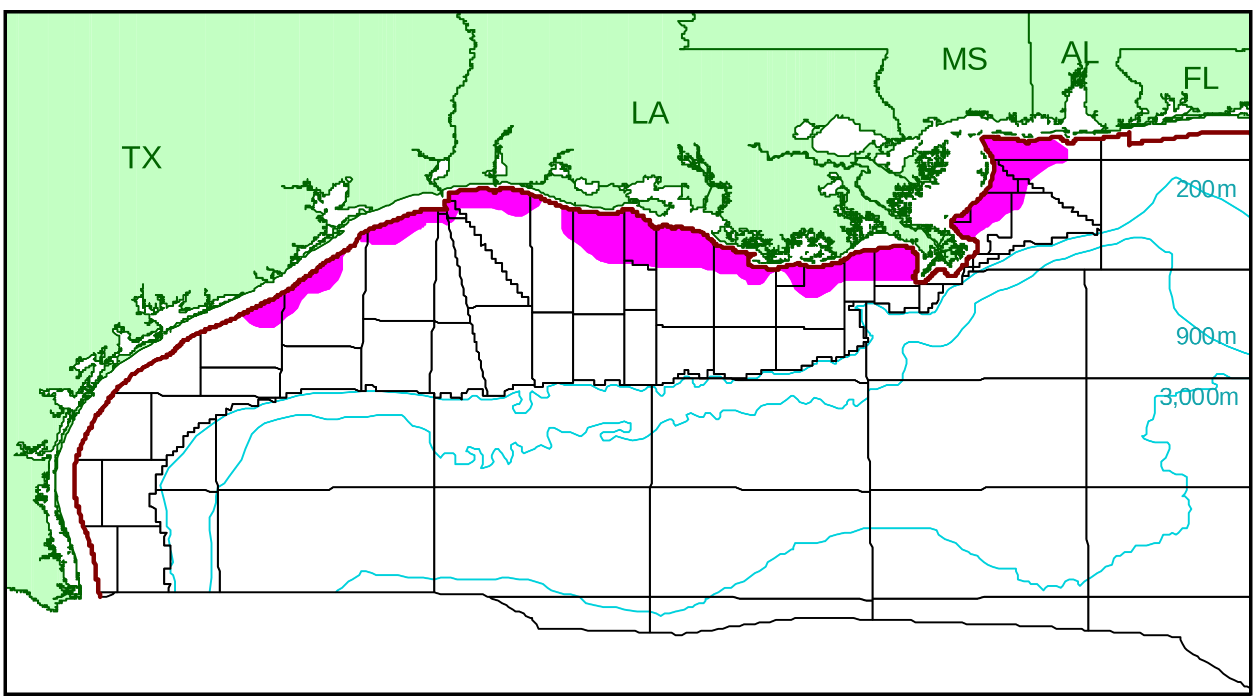


Figure 1. Map of assessed play.

shales). Future discoveries are not limited to the aforementioned productive aggradational depositional environments, structures, or seals.

South Timbalier 34 is the type field, and Kerr-McGee Corporation's 8600 sand represents the LP A play in this field.

DISCOVERIES

The LP A play is predominantly an oil play, with total reserves of 0.498 Bbo and 1.270 Tcfg (0.724 BBOE), of which 0.453 Bbo and 1.085 Tcfg (0.646 BBOE) have been produced. The play contains 117 producible sands in 28 pools (table 1). The first reserves discovered in the play occurred in the Ship Shoal 28 field in 1949 (figure 2). The maximum yearly total reserves were added in 1962 with the discovery of the largest pool in the play in the West Delta 73 field. Just over 90 percent of the cumulative production and total reserves for the play are from pools discovered prior to 1966. On a BOE basis, 30 percent of the play's cumulative production is gas, but remaining total reserves indicate that future production may increase to 42 percent gas. The most recent discoveries, prior to this study's cutoff date of January 1, 1995, were in 1993.

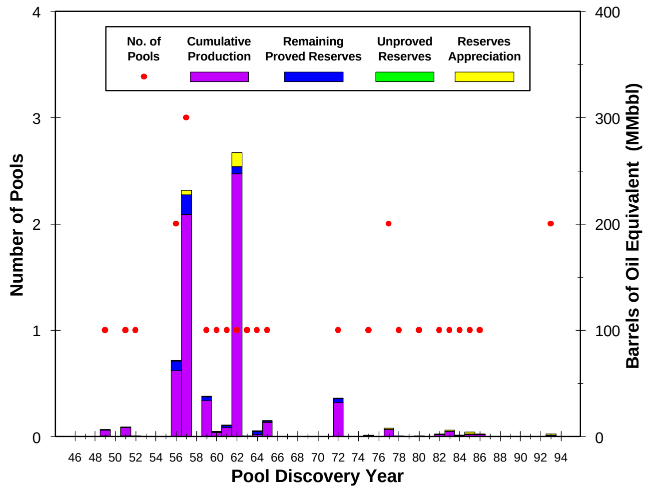


Figure 2. Exploration history graph.

The 28 discovered pools range in size from 0.163 to 267.022 MMBOE. These pools contain 253 reservoirs, of which 78 are nonassociated gas, 133 are undersaturated oil, and 42 are saturated oil.

Of the 11 aggradational plays in the Gulf of Mexico Cenozoic Province, the LP A play is the largest, containing 26 percent of the total reserves and producing 30 percent of the hydrocarbons, based on BOE.

Table 1. Characteristics of the discovered pools.

28 Pools (117 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	12	60	179
Subsea depth (feet)	2,965	7,270	10,493
Number of sands per pool	1	4	22
Porosity	25%	30%	34%
Water saturation	16%	26%	41%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the LP A play is 1.00. This play is the largest aggradational play in the Gulf of Mexico Cenozoic Province, based on a mean total endowment of 0.511 Bbo and 1.503 Tcfg (0.778 BBOE) (table 2). Eighty-three percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.008 to 0.021 Bbo and 0.171 to 0.297 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.013 Bbo and 0.233 Tcfg (0.054 BBOE). These undiscovered resources may occur in as many as 15 pools. The largest undiscovered pool, with a mean size of 15.747 MMBOE, is modeled as the seventh largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 9, 18, 19, and 22 on the pool rank plot. For all the undiscovered pools in the LP A play, the mean mean size is 3.607 MMBOE, which is substantially smaller than the 25.860 mean size of the discovered

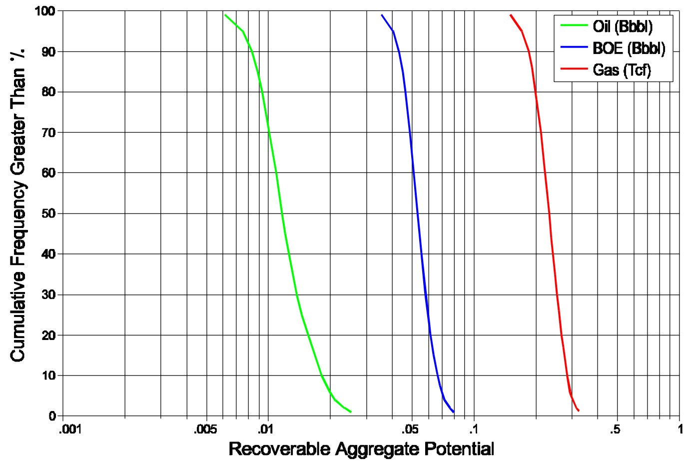


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	28	0.483	1.205	0.697
Cumulative production	--	0.453	1.085	0.646
Remaining proved	--	0.029	0.121	0.051
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.015	0.065	0.027
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.008	0.171	0.040
Mean	15	0.013	0.233	0.054
5th percentile	--	0.021	0.297	0.071
Total Endowment				
95th percentile	--	0.506	1.441	0.764
Mean	43	0.511	1.503	0.778
5th percentile	--	0.519	1.567	0.795

pools. The mean mean size for all pools, including both discovered and undiscovered, is 18.097 MMBOE.

Of the 11 Gulf of Mexico Cenozoic Province aggradational plays, the LP A play is projected to contain the second largest amounts of mean undiscovered oil and gas, at 21 percent and 18 percent, respectively.

Because the LP A play is well explored, it is modeled to have limited potential for discoveries. These undiscovered pools are projected to contribute only 7 percent to the play's BOE mean total endowment.

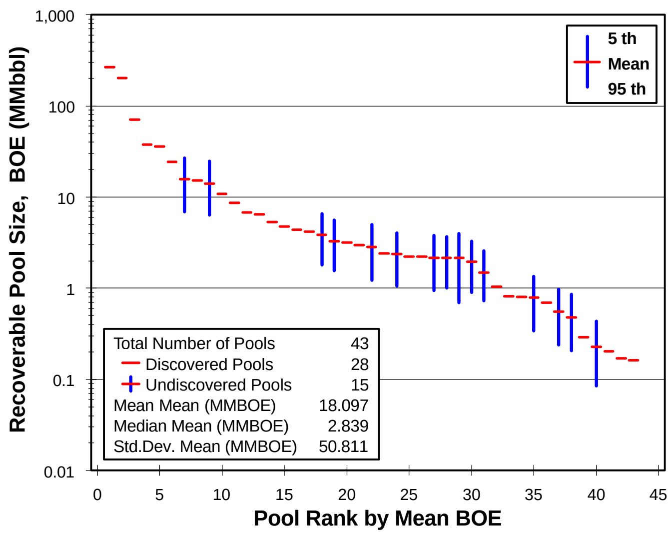


Figure 4. Pool rank plot.

LOWER PLIOCENE PROGRADATIONAL (LP P) PLAY

PLAY DESCRIPTION

The Lower Pliocene Progradational (LP P) play is one of the largest established plays in the Gulf of Mexico Region. The play occurs at the *Textularia* "X" biozone and extends from the North Padre Island Area offshore Texas northeastward to the Mobile, Viosca Knoll, and Destin Dome Areas east of the present-day Mississippi River Delta (figure 1). Productive progradational deposits occur in a continuous band from the West Cameron Area to the eastern extent of the play, but occur very sporadic westward of West Cameron.

Except where the LP P play extends onshore into Texas and Louisiana, the updip limit of this progradational play occurs where it grades into the nearshore deposits of the Lower Pliocene Aggradational (LP A) play. To the northeast and southwest, the LP P play is limited by a marked decrease in sediment influx at the edges of the LP depocenter. Downdip, the LP P play grades into slope shales and the deposits of the Lower Pliocene Fan (LP F) play.

Occurrences of progradational deposits in offshore Texas areas southwestward of West Cameron are rare. The depocenter present in the offshore Texas area during upper upper Miocene (UM3) time no longer received significant amounts of sand-rich sediments during LP time. The LP sediments reflect the depocenter shift to the ancestral Mississippi River Delta System.

PLAY CHARACTERISTICS

The productive LP P play consists of progradational deltaic sediments deposited in delta fringe, shelf blanket, distributary mouth bar, distributary channel, and crevasse splay

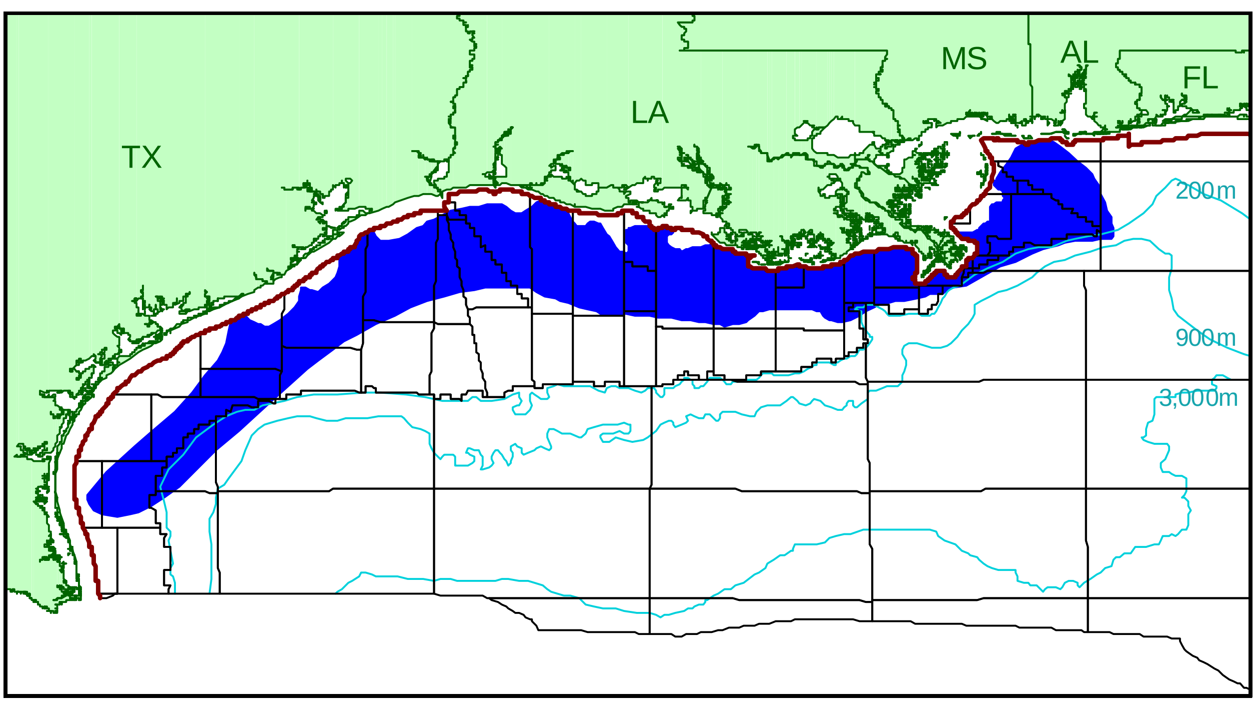


Figure 1. Map of assessed play.

environments. In addition, retrogradational sands locally cap the LP P play. Because these retrogradational, reworked sands are so discontinuous, they are included as part of the LP P play. Salt diapirs, anticlines, and normal faults are the major structural features in the play. Growth faults, stratigraphic pinch-outs, and shale diapirs also occur. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive progradational depositional environments, structures, or seals.

Ship Shoal 170 is the type field. PG&E Resources Offshore Co.'s H-10 sand, Newfield Exploration Co.'s and PG&E Resources Offshore Co.'s I-1 sand, and Newfield Exploration Co.'s I-3 sand represent the LP P play in this field.

DISCOVERIES

The LP P mixed oil and gas play contains total reserves of 1.348 Bbo and 7.656 Tcfg (2.711 BBOE), of which 1.045 Bbo and 5.523 Tcfg (2.028 BBOE) have been produced. The play contains 650 producible sands in 131 pools, and 130 of these pools contain proved reserves (table 1). The first reserves discovered in the play occurred in the Eugene Island 89 and Ship Shoal 28 fields in 1949 (figure 2). The maximum yearly total reserves of 426.203 MMBOE were added in 1967 when seven pools were discovered, including the largest pool in the play in the South Pass 61 field. Though discoveries have maintained a fairly rapid rate, averaging about three per year, 75 percent of the play's total reserves were discovered prior to 1970. Just over 80 percent of the play's cumulative production has come from these same pools. Ten pools have been discovered in the 1990's, the most recent, prior to this study's cutoff date of January 1, 1995, in 1994.

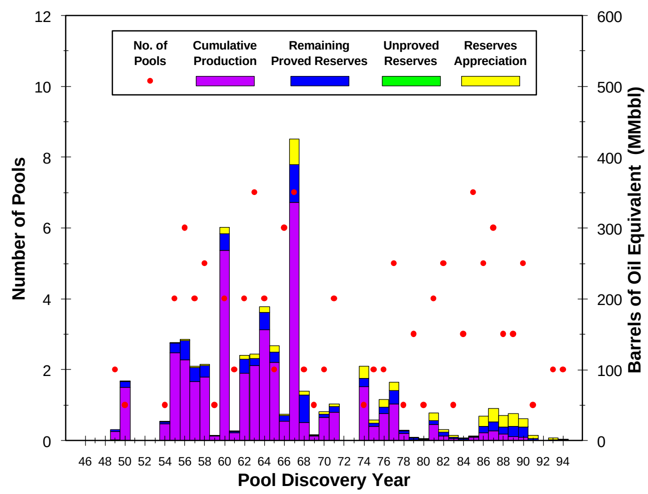


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

131 Pools (650 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	13	103	356
Subsea depth (feet)	1,889	8,961	16,003
Number of sands per pool	1	5	25
Porosity	21%	29%	37%
Water saturation	12%	29%	61%

The 131 discovered pools range in size from 0.033 to 245.398 MMBOE. These pools contain 1,721 reservoirs, of which 696 are nonassociated gas, 872 are undersaturated oil, and 153 are saturated oil.

Of the 61 Gulf of Mexico plays, the LP P play contains the sixth largest amount of total reserves and has produced the fourth largest amount of hydrocarbons, based on BOE. In fact, the play has produced the third largest amount of oil at 11 percent.

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the LP P play is 1.00. This play is the seventh largest in the Gulf of Mexico, based on a mean total endowment of 1.446 Bbo and 8.581 Tcfg (2.974 BBOE) (table 2). Sixty-eight percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.072 to 0.128 Bbo and 0.787 to 1.074 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are

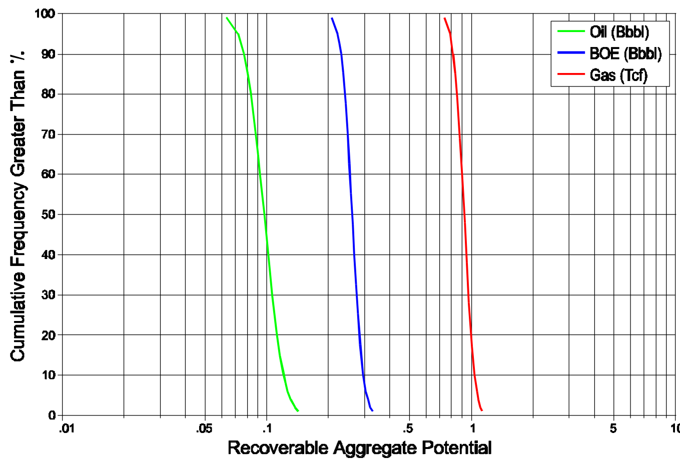


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	130	1.240	6.843	2.457
Cumulative production	--	1.045	5.523	2.028
Remaining proved	--	0.195	1.320	0.430
Unproved	1	<0.001	0.002	<0.001
Appreciation (P & U)	--	0.109	0.810	0.253
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.072	0.787	0.222
Mean	39	0.098	0.925	0.263
5th percentile	--	0.128	1.074	0.308
Total Endowment				
95th percentile	--	1.420	8.443	2.933
Mean	170	1.446	8.581	2.974
5th percentile	--	1.476	8.730	3.019

estimated at 0.098 Bbo and 0.925 Tcfg (0.263 BBOE). These undiscovered resources may occur in as many as 39 pools. The largest undiscovered pool, with a mean size of 30.381 MMBOE, is modeled as the twenty-fourth largest pool in the play (figure 4). For all the undiscovered pools in the LP P play, the mean mean size is 6.734 MMBOE, which is substantially smaller than the 20.692 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 17.490 MMBOE.

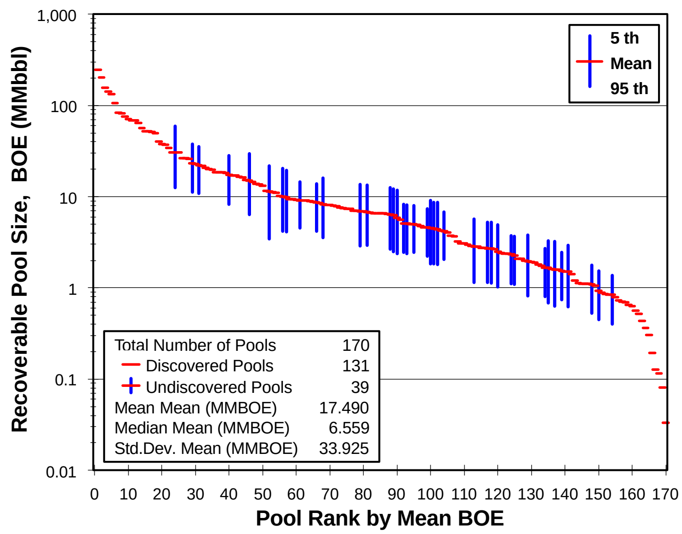


Figure 4. Pool rank plot.

Of the 14 progradational plays in the Gulf of Mexico, the LP P play is projected to contain the third largest amount of mean undiscovered oil resources at 15 percent.

The LP P play is well explored with the largest pools modeled as already discovered. The undiscovered resources contribute only 9 percent to the play's BOE mean total endowment.

LOWER PLIOCENE FAN (LP F) PLAY

PLAY DESCRIPTION

The established Lower Pliocene Fan (LP F) play occurs at the *Textularia* "X" biozone. This play extends from the Port Isabel and Corpus Christi Areas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1).

The play is bounded updip and to the northeast by the shelf/slope break associated with the *Textularia* "X" biozone and grades into the deposits of the Lower Pliocene Progradational (LP P) play. To the southwest, the play is limited by a marked decrease in sediment influx at the edge of the LP depocenter. The southern extension of the play's potential to at least the Sigsbee Escarpment is supported by good reservoir-quality LP sands in the OCS G12662-1 well in Garden Banks block 568.

As compared to the underlying upper upper Miocene (UM3) chronozone, the shelf/slope break of the LP chronozone occurs farther out in the Gulf of Mexico Basin because of the basinward progradation of the ancient delta systems. The depocenter present in the offshore Texas area no longer received significant amounts of sand-rich sediments during LP time as compared with UM3 time. Lower Pliocene sediments reflect the depocenter shift to the ancestral Mississippi River Delta System.

PLAY CHARACTERISTICS

The productive LP F play consists of deepwater turbidites deposited in fan systems as channel fill, fan lobes, and fringe sheet sediments on the LP slope between salt highs. Salt diapirs, anticlines, and normal faults are the play's major structural features. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally

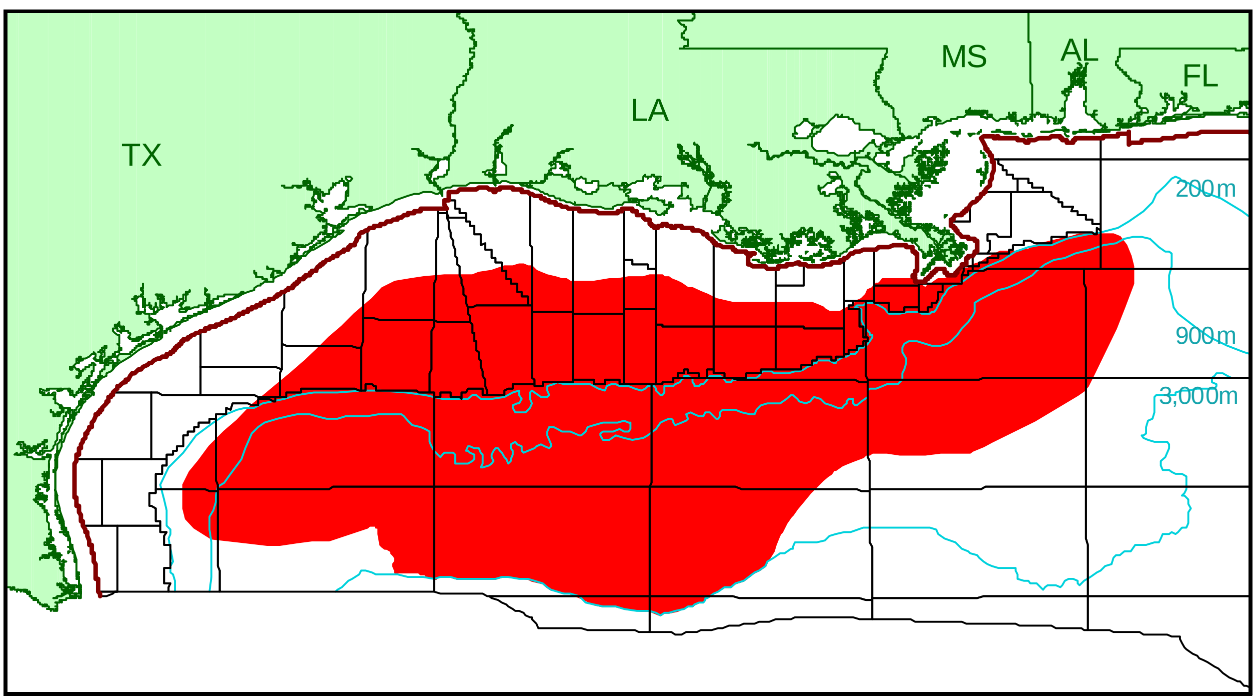


Figure 1. Map of assessed play.

(e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive fan depositional environments, structures, or seals.

West Delta 117 is the type field. Chevron USA Inc.'s H3, H4, H5, H9, H10, K12, J5, J6, J7, and K1 sands and Exxon's I15, I20, I22, and I25 sands represent the LP F play in this field.

DISCOVERIES

The LP F mixed oil and gas play contains total reserves of 0.160 Bbo and 1.104 Tcfg (0.357 BBOE), of which 0.037 Bbo and 0.571 Tcfg (0.139 BBOE) have been produced. The play contains 79 producible sands in 24 pools, and 21 of these pools contain proved reserves (table 1). The first reserves in the play were discovered in the Eugene Island 198 field in 1959 (figure 2). Since 1980, pool discoveries have occurred almost yearly. The maximum yearly total reserves of 101.089 MMBOE were added in 1981 when two pools were found, including the largest discovered pool in the play in the Viosca Knoll 990 field ("Pompano"). This field alone accounts for almost 30 percent of the play's total reserves. Therefore, it is not surprising that slightly over half of the play's cumulative production has been from pools discovered in 1981 or earlier. On a BOE basis, 27 percent of the play's cumulative production is oil, but remaining total reserves indicate future production may increase to 56 percent oil. The most recent discovery, prior to this study's cutoff date of January 1, 1995, occurred in 1994.

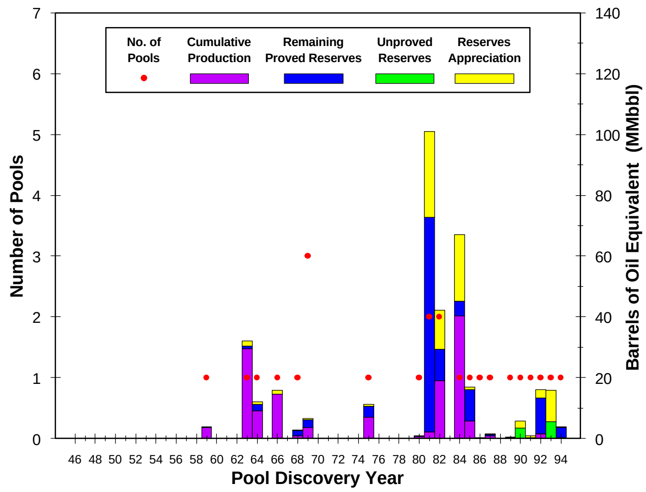


Figure 2. Exploration history graph.

The 24 discovered pools range in size from 0.188 to 97.412 MMBOE. These pools contain 119 reservoirs, of which 64 are nonassociated gas, 51 are undersaturated oil, and 4 are saturated oil.

Table 1. Characteristics of the discovered pools.

24 Pools (79 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	76	525	3,236
Subsea depth (feet)	5,500	12,249	17,109
Number of sands per pool	1	3	14
Porosity	22%	28%	36%
Water saturation	20%	32%	45%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the LP F play is 1.00. The play contains a mean total endowment of 0.603 Bbo and 5.237 Tcfg (1.535 BBOE) (table 2). Nine percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.340 to 0.577 Bbo and 3.265 to 5.517 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.443 Bbo and 4.133 Tcfg (1.178 BBOE). These undiscovered resources may occur in as many as 76 pools. The largest undiscovered pool, with a mean size of 158.090 MMBOE, is modeled as the largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 2, 4, 5, and 7 on the pool rank plot. For all the undiscovered pools in the LP F play, the mean mean size is 15.478 MMBOE, which is comparable to the 14.866 MMBOE mean size of the discovered pools.

Of the 61 plays in the Gulf of Mexico Region, the LP F play is projected to contain

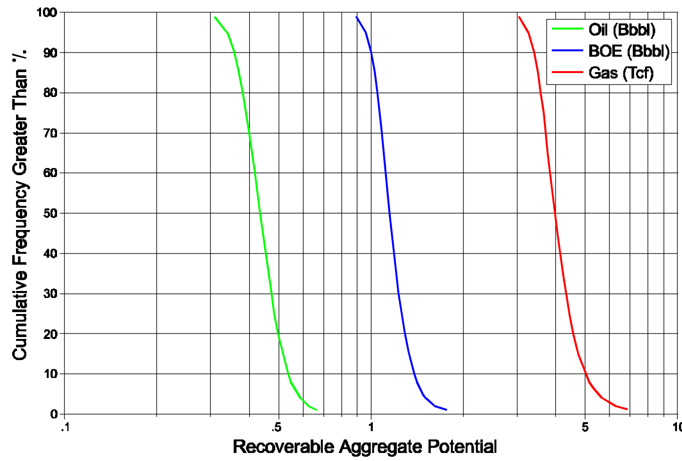


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	21	0.114	0.832	0.262
Cumulative production	--	0.037	0.571	0.139
Remaining proved	--	0.077	0.262	0.123
Unproved	3	0.004	0.028	0.009
Appreciation (P & U)	--	0.042	0.244	0.086
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.340	3.265	0.961
Mean	76	0.443	4.133	1.178
5th percentile	--	0.577	5.517	1.475
Total Endowment				
95th percentile	--	0.500	4.369	1.318
Mean	100	0.603	5.237	1.535
5th percentile	--	0.737	6.621	1.832

the sixth and seventh largest amounts of mean undiscovered oil (5%) and gas (4%) resources, respectively.

A large unexplored area and good potential for sand development in LP sediments support the numerous discoveries modeled for the LP F play. These undiscovered resources are expected to add 77 percent to the play's BOE mean total endowment. Potential for discoveries occurs downdip of existing fields, especially in water depths greater than 1,000 feet.

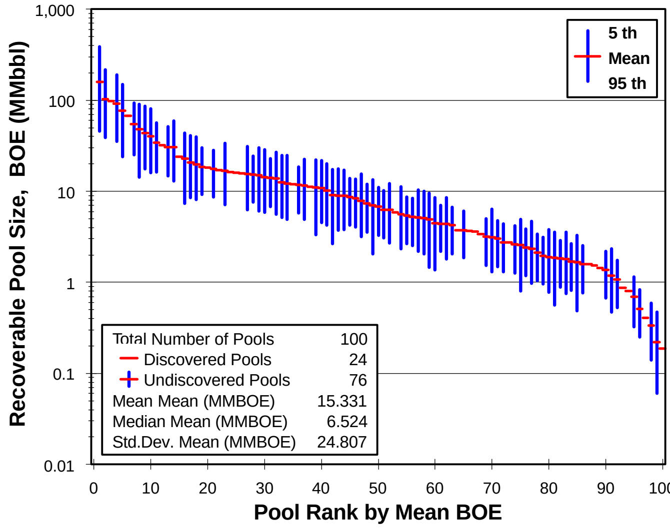


Figure 4. Pool rank plot.

UPPER UPPER MIOCENE (UM3) CHRONOZONE

CHRONOZONE DESCRIPTION

The Upper Upper Miocene (UM3) chronozone corresponds to the *Cristellaria* "K," *Bigenerina* "A," and *Robulus* "E" biozones. The UM3 section reflects delta systems prograding onto the continental shelf and fan deposition on the continental slope of the Gulf of Mexico Basin. Depositional styles present in the UM3 chronozone include retrogradational, aggradational, progradational, and fan, each of which defines one or more plays: the Upper Upper Miocene Western Retrogradational (UM3 R1) play, the Upper Upper Miocene Eastern Retrogradational (UM3 R2) play, the Upper Upper Miocene Aggradational (UM3 A) play, the Upper Upper Miocene Progradational (UM3 P) play, the Upper Upper Miocene Fan (UM3 F) play, and the Upper Upper Miocene Aggradational/Progradational (UM3 AP) play.

The potential for sand development within the UM3 chronozone extends from the South Padre Island Area offshore Texas to the western edges of the Pensacola, Destin Dome, and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). Updip, sand potential extends onshore into Texas and Louisiana. To the southwest, UM3 sands extend into Texas offshore State waters and Mexican national waters. To the northeast, UM3 sands extend onshore into Mississippi and Alabama. The downdip limit extends at least as far as the Sigsbee Escarpment as indicated by UM3 sand development in the OCS G11643-1 well in Keathley Canyon block 255.

Productive and established sand locations in the UM3 chronozone are a result of two ancient depocenters, one in the Texas area and the other in the Louisiana area. The depositional sequences of the UM3 and lower upper Miocene (UM1) chronozones in the Texas offshore occupy approximately the same geographical areas, with only minor

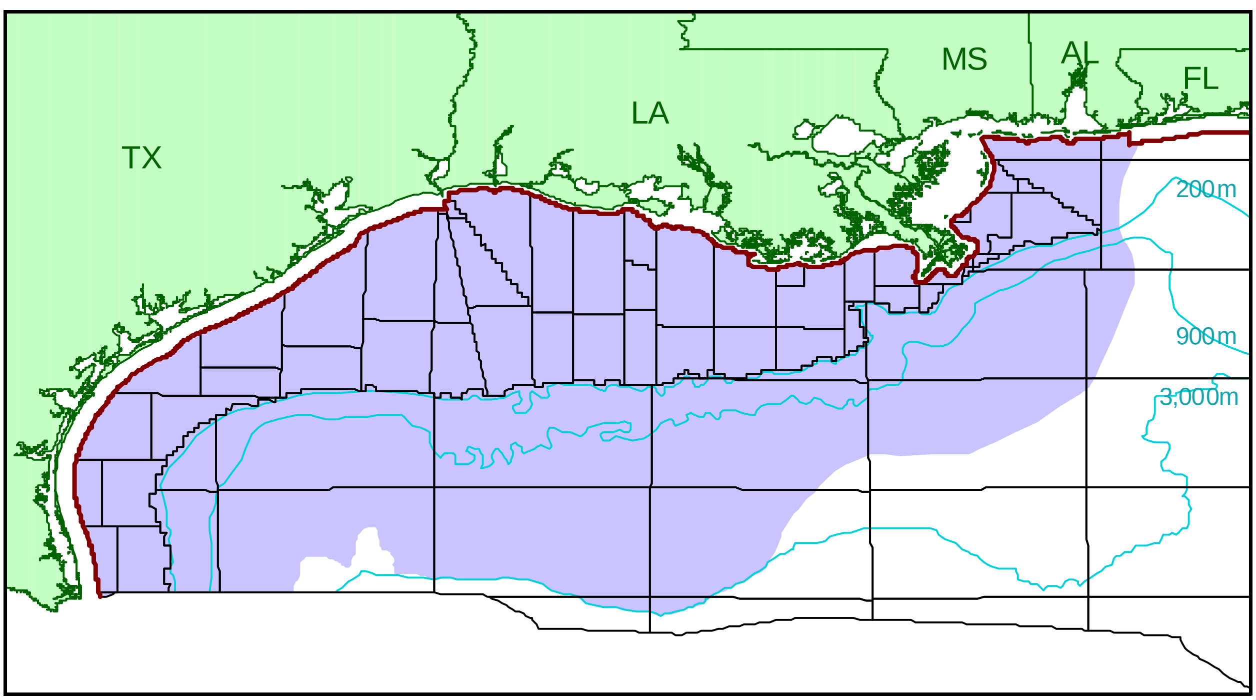


Figure 1. Map of assessed chronozone.

basinward progradation of sediments in UM3 time.

However, in the Louisiana offshore, UM3 sediments show a marked basinward shift, especially the progradational and aggradational sequences, due to the seaward progradation of deltaic deposits from the ancestral Mississippi River.

The UM3 sediments subsided in both the Texas and Louisiana offshore at the end of UM3 time, creating retrogradational deposits. In the Mississippi and Alabama offshore, the extent of the aggradational/progradational (AP) sequence in the UM3 chronozone is found in the same general geographical area as the AP sequence of the UM1 chronozone, indicative of deposition on a stable shelf. However, the UM3 deposits include more aggradational deposits from the ancestral Mobile River System than do the UM1 deposits.

Major structural features in the UM3 chronozone include anticlines, normal faults, and salt diapirs. Other structures include growth faults and stratigraphic pinch-outs.

DISCOVERIES

The UM3 chronozone contains 249 discovered pools in six plays (table 1). Significant amounts of hydrocarbons were recently identified in the Mississippi Canyon 807 field ("Mars"), the Mississippi Canyon 854 field ("Ursa"), and the Mississippi Canyon 211 field ("Mickey"). Of the 21 chronozones in the Gulf of Mexico Region, the UM3 chronozone contains the second largest amount of BOE total reserves, with 3.097 Bbo and 15.696 Tcfg (5.890 BBOE), of which 2.220 Bbo and 10.288 Tcfg (4.050 BBOE) have been produced. The largest number of discoveries in the UM3 chronozone occurred when 18 pools were added in 1984 (figure 2). However, the maximum yearly total reserves of 762.875 MMBOE were added in 1955 with the discovery of seven pools.

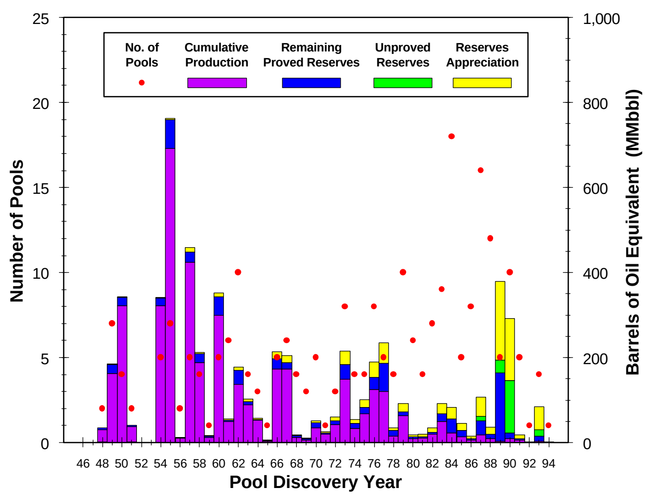


Figure 2. Exploration history graph.

Of the six plays in the UM3 chronozone, the UM3 P play contains the most total reserves in 165 pools, with 2.411 Bbo and 12.110 Tcfg (4.566 BBOE).

Table 1. Characteristics of the discovered pools.

249 Pools (1,176 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	9	212	6,950
Subsea depth (feet)	1,585	8,448	17,865
Number of sands per pool	1	5	45
Porosity	17%	29%	36%
Water saturation	9%	28%	57%

ASSESSMENT RESULTS

The UM3 chronozone contains 397 pools (discovered plus undiscovered), with a mean total endowment estimated at 3.549 Bbo and 20.367 Tcfg (7.174 BBOE) (table 2). This is the third largest BOE mean total endowment of all the chronozones in the Gulf of Mexico.

Assessment results indicate that undiscovered resources may occur in as many as 148 pools, which contain a range of 0.348 to 0.574 Bbo and 3.970 to 5.446 Tcfg at the 95th and 5th percentiles, respectively (figure 3). At mean levels, 0.452 Bbo and 4.671 Tcfg (1.284 BBOE) are projected. These undiscovered resources represent 18 percent of the UM3 chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the fourteenth largest in the chronozone (figure 4).

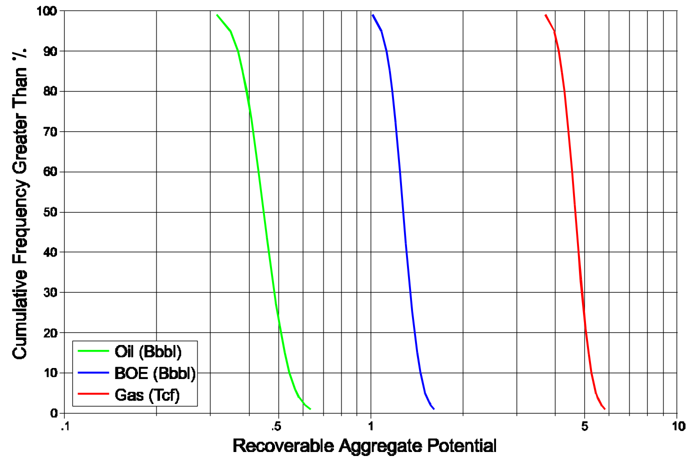


Figure 3. Cumulative probability distribution.

Of the six UM3 plays, the UM3 F play is projected to contain the greatest exploration potential, with mean undiscovered resources estimated at 0.409 Bbo and 3.935 Tcfg (1.109 BBOE) remaining to be found in 90 pools. These undiscovered resources in

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	240	2.610	12.822	4.891
Cumulative production	--	2.220	10.288	4.050
Remaining proved	--	0.390	2.534	0.841
Unproved	9	0.105	0.422	0.180
Appreciation (P & U)	--	0.383	2.452	0.819
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.348	3.970	1.085
Mean	148	0.452	4.671	1.284
5th percentile	--	0.574	5.446	1.504
Total Endowment				
95th percentile	--	3.445	19.666	6.975
Mean	397	3.549	20.367	7.174
5th percentile	--	3.671	21.142	7.394

the UM3 F play represent 15 percent of the BOE mean total endowment for the UM3 chronozone. Recent discoveries in the Mississippi Canyon Area and deepwater drilling results in the Keathley Canyon Area suggest a large potential exploration area for the play. This, coupled with the potential for excellent UM3 sand development in deepwater areas, makes the UM3 F play an attractive exploration target in UM3 strata.

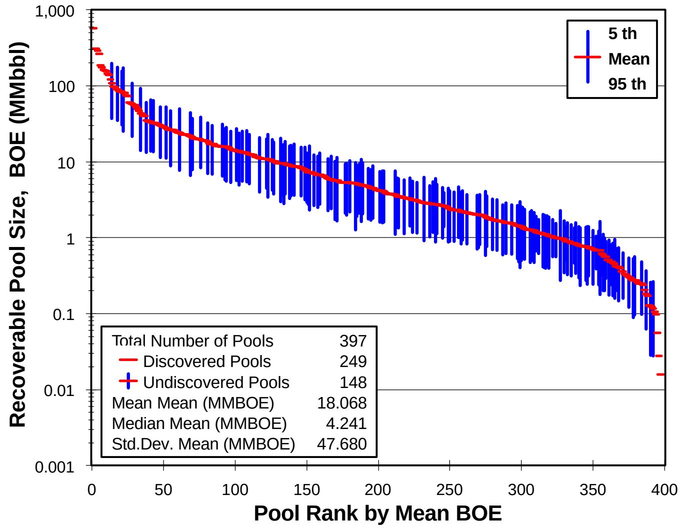


Figure 4. Pool rank plot.

UPPER UPPER MIOCENE WESTERN RETROGRADATIONAL (UM3 R1) PLAY

PLAY DESCRIPTION

The established Upper Upper Miocene Western Retrogradational (UM3 R1) play occurs within the *Cristellaria* "K," *Bigenerina* "A," and *Robulus* "E" biozones. This play extends from the Matagorda Island to High Island Areas offshore Texas (figure 1).

Updip and along strike to the west, the play grades into the deposits of the Upper Upper Miocene Aggradational (UM3 A) play. Downdip and along strike to the east, the UM3 R1 play grades into the deposits of the Upper Upper Miocene Progradational (UM3 P) play.

The UM3 R1 play is entirely in offshore Texas. Clastic influx in the offshore Texas area was waning during UM3 time, and the UM3 R1 play consequently is more sand poor than the other retrogradational play of the UM3 chronozone, the Upper Upper Miocene Eastern Retrogradational (UM3 R2) play, in offshore Louisiana. The UM3 R2 play was deposited in a more clastic-rich, active depocenter.

PLAY CHARACTERISTICS

The productive UM3 R1 play consists of reworked marine sands deposited in offshore bars, barrier islands, washover fans, and beach deposits in a delta-fringe environment. The retrogradational sands become progressively thinner and finer vertically and exhibit a back-stepping log signature, terminating in the *Robulus* “E” flooding surface. Growth faults and anticlines are the dominant structural features in this play. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive retrogradational depositional

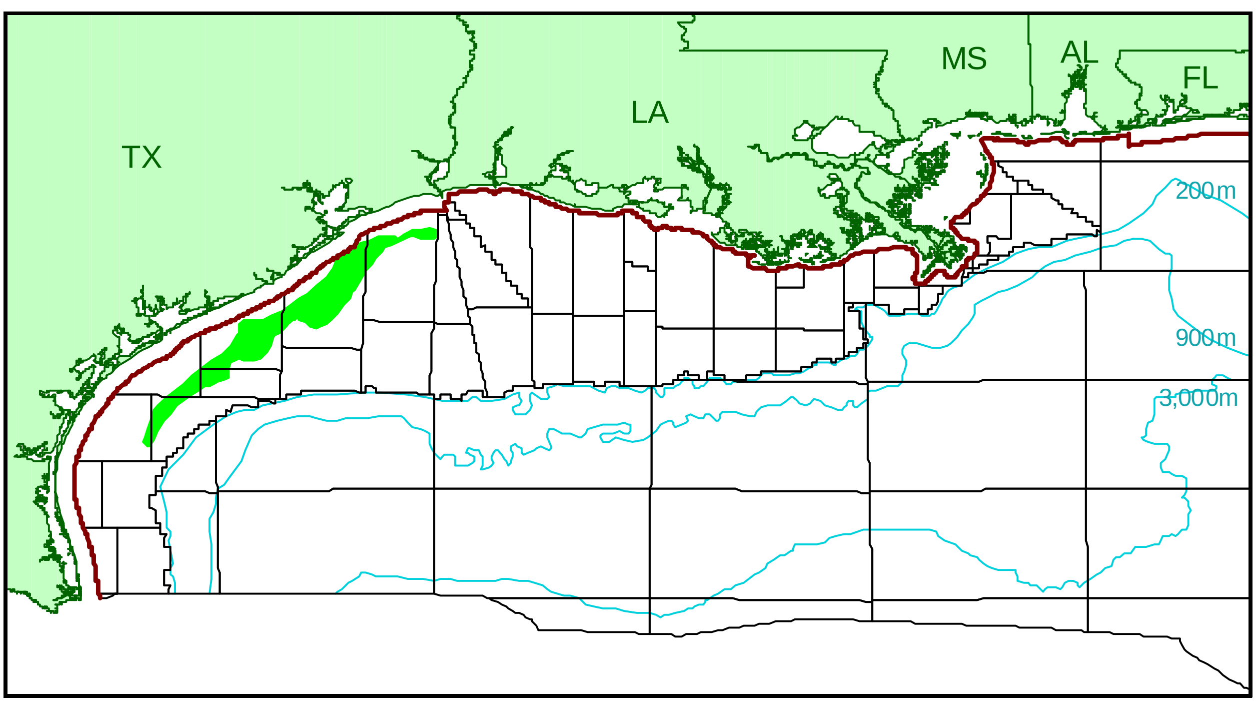


Figure 1. Map of assessed play.

environments, structures, or seals.

Galveston 389 is the type field. Walter Oil and Gas Corporation's 6300, 6400, 6500, and 6700 sands and Seagull Energy E&P's BA-3, BA-4, TL-1, and TL-*2* sands represent the UM3 R1 play in this field.

DISCOVERIES

The UM3 R1 gas play contains total reserves of 0.094 MMbo and 32.774 Bcfg (5.926 MMBOE), of which 0.086 MMbo and 24.954 Bcfg (4.526 MMBOE) have been produced. The play contains 10 producible sands in three pools (table 1). The first and maximum yearly total reserves were added in 1961 when the largest discovered pool in the play was found in the Galveston 389 field (figure 2). The other two pools were discovered in 1979 in the Galveston 391 field and in 1982 in the Galveston 382 field.

The three discovered pools range in size from 1.672 to 2.545 MMBOE. These pools contain 12 reservoirs, all of which are nonassociated gas.

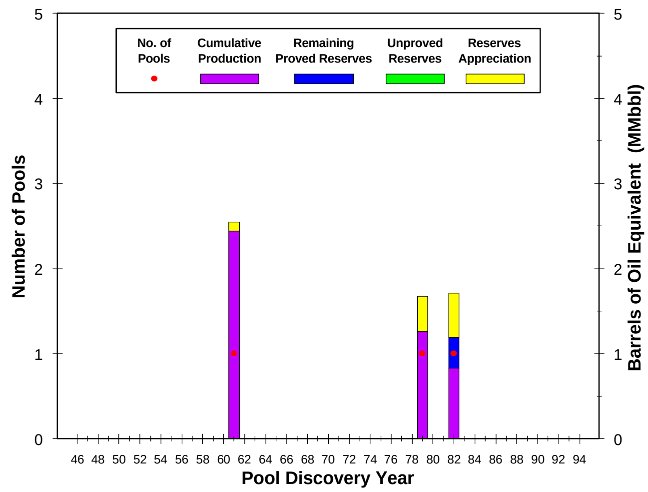


Figure 2. Exploration history graph.

Of the five retrogradational plays in the Gulf of Mexico Region, the UM3 R1 play contains the smallest amount of total reserves (<1%).

Table 1. Characteristics of the discovered pools.

3 Pools (10 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	92	96	100
Subsea depth (feet)	4,565	5,247	6,484
Number of sands per pool	2	3	5
Porosity	25%	29%	31%
Water saturation	31%	36%	40%

ASSESSMENT RESULTS

Because of limited data for the UM3 R1 play, the Upper Lower Miocene Retrogradational (LM4 R) play was used as an analog to model pool sizes in the UM3 R1 play. The LM4 R play was selected as the analog because of similarities in depositional setting, structural style, hydrocarbon type, and statistical information.

The marginal probability of hydrocarbons for the UM3 R1 play is 1.00. The play ranks within the smallest one-fourth of all 61 Gulf of Mexico plays, based on a mean total endowment of less than 0.001 Bbo and 0.065 Tcfg (0.012 BBOE) (table 2). Thirty-eight percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered oil resources are insignificant (<0.001 Bbbl) and that undiscovered gas resources have a range of 0.024 to 0.041 Tcf at the 95th and 5th percentiles, respectively (figure 3). The estimated amount of mean undiscovered gas is 0.032 Tcf (0.006 BBOE). These undiscovered resources may occur in as many as five pools. The largest undiscovered pool, with a mean size of 2.586 MMBOE, is modeled as the largest pool in the play (figure 4). The model results place the other four undiscovered pools in positions 5, 6, 7, and 8 on the pool rank plot. For all the undiscovered pools in the UM3 R1 play, the mean mean size is 1.158 MMBOE, which is comparable to the 1.975 MMBOE mean size of the

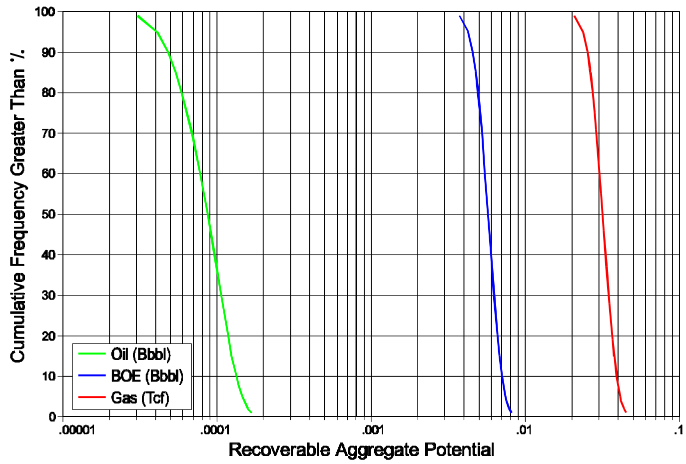


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	**Number of Pools**	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Reserves				
Original proved	3	<0.001	0.027	0.005
Cumulative production	--	<0.001	0.025	0.005
Remaining proved	--	<0.001	0.002	<0.001
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.006	0.001
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.024	0.004
Mean	5	<0.001	0.032	0.006
5th percentile	--	<0.001	0.041	0.007
Total Endowment				
95th percentile	--	<0.001	0.057	0.010
Mean	8	<0.001	0.065	0.012
5th percentile	--	<0.001	0.074	0.013

discovered pools.

The UM3 R1 play has limited potential, and though 50 percent of the play's BOE mean total endowment is projected as undiscovered, these undiscovered resources will add little to the Gulf of Mexico's total resources.

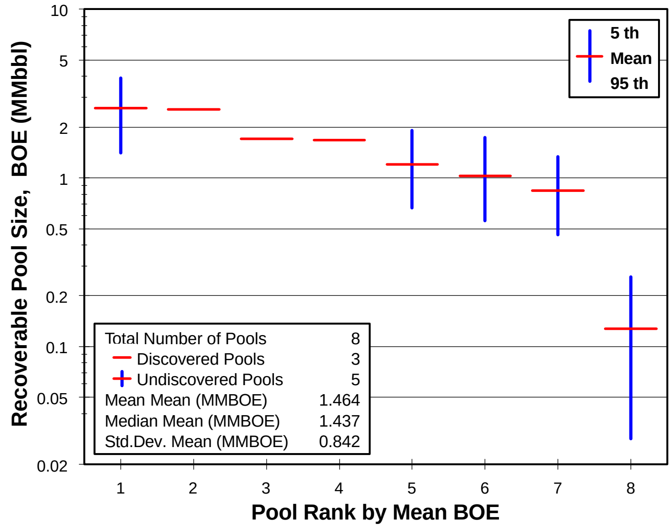


Figure 4. Pool rank plot.

UPPER UPPER MIOCENE EASTERN RETROGRADATIONAL (UM3 R2) PLAY

PLAY DESCRIPTION

The established Upper Upper Miocene Eastern Retrogradational (UM3 R2) play occurs within the *Cristellaria* "K," *Bigenerina* "A," and *Robulus* "E" biozones. This play extends from the Eugene Island Area to the Chandeleur Area east of the present-day Mississippi River Delta (figure 1).

Updip and along strike to the east and west, the play grades into the deposits of the Upper Upper Miocene Aggradational (UM3 A) play or the Upper Upper Miocene Progradational (UM3 P) play. Downdip, the play grades into the deposits of the UM3 P play.

The UM3 R2 play is more sand-rich than the other UM3 retrogradational play, the Upper Upper Miocene Western Retrogradational (UM3 R1) play. The UM3 R1 play was deposited in the offshore Texas area where the clastic influx of the delta systems was waning.

PLAY CHARACTERISTICS

The productive UM3 R2 play consists of reworked marine sands deposited as offshore bars, barrier islands, washover fans, and beach deposits in a deltaic fringe environment. The retrogradational sands become progressively thinner and finer in the vertical sequence and exhibit a back-stepping log signature, terminating in the *Robulus* "E" flooding surface. Salt diapirs, anticlines, and growth faults are the dominant structural features in this play. Normal faults and stratigraphic pinch-outs occur less commonly. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs,

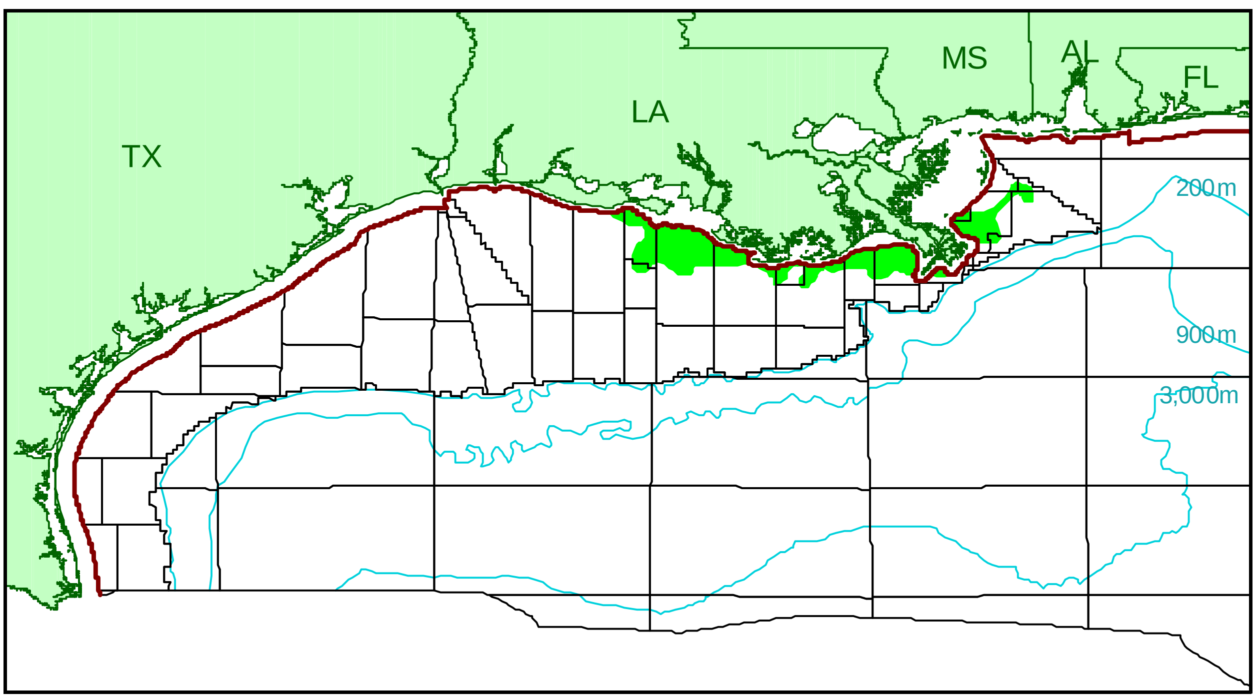


Figure 1. Map of assessed play.

overlying shales). Future discoveries are not limited to the aforementioned productive retrogradational depositional environments, structures, or seals.

South Timbalier 21 is the type field, and Chevron USA Inc.'s S-4, S-4A, S-4B, S-4C, and S-4D sands represent the UM3 R2 play in this field.

DISCOVERIES

The UM3 R2 mixed oil and gas play contains total reserves of 0.086 Bbo and 0.613 Tcfg (0.195 BBOE), of which 0.069 Bbo and 0.461 Tcfg (0.151 BBOE) have been produced. The play contains 38 producible sands in 24 pools (table 1). The first reserves in the play were discovered in the Ship Shoal 28 field in 1949 (figure 2). The maximum yearly total reserves were added in 1960 with the discovery of the largest pool in the play in the Grand Isle 43 field. This pool accounts for almost one-third of the play's total reserves. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1987.

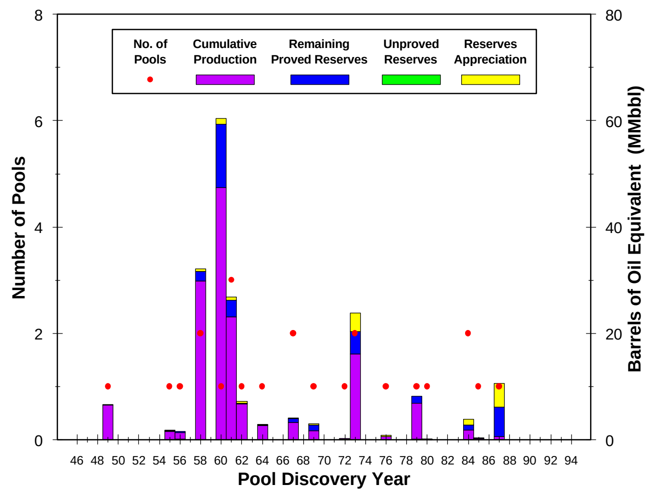


Figure 2. Exploration history graph.

The 24 discovered pools range in size from 0.173 to 60.486 MMBOE. These pools contain 101 reservoirs, 35 of which are nonassociated gas, 49 are undersaturated oil, and 17 are saturated oil.

Table 1. Characteristics of the discovered pools.

24 Pools (38 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	12	64	209
Subsea depth (feet)	2,832	8,458	14,500
Number of sands per pool	1	2	5
Porosity	21%	29%	36%
Water saturation	9%	29%	51%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the UM3 R2 play is 1.00. The play contains a mean total endowment of 0.102 Bbo and 0.744 Tcfg (0.235 BBOE) (table 2). Sixty-four percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.009 to

0.026 Bbo and 0.090 to 0.173 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.016 Bbo and 0.131 Tcfg (0.040 BBOE). These undiscovered resources may occur in as many as seven pools. The largest undiscovered pool, with a mean size of 12.611 MMBOE, is modeled as the sixth largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 8, 13, 14, and 16 on the pool rank plot.

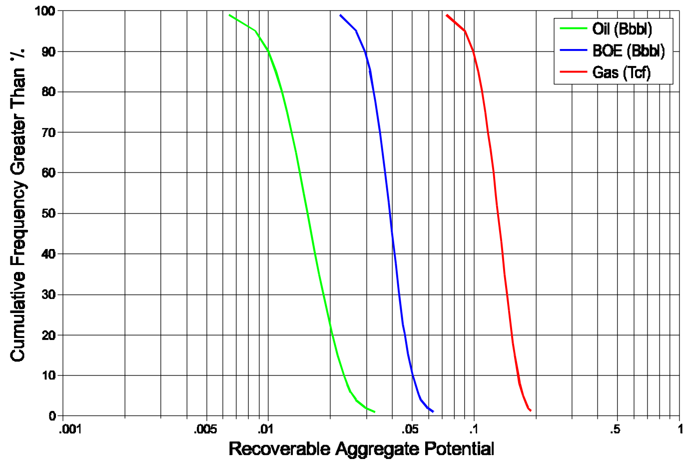


Figure 3. Cumulative probability distribution.

For all the undiscovered pools in the UM3 R2 play, the mean mean size is 5.640 MMBOE, which is smaller than the 8.110 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 7.552 MMBOE.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	24	0.083	0.557	0.182
Cumulative production	--	0.069	0.461	0.151
Remaining proved	--	0.014	0.096	0.031
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.003	0.056	0.013
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.009	0.090	0.027
Mean	7	0.016	0.131	0.040
5th percentile	--	0.026	0.173	0.054
Total Endowment				
95th percentile	--	0.095	0.703	0.222
Mean	31	0.102	0.744	0.235
5th percentile	--	0.112	0.786	0.249

Of the five retrogradational plays in the Gulf of Mexico Region, the UM3 R2 play is projected to contain the largest amount of mean undiscovered oil at 62 percent.

The UM3 R2 play is well explored. The undiscovered pools are projected to be small to moderate in size when compared with the discovered pools. These undiscovered resources are expected to add 17 percent to the play's BOE mean total endowment.

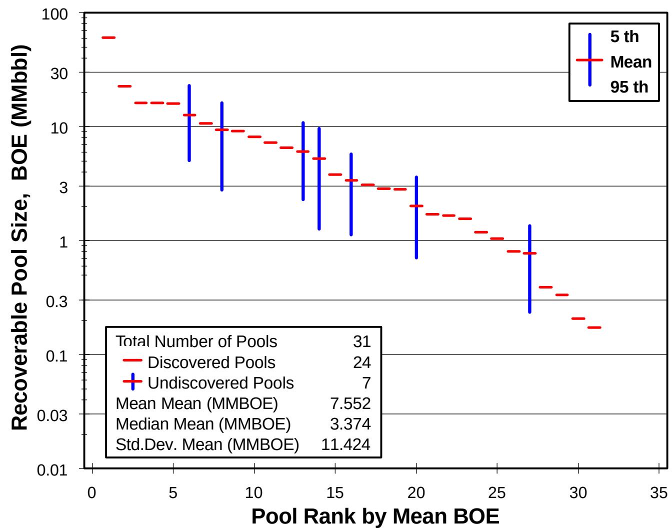


Figure 4. Pool rank plot.

UPPER UPPER MIOCENE AGGRADATIONAL (UM3 A) PLAY

PLAY DESCRIPTION

The established Upper Upper Miocene Aggradational (UM3 A) play occurs within the *Cristellaria* "K," *Bigenerina* "A," and *Robulus* "E" biozones. This play extends in a continuous band from the North Padre Island Area offshore Texas to the East Cameron Area offshore Louisiana (figure 1). East of that, the play is sporadically present in the Federal offshore. The play again enters the offshore east of the present-day Mississippi River Delta in the Main Pass Area.

Updip, the play continues onshore into Texas and Louisiana. To the southwest, the play continues into onshore Texas. Downdip, the play grades into the deposits of the Upper Upper Miocene Progradational (UM3 P) play.

In the Texas offshore, the aggradational sequences of the UM3 and lower upper Miocene (UM1) chronozones occupy very similar geographical areas, indicating stable shelf sedimentation. However, in the Louisiana offshore, the downdip extent of the UM3 aggradational sequence has moved farther offshore than the downdip extent of the UM1 aggradational sequence. Thus, shelfal UM3 aggradational deposits in the Louisiana offshore extend over the underlying UM1 progradational sequence.

PLAY CHARACTERISTICS

The productive sands in the UM3 A play formed as proximal deltaic deposits on the shelf. Aggradational sands typically have a blocky log character. However, some fining-upward sands are found within this play's aggradational sequence. Variation in the amount of clastic influx between the offshore Louisiana and offshore Texas areas resulted in different depositional characteristics within the play sequence.

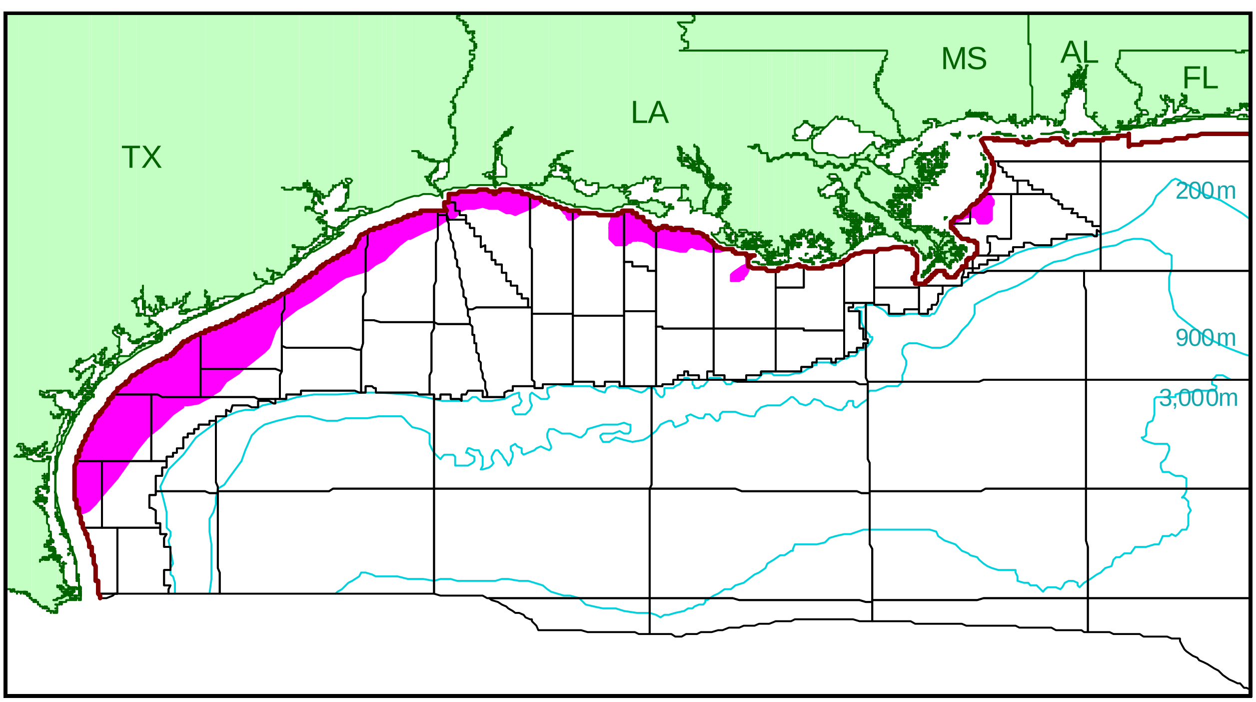


Figure 1. Map of assessed play.

The Louisiana offshore area had a higher clastic influx than did the Texas offshore area during UM3 time. The sediments in the UM3 A play in offshore Louisiana were deposited in fluvial-deltaic to paralic environments. Consequently, the aggradational reservoir sands represent a variety of environments that include channel, point bar, distributary mouth bar, crevasse splay, beach, barrier island, and nearshore bar deposits. Individual channels or stacked channels are common. These sands are thick and well developed due to the high influx of clastic sediments.

In contrast, during UM3 time in the offshore Texas area, the aggradational reservoir sands formed in bays as distributary crevasse splays and in lagoons as storm-generated washover deltas behind barrier islands. These sands are thin and poorly developed due to the low influx of clastic sediments.

Stratigraphic pinch-outs, anticlines, growth faults, and normal faults are the dominant structural features in this play. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive aggradational depositional environments, structures, or seals.

South Marsh Island 241 is the type field, and Texaco E&P's ASEG500 sand represents the UM3 A play in this field.

DISCOVERIES

The UM3 A play is predominantly a gas play, with total reserves of 0.019 Bbo and 0.295 Tcfg (0.071 BBOE), of which 0.016 Bbo and 0.180 Tcfg (0.048 BBOE) have been produced. The play contains 21 producible sands in nine pools (table 1) . The first reserves in the play were discovered in the Eugene Island 32 field in 1950 (figure 2). A hiatus in pool discoveries occurred from 1950 to 1974. Most of the pool discoveries (7 out of 9) occurred between 1974 and 1983. The maximum yearly total reserves were added in 1976 with the discovery of the largest pool in the play in the Ship Shoal 84 field. On a

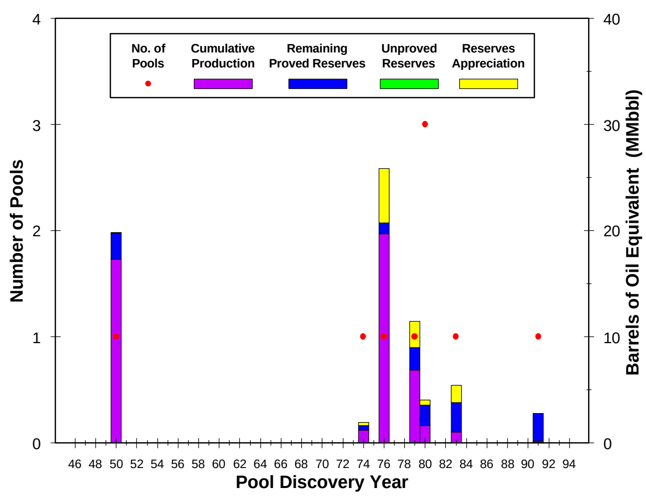


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

9 Pools (21 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	11	30	72
Subsea depth (feet)	1,838	6,617	11,591
Number of sands per pool	1	2	7
Porosity	27%	31%	35%
Water saturation	16%	22%	34%

BOE basis, 67 percent of the play's cumulative production is gas, but remaining total reserves indicate that future production may increase to 87 percent gas. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1991.

The nine discovered pools range in size from 0.106 to 25.839 MMBOE. These pools contain 25 reservoirs, of which 13 are nonassociated gas, 6 are undersaturated oil, and 6 are saturated oil.

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the UM3 A play is 1.00. The play ranks within the smallest one-third of all 61 Gulf of Mexico Region plays, based on a mean total endowment of 0.019 Bbo and 0.311 Tcfg (0.074 BBOE) (table 2). Sixty-five percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered oil resources are insignificant (<0.001 Bbbl) and that undiscovered gas resources have a range of 0.008 to 0.027 Tcf at the 95th and 5th percentiles, respectively (figure 3). The estimated amount of mean undiscovered gas is 0.016 Tcf (0.003 BBOE). These undiscovered resources may occur

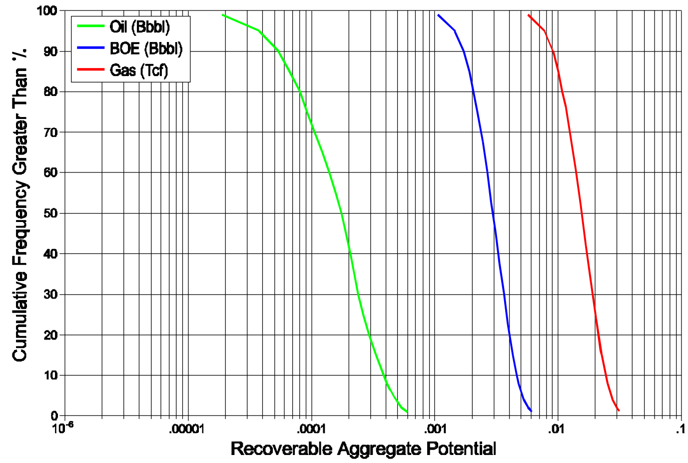


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	**Number of Pools**	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Reserves				
Original proved	9	0.018	0.241	0.061
Cumulative production	--	0.016	0.180	0.048
Remaining proved	--	0.003	0.061	0.013
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.001	0.054	0.010
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.008	0.001
Mean	3	<0.001	0.016	0.003
5th percentile	--	<0.001	0.027	0.005
Total Endowment				
95th percentile	--	0.019	0.303	0.072
Mean	12	0.019	0.311	0.074
5th percentile	--	0.019	0.322	0.076

in as many as three pools. The largest undiscovered pool, with a mean size of 1.421 MMBOE, is modeled as the ninth largest pool in the play (figure 4). The model results place the remaining two undiscovered pools in positions 10 and 11 on the pool rank plot. These three undiscovered pools are projected on the pool rank plot near the smallest discovered pool. For all the undiscovered pools in the UM3 A play, the mean mean size is 1.026 MMBOE, which is significantly smaller than the 7.923 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 6.199 MMBOE.

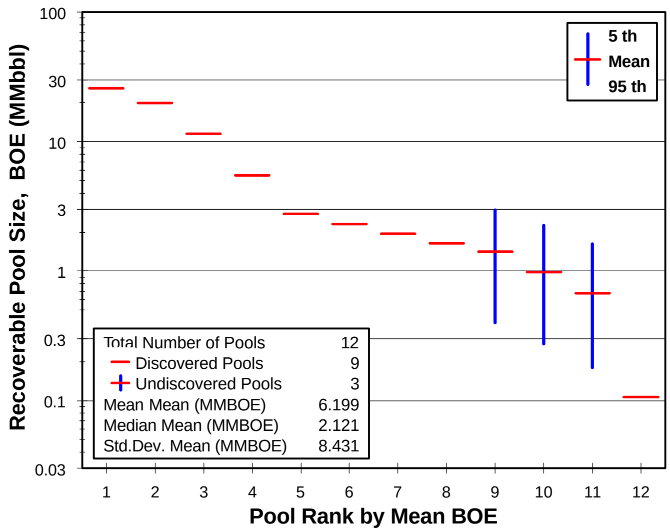


Figure 4. Pool rank plot.

Because of its shallow-water environment, many wells have penetrated this play and found it unproductive. The reservoir potential in offshore Texas is reduced by thin and poorly-developed sands. In the Louisiana offshore, the abundant aggradational sands and thin shale intervals reduce the opportunity of seals for hydrocarbon entrapment. Therefore, the undiscovered resources are projected to contribute only 4 percent to the play's BOE mean total endowment.

UPPER UPPER MIOCENE AGGRADATIONAL/PROGRADATIONAL (UM3 AP) PLAY

PLAY DESCRIPTION

The established Upper Upper Miocene Aggradational/Progradational (UM3 AP) play occurs within the *Cristellaria* "K," *Bigenerina* "A," and *Robulus* "E" biozones. This play is located in the Mobile, Pensacola, Chandeleur, Viosca Knoll, and Destin Dome Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the play continues onshore into Mississippi and Alabama. Downdip, the play is limited by a lack of sand in the distal end of the facies.

The UM3 chronozone is one of three chronozones with combined aggradational and progradational (AP) "Shallow Miocene Bright Spot Trend" plays. The other two chronozones are the upper middle Miocene (MM9) and the lower upper Miocene (UM1). The extent of the AP sequence in the UM3 chronozone is found in the same general geographical area as the AP sequences in the MM9 and UM1 chronozones, indicative of deposition on a stable shelf. Sediments for the AP plays were sourced from a major continental drainage system formed after the Laramide Orogeny and also from the Appalachian region. The clastic influx that formed the AP plays over the Cretaceous shelf was much less than to the Louisiana area depocenter during middle and upper Miocene time.

PLAY CHARACTERISTICS

The UM3 AP play comprises incised-valley fill (channels) typical of a progradational setting, but because the channel sands are often stacked, they also have characteristics

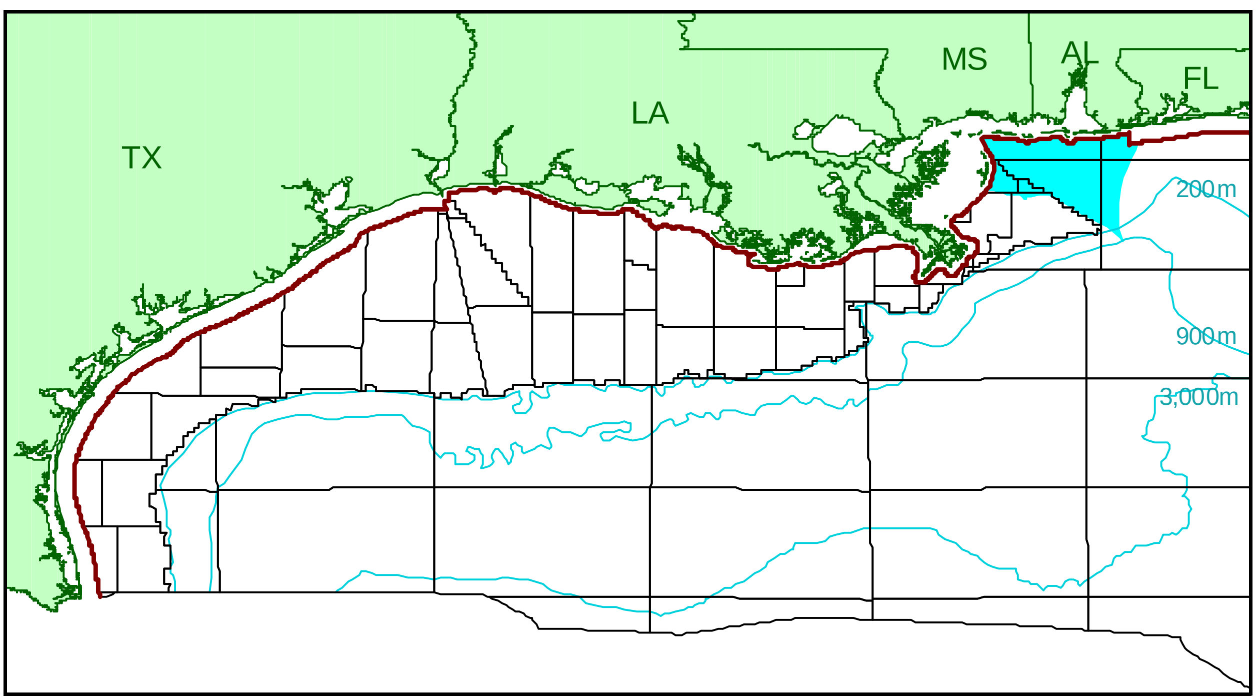


Figure 1. Map of assessed play.

of an aggradational setting. Therefore, the play is referred to as a combination aggradational/progradational (AP) play. The play occurs at shallow depths over the Cretaceous carbonate shelf, and hydrocarbon accumulations are associated with seismic hydrocarbon indicators (bright spots). Regional dip dominates the structural style of the play. Faulting and local uplifts are rare and have no role in the accumulation of hydrocarbons. Channels cut across the regional dip of the shelf area, and their deposits are sealed by lateral shale-outs and overlying shelf shales.

Viosca Knoll 74 is the type field, and Santa Fe Mineral's DISCORBIS 12 sands represent the UM3 AP play in this field.

Discoveries

The UM3 AP gas play contains total reserves of 57.732 Mbo and 354.790 Bcfg (63.188 MMBOE), of which 0.470 Mbo and 47.218 Bcfg (8.402 MMBOE) have been produced. The play contains 24 producible sands in 17 pools, and 15 of these pools contain proved reserves (table 1). The first reserves in the play were discovered in the Chandeleur 14 field in 1983 (figure 2). The maximum yearly total reserves of 34.360 MMBOE were added in 1987 when eight pools were discovered, including the largest pool in the play in the Chandeleur 40 field. Almost half of the play's cumulative production has come from pools discovered prior to 1988. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1994.

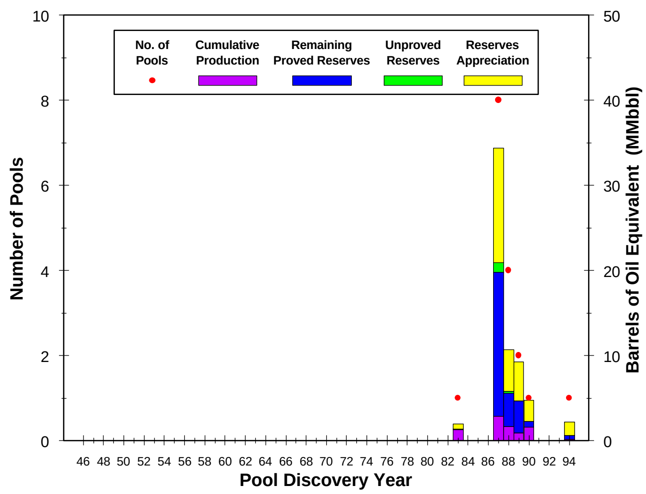


Figure 2. Exploration history graph.

The 17 discovered pools range in size from 0.409 MMBOE to 10.469 MMBOE. These pools contain 26 reservoirs, all of which are nonassociated gas.

The UM3 AP play contains 23 percent of the BOE total reserves contained in the three AP plays.

Table 1. Characteristics of the discovered pools.

17 Pools (24 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	40	91	130
Subsea depth (feet)	1,585	2,515	3,850
Number of sands per pool	1	1	4
Porosity	22%	33%	36%
Water saturation	16%	27%	48%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the UM3 AP play is 1.00. The play ranks within the smallest one-third of all 61 Gulf of Mexico Region plays, based on a mean total endowment of less than 0.001 Bbo and 0.394 Tcfg (0.070 BBOE) (table 2). Twelve percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered oil resources are insignificant (<0.001 Bbbl) and that undiscovered gas resources have a range of 0.033 to 0.046 Tcf at the 95th and 5th percentiles, respectively (figure 3). The estimated amount of mean undiscovered gas is 0.039 Tcf (0.007 BBOE). These undiscovered resources may occur in as many as 13 pools. The largest undiscovered pool, with a mean size of 1.160 MMBOE, is modeled as the seventeenth largest pool in the play (figure 4). For all the undiscovered pools in the UM3 AP play, the mean mean size is 0.541 MMBOE, which is smaller than the 3.717 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is

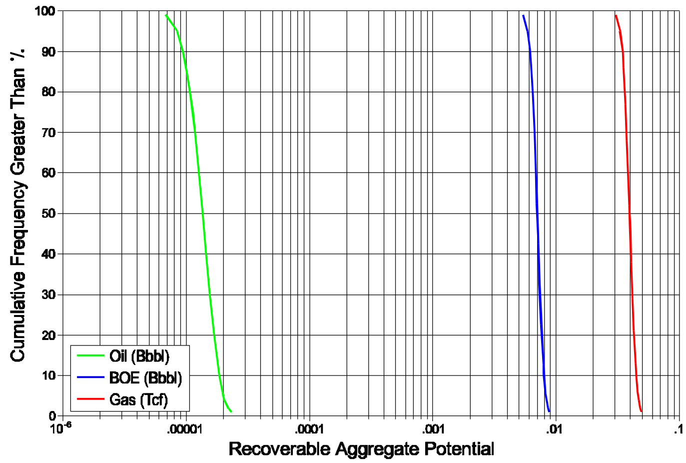


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	**Number of Pools**	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Reserves				
Original proved	15	<0.001	0.192	0.034
Cumulative production	--	<0.001	0.047	0.008
Remaining proved	--	<0.001	0.145	0.026
Unproved	2	<0.001	0.008	0.001
Appreciation (P & U)	--	<0.001	0.155	0.028
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.033	0.006
Mean	13	<0.001	0.039	0.007
5th percentile	--	<0.001	0.046	0.008
Total Endowment				
95th percentile	--	<0.001	0.388	0.069
Mean	30	<0.001	0.394	0.070
5th percentile	--	<0.001	0.401	0.071

2.341 MMBOE.

The limited geographic extent of the UM3 AP play, the small discovered field sizes, and extensive drilling reduce the play's potential for significant discoveries. The undiscovered pools are modeled to be smaller than most of the discovered pools and are expected to add only 10 percent to the play's BOE mean total endowment.

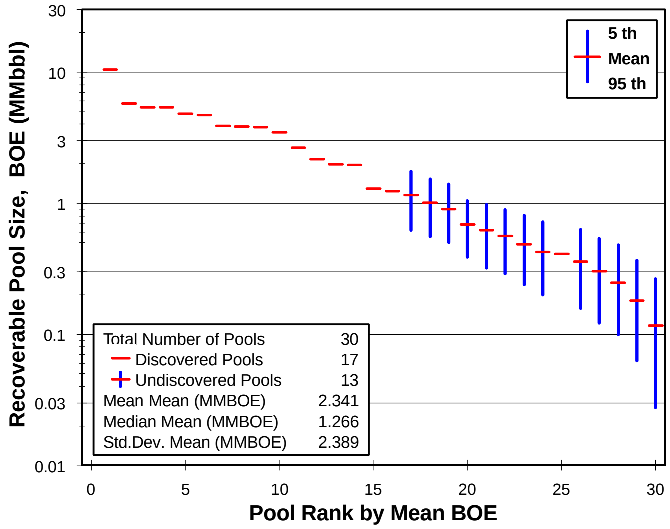


Figure 4. Pool rank plot.

UPPER UPPER MIOCENE PROGRADATIONAL (UM3 P) PLAY

PLAY DESCRIPTION

The Upper Upper Miocene Progradational (UM3 P) play is one of the largest established plays in the Gulf of Mexico Region. The play occurs within the *Cristellaria* "K," *Bigenerina* "A," and *Robulus* "E" biozones and extends from the South Padre Island Area offshore Texas through the Main Pass Area east of the present-day Mississippi River Delta (figure 1).

Updip in the Texas offshore, the play grades into the deposits of the Upper Upper Miocene Aggradational (UM3 A) play. Updip to the north in Louisiana, the UM3 P play continues onshore. The play continues to the southwest into Texas offshore State waters and Mexican national waters. To the northeast, the play is limited by the deposits of the Upper Upper Miocene Aggradational/Progradational (UM3 AP) play overlying the Cretaceous carbonate shelf. Downdip and to the east, the UM3 P play grades into the deposits of the Upper Upper Miocene Fan (UM3 F) play.

The downdip boundary of the UM3 P play is located farther basinward than the downdip boundary of the UM1 progradational play. Therefore, UM3 progradational sediments were deposited over not only UM1 progradational sediments, but also over UM1 fan sediments.

PLAY CHARACTERISTICS

The productive UM3 P play consists of progradational deltaic sediments deposited in delta front, delta fringe, shelf blanket, and offshore bar environments. Other less commonly occurring reservoir sands were deposited as shelf slumps, channel fill, and levee deposits. Anticlines, normal faults, salt diapirs, and growth faults are the major

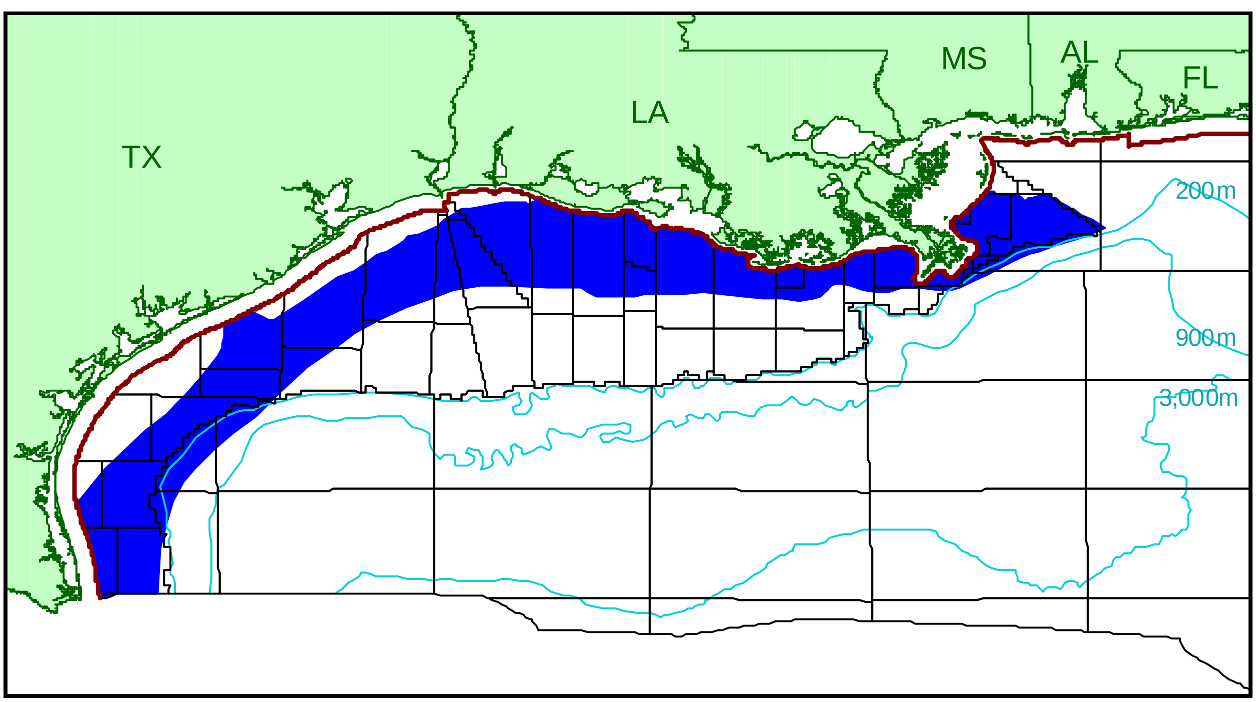


Figure 1. Map of assessed play.

structural features in this play. Stratigraphic pinch-outs occur less frequently. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive progradational depositional environments, structures, or seals.

Ship Shoal 69 is the type field, and Shell Offshore Inc.'s OE sand represents the UM3 P play in this field.

DISCOVERIES

The UM3 P mixed oil and gas play contains total reserves of 2.411 Bbo and 12.110 Tcfg (4.566 BBOE), of which 2.056 Bbo and 9.087 Tcfg (3.673 BBOE) have been produced. The play contains 976 producible sands in 165 pools (table 1). The first reserves in the play were discovered in the Ship Shoal 72 field in 1948 (figure 2). Pool discoveries have averaged three to four per year. The maximum yearly total reserves of 761.181 MMBOE were added in 1955 when six pools were discovered, including the largest pool in the play in the Bay Marchand 2 field. Over 70 percent of the play's total reserves are in pools discovered before 1967. On a BOE basis, 44 percent of the play's cumulative production is gas, but remaining total reserves indicate that future production may increase to 60 percent gas. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1993.

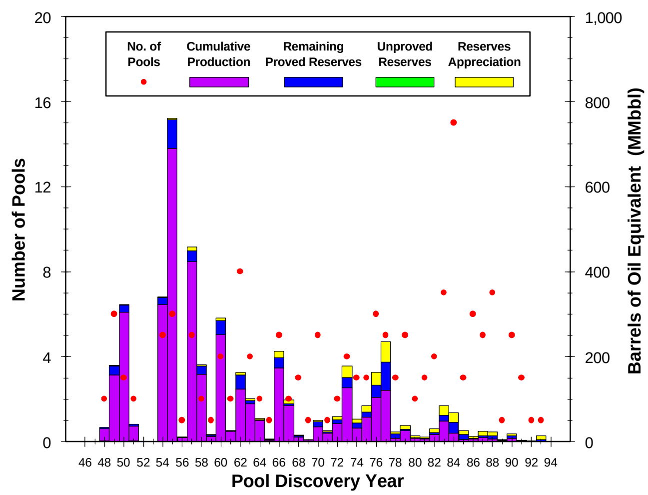


Figure 2. Exploration history graph.

The 165 discovered pools range in size from 0.016 to 572.278 MMBOE. These pools contain 2,329 reservoirs, of which 940 are nonassociated gas, 1,128 are undersaturated oil, and 261 are saturated oil.

Of the 61 plays in the Gulf of Mexico, The UM3 P play is the second largest, based

Table 1. Characteristics of the discovered pools.

165 Pools (976 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	9	71	342
Subsea depth (feet)	1,725	8,356	16,758
Number of sands per pool	1	6	45
Porosity	19%	29%	36%
Water saturation	9%	28%	57%

on BOE total reserves. It has produced 22 percent of the total oil and contains the largest amount of oil total reserves (16%). Additionally, of the 14 progradational plays in the Gulf of Mexico, the UM3 P play has produced 31 percent of the total oil.

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the UM3 P play is 1.00. This play is the third largest in the Gulf of Mexico, based on a mean total endowment of 2.438 Bbo and 12.628 Tcfg (4.685 BBOE) (table 2). Seventy-eight percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.018 to 0.039 Bbo and 0.401 to 0.650 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.027 Bbo and 0.518 Tcfg (0.119 BBOE). These undiscovered resources may occur in as many as 30 pools. The largest undiscovered pool, with a mean size of

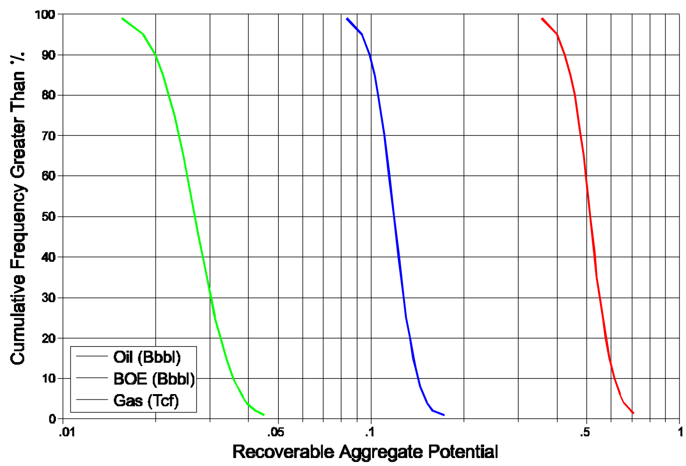


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	165	2.284	10.906	4.225
Cumulative production	--	2.056	9.087	3.673
Remaining proved	--	0.228	1.819	0.552
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.127	1.203	0.341
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.018	0.401	0.093
Mean	30	0.027	0.518	0.119
5th percentile	--	0.039	0.650	0.149
Total Endowment				
95th percentile	--	2.429	12.511	4.659
Mean	195	2.438	12.628	4.685
5th percentile	--	2.450	12.760	4.715

26.223 MMBOE, is modeled as the thirty-fifth largest pool in the play (figure 4). For all the undiscovered pools in the UM3 P play, the mean mean size is 3.986 MMBOE, which is significantly smaller than the 27.674 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 24.030 MMBOE.

In the Texas offshore, limited potential exists downdip of the discovered fields where wells have not penetrated deeply enough to reach the UM3 P play. In the Louisiana offshore, the density of wells that encounter the UM3 P play is high; therefore, limited interfield exploration potential exists. Because of this limited potential, undiscovered resources are projected to occur in small pools that add only 3 percent to the play's BOE mean total endowment.

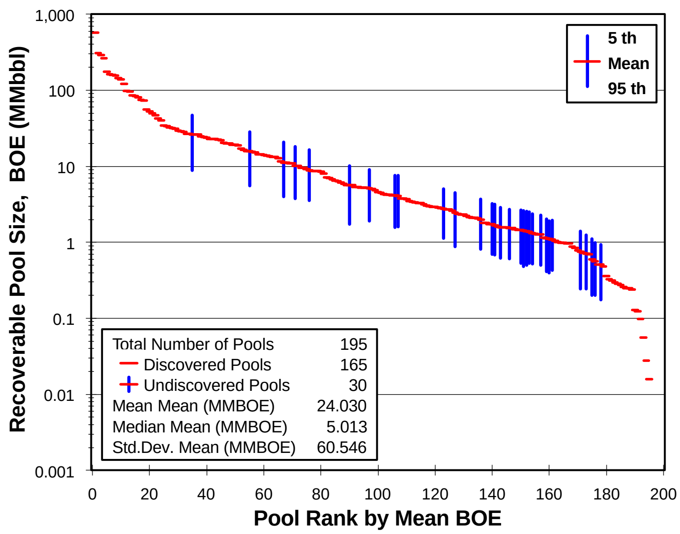


Figure 4. Pool rank plot.

UPPER UPPER MIOCENE FAN (UM3 F) PLAY

PLAY DESCRIPTION

The established Upper Upper Miocene Fan (UM3 F) play occurs within the *Cristellaria* "K," *Bigenerina* "A," and *Robulus* "E" biozones. This play extends from the South Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the play is bounded by the shelf/slope break associated with the *Robulus* "E" biozone and grades into the deposits of the Upper Upper Miocene Progradational (UM3 P) play. To the northeast, the UM3 F play is bounded by the Cretaceous carbonate shelf edge. To the southwest, the play extends into Mexican national waters. The southern extension of the play's potential to at least the Sigsbee Escarpment is supported by recent discoveries of the Mississippi Canyon 807 ("Mars"), Mississippi Canyon 854 ("Ursa"), and Mississippi Canyon 211 ("Mickey") fields, along with excellent reservoir-quality UM3 sands found in Keathley Canyon block 255.

The updip limit of the UM3 fan sequence shows a slight basinward shift compared to the lower upper Miocene (UM1) fan sequence, reflecting the prograding nature of the ancient delta systems through time.

PLAY CHARACTERISTICS

The productive UM3 F play consists of deepwater turbidites deposited in fan systems as channel fill, overbank deposits, and fringe sheet sediments on the UM3 slope. Normal faults, salt diapirs, and anticlines are the major structural features in this play. Growth faults occur less commonly. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or

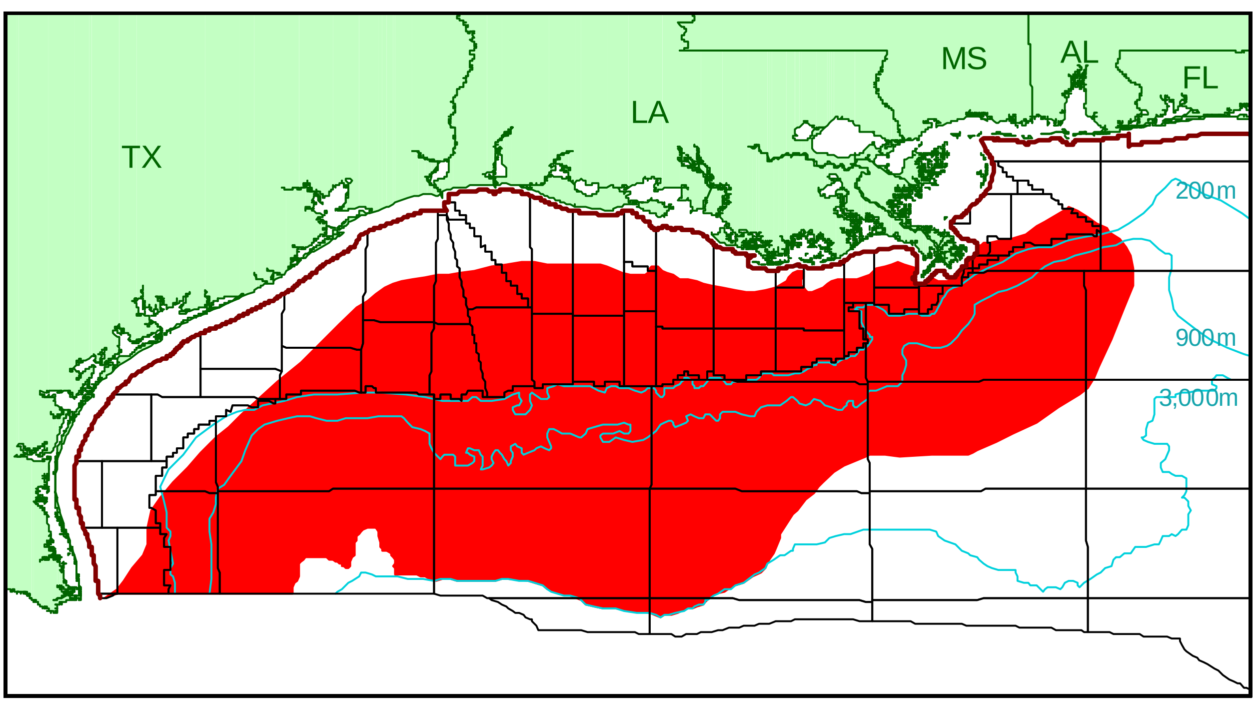


Figure 1. Map of assessed play.

stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive fan depositional environments, structures, or seals.

South Timbalier 76 is the type field, and CNG Producing Co.'s BIG-A1, BIG-A2, and BIG-A3 sands represent the UM3 F play in this field.

DISCOVERIES

The UM3 F mixed oil and gas play contains total reserves of 0.581 Bbo and 2.291 Tcfg (0.989 BBOE), of which 0.079 Bbo and 0.487 Tcfg (0.166 BBOE) have been produced. The play contains 107 producible sands in 31 pools, and 24 of these pools contain proved reserves (table 1). The first reserves in the play were discovered in the South Marsh Island 23 field in 1962 (figure 2). The maximum yearly total reserves of 366.452 MMBOE were added in 1989 when two pools were discovered, including the largest pool in the play in the Mars field. Moreover, 73 percent of the play's total reserves are in pools discovered in 1989 or later. Most of these pools are in deepwater fields. On a BOE basis, 48 percent of the play's cumulative production is oil, but remaining total reserves indicate that future production may increase to 61 percent oil. The most recent discoveries, prior to this study's cutoff date of January 1, 1995, were in 1993.

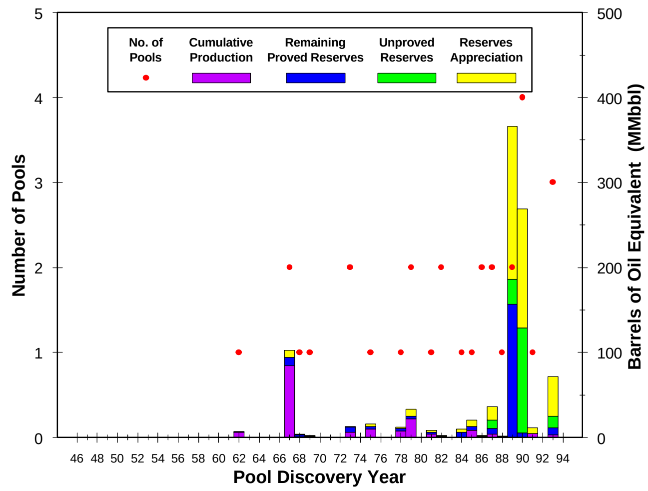


Figure 2. Exploration history graph.

The 31 discovered pools range in size from 0.679 to 307.783 MMBOE. These pools contain 200 reservoirs, of which 73 are nonassociated gas, 117 are undersaturated oil, and 10 are saturated oil.

Of the 15 fan plays in the Gulf of Mexico Region, the UM3 F play contains the third largest amount of total reserves at 8 percent, based on BOE.

Table 1. Characteristics of the discovered pools.

31 Pools (107 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	41	1,204	6,950
Subsea depth (feet)	6,548	13,026	17,865
Number of sands per pool	1	3	21
Porosity	17%	27%	36%
Water saturation	16%	26%	40%

Assessment Results

The marginal probability of hydrocarbons for the UM3 F play is 1.00. The play ranks within the largest one-third of all 61 Gulf of Mexico plays, based on a mean total endowment of 0.990 Bbo and 6.226 Tcfg (2.098 BBOE) (table 2). Eight percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.315 to 0.522 Bbo and 3.308 to 4.590 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.409 Bbo and 3.935 Tcfg (1.109 BBOE). These undiscovered resources may occur in as many as 90 pools. The largest undiscovered pool, with a mean size of 107.960 MMBOE, is modeled as the third largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 5, 6, 7, and 9 on the pool rank plot. For all the undiscovered pools in the UM3 F play, the mean mean size is 12.306 MMBOE, which is significantly smaller than the 31.904 MMBOE mean size of the

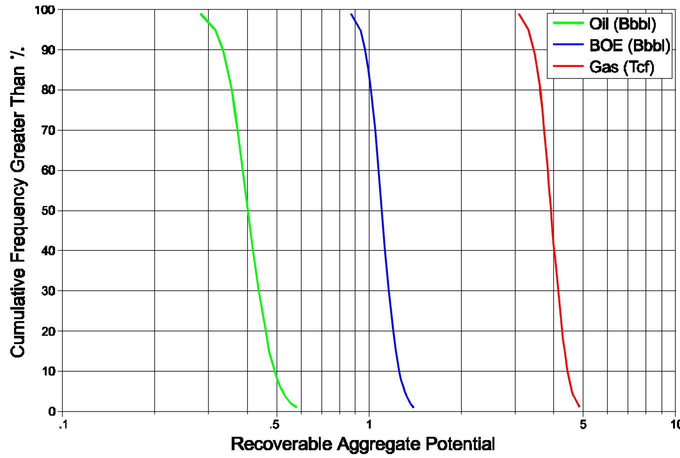


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	24	0.224	0.898	0.384
Cumulative production	--	0.079	0.487	0.166
Remaining proved	--	0.145	0.411	0.218
Unproved	7	0.105	0.415	0.179
Appreciation (P & U)	--	0.253	0.978	0.427
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.315	3.308	0.935
Mean	90	0.409	3.935	1.109
5th percentile	--	0.522	4.590	1.309
Total Endowment				
95th percentile	--	0.896	5.599	1.924
Mean	121	0.990	6.226	2.098
5th percentile	--	1.103	6.881	2.298

discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 17.327 MMBOE.

Of the 61 Gulf of Mexico plays, the UM3 F play is projected to contain the eighth and ninth largest amounts of mean undiscovered oil (5%) and gas (4%), respectively.

Because of the large unexplored area of this play, numerous undiscovered pools are expected to be found, which account for 53 percent of the play's BOE mean total endowment. On the pool rank plot, the projected undiscovered pools are interspersed throughout the entire range of discovered pool sizes. Deepwater drilling results indicate the presence of well-developed UM3 reservoir-quality sands. Therefore, hydrocarbon potential exists downdip of the discovered fields, especially in areas of present-day water depths greater than 1,000 feet.

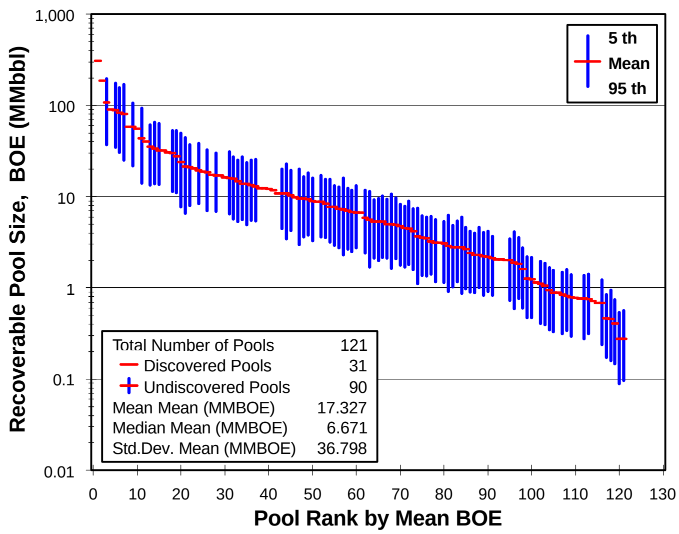


Figure 4. Pool rank plot.

Lower Upper Miocene (UM1) Chronozone

Chronozone Description

The Lower Upper Miocene (UM1) chronozone corresponds to the *Discorbis* 12 biozone. The UM1 section reflects delta systems prograding onto the continental shelf and fan deposition on the continental slope of the Gulf of Mexico Basin. Depositional styles present in the UM1 chronozone include aggradational, progradational, and fan, each of which defines one or more plays: the Lower Upper Miocene Aggradational (UM1 A) play, the Lower Upper Miocene Progradational (UM1 P) play, the Lower Upper Miocene Fan (UM1 F) play, and the Lower Upper Miocene Aggradational/Progradational (UM1 AP) play. Retrogradational sands associated with marine transgressions occur locally in the play areas at the top of the progradational and aggradational deposits. Because these retrogradational sands are discontinuous over any significant distance, they are included as part of these underlying deposits.

The potential for sand development within the UM1 chronozone extends from the South Padre Island Area offshore Texas to the western edges of the Pensacola, Destin Dome, and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). Updip, UM1 sands continue onshore into Texas and Louisiana. To the southwest, sand potential extends into Texas offshore State waters and Mexican national waters. To the northeast, UM1 sands extend onshore into Mississippi and Alabama. The downdip limit extends at least as far as the Sigsbee Escarpment as indicated by strongly developed UM1 reservoir sands in the OCS G08496-1 well in Mississippi Canyon block 657 and the OCS G07955-1 well in the Mississippi Canyon 731 field ("Mensa").

Productive and established sand locations in the UM1 chronozone are a result of two ancient depocenters, one in the Texas area and the other in the Louisiana area. The

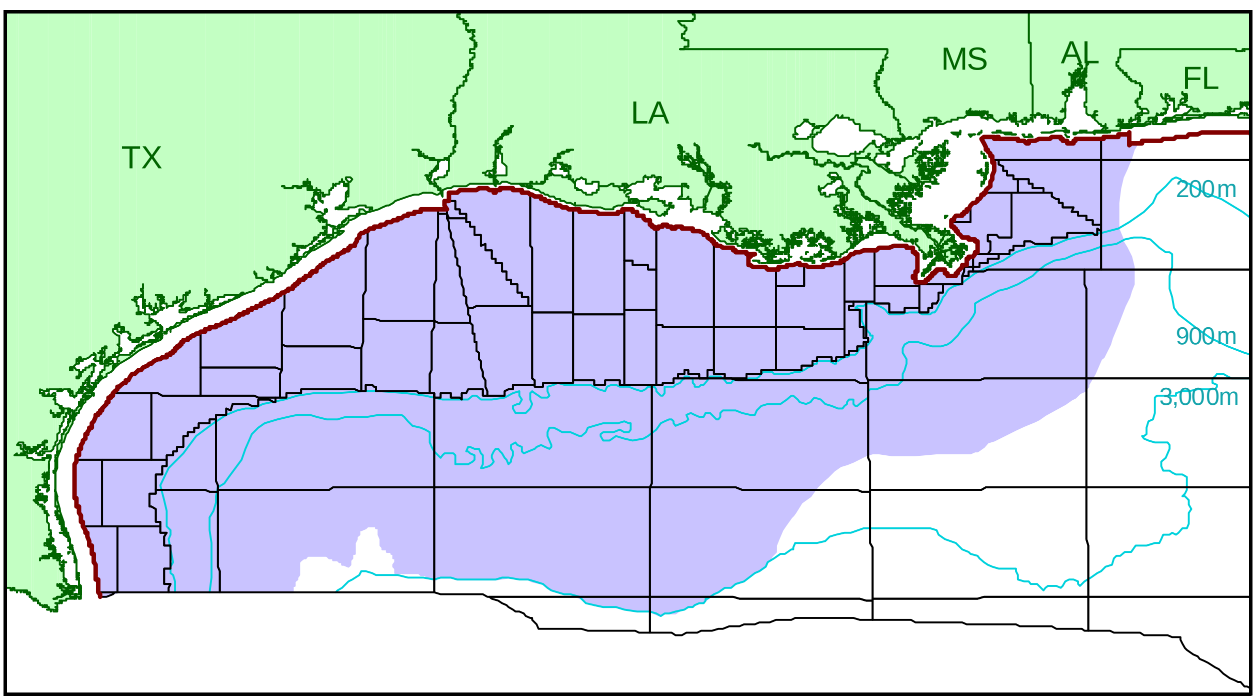


Figure 1. Map of assessed chronozone.

depositional sequences of the UM1 and upper middle Miocene (MM9) chronozones in the Texas offshore occupy approximately the same geographical areas, except for basinward progradation of sediments in UM1 time, especially in offshore Louisiana.

Productive progradational deposits of the UM1 chronozone occur offshore along most of Louisiana, whereas the underlying MM9 productive progradational deposits trend onshore from the eastern Eugene Island to the Breton Sound Areas.

In the Mississippi and Alabama offshore, the extent of the aggradational/ progradational (AP) sequence in the UM1 chronozone is found in the same general geographical area as the AP sequence of the MM9 chronozone, indicative of deposition on a stable shelf. However, the UM1 deposits include more aggradational sediments from the ancestral Mobile River System than do the MM9 sediments.

Major structural features in the UM1 chronozone include normal faults, anticlines, salt diapirs, stratigraphic pinch-outs, and growth faults. Salt ridges also occur, but much less commonly.

DISCOVERIES

The UM1 chronozone contains 155 discovered pools in four plays (table 1). Significant amounts of hydrocarbons were recently identified in the Mensa field and the Viosca Knoll 783 field ("Tahoe"). Total reserves in the chronozone are 0.790 Bbo and 13.158 Tcfg (3.131 BBOE), of which 0.512 Bbo and 8.572 Tcfg (2.037 BBOE) have been produced. The largest number of discoveries in the UM1 chronozone occurred when 12 pools were added in 1984 (figure 2). However, the maximum yearly total reserves of 293.289 MMBOE were added in 1954 with the discovery of four pools.

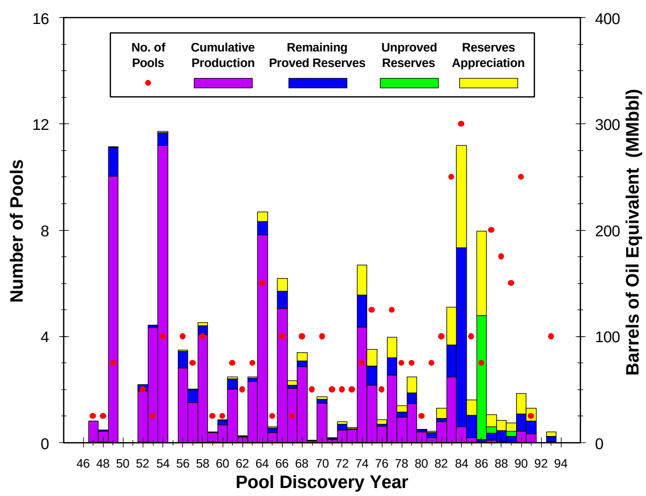


Figure 2. Exploration history graph.

Of the four plays in the UM1 chronozone, the UM1 P play contains the most total reserves in 104 pools, with 0.572 Bbo and 9.567 Tcfg (2.274 BBOE).

Table 1. Characteristics of the discovered pools.

155 Pools (534 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	9	179	7,500
Subsea depth (feet)	1,500	8,969	18,050
Number of sands per pool	1	3	37
Porosity	14%	29%	39%
Water saturation	10%	28%	55%

Assessment Results

The UM1 chronozone contains 278 pools (discovered plus undiscovered), with a mean total endowment estimated at 1.152 Bbo and 17.245 Tcfg (4.220 BBOE) (table 2).

Assessment results indicate that undiscovered resources may occur in as many as 123 pools, which contain a range of 0.286 to 0.449 Bbo and 3.502 to 4.731 Tcfg at the 95th and 5th percentiles, respectively (figure 3). At mean levels, 0.362 Bbo and 4.087 Tcfg (1.089 BBOE) are projected. These undiscovered resources represent 26 percent of the UM1 chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the ninth largest in the chronozone (figure 4).

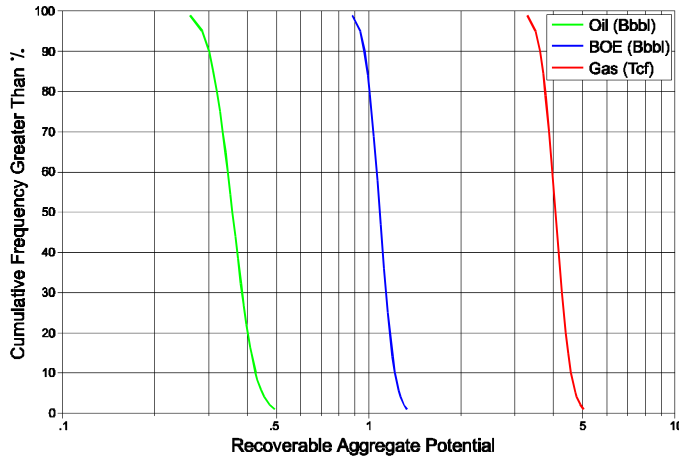


Figure 3. Cumulative probability distribution.

Of the four UM1 plays, the UM1 F play is projected to contain the greatest exploration potential, with mean undiscovered resources estimated at 0.337 Bbo and 3.638 Tcfg (0.984 BBOE) remaining to be found in 85 pools. These undiscovered resources in

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	150	0.675	10.591	2.559
Cumulative production	--	0.512	8.572	2.037
Remaining proved	--	0.163	2.019	0.522
Unproved	5	0.013	0.646	0.128
Appreciation (P & U)	--	0.102	1.921	0.443
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.286	3.502	0.937
Mean	123	0.362	4.087	1.089
5th percentile	--	0.449	4.731	1.255
Total Endowment				
95th percentile	--	1.076	16.660	4.068
Mean	278	1.152	17.245	4.220
5th percentile	--	1.239	17.889	4.386

the UM1 F play represent 23 percent of the BOE mean total endowment for the UM1 chronozone. This percentage, deepwater drilling results that support strongly developed UM1 reservoir sands, and a large unexplored area make the UM1 F play an attractive exploration target in UM1 strata.

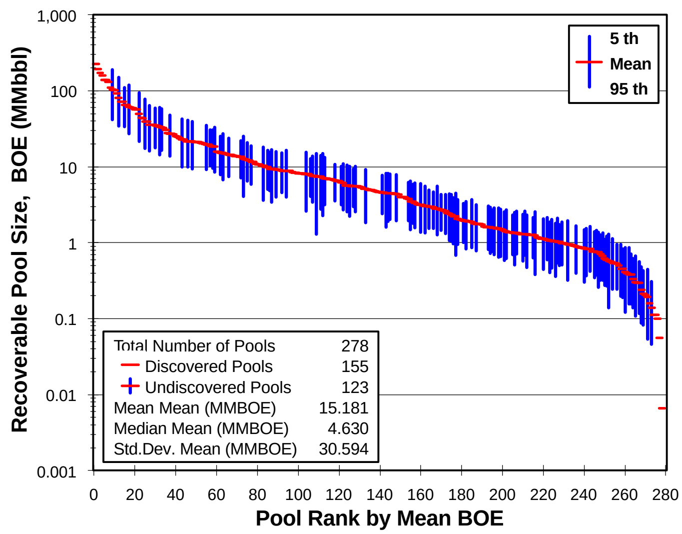


Figure 4. Pool rank plot.

LOWER UPPER MIOCENE AGGRADATIONAL (UM1 A) PLAY

PLAY DESCRIPTION

The established Lower Upper Miocene Aggradational (UM1 A) play occurs at the *Discorbis* 12 biozone. This play extends from the North Padre Island Area offshore Texas to the East Cameron Area offshore Louisiana (figure 1).

To the west, the play continues onshore into Texas. To the east, the play continues onshore into Louisiana. Downdip, the play grades into the sediments of the Lower Upper Miocene Progradational (UM1 P) play.

The downdip extent of the aggradational sequence in the UM1 chronozone is located in approximately the same area as that of the upper middle Miocene (MM9) chronozone, indicating only minor basinward movement of the UM1 aggradational sequence.

PLAY CHARACTERISTICS

The productive UM1 A play consists of thin, delta plain deposits that accumulated as distributary crevasse splays into bays and as storm-generated washover deltas into lagoons behind barrier islands. Although aggradational sands typically exhibit a thick blocky character, the sands of this play are thin and poorly developed due to their depositional origin. In addition, retrogradational sands locally cap the UM1 A play. Because these retrogradational, reworked sands are so discontinuous, they are included as part of the UM1 A play. The structure of the one field in the play is a faulted anticline. Seals are provided by the juxtaposition of sands and shales along faults. Future discoveries are not limited to the above productive aggradational depositional environments, structures, or seals.

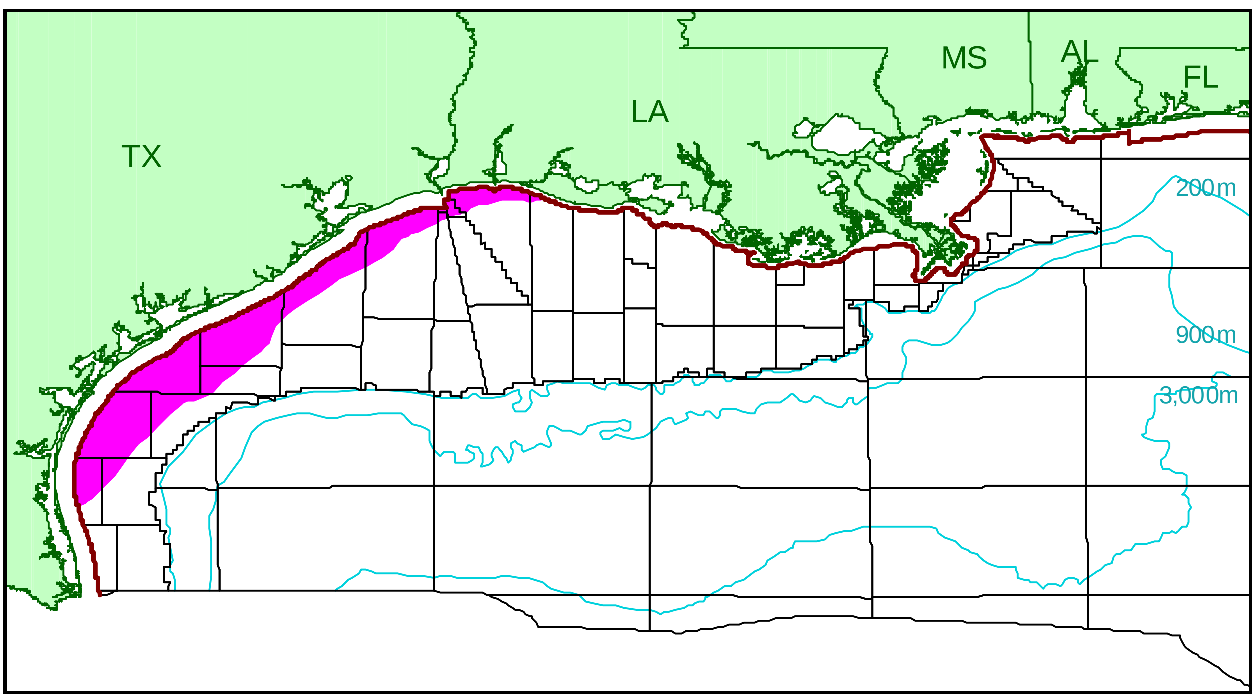


Figure 1. Map of assessed play.

Exxon Corporation's M14 and M8/M10 sands and Taylor Energy Co.'s 2 and 3 sands represent the UM1 A play in the play's only pool in the Matagorda Island 665 field.

DISCOVERIES

The UM1 A gas play contains total reserves of 6.926 Mbo and 119.035 Bcfg (21.188 MMBOE), of which 0.395 Mbo and 36.025 Bcfg (6.411 MMBOE) have been produced. The only pool in the play was found in 1977 in the Matagorda Island 665 field (figure 2). This pool contains four producible sands/reservoirs (table 1), all of which are nonassociated gas.

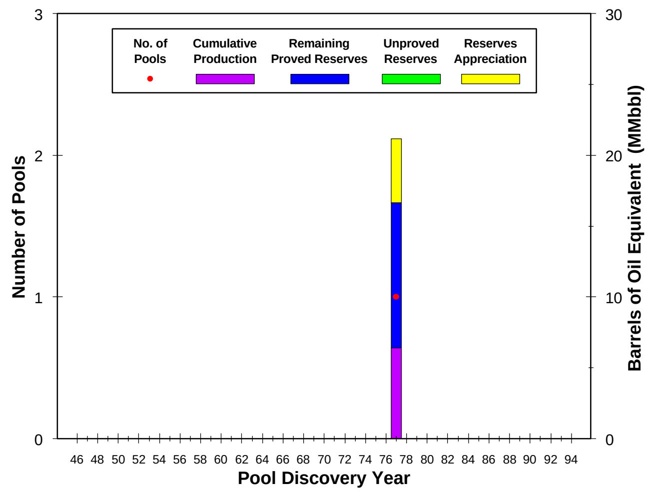


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

1 Pool (4 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	--	72	--
Subsea depth (feet)	--	1,907	--
Number of sands per pool	--	4	--
Porosity (percent)	--	31%	--
Water saturation (percent)	--	24%	--

ASSESSMENT RESULTS

Because of limited data for the UM1 A play, the Upper Lower Miocene Aggradational (LM4 A) play was used as an analog to model pool sizes in the UM1 A play. The LM4 A play was selected because of similarities in depositional setting, structural style, hydrocarbon type, and statistical information.

The marginal probability of hydrocarbons for the UM1 A play is 1.00. The play ranks within the smallest one-fourth of all 61 Gulf of Mexico Region plays, based on a mean total endowment of less than 0.001 Bbo and 0.141 Tcfg (0.025 BBOE) (table 2). Twenty-five percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of less than 0.001 to 0.001 Bbo and 0.015 to 0.032 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The estimated amount of mean undiscovered gas is 0.022 Tcf (0.004 BBOE). These undiscovered resources may occur in as many as three pools. The largest undiscovered pool, with a mean size of 2.681 MMBOE, is modeled as the second largest pool in the play (figure 4). For all the undiscovered pools in the UM1 A play, the mean mean size is 1.433 MMBOE, which is significantly smaller than the size of the discovered pool. The mean mean size for all pools, including both discovered and undiscovered, is 6.371 MMBOE.

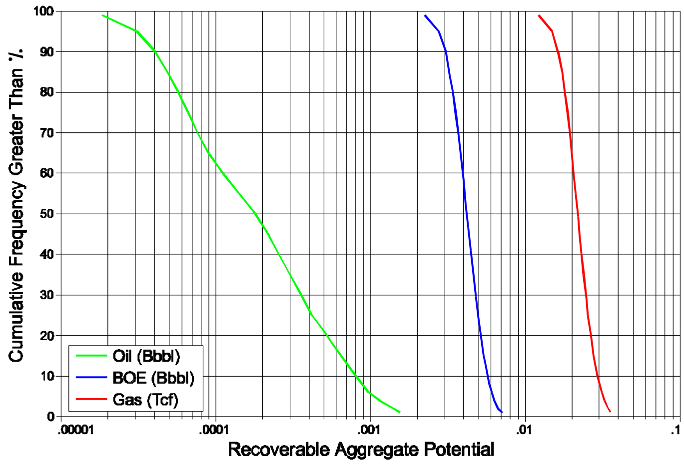


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	**Number of Pools**	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Reserves				
Original proved	1	<0.001	0.094	0.017
Cumulative production	--	<0.001	0.036	0.006
Remaining proved	--	<0.001	0.058	0.010
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.025	0.005
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.015	0.003
Mean	3	<0.001	0.022	0.004
5th percentile	--	0.001	0.032	0.006
Total Endowment				
95th percentile	--	<.001	0.134	0.024
Mean	4	<.001	0.141	0.025
5th percentile	--	0.001	0.151	0.027

Because of the numerous dry wells that penetrate this play, the undiscovered resources are expected to contribute only 16 percent to the play's BOE mean total endowment.

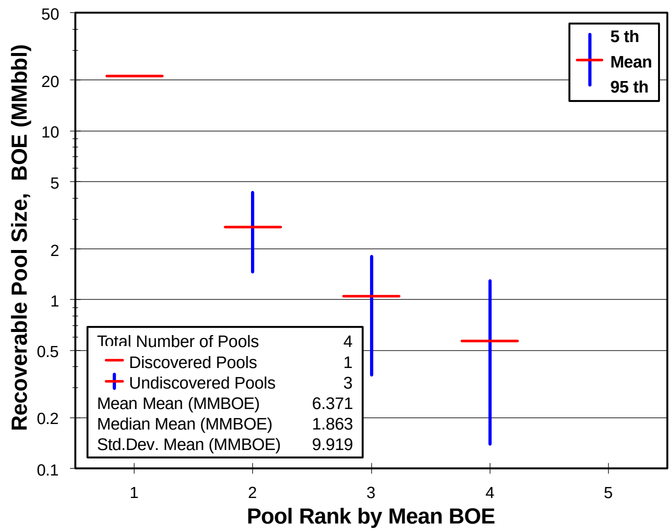


Figure 4. Pool rank plot.

Lower Upper Miocene Aggradational/Progradational (UM1 AP) Play

Play Description

The established Lower Upper Miocene Aggradational/Progradational (UM1 AP) play occurs at the *Discorbis* 12 biozone. This play is located in the Mobile, Pensacola, Chandeleur, Viosca Knoll, and Destin Dome Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the play continues onshore into Mississippi and Alabama. Downdip, the play is limited by a lack of sand in the distal end of the facies.

The UM1 chronozone is one of three chronozones with combined aggradational and progradational (AP) "Shallow Miocene Bright Spot Trend" plays. The other two chronozones are the upper middle Miocene (MM9) and the upper upper Miocene (UM3). The extent of the AP sequence in the UM1 chronozone is found in the same general geographical area as the AP sequences of the MM9 and UM3 chronozones, indicative of deposition on a stable shelf. Sediments for the AP plays were sourced from a major continental drainage system formed after the Laramide Orogeny and also from the Appalachian region. Clastic influx to the Cretaceous shelf area was much less than to the Louisiana area depocenter during middle and upper Miocene times.

Play Characteristics

The UM1 AP play comprises incised-valley fill (channels) typical of a progradational setting, but because the channel sands are often stacked, they also have characteristics of an aggradational setting. Therefore, the play is referred to as a combination aggradational/progradational (AP) play. The play occurs at shallow depths overlying the

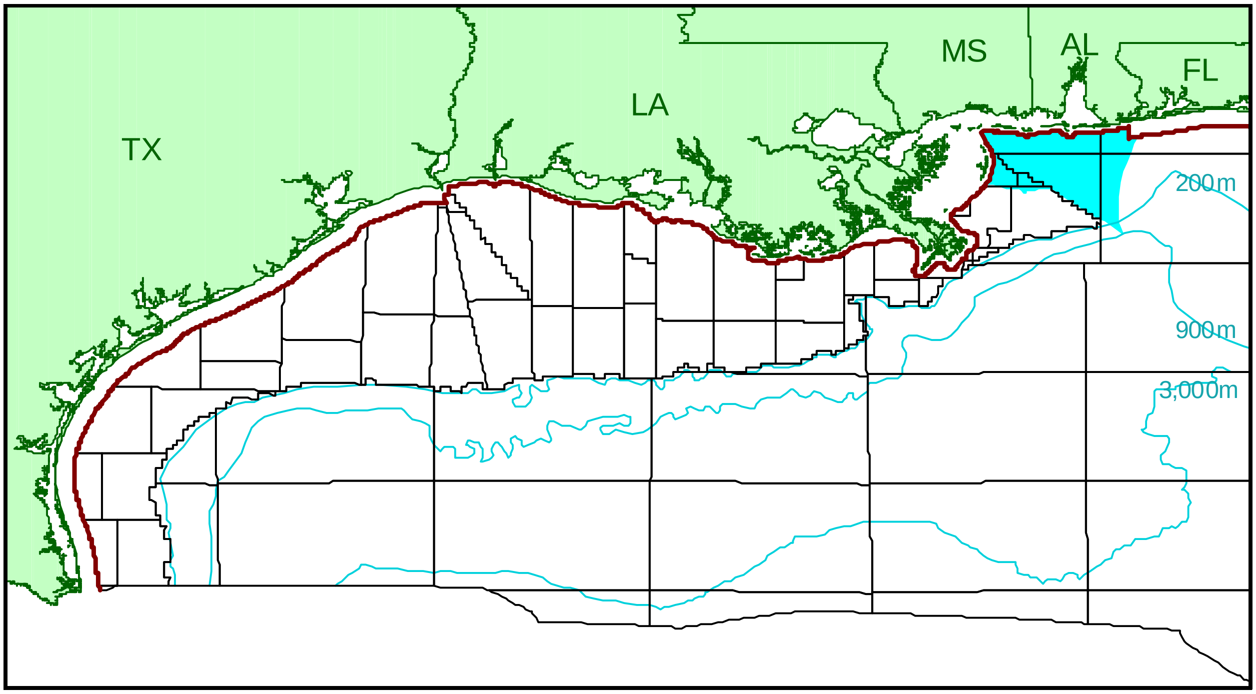


Figure 1. Map of assessed play.

Cretaceous carbonate shelf, and hydrocarbon accumulations are associated with seismic hydrocarbon indicators (bright spots). Regional dip dominates the structural style of the play. Faulting and local uplifts are rare and have no role in the accumulation of hydrocarbons within this play. Channels cut across the regional dip of the shelf area, and their deposits are sealed by lateral shale-outs and overlying Miocene shales.

Mobile 870 is the type field, and Santa Fe International Corporation's DISCORBIS 12 sand represents the UM1 AP play in this field.

DISCOVERIES

The UM1 AP gas play contains total reserves of 25.833 MMbo and 933.923 Bcfg (192.011 MMBOE), of which 0.044 MMbo and 322.640 Bcfg (57.453 MMBOE) have been produced. The play contains 31 producible sands in 25 pools, and 24 of these pools contain proved reserves (table 1). The first reserves in the play were discovered in the Chandeleur 25 field in 1982 (figure 2). The maximum yearly total reserves of 61.543 MMBOE were added in 1983 when two pools were discovered, including the largest pool in the play in the Chandeleur 29 field. Ninety percent of the play's cumulative production is associated with the first six pools found in the play. On a BOE basis, less than 1 percent of the play's cumulative production is oil, but remaining total reserves indicate that future production may increase to 19 percent oil. Discoveries peaked in 1990 when five pools were added to the play. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1993.

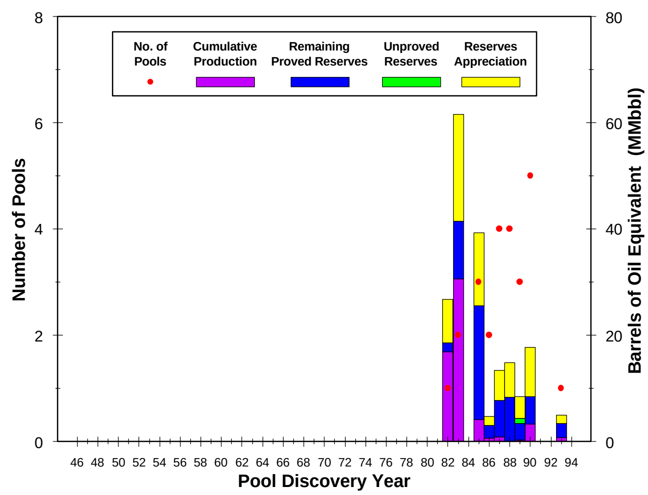


Figure 2. Exploration history graph.

The 25 discovered pools range in size from 0.878 to 34.382 MMBOE. These pools contain 34 reservoirs, all of which are nonassociated gas.

The UM1 AP play contains 69 percent of the BOE total reserves contained in the

Table 1. Characteristics of the discovered pools.

25 Pools (31 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	42	75	126
Subsea depth (feet)	1,500	2,904	4,957
Number of sands per pool	1	1	4
Porosity	26%	34%	39%
Water saturation	10%	25%	46%

three AP plays.

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the UM1 AP play is 1.00. The play contains a mean total endowment of 0.026 Bbo and 1.002 Tcfg (0.204 BBOE) (table 2). Twenty-eight percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered oil resources are insignificant (<0.001 Bbbl) and that undiscovered gas resources have a range of 0.054 to 0.083 Tcf at the 95th and 5th percentiles, respectively (figure 3). The estimated amount of mean undiscovered gas is 0.068 Tcf (0.012 BBOE). These undiscovered resources may occur in as many as 15 pools. The largest undiscovered pool, with a mean size of 1.596 MMBOE, is modeled as the twentieth largest pool in the play (figure 4). For all the undiscovered pools in the UM1 AP play, the mean mean size is 0.803 MMBOE, which is

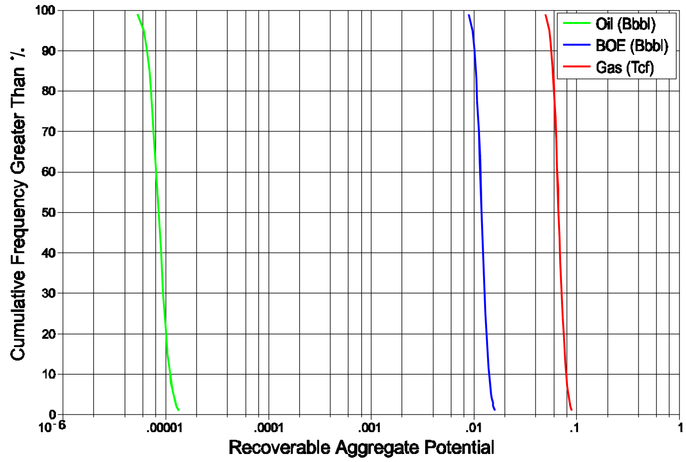


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	24	0.017	0.579	0.120
Cumulative production	--	<0.001	0.323	0.057
Remaining proved	--	0.017	0.257	0.062
Unproved	1	<0.001	0.005	0.001
Appreciation (P & U)	--	0.009	0.350	0.071
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.054	0.010
Mean	15	<0.001	0.068	0.012
5th percentile	--	<0.001	0.083	0.015
Total Endowment				
95th percentile	--	0.026	0.988	0.202
Mean	40	0.026	1.002	0.204
5th percentile	--	0.026	1.017	0.207

smaller than the 7.680 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 5.102 MMBOE.

Undiscovered pools in the UM1 AP play are expected to be much smaller than most of the discovered pools. These undiscovered resources add only 6 percent to the play's BOE mean total endowment. The limited geographic extent of the UM1 AP play, small field sizes, and extensive drilling reduce the play's potential for significant discoveries.

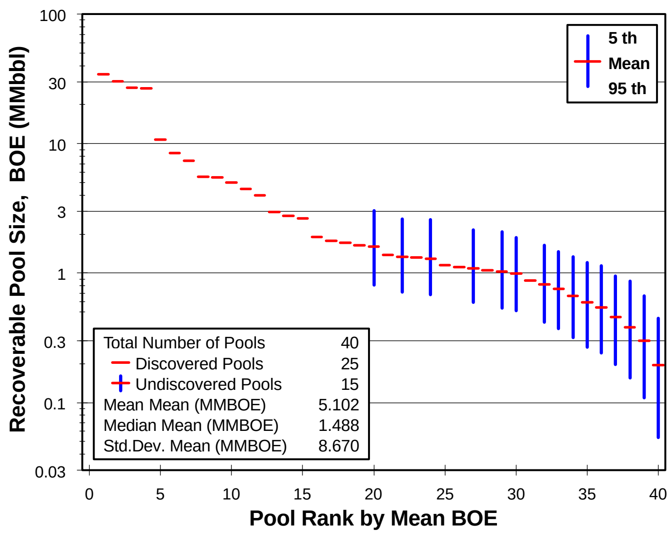


Figure 4. Pool rank plot.

LOWER UPPER MIOCENE PROGRADATIONAL (UM1 P) PLAY

PLAY DESCRIPTION

The Lower Upper Miocene Progradational (UM1 P) play is one of the largest established plays in the Gulf of Mexico Region. The play occurs at the *Discorbis* 12 biozone and extends from the South Padre Island Area offshore Texas to the Main Pass Area east of the present-day Mississippi River Delta (figure 1).

Updip in the Texas offshore, the play grades into the nearshore deposits of the Lower Upper Miocene Aggradational (UM1 A) play. Updip to the north in Louisiana, the UM1 P play continues onshore. To the northeast, the play is limited by the deposits of the Lower Upper Miocene Aggradational/Progradational (UM1 AP) play overlying the Cretaceous carbonate shelf. The UM1 P play continues to the southwest into Texas offshore State waters and Mexican national waters. Downdip and to the east, the play is grades into the deposits of the Lower Upper Miocene Fan (UM1 F) play.

The downdip extent of the UM1 progradational sequence is located farther basinward than the downdip extent of the upper middle Miocene (MM9) progradational sequence. Therefore, the UM1 P play not only overlies MM9 progradational sediments but also MM9 fan sediments.

PLAY CHARACTERISTICS

The productive UM1 P play consists of progradational deltaic sediments deposited in delta front, delta fringe, and shelf blanket environments. In addition, retrogradational sands locally cap the UM1 P play. Because these retrogradational, reworked sands are so discontinuous, they are included as part of the UM1 P play. Normal faults, anticlines, salt diapirs, and growth faults are the major structural features in the play. Less common

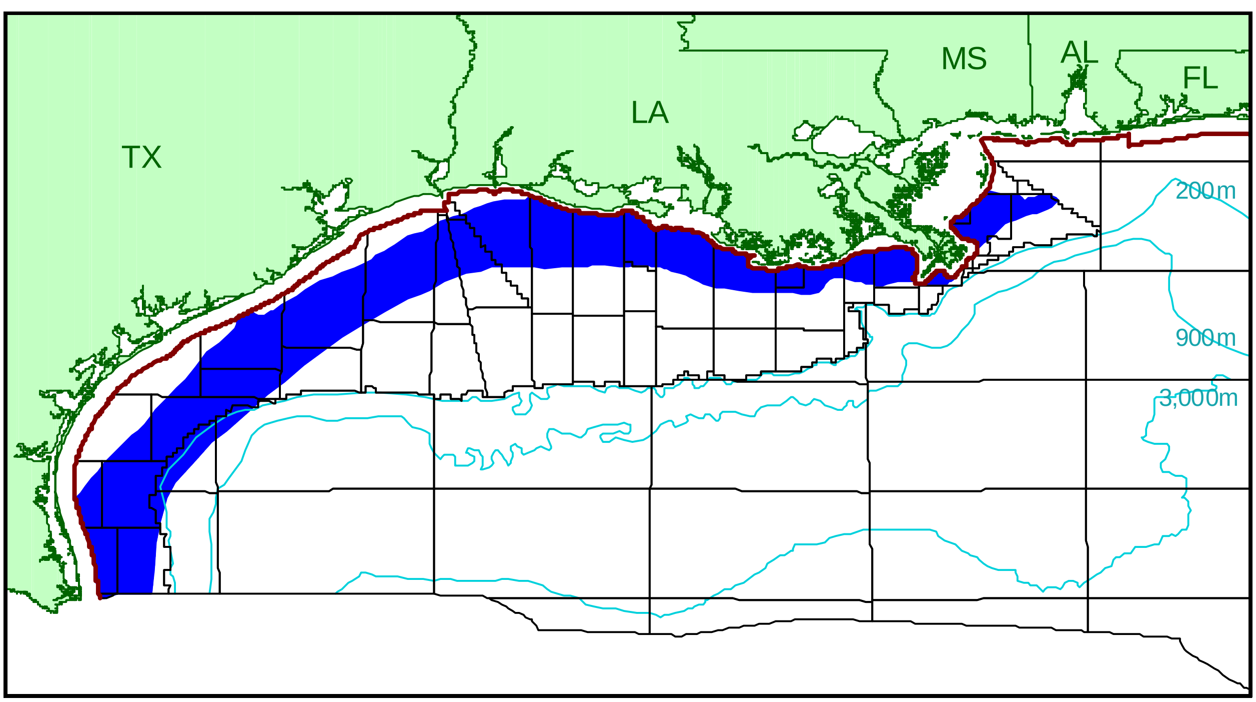


Figure 1. Map of assessed play.

structures include stratigraphic pinch-outs and salt ridges. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive progradational depositional environments, structures, or seals.

Ship Shoal 69 is the type field, and Chevron USA Inc.'s 11300, 11400, 11500, 11700, 11800, 121/12200 and 13200 sands represent the UM1 P play in this field.

DISCOVERIES

The UM1 P play is predominantly a gas play, with total reserves of 0.572 Bbo and 9.567 Tcfg (2.274 BBOE), of which 0.475 Bbo and 7.623 Tcfg (1.831 BBOE) have been produced. The play contains 424 producible sands in 104 pools, and 103 of these pools contain proved reserves (table 1). The first reserves in the play were discovered in the Vermilion 71 field in 1947 (figure 2). The maximum yearly total reserves of 279.742 MMBOE were added in 1954 when three pools were discovered, including the largest pool in the play in the West Delta 30 field. Though almost 50 percent of the pools in the play were discovered in 1975 or later, 80 percent of the play's total reserves is contained in pools discovered prior to 1975. The most recent discoveries, prior to this study's cutoff date of January 1, 1995, were in 1993.

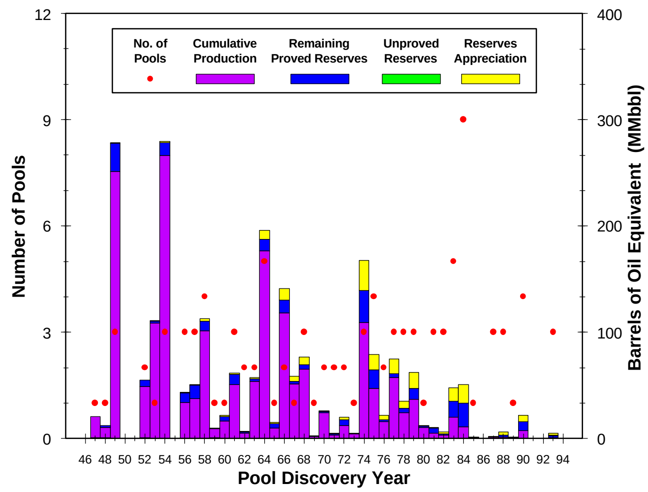


Figure 2. Exploration history graph.

The 104 discovered pools range in size from 0.007 to 173.200 MMBOE. These pools contain 791 reservoirs, of which 504 are nonassociated gas, 215 are undersaturated oil, and 72 are saturated oil.

Of the 61 plays in the Gulf of Mexico Region, the UM1 P play ranks as the eighth largest, based on BOE total reserves (5%) and BOE cumulative production (6%).

Table 1. Characteristics of the discovered pools.

104 Pools (424 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	9	66	379
Subsea depth (feet)	3,771	9,675	17,425
Number of sands per pool	1	4	37
Porosity	14%	28%	34%
Water saturation	10%	29%	55%

Assessment Results

The marginal probability of hydrocarbons for the UM1 P play is 1.00. The play ranks within the largest one-fourth of all 61 Gulf of Mexico plays, based on a mean total endowment of 0.597 Bbo and 9.926 Tcfg (2.363 BBOE) (table 2). Seventy-seven percent of this BOE mean total endowment has been produced.

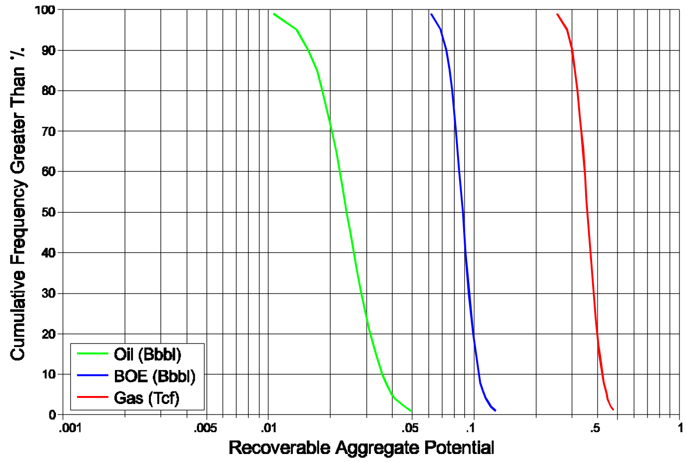


Figure 3. Cumulative probability distribution.

Assessment results indicate that undiscovered resources have a range of 0.014 to 0.040 Bbo and 0.283 to 0.441 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.025 Bbo and 0.359 Tcfg (0.089 BBOE). These undiscovered resources may occur in as many as 20 pools. The largest undiscovered pool, with a mean size of 12.831 MMBOE, is modeled as the fortieth largest pool in the play (figure 4). For all the undiscovered pools in the UM1 P play, the mean mean size is 4.448 MMBOE, which is substantially smaller than the 21.870 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 19.060

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	103	0.535	8.772	2.096
Cumulative production	--	0.475	7.623	1.831
Remaining proved	--	0.060	1.149	0.265
Unproved	1	<0.001	0.003	0.001
Appreciation (P & U)	--	0.037	0.792	0.178
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.014	0.283	0.069
Mean	20	0.025	0.359	0.089
5th percentile	--	0.040	0.441	0.113
Total Endowment				
95th percentile	--	0.586	9.850	2.343
Mean	124	0.597	9.926	2.363
5th percentile	--	0.612	10.008	2.387

MMBOE.

In the Texas offshore, limited potential exists downdip of the discovered fields where wells have not penetrated deep enough to reach UM1 P sediments. In the Louisiana offshore, the density of wells that encounter UM1 P deposits is high; thus, limited interfield exploration potential exists. Because of this limited potential, undiscovered resources are projected to occur in small pools, which add only 4 percent to the play's BOE mean total endowment.

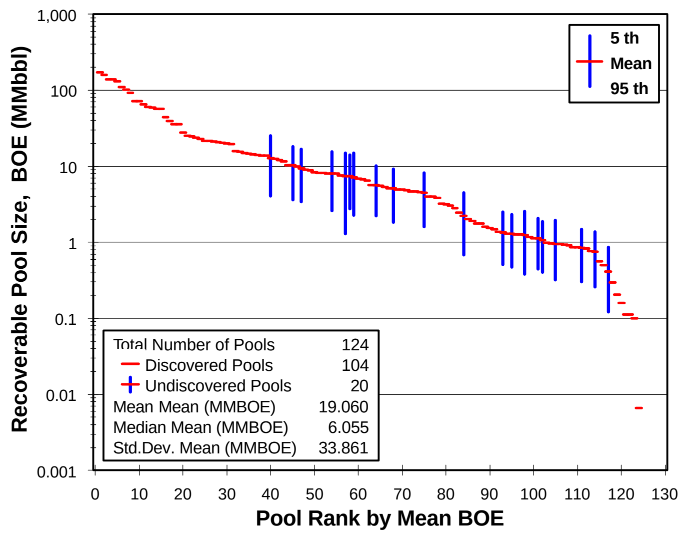


Figure 4. Pool rank plot.

LOWER UPPER MIOCENE FAN (UM1 F) PLAY

PLAY DESCRIPTION

The established Lower Upper Miocene Fan (UM1 F) play occurs at the *Discorbis* 12 biozone. This play extends from the South Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the play is bounded by the shelf/slope break associated with the *Discorbis* 12 biozone and grades into the sediments of the Lower Upper Miocene Progradational (UM1 P) play. To the northeast, the UM1 F play is bounded by the Cretaceous carbonate shelf edge. To the southwest, the UM1 F play extends into Mexican national waters. The southern extension of the play's potential to at least the Sigsbee Escarpment is supported by UM1 sand development in the OCS G07955-1 well in the Mississippi Canyon 731 field ("Mensa") and in the OCS G08496-1 well in Mississippi Canyon block 657.

The updip extent of the UM1 fan sequence is located farther basinward than that of the upper middle Miocene (MM9) chronozone. The UM1 chronozone is the oldest chronozone in which the updip sequence boundary of the fan facies is located predominately in the present-day Federal offshore.

PLAY CHARACTERISTICS

The productive UM1 F play consists of deepwater turbidites deposited in fan systems as channel fill, overbank deposits, and fringe sheet sediments on the UM1 slope. Major structural features in the play are growth faults, anticlines, and salt diapirs. Normal faults and stratigraphic pinch-outs occur less commonly. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting,

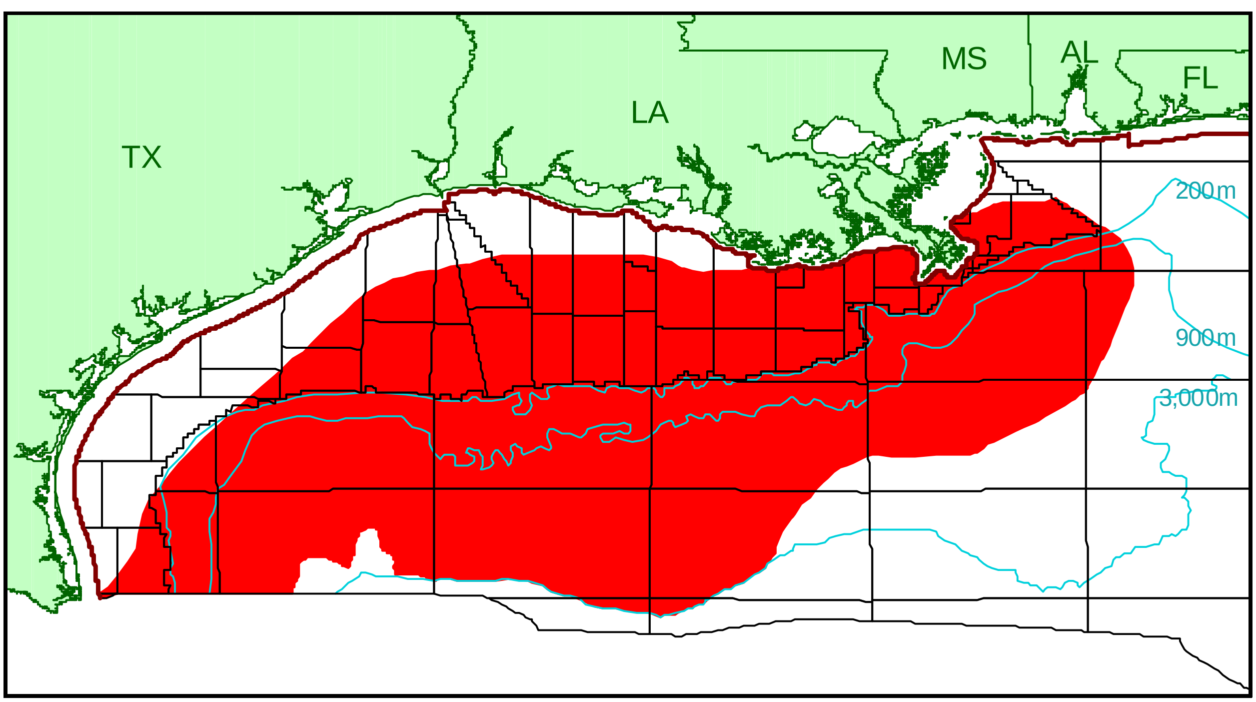


Figure 1. Map of assessed play.

diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive fan depositional environments, structures, or seals.

Main Pass 311 is the type field, and Chevron USA Inc.'s M30 sand represents the UM1 F play in this field.

DISCOVERIES

The UM1 F play is predominantly a mixed oil and gas play, with total reserves of 0.192 Bbo and 2.538 Tcfg (0.643 BBOE), of which 0.037 Bbo and 0.590 Tcfg (0.142 BBOE) have been produced. The play contains 75 producible sands in 25 pools, and 22 of these pools contain proved reserves (table 1). The first reserves in the play were discovered in the West Delta 58 field in 1954 (figure 2). The maximum yearly total reserves of 229.028 MMBOE were added in 1984 when three pools were discovered, including the largest pool in the play in the Viosca Knoll 783 field ("Tahoe"). Over 50 percent of the play's cumulative production occurred from pools discovered prior to 1965. However, 65 percent of the play's total reserves occur in the Mensa and Tahoe deepwater fields discovered in the mid-1980's. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1991.

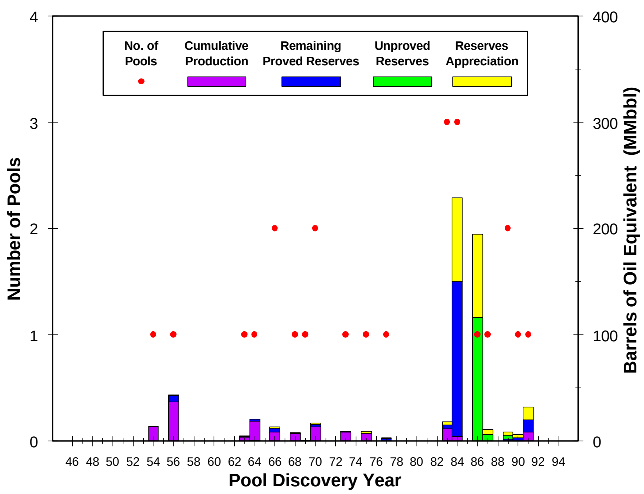


Figure 2. Exploration history graph.

The 25 discovered pools range in size from 0.056 to 224.302 MMBOE. These pools contain 119 reservoirs, of which 78 are nonassociated gas, 35 are undersaturated oil, and 6 are saturated oil.

Table 1. Characteristics of the discovered pools.

25 Pools (75 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	29	758	7,500
Subsea depth (feet)	6,396	12,383	18,050
Number of sands per pool	1	3	10
Porosity	14%	27%	33%
Water saturation	16%	29%	50%

Assessment Results

The marginal probability of hydrocarbons for the UM1 F play is 1.00. The play ranks within the largest one-third of all 61 Gulf of Mexico Region plays, based on a mean total endowment of 0.529 Bbo and 6.176 Tcfg (1.627 BBOE) (table 2). Nine percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources range from 0.268 to 0.416 Bbo and 3.111 to 4.232 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.337 Bbo and 3.638 Tcfg (0.984 BBOE). These undiscovered resources may occur in as many as 85 pools. The largest undiscovered pool, with a mean size of 104.730 MMBOE, is modeled as the third largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 4, 5, 6, and 7 on the pool rank plot. For all the undiscovered pools in the UM1 F play, the mean mean size is 11.576 MMBOE, which is significantly smaller than the 25.740 MMBOE mean size of the

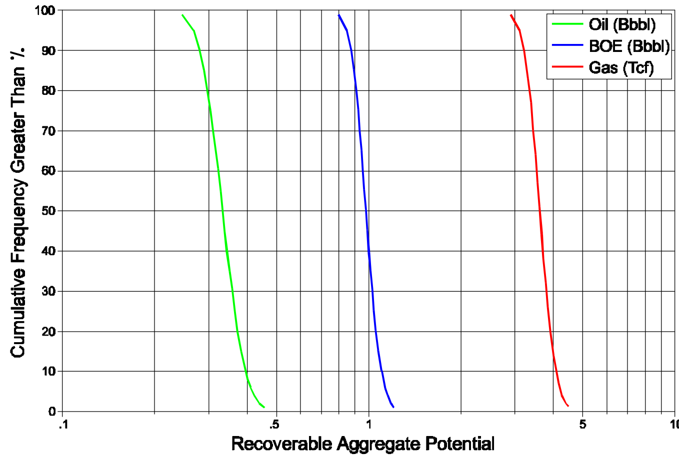


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	22	0.123	1.146	0.327
Cumulative production	--	0.037	0.590	0.142
Remaining proved	--	0.085	0.556	0.184
Unproved	3	0.013	0.638	0.127
Appreciation (P & U)	--	0.056	0.754	0.190
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.268	3.111	0.846
Mean	85	0.337	3.638	0.984
5th percentile	--	0.416	4.232	1.141
Total Endowment				
95th percentile	--	0.460	5.649	1.489
Mean	110	0.529	6.176	1.627
5th percentile	--	0.608	6.770	1.784

discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 14.795 MMBOE.

Of the 61 Gulf of Mexico plays, the UM1 F play is projected to contain the tenth largest amounts of mean undiscovered oil and gas resources, both at 4 percent.

Because of the large unexplored area of this play, numerous undiscovered pools are expected to be added to the play. These undiscovered resources account for 60 percent of the play's BOE mean total endowment. On the pool rank plot, the projected undiscovered pools are interspersed throughout the entire range of discovered pool sizes. Hydrocarbon potential exists downdip of discovered fields, especially in areas of present-day water depths greater than 1,000 feet. Deepwater drilling results indicate the presence of well-developed UM1 reservoir-quality sands.

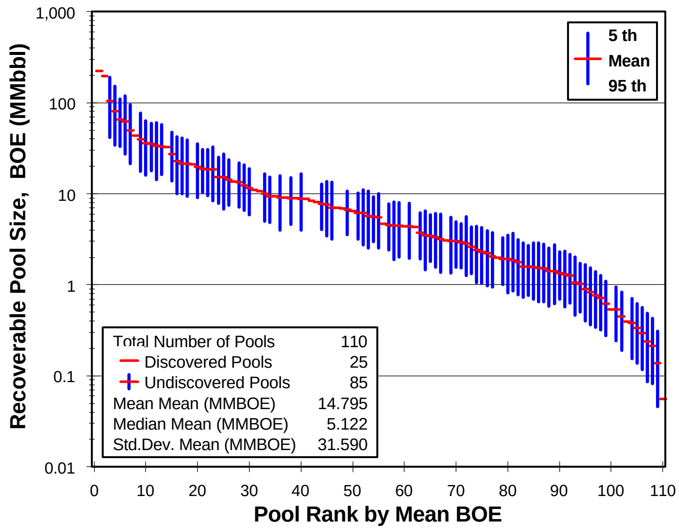


Figure 5. Pool rank plot.

UPPER MIDDLE MIOCENE (MM9) CHRONOZONE

CHRONOZONE DESCRIPTION

The Upper Middle Miocene (MM9) chronozone corresponds to the *Textularia* "W" and *Bigenerina* 2 biozones. The MM9 section reflects delta systems prograding onto the continental shelf and fan deposition on the continental slope of the Gulf of Mexico Basin. Depositional styles present in the MM9 chronozone include aggradational, progradational, and fan, each of which defines one or more plays: the Upper Middle Miocene Aggradational (MM9 A) play, the Upper Middle Miocene Progradational (MM9 P) play, the Upper Middle Miocene Fan (MM9 F) play, and the Upper Middle Miocene Aggradational/Progradational (MM9 AP) play. Retrogradational sands associated with marine transgressions also occur locally in the play areas at the top of the progradational and aggradational deposits. Because these retrogradational sands are discontinuous over any significant distance, they are included as part of these underlying deposits. The remaining play in the MM9 chronozone, the Upper Middle Miocene Structural Retrogradational/Aggradational/Progradational (MM9 RAP) play, is defined by its structural limits due to faulting.

The potential for sand development within the MM9 chronozone extends from the South Padre Island Area offshore Texas to the western edges of the Pensacola, Destin Dome, and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). Updip, MM9 sands extend onshore into Texas and Louisiana. To the southwest, sand potential extends into Texas offshore State waters and Mexican national waters. To the northeast, MM9 sands extend onshore into Mississippi and Alabama. The downdip limit extends at least as far as the Sigsbee Escarpment as indicated by MM9 sand development in the OCS G08512-1 well in Atwater block 471.

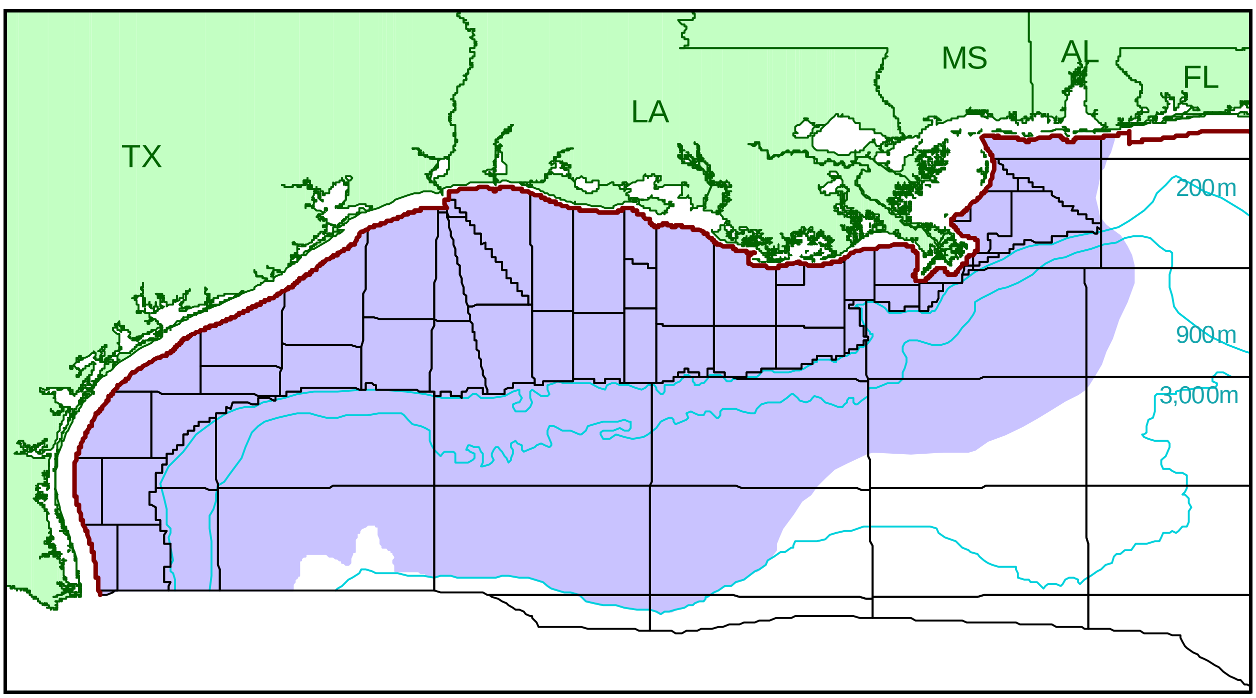


Figure 1. Map of assessed chronozone.

Productive and established sand locations in the MM9 chronozone are a result of two ancient depocenters, one in the Texas area and the other in the Louisiana area. In the offshore Texas area, areally smaller productive plays are observed in the MM9 chronozone as compared with the underlying middle middle Miocene (MM7) chronozone, reflecting lesser amounts of clastic influx from the ancient Texas area delta systems.

In the offshore Louisiana area, the MM9 depocenter had migrated eastward in comparison with the MM7 depocenter. Productive progradational and fan deposits in the MM9 chronozone are observed east of the present-day Mississippi River Delta, whereas in the MM7 chronozone, only one small areas of productive fan deposits are observed in that same area. The deposits of MM9 time are also observed farther offshore of Louisiana than MM7 deposits because of the seaward progradation of deltaic deposits from the ancestral Mississippi River.

Major structural features in the MM9 chronozone include normal faults, anticlines, and growth faults. Less common structures include salt diapirs, stratigraphic pinch-outs, and salt ridges.

DISCOVERIES

The MM9 chronozone contains 98 discovered pools in five plays (table 1). Total reserves in the chronozone are 0.658 Bbo and 8.929 Tcfg (2.247 BBOE), of which 0.225 Bbo and 5.313 Tcfg (1.171 BBOE) have been produced. The largest number of discoveries in the MM9 chronozone occurred when seven pools were added in both 1976 and 1990 (figure 2). However, the maximum yearly total reserves of 478.516 MMBOE were added in 1985 with the discovery of five pools.

Of the five plays in the MM9 chronozone, the MM9 P play contains the most total reserves in 63 pools, with 0.128 Bbo and 6.112 Tcfg (1.215 BBOE).

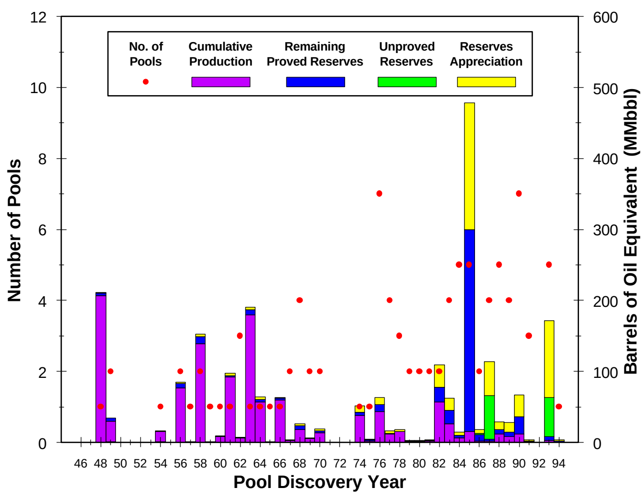


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

98 Pools (244 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	11	228	5,149
Subsea depth (feet)	2,129	8,794	18,800
Number of sands per pool	1	2	10
Porosity	18%	28%	35%
Water saturation	13%	30%	66%

ASSESSMENT RESULTS

The MM9 chronozone contains 220 pools (discovered plus undiscovered), with a mean total endowment estimated at 0.998 Bbo and 14.461 Tcfg (3.571 BBOE) (table 2).

Assessment results indicate that undiscovered resources may occur in as many as 122 pools, which contain a range of 0.238 to 0.465 Bbo and 4.649 to 6.515 Tcfg at the 95th and 5th percentiles, respectively (figure 3). At mean levels, 0.340 Bbo and 5.532 Tcfg (1.324 BBOE) are projected. These undiscovered resources represent 37 percent of the MM9 chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the fourth largest in the chronozone (figure 4).

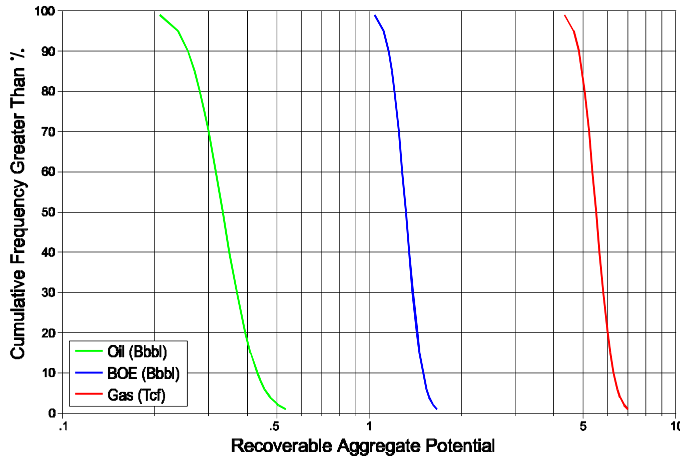


Figure 3. Cumulative probability distribution.

Of the five MM9 plays, the MM9 F play is projected to contain the greatest exploration potential, with mean undiscovered resources estimated at 0.317 Bbo and 4.365 Tcfg (1.094 BBOE) remaining to be found in 86 pools. These undiscovered resources in the MM9 F play represent 31 percent of the BOE mean total endowment for the MM9

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	94	0.391	6.926	1.624
Cumulative production	--	0.225	5.313	1.171
Remaining proved	--	0.166	1.614	0.453
Unproved	4	0.065	0.295	0.118
Appreciation (P & U)	--	0.201	1.708	0.505
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.238	4.649	1.116
Mean	122	0.340	5.532	1.324
5th percentile	--	0.465	6.515	1.555
Total Endowment				
95th percentile	--	0.896	13.578	3.363
Mean	220	0.998	14.461	3.571
5th percentile	--	1.123	15.444	3.802

chronozone. This high percentage, the potential for good MM9 sand development in deepwater areas, and the potential for numerous discoveries within a large unexplored area make the MM9 F play an attractive exploration target in MM9 strata.

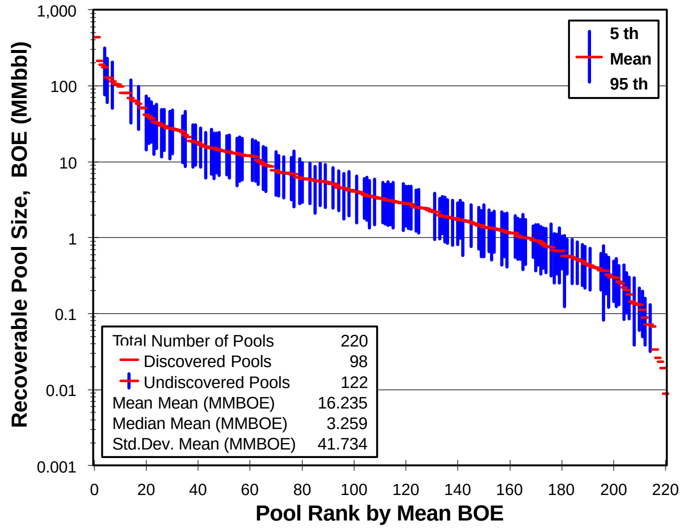


Figure 4. Pool rank plot.

UPPER MIDDLE MIOCENE STRUCTURAL RETROGRADATIONAL/ AGGRADATIONAL/PROGRADATIONAL (MM9 RAP) PLAY

PLAY DESCRIPTION

The established Upper Middle Miocene Structural Retrogradational/Aggradational/ Progradational (MM9 RAP) play occurs within the *Textularia* "W" and *Bigenerina* 2 biozones. The play is defined by its structural position on the downthrown side of the regional Corsair Fault System and is commonly referred to as a "Corsair" play. It extends in a narrow band from the Mustang Island East Addition Area northeastward parallel to the Texas coastline to the central Galveston Area (figure 1).

Updip, the play is bounded by the regional extent of the Corsair Fault System. To the northeast, southwest, and downdip, the play is bounded by the relatively thin, unexpanded sediments of the Upper Middle Miocene Progradational (MM9 P) play not associated with deposition along the Corsair Fault System.

The MM9 RAP play represents the youngest deposition included in the structurally controlled plays of the Corsair Fault System. The underlying Middle Middle Miocene Structural Retrogradational/Aggradational/Progradational/Fan (MM7 RAPF) play contains productive fan sands, unlike the MM9 RAP play. The two plays generally occur in the same geographic location, as both are controlled by the Corsair Fault System.

PLAY CHARACTERISTICS

The productive MM9 RAP play consists of stacked sequences of retrogradational, aggradational, and progradational sands located downthrown to the Corsair Fault in offshore Texas. The presence of these three depositional systems associated with the

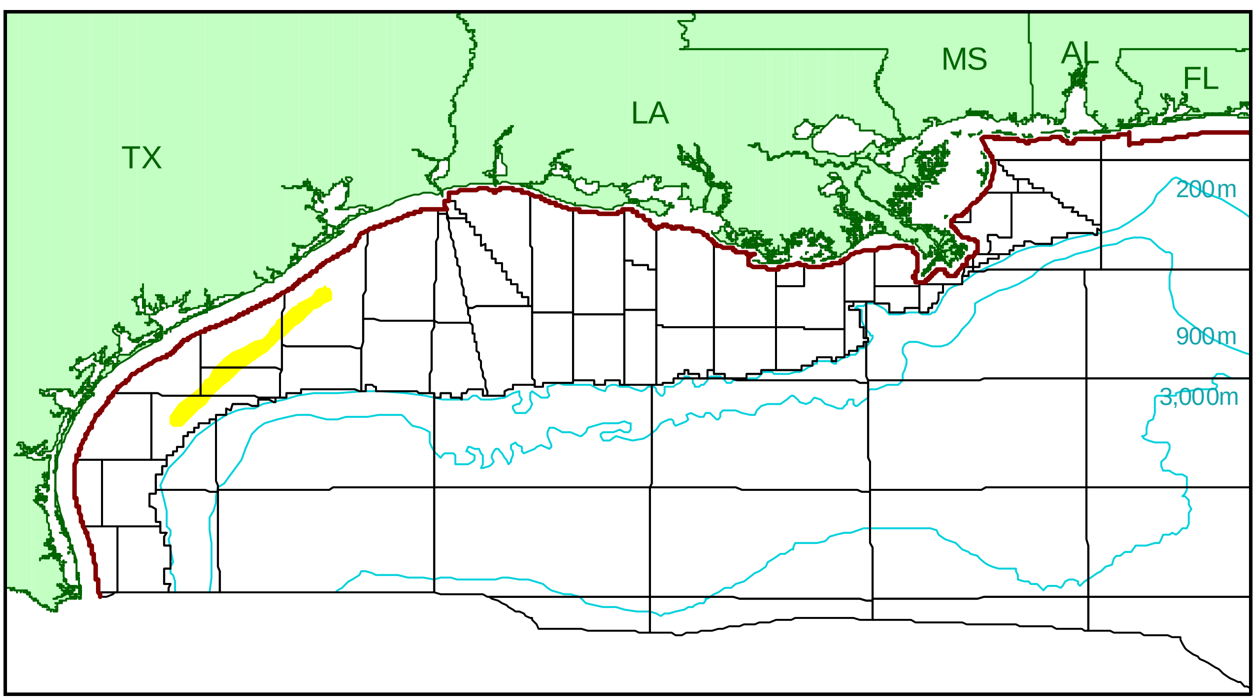


Figure 1. Map of assessed play.

Corsair Fault System accounts for the combination RAP play name. The progradational deposits dominate the 33 producible sands in the MM9 RAP play, with two-thirds of the total.

During MM9 time, growth fault movement occurred in response to a rapid influx of progradational and aggradational sands during periods of lowstand. Reworking of these sands during the *Bigenerina* 2 marine transgression produced the retrogradational deposits that locally cap the MM9 aggradational and progradational sediments. The MM9 section is greatly expanded on the downthrown side of the Corsair Fault. Because sand accumulation was so influenced by structural movement of the fault, the play is considered to be structurally controlled, rather than depositionally controlled.

The major structural feature of the MM9 RAP play is growth faults of the Corsair Fault System, with normal faults, anticlines, and salt diapirs occurring less frequently. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Galveston 350 is the type field, and Walter Oil and Gas Corporation's TEXW1A, TEXW1B, TEXW2, and BIG 2-K sands represent the MM9 RAP play in this field.

DISCOVERIES

The MM9 RAP gas play contains total reserves of 0.387 MMbo and 130.004 Bcfg (23.520 MMBOE), of which 0.187 MMbo and 62.971 Bcfg (11.391 MMBOE) have been produced. The play contains 33 producible sands in 11 pools (table 1). The play began in 1969 when the maximum yearly total reserves of 6.435 MMBOE were found in two pools (figure 2). However, the largest pool in the play was discovered in 1976 in the Brazos 70A field. Over 75 percent of the play's cumulative production occurred from pools discovered during the 1970's or earlier. However, over 60 percent of the total remaining reserves were added

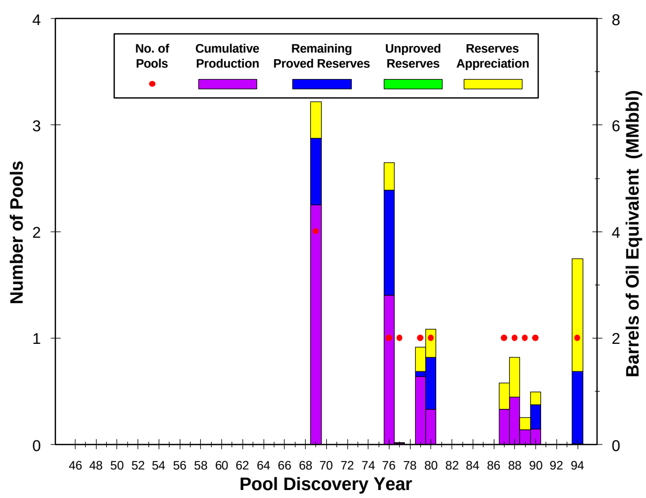


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

11 Pools (33 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	80	112	202
Subsea depth (feet)	5,457	6,866	8,940
Number of sands per pool	1	3	8
Porosity	21%	28%	34%
Water saturation	21%	36%	51%

in 1980 or later. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1994.

The 11 discovered pools range in size from 0.023 to 5.292 MMBOE. These pools contain 40 reservoirs, all of which are nonassociated gas.

Of the total reserves in both the MM9 RAP and MM7 RAPF plays, the MM9 RAP play contains only 5 percent.

Assessment Results

The marginal probability of hydrocarbons for the MM9 RAP play is 1.00. The play ranks within the smallest one-fourth of all 61 Gulf of Mexico Region plays, based on a mean total endowment of less than 0.001 Bbo and 0.148 Tcfg (0.027 BBOE) (table 2). Forty-three percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered oil resources are insignificant (<0.001 Bbbl) and that undiscovered gas resources have a range of 0.014 to 0.022 Tcf at the 95th and 5th percentiles, respectively (figure 3). The estimated amount of mean

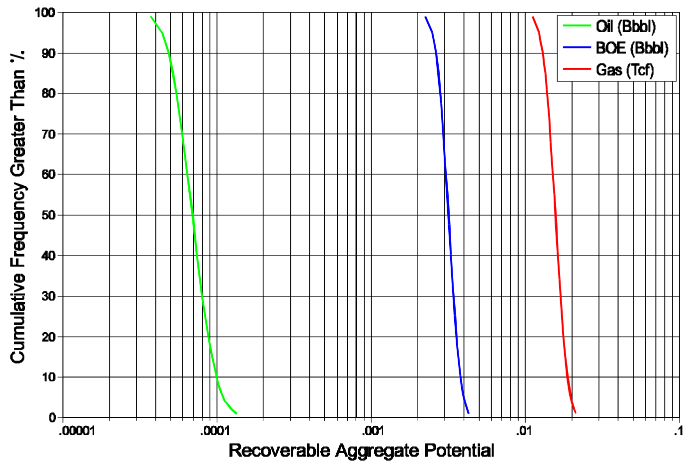


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	11	<0.001	0.097	0.017
Cumulative production	--	<0.001	0.063	0.011
Remaining proved	--	<0.001	0.034	0.006
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.033	0.006
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.014	0.002
Mean	7	<0.001	0.018	0.003
5th percentile	--	<0.001	0.022	0.004
Total Endowment				
95th percentile	--	<0.001	0.144	0.026
Mean	18	<0.001	0.148	0.027
5th percentile	--	<0.001	0.152	0.028

undiscovered gas is 0.018 Tcf (0.003 BBOE). These undiscovered resources may occur in as many as seven pools. The largest undiscovered pool, with a mean size of 0.933 MMBOE, is modeled as the tenth largest pool in the play (figure 4). For all the undiscovered pools in the MM9 RAP play, the mean mean size is 0.457 MMBOE, which is smaller than the 2.138 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 1.484 MMBOE.

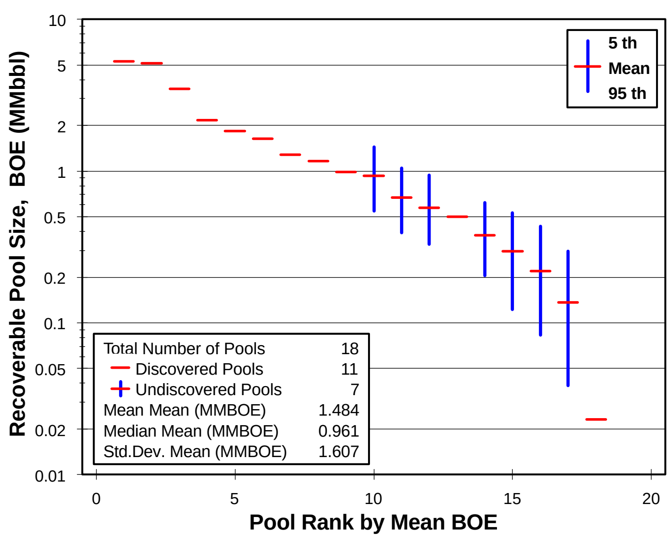


Figure 4. Pool rank plot.

The MM9 RAP play is well drilled and is limited in geographic extent by the Corsair Fault System. Undiscovered resources are expected to account for only 11 percent of the play's BOE mean total endowment. Limited potential between discovered fields exists for additional structural traps along the Corsair Fault System.

UPPER MIDDLE MIOCENE AGGRADATIONAL (MM9 A) PLAY

PLAY DESCRIPTION

The established Upper Middle Miocene Aggradational (MM9 A) play occurs within the *Textularia* "W" and *Bigenerina* 2 biozones. This play extends northeastward from the North Padre Island Area offshore Texas through the West Cameron Area offshore Louisiana (figure 1).

Updip and along strike, the play continues onshore into Texas and Louisiana. Downdip, the play grades into the deposits of the Upper Middle Miocene Progradational (MM9 P) play. Additionally, downdip along the extent of the regional Corsair Fault System, the MM9 A play is bounded by the sediments of the Upper Middle Miocene Structural Retrogradational/Aggradational/Progradational (MM9 RAP) play.

The middle middle Miocene (MM7) and MM9 aggradational deposits occur in the same general geographic area, indicating little shift in the depocenter location from MM7 to MM9 time.

PLAY CHARACTERISTICS

The productive MM9 A play consists of delta plain and shallow-marine shelf deposits that include channel/levee complexes, barrier bars, and distributary mouth bar sands. In addition, retrogradational sands locally cap the MM9 A play. Because these retrogradational, reworked sands are so discontinuous, they are included as part of the MM9 A play. The major structural feature is anticlines which, when faulted, form the traps in the play. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). The paucity of seals in the typically sand-rich aggradational environment accounts for the

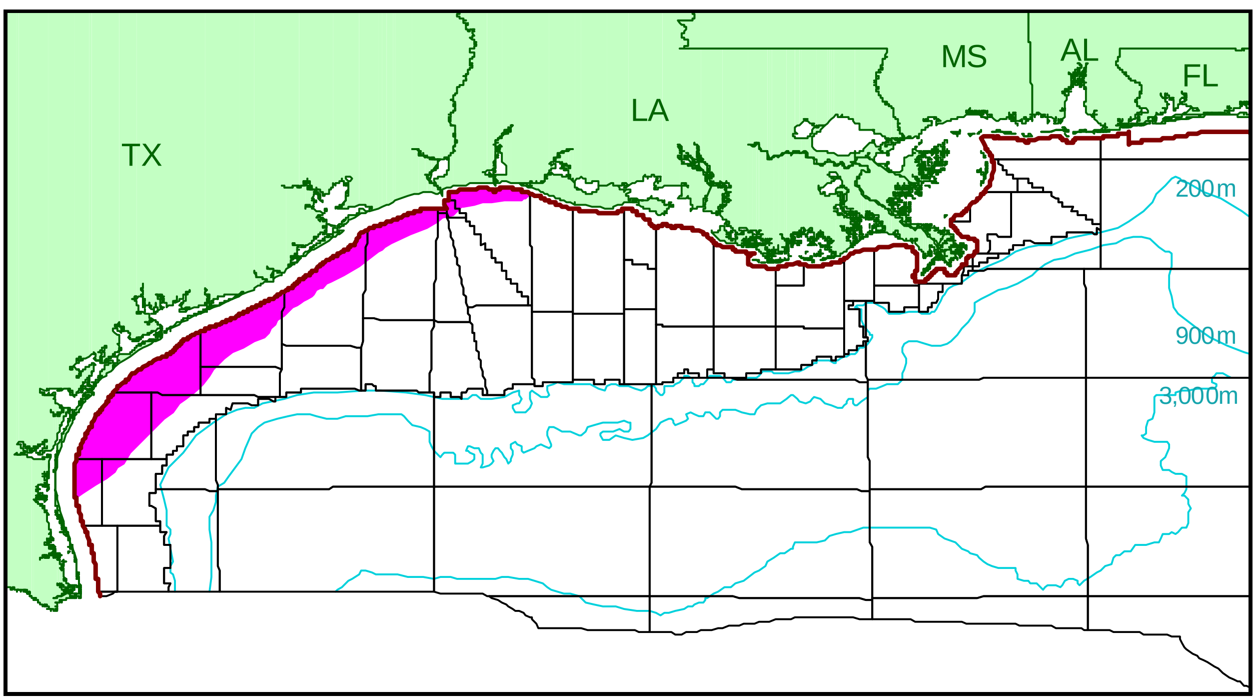


Figure 1. Map of assessed play.

low number of productive sands in the play. Future discoveries are not limited to the aforementioned productive aggradational depositional environments, structures, or seals.

Matagorda Island 7A is the type field, and Taylor Energy Company's I, J, K, and L sands represent the MM9 A play in this field.

DISCOVERIES

The MM9 A gas play contains total reserves of 0.842 Mbo and 26.326 Bcfg(4.685 MMBOE), of which 0.563 Mbo and 19.015 Bcfg (3.384 MMBOE) have been produced. The play contains seven producible sands in two pools (table 1). These two pools are in the Matagorda Island 665 and 7A fields and contain 3.327 and 1.358 MMBOE, respectively (figure 2). Both pools were discovered in 1977.

The two discovered pools contain eight reservoirs, all of which are nonassociated gas.

Of the 11 aggradational plays in the Gulf of Mexico Cenozoic Province, the MM9 A play contains the smallest amount of total reserves (<1%).

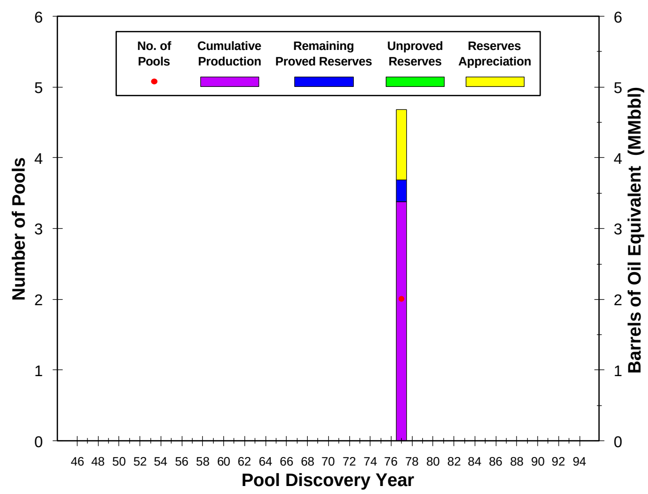


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

2 Pools (7 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	72	132	192
Subsea depth (feet)	2,129	2,913	3,696
Number of sands per pool	3	4	4
Porosity	29%	29%	29%
Water saturation	26%	27%	27%

ASSESSMENT RESULTS

Because of limited data for the MM9 A play, the Middle Middle Miocene Aggradational (MM4 A) play was used as an analog to model pool sizes in the MM9 A play. The MM4 A play was selected as the analog because of similarities in depositional setting, structural style, hydrocarbon type, and statistical information.

The marginal probability of hydrocarbons for the MM9 A play is 1.00. The play ranks within the smallest one-fourth of all 61 Gulf of Mexico plays, based on a mean total endowment of less than 0.001 Bbo and 0.057 Tcfg (0.011 BBOE) (table 2). Thirty-two percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered oil resources are insignificant (<0.001 Bbbl) and that undiscovered gas resources have a range of 0.021 to 0.044 Tcf at the 95th and 5th percentiles, respectively (figure 3). The estimated amount of mean undiscovered gas is 0.031 Tcf (0.006 BBOE). These undiscovered resources may occur in as many as four pools. The largest undiscovered pool, with a mean size of 2.795 MMBOE, is modeled as the second largest pool in the play (figure 4). The model results place the three other undiscovered pools in positions 3, 5, and 6 on the pool rank plot. For the four undiscovered pools in the MM9 A play, the mean mean size is 1.396 MMBOE, which is smaller than the 2.343 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 1.711 MMBOE.

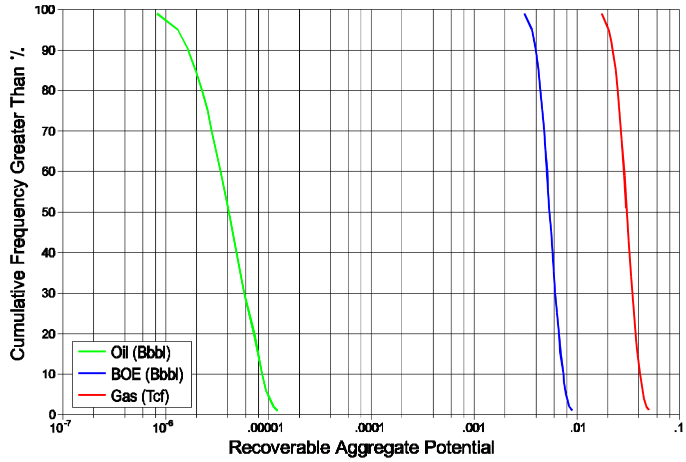


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	2	<0.001	0.021	0.004
Cumulative production	--	<0.001	0.019	0.003
Remaining proved	--	<0.001	0.002	<0.001
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.006	0.001
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.021	0.004
Mean	4	<0.001	0.031	0.006
5th percentile	--	<0.001	0.044	0.008
Total Endowment				
95th percentile	--	<0.001	0.047	0.009
Mean	6	<0.001	0.057	0.011
5th percentile	--	<0.001	0.070	0.013

The highly explored MM9 A play offers minimal potential for discoveries because the existence of seals is problematic. Undiscovered resources are expected to contribute 56 percent to the play's BOE mean total endowment. However, in comparison with many other plays in the Gulf of Mexico, the total endowment for the MM9 A play is very small.

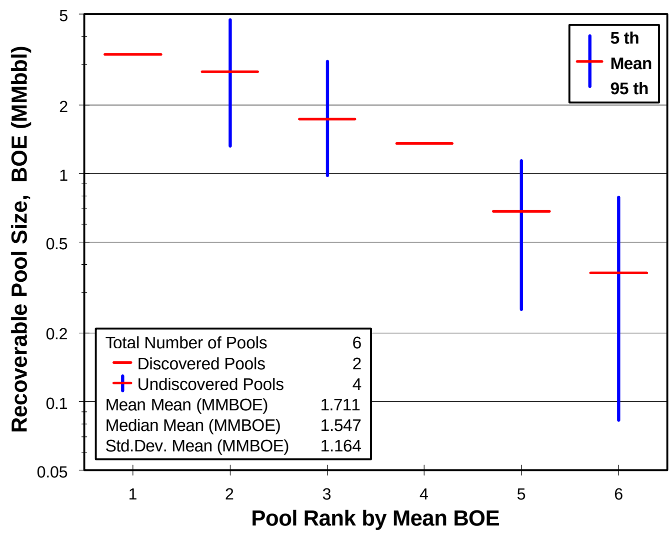


Figure 4. Pool rank plot.

UPPER MIDDLE MIOCENE AGGRADATIONAL/PROGRADATIONAL (MM9 AP) PLAY

PLAY DESCRIPTION

The established Upper Middle Miocene Aggradational/Progradational (MM9 AP) play occurs at the *Bigenerina* 2 biozone. This play is located in the Mobile, Pensacola, Chandeleur, Viosca Knoll, and Destin Dome Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the MM9 AP play continues onshore into Mississippi and Alabama. Downdip, the play is limited by a lack of sand in the distal end of the facies.

The MM9 chronozone is one of three chronozones with combined aggradational and progradational (AP) "Shallow Miocene Bright Spot Trend" plays. The other two chronozones are the lower upper Miocene (UM1) and the upper upper Miocene (UM3). The MM9 AP play represents the oldest productive sediments that overlie the Cretaceous carbonate shelf. The extent of the AP sequence in the MM9 chronozone is found in the same general geographical area as the AP sequences in the UM1 and UM3 chronozones, indicative of deposition on a stable shelf. Sediments for the AP plays were sourced from a major continental drainage system formed after the Laramide Orogeny and also from the Appalachian region. Clastic influx to the Cretaceous shelf area was much less than to the Louisiana area depocenter during middle and upper Miocene times. The middle middle Miocene (MM7) chronozone includes deposits of a similar depositional setting and geographic extent as the MM9 AP play. However, the MM7 chronozone in this area is extremely thin and sand poor and, therefore, not prospective.

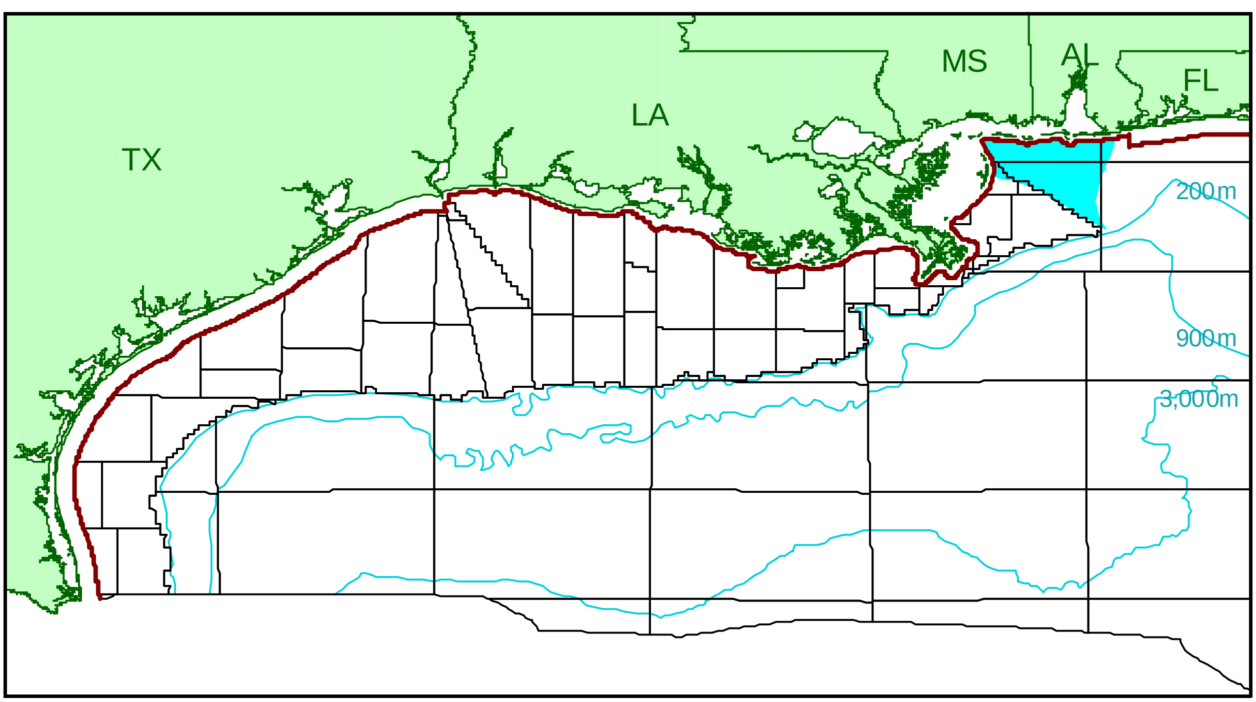


Figure 1. Map of assessed play.

PLAY CHARACTERISTICS

The MM9 AP play comprises incised-valley fill (channels) typical of a progradational setting, but because the channel sands are often stacked, they also have characteristics of an aggradational setting. Therefore, the play is referred to as a combination aggradational/progradational (AP) play. The play occurs at shallow depths overlying the Cretaceous carbonate shelf, and hydrocarbon accumulations are associated with seismic hydrocarbon indicators (bright spots). Regional dip dominates the structural style of the play. Faulting and local uplifts are rare and have no role in the accumulation of hydrocarbons. Channels cut across the regional dip of the shelf area, and their deposits are sealed by overlying and laterally adjacent Miocene shales.

Viosca Knoll 204 is the type field, and Murphy Exploration and Production's 3900 sand represents the MM9 AP play in this field.

DISCOVERIES

The MM9 AP gas play contains total reserves of 0.013 MMbo and 120.593 Bcfg (21.470 MMBOE), of which 0.001 MMbo and 19.656 Bcfg (3.499 MMBOE) have been produced. The play contains four producible sands in three pools (table 1). The maximum yearly total reserves were discovered in the first and largest pool in the play in the Viosca Knoll 204 field in 1986 (figure 2). The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1993.

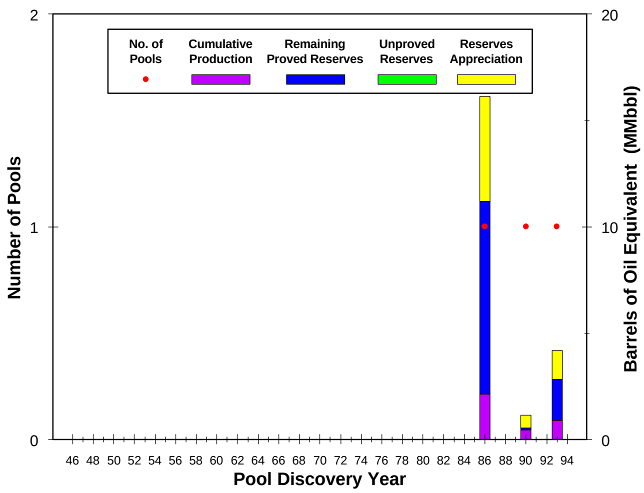


Figure 2. Exploration history graph.

The three discovered pools range in size from 1.160 to 16.124 MMBOE. These pools contain five reservoirs, all of which are nonassociated gas.

The MM9 AP play contains only 8 percent of the BOE total reserves in the three AP plays.

Table 1. Characteristics of the discovered pools.

3 Pools (4 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	46	77	121
Subsea depth (feet)	2,500	3,534	4,150
Number of sands per pool	1	1	2
Porosity	30%	32%	35%
Water saturation	28%	31%	35%

ASSESSMENT RESULTS

Because of limited data for the MM9 AP play, the Upper Upper Miocene Aggradational/Progradational (UM3 AP) play was used as an analog to model pool sizes in the MM9 AP play. The UM3 AP play was selected as the analog because of similarities in depositional setting, structural style, hydrocarbon type, and statistical information.

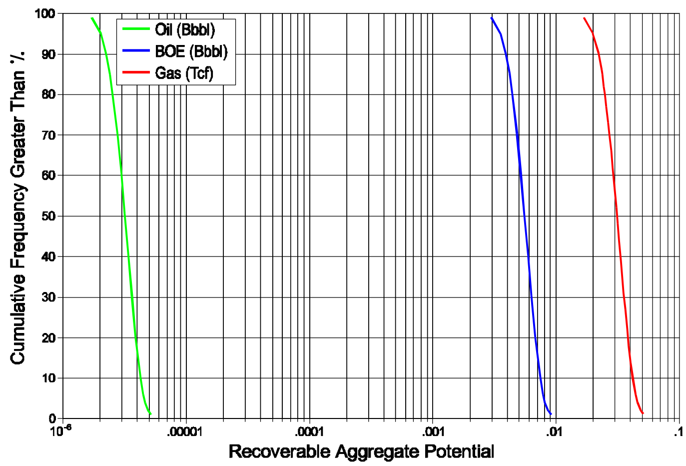


Figure 3. Cumulative probability distribution.

The marginal probability of hydrocarbons for the MM9 AP play is 1.00. The play ranks within the smallest one-fourth of all 61 Gulf of Mexico Region plays, based on a mean total endowment of less than 0.001 Bbo and 0.153 Tcfg (0.027 BBOE) (table 2). Thirteen percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered oil resources are negligible (<0.001 Bbbl) and that undiscovered gas resources have a range of 0.020 to 0.045 Tcf at the 95th and 5th percentiles, respectively (figure 3). The estimated amount of mean undiscovered gas is 0.032 Tcf (0.006 BBOE). These undiscovered resources may occur in as many as

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	3	<0.001	0.082	0.015
Cumulative production	--	<0.001	0.020	0.003
Remaining proved	--	<0.001	0.062	0.011
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.039	0.007
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.020	0.004
Mean	3	<0.001	0.032	0.006
5th percentile	--	<0.001	0.045	0.008
Total Endowment				
95th percentile	--	<0.001	0.141	0.025
Mean	6	<0.001	0.153	0.027
5th percentile	--	<0.001	0.166	0.029

three pools. The largest undiscovered pool, with a mean size of 3.130 MMBOE, is modeled as the third largest pool in the play (figure 4). The model results place the remaining two undiscovered pools in positions 4 and 6 on the pool rank plot. For all the undiscovered pools in the MM9 AP play, the mean mean size is 1.877 MMBOE, which is smaller than the 7.157 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 4.517 MMBOE.

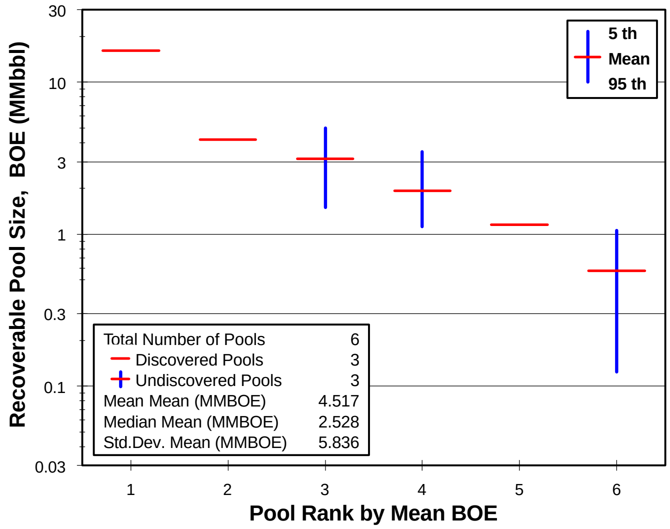


Figure 4. Pool rank plot.

Undiscovered pools in the MM9 AP play are anticipated to be about equal in number and size to the discovered pools and add only 22 percent to the play's BOE mean total endowment. The limited geographic extent of the play and small discovered field sizes reduce the potential for significant discoveries. Additionally, the AP stratigraphic section in the MM9 chronozone is relatively thinner and less sandy offshore than the AP sections in the UM1 and UM3 chronozones. Many wells drilled within the MM9 AP play's gepgraphic limits have not been deep enough to encounter the MM9 section, and therefore have not tested the play interval.

UPPER MIDDLE MIOCENE PROGRADATIONAL (MM9 P) PLAY

PLAY DESCRIPTION

The established Upper Middle Miocene Progradational (MM9 P) play occurs within the *Textularia* "W" and *Bigenerina* 2 biozones. This play extends from the South Padre Island Area of southernmost offshore Texas to the Chandeleur Area east of the present-day Mississippi River Delta (figure 1).

Updip in offshore Texas, the MM9 P play grades into the deposits of the Upper Middle Miocene Aggradational (MM9 A) play, while updip in Louisiana, the MM9 P play extends onshore. To the northeast, the MM9 P play is limited by the deposits of the Upper Middle Miocene Aggradational/Progradational (MM9 AP) play overlying the Cretaceous carbonate shelf. To the southwest, the MM9 P play continues onshore into Texas and into Mexican national waters. Downdip, the play grades into the deposits of the Upper Middle Miocene Fan (MM9 F) play. In parts of the Mustang Island, Matagorda Island, Brazos, and Galveston Areas, the MM9 P play is limited by the Upper Middle Miocene Structural Retrogradational/Aggradational/ Progradational (MM9 RAP) play.

Ancient delta systems in Louisiana and Texas supplied the sediments for the MM9 P play. The MM9 depocenter shifted basinward from middle middle Miocene (MM7) to MM9 time, as evidenced by the occurrence farther offshore of the MM9 progradational deposits in the offshore Louisiana area.

PLAY CHARACTERISTICS

The productive MM9 P play consists of progradational deltaic sediments deposited in delta fringe, shelf blanket, distributary mouth bar, channel, and crevasse splay environments. In addition, retrogradational sands locally cap the MM9 P play. Because

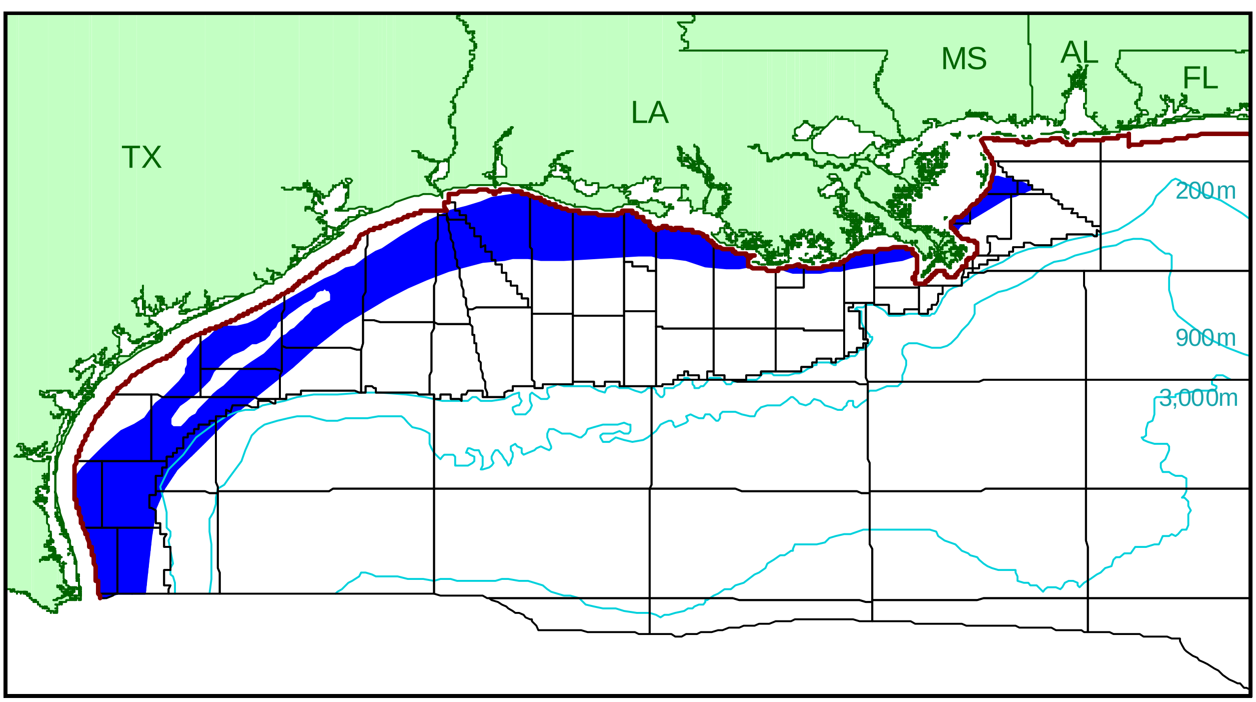


Figure 1. Map of assessed play.

these retrogradational, reworked sands are so discontinuous, they are included as part of the MM9 P play. Normal faults are the major structural feature in the play. Anticlines, growth faults, and salt diapirs and ridges are also present. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive progradational depositional environments, structures, or seals.

South Marsh Island 236 is the type field. Texaco Exploration and Production's TEXL4, TEXL4S, CIBN, and CIBN1 sands and Delmar Operating Inc.'s 38 and CIBCARST sands represent the MM9 P play in this field.

Discoveries

The MM9 P play is predominantly a gas play, with total reserves of 0.128 Bbo and 6.112 Tcfg (1.215 BBOE), of which 0.085 Bbo and 4.847 Tcfg (0.947 BBOE) have been produced. The play contains 151 producible sands in 63 pools (table 1). The first and largest pool in the play was discovered in the Vermilion 39 field in 1948 and accounts for the maximum yearly total reserves added to the play (figure 2). Discoveries have occurred at a steady rate throughout the play's exploration history. Over 75 percent of the play's cumulative production has been from discoveries prior to 1971. Though over half the discoveries occurred after 1975, they added only about 30 percent to the play's total reserves. The most recent discoveries, prior to this study's cutoff date of January 1, 1995, were in 1993.

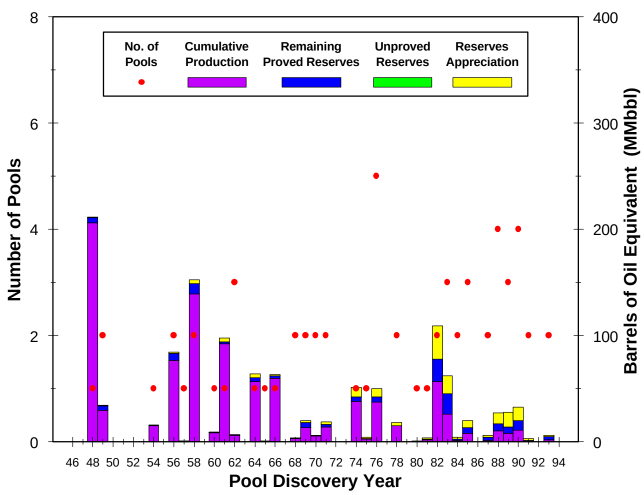


Figure 2. Exploration history graph.

The 63 discovered pools range in size from 0.019 to 210.898 MMBOE. These pools contain 290 reservoirs, of which 266 are nonassociated gas, 15 are undersaturated oil, and 9 are saturated oil.

Table 1. Characteristics of the discovered pools.

63 Pools (151 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	11	54	274
Subsea depth (feet)	3,807	8,733	16,052
Number of sands per pool	1	2	9
Porosity	21%	28%	33%
Water saturation	13%	29%	65%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the MM9 P play is 1.00. The play contains a mean total endowment of 0.150 Bbo and 7.198 Tcfg (1.430 BBOE) (table 2). Sixty-six percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.010 to 0.046 Bbo and 0.870 to 1.302 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.022 Bbo and 1.086 Tcfg (0.215 BBOE). These undiscovered resources may occur in as many as 22 pools. The largest undiscovered pool, with a mean size of 33.882 MMBOE, is modeled as the tenth largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 11, 13, 16, and 17 on the pool rank plot. For all the undiscovered pools in the MM9 P play, the mean mean size is 9.801 MMBOE, which is smaller than the 19.287 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and

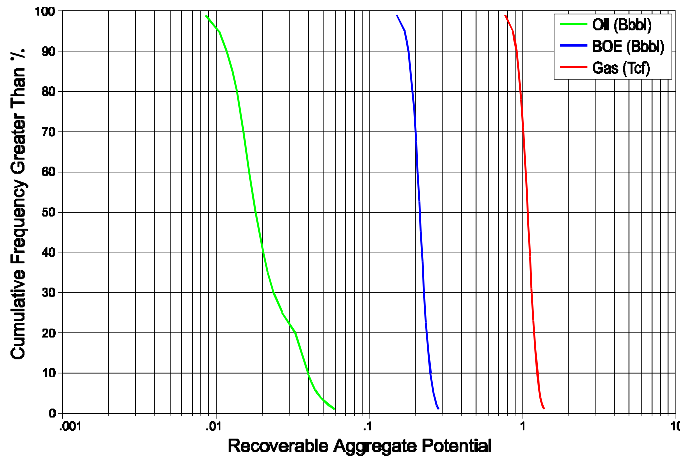


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	63	0.102	5.468	1.075
Cumulative production	--	0.085	4.847	0.947
Remaining proved	--	0.017	0.621	0.127
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.026	0.643	0.141
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.010	0.870	0.171
Mean	22	0.022	1.086	0.215
5th percentile	--	0.046	1.302	0.263
Total Endowment				
95th percentile	--	0.138	6.982	1.386
Mean	85	0.150	7.198	1.430
5th percentile	--	0.174	7.414	1.478

undiscovered, is 16.832 MMBOE.

The largest pools in this well-explored play are modeled as already discovered. Relative to the discovered pools, undiscovered pools are expected to range from small to moderate in size. Their contribution to the play's BOE mean total endowment is only 15 percent.

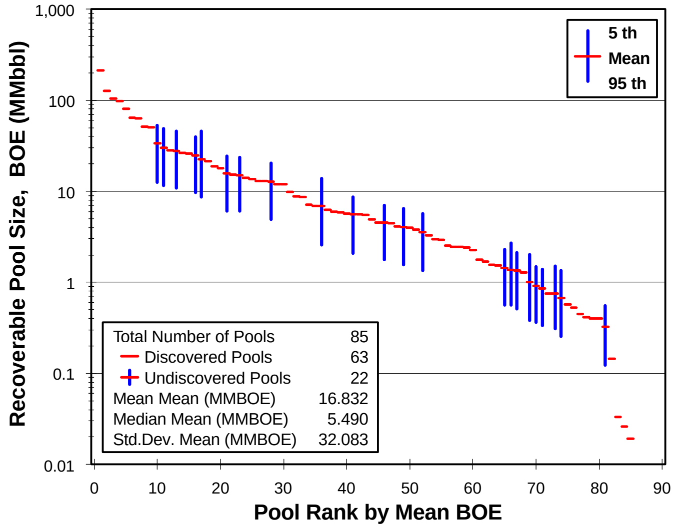


Figure 4. Pool rank plot.

UPPER MIDDLE MIOCENE FAN (MM9 F) PLAY

PLAY DESCRIPTION

The established Upper Middle Miocene Fan (MM9 F) play occurs within the *Textularia* “W” and *Bigenerina* 2 biozones. This play extends from the South Padre Island Area of southernmost offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the MM9 F play is bounded by the shelf/slope break associated with the *Bigenerina* 2 biozone and grades into the deposits of the Upper Middle Miocene Progradational (MM9 P) play, or it continues onshore into Louisiana. Northeastward, the MM9 F play is bounded by the Cretaceous carbonate shelf edge. Southwestward, the play extends into Texas offshore State waters and Mexican national waters. The southern extension of the play’s potential to at least the Sigsbee Escarpment is supported by MM9 sand development in the OCS G08512-1 well in Atwater block 471.

The thickest and most productive area of the MM9 F play lies east of the present-day Mississippi River Delta in the Main Pass and Viosca Knoll Areas. The MM9 shelf/slope break lies farther offshore than that of the middle middle Miocene (MM7) chronozone, indicating basinward progradation of the ancient delta systems.

PLAY CHARACTERISTICS

The productive MM9 F play consists of deepwater turbidites deposited in fan systems as channel fill, overbank deposits, fan lobes, slump sediments, and fringe sheet sediments on the MM9 slope. Anticlines are the major structural feature in the play, though normal faults, salt diapirs, and growth faults also occur. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting,

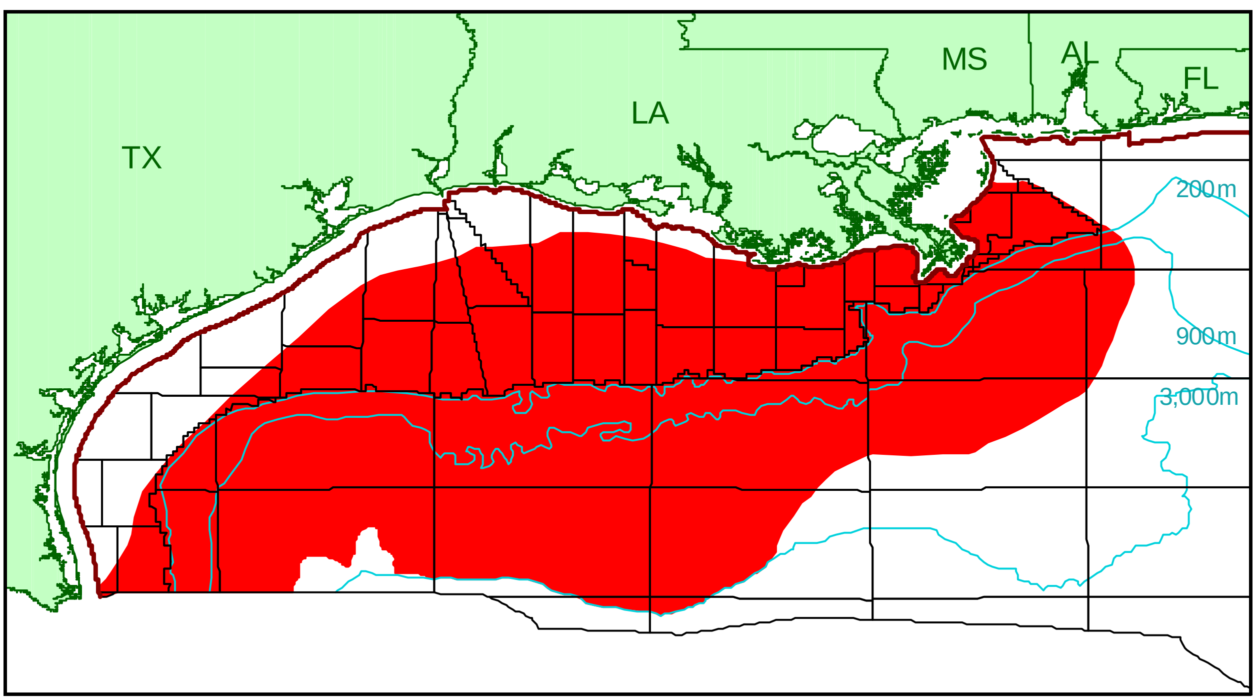


Figure 1. Map of assessed play.

diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive fan depositional environments, structures, or seals.

Main Pass 73 is the type field, and Mobil Oil Exploration and Production's C-9, CY-2A, CY-2B, BB-1, and BB-4 sands represent the MM9 F play in this field.

DISCOVERIES

The MM9 F mixed oil and gas play contains total reserves of 0.530 Bbo and 2.541 Tcfg (0.982 BBOE), of which 0.140 Bbo and 0.364 Tcfg (0.205 BBOE) have been produced. The play contains 49 producible sands in 19 pools (table 1), and 15 of these pools contain proved reserves. The first reserves in the play were discovered in the Eugene Island 89 field in 1959 (figure 2). Discoveries have occurred at a fairly consistent rate since the mid-1970's. The maximum yearly total reserves of 458.202 MMBOE were added in 1985 when two pools were discovered, including the largest pool in the play in the Viosca Knoll 956 field ("Ram-Powell"). Almost 90 percent of the play's cumulative production has come from the Main Pass 41 pool discovered in 1963, whereas over 80 percent of the total reserves have been found since 1974. Additionally, on a BOE basis, 32 percent of the play's cumulative production is gas, but remaining total reserves indicate that future production may increase to 50 percent gas. The most recent discoveries, prior to this study's cutoff date of January 1, 1995, were in 1993.

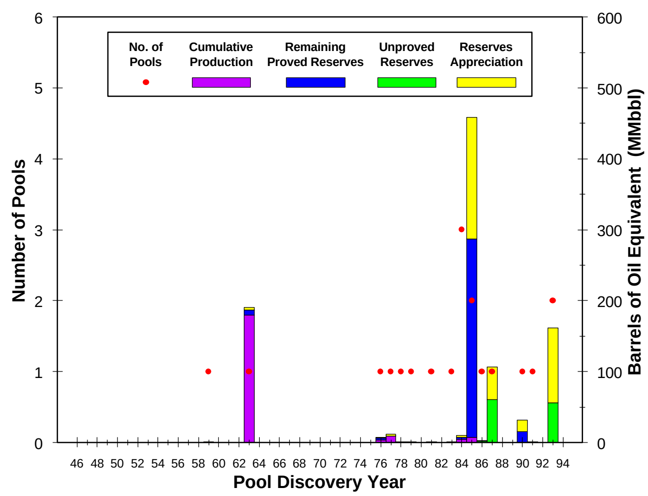


Figure 2. Exploration history graph.

The 19 discovered pools range in size from 0.009 to 432.623 MMBOE. These pools contain 67 reservoirs, of which 30 are nonassociated gas, 29 are undersaturated oil, and 8 are saturated oil.

Table 1. Characteristics of the discovered pools.

19 Pools (49 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	24	907	5,149
Subsea depth (feet)	8,826	11,562	18,800
Number of sands per pool	1	3	10
Porosity	18%	28%	30%
Water saturation	16%	31%	66%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the MM9 F play is 1.00. The play ranks within the largest one-third of all 61 Gulf of Mexico Region plays, based on a mean total endowment of 0.847 Bbo and 6.906 Tcfg (2.076 BBOE) (table 2). Ten percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.226 to 0.433 Bbo and 3.634 to 5.222 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.317 Bbo and 4.365 Tcfg (1.094 BBOE). These undiscovered resources may occur in as many as 86 pools. The largest undiscovered pool, with a mean size of 174.210 MMBOE, is modeled as the third largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 4, 5, 9, and 10 on the pool rank plot. For all the undiscovered pools in the MM9 F play, the mean mean size is 12.732 MMBOE, which is significantly smaller than the 51.685 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 19.780 MMBOE.

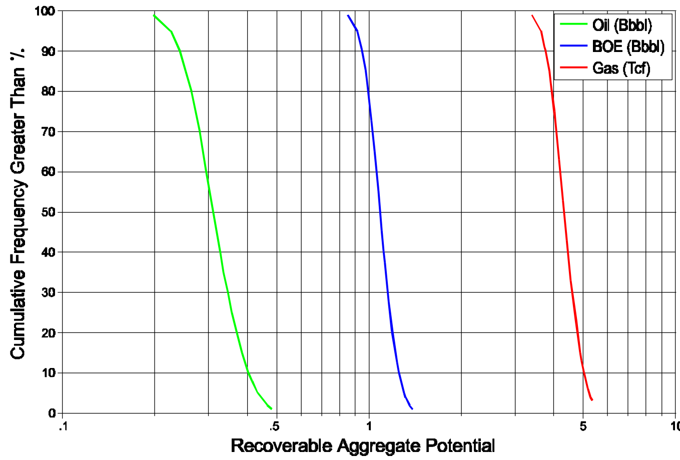


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	15	0.289	1.259	0.513
Cumulative production	--	0.140	0.364	0.205
Remaining proved	--	0.149	0.895	0.308
Unproved	4	0.065	0.295	0.118
Appreciation (P & U)	--	0.175	0.987	0.351
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.226	3.634	0.914
Mean	86	0.317	4.365	1.094
5th percentile	--	0.433	5.222	1.300
Total Endowment				
95th percentile	--	0.756	6.175	1.896
Mean	105	0.847	6.906	2.076
5th percentile	--	0.963	7.763	2.282

Of the 61 Gulf of Mexico plays, the MM9 F is projected to contain the fifth largest amount of mean undiscovered gas resources at 5 percent.

The continued exploration success and large unexplored area make the MM9 F play an attractive MM9 target for exploration in the Gulf of Mexico. The undiscovered pools are expected to be not only numerous but to include discoveries of significant size (>100 MMBOE). These undiscovered resoures account for 53 percent of the play's BOE mean total endowment.

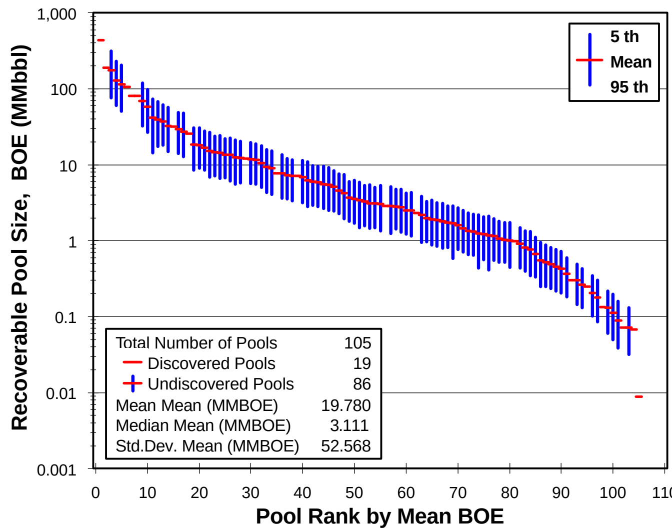


Figure 4. Pool rank plot.

In offshore Louisiana, most of the wells that penetrate MM9 fan deposits are located east of the present-day Mississippi River Delta. Potential in the MM9 fan deposits in offshore Louisiana exists downdip of these discovered fields, especially in water depths greater than 1,000 feet. The Ram-Powell field in 3,318 feet of water shows good sand development in this play interval.

Few wells have penetrated the MM9 F play in offshore Texas and central to western Louisiana because of the great drilling depths. The presence of good sand development in the shelfal aggradational and progradational sediments of the MM9 chronozone indicates that fan systems should have been deposited basinward throughout the area.

MIDDLE MIDDLE MIOCENE (MM7) CHRONOZONE

CHRONOZONE DESCRIPTION

The Middle Middle Miocene (MM7) chronozone corresponds to the *Cibicides opima, Cristellaria* "I," and *Bigenerina humblei* biozones. The MM7 section reflects delta systems prograding onto the continental shelf and fan deposition on the continental slope of the Gulf of Mexico Basin. Depositional styles present in the MM7 chronozone include retrogradational, aggradational, progradational, and fan, each of which defines a play: the Middle Middle Miocene Retrogradational (MM7 R) play, the Middle Middle Miocene Aggradational (MM7 A) play, the Middle Middle Miocene Progradational (MM7 P1) play, and the Middle Middle Miocene Fan (MM7 F) play. The two remaining plays in the MM7 chronozone are defined by their structural limits due to faulting: the Middle Middle Miocene Structural Progradational (MM7 P2) play and the Middle Middle Miocene Structural Retrogradational/Aggradational/Progradational/Fan (MM7 RAPF) play.

The potential for sand development within the MM7 chronozone extends from the South Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). Updip, MM7 sands extend onshore into Texas and Louisiana. To the southwest, sand potential extends into Texas offshore State waters and Mexican national waters. To the northeast, sand potential is bounded by the Cretaceous carbonate shelf edge and a decrease in sediment influx at the edge of the MM7 depocenter. Sediments of a similar depositional setting and geographic extent as the upper middle Miocene (MM9), lower upper Miocene (UM1), and upper upper Miocene (UM3) “Shallow Miocene Bright Spot Trend” plays occurs in the MM7 chronozone, but because these sediments are extremely thin and sand poor, they are not considered prospective. The downdip limit extends at least as far as the Sigsbee Escarpment as indicated by MM7 sand development in the OCS G08512-1 well in Atwater block 471.

Productive and established sand locations in the MM7 chronozone are a result of

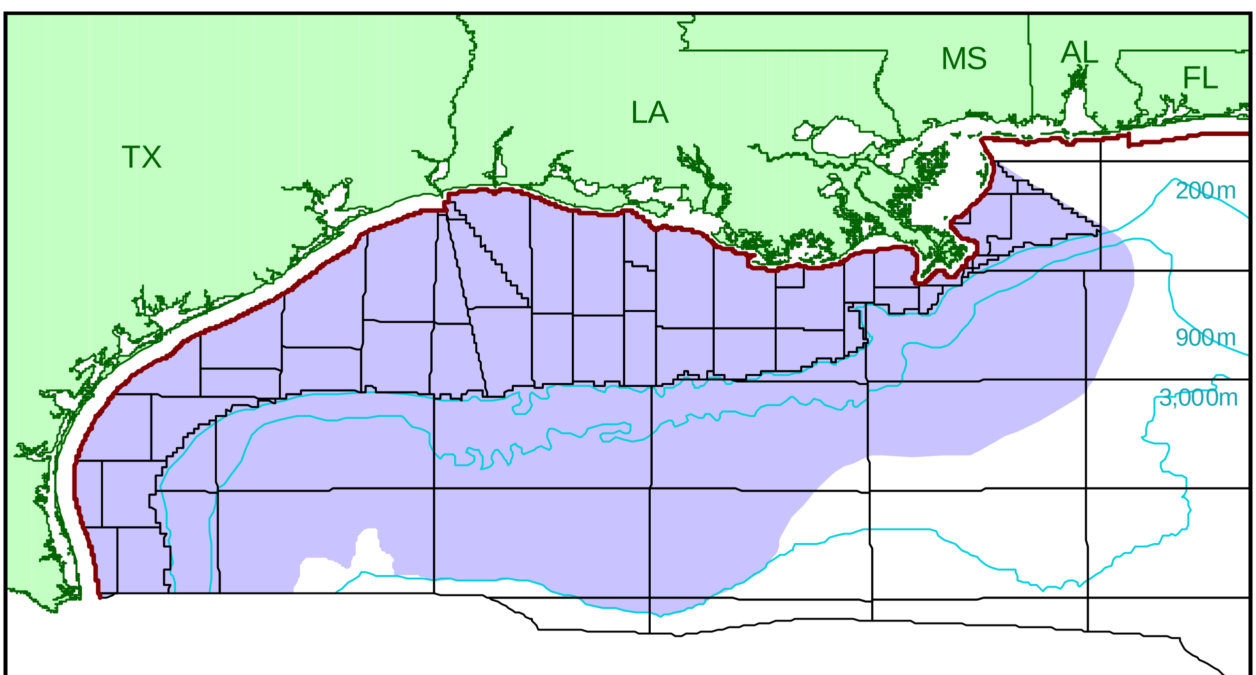


Figure 1. Map of assessed chronozone.

two ancient depocenters, one in the Texas area and the other in the Louisiana area. In the offshore Texas area, no significant lateral shift in depocenter is observed from the underlying lower middle Miocene (MM4) chronozone to the MM7 chronozone. Progradational sediment distributions are very similar for both chronozones offshore Texas. However, in MM7 time, aggradational sands had developed offshore in the Brazos and Galveston Areas, whereas in MM4 time, they had not prograded basinward enough to reach the present-day offshore.

In the offshore Louisiana area, the MM7 depocenter had migrated considerably eastward compared to the MM4 depocenter. Productive fan deposits in the MM7 chronozone are observed east of the present-day Mississippi River Delta. The deposits of MM7 time are also observed farther offshore Louisiana than MM4 deposits due to the seaward progradation of deltaic deposits from the ancestral Mississippi River.

Major structural features in the MM7 chronozone include normal faults, anticlines, and growth faults. Salt diapirs occur less commonly.

DISCOVERIES

The MM7 chronozone contains 126 discovered pools in six plays (table 1). Total reserves in the chronozone are 0.222 Bbo and 14.639 Tcfg (2.827 BBOE), of which 0.149 Bbo and 10.884 Tcfg (2.086 BBOE) have been produced. The largest number of discoveries in the MM7 chronozone occurred when nine pools were added in both 1990 and 1991 (figure 2). However, the maximum yearly total reserves of 503.554 MMBOE were added in 1958 when four pools were discovered.

Of the six MM7 plays, the MM7 P1 play contains the most total reserves in 61 pools, with 0.164 Bbo and 8.854 Tcfg (1.740 BBOE).

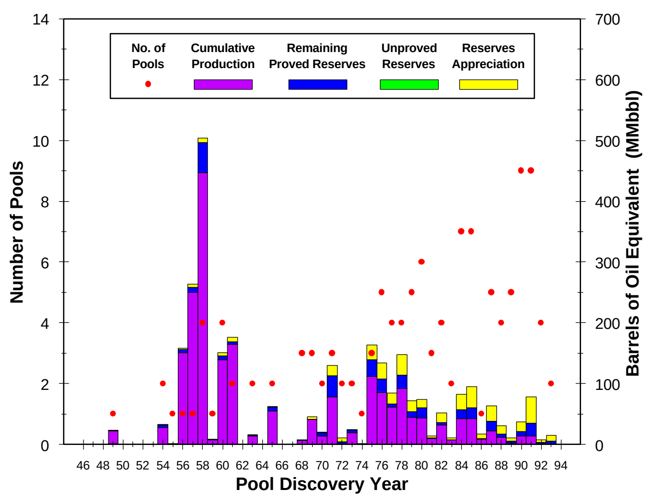


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

126 Pools (391 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	11	79	305
Subsea depth (feet)	3,092	9,011	16,489
Number of sands per pool	1	3	15
Porosity	15%	27%	36%
Water saturation	13%	28%	58%

ASSESSMENT RESULTS

The MM7 chronozone contains 307 pools (discovered and undiscovered), with a mean total endowment estimated at 0.570 Bbo and 27.096 Tcfg (5.392 BBOE) (table 2).

Assessment results indicate that undiscovered resources may occur in as many as 181 pools, which contain a range of 0.259 to 0.455 Bbo and 8.797 to 16.953 Tcfg at the 95th and 5th percentiles, respectively (figure 3). At mean levels, 0.348 Bbo and 12.457 Tcfg (2.565 BBOE) are projected. These undiscovered resources represent 48 percent of the MM7 chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the largest in the chronozone (figure 4). Additionally, of the 21 Gulf of Mexico Region chronozones, the MM7 chronozone is projected to contain the second largest amount of mean undiscovered gas.

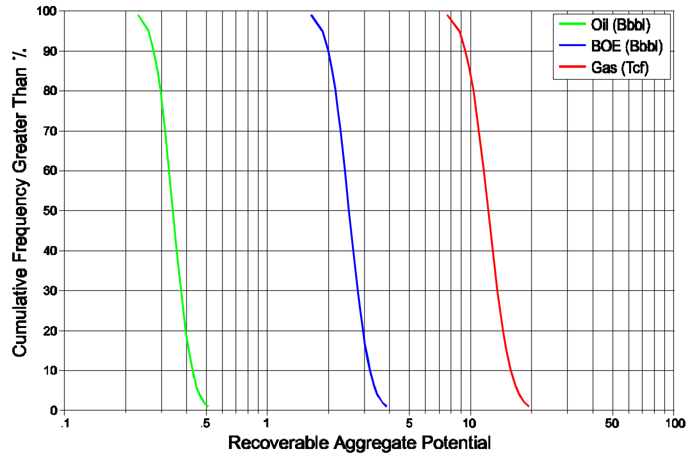


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	126	0.180	12.601	2.422
Cumulative production	--	0.149	10.884	2.086
Remaining proved	--	0.031	1.717	0.336
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.042	2.038	0.405
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.259	8.797	1.864
Mean	181	0.348	12.457	2.565
5th percentile	--	0.455	16.953	3.412
Total Endowment				
95th percentile	--	0.481	23.436	4.691
Mean	307	0.570	27.096	5.392
5th percentile	--	0.677	31.592	6.239

Of the six MM7 plays, the MM7 F play is projected to contain the greatest exploration potential, with mean undiscovered resources estimated at 0.312 Bbo and 8.468 Tcfg (1.820 BBOE) remaining to be found in 83 pools. These undiscovered resources in the MM7 F play represent 34 percent of the BOE mean total endowment for the MM7 chronozone. This high percentage and the potential for numerous discoveries within a large unexplored area make the MM7 F play an attractive exploration target in MM7 strata.

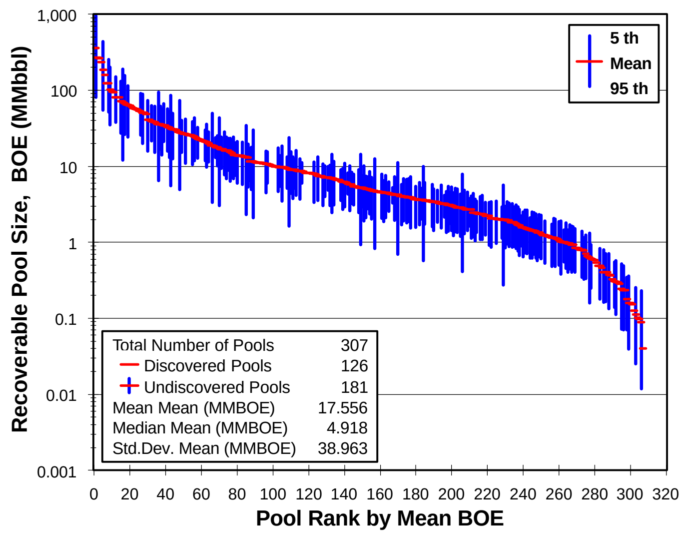


Figure 4. Pool rank plot.

MIDDLE MIDDLE MIOCENE RETROGRADATIONAL (MM7 R) PLAY

PLAY DESCRIPTION

The established Middle Middle Miocene Retrogradational (MM7 R) play occurs within the *Cristellaria* "I" and *Bigenerina humblei* biozones. This play extends discontinuously from the South Padre Island Area offshore Texas to the South Marsh Island Area offshore Louisiana (figure 1).

These retrogradational deposits are mainly associated with the *Bigenerina humblei* flooding surface, which caps the MM7 chronozone. However, in isolated portions of the High Island and West Cameron Areas, a secondary flooding surface associated with the *Cristellaria* "I" biozone occurs. Updip, the retrogradational sands either shale out, which represents the *Bigenerina humblei* flooding surface, or younger MM7 aggradational or progradational sands cap the *Cristellaria* "I" flooding surface. Along strike to the east, the play extends onshore into Louisiana. Along strike to the southwest, the play extends onshore into Texas. Downdip, the play grades into the sediments of the Middle Middle Miocene Progradational (MM7 P1) play.

Productive and established sand locations in the MM7 R play are a result of two separate depocenters in MM7 time, one in the Texas area and the other in the Louisiana area. No significant lateral shift in either depocenter is observed in the offshore areas from the underlying lower middle Miocene (MM4) chronozone to the MM7 chronozone. However, the MM7 R play occurs farther offshore than the MM4 retrogradational sequence, indicative of the prograding nature of the ancient delta systems.

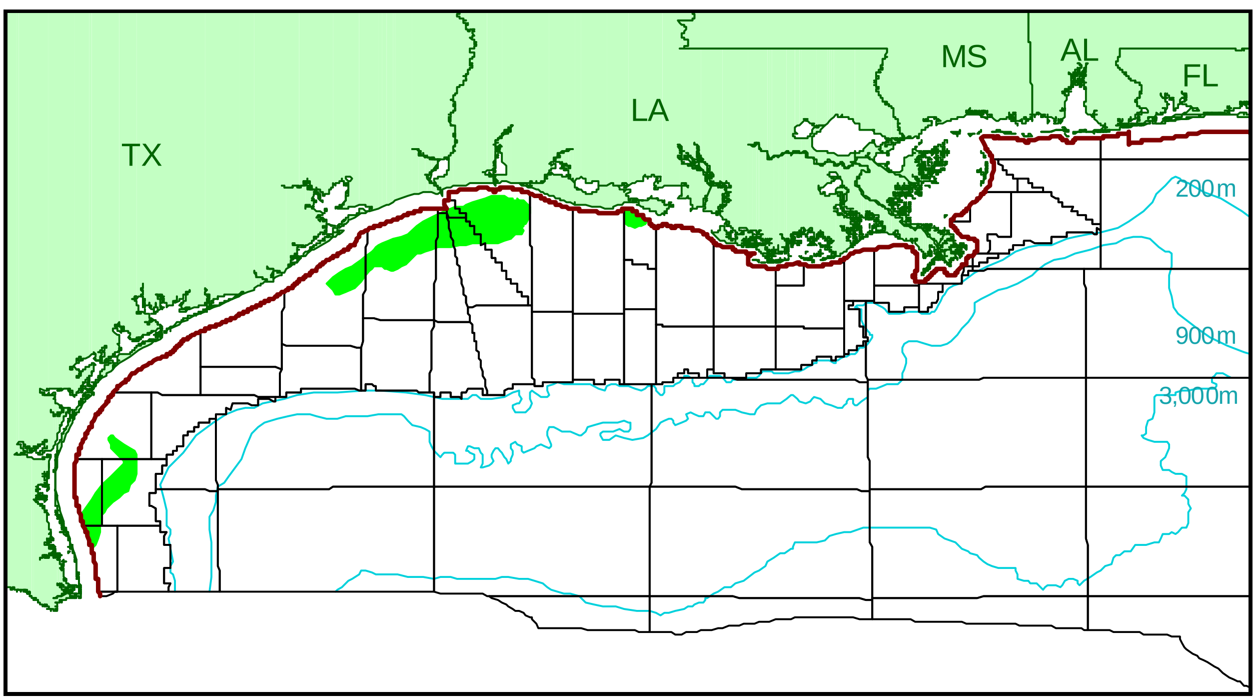


Figure 1. Map of assessed play.

PLAY CHARACTERISTICS

The productive MM7 R play is characterized by predominately upward-fining, back-stepping sands, which terminate in the *Bigenerina humblei* or *Cristellaria* "I" flooding surface. These reworked marine deposits include delta fringe sands, barrier bars, channel/levee complexes, delta front sands, and crevasse splay sands. Growth faults are the major structural feature in this play. Anticlines and normal faults are also present. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive retrogradational depositional environments, structures, or seals.

Galveston 288 is the type field, and Ivory Production Company's E, E0, E1, G2, G3, and G4 sands represent the MM7 R play in this field.

DISCOVERIES

The MM7 R gas play contains total reserves of 0.028 Bbo and 2.237 Tcfg (0.426 BBOE), of which 0.020 Bbo and 1.721 Tcfg (0.326 BBOE) have been produced. The play contains 69 producible sands in 23 pools (table 1). The first reserves in the play were discovered in the West Cameron 149 field in 1949 (figure 2). The maximum yearly total reserves of 124.230 MMBOE were added in 1960 when two pools were discovered, including the largest pool in the play in the Galveston 288 field. Almost two-thirds of the play's discoveries were found since 1979. However, over 65 percent of the play's cumulative production has come from pools discovered prior to 1962, indicative of the large size of the early discoveries. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1991. The 23 discovered pools range in size from 0.097 to 123.645 MMBOE. These pools contain 118 reservoirs, of which 111 are nonassociated gas, 2 are undersaturated oil, and 5 are saturated oil.

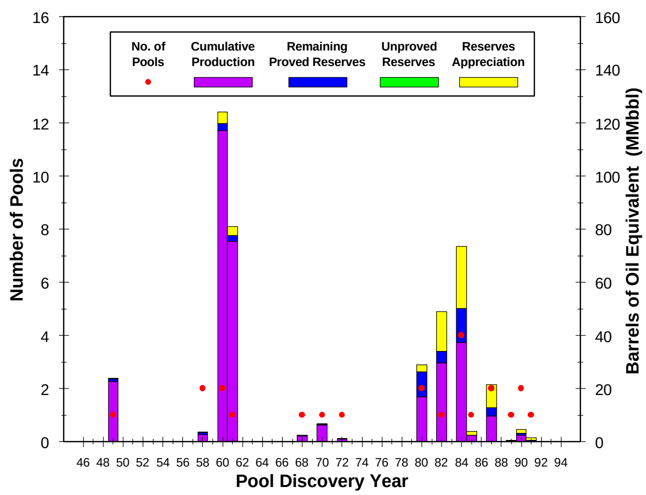


Figure 2. Exploration history graph.

Of the five retrogradational plays in the Gulf of Mexico Region, the MM7 R play is the largest, containing 44 percent of the total reserves and accounting for 47 percent of the

Table 1. Characteristics of the discovered pools.

23 Pools (69 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	11	61	221
Subsea depth (feet)	3,960	8,294	11,287
Number of sands per pool	1	3	12
Porosity	23%	27%	32%
Water saturation	16%	29%	47%

cumulative production, based on BOE.

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the MM7 R play is 1.00. This play is the largest retrogradational play in the Gulf of Mexico, based on a mean total endowment of 0.033 Bbo and 2.525 Tcfg (0.482 BBOE) (table 2). Sixty-eight percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.002 to 0.007 Bbo and 0.237 to 0.343 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.005 Bbo and 0.288 Tcfg (0.056 BBOE). These undiscovered resources may occur in as many as 17 pools. The largest undiscovered pool, with a mean size of 6.804 MMBOE, is modeled as the twelfth largest pool in the play (figure 4). For all the undiscovered pools in the MM7 R play, the mean mean size is 3.289

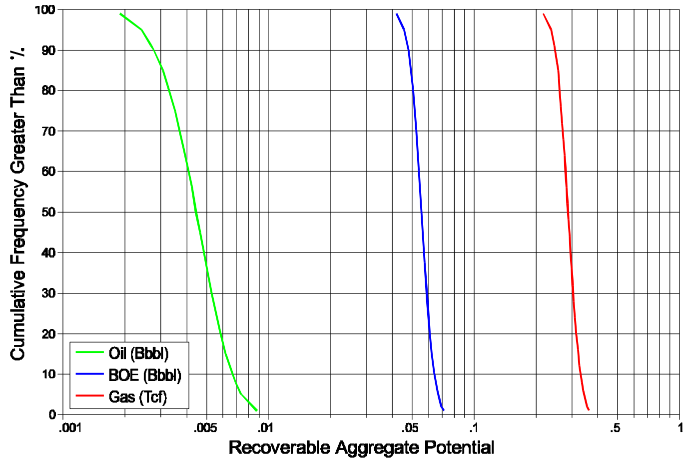


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	**Number of Pools**	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Reserves				
Original proved	23	0.024	1.912	0.364
Cumulative production	--	0.020	1.721	0.326
Remaining proved	--	0.004	0.191	0.038
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.004	0.325	0.062
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.002	0.237	0.046
Mean	17	0.005	0.288	0.056
5th percentile	--	0.007	0.343	0.067
Total Endowment				
95th percentile	--	0.030	2.474	0.472
Mean	40	0.033	2.525	0.482
5th percentile	--	0.035	2.580	0.493

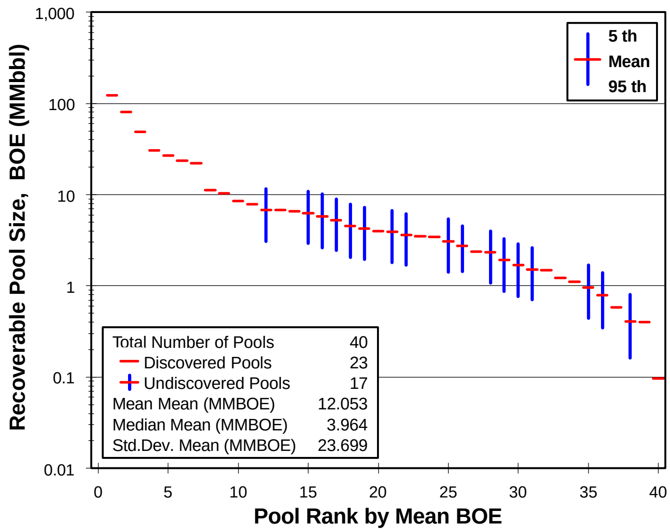


Figure 4. Pool rank plot.

MMBOE, which is substantially smaller than the 18.530 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 12.053 MMBOE.

Of the five Gulf of Mexico retrogradational plays, the MM7 R play is projected to contain the largest amount of mean undiscovered gas resources at 35 percent.

The MM7 R play is well explored. Relative to the discovered pools in the play, the undiscovered pools are expected to be small to moderate in size. These undiscovered resources are expected to contribute only 12 percent to the play's BOE mean total endowment. Limited interfield exploration potential exists for untested structures and stratigraphic traps.

MIDDLE MIDDLE MIOCENE STRUCTURAL RETROGRADATIONAL/ AGGRADATIONAL/PROGRADATIONAL/FAN (MM7 RAPF) PLAY

PLAY DESCRIPTION

The established Middle Middle Miocene Structural Retrogradational/Aggradational/Progradational/Fan (MM7 RAPF) play occurs within the *Cibicides opima, Cristellaria* "I," and *Bigenerina humblei* biozones. The play is defined by its structural position downthrown to the regional Corsair Fault System and is commonly referred to as a "Corsair" play. It extends in a narrow zone from the Mustang Island East Addition Area northeastward parallel to the Texas coastline to the central Galveston Area (figure 1).

The play is bounded updip by the regional extent of the Corsair Fault System. To the northeast, southwest, and downdip, the play is limited by the relatively thin, unexpanded sediments of the Middle Middle Miocene Progradational (MM7 P1) and Middle Middle Miocene Fan (MM7 F) plays, which show no structural control by the Corsair Fault System.

The MM7 RAPF play represents the oldest deposition included in the structurally controlled plays of the Corsair Fault System. The overlying Upper Middle Miocene Structural Retrogradational/Aggradational/Progradational (MM9 RAP) play has no productive fan sands identified within it, unlike the MM7 RAPF play. The two plays generally occur in the same geographic location, as both are controlled by the Corsair Fault System.

PLAY CHARACTERISTICS

The MM7 RAPF play consists of stacked sequences of retrogradational, aggradational, progradational, and fan sands located downthrown to the Corsair Fault in

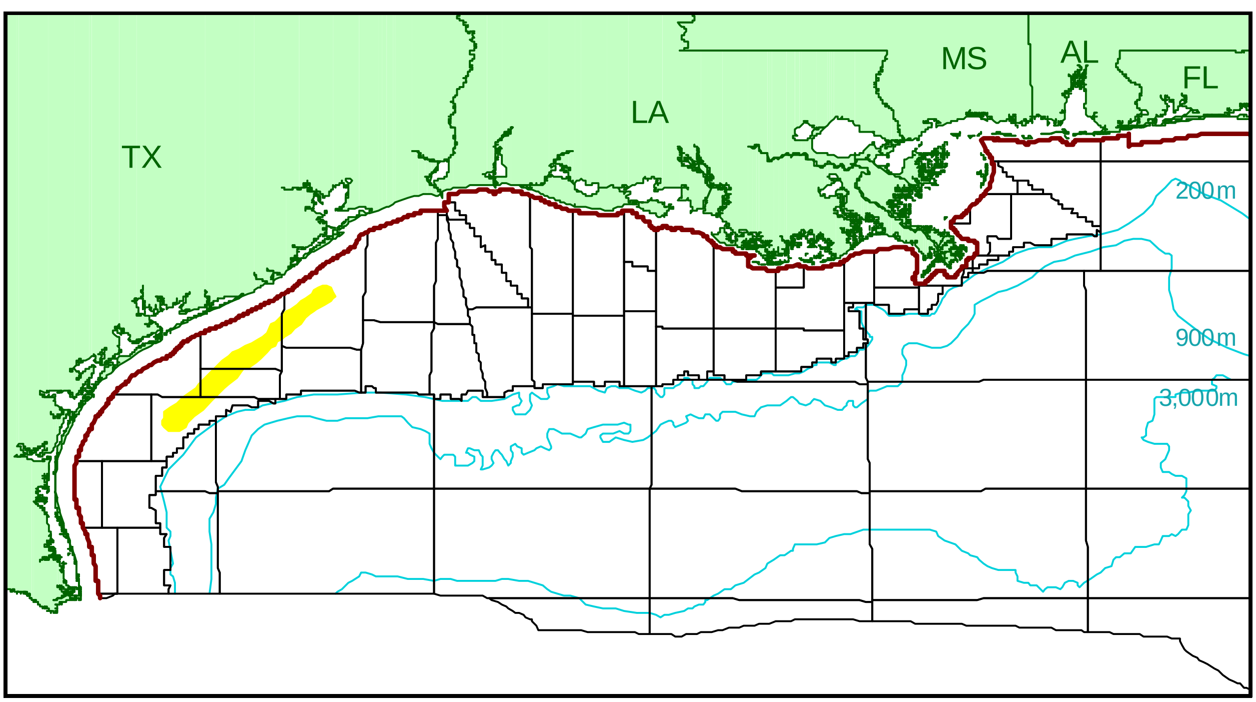


Figure 1. Map of assessed play.

offshore Texas. The play, therefore, is referred to as a combined RAPF play. Production occurs from all four depositional environments. The progradational and retrogradational deposits dominate the 100 producible sands at 48 percent and 31 percent, respectively.

The MM7 section was greatly influenced by movement along the Corsair Fault during deposition, as evidenced by the much thicker section on the fault's downthrown side. Because sand accumulation was so influenced by structural movement of the fault, the play is considered to be structurally controlled, rather than depositionally controlled.

The major structural feature in this play is growth faulting of the Corsair Fault System. Anticlines, normal faults, and salt diapirs occur less frequently. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Brazos 578 is the type field. Brock Minerals Corporation's FOSHI-FOSHI, D/C, and BIG HUM sands and Shell Offshore Inc.'s P sand represent the MM7 RAPF play in this field.

DISCOVERIES

The MM7 RAPF gas play contains total reserves of 0.010 Bbo and 2.833 Tcfg (0.514 BBOE), of which 0.005 Bbo and 1.696 Tcfg (0.307 BBOE) have been produced. The play contains 100 producible sands in 22 pools (table 1). The first reserves in the play were discovered in the Brazos 76A field in 1969 (figure 2). Discoveries peaked in the 1970's, when 85 percent of the total reserves were added. Over 80 percent of the play's cumulative production has come from discoveries made in the 1970's. The maximum yearly total reserves of 141.006 MMBOE were found in 1978 with the discovery of three pools.

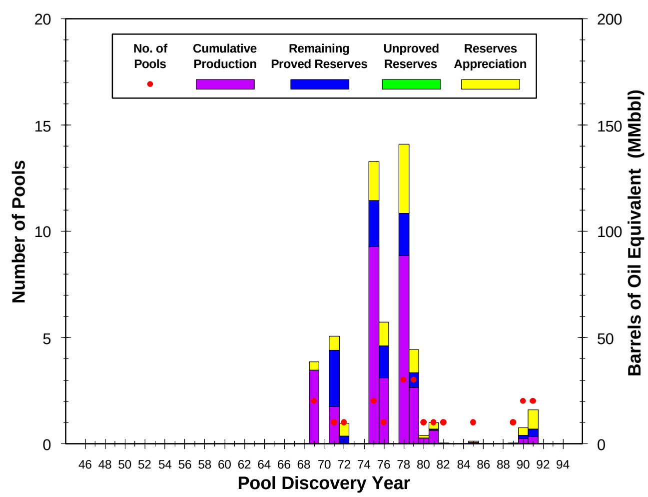


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

22 Pools (100 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	80	145	305
Subsea depth (feet)	5,890	9,929	16,489
Number of sands per pool	1	5	15
Porosity	19%	26%	33%
Water saturation	14%	31%	41%

However, the largest pool in the play was discovered in the Brazos 133A field in 1975. The most recent discoveries, prior to this study's cutoff date of January 1, 1995, were in 1991.

The 22 discovered pools range in size from 0.125 to 96.357 MMBOE. These pools contain 168 reservoirs, all of which are nonassociated gas.

Of the total reserves in both the MM7 RAPF and MM9 RAP plays, the MM7 RAPF play contains 95 percent.

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the MM7 RAPF play is 1.00. The play contains a mean total endowment of 0.014 Bbo and 4.255 Tcfg (0.771 BBOE) (table 2). Forty percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.002 to 0.008 Bbo and 0.810 to 2.207 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.004 Bbo and 1.422 Tcfg

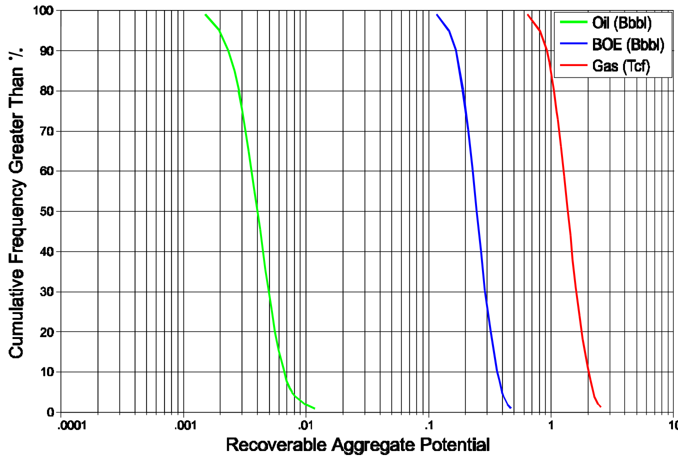


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	22	0.008	2.245	0.407
Cumulative production	--	0.005	1.696	0.307
Remaining proved	--	0.002	0.549	0.100
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.002	0.588	0.107
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.002	0.810	0.147
Mean	15	0.004	1.422	0.257
5th percentile	--	0.008	2.207	0.399
Total Endowment				
95th percentile	--	0.012	3.643	0.661
Mean	37	0.014	4.255	0.771
5th percentile	--	0.018	5.040	0.913

(0.257 BBOE). These undiscovered resources may occur in as many as 15 pools. The largest undiscovered pool, with a mean size of 70.652 MMBOE, is modeled as the second largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 9, 11,12, and 14 on the pool rank plot. For all the undiscovered pools in the MM7 RAPF play, the mean mean size is 17.180 MMBOE, which is smaller than the 23.352 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 20.850 MMBOE.

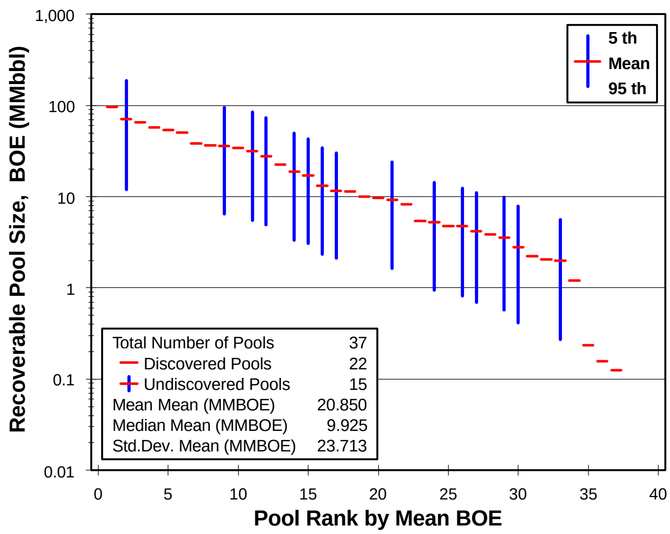


Figure 4. Pool rank plot.

The MM7 RAPF play is well explored, with a limited geographic extent. The undiscovered resources are estimated to account for 33 percent of the play's BOE mean total endowment. Exploration potential between discovered fields exists for additional structural traps along the Corsair Fault System. Even though the play is projected to have moderately good exploration potential, that potential is of localized interest only.

MIDDLE MIDDLE MIOCENE AGGRADATIONAL (MM7 A) PLAY

PLAY DESCRIPTION

The established Middle Middle Miocene Aggradational (MM7 A) play occurs within the *Cibicides opima, Cristellaria* "I," and *Bigenerina humblei* biozones. This play extends from the North Padre Island Area offshore Texas to the northwestern portion of the East Cameron Area offshore Louisiana (figure 1).

Updip and along strike, the play continues onshore into Texas and Louisiana. Downdip, the play grades into the sediments of the Middle Middle Miocene Progradational (MM7 P1) and Middle Middle Miocene Retrogradational (MM7 R) plays.

Productive and established sand locations in the MM7 A play are a result of two separate depocenters in MM7 time, one in the Texas area and the other in the Louisiana area. No significant lateral shift in either depocenter is observed in the offshore areas from the underlying lower middle Miocene (MM4) chronozone to the MM7 chronozone. However, in the MM7 chronozone, aggradational sands had developed offshore extending across the Brazos and Galveston Areas, whereas in the MM4 chronozone, the ancient delta systems had not prograded far enough basinward to deposit aggradational sands in the present-day offshore in most of those areas.

PLAY CHARACTERISTICS

The productive MM7 A play consists of delta plain and adjacent shallow-water deposits that comprise numerous stacked channel and distributary mouth bar sands with interbedded thin shales. Additionally, well-developed retrogradation deposits associated with the *Cristellaria* "I" and *Bigenerina humblei* marine transgressions locally cap the aggradational deposits of the MM7 A play. The major structural feature in the play is

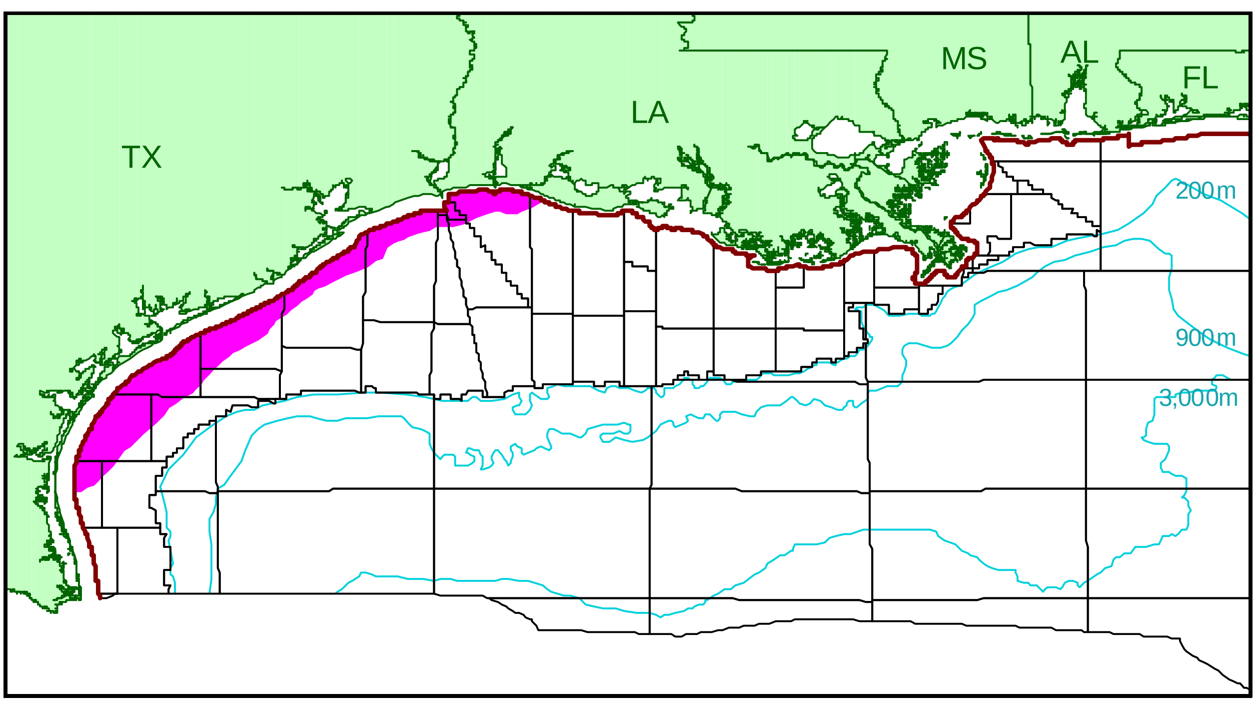


Figure 1. Map of assessed play.

anticlines. Less common structural features include normal and growth faults. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive aggradational depositional environments, structures, or seals.

Matagorda Island 665 is the type field. Exxon Corporation's R50 sand and Taylor Energy Company's 5, 6, and 7 sands represent the MM7 A play in this field.

DISCOVERIES

The MM7 A gas play contains total reserves of 0.354 MMbo and 99.283 Bcfg (18.020 MMBOE), of which 0.234 MMbo and 62.498 Bcfg (11.354 MMBOE) have been produced. The play contains 16 producible sands in seven pools (table 1). The first reserves in the play were discovered in the West Cameron 45 field in 1955 (figure 2). After the West Cameron 45 pool was discovered, no new pools were found until 1974. The maximum yearly total reserves were added in 1977, with the discovery of the largest discovered pool in the play in the Matagorda Island 665 field. This pool accounts for 58 percent of the play's cumulative production. In the last 10 years of the play's history, four of the seven pools in the play have been discovered. The most recent pool discovery, prior to this study's cutoff date of January 1, 1995, was in 1992.

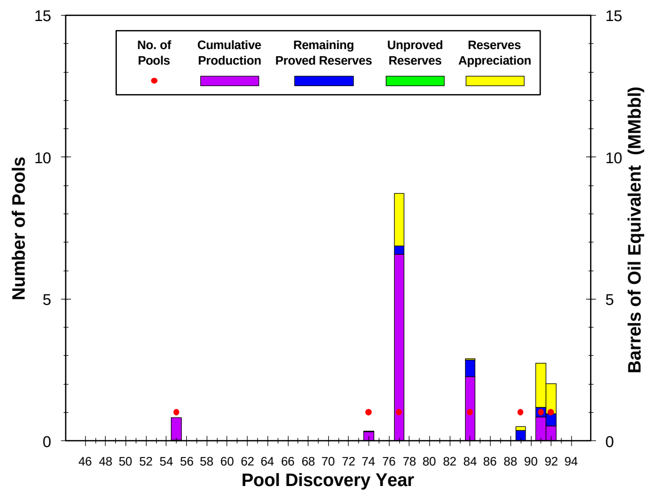


Figure 2. Exploration history graph.

The seven discovered pools range in size from 0.329 to 8.728 MMBOE. These pools contain 19 reservoirs, of which 17 are nonassociated gas, 1 is undersaturated oil, and 1 is saturated oil.

Table 1. Characteristics of the discovered pools.

7 Pools (16 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	33	57	86
Subsea depth (feet)	3,092	5,281	6,688
Number of sands per pool	1	2	6
Porosity	30%	31%	36%
Water saturation	17%	24%	32%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the MM7 A play is 1.00. The play ranks within the smallest one-fourth of all 61 Gulf of Mexico Region plays, based on a mean total endowment of 0.002 Bbo and 0.276 Tcfg (0.051 BBOE) (table 2). Twenty-two percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.001 to 0.003 Bbo and 0.121 to 0.244 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.002 Bbo and 0.177 Tcfg (0.033 BBOE). These undiscovered resources may occur in as many as 13 pools. The largest undiscovered pool, with a mean size of 9.682 MMBOE, is modeled as the largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 3, 4, 5, and 6 on the pool rank plot. For all the undiscovered pools in the MM7 A play, the mean mean size is 2.553 MMBOE, which is comparable to the 2.574 MMBOE mean size of the discovered pools.

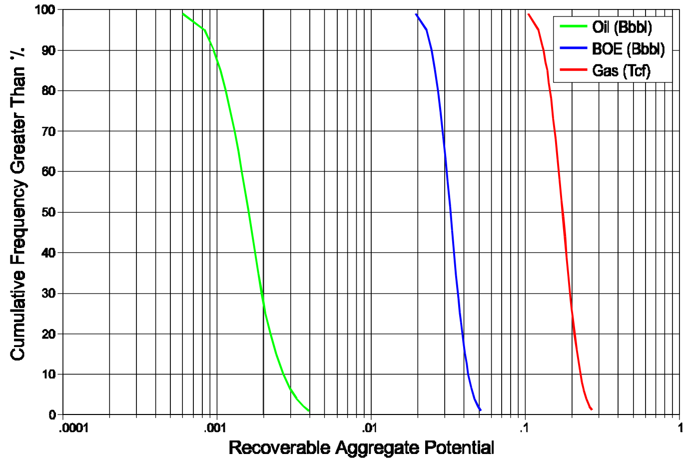


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	**Number of Pools**	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Reserves				
Original proved	7	<0.001	0.074	0.013
Cumulative production	--	<0.001	0.062	0.011
Remaining proved	--	<0.001	0.011	0.002
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.026	0.005
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.001	0.121	0.023
Mean	13	0.002	0.177	0.033
5th percentile	--	0.003	0.244	0.046
Total Endowment				
95th percentile	--	0.001	0.220	0.041
Mean	20	0.002	0.276	0.051
5th percentile	--	0.003	0.343	0.064

Of the 11 aggradational plays in the Gulf of Mexico Cenozoic Province, the MM7 A play is projected to contain the third largest amount of mean undiscovered gas resources at 14 percent.

The number of undiscovered pools is expected to be about twice that of the discovered pools, with many of the largest pools projected as undiscovered. These undiscovered resources contribute 65 percent to the play's BOE mean total endowment. Exploration potential exists for untested structures between the seven discovered fields. However, because the MM7 A play is one of the smallest in the Gulf of Mexico, the play's undiscovered resources add minimally to the total endowment of the basin.

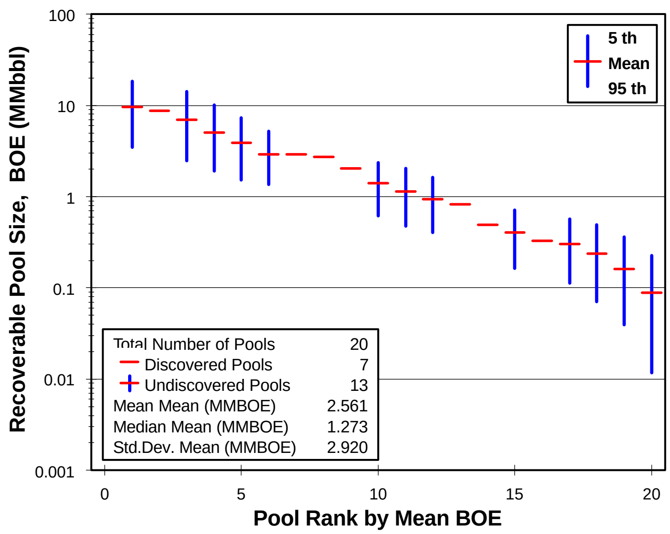


Figure 4. Pool rank plot.

MIDDLE MIDDLE MIOCENE PROGRADATIONAL (MM7 P1) PLAY

PLAY DESCRIPTION

The Middle Middle Miocene Progradational (MM7 P1) play is one of the largest established plays in the Gulf of Mexico Region. The play occurs within the *Cibicides opima, Cristellaria* "I," and *Bigenerina humblei* biozones and extends from the South Padre Island Area offshore Texas to the Eugene Island Area offshore Louisiana (figure 1).

Updip and along strike to the northeast, the play continues onshore into Texas and Louisiana. Along strike to the southwest, the play continues into Texas offshore State waters and Mexican national waters. Downdip, the play grades into the deposits of the Middle Middle Miocene Fan (MM7 F) play. In parts of the Mustang Island, Matagorda Island, Brazos, and Galveston Areas, the MM7 P1 play is limited by the Middle Middle Miocene Structural Retrogradational/Aggradational/ Progradational/Fan (MM7 RAPF) play and the Middle Middle Miocene Structural Progradational (MM7 P2) play.

Productive and established sand locations in the MM7 P1 play are a result of two separate depocenters in MM7 time, one in the Texas area and the other in the Louisiana area. No significant lateral shift in either depocenter is observed in the offshore areas from the underlying lower middle Miocene (MM4) chronozone to the MM7 chronozone. However, progradational sediments of the MM7 chronozone are located farther basinward than those of the MM4 chronozone due to prograding of the ancient delta systems.

The MM7 P1 play is a geographically extensive, stratigraphically controlled play, in contrast to the other progradational play in the MM7 chronozone, the MM7 P2 play, which is a small, geographically isolated, structurally controlled play.

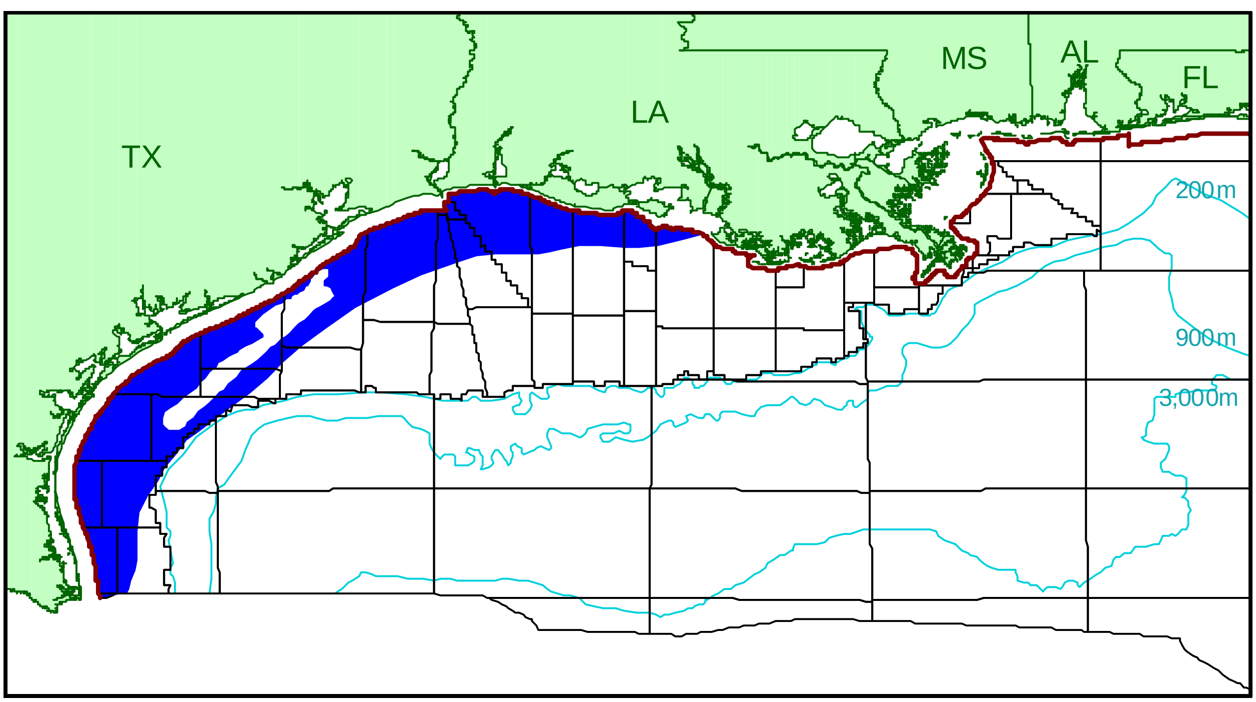


Figure 1. Map of assessed play.

PLAY CHARACTERISTICS

The productive MM7 P1 play consists of progradational deltaic sediments deposited in channel and stacked channel, delta fringe, crevasse splay, shelf and upper slope slump, delta front, and shelf blanket environments. Additionally, well-developed retrogradational deposits associated with the *Cristellaria* "I" and *Bigenerina humblei* marine transgressions locally cap the progradational deposits of the MM7 P1 play. The major structural features in the play are normal faults, anticlines, and growth faults. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive progradational depositional environments, structures, or seals.

South Marsh Island 239 is the type field, and Texaco Exploration and Production's CIBN and CIBO sands represent the MM7 P1 play in this field.

DISCOVERIES

The MM7 P1 gas play contains total reserves of 0.164 Bbo and 8.854 Tcfg (1.740 BBOE), of which 0.118 Bbo and 7.192 Tcfg (1.398 BBOE) have been produced. The play contains 189 producible sands in 61 pools (table 1). The first reserves in the play were discovered in the West Cameron 110 field in 1954 (figure 2). The maximum yearly total reserves of 499.936 MMBOE were added in 1958 when two pools were discovered, including the largest pool in the play in the Tiger Shoal field. Pool discoveries have been the most active during the last 20 years when 39 of the play's 61 pools were found. However, over 75 percent of the play's

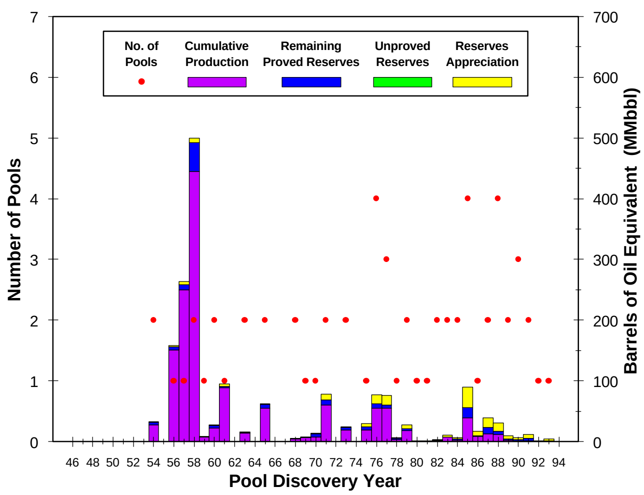


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

61 Pools (189 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	11	69	274
Subsea depth (feet)	3,500	8,940	14,548
Number of sands per pool	1	3	11
Porosity	15%	27%	32%
Water saturation	16%	28%	47%

cumulative production occurred from pools discovered prior to 1968, which is indicative of the large pool size of the early discoveries. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1993.

The 61 discovered pools range in size from 0.101 to 267.750 MMBOE. These pools contain 393 reservoirs, of which 362 are nonassociated gas, 16 are undersaturated oil, and 15 are saturated oil.

Of the 61 Gulf of Mexico plays, the MM7 P1 play contains the tenth largest amount of total reserves (4%) and has produced the ninth largest amount of hydrocarbons (5%), based on BOE.

Assessment Results

The marginal probability of hydrocarbons for the MM7 P1 play is 1.00. The play contains a mean total endowment of 0.183 Bbo and 10.095 Tcfg (1.980 BBOE) (table 2). Seventy-one percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.011 to 0.031 Bbo and 1.031 to 1.475 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.019 Bbo and 1.241 Tcfg (0.240 BBOE). These undiscovered

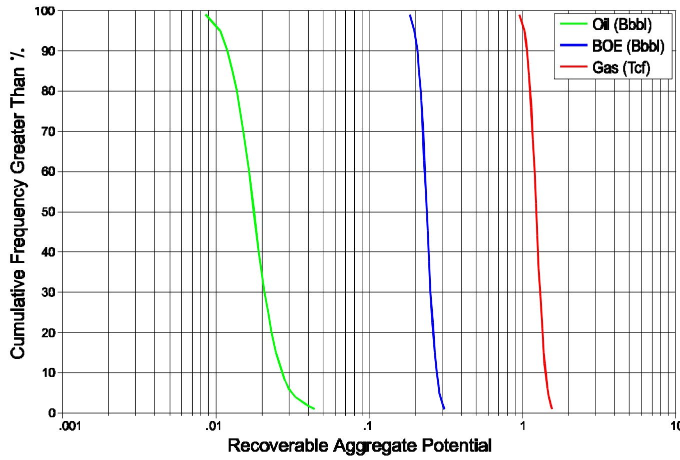


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	**Number of Pools**	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Reserves				
Original proved	61	0.138	8.021	1.565
Cumulative production	--	0.118	7.192	1.398
Remaining proved	--	0.020	0.829	0.167
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.027	0.833	0.175
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.011	1.031	0.198
Mean	39	0.019	1.241	0.240
5th percentile	--	0.031	1.475	0.287
Total Endowment				
95th percentile	--	0.175	9.885	1.938
Mean	100	0.183	10.095	1.980
5th percentile	--	0.195	10.329	2.027

resources may occur in as many as 39 pools. The largest undiscovered pool, with a mean size of 35.346 MMBOE, is modeled as the eleventh largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 12, 17, 19, and 23 on the pool rank plot. For all the undiscovered pools in the MM7 P1 play, the mean mean size is 6.141 MMBOE, which is substantially smaller than the 28.523 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 19.794 MMBOE.

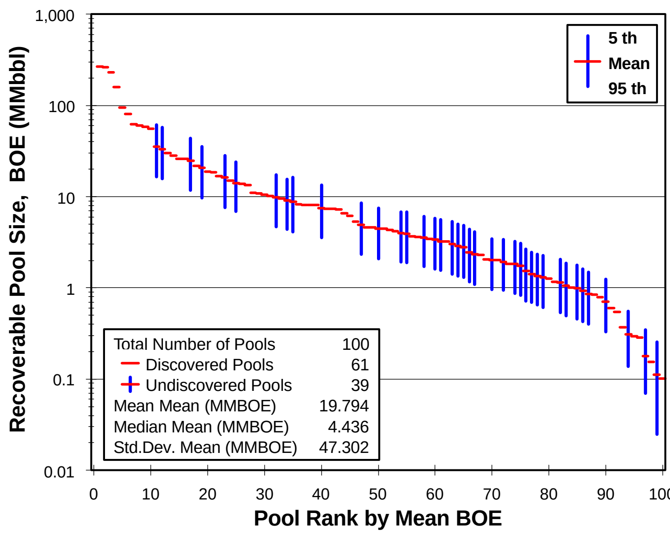


Figure 4. Pool rank plot.

Of the 14 progradational plays in the Gulf of Mexico, the MM7 P1 play is projected to contain the third largest amount of mean undiscovered gas resources at 7 percent.

The MM7 P1 play is well explored and contains a large amount of total reserves. Undiscovered polls are expected to be of moderate size compared with the discovered pools. These undiscovered resources are expected to account for only 12 percent of the play's BOE mean total endowment. Exploration potential is believed to exist downdip of existing fields, where wells have been too shallow to test the MM7 section, and in interfield structures.

MIDDLE MIDDLE MIOCENE STRUCTURAL PROGRADATIONAL (MM7 P2) PLAY

PLAY DESCRIPTION

The established Middle Middle Miocene Structural Progradational (MM7 P2) play occurs within the *Cibicides opima, Cristellaria* "I," and *Bigenerina humblei* biozones and is commonly referred to as the "Seagull" play. This play extends in a narrow zone from the Brazos Area northeastward parallel to the Texas coastline to the Galveston Area (figure 1).

The play is bounded updip by a major growth fault. Downdip, the play is bounded by the Middle Middle Miocene Structural Retrogradational/Aggradational/Progradational /Fan (MM7 RAPF) play. Along strike to the west and east, the play is limited by the sediments of the Middle Middle Miocene Progradational (MM7 P1) play.

Because this play is bounded by major growth faults, it is considered structurally controlled, instead of depositionally controlled. The play is defined by its structural position, which acted as the depocenter for the play's sediments. A series of slumps and slides occurred along the defining faults. Sediments prograded over these slumps and slides, forming a veneer of sands and shales. The reservoirs of the MM7 P2 play occur in this sediment veneer. In contrast, the MM7 P1 play is geographically extensive and stratigraphically controlled.

PLAY CHARACTERISTICS

The prominent feature of this play is gas production from small anticlines arched over shale diapirs that originated within failed lower middle Miocene (MM4) shelf muds. The play is also characterized by seismic hydrocarbon indicators (bright spots). Major

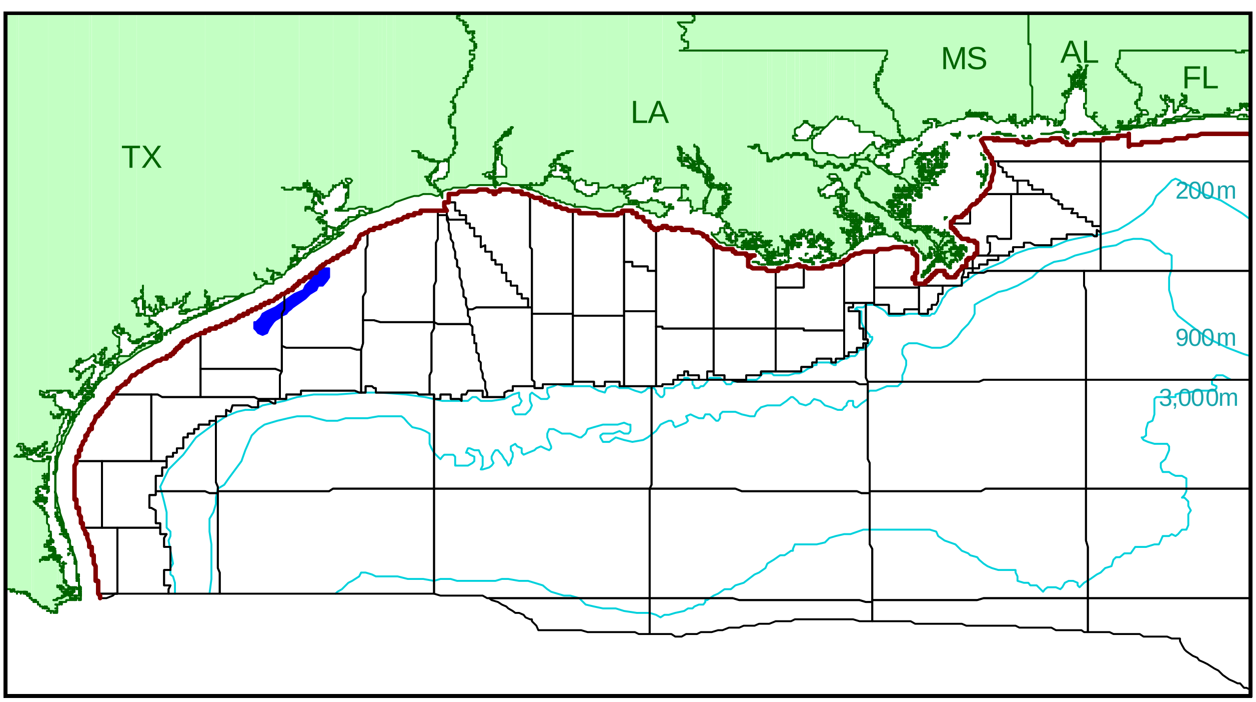


Figure 1. Map of assessed play.

structural features in the play are anticlines and normal faults. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales).

Brazos 431 is the type field, and Seagull Energy E & P Inc.'s BASAL BIG HUM sand represents the MM7 P2 play in this field.

DISCOVERIES

The MM7 P2 gas play contains total reserves of 1.722 MMbo and 376.872 Bcfg (68.781 MMBOE), of which 0.424 MMbo and 75.764 Bcfg (13.905 MMBOE) have been produced. The play contains nine producible sands in six pools (table 1). The first reserves in the play were discovered in the Brazos 455 field in 1987 (figure 2). The maximum yearly total reserves of 46.914 MMBOE were added in 1991 when three pools were found, including the largest discovered pool in the play in the Brazos 397 field. Five of the six pools in the play were discovered in the 1990's. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1992.

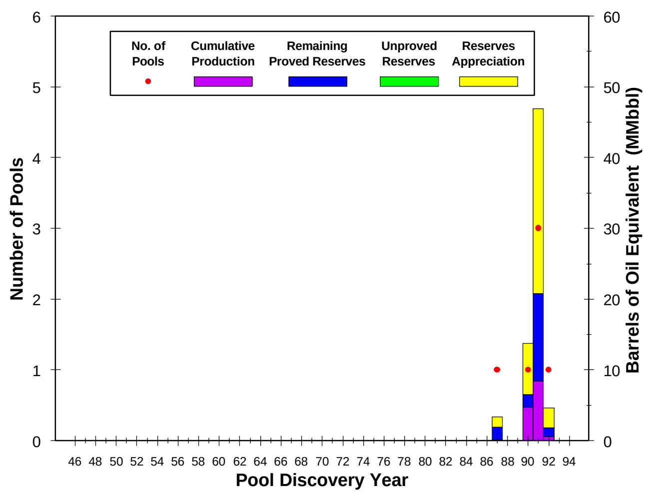


Figure 2. Exploration history graph.

The six discovered pools range in size from 3.401 to 25.775 MMBOE. These pools contain 12 reservoirs, all of which are nonassociated gas.

Table 1. Characteristics of the discovered pools.

6 Pools (9 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	57	76	92
Subsea depth (feet)	5,443	6,776	7,800
Number of sands per pool	1	2	2
Porosity	26%	29%	31%
Water saturation	16%	21%	28%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the MM7 P2 play is 1.00. The play contains a mean total endowment of 0.008 Bbo and 1.238 Tcfg (0.228 BBOE) (table 2). Six percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.002 to 0.016 Bbo and 0.587 to 1.382 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.006 Bbo and 0.861 Tcfg (0.159 BBOE). These undiscovered resources may occur in as many as 14 pools. The largest undiscovered pool, with a mean size of 68.057 MMBOE, is modeled as the largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 2, 4, 8, and 9 on the pool rank plot. For all the undiscovered pools in the MM7 P2 play, the mean mean size is 11.371 MMBOE, which is comparable to the 11.463 MMBOE mean size of the discovered pools.

The number of projected undiscovered pools is more than double the number of

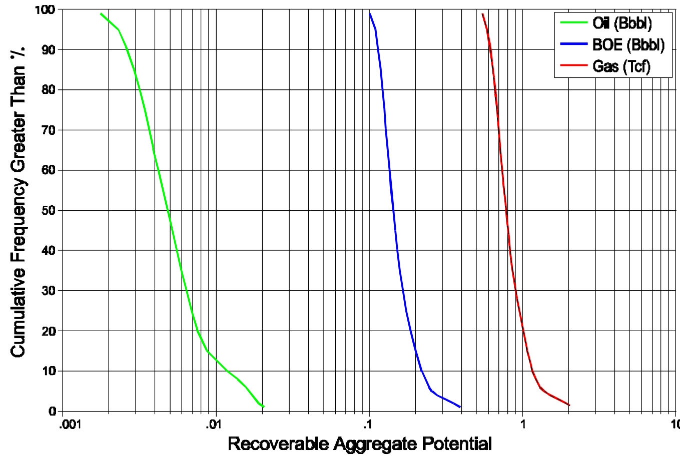


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	6	0.001	0.171	0.031
Cumulative production	--	<0.001	0.076	0.014
Remaining proved	--	0.001	0.095	0.017
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.001	0.206	0.038
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.002	0.587	0.109
Mean	14	0.006	0.861	0.159
5th percentile	--	0.016	1.382	0.256
Total Endowment				
95th percentile	--	0.004	0.964	0.178
Mean	20	0.008	1.238	0.228
5th percentile	--	0.018	1.759	0.325

discovered pools. These undiscovered resources account for 70 percent of the play's BOE mean total endowment. However, compared to many other plays in the Gulf of Mexico, the MM7 P2 play's total endowment is relatively small. In addition, the play's structural bounds limit the size of the exploration area. Therefore, even though the MM7 P2 play is projected to have good exploration potential, that potential is of localized interest only.

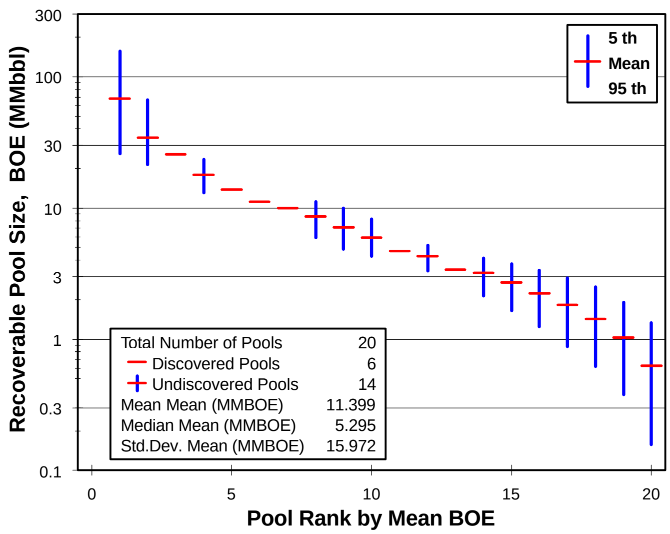


Figure 4. Pool rank plot.

MIDDLE MIDDLE MIOCENE FAN (MM7 F) PLAY

PLAY DESCRIPTION

The established Middle Middle Miocene Fan (MM7 F) play occurs within the *Cibicides opima, Cristellaria* "I," and *Bigenerina humblei* biozones. This play extends from the South Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the play is limited by the shelf/slope break associated with the *Bigenerina humblei* biozone and grades into the sediments of the Middle Middle Miocene Progradational (MM7 P1) play, or it continues onshore into Louisiana. To the southwest, the MM7 F play extends into Texas offshore State waters and Mexican national waters. To the northeast, the play potential is bounded by the Cretaceous carbonate shelf edge and a decrease in sediment influx at the edge of the MM7 depocenter. The southern extension of the play's potential to at least the Sigsbee Escarpment is supported by MM7 sand development in the OCS G08512-1 well in Atwater block 471.

Productive and established sand locations in the MM7 F play are a result of two separate depocenters in MM7 time, one in the Texas area and the other in the Louisiana area. No significant lateral shift in either the Texas or Louisiana depocenters is observed in the offshore areas from the underlying lower middle Miocene (MM4) chronozone to the MM7 chronozone. However, the shelf/slope break of MM7 time is located farther basinward than that of MM4 time, indicative of the prograding nature of the ancient delta systems.

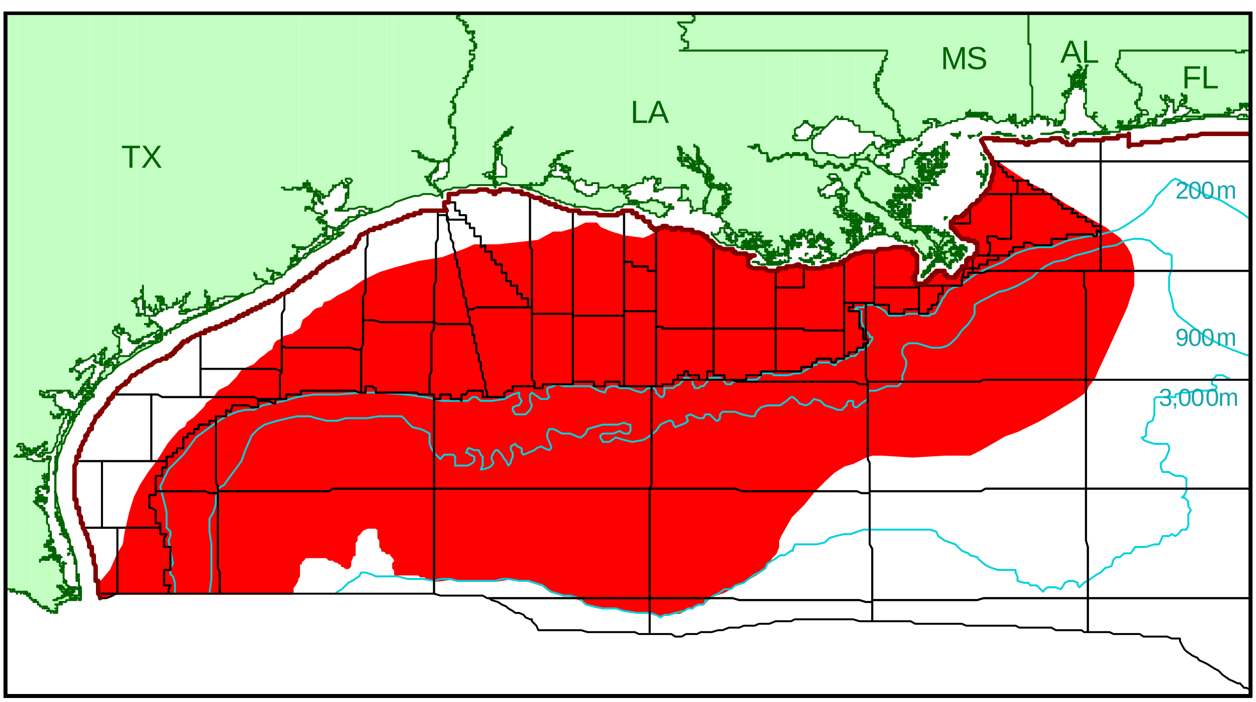


Figure 1. Map of assessed play.

PLAY CHARACTERISTICS

The productive MM7 F play consists of deepwater turbidites deposited in fan systems as channel fill, fan lobes, and fringe sheet sediments on the MM7 slope. Major structural features in the play include normal faults, anticlines, and salt diapirs. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive fan depositional environments, structures, or seals.

Eugene Island 24 is the type field, and Amerada Hess Corporation's 14200 and 15000 (equals Murphy Exploration & Production's CIBOP) sands represent the MM7 F play in this field.

DISCOVERIES

The MM7 F play is predominantly a gas play, with total reserves of 0.018 Bbo and 0.239 Tcfg (0.060 BBOE), of which 0.005 Bbo and 0.137 Tcfg (0.029 BBOE) have been produced. The play contains eight producible sands in seven pools (table 1). Hydrocarbons were first found in 1980 when the maximum yearly total reserves of 41.565 MMBOE were added by the discovery of two pools, including the largest discovered pool in the play in the Eugene Island 24 field (figure 2). On a BOE basis, 17 percent of the play's cumulative production is oil, but remaining total reserves indicate that future production may increase to nearly 42 percent oil. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1993.

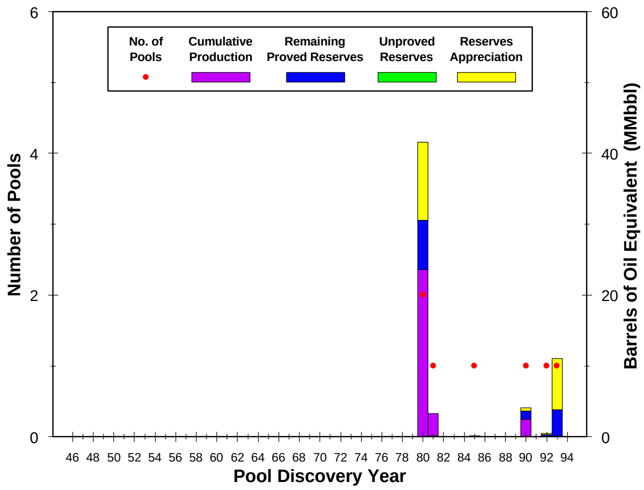


Figure 2. Exploration history graph.

The seven discovered pools range in size from 0.040 to 40.911 MMBOE. These pools contain 12 reservoirs, of which 11 are nonassociated gas and 1 is undersaturated oil.

Table 1. Characteristics of the discovered pools.

7 Pools (8 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	13	43	136
Subsea depth (feet)	12,775	14,750	16,165
Number of sands per pool	1	1	2
Porosity	18%	25%	31%
Water saturation	13%	32%	58%

Assessment Results

Because of limited data for the MM7 F play, the Middle Lower Miocene Fan (LM2 F) play was used as an analog to model pool sizes in the MM7 F play. The LM2 F play was selected as the analog due to similarities in depositional setting, structural style, hydrocarbon type, and statistical information.

The marginal probability of hydrocarbons for the MM7 F play is 1.00. The play contains a mean total endowment of 0.330 Bbo and 8.707 Tcfg (1.880 BBOE) (table 2). Less than 2 percent of this BOE mean total endowment has been produced.

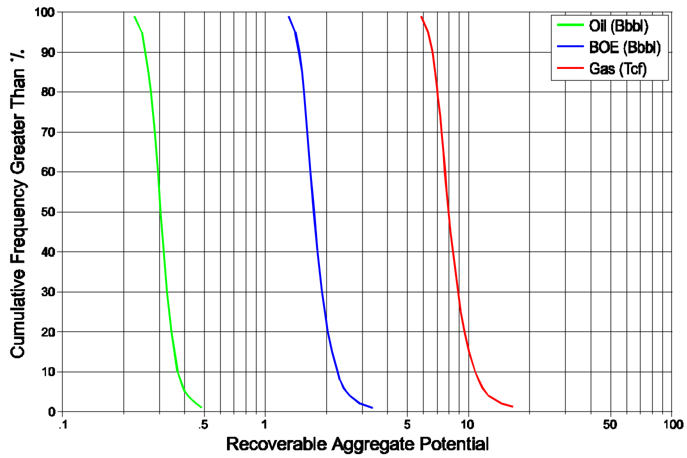


Figure 3. Cumulative probability distribution.

Assessment results indicate that undiscovered resources have a range of 0.246 to 0.403 Bbo and 6.295 to 12.071 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.312 Bbo and 8.468 Tcfg (1.820 BBOE). These undiscovered resources may occur in as many as 83 pools. The largest undiscovered pool, with a mean size of 358.620 MMBOE, is modeled as the largest pool

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	7	0.010	0.178	0.042
Cumulative production	--	0.005	0.137	0.029
Remaining proved	--	0.005	0.041	0.012
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.008	0.061	0.019
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.246	6.295	1.402
Mean	83	0.312	8.468	1.820
5th percentile	--	0.403	12.071	2.502
Total Endowment				
95th percentile	--	0.264	6.534	1.462
Mean	90	0.330	8.707	1.880
5th percentile	--	0.421	12.310	2.562

in the play (figure 4). In fact, the top 10 largest pools in the play are modeled as undiscovered accumulations on the pool rank plot. For all the undiscovered pools in the MM7 F play, the mean mean size is 21.894 MMBOE, which is significantly larger than the 8.635 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 20.863 MMBOE.

Of the 61 Gulf of Mexico Region plays and of the 15 Gulf of Mexico fan plays, the MM7 F play is projected to contain the second largest amounts of mean undiscovered gas resources, at 9 percent and 13 percent, respectively.

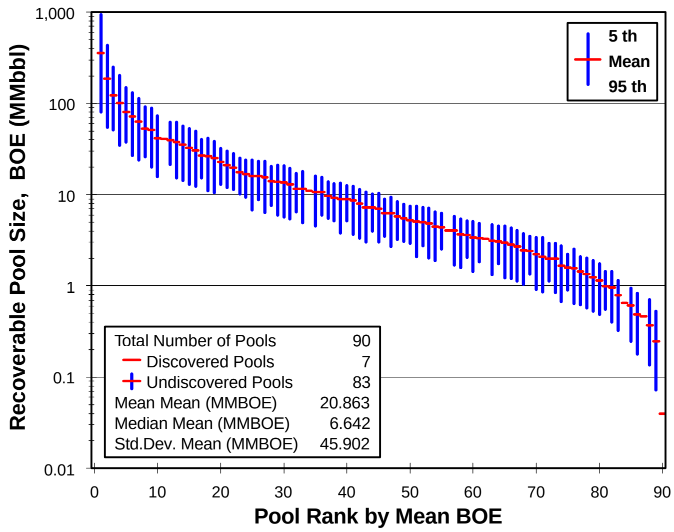


Figure 4. Pool rank plot.

The MM7 F play contains only seven discovered pools so far. Because of a large unexplored area in the play, numerous pools are expected to be found, accounting for nearly all of the play's mean total endowment. Exploration potential exists downdip and laterally of the discovered fields where wells have been too shallow to test the MM7 section.

LOWER MIDDLE MIOCENE (MM4) CHRONOZONE

CHRONOZONE DESCRIPTION

The Lower Middle Miocene (MM4) chronozone corresponds to the *Gyroidina* "K," *Cristellaria* 54, *Robulus* 43, and *Amphistegina* "B" biozones. The MM4 section reflects delta systems prograding onto the continental shelf and fan deposition on the continental slope of the Gulf of Mexico Basin. Depositional styles present in the MM4 chronozone include retrogradational, aggradational, progradational, and fan, each of which defines a play: the Lower Middle Miocene Retrogradational (MM4 R) play, the Lower Middle Miocene Aggradational (MM4 A) play, the Lower Middle Miocene Progradational (MM4 P) play, and the Lower Middle Miocene Fan (MM4 F) play.

The potential for sand development within the MM4 chronozone extends from the South Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). Updip, MM4 sands extend onshore into Texas and Louisiana. Southwestward, sand potential within the MM4 chronozone extends into Texas offshore State waters and Mexican national waters. To the northeast, sand potential is bounded by the Cretaceous carbonate shelf edge and by a decrease in sediment influx at the edge of the MM4 depocenter. The downdip limit extends at least as far as the Sigsbee Escarpment as indicated by MM4 sand development in the OCS G08512-1 well in Atwater block 471.

Productive and established sand locations in the MM4 chronozone are a result of two ancient depocenters, one in the Texas area and the other in the Louisiana area. Retrogradational, aggradational, and progradational sediments of the MM4 chronozone are much more areally extensive than those sediments of the underlying upper lower Miocene

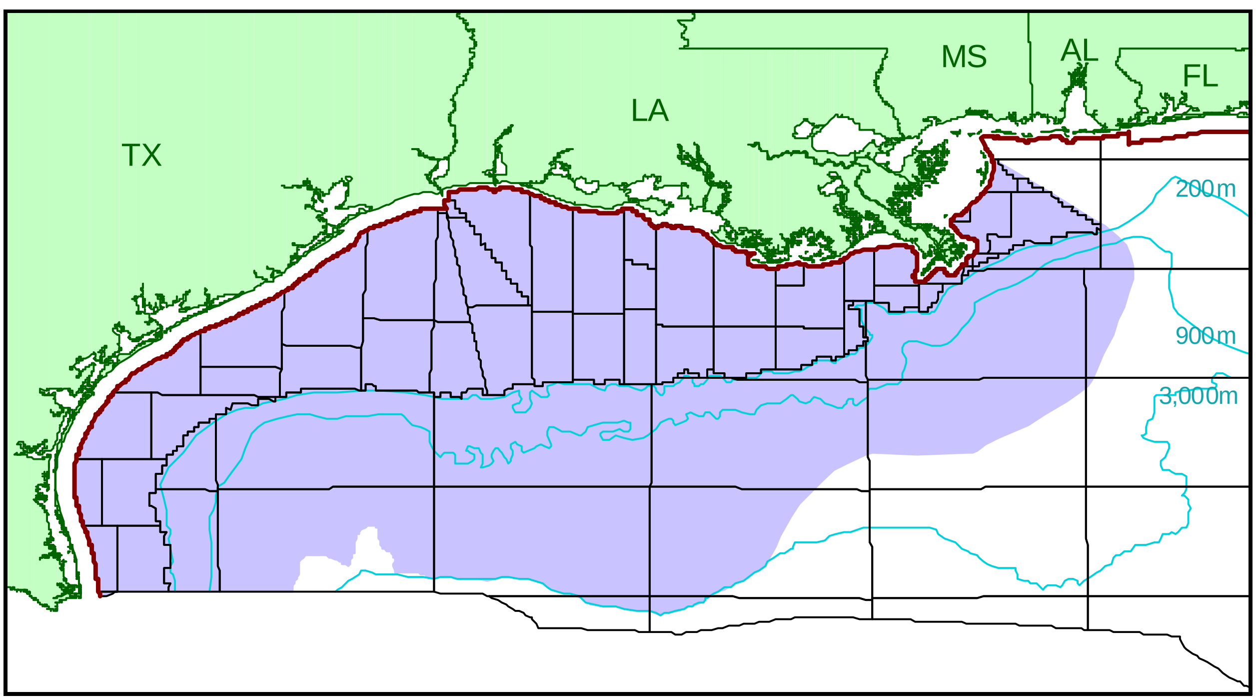


Figure 1. Map of assessed chronozone.

(LM4) chronozone. Unlike the LM4 chronozone, no productive fan sediments have been identified for the MM4 chronozone in wells west of the High Island Area. However, MM4 fan sediments are expected to be present downdip of the well-developed MM4 progradational sediments in the offshore Texas area.

Major structural features in the MM4 chronozone include normal faults, anticlines, shale diapirs, and growth faults. Less common structures include salt diapirs, rotational slump blocks, and unconformities.

DISCOVERIES

The MM4 chronozone contains 147 discovered pools in four plays (table 1). Total reserves in the chronozone are 0.205 Bbo and 11.527 Tcfg (2.256 BBOE), of which 0.143 Bbo and 7.372 Tcfg (1.455 BBOE) have been produced. The largest number of discoveries in the MM4 chronozone occurred when 16 pools were added in 1988 (figure 2). However, the maximum yearly total reserves of 225.748 MMBOE were added in 1956 with the discovery of the Vermilion 14 pool.

Of the four plays in the MM4 chronozone, the MM4 P play contains the most total reserves in 79 pools, with 0.115 Bbo and 8.331 Tcfg (1.598 BBOE).

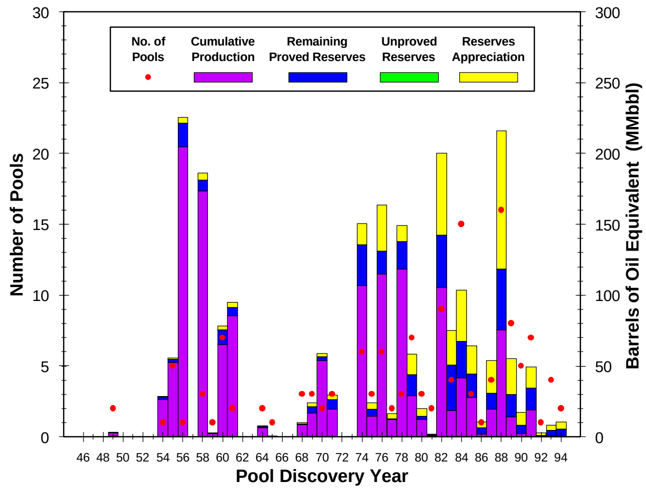


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

147 Pools (559 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	11	70	215
Subsea depth (feet)	4,574	8,566	18,000
Number of sands per pool	1	4	21
Porosity	18%	27%	33%
Water saturation	16%	31%	65%

ASSESSMENT RESULTS

The MM4 chronozone contains 271 pools (discovered plus undiscovered), with a mean total endowment estimated at 0.431 Bbo and 16.685 Tcfg (3.400 BBOE) (table 2).

Assessment results indicate that undiscovered resources may occur in as many as 124 pools, which contain a range of 0.197 to 0.257 Bbo and 4.650 to 5.699 Tcfg at the 95th and 5th percentiles, respectively (figure 3). At mean levels, 0.226 Bbo and 5.158 Tcfg (1.144 BBOE) are projected. These undiscovered resources represent 34 percent of the MM4 chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the sixth largest in the chronozone (figure 4).

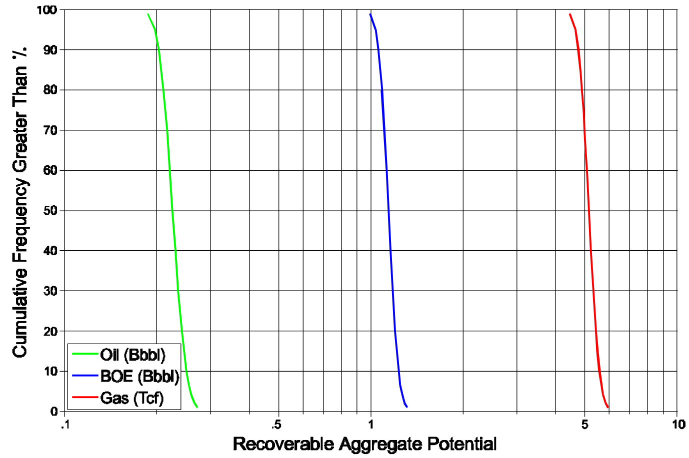


Figure 3. Cumulative probability distribution.

Of the four MM4 plays, the MM4 F play is projected to contain the greatest exploration potential, with mean undiscovered resources estimated at 0.210 Bbo and 4.059

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	147	0.176	9.242	1.821
Cumulative production	--	0.143	7.372	1.455
Remaining proved	--	0.033	1.870	0.366
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.028	2.286	0.435
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.197	4.650	1.036
Mean	124	0.226	5.158	1.144
5th percentile	--	0.257	5.699	1.258
Total Endowment				
95th percentile	--	0.402	16.177	3.292
Mean	271	0.431	16.685	3.400
5th percentile	--	0.462	17.226	3.514

Tcfg (0.932 BBOE) remaining to be found in 75 pools. These undiscovered resources in the MM4 F play represent 27 percent of the BOE mean total endowment for the MM4 chronozone. This percentage, the potential for numerous discoveries within a large unexplored area, and established fan production make the MM4 F play an attractive exploration target in MM4 strata.

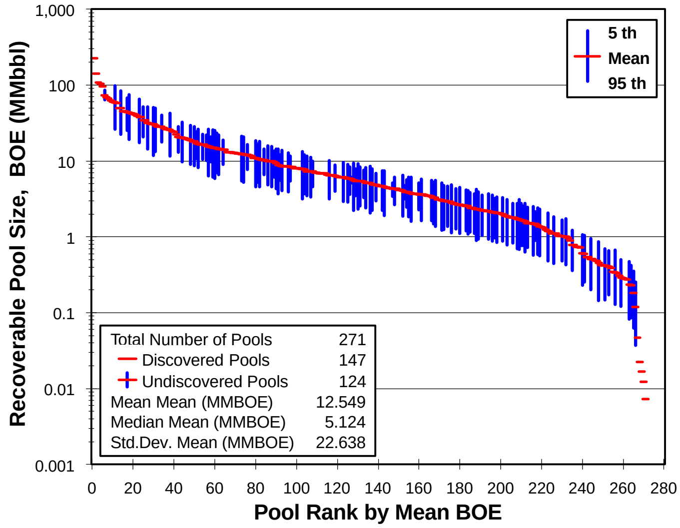


Figure 4. Pool rank plot.

LOWER MIDDLE MIOCENE RETROGRADATIONAL (MM4 R) PLAY

PLAY DESCRIPTION

The established Lower Middle Miocene Retrogradational (MM4 R) play occurs within the *Cristellaria* 54/*Eponides* 14, *Robulus* 43, and *Amphistegina* "B" biozones. This play extends from the South Padre Island Area offshore Texas through the East Cameron Area offshore Louisiana (figure 1).

Updip, the play continues onshore into Texas and Louisiana. Downdip and to the east, the play grades into the sediments of the Lower Middle Miocene Progradational (MM4 P) play. To the southwest, the MM4 R play extends onshore into Texas.

Two major depocenters existed in both upper lower Miocene (LM4) and MM4 times, one centered in the Texas area and the other centered in the Louisiana area. Deposition of retrogradational sequences in the offshore Federal area appears much more extensive for the MM4 chronozone than for the LM4 chronozone. The Upper Lower Miocene Retrogradational (LM4 R) play is confined to the offshore Texas area, while the MM4 R play extends eastward into the offshore Louisiana area.

PLAY CHARACTERISTICS

The productive MM4 R play consists of reworked marine deposits including channel/levee complexes, barrier and distributary mouth bars, and delta fringe sands. Three distinct retrogradational sequences are present in the play. They are associated with significant marine transgressions defined by the *Cristellaria* 54, the *Robulus* 43, and the *Amphistegina* "B" biozones. These retrogradational sequences locally cap either the aggradational or progradational facies of the MM4 chronozone. Major structural features in this play are normal faults, anticlines, and shale diapirs. Salt diapirs, rotational slump

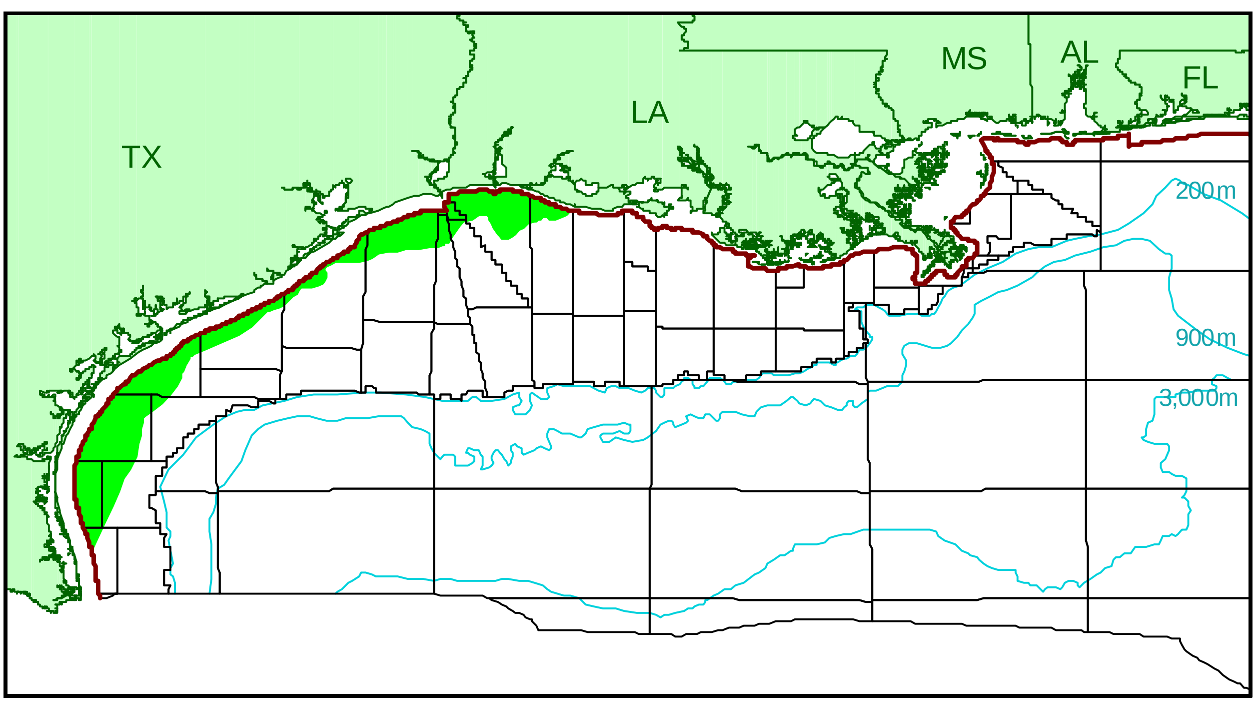


Figure 1. Map of assessed play.

blocks, and growth faults also occur, but much less frequently. Seals are provided by the juxtaposition of reservoir sands with shales and salt, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive retrogradational depositional environments, structures, or seals.

Sabine 13 is the type field, and Pennzoil Petroleum Company's MN2, MN3, and MN4 sands represent the MM4 R play in this field.

DISCOVERIES

The MM4 R gas play contains total reserves of 0.032 Bbo and 1.282 Tcfg (0.260 BBOE), of which 0.026 Bbo and 0.920 Tcfg (0.190 BBOE) have been produced. The play contains 84 producible sands in 40 pools (table 1). The first reserves in the play were discovered in the West Cameron 45 field in 1949 (figure 2). The maximum yearly total reserves of 58.689 MMBOE were added in 1970 when two pools were discovered, including the largest pool in the play in the East Cameron 33 field. In fact, 52 percent of the play's cumulative production has come from discoveries made in just two years, 1970 and 1974. Discoveries peaked in the 1980's when 16 pools were added to the play. Four pools have been discovered in the 1990's, the most recent, prior to this study's cutoff date of January 1, 1995, in 1993.

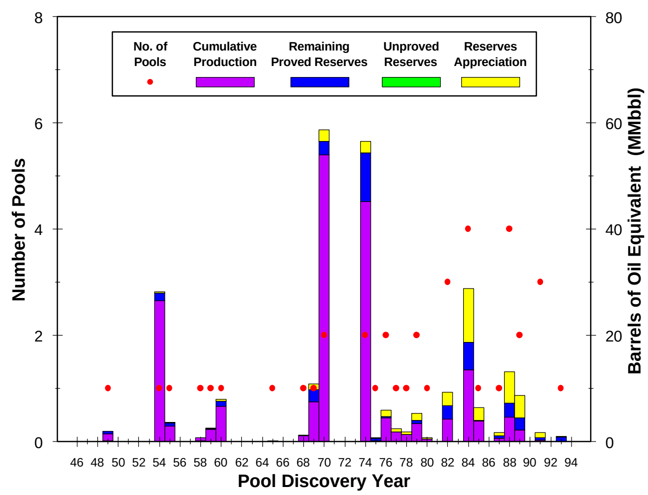


Figure 2. Exploration history graph.

The 40 discovered pools range in size from 0.017 to 58.276 MMBOE. These pools contain 157 reservoirs, of which 133 are nonassociated gas, 13 are undersaturated oil, and 11 are saturated oil.

Table 1. Characteristics of the discovered pools.

40 Pools (84 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	31	74	189
Subsea depth (feet)	4,729	7,163	14,490
Number of sands per pool	1	2	11
Porosity	24%	28%	32%
Water saturation	16%	31%	52%

Assessment Results

The marginal probability of hydrocarbons for the MM4 R play is 1.00. The play contains a mean total endowment of 0.037 Bbo and 1.529 Tcfg (0.309 BBOE) (table 2). Sixty-one percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.002 to 0.009 Bbo and 0.186 to 0.314 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.005 Bbo and 0.247 Tcfg (0.049 BBOE). These undiscovered resources may occur in as many as 15 pools. The largest undiscovered pool, with a mean size of 14.926 MMBOE, is modeled as the fifth largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 8, 14, 17, and 18 on the pool rank plot. For all the undiscovered pools in the MM4 A play, the mean mean size is 3.300 MMBOE, which is about half as large as the 6.510 MMBOE mean size of the discovered pools. The mean

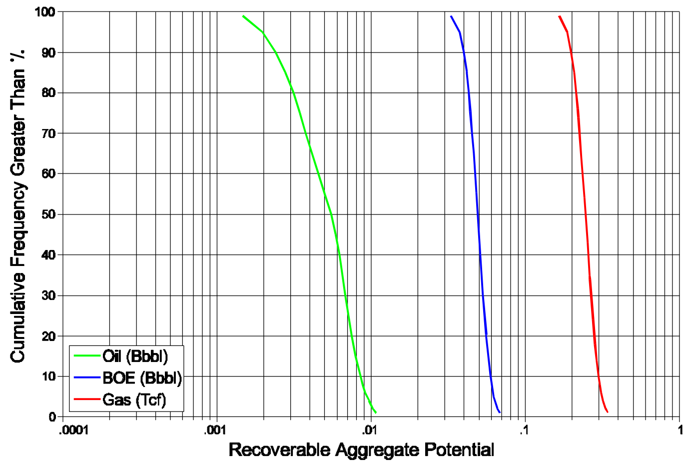


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	40	0.030	1.086	0.223
Cumulative production	--	0.026	0.920	0.190
Remaining proved	--	0.004	0.166	0.034
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.002	0.196	0.037
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.002	0.186	0.037
Mean	15	0.005	0.247	0.049
5th percentile	--	0.009	0.314	0.063
Total Endowment				
95th percentile	--	0.034	1.468	0.297
Mean	55	0.037	1.529	0.309
5th percentile	--	0.041	1.596	0.323

mean size for all pools, including both discovered and undiscovered, is 5.635 MMBOE.

The MM4 R play is well explored, with undiscovered pools expected to be limited in number. Relative to the discovered pools, the undiscovered pools are modeled to range from small to moderate in size, contributing only 16 percent to the play's BOE mean total endowment. Therefore, limited exploration potential occurs between existing fields.

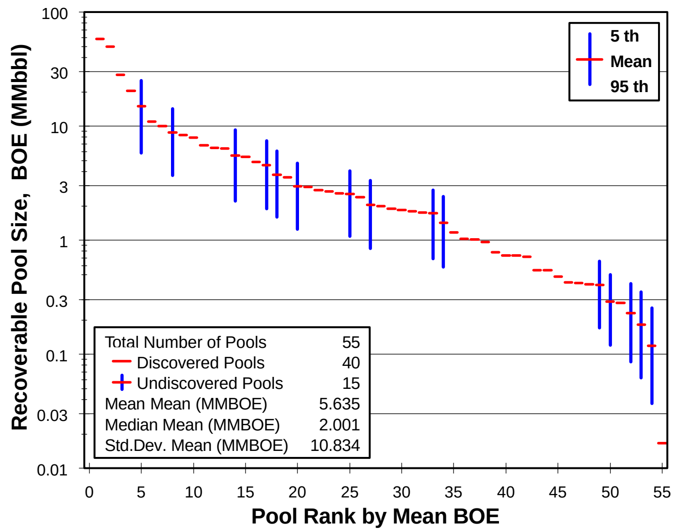


Figure 4. Pool rank plot.

LOWER MIDDLE MIOCENE AGGRADATIONAL (MM4 A) PLAY

PLAY DESCRIPTION

The established Lower Middle Miocene Aggradational (MM4 A) play occurs within the *Cristellaria* 54/*Eponides* 14, *Robulus* 43, and *Amphistegina* "B" biozones. This play extends from the North Padre Island Area offshore Texas to the East Cameron Area offshore Louisiana (figure 1).

Updip, the MM4 A play continues onshore into Texas and Louisiana. To the northeast, southwest, and downdip, the play grades into the sediments of the Lower Middle Miocene Progradational (MM4 P) play.

Two major depocenters, one centered in the Texas area and the other centered in the Louisiana area, were active in both upper lower Miocene (LM4) and MM4 times. The MM4 aggradational sediments are much more areally extensive in the offshore Federal area than the LM4 aggradational sediments. The Upper Lower Miocene Aggradational (LM4 A) play is confined to the offshore Texas area, while the MM4 A play extends eastward into the offshore Louisiana area.

PLAY CHARACTERISTICS

The productive MM4 A play consists of delta plain and adjacent shallow-water deposits. Cut-and-fill sequences formed by distributary channels occur most frequently. Crevasse splay sands, distributary mouth bars, and shelf blanket sands also characterize this play. Aggradational deposits are characteristically very sandy. They are typically the least productive of all the depositional styles because of a lack of shale to seal hydrocarbons. Well-developed retrogradational deposits associated with the *Cristellaria* 54, the *Robulus* 43, or the *Amphistegina* "B" marine transgressions locally cap the

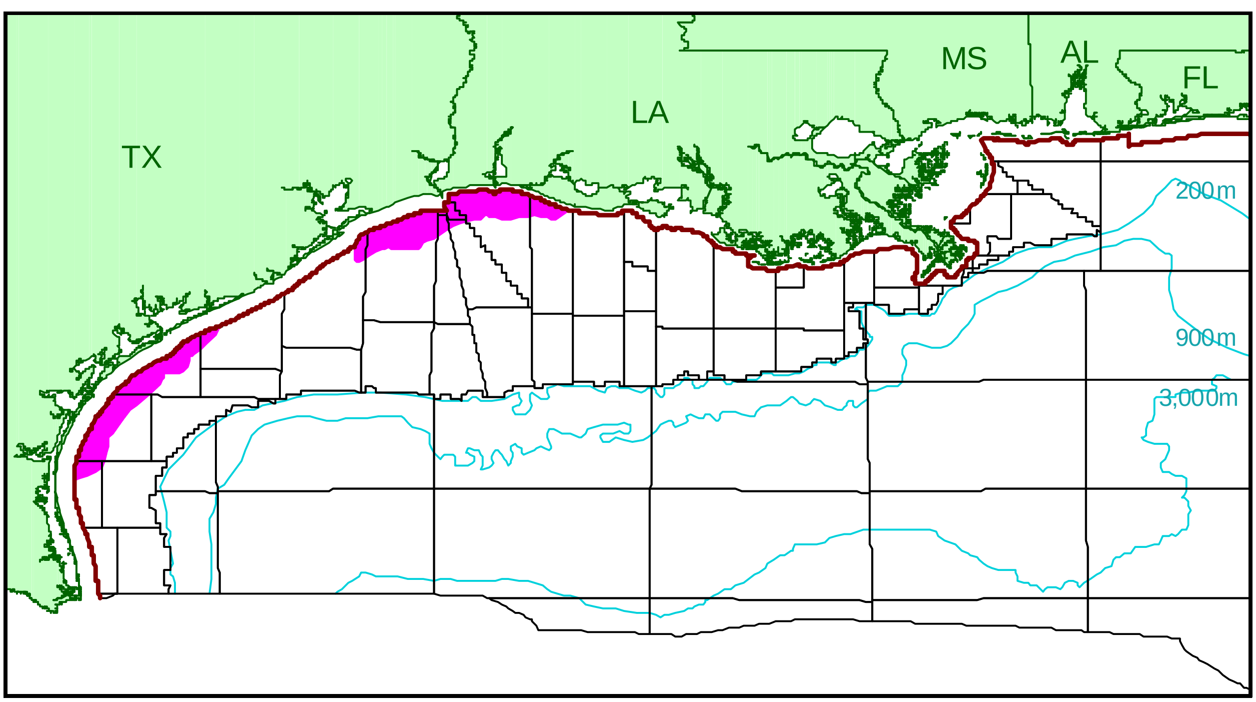


Figure 1. Map of assessed play.

aggradational deposits of the play. The major structural feature in this play is normal faulting. Anticlines, shale diapirs, and growth faults also occur. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive aggradational depositional environments, structures, or seals.

Sabine 13 is the type field, and Pennzoil Petroleum Company's MN7 and MN14 sands represent the MM4 A play in this field.

DISCOVERIES

The MM4 A gas play contains total reserves of 0.015 Bbo and 0.598 Tcfg (0.122 BBOE), of which 0.010 Bbo and 0.444 Tcfg (0.089 BBOE) have been produced. The play contains 51 producible sands in 18 pools (table 1). The first reserves in the play were discovered in the West Cameron 45 field in 1949 (figure 2). The maximum yearly total reserves were added in 1961 with the discovery of the largest pool in the play in the High Island 160 field. Two-thirds of the pool discoveries occurred during the 1960's and 1970's. In fact, 97 percent of the play's cumulative production has come from pools discovered prior to 1978. The most recent discoveries, prior to this study's cutoff date of January 1, 1995, were in 1989.

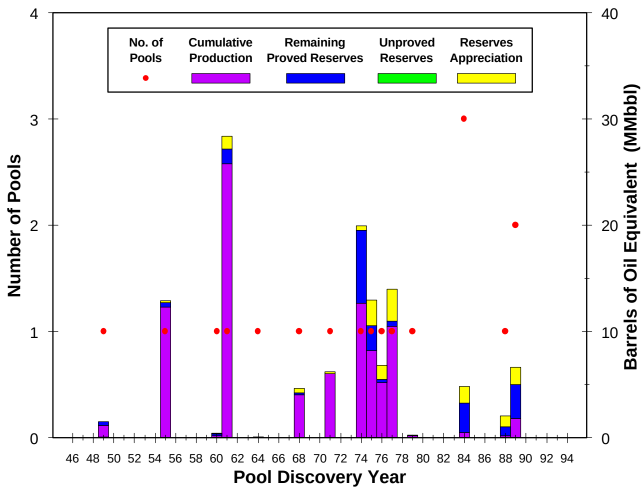


Figure 2. Exploration history graph.

The 18 discovered pools range in size from 0.012 to 28.355 MMBOE. These pools contain 80 reservoirs, of which 72 are nonassociated gas, 6 are undersaturated oil, and 2 are saturated oil.

Table 1. Characteristics of the discovered pools.

18 Pools (51 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	29	57	122
Subsea depth (feet)	4,574	7,787	10,842
Number of sands per pool	1	3	8
Porosity	20%	27%	32%
Water saturation	18%	31%	54%

Assessment Results

The marginal probability of hydrocarbons for the MM4 A play is 1.00. The play ranks within the smallest one-third of all 61 Gulf of Mexico Region plays, based on a mean total endowment of 0.015 Bbo and 0.627 Tcfg (0.127 BBOE) (table 2). Seventy percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources range from less than 0.001 to 0.001 Bbo and 0.018 to 0.041 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are insignificant for oil (<0.001 Bbbl) and 0.029 Tcfg (0.005 BBOE). These undiscovered resources may occur in as many as four pools. The largest undiscovered pool, with a mean size of 2.335 MMBOE, is modeled as the twelfth largest pool in the play (figure 4). The model results place the remaining three undiscovered pools in positions 14, 16, and 18 on the pool rank plot. For all the undiscovered pools in the MM4 A play, the mean mean size is 1.405 MMBOE, which is smaller than the 6.756 MMBOE mean size of the

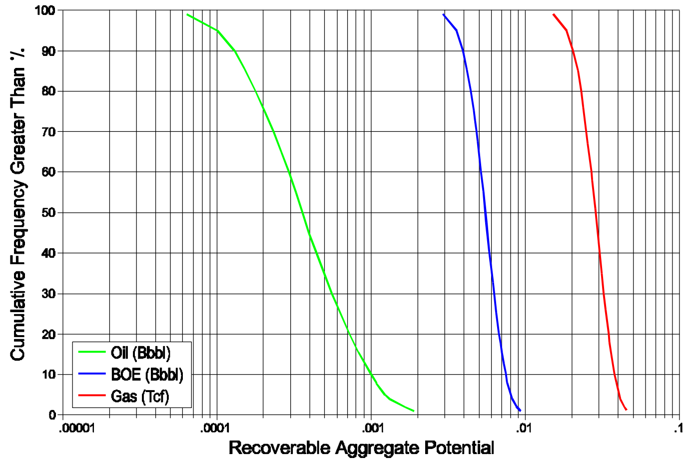


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	**Number of Pools**	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Reserves				
Original proved	18	0.015	0.525	0.108
Cumulative production	--	0.010	0.444	0.089
Remaining proved	--	0.005	0.081	0.019
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.001	0.073	0.013
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.018	0.004
Mean	4	<0.001	0.029	0.005
5th percentile	--	0.001	0.041	0.008
Total Endowment				
95th percentile	--	0.015	0.616	0.126
Mean	22	0.015	0.627	0.127
5th percentile	--	0.016	0.639	0.130

discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 5.783 MMBOE.

Because of a lack of seals in this sand-rich play and the high drilling density, the MM4 A play is modeled to have very limited potential for discoveries. Relative to the discovered pools, undiscovered pools are expected to be small in size, accounting for only 4 percent of the play's BOE mean total endowment.

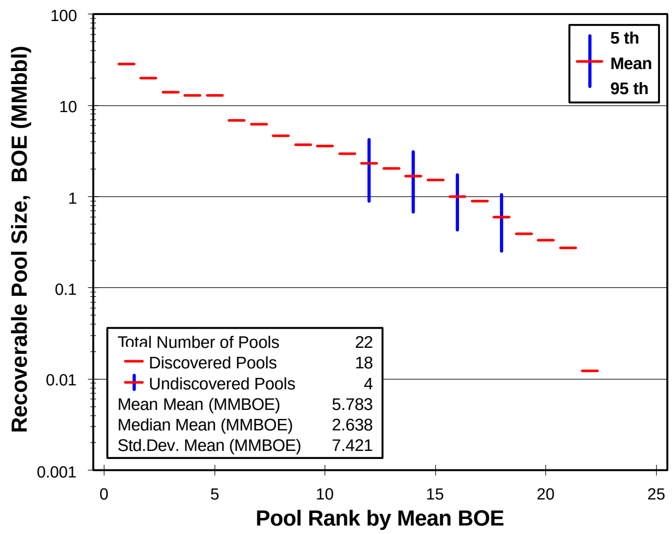


Figure 4. Pool rank plot.

LOWER MIDDLE MIOCENE PROGRADATIONAL (MM4 P) PLAY

PLAY DESCRIPTION

The established Lower Middle Miocene Progradational (MM4 P) play occurs within the *Gyroidina* "K," *Cristellaria* 54/*Eponides* 14, *Robulus* 43, and *Amphistegina* "B" biozones. This play extends from the South Padre Island Area offshore Texas to the northwestern portion of the Eugene Island Area offshore Louisiana (figure 1).

Updip, the play continues onshore into Texas and Louisiana. To the northeast, the MM4 P play continues onshore into Louisiana. To the southwest, the play extends into Texas offshore State waters and Mexican national waters. Downdip, the play is limited by a lack of sand or grades into the deposits of the Lower Middle Miocene Fan (MM4 F) play.

Two major depocenters were active in both upper lower Miocene (LM4) and MM4 times, one centered in the Texas area and the other centered in the Louisiana area. Deposition of progradational sediments appears much more continuous in the offshore Texas and Louisiana areas in the MM4 chronozone than in the LM4 chronozone. The MM4 progradational sediments also show a basinward shift from those of the LM4 chronozone due to prograding of the ancient delta systems.

PLAY CHARACTERISTICS

The productive MM4 P play consists of progradational deltaic sediments deposited in delta fringe, shelf blanket, distributary mouth bar, channel, and crevasse splay environments. Well-developed retrogradational deposits associated with the *Cristellaria* 54, the *Robulus* 43, or the *Amphistegina* "B" marine transgressions locally cap the progradational deposits of the MM4 P play. Major structural features in this play are normal faults and anticlines. Growth faults, shale diapirs, and unconformities are also

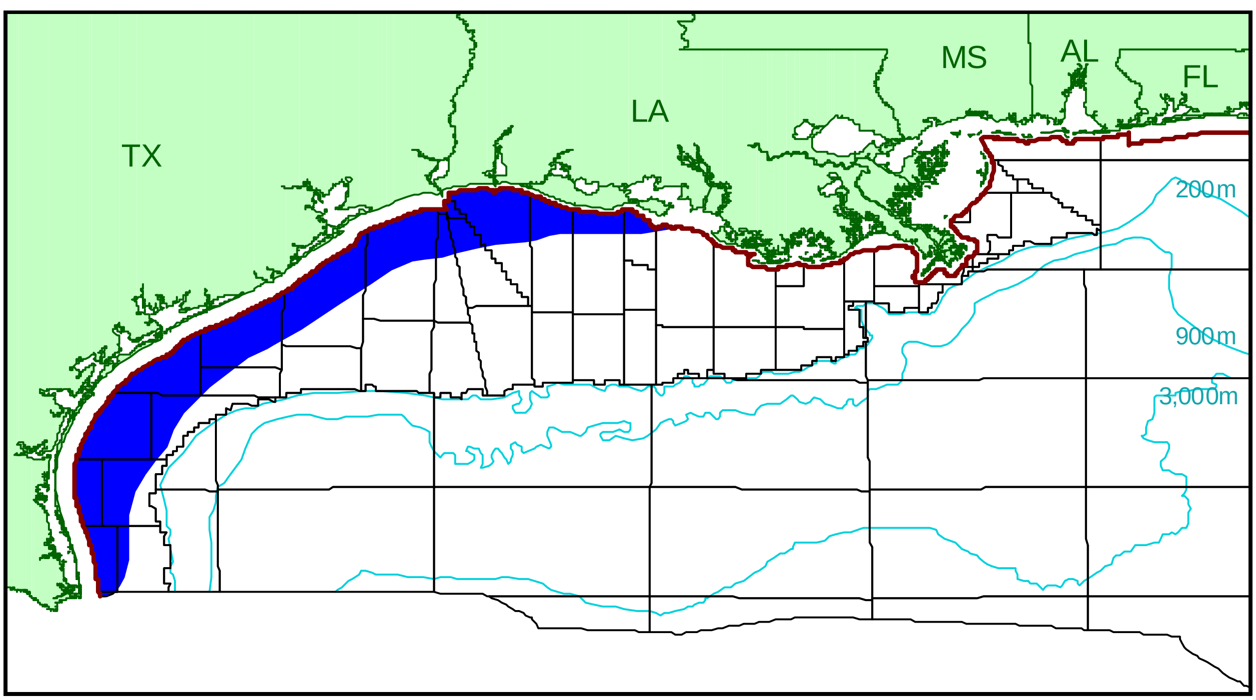


Figure 1. Map of assessed play.

present. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting, diapiric piercement) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive progradational depositional environments, structures, or seals.

Mustang Island 31A is the type field, and Chevron USA Inc.'s 8100, 8700, ST 9773/9661, 8900, 9100, 9200, and 9700 sands represent the MM4 P play in this field.

DISCOVERIES

The MM4 P gas play contains total reserves of 0.115 Bbo and 8.331 Tcfg (1.598 BBOE), of which 0.083 Bbo and 5.136 Tcfg (0.997 BBOE) have been produced. The play contains 400 producible sands in 79 pools (table 1). The first reserves in the play were discovered in the Galveston 189 field in 1955 (figure 2). The maximum yearly total reserves were added in 1956 by the discovery of the largest pool in the play in the Vermilion 14 field. Fifty-three percent of the play's cumulative production has come from pools discovered prior to 1962. However, almost 60 percent of the total reserves are in pools discovered in 1976 or later.

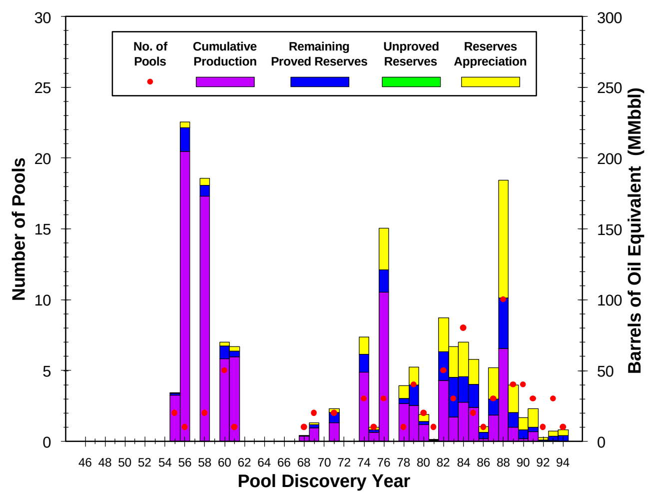


Figure 2. Exploration history graph.

The number of pool discoveries peaked in the 1980's at 39. In the 1990's, 12 pools have already been discovered. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1994.

The 79 discovered pools range in size from 0.007 to 225.748 MMBOE. These pools contain 604 reservoirs, of which 577 are nonassociated gas, 18 are undersaturated oil, and 9 are saturated oil.

Of the 61 Gulf of Mexico Region plays, the MM4 P play ranks as the tenth largest hydrocarbon producer (3%), based on BOE.

Table 1. Characteristics of the discovered pools.

79 Pools (400 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	11	74	215
Subsea depth (feet)	5,560	8,779	15,900
Number of sands per pool	1	5	21
Porosity	18%	27%	33%
Water saturation	16%	32%	65%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the MM4 P play is 1.00. The play contains a mean total endowment of 0.126 Bbo and 9.154 Tcfg (1.756 BBOE) (table 2). Fifty-seven percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.006 to 0.019 Bbo and 0.674 to 0.984 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.011 Bbo and 0.823 Tcfg (0.158 BBOE). These undiscovered resources may occur in as many as 30 pools. The largest undiscovered pool, with a mean size of 30.267 MMBOE, is modeled as the eighteenth largest pool in the play (figure 4). For all the undiscovered pools in the MM4 P play, the mean mean size is 5.267 MMBOE, which is substantially smaller than the 20.225 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 16.108 MMBOE.

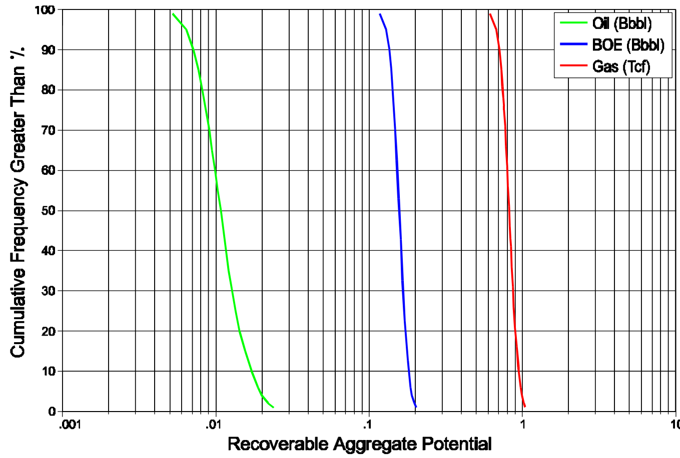


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	**Number of Pools**	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Reserves				
Original proved	79	0.098	6.525	1.259
Cumulative production	--	0.083	5.136	0.997
Remaining proved	--	0.015	1.389	0.262
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.017	1.806	0.339
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.006	0.674	0.129
Mean	30	0.011	0.823	0.158
5th percentile	--	0.019	0.984	0.189
Total Endowment				
95th percentile	--	0.121	9.005	1.727
Mean	109	0.126	9.154	1.756
5th percentile	--	0.134	9.315	1.787

The largest pools in this play are modeled as already discovered. Relative to the discovered pools, undiscovered pools are expected to range from small to moderate in size. Their contribution to the play's BOE mean total endowment is only 9 percent. Future discoveries may occur between existing fields in this well explored play.

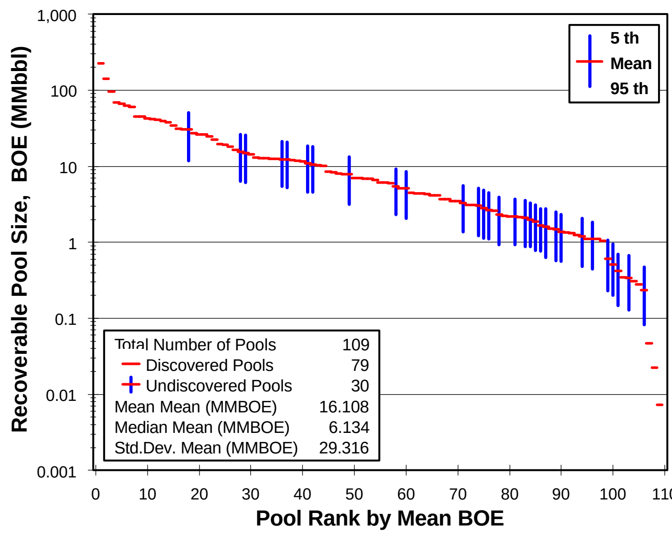


Figure 4. Pool rank plot.

LOWER MIDDLE MIOCENE FAN (MM4 F) PLAY

PLAY DESCRIPTION

The established Lower Middle Miocene Fan (MM4 F) play occurs within the *Gyroidina* "K," *Cristellaria* 54/*Eponides* 14, *Robulus* 43, and *Amphistegina* "B" biozones. This play extends from the South Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the MM4 F play continues onshore into Louisiana or is bounded by the shelf/slope break associated with the *Amphistegina* "B" biozone and grades into the deposits of the Lower Middle Miocene Progradational (MM4 P) play. To the southwest, the MM4 F play extends into Texas offshore State waters and Mexican national waters. To the northeast, the play is bounded by the Cretaceous carbonate shelf edge and a decrease in sediment influx at the edge of the MM4 depocenter. The southern extension of the play's potential to at least the Sigsbee Escarpment is supported by MM4 sand development in the OCS G08512-1 well in Atwater block 471.

Two major depocenters were active in both upper lower Miocene (LM4) and MM4 times, one centered in the Texas area and the other centered in the Louisiana area. Fan deposition in the underlying LM4 chronozone is best developed in the Mustang Island to Brazos Areas offshore Texas. During MM4 time, fans appear best developed farther east from the High Island to Vermilion Areas.

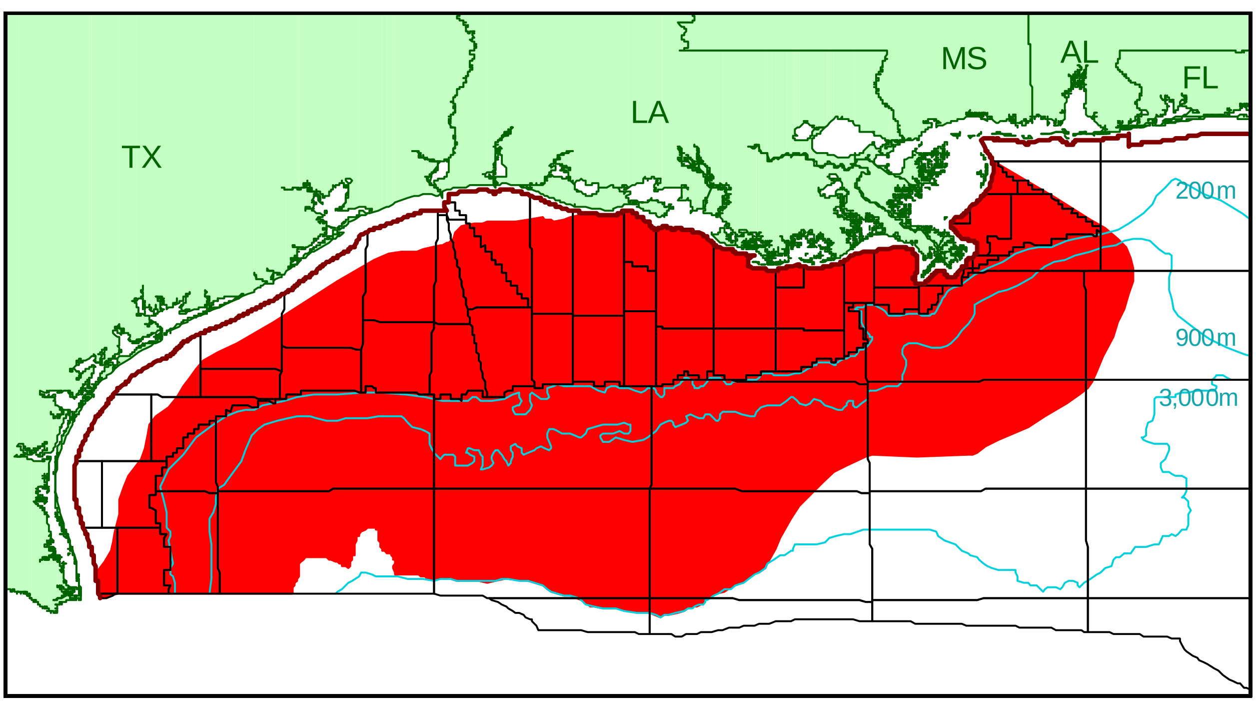


Figure 1. Map of assessed play.

PLAY CHARACTERISTICS

The productive MM4 F play consists of deepwater turbidites deposited in fan systems as channel fill, fan lobes, and fringe sheet sediments on the MM4 slope. Normal faults are the major structural feature in this play. Less common structures include anticlines and growth faults. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive fan depositional environments, structures, or seals.

East Cameron 60 is the type field, and Vastar Resources Inc.'s PQ sand represents the MM4 F play in this field.

DISCOVERIES

The MM4 F gas play contains total reserves of 0.042 Bbo and 1.316 Tcfg (0.276 BBOE), of which 0.024 Bbo and 0.871 Tcfg (0.179 BBOE) have been produced. The play contains 24 producible sands in 10 pools (table 1). The first reserves in the play were discovered in the East Cameron 49 field in 1955 (figure 2). The maximum yearly total reserves were added in 1978 with the discovery of the largest pool in the play in the Vermilion 14 field. Only one pool was discovered in any given year in the MM4 F play. Two of these pools, the Vermilion 14 and 24 fields, account for over 75 percent of the BOE total reserves in the play. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1994.

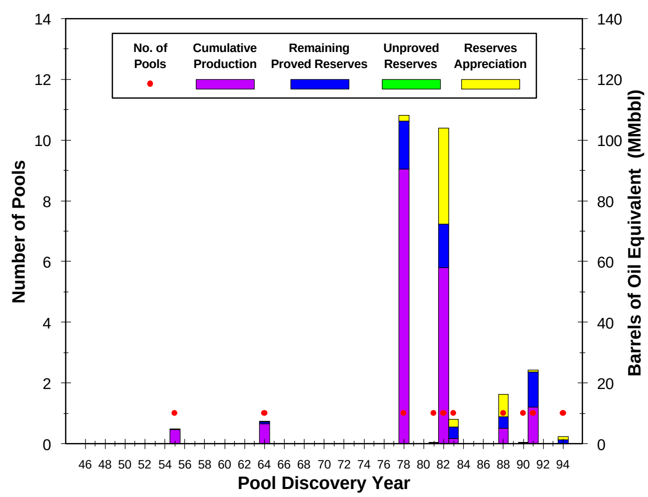


Figure 2. Exploration history graph.

The 10 discovered pools range in size from 0.490 to 108.225 MMBOE. These pools contain 26 reservoirs, of which 25 are nonassociated gas and 1 is undersaturated oil.

Table 1. Characteristics of the discovered pools.

10 Pools (24 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	25	43	55
Subsea depth (feet)	10,127	13,898	18,000
Number of sands per pool	1	2	7
Porosity	18%	23%	28%
Water saturation	19%	30%	56%

Assessment Results

The marginal probability of hydrocarbons for the MM4 F play is 1.00. The play contains a mean total endowment of 0.252 Bbo and 5.375 Tcfg (1.208 BBOE) (table 2). Fifteen percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.187 to 0.234 Bbo and 3.666 to 4.458 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.210 Bbo and 4.059 Tcfg (0.932 BBOE). These undiscovered resources may occur in as many as 75 pools. The largest undiscovered pool, with a mean size of 72.829 MMBOE, is modeled as the third largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 4, 5, 6, and 7 on the pool rank plot. For all the undiscovered pools in the MM4 F play, the mean mean size is 12.422 MMBOE, which is significantly smaller than the 27.610 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and

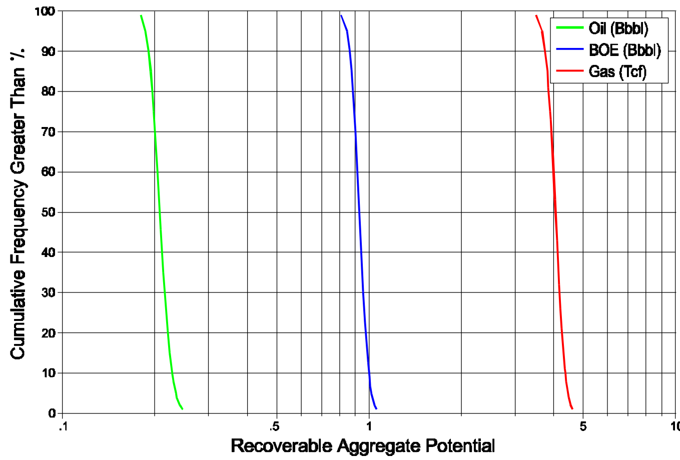


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	10	0.034	1.105	0.231
Cumulative production	--	0.024	0.871	0.179
Remaining proved	--	0.010	0.234	0.051
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.008	0.211	0.046
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.187	3.666	0.846
Mean	75	0.210	4.059	0.932
5th percentile	--	0.234	4.458	1.019
Total Endowment				
95th percentile	--	0.229	4.982	1.122
Mean	85	0.252	5.375	1.208
5th percentile	--	0.276	5.774	1.295

undiscovered, is 14.209 MMBOE.

Of the 61 plays in the Gulf of Mexico Region, the MM4 F play is projected to contain the eighth largest amount of mean undiscovered gas resources at 4 percent.

A large unexplored area supports the potential for numerous discoveries in the play. Relative to the discovered pools, undiscovered pools are modeled to occur at all pool-size levels, accounting for 77 percent of the play's BOE mean total endowment. Potential for discoveries occurs to the west, east, and downdip of existing fields where the MM4 fan deposits have not been reached by drilling. Specifically, MM4 fan deposits have not as yet been identified west of the High Island Area in the Federal offshore, but they are assumed to be present downdip of the well-developed MM4 P play.

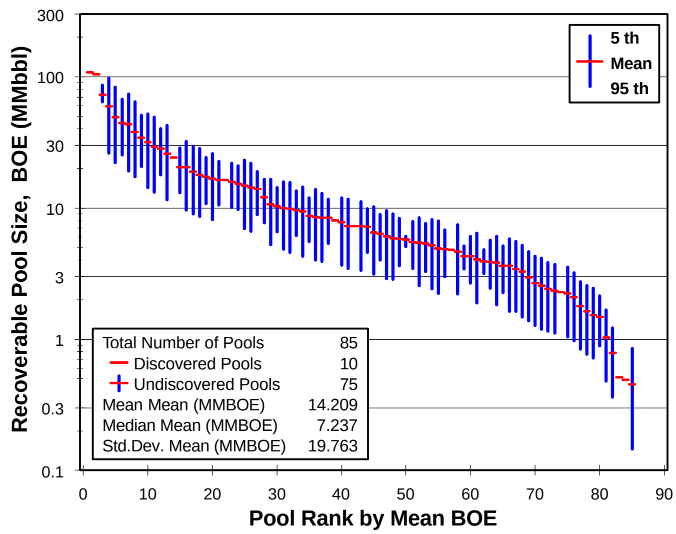


Figure 4. Pool rank plot.

Upper Lower Miocene (LM4) Chronozone

Chronozone Description

The Upper Lower Miocene (LM4) chronozone corresponds to the *Marginulina ascensionensis* and *Discorbis bolivina* biozones. The LM4 section reflects delta systems prograding onto the continental shelf and fan deposition on the continental slope of the Gulf of Mexico Basin. Depositional styles present in the LM4 chronozone include retrogradational, aggradational, progradational, and fan, each of which defines a play: the Upper Lower Miocene Retrogradational (LM4 R) play, the Upper Lower Miocene Aggradational (LM4 A) play, the Upper Lower Miocene Progradational (LM4 P) play, and the Upper Lower Miocene Fan (LM4 F) play.

The potential for sand development within the LM4 chronozone extends from the South Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). Updip, LM4 sands extend onshore into Texas and Louisiana. To the southwest, sand potential extends into Texas offshore State waters and Mexican national waters. To the northeast, sand potential is bounded by the Cretaceous carbonate shelf edge and by a decrease in sediment influx at the edge of the LM4 depocenter. The downdip limit extends at least as far as the Sigsbee Escarpment as indicated by LM4 sand development in the OCS G08512-1 well in Atwater block 471.

Productive and established sand locations in the LM4 chronozone are a result of two ancient depocenters, one in the Texas area and the other in the Louisiana area. In the offshore Texas area, no significant lateral shift in depocenter is observed from the underlying middle lower Miocene (LM2) chronozone to the LM4 chronozone. However, the ancient Texas delta systems had prograded more basinward by LM4 time, depositing

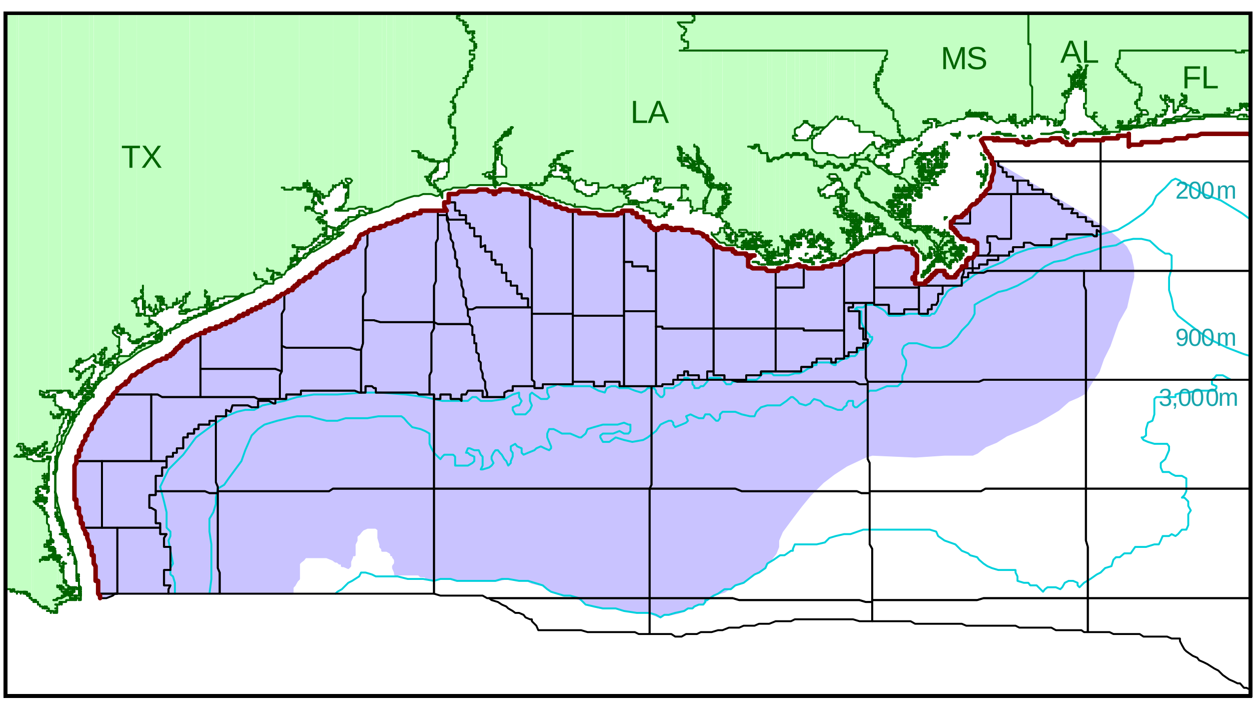


Figure 1. Map of assessed chronozone.

retrogradational and aggradational sediments in the present-day offshore Texas area.

Similarly in the offshore Louisiana area, no significant lateral shift in depocenter is observed from the LM2 chronozone to the LM4 chronozone. There still were no retrogradational or aggradational sediments offshore Louisiana through LM4 time.

Normal faults, anticlines, and growth faults are the dominant structural features in the LM4 chronozone. Less common structures include shale diapirs and rotational slump blocks.

DISCOVERIES

The LM4 chronozone contains 69 discovered pools in four plays (table 1). Total reserves in the chronozone are 0.043 Bbo and 4.482 Tcfg (0.841 BBOE), of which 0.030 Bbo and 2.377 Tcfg (0.453 BBOE) have been produced. The largest number of discoveries in the LM4 chronozone occurred when 10 pools were added in 1982 (figure 2). However, the maximum yearly total reserves of 152.424 MMBOE were added in 1988 when nine pools were discovered.

Of the four plays in the LM4 chronozone, the LM4 P play contains the most total reserves in 41 pools, with 0.040 Bbo and 3.458 Tcfg (0.655 BBOE).

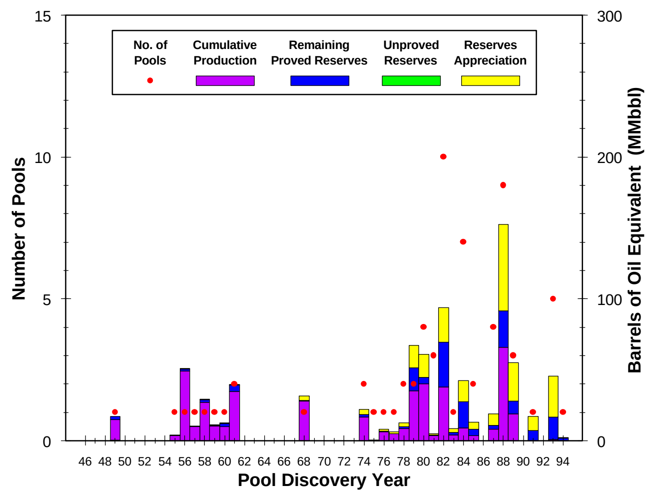


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

69 Pools (196 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	29	94	215
Subsea depth (feet)	5,230	8,947	13,250
Number of sands per pool	1	3	13
Porosity	20%	26%	31%
Water saturation	10%	30%	54%

ASSESSMENT RESULTS

The LM4 chronozone contains 181 pools (discovered plus undiscovered), with a mean total endowment estimated at 0.144 Bbo and 9.163 Tcfg (1.775 BBOE) (table 2).

Assessment results indicate that undiscovered resources may occur in as many as 112 pools, which contain a range of 0.065 to 0.148 Bbo and 3.596 to 5.953 Tcfg at the 95th and 5th percentiles, respectively (figure 3). At mean levels, 0.101 Bbo and 4.681 Tcfg (0.934 BBOE) are projected. These undiscovered resources represent 53 percent of the LM4 chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the largest in the chronozone (figure 4).

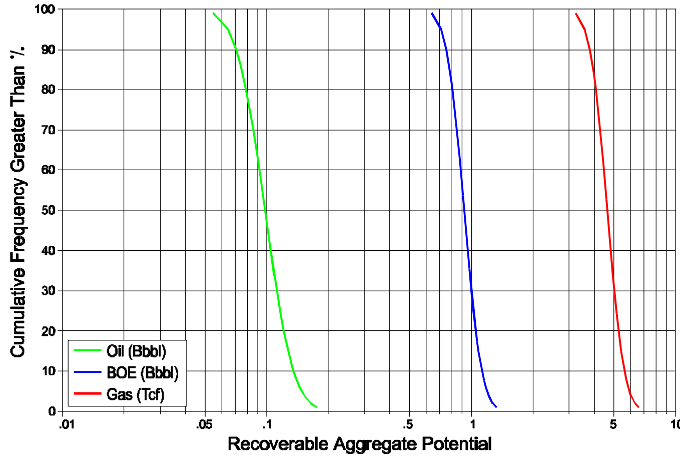


Figure 3. Cumulative probability distribution.

Of the four LM4 plays, the LM4 F play is projected to contain the greatest exploration potential, with mean undiscovered resources estimated at 0.090 Bbo and 3.446 Tcfg (0.703 BBOE) remaining to be found in 78 pools. These undiscovered resources in

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	69	0.036	3.227	0.610
Cumulative production	--	0.030	2.377	0.453
Remaining proved	--	0.006	0.849	0.157
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.007	1.255	0.231
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.065	3.596	0.712
Mean	112	0.101	4.681	0.934
5th percentile	--	0.148	5.953	1.195
Total Endowment				
95th percentile	--	0.108	8.078	1.553
Mean	181	0.144	9.163	1.775
5th percentile	--	0.191	10.435	2.036

the LM4 F play represent 40 percent of the BOE mean total endowment for the LM4 chronozone. This high percentage and the potential for numerous discoveries within a large unexplored area make the LM4 F play an attractive exploration target in LM4 strata.

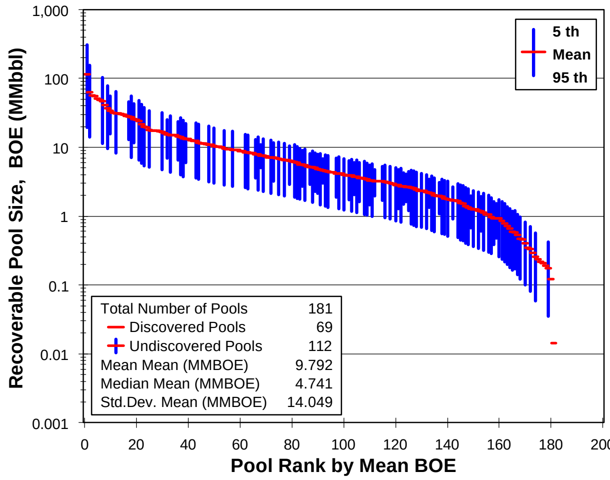


Figure 4. Pool rank plot.

UPPER LOWER MIOCENE RETROGRADATIONAL (LM4 R) PLAY

PLAY DESCRIPTION

The established Upper Lower Miocene Retrogradational (LM4 R) play occurs at the *Discorbis bolivarensis* biozone. This play extends from the North Padre Island Area to the northwestern edge of the Brazos Area offshore Texas. There are no discovered retrogradational sands in offshore Louisiana (figure 1).

Updip, the play continues onshore into Texas. Downdip, the play grades into the deposits of the Upper Lower Miocene Aggradational (LM4 A) and Upper Lower Miocene Progradational (LM4 P) plays.

The location of the LM4 R play is a result of an ancient depocenter located in the Texas area. No significant lateral shift in this depocenter is observed in the offshore Texas area from the underlying middle lower Miocene (LM2) chronozone to the LM4 chronozone. However, the ancient delta systems had progaded more basinward by LM4 time, depositing the retrogradational sands that compose this play in the present-day offshore Texas area. Middle lower Miocene retrogradational sediments have not been discovered as yet in offshore Texas.

PLAY CHARACTERISTICS

The productive LM4 R play is characterized by upward-fining, back-stepping sands. These reworked marine deposits include channel/levee complexes, distributary mouth bars, barrier bars, and delta fringe sands. The deposits in this play are associated with a significant marine transgression defined by the *Discorbis bolivarensis* biozone. These retrogradational deposits cap either the aggradational or progradational sediments of the LM4 chronozone. Major structural features in this play are anticlines and normal faults.

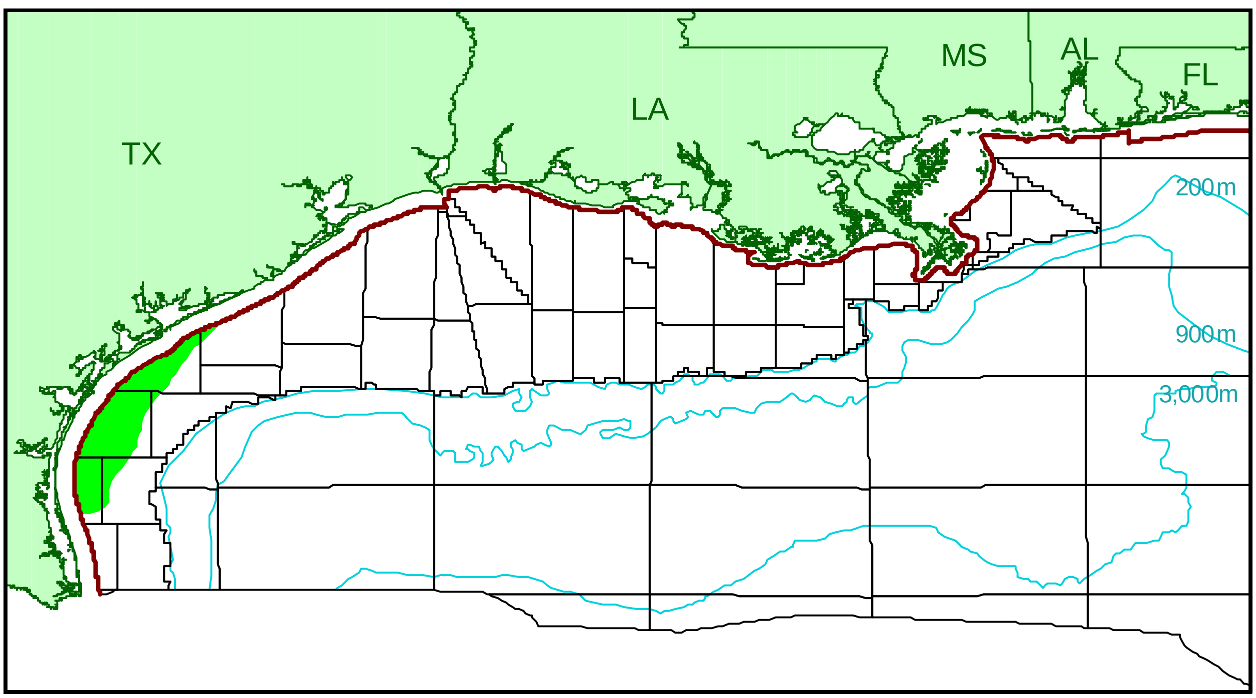


Figure 1. Map of assessed play.

Less common structures are growth faults and shale diapirs. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive retrogradational depositional environments, structures, or seals.

Matagorda Island 703 is the type field, and Vastar Resources Inc.'s FT/1234 sand represents the LM4 R play in this field.

DISCOVERIES

The LM4 R gas play contains total reserves of 0.002 Bbo and 0.503 Tcfg (0.091 BBOE), of which 0.001 Bbo and 0.161 Tcfg (0.029 BBOE) have been produced. The play contains 29 producible sands in 15 pools (table 1). The first reserves in the play were discovered in the Mustang Island 757 field in 1976 (figure 2). The maximum yearly total reserves of 25.313 MMBOE were added in 1982 when six pools were discovered, including the largest pool in the play in the Matagorda Island 703 field. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1993.

The 15 discovered pools range in size from 0.192 to 19.261 MMBOE. These pools contain 38 reservoirs, all of which are nonassociated gas.

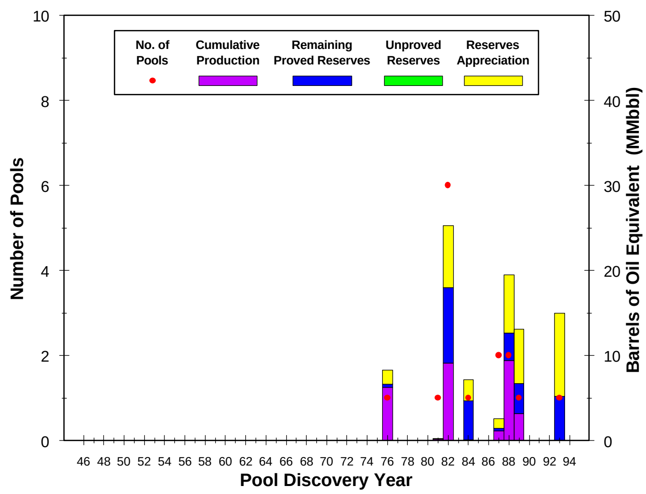


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

15 Pools (29 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	77	125	215
Subsea depth (feet)	5,230	7,457	11,091
Number of sands per pool	1	2	4
Porosity	22%	27%	31%
Water saturation	19%	36%	54%

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	15	0.001	0.306	0.055
Cumulative production	--	0.001	0.161	0.029
Remaining proved	--	<0.000	0.145	0.026
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.001	0.197	0.036
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.092	0.016
Mean	8	<0.001	0.114	0.020
5th percentile	--	<0.001	0.139	0.025
Total Endowment				
95th percentile	--	0.002	0.595	0.107
Mean	23	0.002	0.617	0.111
5th percentile	--	0.002	0.642	0.116

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the LM4 R play is 1.00. The play ranks within the smallest one-third of all 61 Gulf of Mexico Region plays, based on a mean total endowment of 0.002 Bbo and 0.617 Tcfg (0.111 BBOE) (table 2). Twenty-six percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered oil resources are insignificant (<0.001 Bbbl) and that undiscovered gas resources have a range of 0.092 to 0.139 Tcf at the 95th and 5th percentiles, respectively (figure 3). The estimated amount of mean undiscovered gas is 0.114 Tcf (0.020 BBOE). These undiscovered resources may occur in as many as eight pools. The largest undiscovered pool, with a mean size of 5.168 MMBOE, is modeled as the seventh largest pool in the play (figure 4). For all the undiscovered pools in the LM4 R play, the mean mean size is 2.572 MMBOE, which is smaller than the 6.074 MMBOE

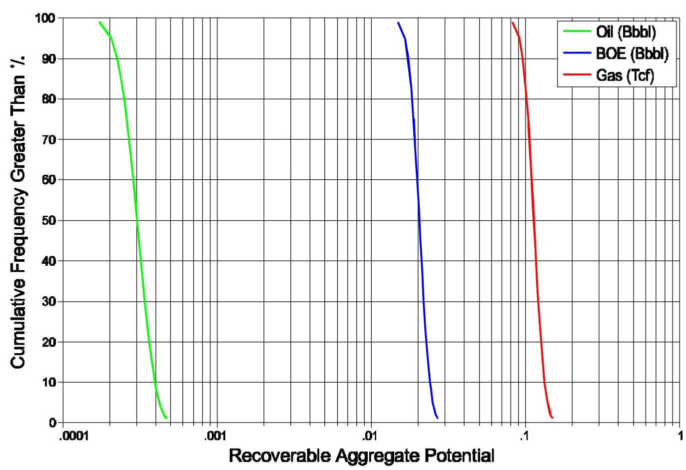


Figure 3. Cumulative probability distribution.

mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 4.856 MMBOE.

The LM4 R play is well explored. Relative to the discovered pools in the play, the undiscovered pools are expected to be moderate in size. These undiscovered resources are expected to contribute only 18 percent to the play's BOE mean total endowment. Limited interfield exploration potential exists in small untested structures and stratigraphic traps.

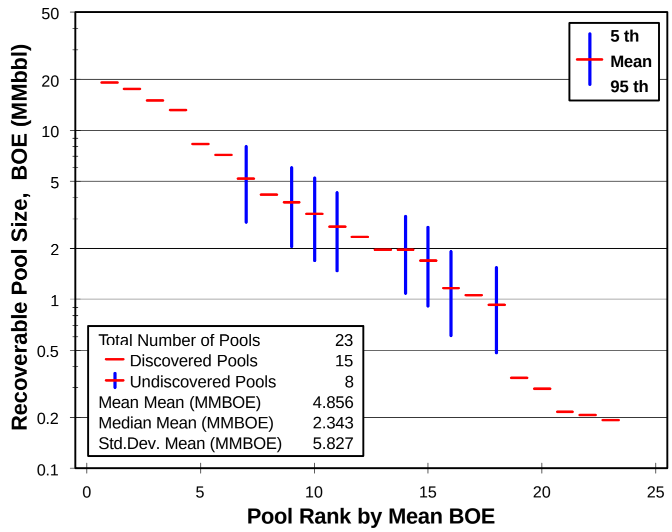


Figure 4. Pool rank plot.

UPPER LOWER MIOCENE AGGRADATIONAL (LM4 A) PLAY

PLAY DESCRIPTION

The established Upper Lower Miocene Aggradational (LM4 A) play occurs within the *Marginulina ascensionensis* and *Discorbis bolivarensis* biozones. This play extends from the North Padre Island Area to the eastern edge of the Matagorda Island Area offshore Texas. There are no discovered aggradational sands in offshore Louisiana (figure 1).

Updip and along strike, the play continues onshore into Texas. Downdip, the play grades into the deposits of the Upper Lower Miocene Progradational (LM4 P) play.

The location of the LM4 A play is a result of an ancient depocenter located in the Texas area. No significant lateral shift in this depocenter is observed from the underlying middle lower Miocene (LM2) chronozone to the LM4 chronozone. However, the ancient delta systems had prograded more basinward by LM4 time, depositing the aggradational sands that compose this play. Middle lower Miocene aggradational sediments have not been discovered as yet in offshore Texas.

PLAY CHARACTERISTICS

The productive LM4 A play is characterized by a thick, shelf-building section with coarse sands, often blocky in log character. These sands were deposited in delta plain and adjacent shallow-water environments and include channels and stacked channels, distributary mouth bars, shelf blanket deposits, crevasse splays, and delta fringe deposits. Major structural features in this play are normal faults, growth faults, and anticlines. Less common structures include shale diapirs. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the

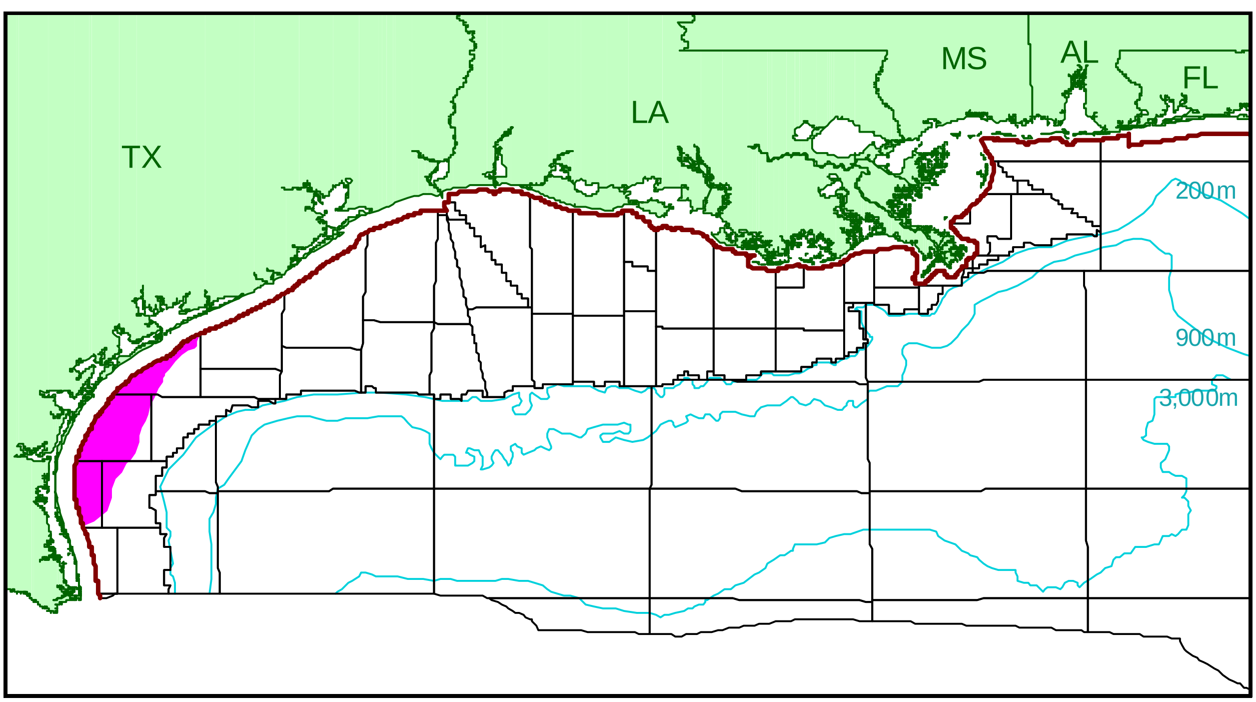


Figure 1. Map of assessed play.

aforementioned productive aggradational depositional environments, structures, or seals.

Mustang Island 31A is the type field, and Chevron USA Inc.'s MP-2, MP-3A, MP-3C, and MP4B sands represent the LM4 A play in this field.

Discoveries

The LM4 A gas play contains total reserves of 1.270 MMbo and 505.949 Bcfg (91.296 MMBOE), of which 0.395 MMbo and 154.089 Bcfg (27.813 MMBOE) have been produced. The play contains 27 producible sands in 11 pools (table 1). The first reserves in the play were discovered in the Mustang Island 757 field in 1977 (figure 2). The maximum yearly total reserves were added in 1982 with the discovery of the largest pool in the play in the Mustang Island 31A field. The most recent discoveries, prior to this study's cutoff date of January 1, 1995, were in 1993.

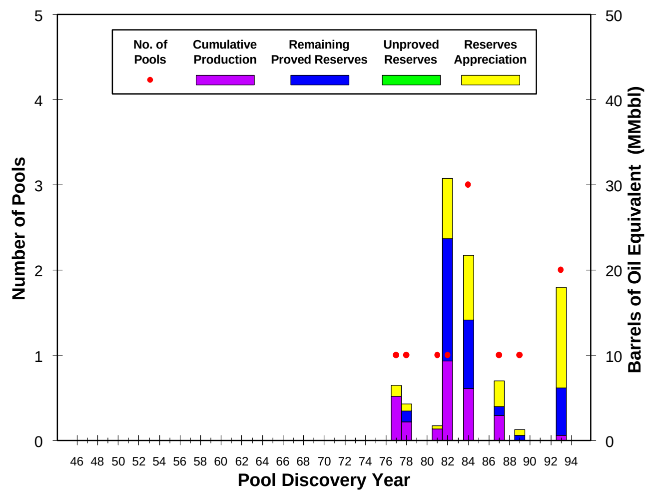


Figure 2. Exploration history graph.

The 11 discovered pools range in size from 0.123 to 30.765 MMBOE. These pools contain 33 reservoirs, all of which are nonassociated gas.

Assessment Results

The marginal probability of hydrocarbons for the LM4 A play is 1.00. The play ranks within the smallest one-third of all 61 Gulf of Mexico Region plays, based on a mean total endowment of 0.002 Bbo and 0.628 Tcfg (0.114 BBOE) (table 2). Twenty-four percent of this BOE mean total endowment has been produced.

Table 1. Characteristics of the discovered pools.

11 Pools (27 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	108	144	215
Subsea depth (feet)	6,310	7,899	11,930
Number of sands per pool	1	2	4
Porosity	21%	26%	30%
Water saturation	10%	29%	40%

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	11	0.001	0.325	0.059
Cumulative production	--	<0.001	0.154	0.028
Remaining proved	--	0.001	0.171	0.031
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.180	0.033
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.103	0.019
Mean	8	0.001	0.122	0.023
5th percentile	--	0.003	0.142	0.028
Total Endowment				
95th percentile	--	0.001	0.609	0.110
Mean	19	0.002	0.628	0.114
5th percentile	--	0.004	0.648	0.119

Assessment results indicate that undiscovered resources have a range of less than 0.001 to 0.003 Bbo and 0.103 to 0.142 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.001 Bbo and 0.122 Tcfg (0.023 BBOE). These undiscovered resources may occur in as many as eight pools. The largest undiscovered pool, with a mean size of 7.610 MMBOE, is modeled as the fifth largest pool in the play (figure 4). For all the undiscovered pools in the LM4 A play, the mean mean size is 2.886 MMBOE, which is smaller than the 8.300 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 6.020 MMBOE.

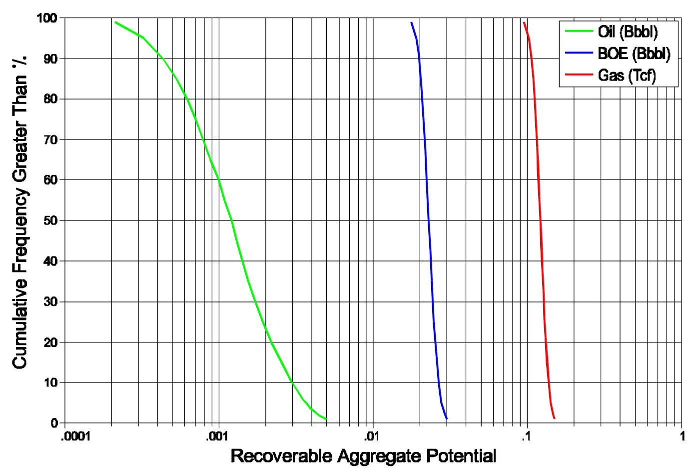


Figure 3. Cumulative probability distribution.

Relative to the discovered pool sizes in the LM4 A play, the undiscovered pools are expected to be small to moderate, contributing 20 percent to the play's BOE mean total endowment. This is a result of the relatively small number of seals in this sand-rich, aggradational depositional environment. Limited interfield exploration potential exists for untested structures.

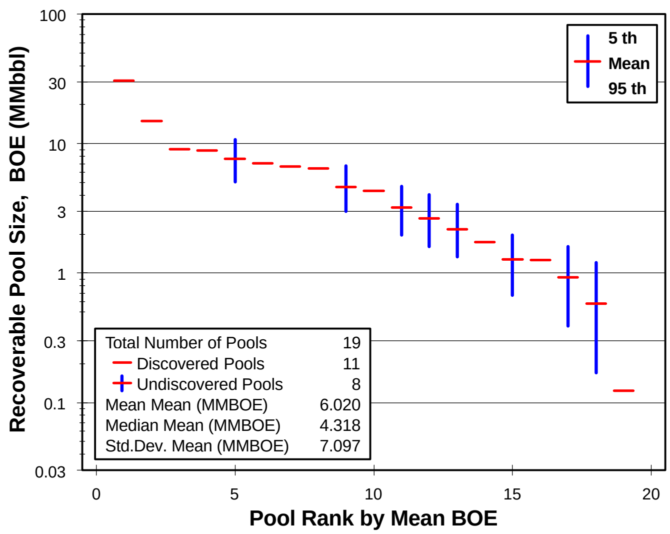


Figure 4. Pool rank plot.

UPPER LOWER MIOCENE PROGRADATIONAL (LM4 P) PLAY

PLAY DESCRIPTION

The established Upper Lower Miocene Progradational (LM4 P) play occurs within the *Marginulina ascensionensis* and *Discorbis bolivarensis* biozones. This play extends from the South Padre Island Area offshore Texas to the South Marsh Island Area offshore Louisiana (figure 1).

Updip and along strike, the play continues onshore into Texas and Louisiana. Downdip, the play grades into the deposits of the Upper Lower Miocene Fan (LM4 F) play.

Productive and established sand locations in the LM4 P play are a result of two separate depocenters in LM4 time, one in the Texas area and the other in the Louisiana area. No significant lateral shift in either depocenter is observed from the underlying middle lower Miocene (LM2) chronozone to the LM4 chronozone. However, the progradational sands of this play occur farther basinward than those deposited in LM2 time, indicative of the prograding nature of the ancient delta systems.

PLAY CHARACTERISTICS

The productive LM4 P play consists of progradational deltaic sediments deposited in delta fringe, shelf blanket, delta front, channel, slump, and crevasse splay environments. Major structural features in this play are normal faults, anticlines, shale diapirs, and growth faults. Less common structures include unconformities and rotational slump blocks. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive progradational depositional environments, structures, or seals.

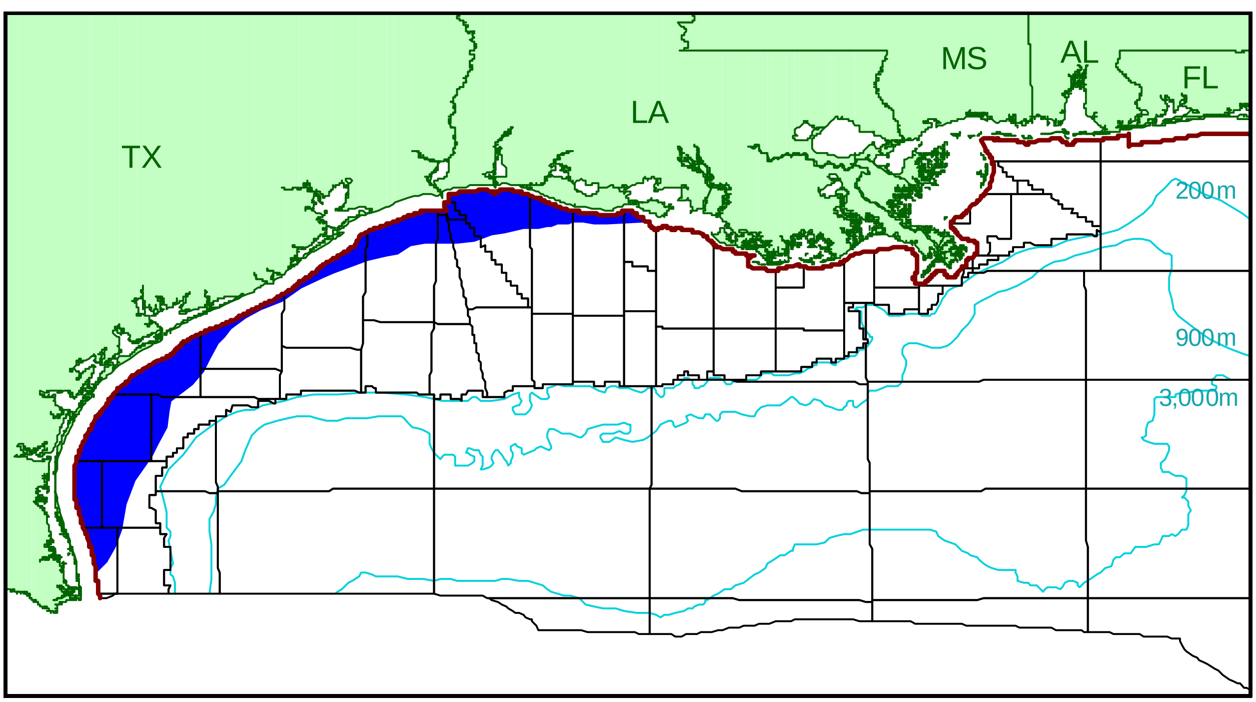


Figure 1. Map of assessed play.

Matagorda Island 527 is the type field. Seagull Energy E & P Inc.'s 8200, 8300, 8600, 8700, 9000, 9100, 9200, and LO (equals Elf Exploration's EL) sands; Enron Oil and Gas Company's D, D2, E, F, G, and H sands; McMoRan Oil & Gas Company's H sand; and Elf Exploration's H sand represent the LM4 P play in this field.

DISCOVERIES

The LM4 P gas play contains total reserves of 0.040 Bbo and 3.458 Tcfg (0.655 BBOE), of which 0.029 Bbo and 2.054 Tcfg (0.395 BBOE) have been produced. The play contains 137 producible sands in 41 pools (table 1). The first reserves in the play were discovered in the West Cameron 45 field in 1949 (figure 2). The maximum yearly total reserves of 132.951 MMBOE were added in 1988 with the discovery of seven pools. However, the largest pool in the play was found in 1979 in the Matagorda Island 527 field. In fact, pools discovered in 1979 or later contain 64 percent of the play's total reserves. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1994.

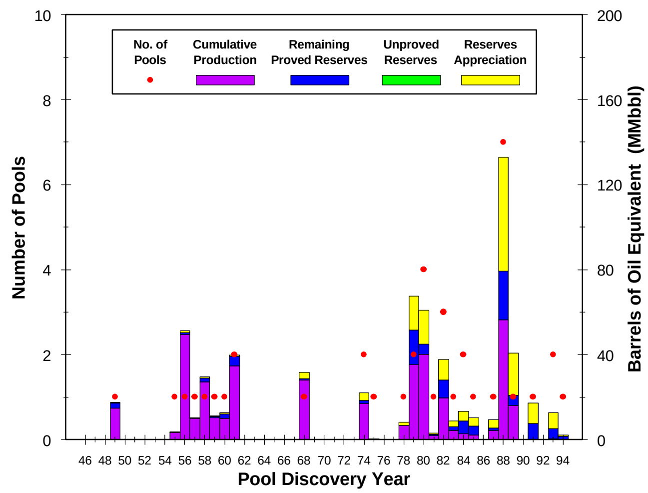


Figure 2. Exploration history graph.

The 41 discovered pools range in size from 0.235 to 56.135 MMBOE. These pools contain 265 reservoirs, of which 248 are nonassociated gas, 10 are undersaturated oil, and 7 are saturated oil.

Table 1. Characteristics of the discovered pools.

41 Pools (137 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	29	66	145
Subsea depth (feet)	6,130	9,575	12,947
Number of sands per pool	1	3	13
Porosity	20%	26%	31%
Water saturation	16%	29%	41%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the LM4 P play is 1.00. The play contains a mean total endowment of 0.050 Bbo and 4.457 Tcfg (0.843 BBOE) (table 2). Forty-seven percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.006 to 0.015 Bbo and 0.817 to 1.205 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.010 Bbo and 0.999 Tcfg (0.188 BBOE). These undiscovered resources may occur in as many as 18 pools. The largest undiscovered pool, with a mean size of 34.057 MMBOE, is modeled as the sixth largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 11, 12, 18, and 19 on the pool rank plot. For all the undiscovered pools in the LM4 P play, the mean mean size is 10.421 MMBOE, which is smaller than the 15.976 MMBOE mean size of the discovered pools. The mean mean size

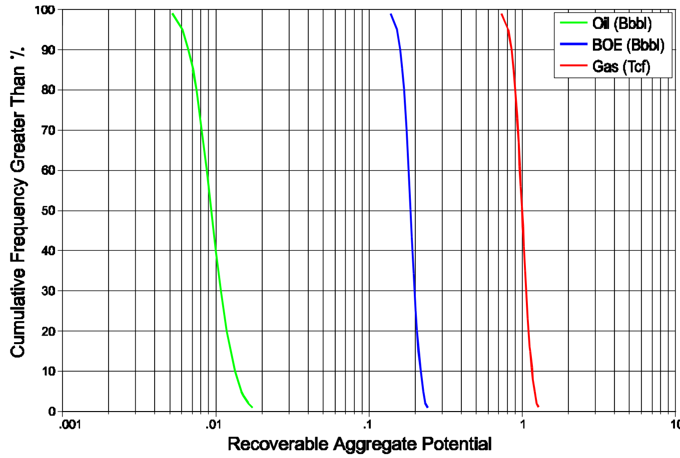


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	41	0.034	2.586	0.494
Cumulative production	--	0.029	2.054	0.395
Remaining proved	--	0.005	0.531	0.099
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.006	0.872	0.161
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.006	0.817	0.152
Mean	18	0.010	0.999	0.188
5th percentile	--	0.015	1.205	0.226
Total Endowment				
95th percentile	--	0.046	4.275	0.807
Mean	59	0.050	4.457	0.843
5th percentile	--	0.055	4.663	0.881

for all pools, including both discovered and undiscovered, is 14.282 MMBOE.

The LM4 P play is well explored. Relative to the discovered pools, most undiscovered pools are expected to be moderate in size. These undiscovered resources account for 22 percent of the BOE mean total endowment for the play. Interfield exploration potential exists for untested structures.

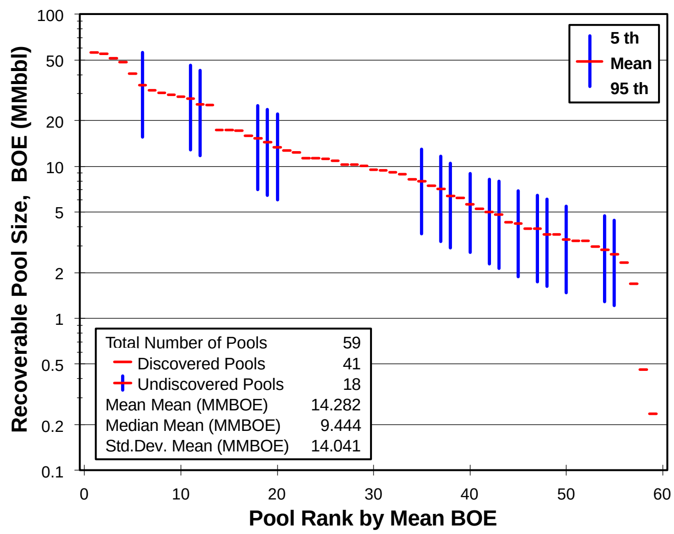


Figure 4. Pool rank plot.

UPPER LOWER MIOCENE FAN (LM4 F) PLAY

PLAY DESCRIPTION

The established Upper Lower Miocene Fan (LM4 F) play occurs within the *Marginulina ascensionensis* and *Discorbis bolivarensis* biozones. This play extends from the South Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1)

Updip, the play is either limited by the shelf/slope break associated with the *Discorbis bolivarensis* biozone and grades into the sediments of the Upper Lower Miocene Progradational (LM4 P) play, or it continues onshore into Texas and Louisiana. To the southwest, the LM4 F play extends into Texas offshore State waters and Mexican national waters. To the northeast, the play potential is bounded by the Cretaceous carbonate shelf edge and by a decrease in sediment influx at the edge of the LM4 depocenter. The southern extension of the play's potential to at least the Sigsbee Escarpment is supported by LM4 sand development in the OCS G08512-1 well in Atwater block 471.

Productive and established sand locations in the LM4 F play are a result of two separate depocenters in LM4 time, one in the Texas area and the other in the Louisiana area. No significant lateral shift in either depocenter is observed from the underlying middle lower Miocene (LM2) chronozone to the LM4 chronozone. However, both the Texas and Louisiana shelf/slope breaks occur farther basinward in LM4 time, indicative of the prograding nature of the ancient delta systems.

PLAY CHARACTERISTICS

The productive LM4 F play consists of deepwater turbidites deposited in fan systems as fan lobes on the LM4 slope. Major structural features in this play are anticlines

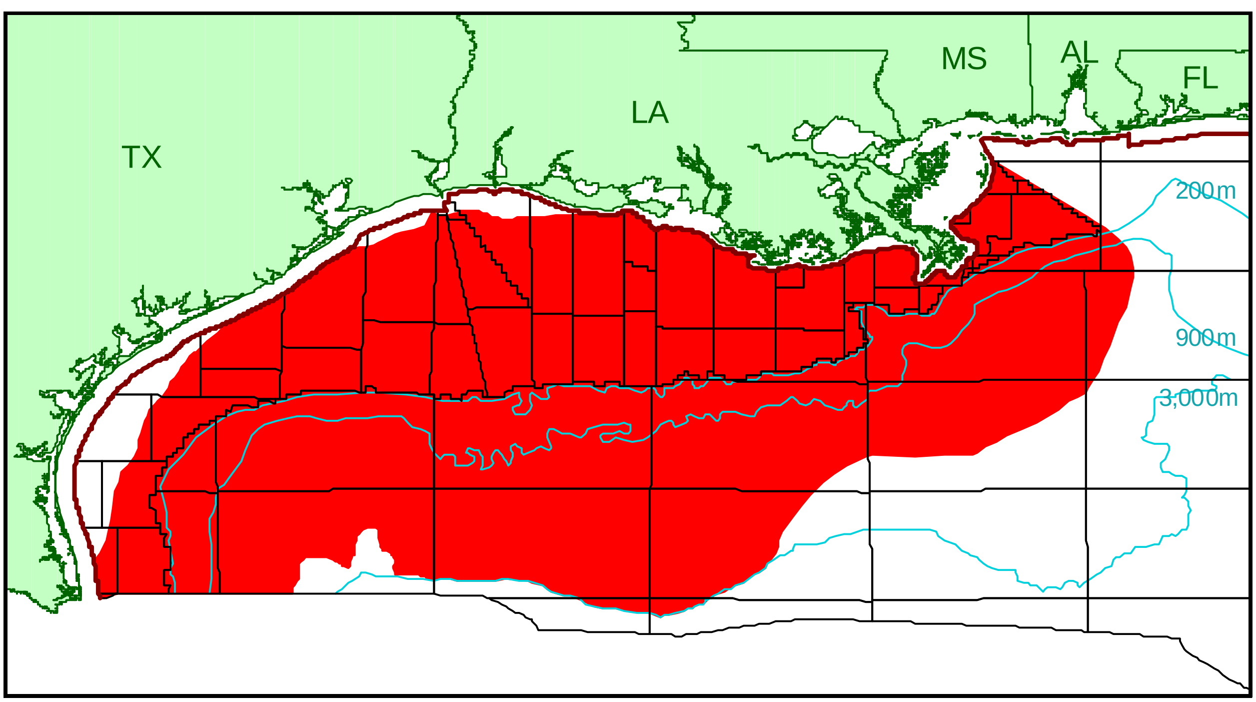


Figure 1. Map of assessed play.

and growth faults. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive fan depositional environments, structures, or seals.

Matagorda Island 639 is the type field, and Louisiana Land and Exploration's 1st MARG A and 13200 sands represent the LM4 F play in this field.

DISCOVERIES

The LM4 F gas play contains total reserves of 0.340 MMbo and 15.357 Bcfg (3.073 MMBOE), of which 0.165 MMbo and 7.870 Bcfg (1.565 MMBOE) have been produced. The play contains only three producible sands, each with one nonassociated gas reservoir, in two pools (table 1). The first reserves in the play were discovered in the Mustang Island 90A field in 1984 (figure 2). The largest pool, with 3.058 MMBOE, was found in 1985 in the Matagorda Island 639 field.

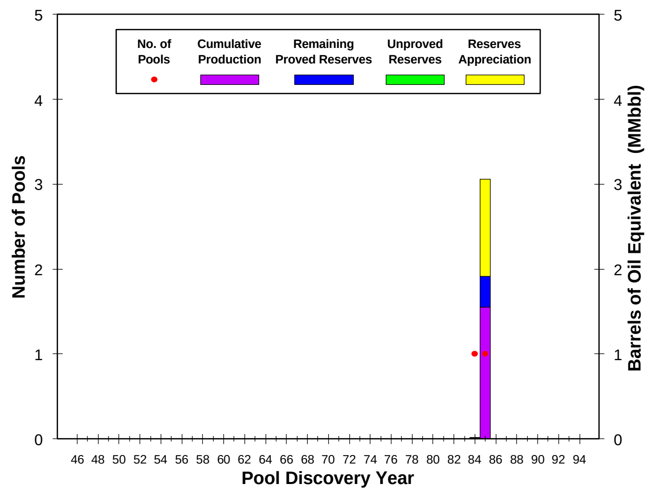


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

2 Pools (3 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	112	151	189
Subsea depth (feet)	12,800	13,025	13,250
Number of sands per pool	1	2	2
Porosity	21%	24%	26%
Water saturation	23%	31%	39%

ASSESSMENT RESULTS

Because of limited data for the LM4 F play, the Upper Pliocene Fan (UP F) play was used as an analog to model pool sizes in the LM4 F play. The UP F play was selected as the analog because of similarities in depositional setting, structural style, hydrocarbon type, and statistical information.

The marginal probability of hydrocarbons for the LM4 F play is 1.00. The play contains a mean total endowment of 0.090 Bbo and 3.461 Tcfg (0.706 BBOE) (table 2).

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	2	<0.001	0.010	0.002
Cumulative production	--	<0.001	0.008	0.002
Remaining proved	--	<0.001	0.002	<0.001
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	<0.001	0.006	0.001
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.056	2.499	0.538
Mean	78	0.090	3.446	0.703
5th percentile	--	0.133	4.594	0.943
Total Endowment				
95th percentile	--	0.056	2.514	0.541
Mean	80	0.090	3.461	0.706
5th percentile	--	0.133	4.609	0.946

Less than 1 percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.056 to 0.133 Bbo and 2.499 to 4.594 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.090 Bbo and 3.446 Tcfg (0.703 BBOE). These undiscovered resources may occur in as many as 78 pools, with the top 43 largest pools modeled as undiscovered accumulations (figure 4). The largest undiscovered pool has a mean size of 114.310 MMBOE. For all the undiscovered pools in the LM4 F play, the mean mean size is 8.983 MMBOE.

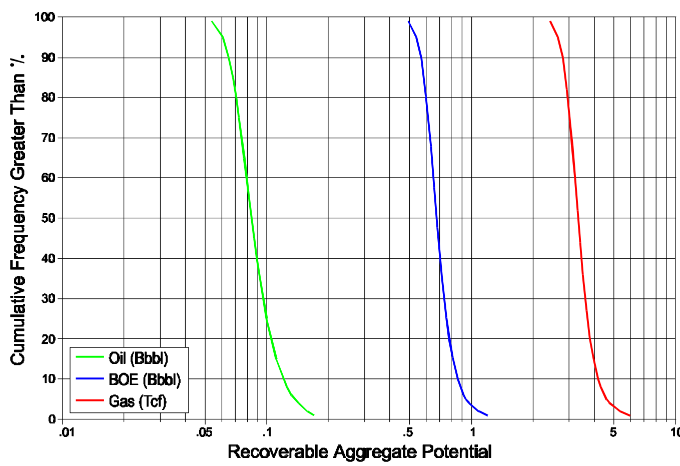


Figure 3. Cumulative probability distribution.

Because of a large unexplored area in the play, numerous pools are expected to be found, accounting for nearly all of the play's mean total endowment. There are no discovered fields in this play as yet in offshore Louisiana, and hence, this area represents good exploration potential. Limited exploration potential exists in the Brazos and

Galveston Areas offshore Texas because of sparse sand development.

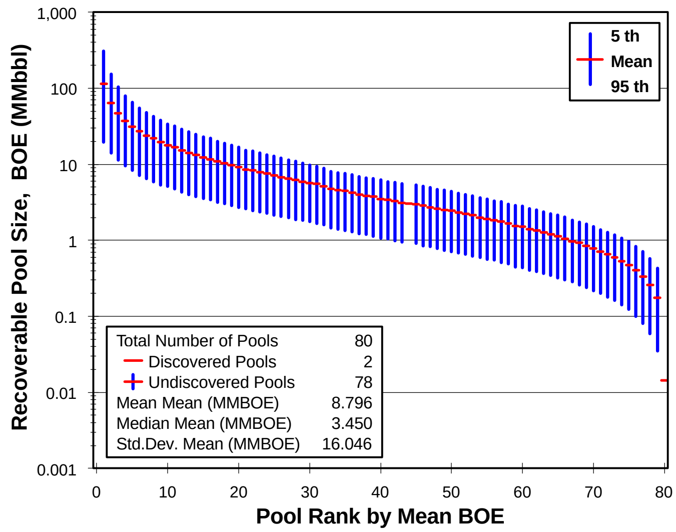


Figure 4. Pool rank plot.

MIDDLE LOWER MIOCENE (LM2) CHRONOZONE

CHRONOZONE DESCRIPTION

The Middle Lower Miocene (LM2) chronozone corresponds to the *Siphonina davisi* biozone. The LM2 section reflects delta systems prograding onto the continental shelf and fan deposition on the continental slope of the Gulf of Mexico Basin. There are two depositional styles present in the LM2 chronozone, progradational and fan, with both defining a play: the Middle Lower Miocene Progradational (LM2 P) play and the Middle Lower Miocene Fan (LM2 F) play.

The potential for sand development within the LM2 chronozone extends from the South Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). Updip, LM2 sands extend onshore into Texas and Louisiana. To the southwest, sand potential extends into Texas offshore State waters and Mexican national waters. To the northeast, sand potential is bounded by the Cretaceous carbonate shelf edge and by a decrease in sediment influx at the edge of the LM2 depocenter. The downdip limit extends at least as far as the Sigsbee Escarpment as indicated by LM2 sand development in the OCS G08512-1 well in Atwater block 471.

Productive and established sand locations in the LM2 chronozone are a result of two ancient depocenters, one in the Texas area and the other in the Louisiana area. As in lower lower Miocene (LM1) time, retrogradational and aggradational sands were being deposited only in the present-day onshore areas of Texas and Louisiana during LM2 time. Only progradational and fan sediments were being deposited in the offshore areas of Texas and Louisiana.

In the offshore Texas area, no significant lateral shift in depocenter is observed from

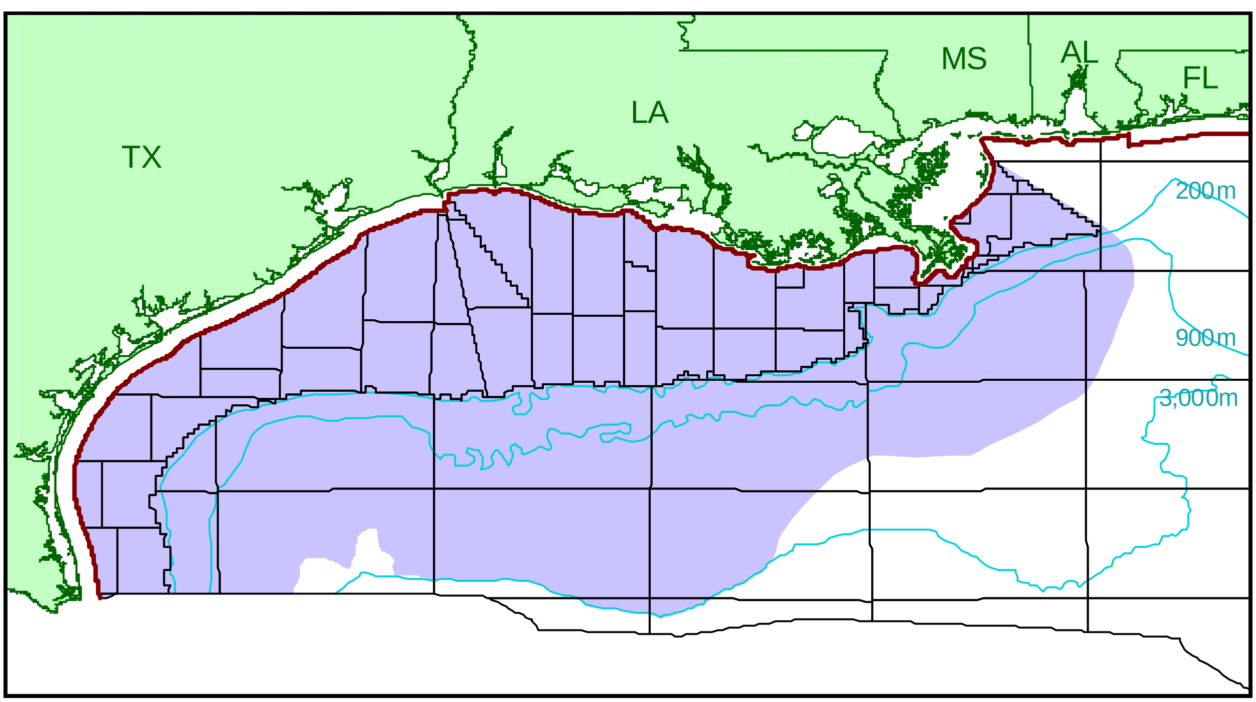


Figure 1. Map of assessed chronozone.

the underlying LM1 chronozone to the LM2 chronozone. However, LM2 progradational deposits occur more basinward than LM1 progradational deposits. Similarly in the offshore Louisiana area, no significant lateral shift in depocenter is observed from the LM1 chronozone to the LM2 chronozone. Both chronozones have progradational and fan sediments over generally the same area offshore Louisiana.

Normal faults, anticlines, and growth faults are the dominant structural features in the LM2 chronozone. Less common structures include shale diapirs and rotational slump blocks.

DISCOVERIES

The LM2 chronozone contains 44 discovered pools in two plays (table 1). Total reserves in the chronozone are 0.044 Bbo and 4.965 Tcfg (0.927 BBOE), of which 0.030 Bbo and 2.440 Tcfg (0.464 BBOE) have been produced. The largest number of discoveries in the LM2 chronozone occurred when seven pools were added in 1980 (figure 2). However, the maximum yearly total reserves of 242.451 MMBOE were added in 1956 when two pools were discovered.

Of both plays in the LM2 chronozone, the LM2 P play contains the most total reserves in 29 pools, with 0.029 Bbo and 3.374 Tcfg (0.630 BBOE).

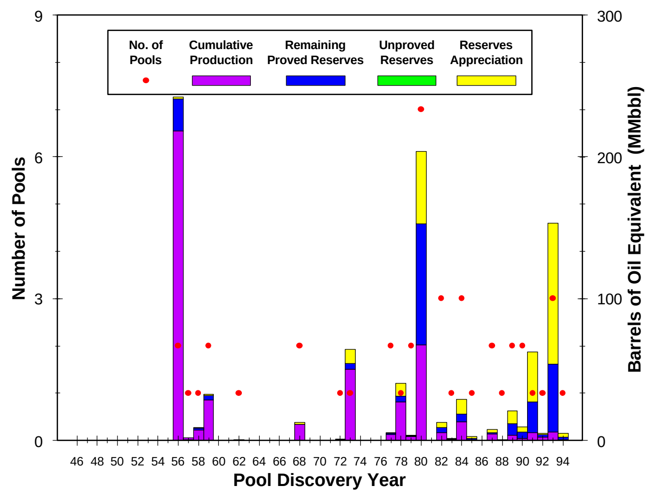


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

44 Pools (140 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	24	68	177
Subsea depth (feet)	6,285	10,745	15,080
Number of sands per pool	1	3	18
Porosity	17%	26%	33%
Water saturation	16%	29%	48%

Assessment Results

The LM2 chronozone contains 83 pools (discovered plus undiscovered), with a mean total endowment estimated at 0.069 Bbo and 7.493 Tcfg (1.402 BBOE) (table 2).

Assessment results indicate that undiscovered resources may occur in as many as 39 pools, which contain a range of 0.018 to 0.035 Bbo and 2.122 to 2.979 Tcfg at the 95th and 5th percentiles, respectively (figure 3). At mean levels, 0.025 Bbo and 2.528 Tcfg (0.475 BBOE) are projected. These undiscovered resources represent 34 percent of the LM2 chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the seventh largest in the chronozone (figure 4).

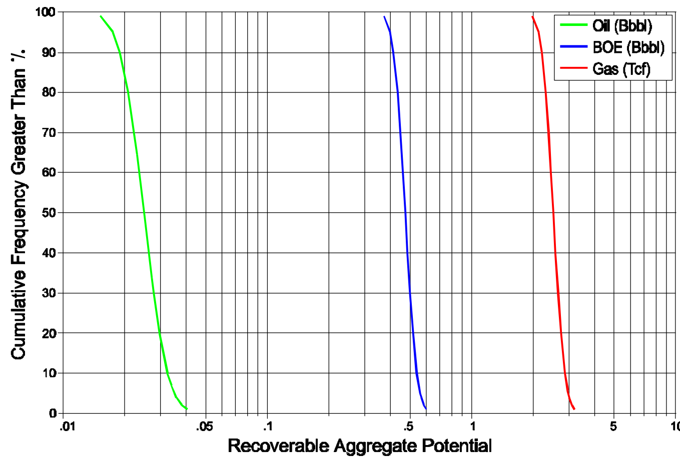


Figure 3. Cumulative probability distribution.

Of both LM2 plays, the LM2 F play is projected to contain the greatest exploration potential, with mean undiscovered resources estimated at 0.015 Bbo and 1.546 Tcfg (0.290 BBOE) remaining to be found in 29 pools. These undiscovered resources in the LM2 F play represent 21 percent of the BOE mean total endowment for the LM2

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	44	0.038	3.628	0.683
Cumulative production	--	0.030	2.440	0.464
Remaining proved	--	0.008	1.187	0.219
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.006	1.337	0.244
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.018	2.122	0.399
Mean	39	0.025	2.528	0.475
5th percentile	--	0.035	2.979	0.560
Total Endowment				
95th percentile	--	0.062	7.087	1.326
Mean	83	0.069	7.493	1.402
5th percentile	--	0.079	7.944	1.487

chronozone. This percentage and the potential for numerous discoveries within a large unexplored area make the LM2 F play an attractive exploration target in LM2 strata.

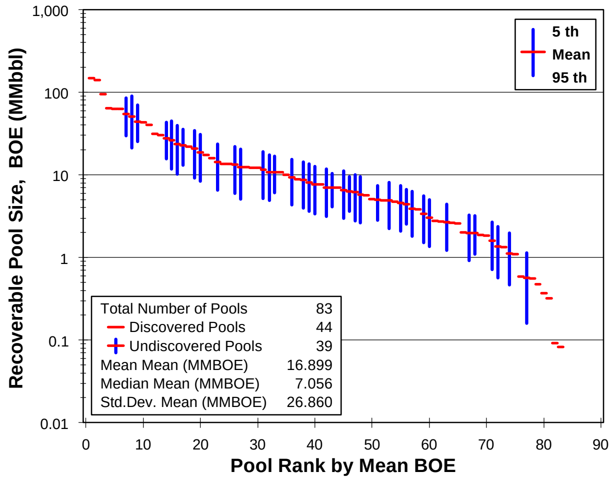


Figure 4. Pool rank plot.

MIDDLE LOWER MIOCENE PROGRADATIONAL (LM2 P) PLAY

PLAY DESCRIPTION

The established Middle Lower Miocene Progradational (LM2 P) play occurs at the *Siphonina davisi* biozone. This play consists of two separate regions: (1) a western region that extends from the northernmost portion of the South Padre Island Area to the western edge of the Brazos Area offshore Texas and (2) an eastern region that extends from the northeastern portion of the Galveston Area offshore Texas to the northernmost South Marsh Island Area offshore Louisiana (figure 1).

In the western region, updip and along strike, the play continues onshore into Texas. Downdip, the play grades into the deposits of the Middle Lower Miocene Fan (LM2 F) play. Similarly, in the eastern region, updip and along strike, the LM2 P play continues onshore into Texas and Louisiana. Downdip, the play grades into the deposits of the LM2 F play.

The locations of the western and eastern regions of the LM2 P play are a result of two separate depocenters in LM2 time, one in the Texas area and the other in the Louisiana area. No significant lateral shift in either depocenter is observed from the underlying lower lower Miocene (LM1) chronozone to the LM2 chronozone. However, in both regions of this play, the progradational sands occur farther basinward than those of the LM1 chronozone, indicative of the prograding nature of the ancient delta systems.

PLAY CHARACTERISTICS

The productive LM2 P play consists of progradational deltaic sediments deposited in delta fringe, shelf blanket, delta front, channel, and crevasse splay environments. Major structural features in this play are normal faults, growth faults, and anticlines. Less common structures include shale diapirs and rotational slump blocks. Seals are provided

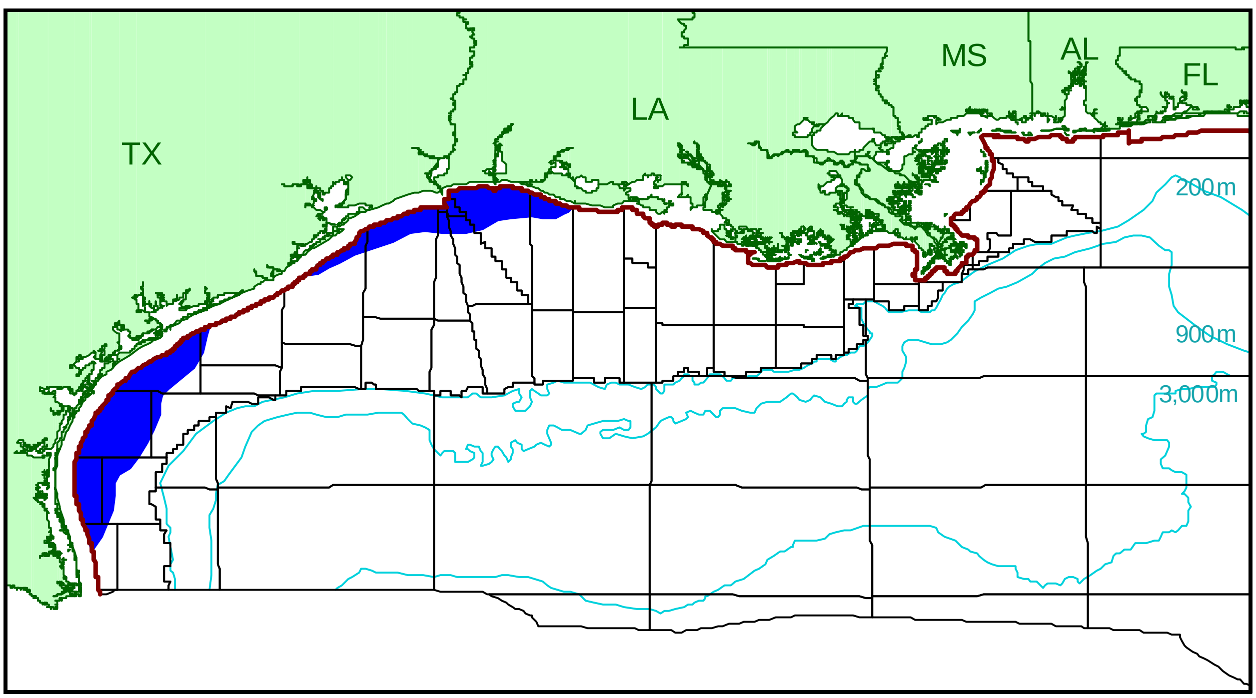


Figure 1. Map of assessed play.

by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive progradational depositional environments, structures, or seals.

West Cameron 45 is the type field. Pennzoil Petroleum Company's D01, D02, D04, D06, D08, D10, E01, E04, E08, F04, F06, and F09 sands; Midcontinent Offshore Inc.'s D01, D04, E04, E08, E09, F06, F09, PLANIA, PLAN3, PLAN4, PLAN5, PLAN6, and PLAN7 sands; and BP Exploration & Oil Inc.'s "Rose" (equals Forest Oil Corp.'s ROB6 and Hall-Houston Oil Company's 9600) sand represent the LM2 P play in this field.

DISCOVERIES

The LM2 P gas play contains total reserves of 0.029 Bbo and 3.374 Tcfg (0.630 BBOE), of which 0.020 Bbo and 1.424 Tcfg (0.273 BBOE) have been produced. The play contains 93 producible sands in 29 pools (table 1). The first and largest pool in the play was discovered in the West Cameron 45 field in 1956 (figure 2). The maximum yearly total reserves of 150.716 MMBOE were added in 1993 with the discovery of two pools. In fact, almost 75 percent of the total reserves in this play were found after 1976. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1994.

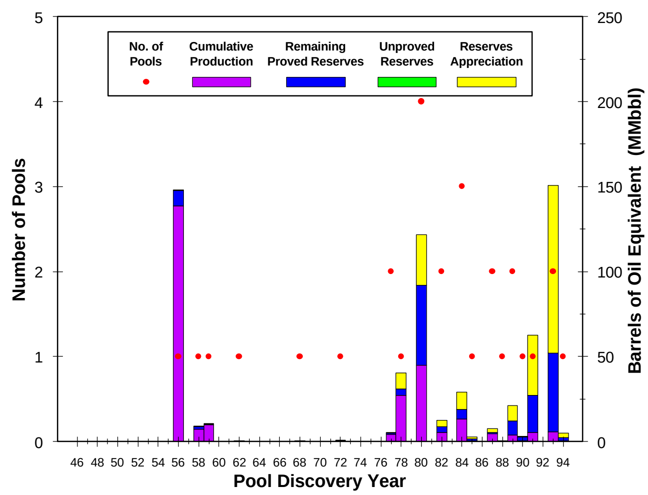


Figure 2. Exploration history graph.

The 29 discovered pools range in size from 0.082 to 147.782 MMBOE. These pools contain 167 reservoirs, of which 155 are nonassociated gas, 5 are undersaturated oil, and 7 are saturated oil.

Table 1. Characteristics of the discovered pools.

29 Pools (93 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	24	74	177
Subsea depth (feet)	6,285	9,965	14,630
Number of sands per pool	1	3	18
Porosity	17%	27%	33%
Water saturation	16%	29%	47%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the LM2 P play is 1.00. The play contains a mean total endowment of 0.039 Bbo and 4.356 Tcfg (0.815 BBOE) (table 2). Thirty-four percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.005 to 0.016 Bbo and 0.777 to 1.219 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.010 Bbo and 0.982 Tcfg (0.185 BBOE). These undiscovered resources may occur in as many as 10 pools. The largest undiscovered pool, with a mean size of 54.412 MMBOE, is modeled as the fifth largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 6, 9, 10, and 17 on the pool rank plot. For all the undiscovered pools in the LM2 P play, the mean mean size is 18.474 MMBOE, which is comparable to the 21.712 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and

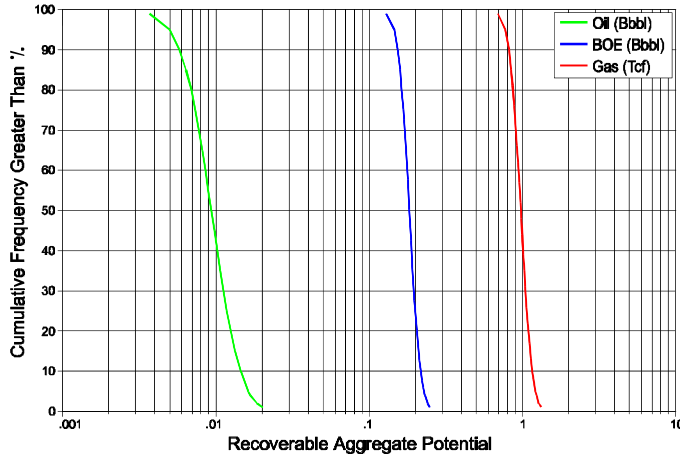


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	29	0.025	2.258	0.427
Cumulative production	--	0.020	1.424	0.273
Remaining proved	--	0.005	0.834	0.154
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.005	1.116	0.203
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.005	0.777	0.146
Mean	10	0.010	0.982	0.185
5th percentile	--	0.016	1.219	0.228
Total Endowment				
95th percentile	--	0.034	4.151	0.776
Mean	39	0.039	4.356	0.815
5th percentile	--	0.045	4.593	0.858

undiscovered, is 20.882 MMBOE.

The LM2 P play is well explored, with few pools expected to be found. The undiscovered resources account for 23 percent of the play's BOE mean total endowment. Limited interfield exploration potential exists for untested structures.

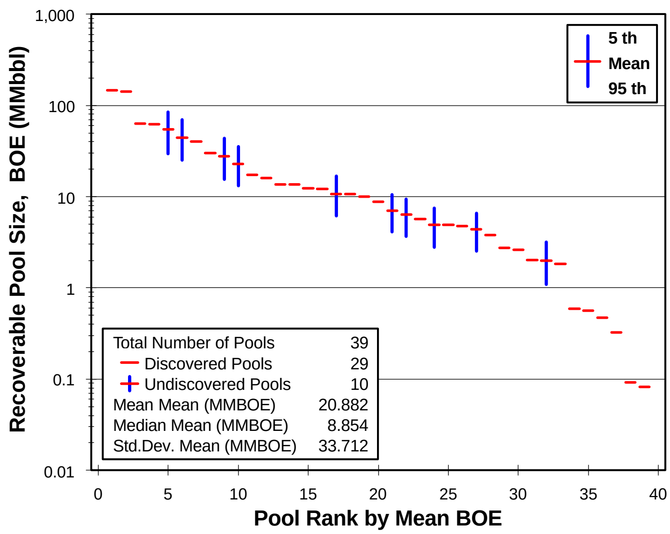


Figure 4. Pool rank plot.

MIDDLE LOWER MIOCENE FAN (LM2 F) PLAY

PLAY DESCRIPTION

The established Middle Lower Miocene Fan (LM2 F) play occurs at the *Siphonina davisi* biozone. This play extends from the South Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the play continues onshore into Texas and Louisiana, except in the High Island, Mustang Island, and North Padre Island Areas, where the play is limited by the shelf/slope break associated with the *Siphonina davisi* biozone and grades into the sediments of the Middle Lower Miocene Progradational (LM2 P) play. To the southwest, the LM2 F play extends into Texas offshore State waters and Mexican national waters. To the northeast, the play potential is bounded by the Cretaceous carbonate shelf edge and by a decrease in sediment influx at the edge of the LM2 depocenter. The southern extension of the play's potential to at least the Sigsbee Escarpment is supported by LM2 sand development in the OCS G08512-1 well in Atwater block 471.

Productive and established sand locations in the LM2 F play are a result of two separate depocenters in LM2 time, one in the Texas area and the other in the Louisiana area. No significant lateral shift in either depocenter is observed from the underlying lower lower Miocene (LM1) chronozone to the LM2 chronozone.

PLAY CHARACTERISTICS

The productive LM2 F play consists of deepwater turbidites deposited in fan systems as fan lobes, fringe sheet sediments, and channel fill on the LM2 slope. Major structural features in this play are normal faults and anticlines. Shale diapirs and growth

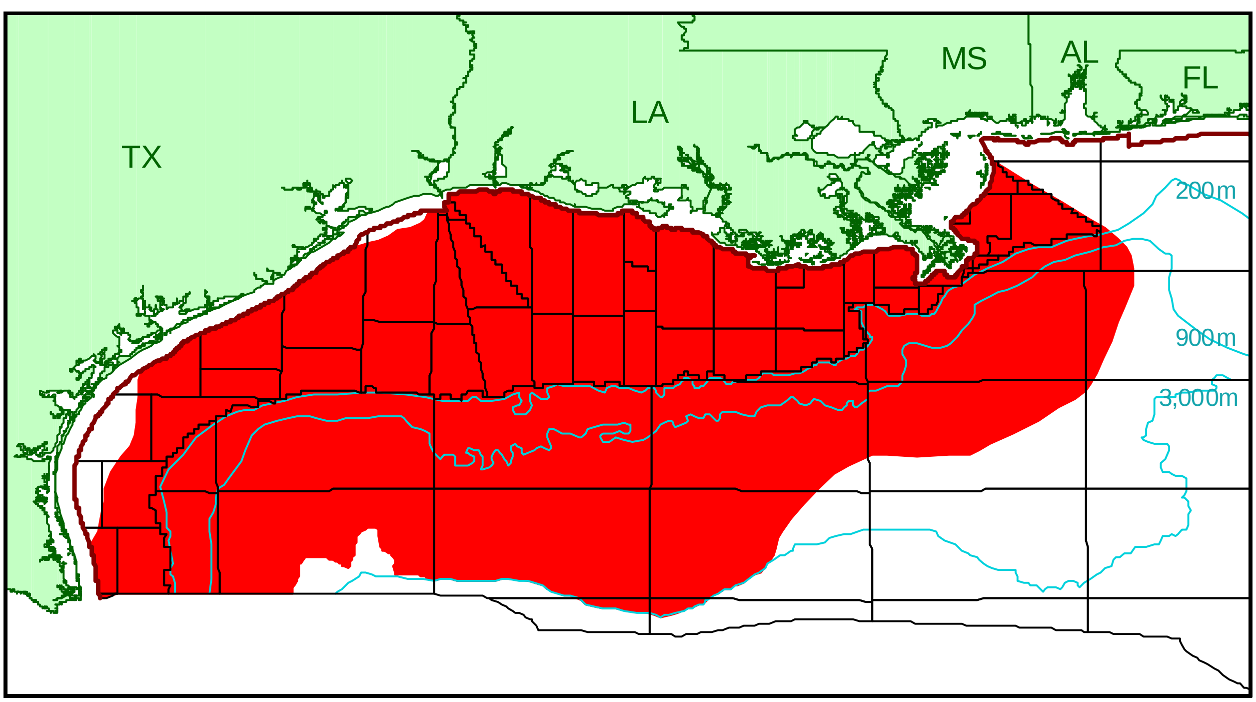


Figure 1. Map of assessed play.

faults also occur, but less commonly. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive fan depositional environments, structures, or seals.

Matagorda Island 668 is the type field. Vastar Resources Inc.'s KR, KQ (equals Oxy USA Inc.'s 2MK), LJ, and LC (equals Oxy USA Inc.'s CM15) sands represent the LM2 F play in this field.

DISCOVERIES

The LM2 F gas play contains total reserves of 0.014 Bbo and 1.591 Tcfg (0.297 BBOE), of which 0.010 Bbo and 1.017 Tcfg (0.191 BBOE) have been produced. The play contains 47 producible sands in 15 pools (table 1). The first reserves in the play were discovered in the West Cameron 71 field in 1956 (figure 2). The maximum yearly total reserves were added in 1956 with the discovery of the largest pool in the play in the West Cameron 71 field. Eighty-five percent of the cumulative production from this play occurred from pools discovered prior to 1974. Though one-third of the discoveries occurred in 1982 or later, they added only 5 percent to the play's total reserves. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1993.

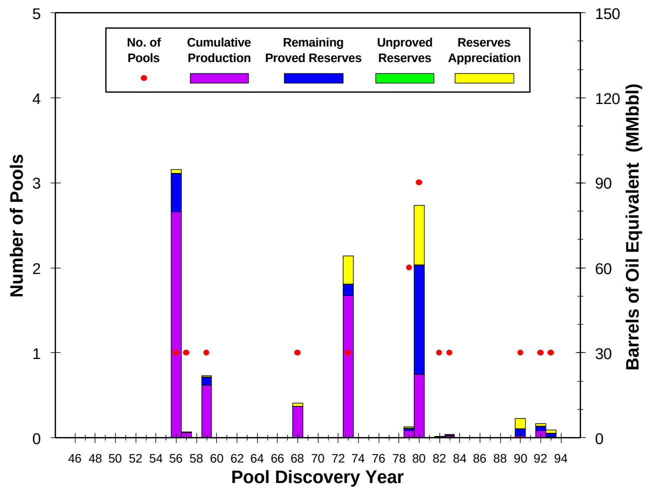


Figure 2. Exploration history graph.

The 15 discovered pools range in size from 0.371 to 94.669 MMBOE. These pools contain 100 reservoirs, of which 99 are nonassociated gas and 1 is saturated oil.

Table 1. Characteristics of the discovered pools.

15 Pools (47 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	29	58	103
Subsea depth (feet)	9,536	12,252	15,080
Number of sands per pool	1	3	9
Porosity	19%	25%	32%
Water saturation	20%	30%	48%

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	15	0.013	1.370	0.257
Cumulative production	--	0.010	1.017	0.191
Remaining proved	--	0.003	0.353	0.065
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.001	0.221	0.041
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.011	1.282	0.239
Mean	29	0.015	1.546	0.290
5th percentile	--	0.020	1.840	0.345
Total Endowment				
95th percentile	--	0.025	2.873	0.536
Mean	44	0.029	3.137	0.587
5th percentile	--	0.034	3.431	0.642

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the LM2 F play is 1.00. The play contains a mean total endowment of 0.029 Bbo and 3.137 Tcfg (0.587 BBOE) (table 2). Thirty-three percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.011 to 0.020 Bbo and 1.282 to 1.840 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.015 Bbo and 1.546 Tcfg (0.290 BBOE). These undiscovered resources may occur in as many as 29 pools. The largest undiscovered pool, with a mean size of 50.841 MMBOE, is modeled as the third largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 6, 7, 9, and 10 on the pool rank plot. For all the undiscovered pools in the LM2 F play, the mean mean size is 10.025 MMBOE, which is smaller than the 19.830 MMBOE mean size of the discovered pools. The mean mean size

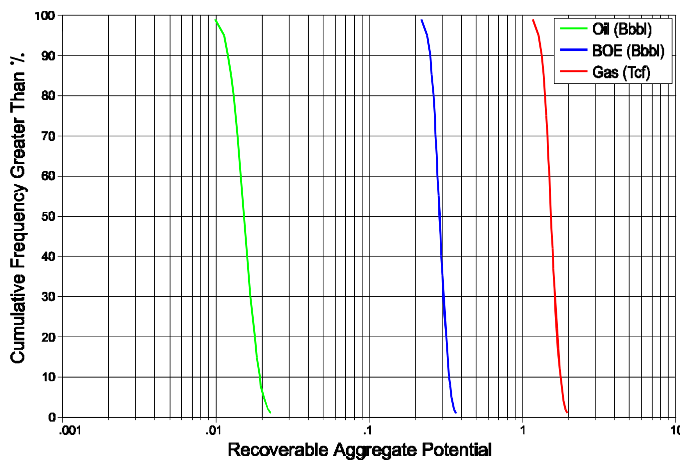


Figure 3. Cumulative probability distribution.

for all pools, including both discovered and undiscovered, is 13.368 MMBOE.

Of the 15 fan plays in the Gulf of Mexico Region, the LM2 F play contains the smallest mean total endowment (2%), based on BOE.

The LM2 F play has a large unexplored area. Numerous undiscovered pools, comparable to the range of sizes for the discovered pools, are expected to be found, accounting for nearly half of the play's mean total endowment. The greatest exploration potential exists downdip of discovered fields where wells have been too shallow to test the LM2 section. Limited exploration potential exists between the two productive areas of the play in the Brazos and Galveston Areas offshore Texas because of sparse sand development.

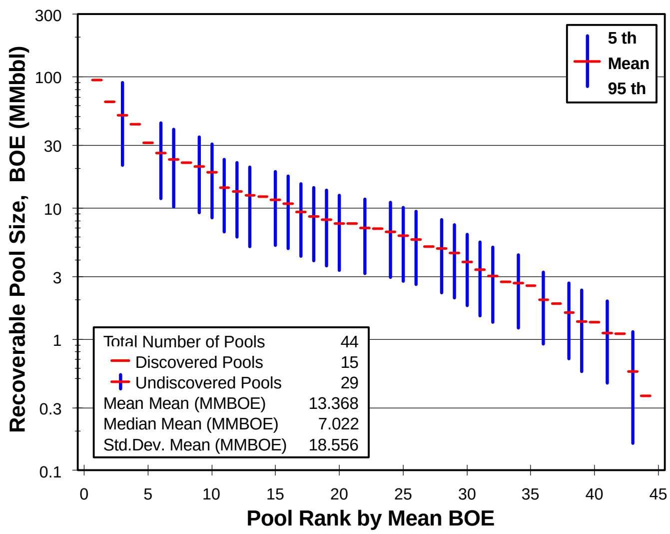


Figure 4. Pool rank plot.

LOWER LOWER MIOCENE (LM1) CHRONOZONE

CHRONOZONE DESCRIPTION

The Lower Lower Miocene (LM1) chronozone corresponds to the *Lenticulina hanseni* biozone. The LM1 section reflects delta systems prograding onto the continental shelf and fan deposition on the continental slope of the Gulf of Mexico Basin. There are two depositional styles present in the LM1 chronozone, progradational and fan, with both defining a play: the Lower Lower Miocene Progradational (LM1 P) play and the Lower Lower Miocene Fan (LM1 F) play.

The potential for sand development within the LM1 chronozone extends from the South Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). Updip, sands in the LM1 chronozone extend onshore into Texas and Louisiana. To the southwest, sand potential extends into Texas offshore State waters and Mexican national waters. To the northeast, sand potential is bounded by the Cretaceous carbonate shelf edge and a decrease in sediment influx at the edge of the LM1 depocenter. The downdip limit extends at least as far as the Sigsbee Escarpment as indicated by LM1 sand development in the OCS G08512-1 well in Atwater block 471.

Productive and established sand locations in the LM1 chronozone are a result of two ancient depocenters, one in the Texas area and the other in the Louisiana area. During LM1 time, retrogradational and aggradational sands were deposited in the present-day onshore Texas and Louisiana areas. Neither the Texas nor Louisiana ancient delta systems had prograded basinward enough at this time to deposit sediments other than progradational and fan in the present-day offshore areas.

Normal faults are the dominant structural feature in the LM1 chronozone. Less

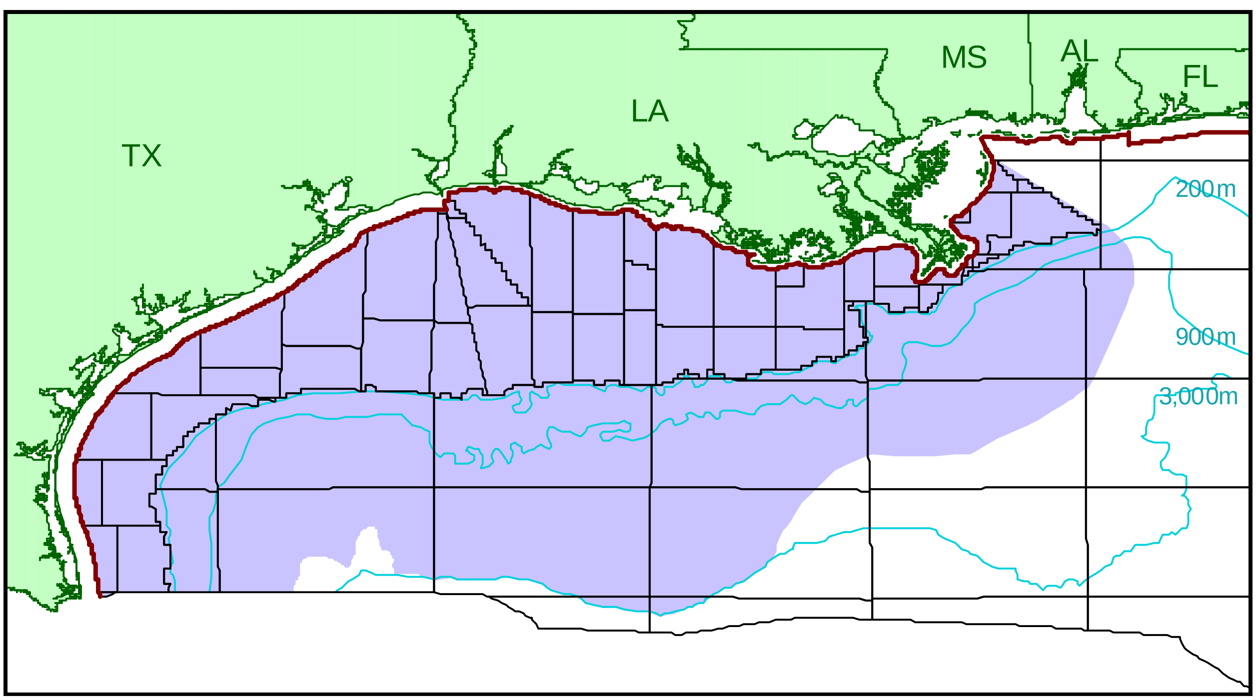


Figure 1. Map of assessed chronozone.

common structures include growth faults, shale diapirs, rotational slump blocks, and anticlines.

DISCOVERIES

The LM1 chronozone contains 20 discovered pools in two plays (table 1). Total reserves in the chronozone are 0.024 Bbo and 3.187 Tcfg (0.591 BBOE), of which 0.012 Bbo and 1.748 Tcfg (0.323 BBOE) have been produced. The largest number of discoveries in the LM1 chronozone occurred when five pools added the maximum yearly total reserves of 196.674 MMBOE in 1982 (figure 2).

Of both plays in the LM1 chronozone, the LM1 F play contains the most total reserves in 15 discovered pools, with 0.021 Bbo and 2.978 Tcfg (0.551 BBOE).

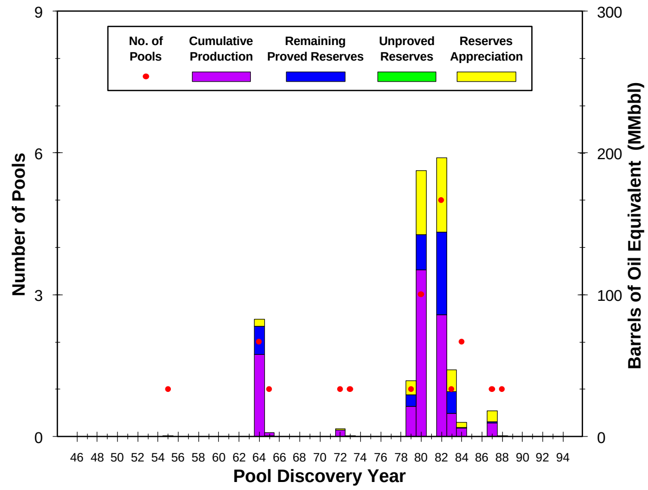


Figure 2. Exploration history graph.

Table 1. Characteristics of the discovered pools.

20 Pools (59 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	17	48	121
Subsea depth (feet)	11,024	13,424	18,250
Number of sands per pool	1	3	9
Porosity	16%	25%	31%
Water saturation	17%	30%	43%

ASSESSMENT RESULTS

The LM1 chronozone contains 59 pools (discovered plus undiscovered), with a mean total endowment estimated at 0.049 Bbo and 5.557 Tcfg (1.038 BBOE) (table 2).

Assessment results indicate that undiscovered resources may occur in as many as 39 pools, which contain a range of 0.018 to 0.035 Bbo and 1.978

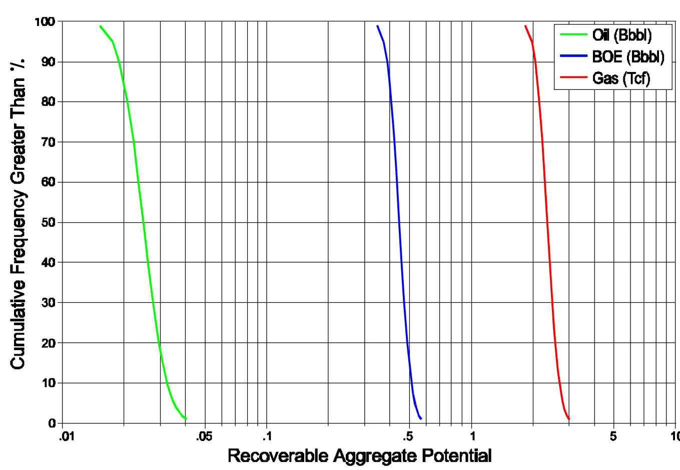


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	20	0.018	2.431	0.451
Cumulative production	--	0.012	1.748	0.323
Remaining proved	--	0.006	0.682	0.128
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.005	0.757	0.140
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.018	1.978	0.373
Mean	39	0.025	2.370	0.447
5th percentile	--	0.035	2.808	0.530
Total Endowment				
95th percentile	--	0.042	5.165	0.964
Mean	59	0.049	5.557	1.038
5th percentile	--	0.059	5.995	1.121

to 2.808 Tcfg at the 95th and 5th percentiles, respectively (figure 3). At mean levels, 0.025 Bbo and 2.370 Tcfg (0.447 BBOE) are projected. These undiscovered resources represent 43 percent of the LM1 chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the third largest in the chronozone (figure 4).

Of both LM1 plays, the LM1 F play is projected to contain the greatest exploration potential, with mean undiscovered resources estimated at 0.024 Bbo and 2.289 Tcfg (0.431 BBOE) remaining to be found in 34 pools. These undiscovered resources in the LM1 F play represent 42 percent of the BOE mean total endowment for the LM1 chronozone. This high percentage and the potential for numerous discoveries within a large unexplored area make the LM1 F play an attractive exploration target in LM1 strata.

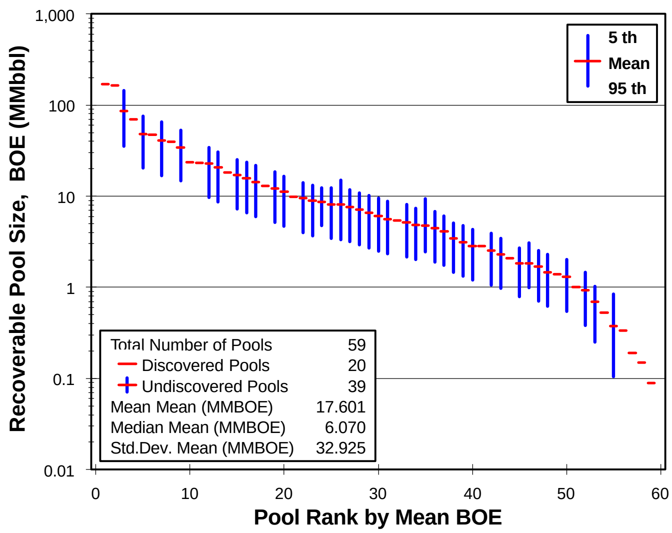


Figure 4. Pool rank plot.

LOWER LOWER MIOCENE PROGRADATIONAL (LM1 P) PLAY

PLAY DESCRIPTION

The established Lower Lower Miocene Progradational (LM1 P) play occurs at the *Lenticulina hanseni* biozone. This play consists of two separate regions: (1) a western region that includes parts of the North Padre Island, Mustang Island, Matagorda Island, and Brazos Areas offshore Texas and (2) an eastern region that extends from the High Island Area offshore Texas to the East Cameron Area offshore Louisiana (figure 1).

In the western region, updip and along strike, the play continues onshore into Texas, but is nonproductive in Federal waters. Downdip, the play grades into the deposits of the Lower Lower Miocene Fan (LM1 F) play. Similarly, in the eastern region, updip and along strike, the play continues onshore into Texas and Louisiana. Downdip, the play grades into the deposits of the LM1 F play.

The locations of the western and eastern regions of the LM1 P play are a result of two separate depocenters in LM1 time, one in the Texas area and the other in the Louisiana area. The delta systems had not prograded far enough basinward through LM1 time to deposit aggradational or retrogradational sediments in the present-day offshore areas.

PLAY CHARACTERISTICS

The productive LM1 P play consists of progradational deltaic sediments deposited in outer shelf, delta fringe environments. Normal faults are the major structural feature in this play. Less common structures include rotational slump blocks and growth faults. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future

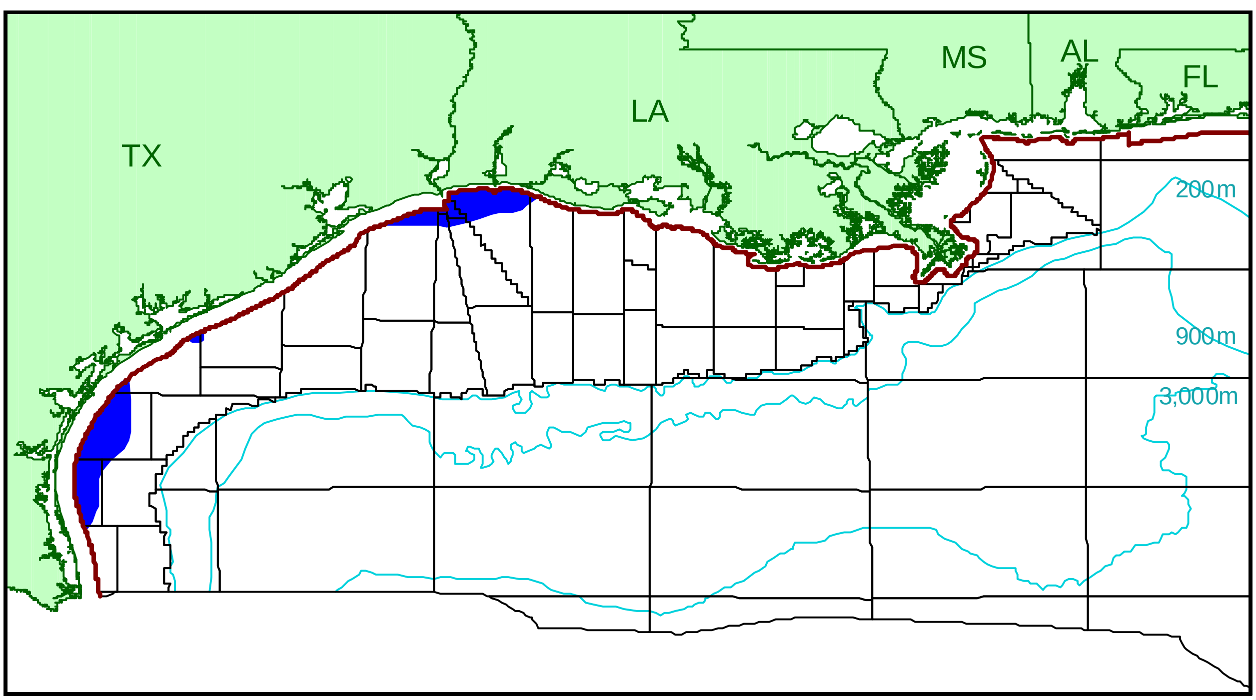


Figure 1. Map of assessed play.

discoveries are not limited to the aforementioned productive progradational depositional environments, structures, or seals.

West Cameron 55 is the type field, and Zilka Energy Company's BD-1 sand represents the LM1 P play in this field.

DISCOVERIES

The LM1 P gas play contains total reserves of 0.003 Bbo and 0.210 Tcfg (0.040 BBOE), of which 0.001 Bbo and 0.035 Tcfg (0.007 BBOE) have been produced. The play contains 15 producible sands in five pools (table 1). The first reserves in the play were discovered in the West Cameron 17 field in 1964 (figure 2). The pool discovery histogram illustrates a bimodal distribution with two pools discovered in the 1960's and the remaining three discovered in the early 1980's. The maximum yearly total reserves were added in 1982 by the discovery of the largest pool in the play in the West Cameron 55 field. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1984.

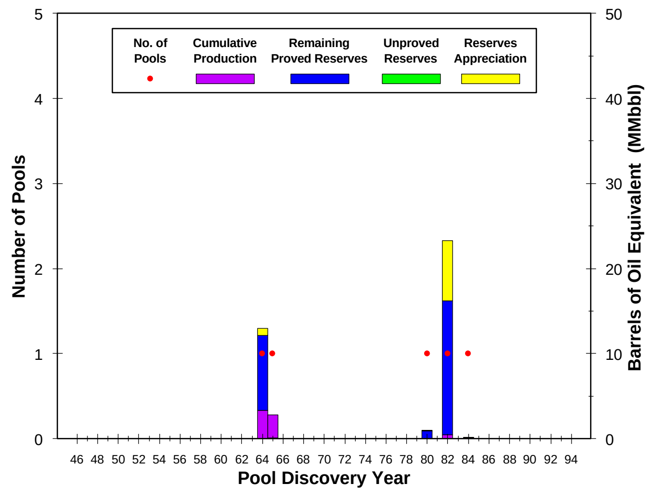


Figure 2. Exploration history graph.

The five discovered pools range in size from 0.089 to 23.298 MMBOE. These pools contain 19 reservoirs, all of which are nonassociated gas.

Of the 14 progradational plays in the Gulf of Mexico Region, the LM1 P play contains the smallest amount of BOE total reserves (<1%).

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the LM1 P play is 1.00. The play ranks

Table 1. Characteristics of the discovered pools.

5 Pools (15 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	17	31	37
Subsea depth (feet)	11,024	11,548	11,937
Number of sands per pool	1	3	9
Porosity	21%	26%	31%
Water saturation	21%	29%	33%

within the smallest one-fourth of all 61 Gulf of Mexico plays, based on a mean total endowment of 0.004 Bbo and 0.291 Tcfg (0.056 BBOE) (table 2). Twelve percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of less than 0.001 to 0.003 Bbo and 0.050 to 0.121 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.001 Bbo and 0.081 Tcfg (0.016 BBOE). These undiscovered resources may occur in as many as five pools. The largest undiscovered pool, with a mean size of 8.127 MMBOE, is modeled as the third largest pool in the play (figure 4). The model results place the remaining four undiscovered pools in positions 4, 6, 8, and 9 on the pool rank plot. For all the undiscovered pools in the LM1 P play, the mean mean size is 3.157 MMBOE, which is smaller than the 8.039 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 5.598 MMBOE.

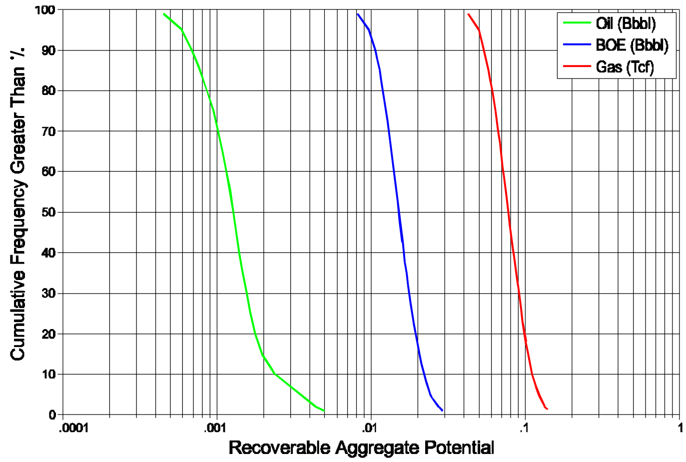


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	**Number of Pools**	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Reserves				
Original proved	5	0.002	0.168	0.032
Cumulative production	--	0.001	0.035	0.007
Remaining proved	--	0.002	0.134	0.026
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.001	0.041	0.008
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	<0.001	0.050	0.010
Mean	5	0.001	0.081	0.016
5th percentile	--	0.003	0.121	0.024
Total Endowment				
95th percentile	--	0.003	0.260	0.050
Mean	10	0.004	0.291	0.056
5th percentile	--	0.006	0.331	0.064

The LM1 P play is well explored. Relative to the five discovered pools, the five undiscovered pools are expected to be small to moderate in size, contributing 28 percent to the play's BOE mean total endowment. Interfield exploration potential exists for untested structures.

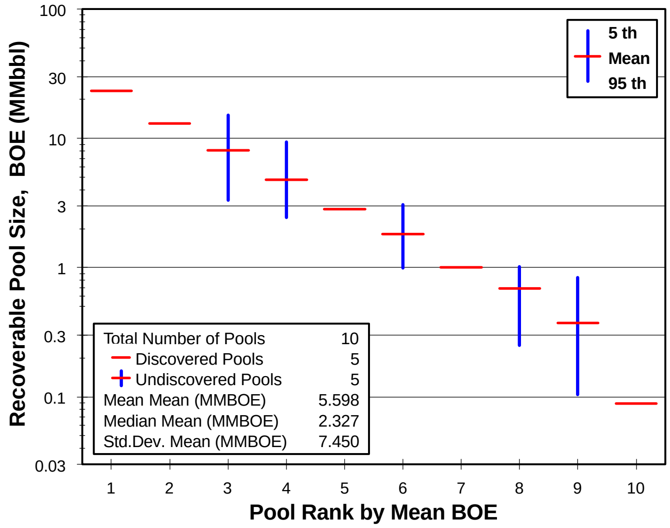


Figure 4. Pool rank plot.

Lower Lower Miocene Fan (LM1 F) Play

Play Description

The established Lower Lower Miocene Fan (LM1 F) play occurs at the *Lenticulina hanseni* biozone. This play extends from the South Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1).

Updip, the play continues onshore into Texas and Louisiana except in the North Padre Island and Mustang Island Areas, where the play is limited by the shelf/slope break associated with the *Lenticulina hanseni* biozone and grades into the sediments of the Lower Lower Miocene Progradational (LM1 P) play. To the southwest, the LM1 F play extends into Texas offshore State waters and Mexican national waters. To the northeast, the play potential is bounded by the Cretaceous carbonate shelf edge and a decrease in sediment influx at the edge of the LM1 depocenter. The southern extension of the play's potential to at least the Sigsbee Escarpment is supported by LM1 sand development in the OCS G08512-1 well in Atwater block 471.

Productive and established sand locations in the LM1 F play are a result of two separate depocenters in LM1 time, one in the Texas area and the other in the Louisiana area. The delta systems had not prograded far enough basinward through LM1 time to deposit aggradational or retrogradational sediments in the present-day offshore areas.

Play Characteristics

The productive LM1 F play consists of deepwater turbidites deposited in fan systems as fan lobes, fringe sheet sediments, channel fill, and slump sediments on the LM1 slope. Normal faults are the major structural feature in this play. Less commonly,

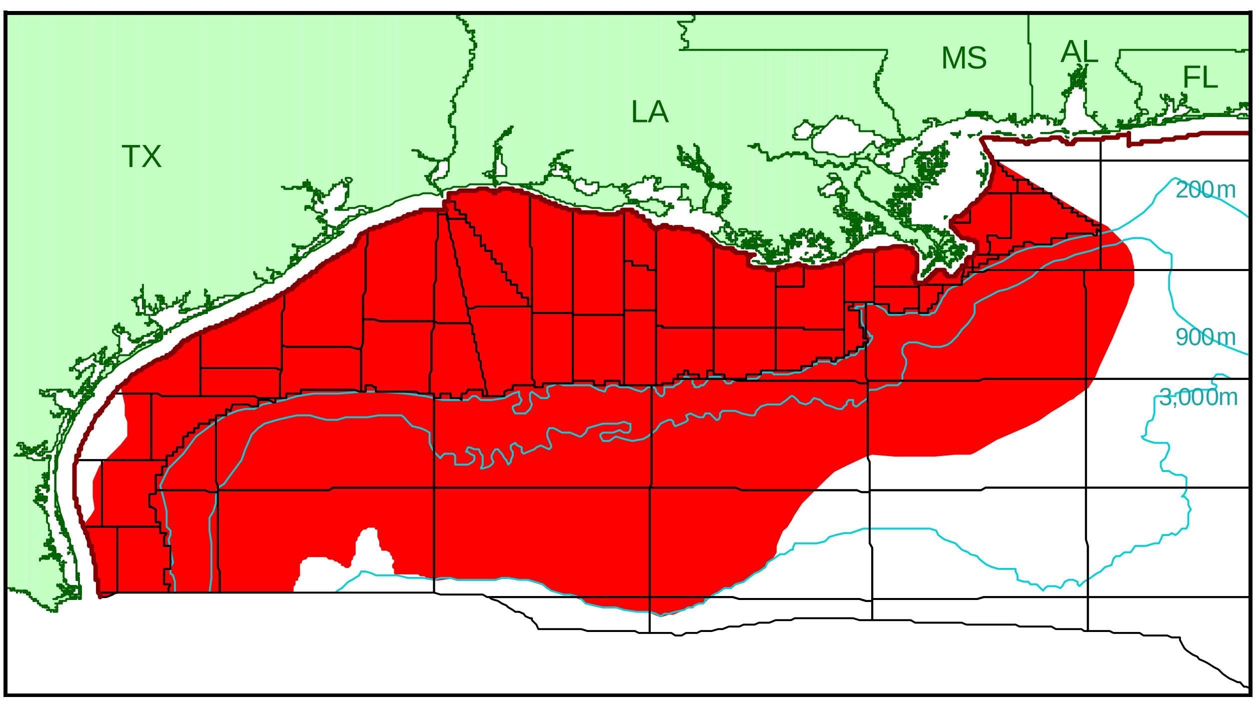


Figure 1. Map of assessed play.

anticlines, shale diapirs, rotational slump blocks, and growth faults occur. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales). Future discoveries are not limited to the aforementioned productive fan depositional environments, structures, or seals.

Matagorda Island 668 is the type field. Oxy USA Inc.'s CM15B, 3 BASAL, CM15C, and CM15 sands and Vastar Resources Inc.'s LQ, LR, and ML sands represent the LM1 F play in this field.

DISCOVERIES

The LM1 F gas play contains total reserves of 0.021 Bbo and 2.978 Tcfg (0.551 BBOE), of which 0.012 Bbo and 1.714 Tcfg (0.316 BBOE) have been produced. The play contains 44 producible sands in 15 pools (table 1). The first reserves in the play were discovered in the West Cameron 40 field in 1955 (figure 2). Pool discoveries were minimal until the 1980's when 10 out of the play's 15 pools were found. The maximum yearly total reserves of 186.673 MMBOE were added in 1980 with the discovery of two pools. However, the largest pool in the play was found in 1982 in the Matagorda Island 623 field. In fact, 90 percent of the cumulative production from this play occurred from pools discovered prior to 1983. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1988.

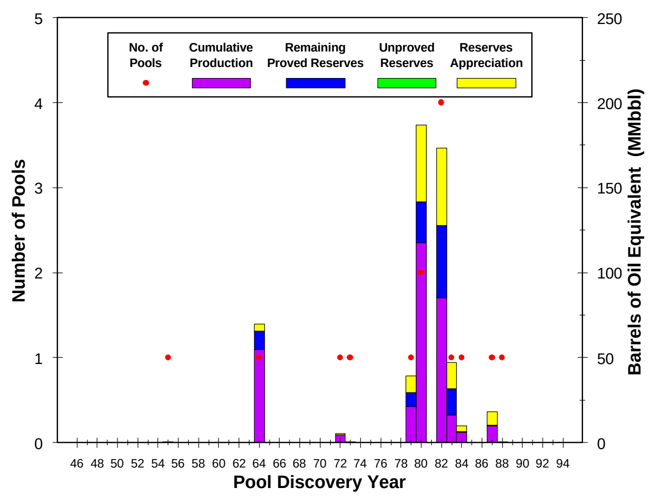


Figure 2. Exploration history graph.

The 15 discovered pools range in size from 0.150 to 169.725 MMBOE. These pools contain 69 reservoirs, of which 68 are nonassociated gas and 1 is undersaturated oil.

Of the 15 fan plays in the Gulf of Mexico Region, the LM1 F play is the third largest gas play, producing 10 percent of the gas and containing 8 percent of the gas total reserves.

Table 1. Characteristics of the discovered pools.

15 Pools (44 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	17	53	121
Subsea depth (feet)	11,822	14,049	18,250
Number of sands per pool	1	3	8
Porosity	16%	24%	31%
Water saturation	17%	31%	43%

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the LM1 F play is 1.00. The play contains a mean total endowment of 0.045 Bbo and 5.267 Tcfg (0.982 BBOE) (table 2). Thirty-two percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.017 to 0.033 Bbo and 1.915 to 2.707 Tcfg at the 95th and 5th percentiles, respectively (figure 3). The mean undiscovered resources are estimated at 0.024 Bbo and 2.289 Tcfg (0.431 BBOE). These undiscovered resources may occur in as many as 34 pools. The largest undiscovered pool, with a mean size of 86.578 MMBOE, is modeled to be the third largest pool in the play (figure 4). The model results place the next four largest undiscovered pools in positions 5, 7, 9, and 11 on the pool rank plot. For all the undiscovered pools in the LM1 F play, the mean mean size is 12.696 MMBOE, which is substantially smaller than the 36.722 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and

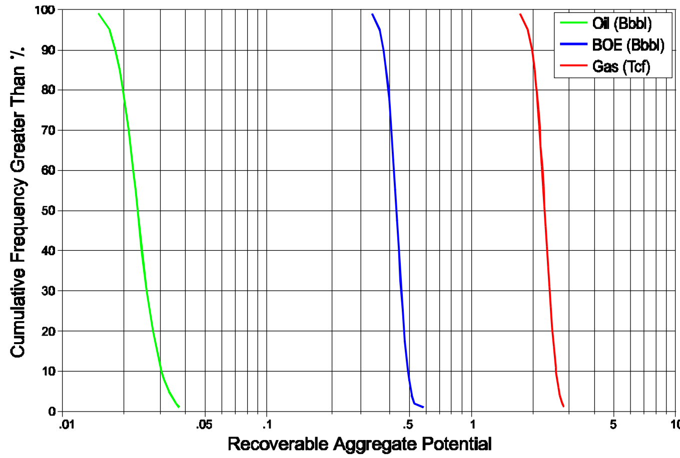


Figure 3. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	15	0.016	2.262	0.419
Cumulative production	--	0.012	1.714	0.316
Remaining proved	--	0.005	0.548	0.102
Unproved	0	0.000	0.000	0.000
Appreciation (P & U)	--	0.005	0.715	0.132
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.017	1.915	0.356
Mean	34	0.024	2.289	0.431
5th percentile	--	0.033	2.707	0.506
Total Endowment				
95th percentile	--	0.038	4.893	0.907
Mean	49	0.045	5.267	0.982
5th percentile	--	0.054	5.685	1.057

undiscovered, is 20.051 MMBOE.

The LM1 F play has a large unexplored area. Numerous undiscovered pools, comparable to the range of sizes for the discovered pools, are expected to be found, accounting for 44 percent of the play's BOE mean total endowment. The greatest exploration potential exists downdip of discovered fields where wells have been too shallow to test the LM1 section. Limited exploration potential exists between the two productive areas of the play in the Brazos and Galveston Areas offshore Texas because of sparse sand development.

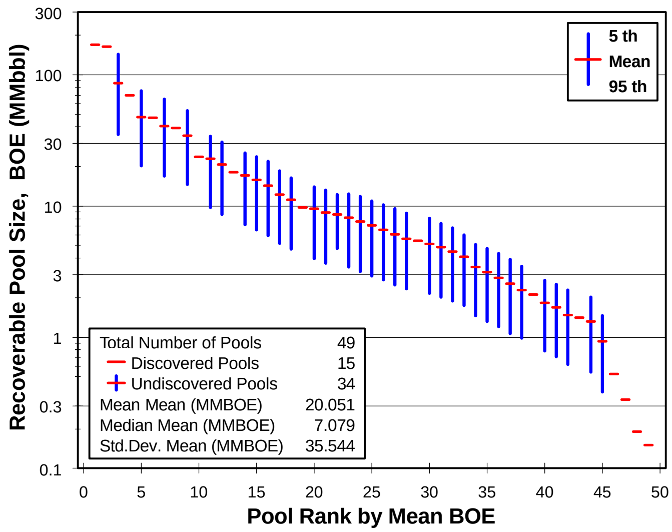


Figure 4. Pool rank plot.

OLIGOCENE/EOCENE (O/E) CHRONOZONE

CHRONOZONE DESCRIPTION

The Oligocene/Ecocene (O/E) chronozone corresponds to the *Marginulina texana* biozone. The O/E chronozone comprises the frontier Oligocene Fan (O F) play and the conceptual Perdido Fold Belt (O/E X) play. The O/E X play includes both Oligocene and Eocene sediments as potential reservoir targets. Because both plays include sediments of Oligocene age and have very limited data available, the Oligocene and Eocene were combined at the chronozone level.

The potential for sand development in the O/E chronozone extends from the South Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). Updip, the potential for O/E sand development continues onshore into Texas and Louisiana. To the northeast, the sand potential is bounded by the Cretaceous carbonate shelf edge and a decrease in sediment influx at the edge of the O/E depocenter. To the southwest, the potential extends into Mexican national waters. Downdip, the potential extends at least as far as the Sigsbee Escarpment.

The O F play is characteristically similar to the younger Cenozoic deepwater Gulf of Mexico fans and consists of turbidites deposited in fan systems as fan lobes, fringe sheet sands, channel fill, and submarine slumps. Normal faults dominate the structural style.

The O/E X play is a structural play consisting of large, compressional folds that occur in front of and beneath the leading edge of the Sigsbee Escarpment in the southeastern Alaminos Canyon Area. The play extends downdip into Mexican national waters. Potential reservoir rocks of Oligocene and Eocene age may consists of mass-

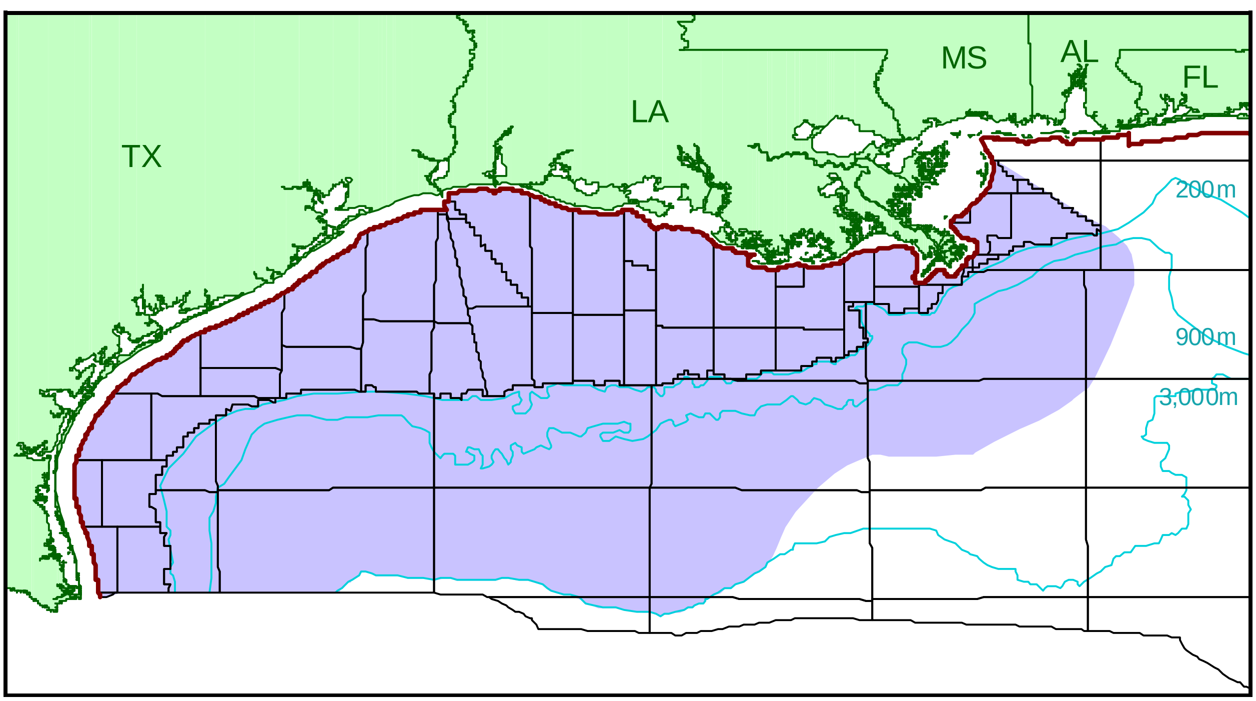


Figure 1. Map of assessed chronozone.

transport facies, debris-flows, and submarine slumps.

Discoveries

There were no discoveries in the O/E chronozone prior to this study's cutoff date of January 1, 1995.

Assessment Results

Assessment results indicate that undiscovered resources in the chronozone may occur in as many as 40 pools. These undiscovered resources are estimated to be 0.126 Bbo and 2.844 Tcfg at the 95th percentile but 2.327 Bbo and 9.576 Tcfg at the 5th percentile (table 1 and figure 2). At mean levels, 0.803 Bbo and 5.586 Tcfg (1.797 BBOE) are projected. The 40 undiscovered pools have a mean mean size of 12.134 MMBOE (figure 3). Of the two O/E chronozone plays, the O/E X play is estimated to contain 65 percent of the BOE mean total endowment for the chronozone.

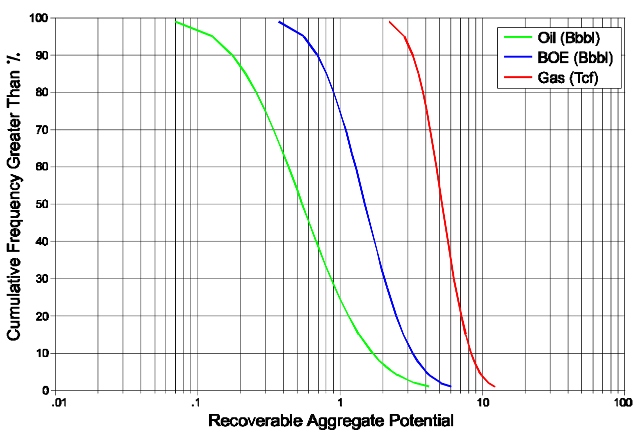


Figure 2. Cumulative probability distribution.

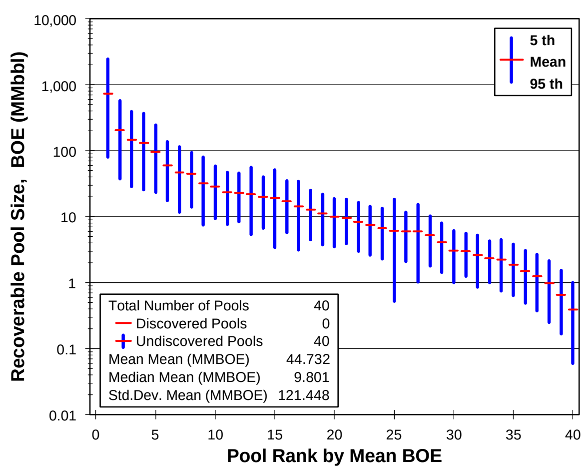


Figure 3. Pool rank plot.

Table 1. Assessment results.

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	--	0.126	2.844	0.558
Mean	40	0.803	5.586	1.797
5th percentile	--	2.327	9.576	4.032
Total Endowment				
95th percentile	--	0.126	2.844	0.558
Mean	40	0.803	5.586	1.797
5th percentile	--	2.327	9.576	4.032

Oligocene Fan (O F) Play

Play Description

The frontier Oligocene Fan (O F) play occurs at the *Marginulina texana* biozone. This play extends from the South Padre Island Area offshore Texas to the western edges of the Destin Dome and Desoto Canyon Areas east of the present-day Mississippi River Delta (figure 1). An analysis of seismic and paleontologic data indicate that fan sands may occur as deep as the base of the middle Oligocene throughout state and federal waters in the south Texas area.

The O F play is modeled after the Lower Lower Miocene Fan (LM1 F) play. Updip, the play continues onshore into Texas and Louisiana. To the southwest, the O F play extends into Mexican national waters. To the northeast, the play potential is bounded by the Cretaceous carbonate shelf edge and a decrease in sediment influx at the edge of the Oligocene depocenter. Downdip, the play potential extends at least as far as the Sigsbee Escarpment.

Oligocene sands deposited in a fan environment are recognized in the Mustang Island 858 field. Two significant wells in East Breaks blocks 191 and 404 were drilled on structural highs. These wells were drilled to a total depth of more than 10,000 feet, subsea, and were terminated just above the top of the middle Oligocene (planktonic equivalent of *Marginulina howei*) in a lower bathyal to abyssal paleoecological environment.

Play Characteristics

The O F play consists of deepwater turbidites deposited in fan systems as fan lobes, fringe sheet sands, channel fill, and slump sediments. As in the LM1 F play, normal faults dominate the O F play's structural style. Less commonly, anticlines, shale diapirs,

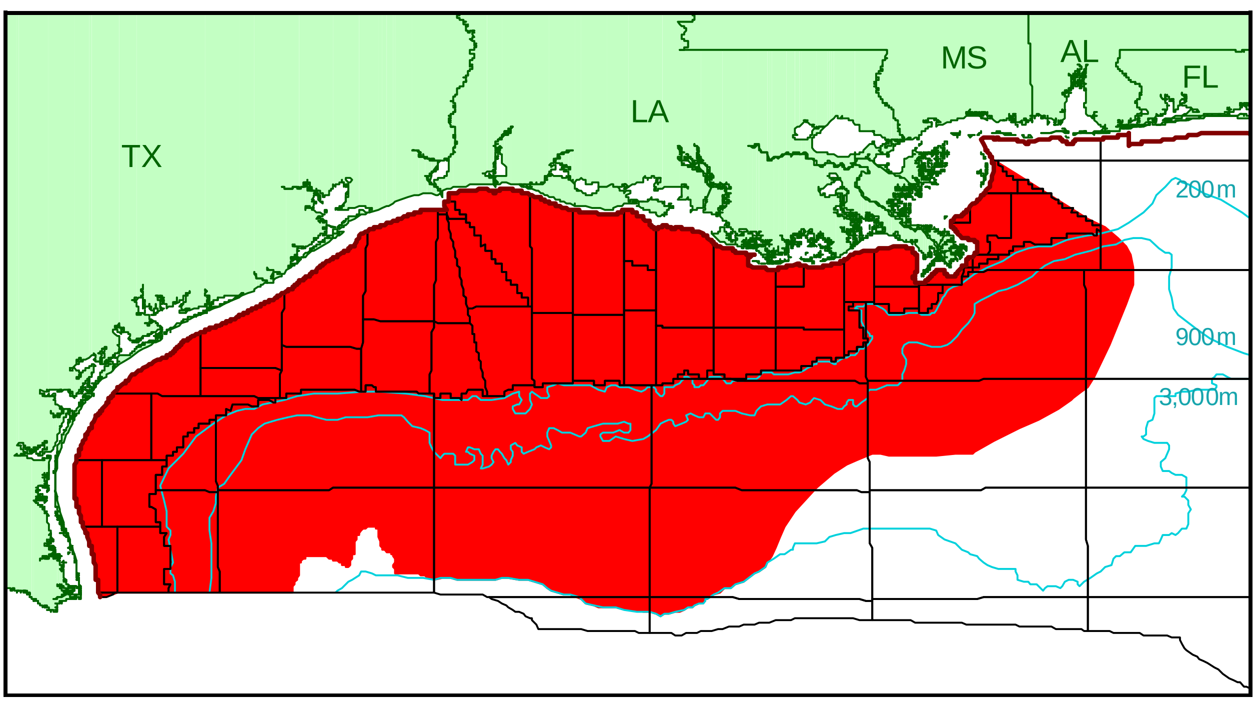


Figure 1. Map of assessed play.

rotational slump blocks, and growth faults occur. Seals are provided by the juxtaposition of reservoir sands with shales, either structurally (e.g., faulting) or stratigraphically (e.g., lateral shale-outs, overlying shales).

DISCOVERIES

There were no discoveries in the O F play prior to this study's cutoff date of January 1, 1995.

ASSESSMENT RESULTS

Because of limited data for the O F play, the LM1 F play was used as an analog to model pool sizes in the O F play. The LM1 F play was selected as the analog because of similarities in depositional setting, areal extent, structural style, and statistical information.

The marginal probability of hydrocarbons for the O F Play is 1.00. One hundred percent of the play's total endowment is undiscovered conventionally recoverable resources. Assessment results indicate that these undiscovered resources have a range of 0.026 to 0.078 Bbo and 1.976 to 5.471 Tcfg at the 95th and 5th percentiles, respectively (table 1 and figure 2). The mean undiscovered resources are estimated at 0.043 and 3.249 Tcfg (0.621 BBOE). These undiscovered resources may occur in as many as 30 pools, which range in size from 0.392 to 205.090 MMBOE (figure 3). For all the undiscovered pools in the O F play, the mean mean size is 20.657 MMBOE.

The O F play has a large unexplored area with a relatively large number of undiscovered pools. Exploration potential exists on the shelf where wells have been too shallow to test the O F section and in the largely unexplored deepwater areas of the Gulf of Mexico.

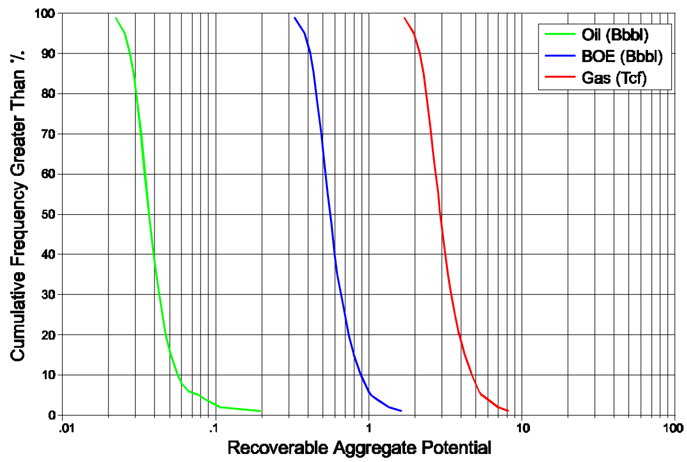


Figure 2. Cumulative probability distribution.

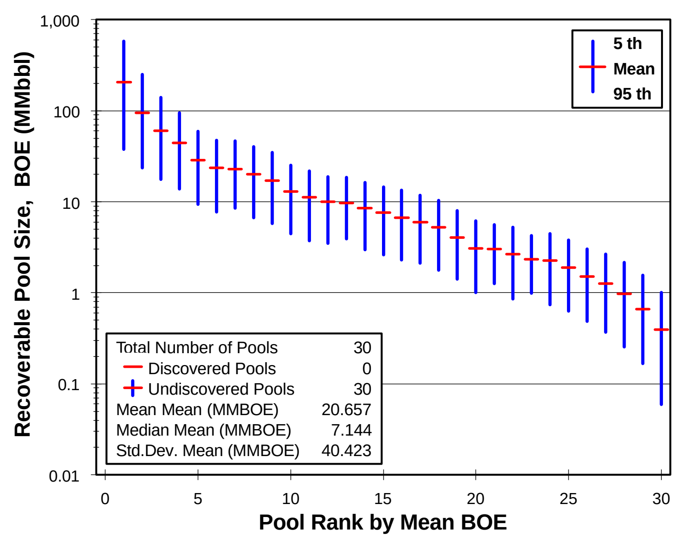


Figure 3. Pool rank plot.

Table 1. Assessment results.

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	--	0.026	1.976	0.380
Mean	30	0.043	3.249	0.621
5th percentile	--	0.078	5.471	1.040
Total Endowment				
95th percentile	--	0.026	1.976	0.380
Mean	30	0.043	3.249	0.621
5th percentile	--	0.078	5.471	1.040

PERDIDO FOLD BELT (O/E X) PLAY

PLAY DESCRIPTION

The conceptual Perdido Fold Belt (O/E X) play, as assessed in this report, is lower Tertiary aged occurring in the Oligocene and Eocene Series. This play extends from the southeastern Alaminos Canyon Area offshore Texas southward into Mexican national waters (figure 1). An analysis of seismic data indicates the play is found in front of and beneath the leading edge of the Sigsbee Escarpment.

The area where the O/E X play is located contains large, untested compressional folds in water depths ranging from about 7,000 feet to greater than 10,000 feet. The folds trend parallel to the continental margin. The timing of structural deformation for the play is interpreted as late Oligocene. The cause of deformation is probably gravity sliding above a weak basal detachment in response to expansion systems to the west.

There were no wells in the O/E X play prior to this study's cutoff date of January 1, 1995. Due to the lack of well control, a great deal of the stratigraphy of the play area is conjecture. The sediment thickness in this area is estimated to be in excess of 30,000 feet. The present interpretation of the general stratigraphy of the section is as follows: oceanic crust, Jurassic aged salt, late Jurassic and early Cretaceous aged fine-grained marine carbonates, late Cretaceous fine-grained marine carbonates with interbedded siliciclastics derived from the Laramide Orogeny, and Cenozoic aged clastic and hemipelagic accumulations.

The reservoir rocks of the play probably consist of mass-transport facies, debris-flows, and submarine slumps; hydrocarbon seals are formed by shales in the section. Although there are no wells to confirm source rocks or thermal maturation in the section, numerous oil seeps have been documented in this area of the Gulf of Mexico.

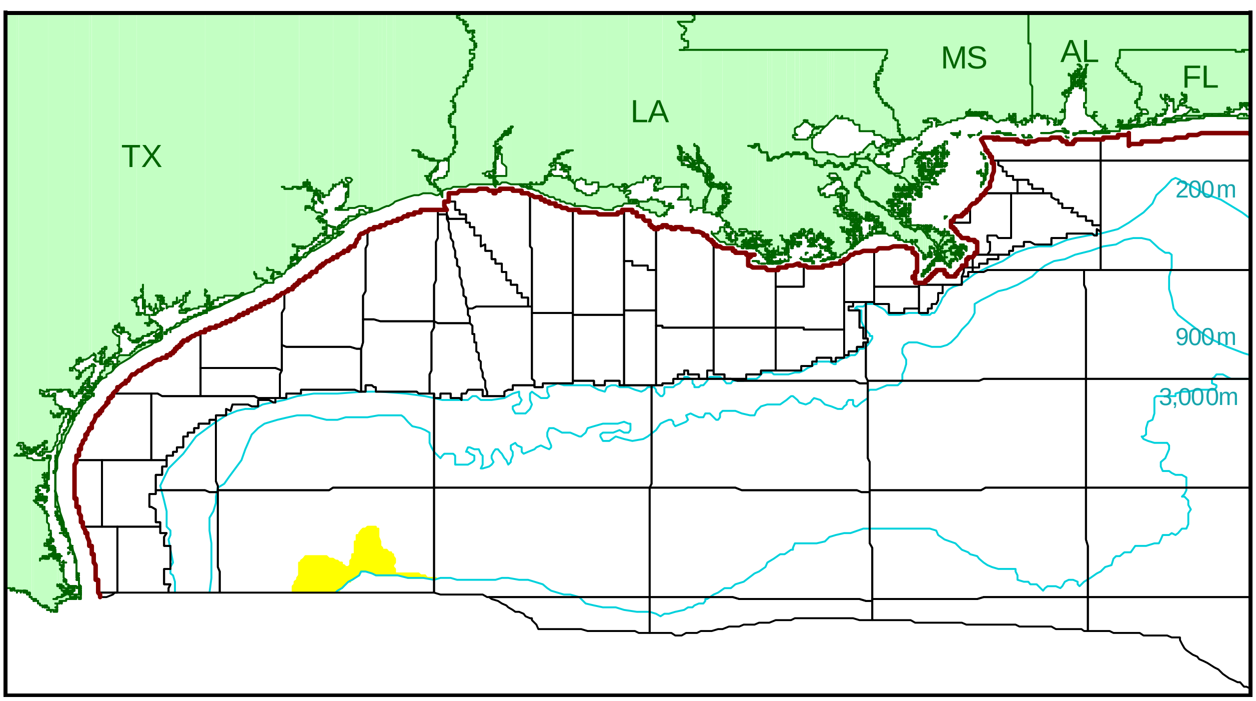


Figure 1. Map of assessed play.

Play Characteristics

The O/E X play is delineated by long subparallel folds that trend southwest-northeast across the area. Individual anticlines are enormous when compared to typical Gulf Coast anticlines. Structural relief of several thousand feet is common. The depositional and reservoir characteristics of the play are modeled after the late Cenozoic fan plays, with emphasis on the lower Miocene fan plays. To the south and east, the depositional system of the play is modeled to reflect a decrease in sediment influx from a source to the north and west toward the abyssal Gulf of Mexico Basin.

Discoveries

There were no discoveries in the O/E X play prior to this study's cutoff date of January 1, 1995.

Assessment Results

The marginal probability of hydrocarbons for the O/E X play is 1.00. One hundred percent of the play's mean total endowment is undiscovered conventionally recoverable resources. Assessment results indicate that these undiscovered resources have a range of 0.181 to 2.206 Bbo and 1.030 to 4.571 Tcfg at the 95th and 5th percentiles, respectively (table 1 and figure 2). The mean undiscovered resources are estimated at 0.760 Bbo and 2.337 Tcfg (1.176 BBOE). These undiscovered resources may occur in as many as 10 pools, which range in size from 5.987 to 742.450 MMBOE (figure 3). For all the undiscovered pools in the O/E X play, the mean mean size is 116.958 MMBOE.

The O/E X play has a small unexplored area in the Alaminos Canyon Area with many untested structures.

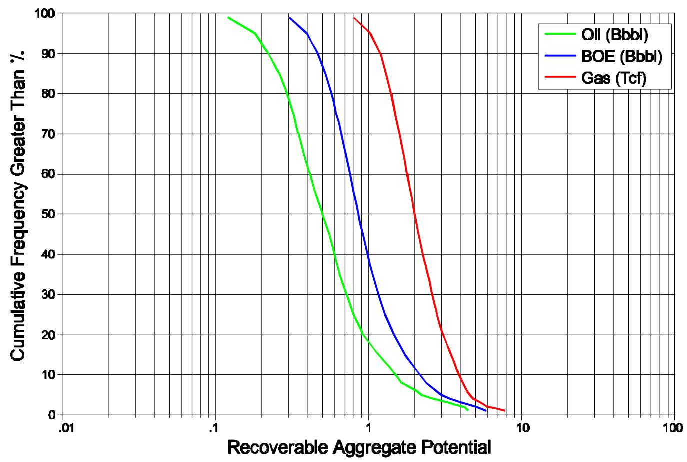


Figure 2. Cumulative probability distribution.

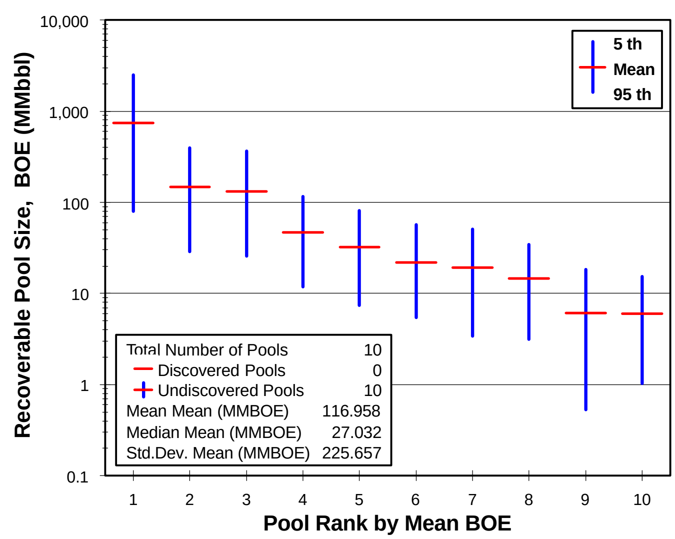


Figure 3. Pool rank plot.

Table 1. Assessment results.

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	--	0.181	1.030	0.396
Mean	10	0.760	2.337	1.176
5th percentile	--	2.206	4.571	2.968
Total Endowment				
95th percentile	--	0.181	1.030	0.396
Mean	10	0.760	2.337	1.176
5th percentile	--	2.206	4.571	2.968

PALEOCENE (L) CHRONOZONE

The Paleocene (L) chronozone was not assessed because the existence of reservoir-quality sands in the Federal offshore is highly unlikely.

UPPER CRETACEOUS (UK) CHRONOZONE

The Upper Cretaceous (UK) chronozone contains only one play [see Upper Cretaceous Clastic (UK CL) play].

UPPER CRETACEOUS CLASTIC (UK CL) PLAY

Play Description

The frontier Upper Cretaceous Clastic (UK CL) play occurs at the *Rotalipora cushmani* biozone. This play extends from the Mobile/Viosca Knoll Areas to the Pensacola/Destin Dome Areas (figure 1). Updip, the UK CL play extends onshore. The downdip limit occurs where upper Cretaceous sands interfinger with prodelta shales.

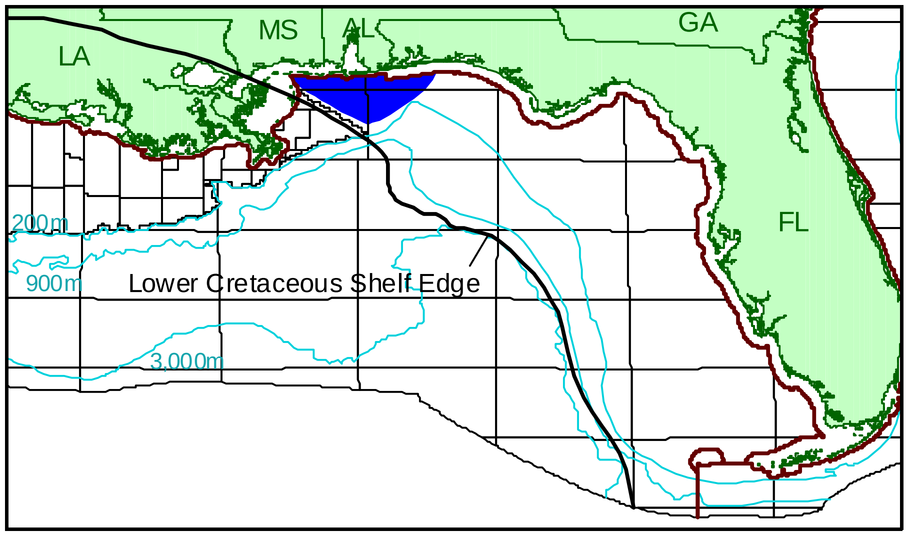


Figure 1. Map of assessed play.

PLAY CHARACTERISTICS

The UK CL play consists of progradational sands and aggradational stacked barrier bars and channels of the Tuscaloosa Formation (figure 2). However, the Tuscaloosa Formation exhibits poor reservoir-quality sands in the Federal OCS. Major structural features in this play are anticlines and faults related to salt tectonics. Potential source rocks are carbonates of the Upper Jurassic Smackover Formation, with faults acting as migration routes, and shales of the Tuscaloosa Formation. Late Cretaceous marine shales provide seals for the UK CL play.

The analog type field for the UK CL play is the Hub Field, Marion County, Mississippi, which produces from the Upper Cretaceous Tuscaloosa Formation.

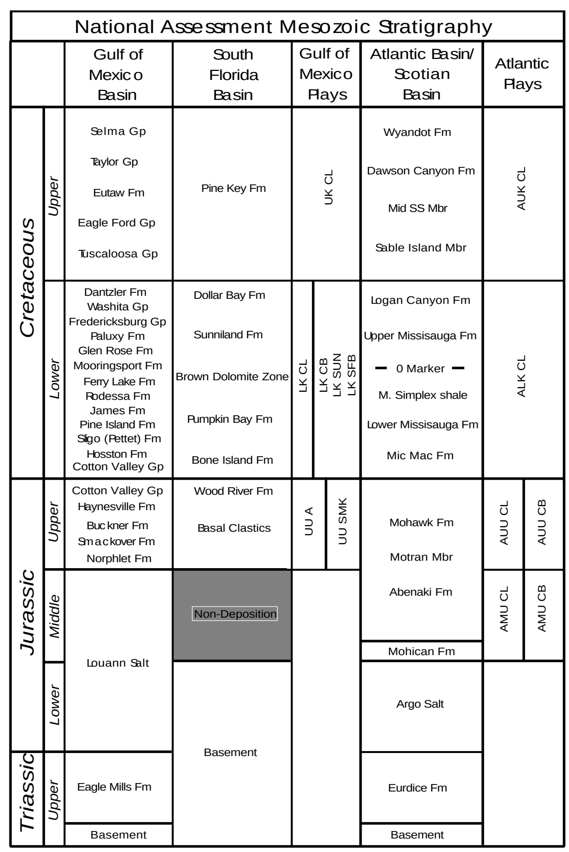


Figure 2. Stratigraphic column.

DISCOVERIES

One minor gas show occurred in the Upper Cretaceous Tuscaloosa Formation in Exxon's OCS G02486-1 well in Destin Dome block 162. However, the show occurs in a basal fluvial depositional environment and is not considered to be part of the relatively more prospective deltaic depositional environment of the UK CL play. Of the Federal OCS wells that penetrated the UK CL play as defined, no significant hydrocarbons were encountered (the Mesozoic well database [wellmeso.dbf] is presented in the CD-ROM DataFiles directory).

ASSESSMENT RESULTS

Because the UK CL play is not currently productive in the Federal OCS, the productive Tuscaloosa and Eutaw Formations of onshore Louisiana, Mississippi, and Alabama were used as an analog for this assessment (figure 2). This analog covers an area of 11.4 million acres (17,835 square miles). The best reservoir sand development in the analog occurs in reworked, retrogradational sands, which are poorly developed in the Federal OCS. Exploration in the analog has a success rate of approximately 10 percent, and drilling is at a mature stage with approximately 80 percent of the analog explored. Analog fields contain an average of 63 percent oil, 3 percent gas, and 34 percent mixed hydrocarbons. Production from the analog fields ranges from less than 1 to 678 MMBOE. Net pay ranges from 7 to 95 feet at depths of 4,700 to 14,630 feet. Reservoirs are characterized by porosities of 15 to 31 percent, oil gravities of 5 to 68^{o} API, and GOR's of 50 to 164,500 scf/stb.

The marginal probability of hydrocarbons for the UK CL play is 0.56. Assessment results indicate that undiscovered resources are estimated to be zero at the 95th percentile but 0.190 Bbo and 0.257 Tcfg at the 5th percentile (table 1 and figure 3). The mean undiscovered resources are estimated at 0.045 Bbo and 0.070 Tcfg (0.057 BBOE). These undiscovered resources may occur in as many as five pools, which have an unrisked mean size range of 1.055 to 80.301 MMBOE (figure 4). These pools have an unrisked mean mean size estimated at 20.626 MMBOE.

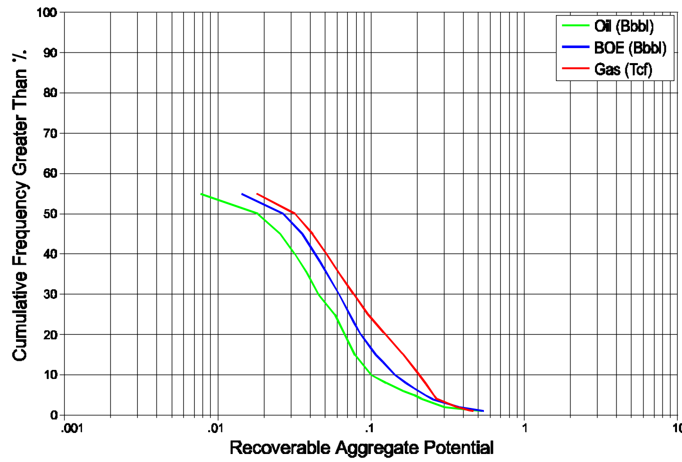


Figure 3. Cumulative probability distribution.

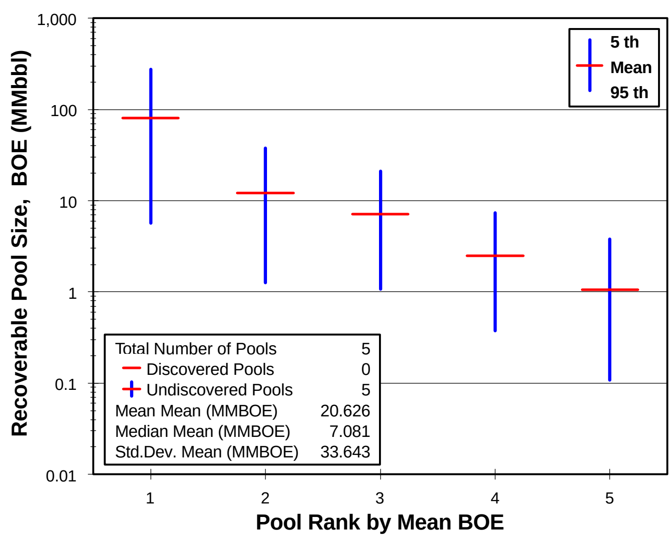


Figure 4. Pool rank plot.

Because of poor sand development in the Tuscaloosa Formation and the large number of dry holes that have tested this play in the Federal OCS, the UK CL play is expected to have few discoveries.

Table 1. Assessment results.

Marginal Probability = 0.56	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	--	0.000	0.000	0.000
Mean	5	0.045	0.070	0.057
5th percentile	--	0.190	0.257	0.226
Total Endowment				
95th percentile	--	0.000	0.000	0.000
Mean	5	0.045	0.070	0.057
5th percentile	--	0.190	0.257	0.226

LOWER CRETACEOUS (LK) CHRONOZONE

CHRONOZONE DESCRIPTION

The Lower Cretaceous (LK) chronozone in the Gulf of Mexico Region corresponds to the *Schuleridea lacustris*, *Choffatella decipiens*, *Orbitolina texana*, *Eocytheropteron trinitiensis*, *Dictyoconus walnutensis*, *Cythereis fredericksburgensis*, *Fossocytheridea lenoirensis*, and *Lenticulina washitaensis* biozones. The lower Cretaceous section consists of clastics and carbonates, each of which defines one or more plays: the Lower Cretaceous Clastic (LK CL) play, the Lower Cretaceous Shelf-Margin Carbonate (LK CB) play, the Lower Cretaceous Sunniland Carbonate (LK SUN) play, and the Lower Cretaceous South Florida Basin Carbonate (LK SFB) play. The clastics consist mainly of barrier bars and channels deposited in an aggradational delta plain environment of the Hosston, Paluxy, and Dantzler Formations and the Fredericksburg and Washita Groups (figure 1). The carbonates consist of shelf-edge rudistid bioherms, localized patch reefs, reef talus, platform grainstones, and porous dolomites associated with cyclothems. In the eastern Gulf of Mexico, formations comprising the carbonate plays include the Sligo, James, and Mooringsport. In the South Florida area, formations comprising the carbonate plays include Bone Island, Pumpkin Bay, and Sunniland, and the Brown Dolomite Zone of the Lehigh Acres Formation.

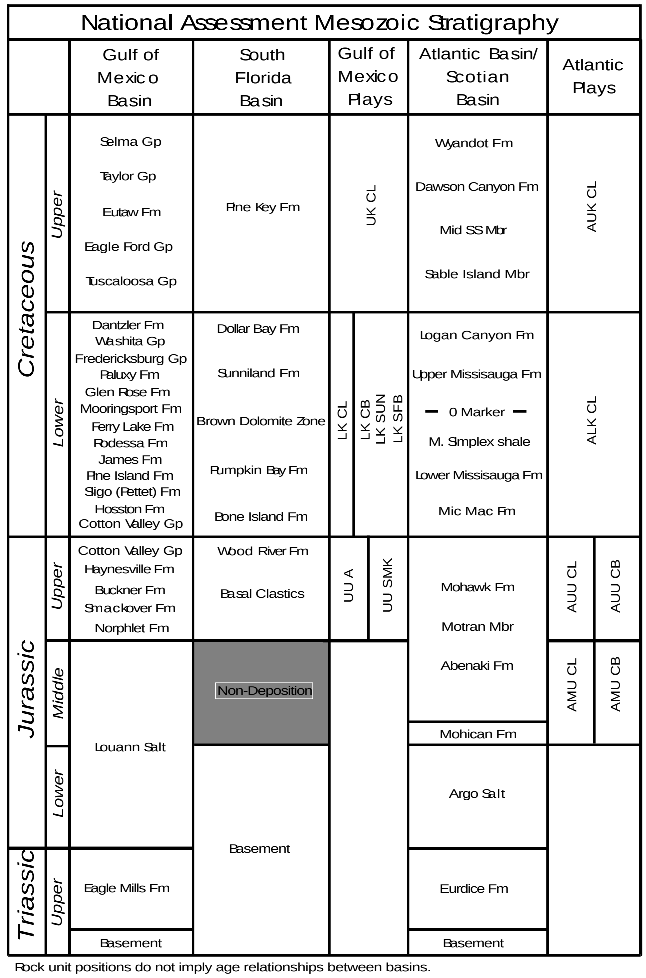


Figure 1. Stratigraphic column.

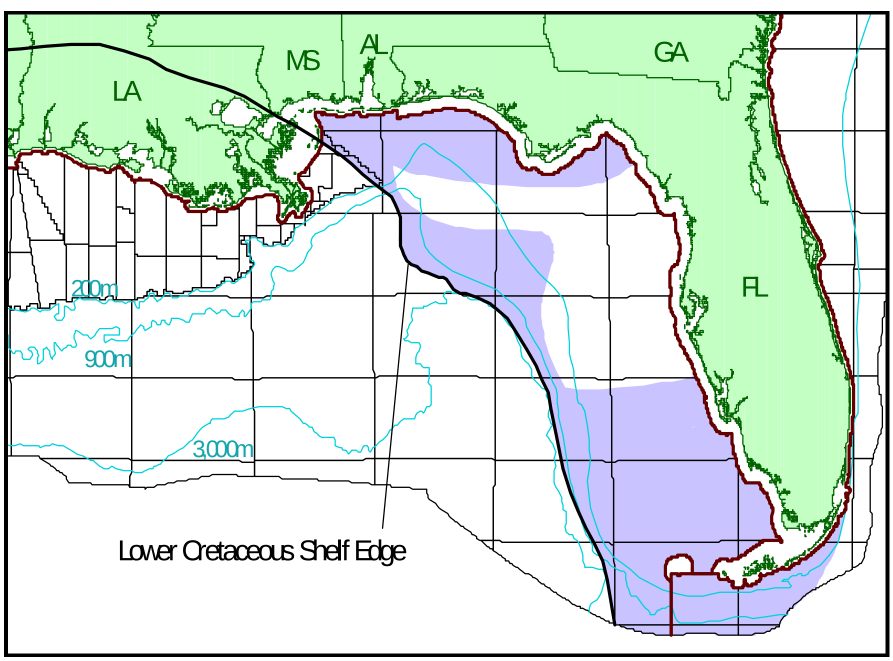


Figure 2. Map of assessed chronozone.

Clastic reservoir potential in the lower Cretaceous chronozone extends south of Mississippi, Alabama, and Florida offshore State waters into the northern portions of the Mobile, Destin Dome, Apalachicola, and Gainesville Areas (figure 2). Carbonate reservoir potential exists along the lower Cretaceous shelf-edge reef and back-reef system and in the South Florida Basin (figure 3). To the north and east, carbonate reservoir potential extends onshore into Mississippi, Alabama, and Florida. To the southwest, carbonate reservoir potential is limited by fore-reef facies of dark shales and carbonate muds.

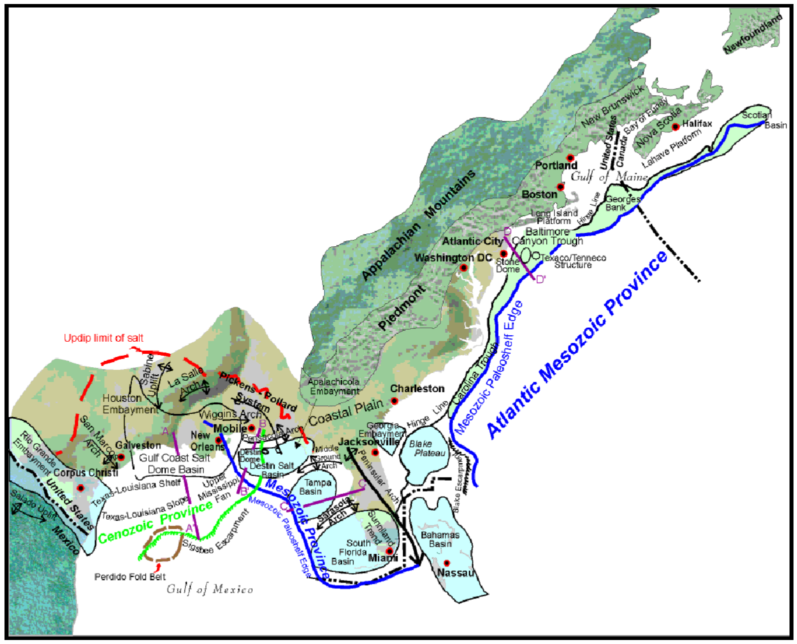


Figure 3. Physiographic map.

Discoveries

Of the four plays in the lower Cretaceous chronozone, the only play that has discovered pools is the LK CB play, with two (table 1). Total reserves in the chronozone are 0.003 Bbo and 0.436 Tcfg (0.080 BBOE), of which 0.054 MMbo and 0.325 Bcfg (0.112 MMBOE) have been produced. The maximum yearly reserves of 80.106 MMBOE were added 1993 with the discovery of the Viosca Knoll 252 field (figure 4).

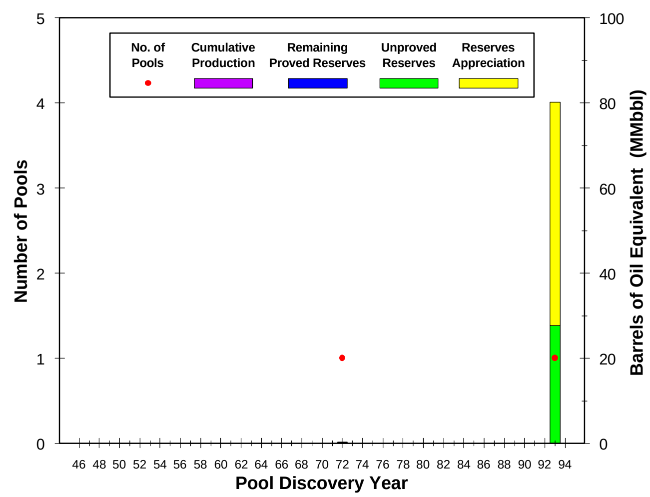


Figure 4. Exploration history graph.

Table 1. Characteristics of the discovered pools.

2 Pools (2 Reservoirs)	Minimum	Mean	Maximum
Water depth (feet)	120	204	288
Subsea depth (feet)	8,700	11,500	14,300
Number of reservoirs per pool	1	1	1
Porosity	10%	15%	20%
Water saturation	26%	29%	32%

Assessment Results

The LK chronozone contains 139 pools (discovered plus undiscovered), with a mean total endowment estimated at 1.391 Bbo and 1.305 Tcfg (1.622 BBOE) (table 2).

Assessment results indicate that undiscovered resources may occur in as many as 137 pools, which contain a range of 0.921 to 1.980 Bbo and 0.530 to 1.320 Tcfg at the 95th and 5th percentiles, respectively (figure 5). At mean levels, 1.388 Bbo and 0.869 Tcfg (1.542 BBOE) are projected. These undiscovered resources represent 95 percent of the chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the largest in the chronozone (figure 6). Additionally, when compared with the 21 Gulf of Mexico Region chronozones, the lower Cretaceous chronozone is projected to contain the largest amount of mean undiscovered oil.

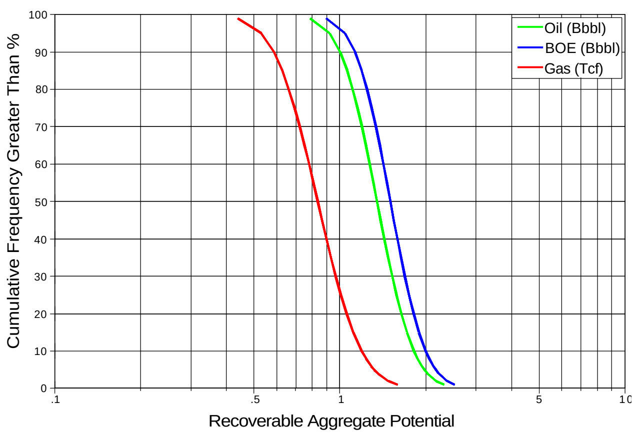


Figure 5. Cumulative probability distribution.

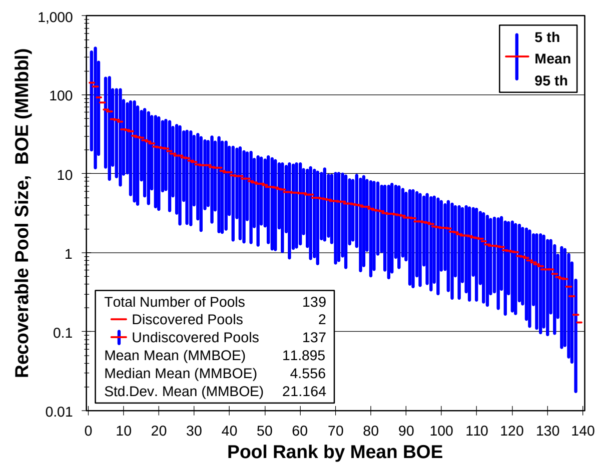


Figure 6. Pool rank plot.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	1	<0.001	<0.001	<0.001
Cumulative production	--	<0.001	<0.001	<0.001
Remaining proved	--	0.000	0.000	0.000
Unproved	1	0.001	0.150	0.028
Appreciation (P & U)	--	0.002	0.285	0.052
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.921	0.530	1.042
Mean	137	1.388	0.869	1.542
5th percentile	--	1.980	1.320	2.171
Total Endowment				
95th percentile	--	0.924	0.966	1.122
Mean	139	1.391	1.305	1.622
5th percentile	--	1.983	1.756	2.251

LOWER CRETACEOUS CLASTIC (LK CL) PLAY

PLAY DESCRIPTION

The frontier Lower Cretaceous Clastic (LK CL) play occurs within the *Schuleridea lacustris, Eocytheropteron trinitiensis*, *Cythereis fredericksburgensis*, *Fossocytheridea lenoirensis*, and *Lenticulina washitaensis* biozones. This play extends south of Mississippi, Alabama, and Florida offshore State waters into the northern portions of the Mobile, Destin Dome, Apalachicola, and Gainesville Areas (figure 1).

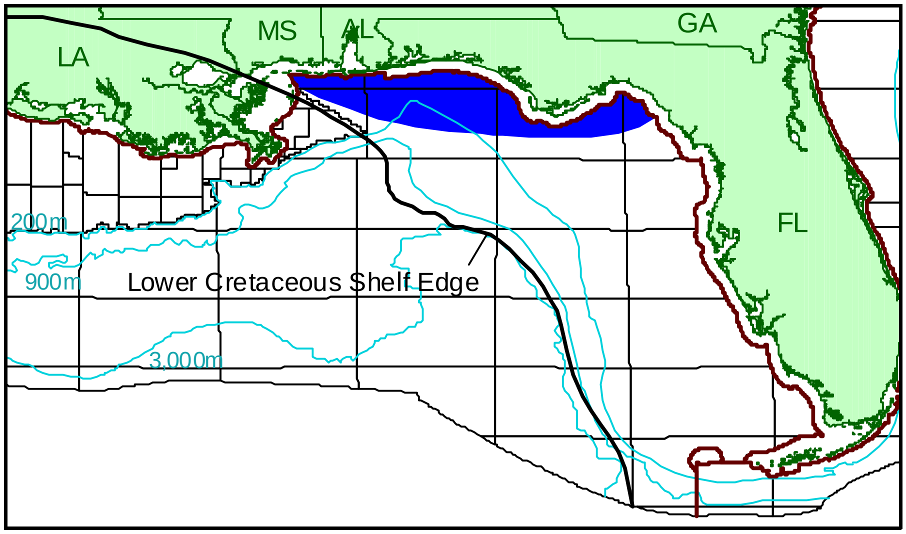
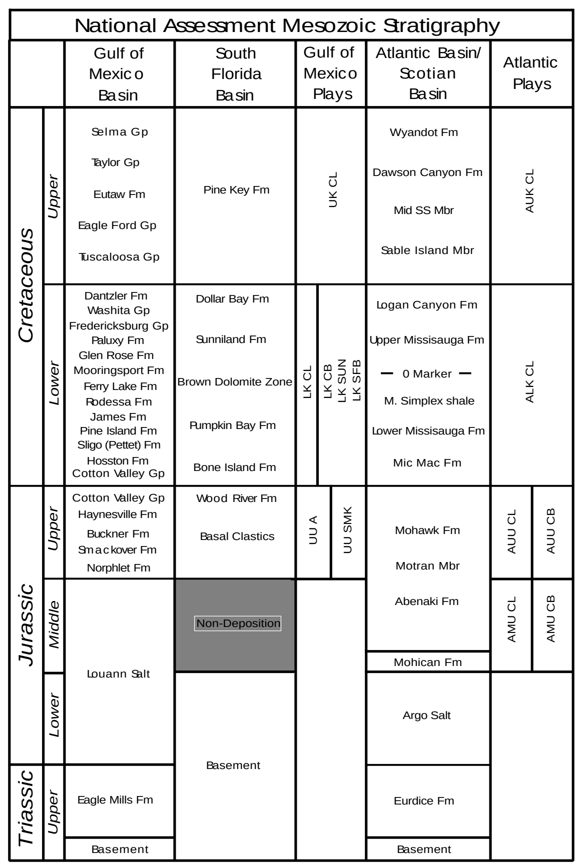


Figure 1. Map of assessed play.

Updip, the LK CL play extends onshore, while the downdip limit occurs where lower Cretaceous clastic sands interfinger with prodelta shales.

PLAY CHARACTERISTICS

The LK CL play consists mainly of aggradational, with some progradational, siliciclastic sediments that were deposited in a delta plain environment as barrier bars and channels of the Hosston, Paluxy, and Dantzler Formations (figure 2). Potential reservoirs in the LK CL play are predominantly barrier bar and channel sand deposits. The clastic Hosston Formation comprises barrier bars and stream channels, with gross interval thicknesses of 2,000 feet in the Mobile Area and 2,700 feet in the Destin Dome Area. The Paluxy Formation is widespread offshore and locally has high porosity in barrier bars and stream channels, with gross interval thicknesses ranging from 900 feet in the Mobile Area to over 2,200 feet in the Destin Dome Area. The Dantzler Formation is



Rock unit positions do not imply age relationships between basins.

Figure 2. Stratigraphic column.

thickest over the Destin Dome, but thins to the south away from its source area. Structures in the play are related to salt tectonics and faulting, and stratigraphic traps are related to facies changes. The Upper Jurassic Smackover Formation is the main source rock for the LK CL play, and early Cretaceous marine shales provide seals.

The analog type field for the LK CL play is the Oak Grove Field, Simpson County, Mississippi, which produces from the Lower Cretaceous Rodessa Formation.

Discoveries

Of the Federal OCS wells that penetrated this play, all were dry (the Mesozoic well database [wellmeso.dbf] is presented in the CD-ROM DataFiles directory). However, this play was probably not the primary exploration target for these wells.

Assessment Results

Because the LK CL play is not currently productive in the Federal OCS, the productive Hosston, Rodessa, Paluxy, and Dantzler Formations and the Fredericksburg and Washita Groups of onshore Louisiana, Mississippi, and Alabama were used as an analog for this assessment (figure 2). The analog encompasses an area of 13.7 million acres (21,395 square miles). Exploration in the analog has a success rate of approximately 10 percent, and drilling is at a mature stage with approximately 75 percent of the analog explored. Analog fields contain an average of 27 percent oil, 43 percent gas, and 30 percent mixed hydrocarbons. Production from the analog fields ranges from less than 1 to 398 MMBOE. Net pay ranges from 10 to 179 feet at depths of 7,100 to 17,150 feet. Reservoirs are characterized by porosities of 8 to 30 percent, oil gravities of 15 to 69^{o} API, and GOR's of 6 to 423,458 scf/stb.

The marginal probability of hydrocarbons for the LK CL play is 0.65. Assessment results indicate that undiscovered resources are estimated to be zero at the 95th percentile but 0.093 Bbo and 0.244 Tcfg at the 5th percentile (table 1 and figure 3). The mean undiscovered resources are estimated at 0.037 Bbo and 0.110 Tcfg (0.057 BBOE).

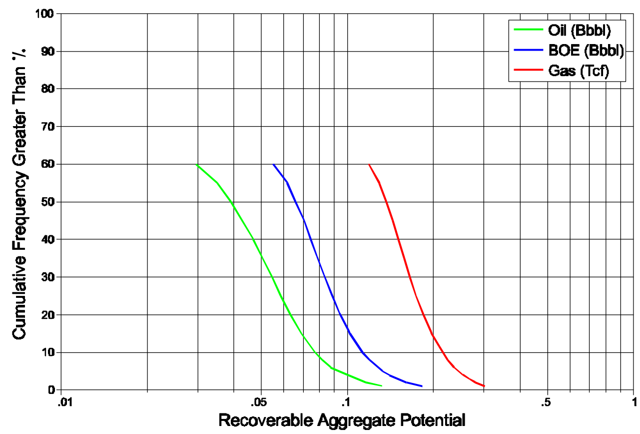


Figure 3. Cumulative probability distribution.

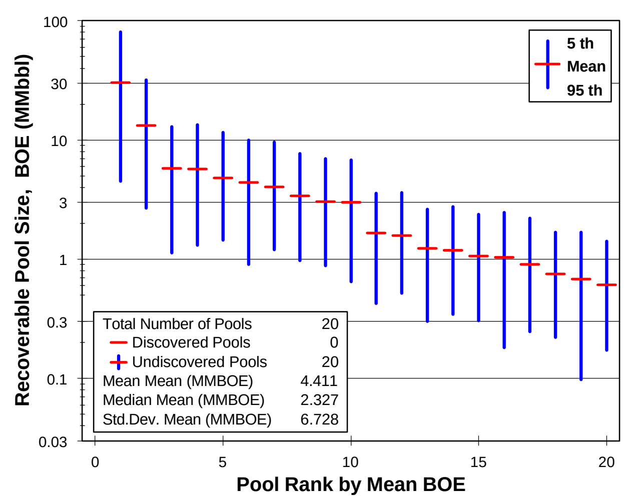


Figure 4. Pool rank plot.

These undiscovered resources may occur in as many as 20 pools, which have an unrisked mean size range of 0.613 to 30.149 MMBOE (figure 4). These pools have an unrisked mean mean size estimated at 4.411 MMBOE.

Table 1. Assessment results.

Marginal Probability = 0.65	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	--	0.000	0.000	0.000
Mean	20	0.037	0.110	0.057
5th percentile	--	0.093	0.244	0.133
Total Endowment				
95th percentile	--	0.000	0.000	0.000
Mean	20	0.037	0.110	0.057
5th percentile	--	0.093	0.244	0.133

LOWER CRETACEOUS SHELF-MARGIN CARBONATE (LK CB) PLAY

PLAY DESCRIPTION

The established Lower Cretaceous Shelf-Margin Carbonate (LK CB) play occurs within the *Choffatella decipiens*, *Orbitolina texana*, *Dictyoconus walnutensis*, and *Lenticulina washitensis* biozones. The play extends from the Mobile/Chandeleur Areas southeastward along the lower Cretaceous shelf edge to the U.S.-Cuba International Boundary (figure 1).

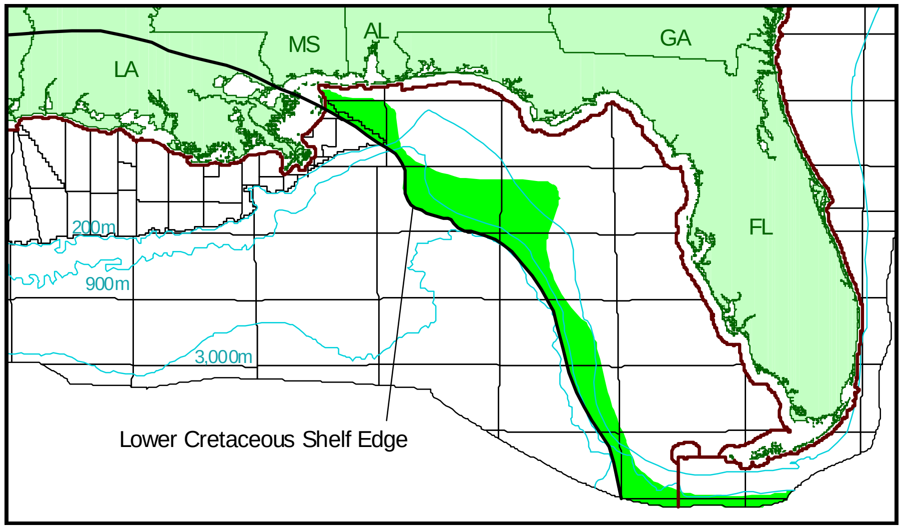
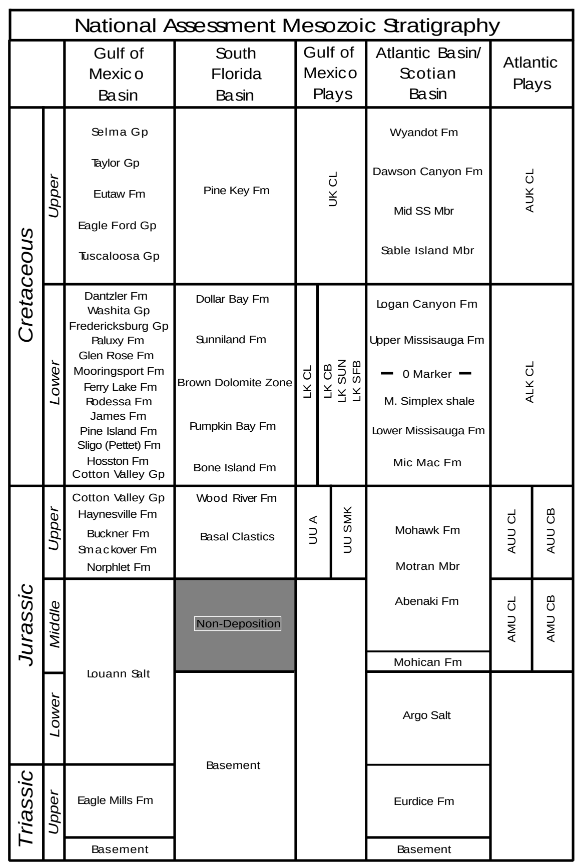


Figure 1. Map of assessed play.

The play is limited to the northeast by back-reef platform sediments characterized by carbonate muds, except where shoaling produced locally higher energy facies. Fore-reef facies of dark shales and carbonate muds bound the play to the southwest.

The LK CB play is one of only two Mesozoic plays, along with the Upper Jurassic Aggradational (UU A) play, in the Gulf of Mexico Region that has had Federal production. The Main Pass 253 field produced briefly from the Lower Cretaceous Washita Formation in the LK CB play (figure 2).



Rock unit positions do not imply age relationships between basins.

Figure 2. Stratigraphic column.

PLAY CHARACTERISTICS

The LK CB play consists of shelf-edge rudistid bioherms, reef talus, and localized patch reefs of the Sligo, James, and Mooringsport Formations and the Fredericksburg and Washita Groups of the Main Pass, Viosca Knoll, and western Desoto Canyon Areas (figure 2). The play also consists of shelf-edge rudistid bioherms and talus of the Sunniland Formation and the Brown Dolomite Zone in the Lehigh

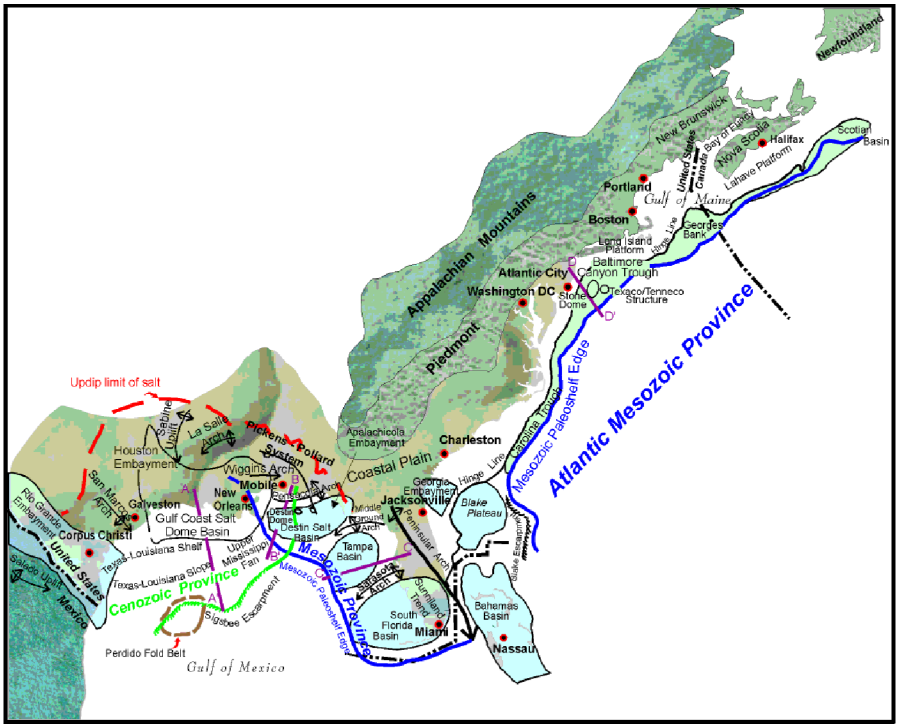


Figure 3. Physiographic map.

Acres Formation in the South Florida Basin area (figure 3). Structure along the reef trend is related primarily to reef growth, and traps are mainly stratigraphic. Potential source rocks are early Cretaceous, locally occurring, organic-rich, lagoonal carbonates; deepwater limestones; or shales. Early Cretaceous marine shales, micrites, and anhydrites provide seals for the LK CB play.

Main Pass 253 is the type field, and the LK1 reservoir represents the LK CB play in this field.

Discoveries

The LK CB gas play contains total reserves of 0.003 Bbo and 0.436 Tcfg (0.080 BBOE), of which 0.054 MMbo and 0.325 Bcfg (0.112 MMBOE) have been produced. The play contains two pools/reservoirs (table 1), one of which is nonassociated gas and the other is saturated oil (the Mesozoic well database [wellmeso.dbf] is presented in the CD-ROM DataFiles directory). Of these two discovered pools, one contains proved reserves. The first pool, which contains 0.131 MMBOE, was discovered in 1972 in the Main Pass 253 field (figure 4). The maximum yearly total reserves of 80.106 MMBOE were added in 1993 when the largest discovered pool in the play in the Viosca Knoll 252 field was found. This

Table 1. Characteristics of the discovered pools.

2 Pools (2 Reservoirs)	Minimum	Mean	Maximum
Water depth (feet)	120	204	288
Subsea depth (feet)	8,700	11,500	14,300
Number of reservoirs per pool	1	1	1
Porosity	10%	15%	20%
Water saturation	26%	29%	32%

pool accounts for almost 100 percent of the play's total reserves, but none of its cumulative production. On a BOE basis, 52 percent of the play's cumulative production is gas, but remaining total reserves indicate that future production may increase to 97 percent gas.

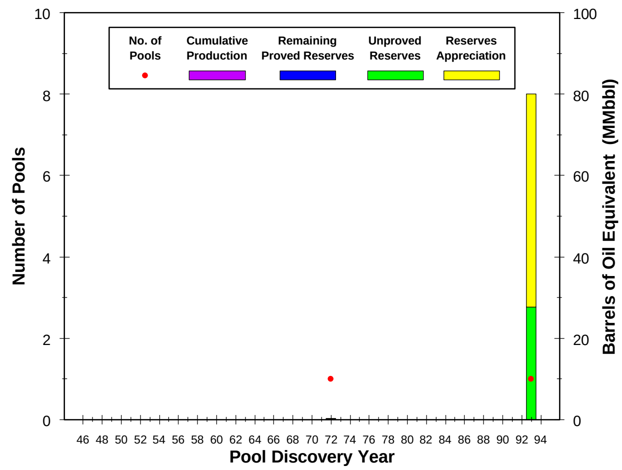


Figure 4. Exploration history graph.

ASSESSMENT RESULTS

Because the LK CB play contains only two discovered fields, an onshore producing analog was used to provide input parameters for this assessment. The analog comprises the onshore Texas Glen Rose Formation (equivalent to the Rodessa and Mooringsport Formations) and onshore Louisiana and Mississippi Pettet and Mooringsport Formations and Fredericksburg and Washita Groups (figure 2). The analog covers an area of 14.7 million acres (23,035 square miles). Exploration has a success rate of approximately 10 percent, and drilling is at a mature stage with approximately 80 percent of the analog explored. Analog fields contain an average of 38 percent oil, 46 percent gas, and 16 percent mixed hydrocarbons. Production from the analog fields ranges from 1 to 86.8 MMBOE. Net pay ranges from 12 to 179 feet at depths of 4,650 to 14,800 feet. Fields within the analog are characterized by porosities of 12 to 26 percent, oil gravities of 13 to 62° API, and GOR's of 35 to 120,284 scf/stb.

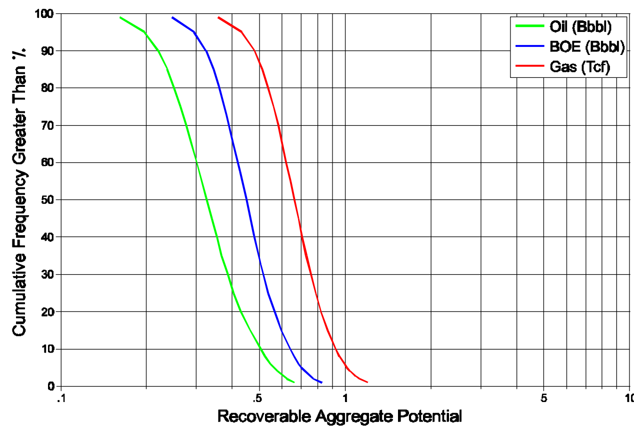


Figure 5. Cumulative probability distribution.

The marginal probability of hydrocarbons for the LK CB play is 1.00. The play contains a mean total endowment of 0.348 Bbo and 1.122 Tcfg (0.547 BBOE) (table 2). Less than 1 percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.196 to 0.562 Bbo and 0.432 to 1.014 Tcfg at the 95th and 5th percentiles, respectively (figure 5). The mean undiscovered resources are estimated at 0.345 Bbo and 0.686 Tcfg (0.467 BBOE). These undiscovered resources may occur in as many as 26 pools (figure 6). The only two discovered pools are modeled as the second largest and the smallest. The undiscovered pools have a mean size range of 0.477 to 140.950 MMBOE. For all the undiscovered pools in the LK CB play, the mean mean size is 17.994 MMBOE.

Of the 61 Gulf of Mexico Region plays, the LK CB play is projected to contain the ninth largest amount of mean undiscovered oil resources.

The lower Cretaceous shelf margin can be traced around almost the entire Gulf of

Mexico, from southern offshore Florida, across Louisiana and Texas, into Mexico and around the Yucatan Peninsula. Good porous carbonate reservoirs may be found along this entire trend. Although the Texas fields along the Sligo-Stuart City Reef Trend have been small, fields along the lower Cretaceous shelf-edge margin in Mexico include giant field complexes, such as the Golden Lane and parts of the Reforma Area. Other wells in the U.S. offshore have tested the lower Cretaceous shelf-margin carbonate potential and encountered both porosity and charge, but only in two locations have adequate traps been found. Although the LK CB play has only two discovered fields, the large extent of the lower Cretaceous shelf margin suggests that future discoveries are probable, especially if some form of trap can be identified. The undiscovered resources are estimated to account for 85 percent of the play's BOE mean total endowment.

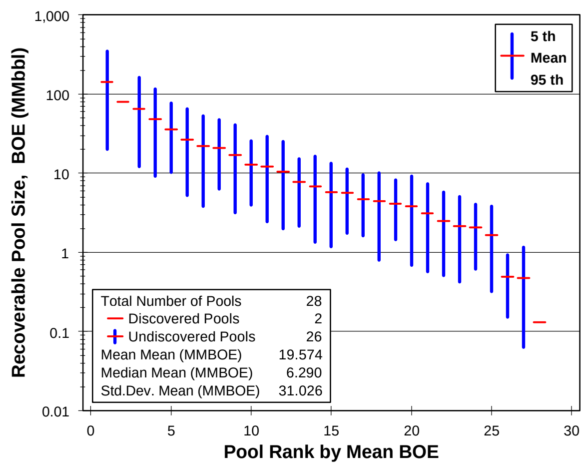


Figure 6. Pool rank plot.

Table 2. Assessment results.

Marginal Probability = 1.00	**Number of Pools**	**Oil (Bbbl)**	**Gas (Tcf)**	**BOE (Bbbl)**
Reserves				
Original proved	1	<0.001	<0.001	<0.001
Cumulative production	--	<0.001	<0.001	<0.001
Remaining proved	--	0.000	0.000	0.000
Unproved	1	0.001	0.150	0.028
Appreciation (P & U)	--	0.002	0.285	0.052
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.196	0.432	0.294
Mean	26	0.345	0.686	0.467
5th percentile	--	0.562	1.014	0.700
Total Endowment				
95th percentile	--	0.199	0.868	0.374
Mean	28	0.348	1.122	0.547
5th percentile	--	0.565	1.450	0.780

LOWER CRETACEOUS SUNNILAND CARBONATE (LK SUN) PLAY

PLAY DESCRIPTION

The frontier Lower Cretaceous Sunniland Carbonate (LK SUN) play occurs at the *Orbitolina texana* biozone. This play is located along the perimeter of the Lower Cretaceous South Florida Basin Carbonate (LK SFB) play (figure 1).

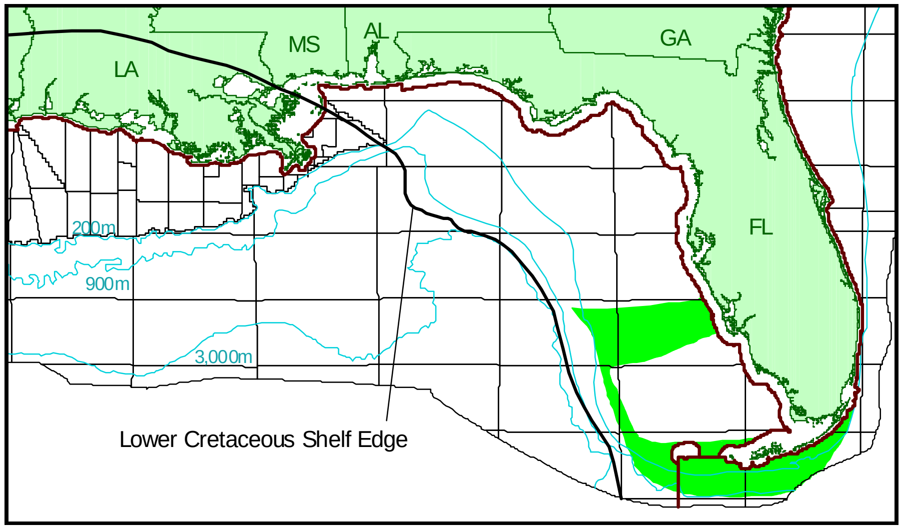


Figure 1. Map of assessed play.

To the north, a facies change to clastics limits the LK SUN play. To the south and west, the play is limited by the rudistid bioherms of the Lower Cretaceous Shelf-Margin Carbonate (LK CB) play. To the east, the play continues onshore into Florida as the producing Sunniland Trend (figure 2).

PLAY CHARACTERISTICS

The LK SUN play consists of platform grainstones, patch reefs, and reef talus of the Bone Island, Pumpkin Bay, and Sunniland Formations, and the Brown Dolomite Zone of the Lehigh Acres Formation (figure 3). Structures are related to reef buildups, and traps are mainly stratigraphic. Potential reservoirs in the LK SUN play are primarily patch reefs built up on local basement highs. Other reservoirs may

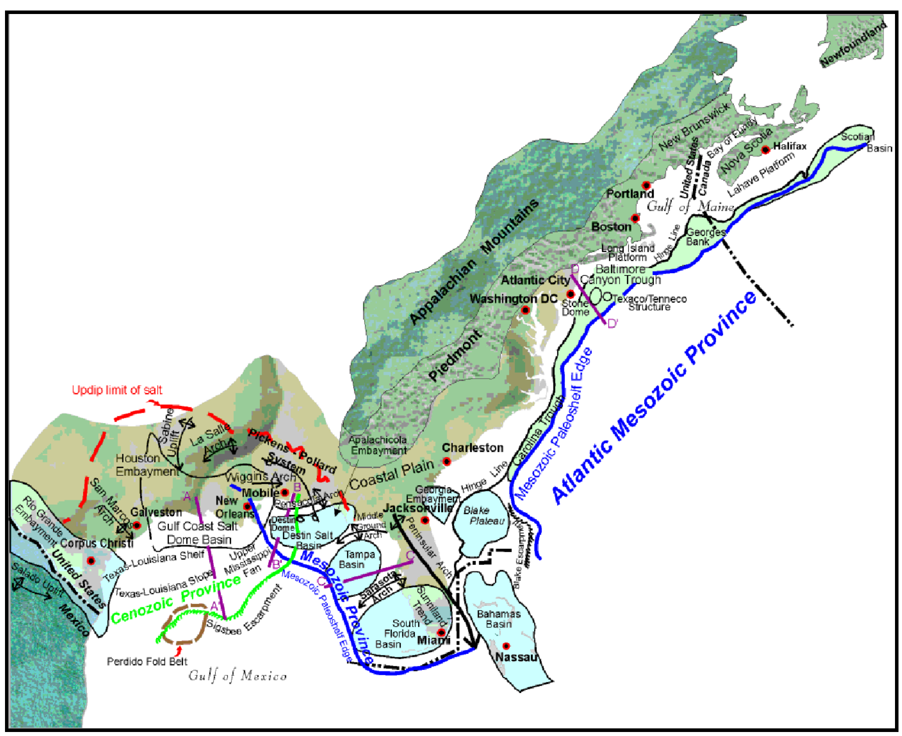
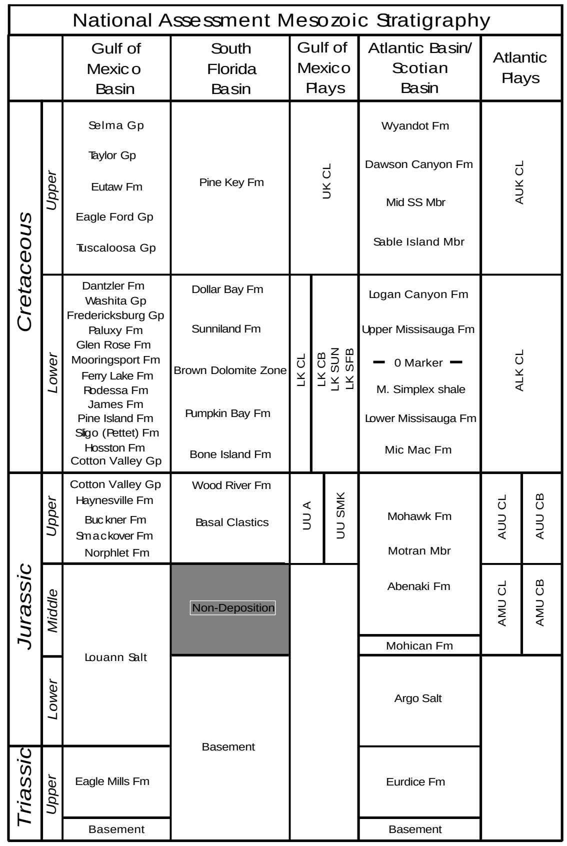


Figure 2. Physiographic map.

include platform grainstones and reef talus. Potential source rocks are locally occurring, early Cretaceous carbonates. Early Cretaceous marine shales, micrites, and anhydrites provide seals for the LK SUN play.

The analog type field for the LK SUN play is the Sunoco West Felda Field, Hendry County, Florida.



Rock unit positions do not imply age relationships between basins.

Figure 3. Stratigraphic column.

Discoveries

Approximately 400 wells have been drilled in the onshore Sunniland Trend (including the Marquesa Keys wells), with about 100 MMBOE produced. The onshore Sunniland Trend contains 14 fields. The first discovery was the Sunniland Field, Collier County, Florida, in 1943. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was the Corkscrew Field, Collier County, Florida, in 1985.

The LK SUN play is not currently productive in the Federal OCS. Two wells in the offshore State waters of Florida Straits contained hydrocarbons. Seven wells in the Federal OCS have tested the LK SUN play, of which the number 1 well in block 519 of the Dry Tortugas Area and the number 1 well in block 672 of the Charlotte Harbor Area encountered oil shows (the Mesozoic well database [wellmeso.dbf] is presented in the CD-ROM DataFiles directory).

Assessment Results

Because the LK SUN is not as yet productive in the Federal OCS area, the productive Sunniland Trend of onshore Florida was used as an analog for this assessment (figure 2). The Sunniland Trend analog covers an area of 742,400 acres (1,160 square miles). Exploration has a success rate of approximately 10 percent, and drilling is at a mature stage with approximately 90 percent of the analog explored. Analog fields average greater than 90 percent oil. Production from the analog fields ranges from less than 1 to 43.3 MMBOE. Net pay ranges from less than 3 to 24 feet at depths of 11,450 to 11,900 feet. Fields are

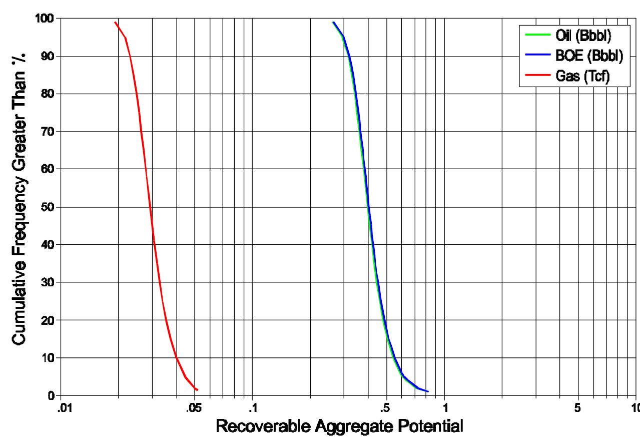


Figure 4. Cumulative probability distribution.

characterized by porosities of 7 to 17 percent, oil gravities of 21 to 28° API, and GOR's of 10 to 890 scf/stb.

The marginal probability of hydrocarbons for the LK SUN play is 1.00. Assessment results indicate that undiscovered resources have a range of 0.295 to 0.609 Bbo and 0.022 to 0.045 Tcfg at the 95th and 5th percentiles, respectively (table 1 and figure 4). The mean undiscovered resources are estimated at 0.419 Bbo and 0.031 Tcfg (0.425 BBOE). These undiscovered resources may occur in as many as 33 pools, which have a mean size range of 0.618 to 93.361 MMBOE (figure 5). These pools have a mean mean size estimated at 12.874 MMBOE.

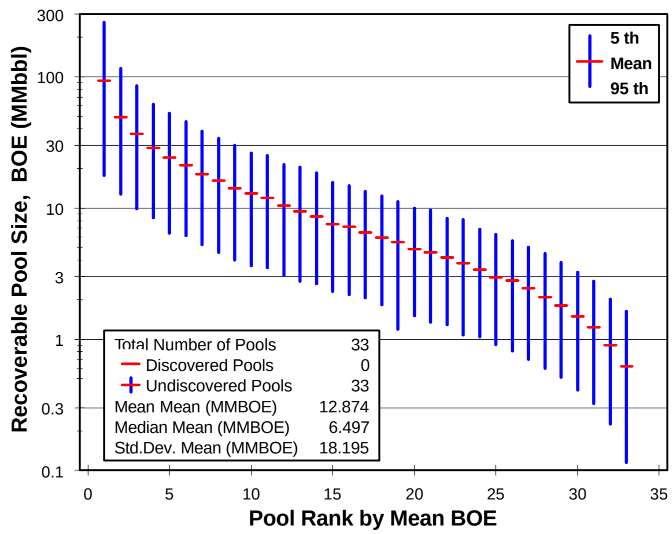


Figure 5. Pool rank plot.

Of the 61 Gulf of Mexico Region plays, the LK SUN play is projected to contain the seventh largest amount of mean undiscovered oil resources.

Areas of potential discoveries occur in the carbonate trend near the perimeter of the South Florida Basin (figure 2).

Table 1. Assessment results.

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	--	0.295	0.022	0.298
Mean	33	0.419	0.031	0.425
5th percentile	--	0.609	0.045	0.617
Total Endowment				
95th percentile	--	0.295	0.022	0.298
Mean	33	0.419	0.031	0.425
5th percentile	--	0.609	0.045	0.617

LOWER CRETACEOUS SOUTH FLORIDA BASIN CARBONATE (LK SFB) PLAY

PLAY DESCRIPTION

The conceptual Lower Cretaceous South Florida Basin Carbonate (LK SFB) play occurs within the *Choffatella decipiens*, *Orbitolina texana*, and *Dictyoconus walnutensis biozones.* This play is located in the interior of the South Florida Basin (figure 1 and figure 2). The LK SFB play is bounded in all directions by the Lower Cretaceous Sunniland Carbonate (LK SUN) play.

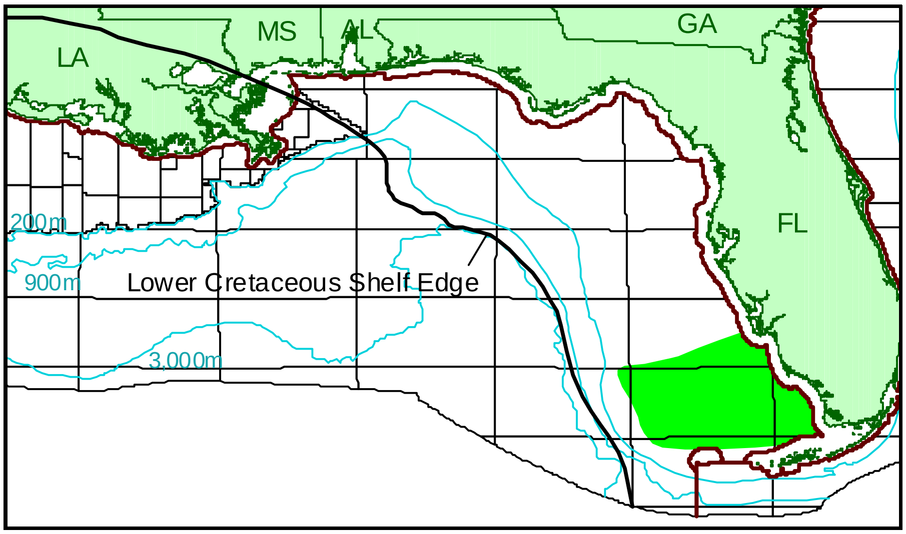


Figure 1. Map of assessed play.

PLAY CHARACTERISTICS

The LK SFB play consists of platform limestones, patch reefs, reef talus, and porous dolomites associated with cyclothems of the Bone Island, Pumpkin Bay, and Sunniland Formations, and the Brown Dolomite Zone of the Lehigh Acres Formation (figure 3). Structural closures over reefal buildups are possible, but traps are mainly stratigraphic and related to platform limestones, patch reefs, and reef talus.

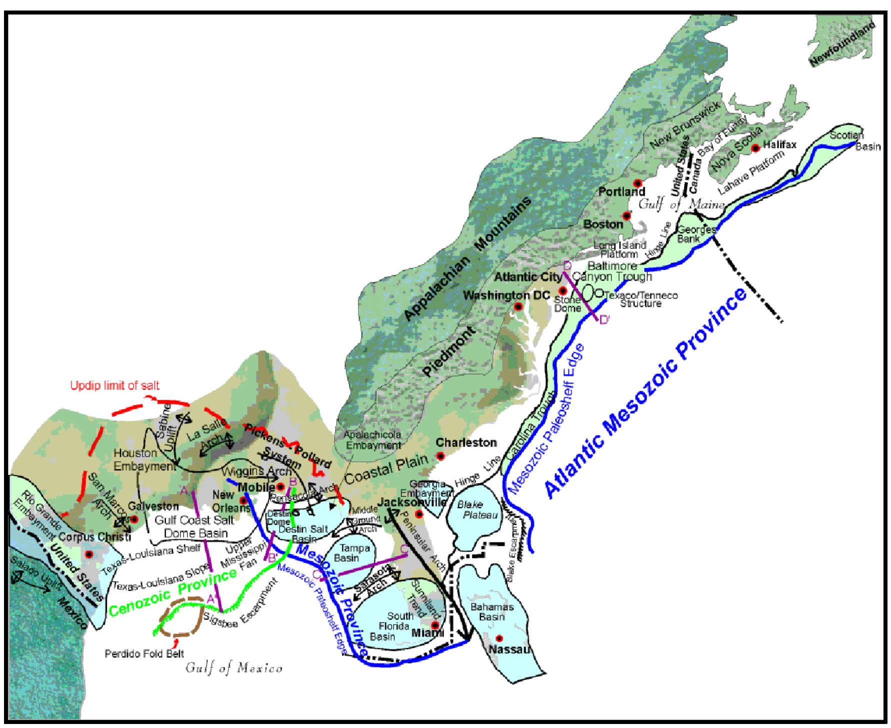


Figure 2. Physiographic map.

Potential source rocks are locally occurring, early Cretaceous carbonates. Early Cretaceous marine shales, micrites, and anhydrites provide seals for the LK SFB play.

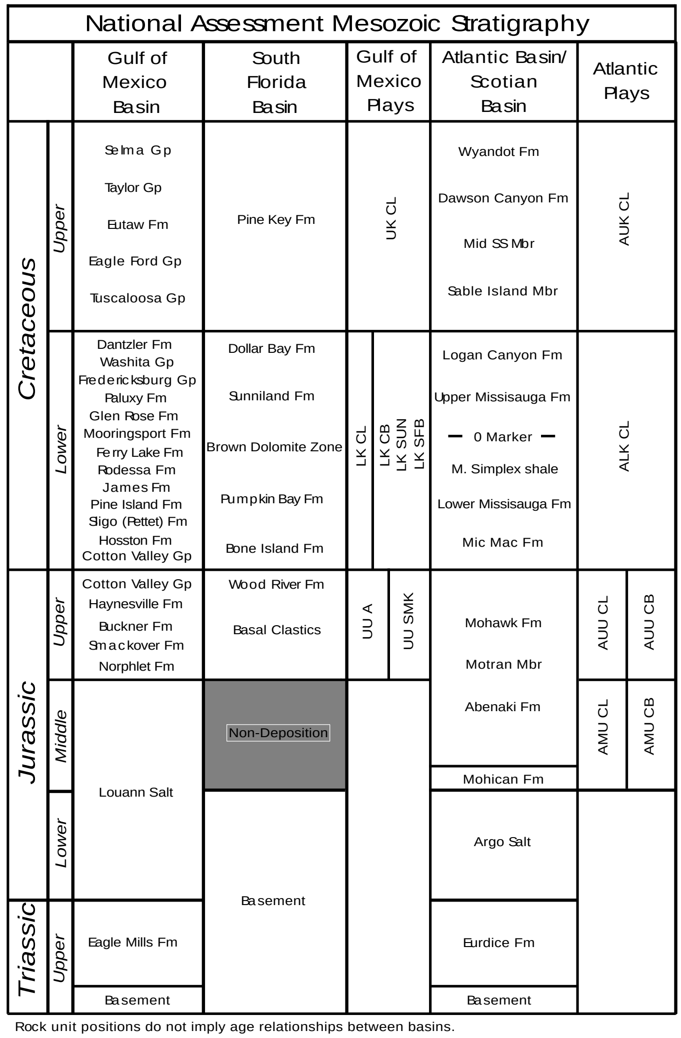
The analog type field for the LK SFB play is the Sunoco West Felda Field, Hendry County, Florida.

Discoveries

No Federal OCS wells have been drilled in this play.

Assessment Results

Because the LK SFB play has not been drilled in the Federal OCS, the productive Sunniland Trend of onshore Florida was used as an analog for this assessment (figure 2). The analog covers an area of 742,400 acres (1,160 square miles). Exploration has a success rate of approximately 10 percent, and drilling is at a mature stage with approximately 90 percent of the analog explored. Analog fields average greater than 90 percent oil. Production from the analog fields ranges from less than 1 to 43.3 MMBOE. Net pay ranges from less than 3 to 24 feet at depths of 11,450 to 11,900 feet. Fields are characterized by porosities of 7 to 17 percent, oil gravities of 21 to 28° API, and GOR's of 10 to 890 scf/stb. The marginal probability of hydrocarbons for the LK SFB play is 1.00. Assessment results indicate that undiscovered resources have a range of 0.400 to 0.881 Bbo and 0.029 to 0.065 Tcfg at the 95th and 5th percentiles, respectively (table 1 and figure 4) The mean undiscovered resources are estimated at 0.587 Bbo and 0.042 Tcfg (0.593 BBOE). These undiscovered



Rock unit positions do not imply age relationships between basins.

Figure 3. Stratigraphic column.

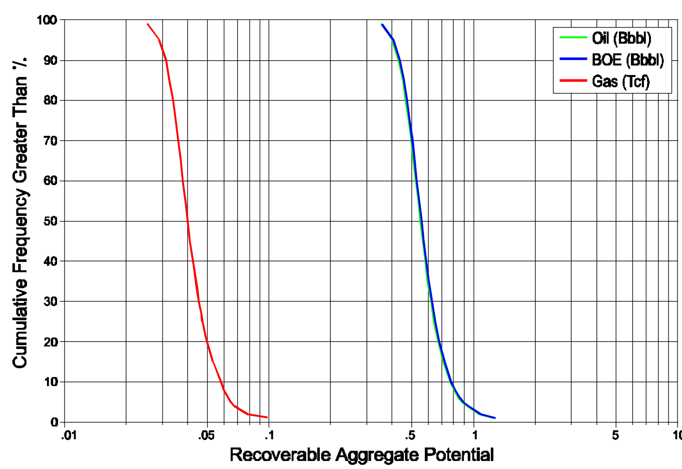


Figure 4. Cumulative probability distribution.

Table 1. Assessment results.

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	--	0.400	0.029	0.405
Mean	58	0.587	0.042	0.593
5th percentile	--	0.881	0.065	0.893
Total Endowment				
95th percentile	--	0.400	0.029	0.405
Mean	58	0.587	0.042	0.593
5th percentile	--	0.881	0.065	0.893

resources may occur in as many as 58 pools, which have a mean size range of 0.165 to 126.720 MMBOE (figure 5). These pools have a mean mean size estimated at 10.211 MMBOE.

Areas of potential discoveries occur entirely within the interior of the South Florida Basin (figure 2).

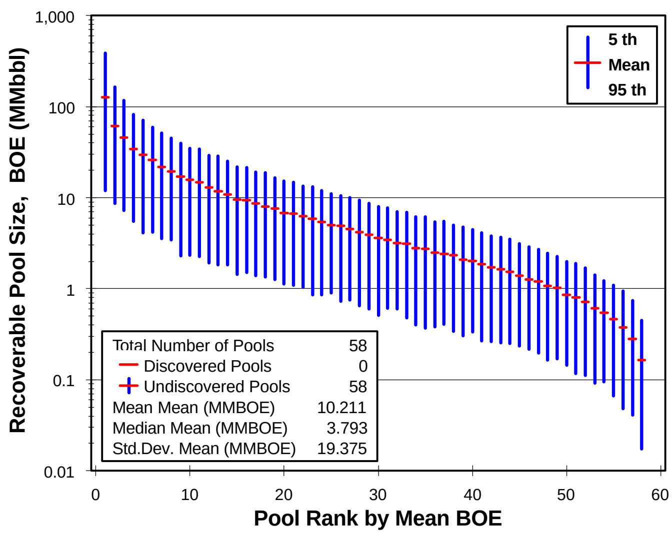


Figure 5. Pool rank plot.

UPPER JURASSIC (UU) CHRONOZONE

CHRONOZONE DESCRIPTION

The Upper Jurassic (UU) chronozone in the Gulf of Mexico Region corresponds to the *Pseudocyclammina jaccardi* biozone. The upper Jurassic section consists of clastics and carbonates, each of which defines a play: the Upper Jurassic Aggradational (UU A) play and the Upper Jurassic Smackover Carbonate (UU SMK) play (figure 1). The clastics consist of aggradational eolian dune facies of the Norphlet Formation, and the carbonates consist of oolitic grainstones and algal carbonates of the Smackover Formation. One additional play, the Upper Jurassic to Lower Cretaceous Transition Zone (UU-LK TZ) play, is also present in the chronozone, but was not assessed due to a probable lack of source rocks.

Reservoir potential in the upper Jurassic chronozone occurs in the Mobile, Pensacola, and Destin Dome Areas of the Federal OCS (figure 2). Updip, the plays extend onshore. Downdip, reservoir potential is limited by a facies change to marine shales and micrites.

Productive reservoirs in the upper Jurassic chronozone are related to faulted anticlines associated with salt tectonics and stratigraphic traps associated with dune facies, oolitic grainstones, and algal carbonates.

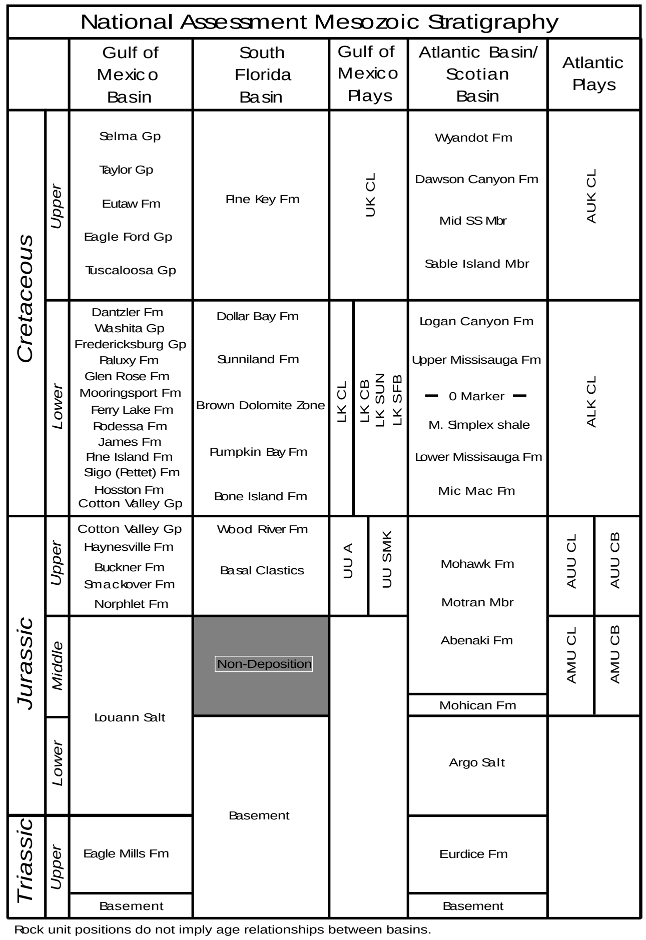


Figure 1. Stratigraphic column.

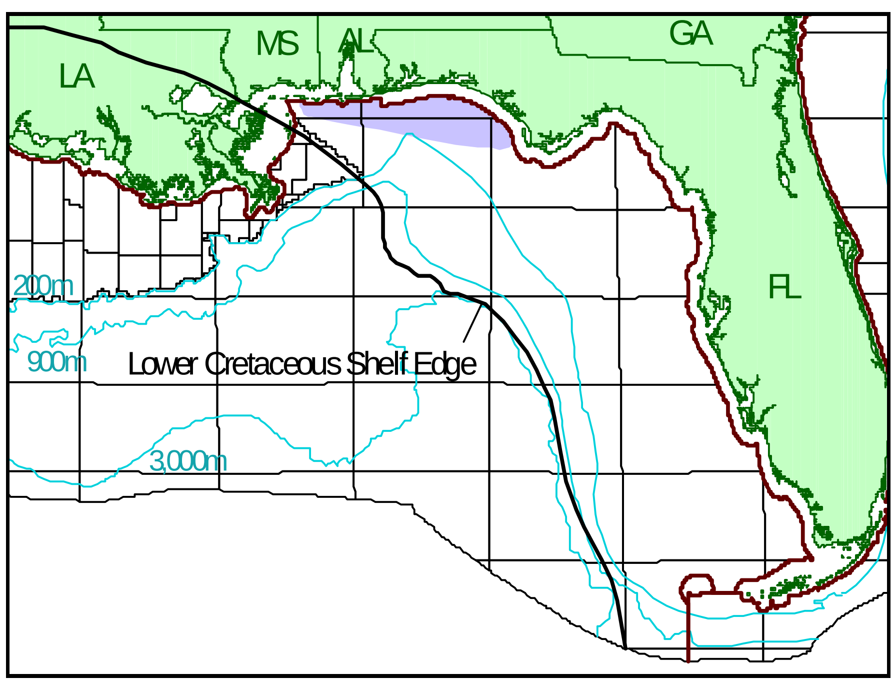


Figure 2. Map of assessed chronozone.

Table 1. Characteristics of the discovered pools.

9 Pools (9 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	37	64	187
Subsea depth (feet)	21,243	21,858	22,600
Number of sands per pool	1	1	1
Porosity	10%	13%	16%
Water saturation	19%	31%	52%

Discoveries

Of the two plays in the upper Jurassic chronozone, the UU A play has nine discovered pools in Federal waters, while the UU SMK play has none (table 1). The chronozone contains total reserves of 0.264 MMbo and 3.373 Tcfg (0.600 BBOE), of which 0.016 MMbo and 0.198 Tcfg (0.035 BBOE) have been produced. The largest number of discoveries occurred in 1988 when three pools added the maximum yearly total reserves of 187.324 MMBOE (figure 3).

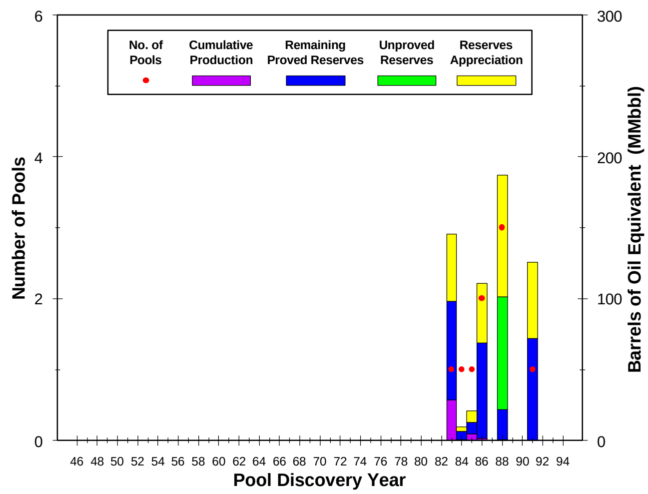


Figure 3. Exploration history graph.

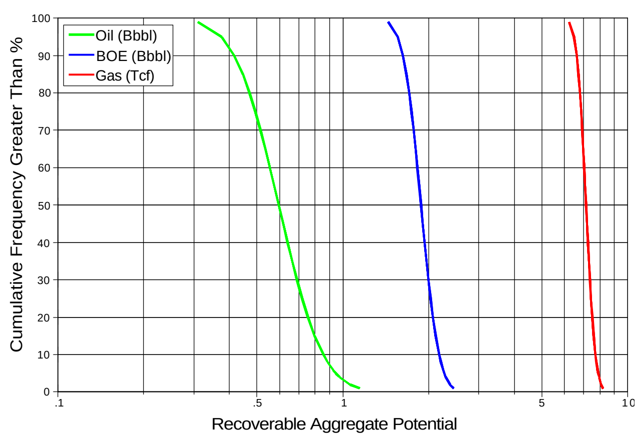


Figure 4. Cumulative probability distribution.

Assessment Results

The upper Jurassic chronozone contains 46 pools (discovered plus undiscovered), with a mean total endowment estimated at 0.620 Bbo and 10.542 Tcfg (2.496 BBOE) (table 2).

Assessment results indicate that undiscovered resources may occur in as many as 37 pools, which contain a range of 0.375 to 0.947 Bbo and 6.490 to 7.890 Tcfg at the 95th and 5th percentiles, respectively (figure 4). At mean levels, 0.620 Bbo and 7.169 Tcfg (1.896 BBOE) are projected. These undiscovered resources represent 76 percent of the upper

Jurassic chronozone's BOE mean total endowment. The largest undiscovered pool is modeled as the largest pool in the chronozone (figure 5).

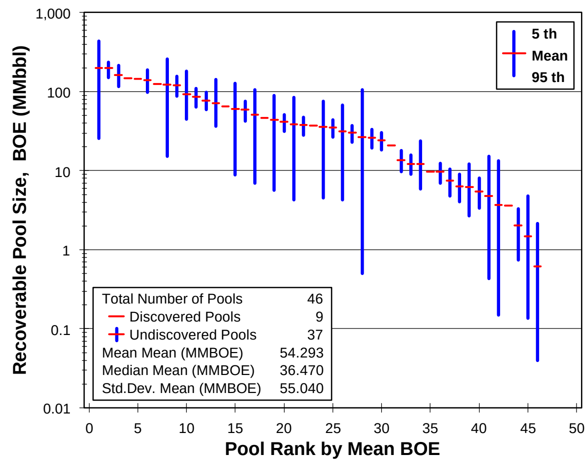


Figure 5. Pool rank plot.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	8	<0.001	1.572	0.280
Cumulative production	--	<0.001	0.198	0.035
Remaining proved	--	<0.001	1.374	0.245
Unproved	1	<0.001	0.446	0.079
Appreciation (P & U)	--	<0.001	1.355	0.241
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.375	6.490	1.561
Mean	37	0.620	7.169	1.896
5th percentile	--	0.947	7.890	2.273
Total Endowment				
95th percentile	--	0.375	9.863	2.161
Mean	46	0.620	10.542	2.496
5th percentile	--	0.947	11.263	2.873

UPPER JURASSIC AGGRADATIONAL (UU A) PLAY

PLAY DESCRIPTION

The established Upper Jurassic Aggradational (UU A) play is the largest established Mesozoic play in the Gulf of Mexico Region and occurs in the Mobile, Viosca Knoll, Pensacola, Destin Dome, and Apalachicola Areas in the Federal OCS (figure 1). The play extends onshore updip and is limited by a facies change to marine shales and micrites downdip.

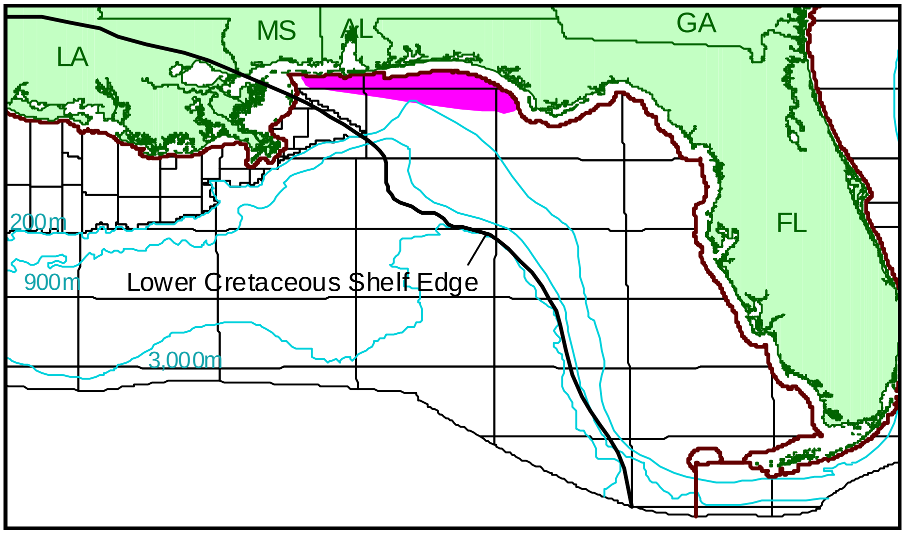
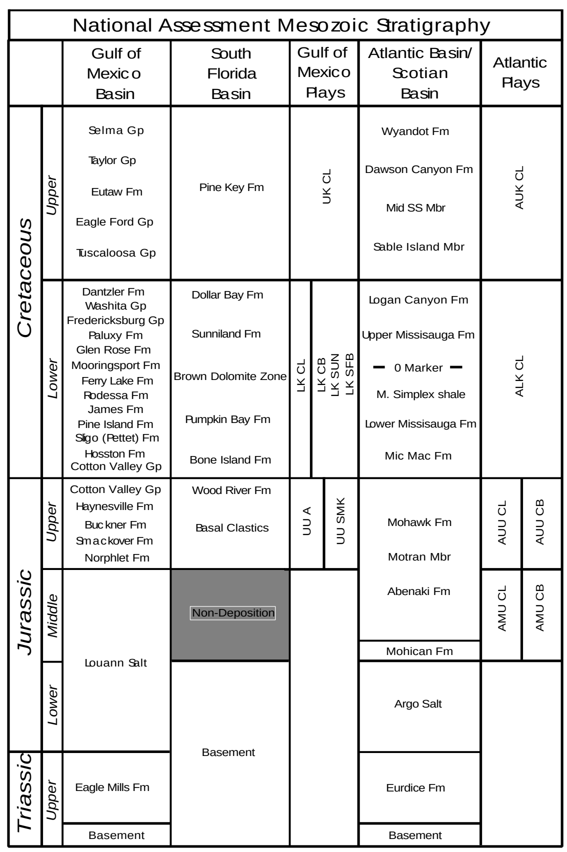


Figure 1. Map of assessed play.

The UU A is one of only two Mesozoic plays, along with the Lower Cretaceous Shelf-Margin Carbonate (LK CB) play, in the Gulf of Mexico that has had Federal production.



Rock unit positions do not imply age relationships between basins.

Figure 2. Stratigraphic column.

PLAY CHARACTERISTICS

The UU A play consists of aggradational eolian dune facies of the Norphlet Formation (figure 2). The Norphlet sands were derived from erosion of the exposed southern Appalachian highlands and basement highs. The updip area of the Norphlet Formation was deposited as alluvial fan and braided stream facies, while downdip, the Norphlet Formation formed as dune and interdune facies. Dune facies provide the most potential for offshore hydrocarbon accumulations, but are highly variable in thickness. Geopressured reservoirs occur in the southern and western Mobile and western Destin Dome Areas. Structures are mainly faulted anticlines related to salt tectonics. The overlying Upper Jurassic Smackover Formation is the source of hydrocarbons and provides seals for the siliciclastic reservoirs of the Norphlet Formation.

Mobile 823 is the type field, and the Norphlet reservoir represents the UU A play in this field.

Discoveries

The UU A gas play contains total reserves of 0.264 MMbo and 3.373 Tcfg (600.479 MMBOE), of which 0.016 MMbo and 0.198 Tcfg (35.253 MMBOE) have been produced. The first Norphlet Formation discovery was in the Pelahatchie Field, Rankin County, Mississippi, in 1967. Subsequently, more than 40 fields were discovered within the play onshore. The play did not become a Federal OCS target until the 1979 gas discovery in the Lower Mobile Bay-Mary Ann Field in offshore State waters. Since then, nine pools with nine producible sands have been discovered in the UU A play in the Federal OCS (table 1 and figure 3). The first reserves in the Federal OCS portion of the play were found in 1983 in the Mobile 823 field. The most active year for discoveries was in 1988, when the maximum yearly total reserves of 187.324 MMBOE were added with the discovery of three pools, including the largest pool in the play in the Destin Dome 56 field. The most recent discovery, prior to this study's cutoff date of January 1, 1995, was in 1991. It should be noted that 28 feet of gas was discovered in the OCS G07857-2 well in Mobile block 991 (the Mesozoic well database [wellmeso.dbf] is presented in the CD-ROM DataFiles directory). However, the gas occurs in a tight sand deposited in a beach environment and is not considered to be part of the prospective dune environment that defines the UU A play.

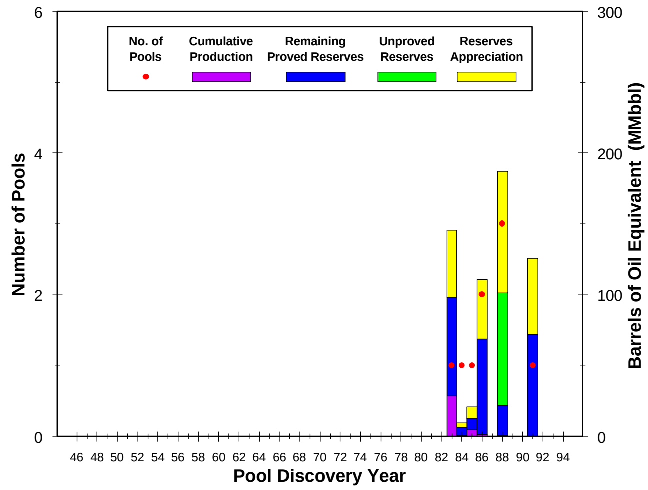


Figure 3. Exploration history graph.

The nine discovered pools range in size from 3.599 to 146.769 MMBOE. These pools contain 12 reservoirs, all of which are nonassociated gas.

Of the nine Mesozoic plays in the Gulf of Mexico, the UU A play is the largest,

Table 1. Characteristics of the discovered pools.

9 Pools (9 Producible Sands)	Minimum	Mean	Maximum
Water depth (feet)	37	64	187
Subsea depth (feet)	21,243	21,858	22,600
Number of sands per pool	1	1	1
Porosity	10%	13%	16%
Water saturation	19%	31%	52%

containing 88 percent of the total reserves and producing over 99 percent of the hydrocarbons, based on BOE.

ASSESSMENT RESULTS

The marginal probability of hydrocarbons for the UU A play is 1.00. This play is the tenth largest in the Gulf of Mexico, based on a mean total endowment of 0.591 Bbo and 10.494 Tcfg (2.458 BBOE) (table 2). Just over 1 percent of this BOE mean total endowment has been produced.

Assessment results indicate that undiscovered resources have a range of 0.360 to 0.856 Bbo and 6.470 to 7.808 Tcfg at the 95th and 5th percentiles, respectively (figure 4). The mean undiscovered resources are estimated at 0.591 Bbo and 7.121 Tcfg (1.858 BBOE). These undiscovered resources may occur in as many as 32 pools. The largest undiscovered pool, with a mean size of 200.410 MMBOE, is modeled as the largest pool in the play (figure 5). The model results place the next four largest undiscovered

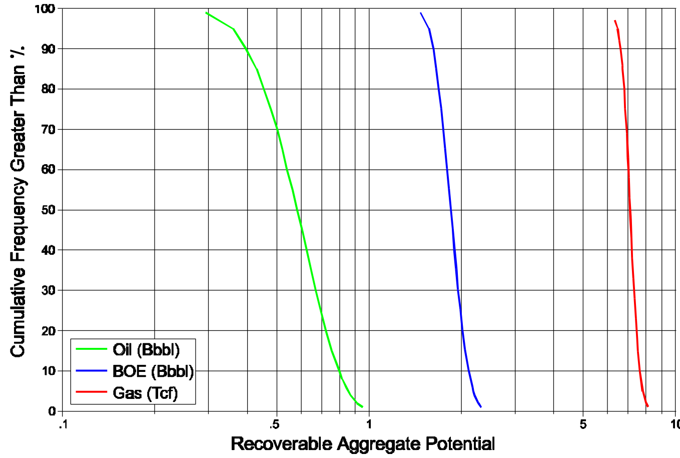


Figure 4. Cumulative probability distribution.

Table 2. Assessment results.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	8	<0.001	1.572	0.280
Cumulative production	--	<0.001	0.198	0.035
Remaining proved	--	<0.001	1.374	0.245
Unproved	1	<0.001	0.446	0.079
Appreciation (P & U)	--	<0.001	1.355	0.241
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	0.360	6.470	1.565
Mean	32	0.591	7.121	1.858
5th percentile	--	0.856	7.808	2.188
Total Endowment				
95th percentile	--	0.360	9.843	2.165
Mean	41	0.591	10.494	2.458
5th percentile	--	0.858	11.181	2.788

pools in positions 2, 3, 6, and 8 on the pool rank plot. For all the undiscovered pools in the UU A play, the mean mean size is 58.127 MMBOE, which is smaller than the 66.720 MMBOE mean size of the discovered pools. The mean mean size for all pools, including both discovered and undiscovered, is 60.013 MMBOE.

Of the 61 plays in the Gulf of Mexico, the UU A play is projected to contain the fourth largest amounts of mean undiscovered oil and gas resources.

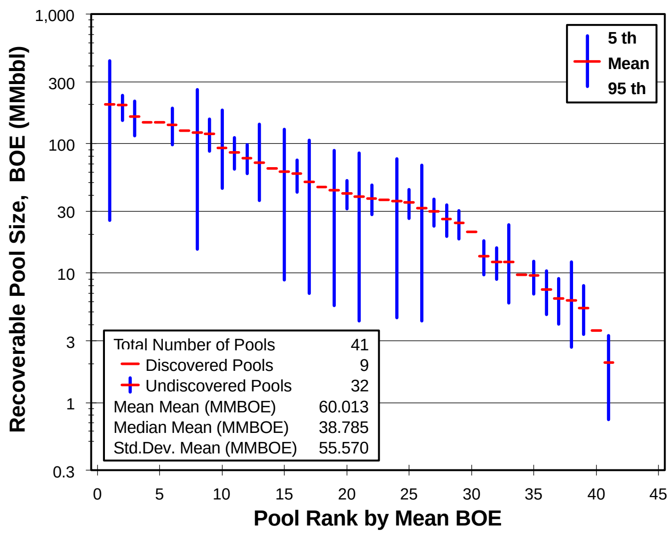


Figure 5. Pool rank plot.

With a large number of pools modeled as undiscovered, the UU A play has good exploration potential. These undiscovered pools are expected to account for 76 percent of the play's BOE mean total endowment. Areas of potential discoveries occur in the dune reservoir facies of the Pensacola and Destin Dome Areas, where the largest accumulations of sand are located. Although the UU A play is typically a gas play, oil and condensate have been found in the Destin Dome Area.

UPPER JURASSIC SMACKOVER CARBONATE (UU SMK) PLAY

PLAY DESCRIPTION

The frontier Upper Jurassic Smackover Carbonate (UU SMK) play occurs at the *Pseudo-cyclammina jaccardi* biozone. This play is located primarily in the Pensacola Area (figure 1). Updip, the play extends onshore, while downdip, it is limited by a facies change to marine micrites.

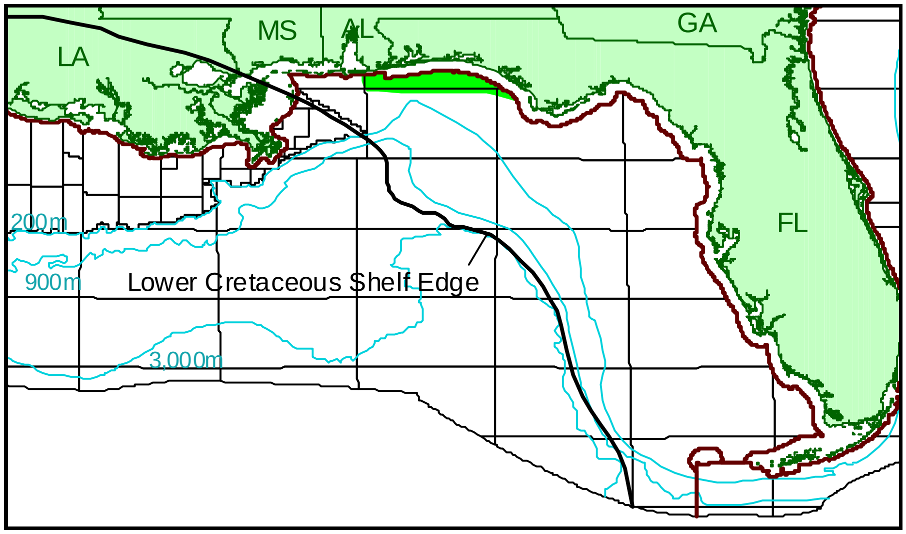


Figure 1. Map of assessed play.

PLAY CHARACTERISTICS

The UU SMK play mainly consists of oolitic grainstones and algal carbonates of the Smackover Formation (figure 2). Potential reservoirs are located primarily in the Pensacola Area, where localized carbonate buildups formed on basement highs and the varying topography of the underlying Norphlet Formation. These potential reservoirs occur primarily in oolitic and algal carbonates, which are often dolomitized and subaerially exposed and leached. Major structural features in this play are anticlines associated with the underlying Louann Salt, growth faults, and normal faults. However, traps are mainly stratigraphic. The Smackover Formation is self-sourced by a low-energy, algal-rich, micritic facies at its base. Additionally, the shales, anhydrites, and carbonates of the Smackover Formation provide the play's seals.

The analog type field for the UU SMK play is the Little Escambia Creek Field, Escambia County, Alabama, which produces from the Smackover Formation.

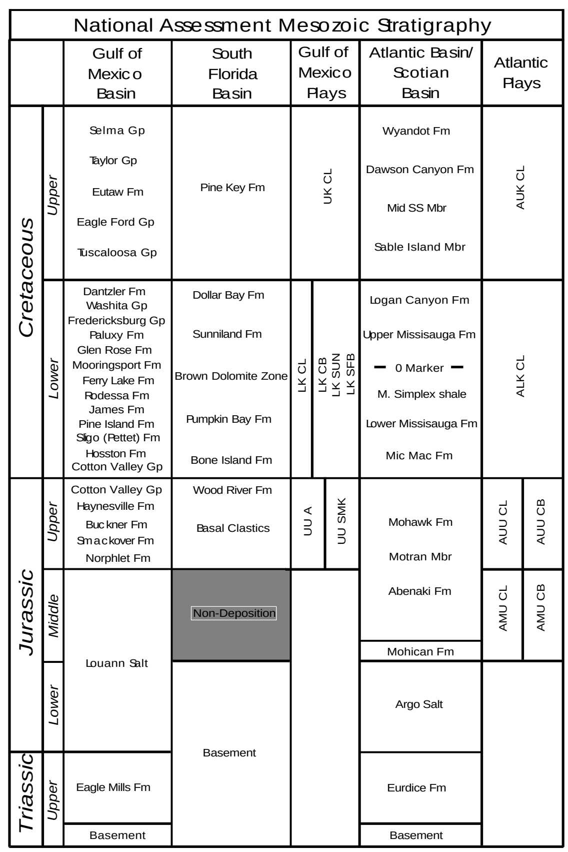


Figure 2. Stratigraphic column.

DISCOVERIES

Two wells, Sohio's OCS G06391-1 and Tenneco's OCS G06391-2 in Pensacola block 948, encountered hydrocarbon shows (the Mesozoic well database [wellmeso.dbf] is presented in the CD-ROM DataFiles directory). Texaco's OCS G06396-1 well in Pensacola block 996 discovered 22 feet of oil, which was never tested.

ASSESSMENT RESULTS

Because the UU SMK play is not productive in the Federal OCS, an analog comprising the productive Smackover of onshore Louisiana, Mississippi, and Alabama was used for this assessment. This analog covers an area of 8.2 million acres (12,850 square miles). Onshore Smackover fields associated with the Pickens-Pollard Fault System produce oil primarily north of the fault system and oil and gas south of the fault system (figure 3). This fault system extends offshore into the Destin Dome Area. In addition, the onshore Pensacola Arch extends offshore as basement highs in the Pensacola Area. Exploration of the analog has a success rate of approximately 10 percent, and drilling is at a mature stage with approximately 90 percent of the analog explored. Analog fields contain an average of 41 percent oil, 9 percent gas, and 50 percent mixed hydrocarbons. Production from the analog fields ranges from less than 1 to 481.5 MMBOE. Net pay ranges from 4 to 335 feet at depths of 11,392 to 18,425 feet. Fields are characterized by porosities of 8 to 28 percent, oil gravities of 19 to 54^{o} API, and GOR's of 144 to 12,400

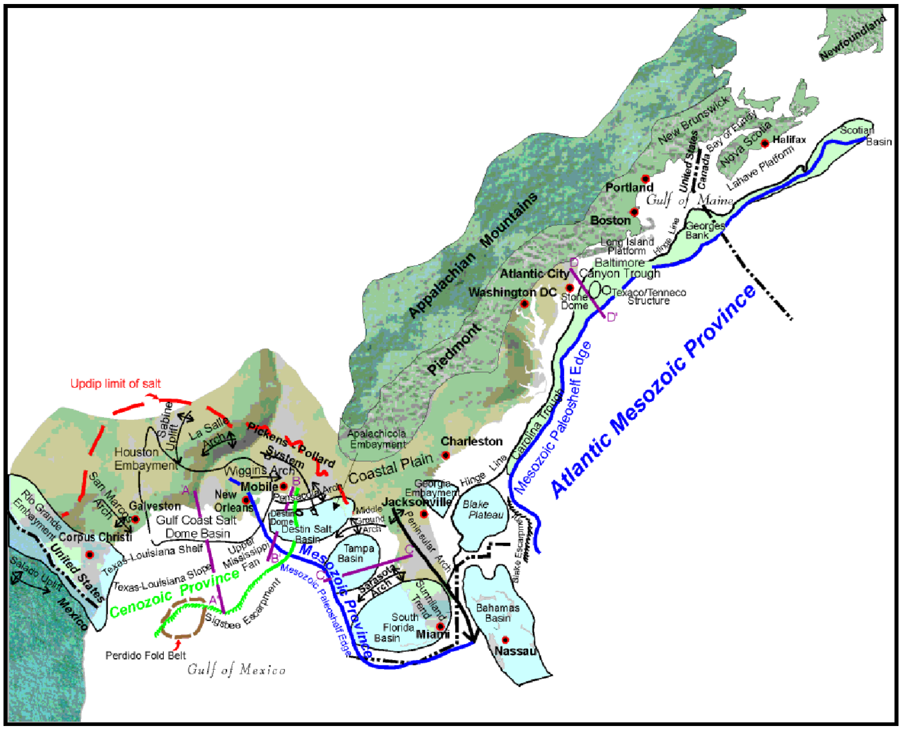


Figure 3. Physiographic map.

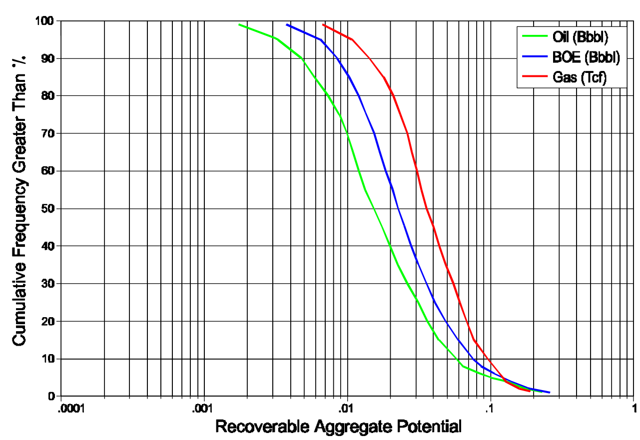


Figure 4. Cumulative probability distribution.

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The marginal probability of hydrocarbons for the UU SMK play is 1.00. Assessment results indicate that undiscovered resources have a range of 0.003 to 0.101 Bbo and 0.011 to 0.122 Tcfg at the 95th and 5th percentiles, respectively (table 1 and figure 4). The mean undiscovered resources are estimated at 0.029 Bbo and 0.048 Tcfg (0.038 BBOE). These undiscovered resources may occur in as many as five pools, which have a mean size range of 0.613 to 26.423 MMBOE (figure5). These pools have a mean mean size estimated at 7.394 MMBOE.

Because of the limited geographic area of the prospective high-energy facies, few discoveries are expected.

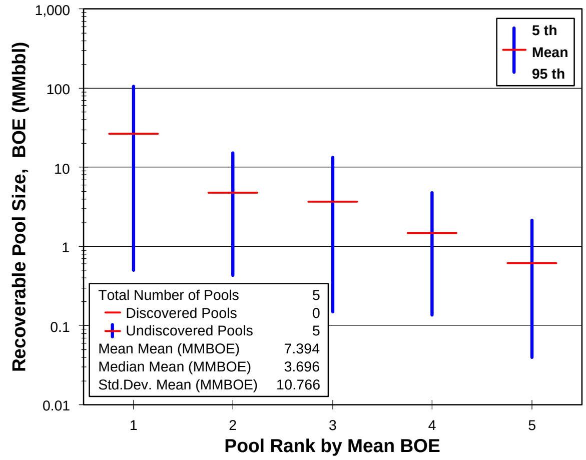


Figure 5. Pool rank plot.

Table 1. Assessment results.

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	--	0.003	0.011	0.006
Mean	5	0.029	0.048	0.038
5th percentile	--	0.101	0.122	0.121
Total Endowment				
95th percentile	--	0.003	0.011	0.006
Mean	5	0.029	0.048	0.038
5th percentile	--	0.101	0.122	0.121

UPPER JURASSIC TO LOWER CRETACEOUS TRANSITION ZONE (UU-LK TZ) PLAY

The conceptual Upper Jurassic to Lower Cretaceous Transition Zone (UU-LK TZ) play is located in the Tampa Basin Area that separates the clastics of the Middle Ground Arch and the carbonates of the Sarasota Arch (figure 1). Seismic data show mainly flat-lying units with little structural disruption in the Tampa Basin. Potential reservoirs are inferred to be interfingered, fine-grained clastics and carbonates.

The play is considered to have low potential because the Tampa Basin lacks source rocks. Therefore, the UU-LK TZ play was not assessed.

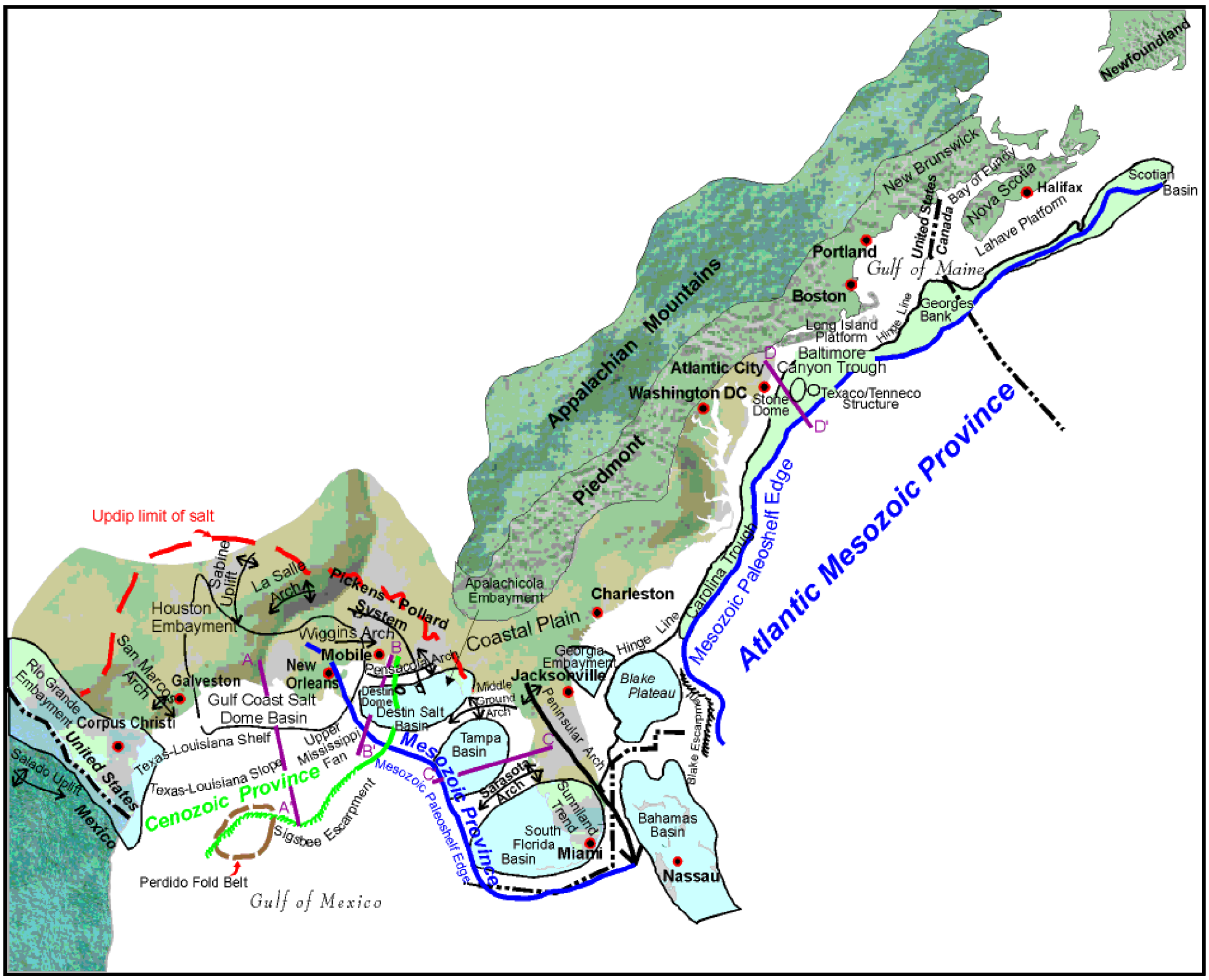


Figure 1. Physiographic map.

MIDDLE JURASSIC (MU) CHRONOZONE

The Middle Jurassic (MU) chronozone contains only one play [see Middle Jurassic to Upper Jurassic Florida Basal Clastic (MU-UU FBCL) play].

MIDDLE JURASSIC TO UPPER JURASSIC FLORIDA BASAL CLASTIC (MU-UU FBCL) PLAY

The conceptual Middle Jurassic to Upper Jurassic Florida Basal Clastic (MU-UU FBCL) play consists of siliciclastics derived from weathered basement rocks exposed from Middle Jurassic to Late Jurassic time. Potential reservoirs locally occur as a thin veneer of alluvial, strand plain, and deltaic deposits immediately overlying the middle Jurassic basement of south Florida.

Though one hydrocarbon show occurred in the Great Isaac well in the Bahamas Basin (figure 1), reservoir quality of these basal clastics was poor. Therefore, the MU-UU FBCL play was not assessed.

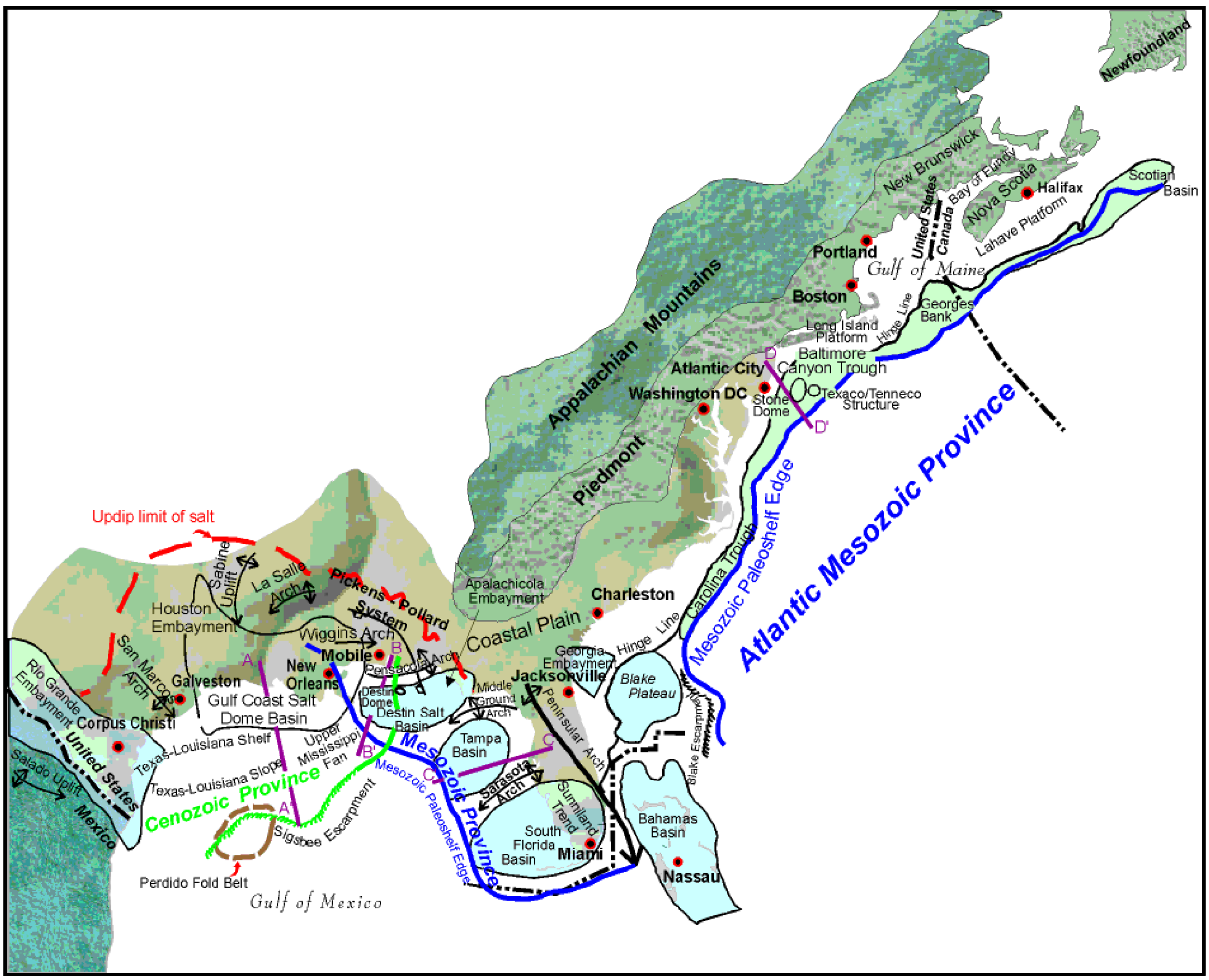


Figure 1. Physiographic map.

LOWER JURASSIC (LU) CHRONOZONE

The Lower Jurassic (LU) chronozone was not assessed. The dominantly evaporitic sediments were not considered to be of reservoir quality. Sediment type and lack of any onshore analogs provided the basis for condemning this chronozone.

UPPER TRIASSIC (UTR) CHRONOZONE

The Upper Triassic (UTR) chronozone was not assessed. The dominantly evaporitic sediments were not considered to be of reservoir quality. Sediment type and lack of any onshore analogs provided the basis for condemning this chronozone.

ATLANTIC UPPER CRETACEOUS (AUK) CHRONOZONE

The Atlantic Upper Cretaceous (AUK) chronozone contains only one play [see Atlantic Upper Cretaceous Clastic (AUK CL) play].

ATLANTIC UPPER CRETACEOUS CLASTIC (AUK CL) PLAY

The conceptual Atlantic Upper Cretaceous Clastic (AUK CL) play is identified in the Georges Bank, Baltimore Canyon, and Georgia Embayment Areas of the Atlantic Margin and extends onshore (figure 1). In Late Cretaceous time, clastic sediments were eroded from the Appalachian Mountain System. During low stands of sea level, these sediments prograded seaward over the shelf and onto the slope. Therefore, possible reservoirs occur in deltaic complexes, barrier bars, and channel systems on the shelf, and in fan complexes on the slope.

The AUK CL play was not assessed because burial depth and proximity to thermally mature source rocks were inadequate.

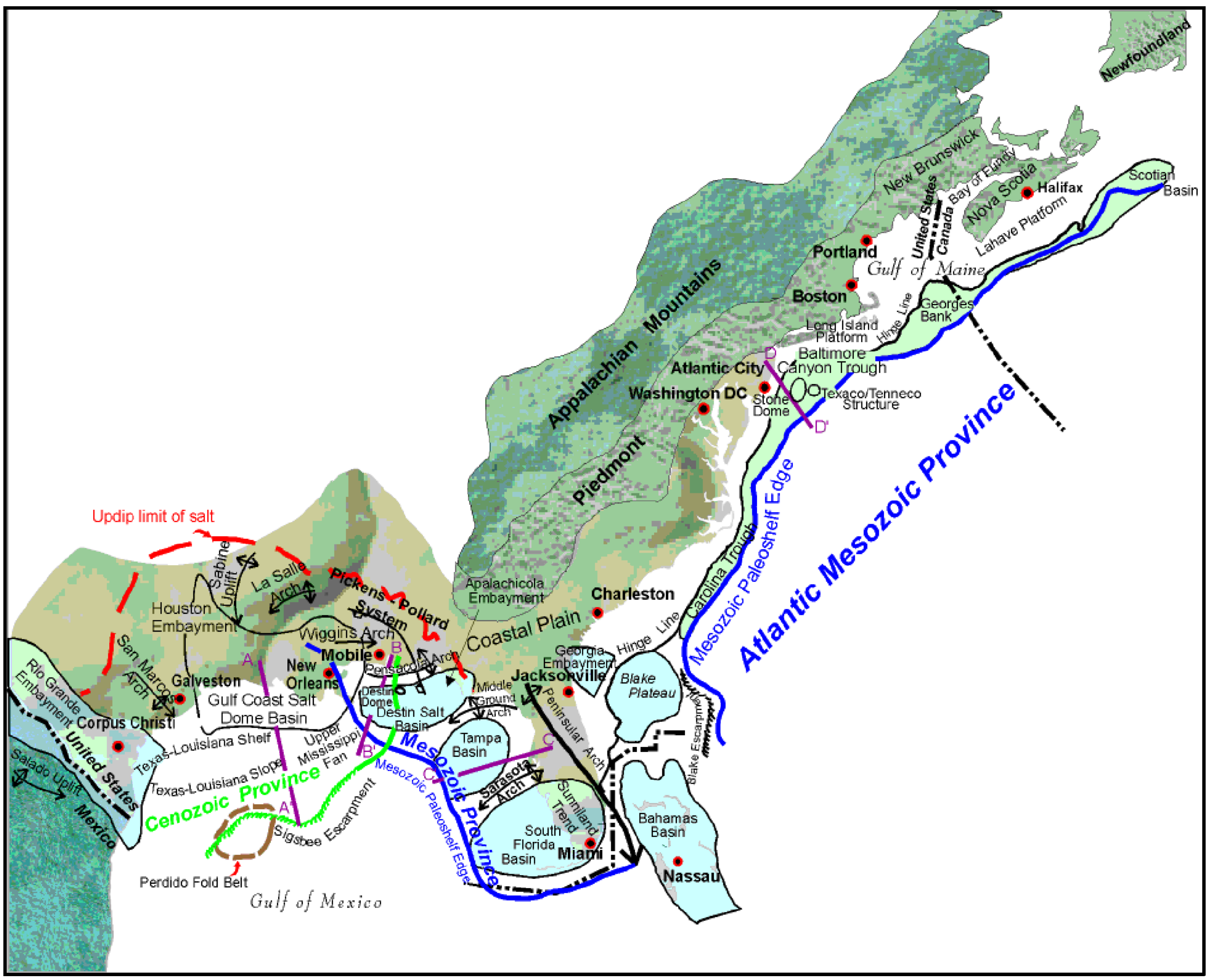


Figure 1. Physiographic map.

ATLANTIC LOWER CRETACEOUS (ALK) CHRONOZONE

The Atlantic Lower Cretaceous (ALK) chronozone contains only one play [see Atlantic Lower Cretaceous Clastic (ALK CL) play]

ATLANTIC LOWER CRETACEOUS CLASTIC (ALK CL) PLAY

PLAY DESCRIPTION

The frontier Atlantic Lower Cretaceous Clastic (ALK CL) play occurs within the *Polycostella senaria*, *Choffatella decipiens*, *Muderongia simplex*, and *Favusella washitaensis* biozones. This play extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 1 and figure 2).

The updip limit for this play coincides with the updip limit of potential source rocks, which are late Jurassic. Lower Cretaceous clastic sediments prograded over the Upper Jurassic Carbonate (AUU CB) play and onto the slope, defining the downdip limit of the play.

The ALK CL play is stratigraphically and structurally similar to the Atlantic Upper Jurassic Clastic (AUU CL) and the Atlantic Middle Jurassic Clastic (AMU CL) plays. The ALK CL play, however, does cover a larger geographic area than either the AUU CL or AMU CL play.

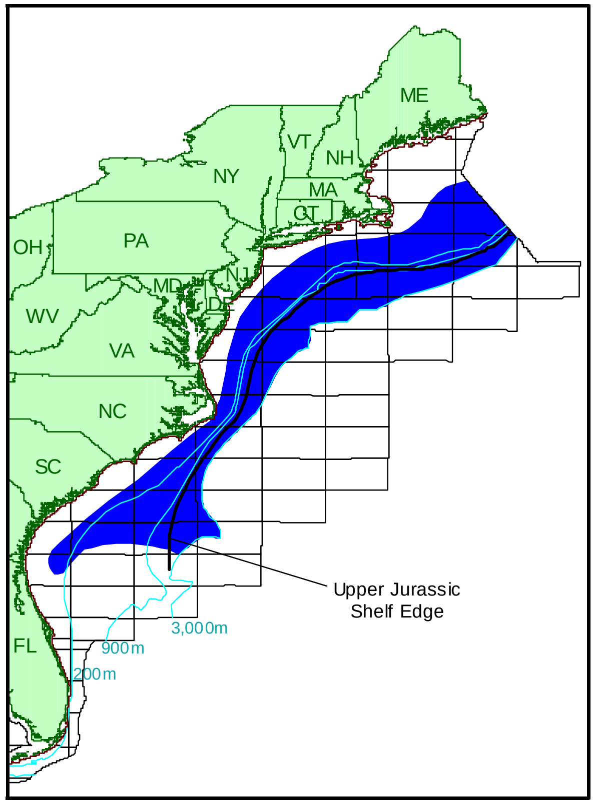


Figure 1. Map of assessed play.

PLAY CHARACTERISTICS

In the lower Cretaceous, clastic sediments were eroded from the Appalachian Mountain System. During low stands of sea level, these sediments formed deltaic complexes that prograded seaward over the shelf-edge reef and onto the slope. Potential lower Cretaceous reservoirs may occur in deltaic complexes, barrier bars, and channel systems on the shelf, and in fan complexes on the slope. Petrophysical analyses of cores indicate that some of the best reservoir-quality sands in the Atlantic Mesozoic Province

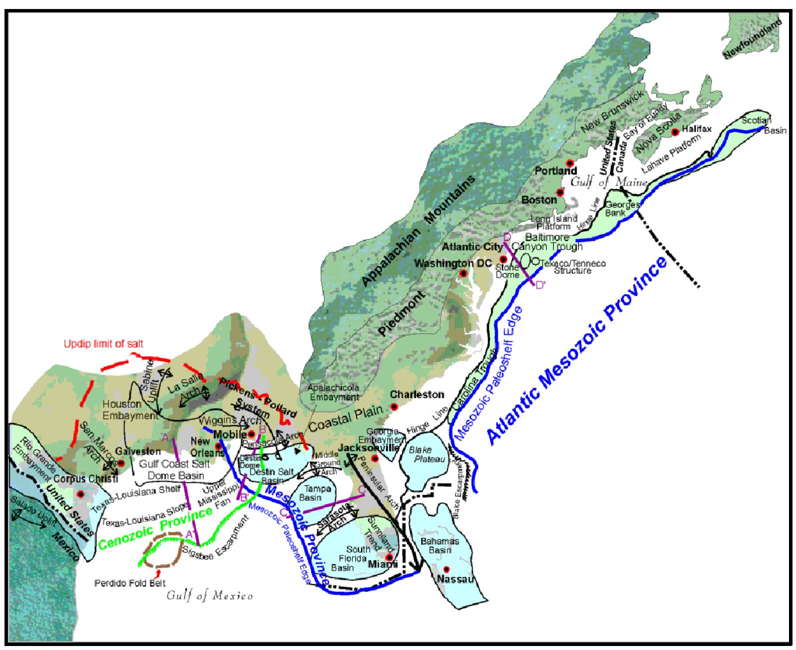
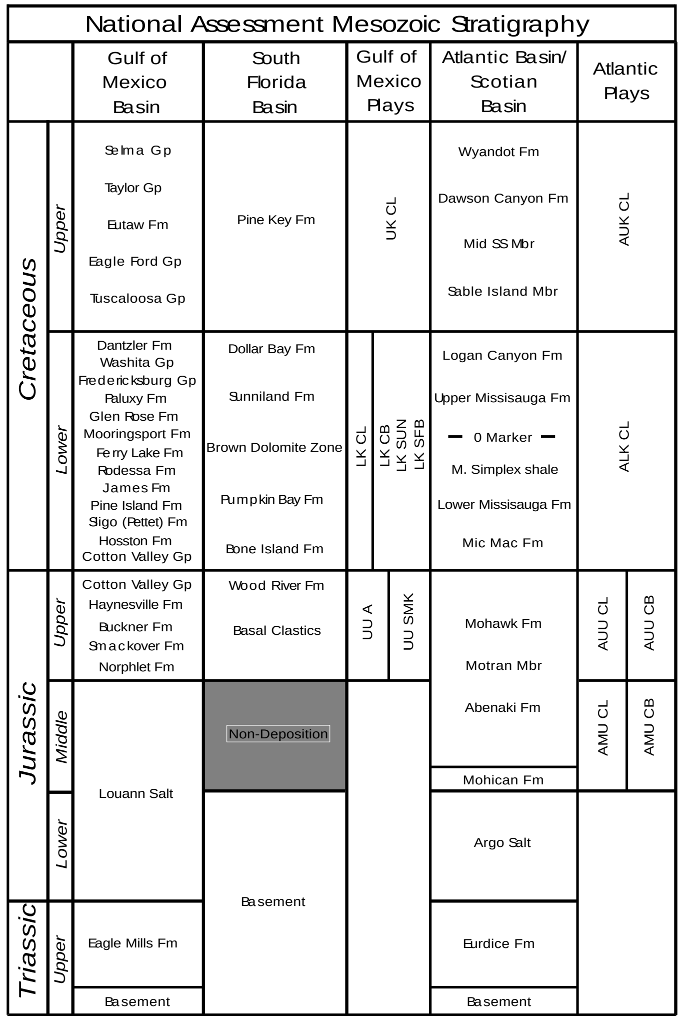


Figure 2. Physiographic map.

occur in this play.

Structures on the shelf are related mainly to anticlines, normal faults, and growth faults. Structures on the slope include anticlines and pinch-outs against diapirs. Stratigraphic traps also occur on both the shelf and slope. Potential source rocks include shelf and slope Jurassic shales. Geochemical analysis indicates organic matter to be primarily Type III with total organic carbon (TOC) ranging from 0.5 to 3 percent. The hydrocarbon evolution window (HEW) extends from approximately 7,000 to 18,000 feet. Jurassic lagoonal and platform carbonates may also provide good source rock potential. Seals are provided by early to late Cretaceous limestones or overlying shales.

The analog type field for the ALK CL play is the Citronelle Field, Mobile County, Alabama. Production from the lower Cretaceous clastic section in this field occurs from the Rodessa Formation (figure 3).



Rock unit positions do not imply age relationships between basins.

Figure 3. Stratigraphic column.

DISCOVERIES

Exploration in the Atlantic Federal OCS area consists of 46 exploration and 5 COST wells (the Mesozoic well database [wellmeso.dbf] is presented in the CD-ROM DataFiles directory). Of these wells, all but one penetrated the lower Cretaceous interval. The only hydrocarbons detected in the ALK CL play occurred in Tenneco's Hudson Canyon 642-2 well drilled in 1979. The well flowed at 640 bopd.

ASSESSMENT RESULTS

Since the ALK CL play contains no active Federal fields, productive lower Cretaceous clastic sediments of the onshore eastern Gulf of Mexico and lower Cretaceous and upper Jurassic clastic sediments of the Canadian offshore Scotian Basin provide the analogs for input parameters used in this assessment (figure 2).

The onshore lower Cretaceous clastic analog comprises the Hosston, Rodessa, Paluxy, and Dantzler Formations of Louisiana, Mississippi, and Alabama (figure 3). This analog encompasses an area of 13.7 million acres (21,395 square miles). Exploration has a success rate of approximately 10 percent, and drilling is at a mature stage with approximately 75 percent of the analog explored. These analog fields contain an average of 39 percent oil, 35 percent gas, and 26 percent mixed hydrocarbons. Fields producing from the well-established Norphlet trend were not used as analogs in this assessment because they produce from eolian sands, which are not analogous to the deltaic deposits in the ALK CL play.

The Scotian Basin clastic analog comprises the Lower Cretaceous Missisauga and Logan Canyon Formations and the Upper Cretaceous Dawson Canyon and Wyandot Formations (figure 3). This analog covers an area of 35 million acres (54,700 square miles). Exploration has a success rate of approximately 30 percent, and drilling is at an immature stage with approximately 30 percent of the analog explored. This analog was used primarily for field size distribution parameters, as production data are not public record.

The marginal probability of hydrocarbons for the ALK CL play is 1.00. Assessment results indicate that undiscovered resources have a range of 0.431 to 1.143 Bbo and 7.840 to 18.813 Tcfg at the 95th and 5th percentiles, respectively (table 1 and figure 4). The mean undiscovered resources are estimated at 0.722 Bbo and 11.767 Tcfg (2.816 BBOE). These undiscovered resources may occur in as many as 120 pools, which have a mean size range of 0.064 to 534.780 MMBOE (figure 5). These pools have a mean mean size estimated at 23.193 MMBOE.

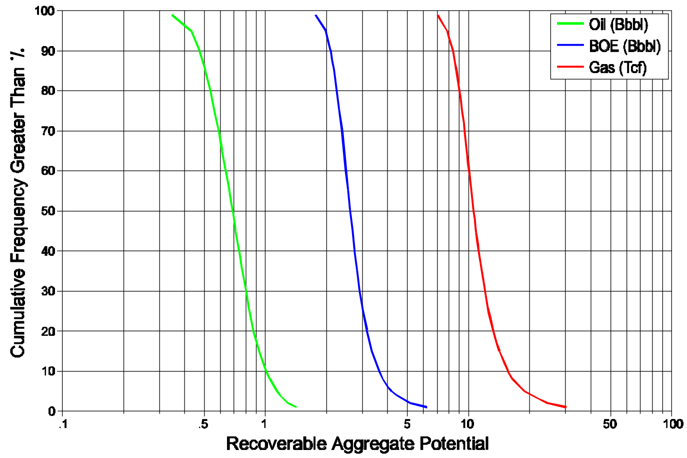


Figure 4. Cumulative probability distribution.

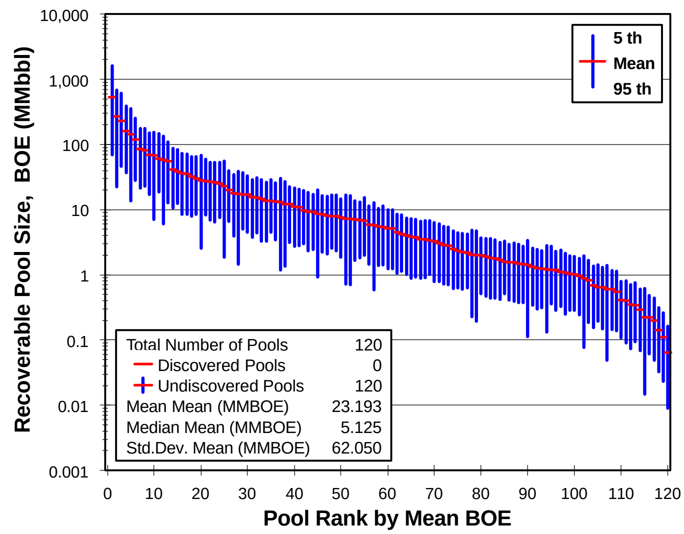


Figure 5. Pool rank plot.

Of the 11 Atlantic plays, the ALK CL play is projected to contain the largest amount of undiscovered gas resources (43%) and the second largest amount of undiscovered oil resources (32%).

Potential for discoveries extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 2).

Table 1. Assessment results.

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	--	0.431	7.840	1.985
Mean	120	0.722	11.767	2.816
5th percentile	--	1.143	18.813	4.190
Total Endowment				
95th percentile	--	0.431	7.840	1.985
Mean	120	0.722	11.767	2.816
5th percentile	--	1.143	18.813	4.190

ATLANTIC UPPER JURASSIC (AUU) CHRONZONE

CHRONOZONE DESCRIPTION

The Atlantic Upper Jurassic (AUU) chronozone corresponds to the *Pseudocyclammina jaccardi*, *Senoniasphaera jurassica*, *Epistomina uhligi*, and *Ctenedodinium penneum* biozones. The upper Jurassic section in the Atlantic Basin consists of clastics and carbonates, each of which defines a play: the Atlantic Upper Jurassic Clastic (AUU CL) play and the Atlantic Upper Jurassic Carbonate (AUU CB) play. The clastics consist of deltaic complexes, barrier bars, and channel systems of retrogradational, aggradational, and progradational deposits on the shelf and fan complexes on the slope. The carbonates consist of shallow-water limestone platforms and reef complexes developed where deltaic clastic influx was minimal. In addition to upper Jurassic carbonates, possible lowermost Cretaceous carbonates that occur in the seaward-most edge of the carbonate complex as a discontinuous, thin section are included in the AUU CB play. Two additional plays, the Atlantic Upper Jurassic to Upper Cretaceous Basin Floor Fan (AUU-UK BFF) play and the Atlantic Upper Jurassic to Lower Cretaceous Transition Zone (AUU-LK TZ) play, are also present in the chronozone, but were not assessed due to a probable lack of source rocks and questionable seismic structures, respectively.

Reservoir potential in the chronozone extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 1 and figure 2). The updip reservoir potential is limited by

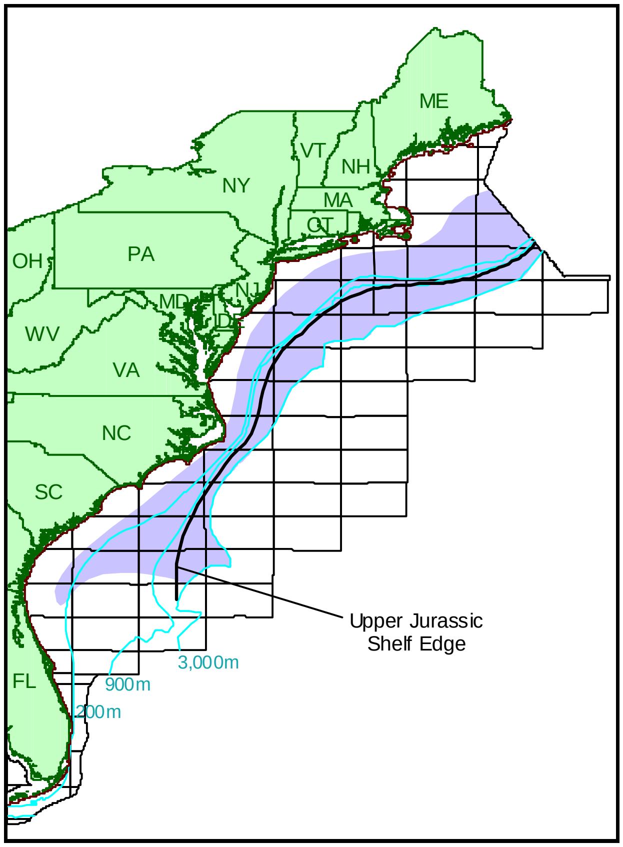


Figure 1. Map of assessed chronozone.

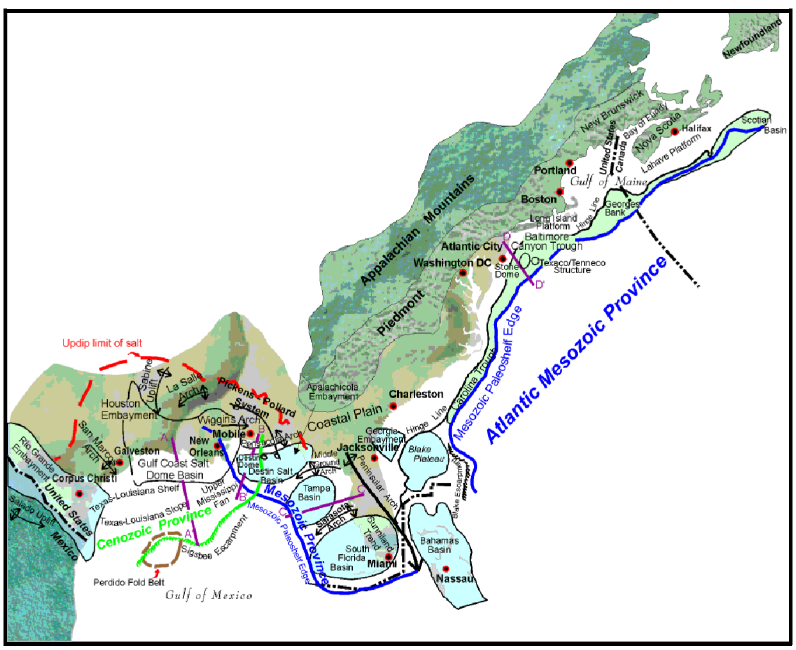


Figure 2. Physiographic map.

the shoreward erosional limit of upper Jurassic clastics. The downdip reservoir potential is limited by the extent of slope fans.

DISCOVERIES

No pools in the chronozone have as yet been discovered in the Federal OCS.

ASSESSMENT RESULTS

The Atlantic plays in the upper Jurassic chronozone are not as yet productive. Assessment results indicate that undiscovered resources may occur in as many as 235 pools, which contain a range of 0.527 to 1.733 Bbo and 6.135 to 15.667 Tcfg at the 95th and 5th percentiles, respectively (table 1 and figure 2). At mean levels, 1.020 Bbo and 10.210 Tcfg (2.837 BBOE) are projected. The 235 undiscovered pools have a mean mean size of 12.379 MMBOE (figure 3). Of the two plays in the chronozone, the AUU CL play is estimated to contain 85 percent of the BOE mean total endowment for the chronozone.

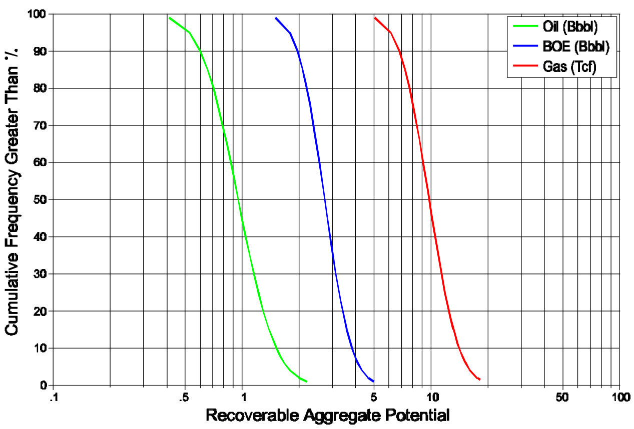


Figure 3. Cumulative probability distribution.

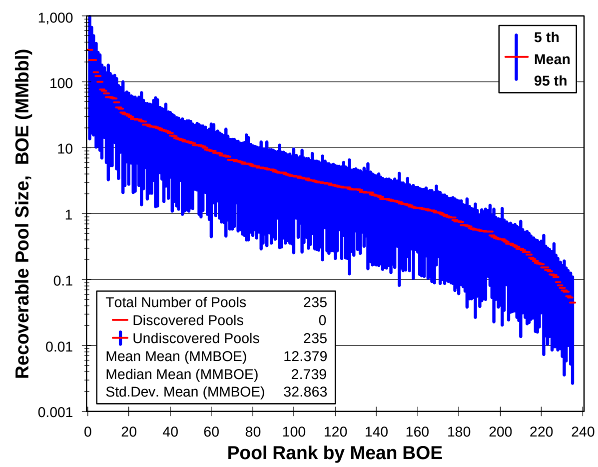


Figure 4. Pool rank plot.

Table 1. Assessment results.

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	--	0.527	6.135	1.791
Mean	235	1.020	10.210	2.837
5th percentile	--	1.733	15.667	4.201
Total Endowment				
95th percentile	--	0.527	6.135	1.791
Mean	235	1.020	10.210	2.837
5th percentile	--	1.733	15.667	4.201

ATLANTIC UPPER JURASSIC CLASTIC (AUU CL) PLAY

PLAY DESCRIPTION

The frontier Atlantic Upper Jurassic Clastic (AUU CL) play occurs within the *Pseudocyclammina jaccardi*, *Senoniasphaera jurassica*, *Epistomina uhligi*, and *Ctenidodinium penneum* biozones. This play extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 1 and figure 2).

The updip assessment limit was determined by the shoreward erosional limit of upper Jurassic sediments. Downdip, deltas deposited clastic sediments on the shelf. The upper Jurassic sediments exhibit a lateral facies change from nearshore clastic sediments to the platform carbonates and shelf-edge reef of the Atlantic Upper Jurassic Carbonate (AUU CB) play. Where clastic sediment influx was great enough, deltas crossed the AUU CB play, depositing fans on the slope. These slope fans define the downdip limit of the AUU CL play.

The AUU CL play is stratigraphically and structurally similar to the Atlantic Lower Cretaceous Clastic (ALK CL) and Atlantic Middle Jurassic Clastic (AMU CL) plays.

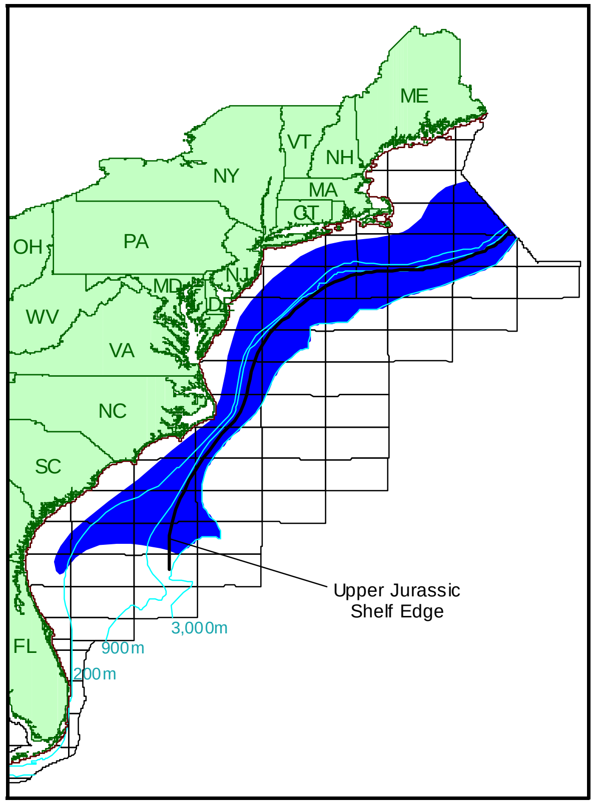


Figure 1. Map of assessed play.

PLAY CHARACTERISTICS

In the upper Jurassic, clastic sediments were eroded from the Appalachian Mountain System. During low stands of sea level, these sediments formed deltaic complexes that prograded across the shelf. Where clastic sediment influx was great enough, fans formed on the slope. Potential upper Jurassic reservoirs may occur in deltaic complexes, barrier bars, and channel systems on the shelf, and in fan complexes on the slope.

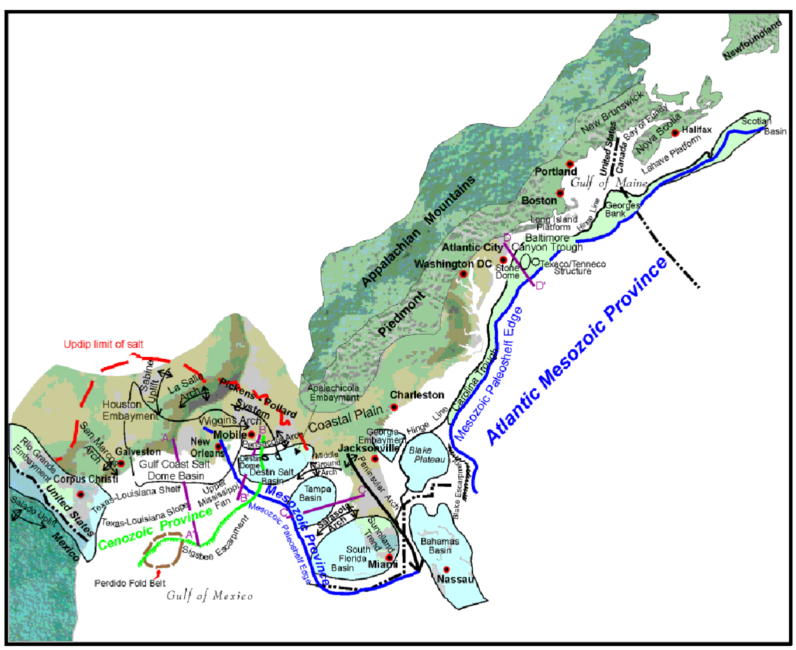
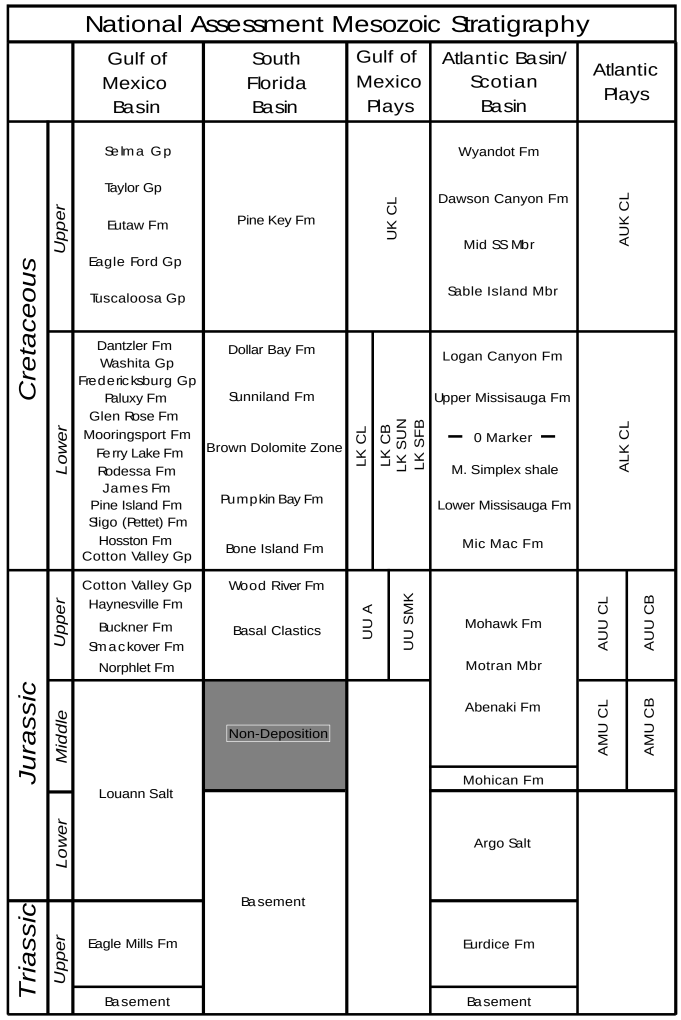


Figure 2. Physiographic map.

Structures on the shelf are related to normal faults, growth faults, and anticlines. Structures on the slope include anticlines and pinch-outs against diapiric structures. Stratigraphic closures also occur on both the shelf and slope. Potential source rocks include Jurassic shelf and slope shales. Geochemical analysis indicates organic matter to be primarily Type III with total organic carbon (TOC) ranging from 0.5 to 3 percent. The hydrocarbon evolution window (HEW) extends from approximately 7,000 to 18,000 feet. Jurassic lagoonal and platform carbonates may also provide good source rock potential. Seals are provided by upper Jurassic or lowermost Cretaceous limestones or overlying shales.

The analog type field for the AUU CL play is the Thomasville Field, Rankin County, Mississippi. Production from the upper Jurassic clastic section in this field occurs from the Smackover Formation (figure 3).



Rock unit positions do not imply age relationships between basins.

Figure 3. Stratigraphic column.

DISCOVERIES

Exploration in the Atlantic Federal OCS area consists of 46 exploration and 5 COST wells, of which 41 penetrated confirmed or probable upper Jurassic clastic sediments (the Mesozoic well database [wellmeso.dbf] is presented in the CD-ROM DataFiles directory). Five of the eight wells in the relinquished Hudson Canyon 598 field encountered significant hydrocarbon volumes (95 MMcfd total) from upper Jurassic clastic intervals.

ASSESSMENT RESULTS

Since the AUU CL play contains no active Federal fields, productive upper Jurassic clastic sediments of the onshore eastern Gulf of Mexico and the Canadian offshore Scotian Basin provide the analogs for input parameters used in this assessment (figure 2).

The onshore upper Jurassic clastic analog comprises the Smackover Formation and Cotton Valley Group of Mississippi and Alabama (figure 3). This analog covers an area of 6.2 million acres (9,750 square miles). Exploration in the analog has a success rate of approximately 10 percent, and drilling is at a mature stage with approximately 60 to 90 percent of this analog explored. These analog fields contain an average of 40 percent oil, 29 percent gas, and 31 percent mixed hydrocarbons. Fields producing from the well-established Norphlet trend were not used as analogs in this assessment because they produce from eolian sands, which are not analogous to the deltaic deposits in the AUU CL play.

The Scotian Basin upper Jurassic clastic analog comprises the Mic Mac Formation and covers an area of 35 million acres (54,700 square miles) (figure 3). Exploration in this analog has a success rate of approximately 30 percent, and drilling is at an immature stage with approximately 30 percent of the analog explored. This analog was used primarily for field size distribution parameters, as production data are not public record.

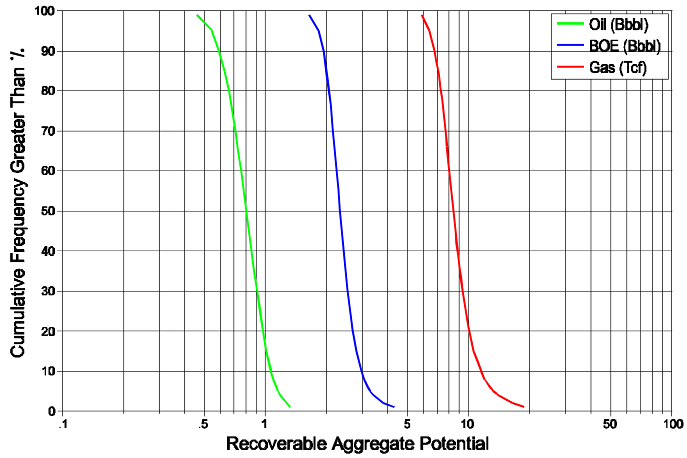


Figure 4. Cumulative probability distribution.

The marginal probability of hydrocarbons for the AUU CL play is 1.00. Assessment results indicate that undiscovered resources have a range of 0.545 to 1.153 Bbo and 6.401 to 13.270 Tcfg at the 95th and 5th percentiles, respectively (table 1 and figure 4). The mean undiscovered resources are estimated at 0.822 Bbo and 8.953 Tcfg (2.415 BBOE). These undiscovered resources may occur in as many as 200 pools, which have a mean size range of 0.045 to 310.220 MMBOE (figure 5). These pools have a mean mean size estimated at 12.074 MMBOE.

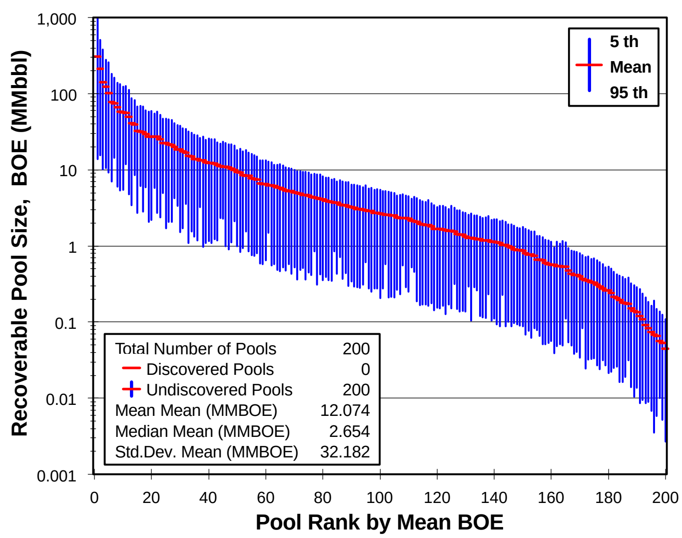


Figure 5. Pool rank plot.

Of the 11 Atlantic plays, the AUU CL play is projected to contain the largest amount of undiscovered oil resources (36%) and the second largest amount of undiscovered gas resources (33%).

Potential for discoveries extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 2).

Table 1. Assessment results.

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	--	0.545	6.401	1.832
Mean	200	0.822	8.953	2.415
5th percentile	--	1.153	13.270	3.273
Total Endowment				
95th percentile	--	0.545	6.401	1.832
Mean	200	0.822	8.953	2.415
5th percentile	--	1.153	13.270	3.273

ATLANTIC UPPER JURASSIC CARBONATE (AUU CB) PLAY

PLAY DESCRIPTION

The frontier Atlantic Upper Jurassic Carbonate (AUU CB) play occurs within the *Pseudocyclammina jaccardi*, *Senoniasphaera jurassica*, *Epistomina uhligi*, and *Ctenidodinium penneum* biozones. This play extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 1 and figure 2).

The AUU CB play is stratigraphically similar to the Atlantic Middle Jurassic Carbonate (AMU CB) play; however, the carbonate platform became successively narrower through the upper Jurassic, owing to increasing siliciclastic influx. Though not conclusive, micropaleontological evidence suggests that the seaward-most edge of the carbonate complex may be lowermost Cretaceous. These possible lowermost Cretaceous carbonates are thin, averaging about 200 feet, and cover too small an area to be mappable on a regional scale. Therefore, all possible lowermost Cretaceous shelf-edge carbonates are included in the AUU CB play.

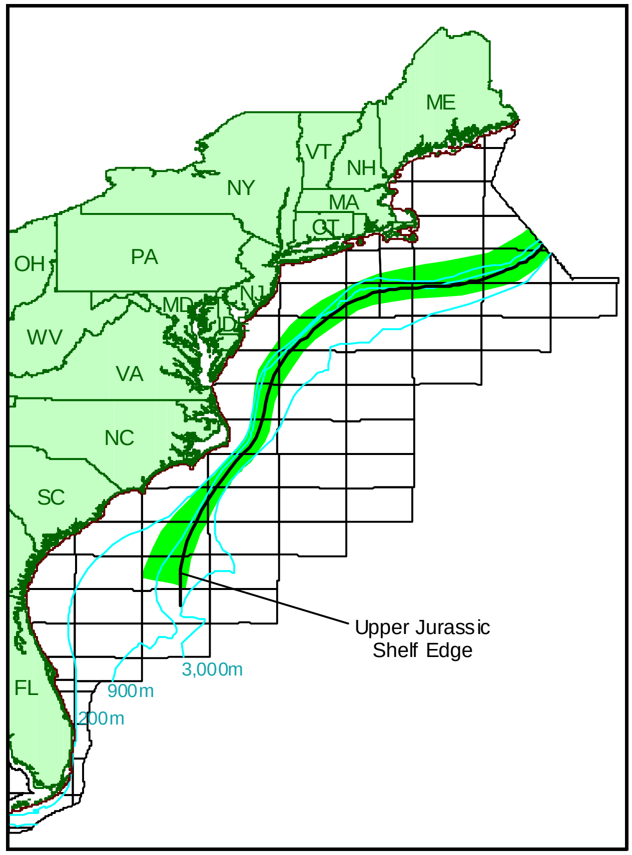


Figure 1. Map of assessed play.

PLAY CHARACTERISTICS

The AUU CB play consists of late Jurassic shelf-edge reef complexes with associated back-reef carbonate platforms and reef-face carbonate talus, and possible earlymost Cretaceous carbonates. Shallow-water limestone platforms and reef complexes developed where deltaic clastic influx was

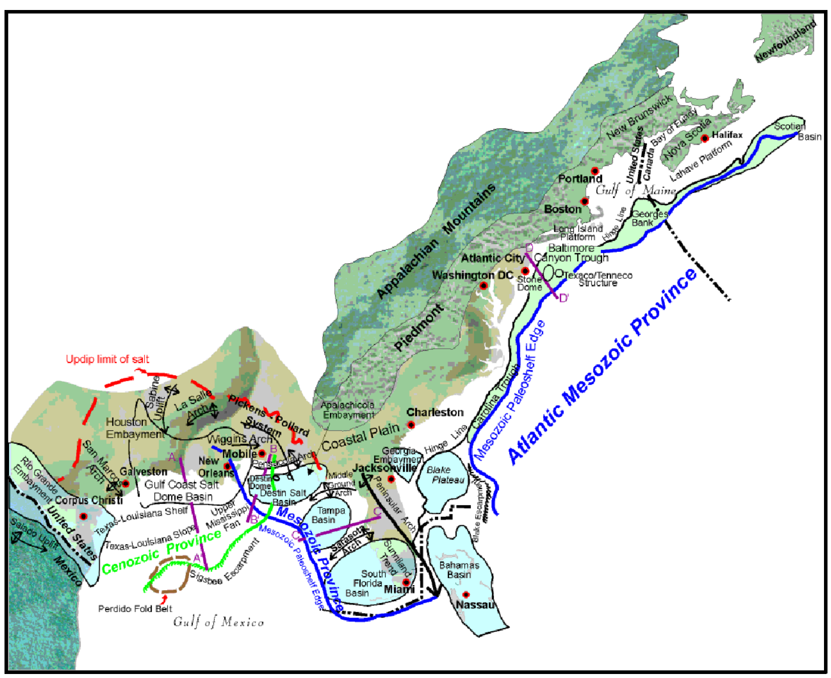
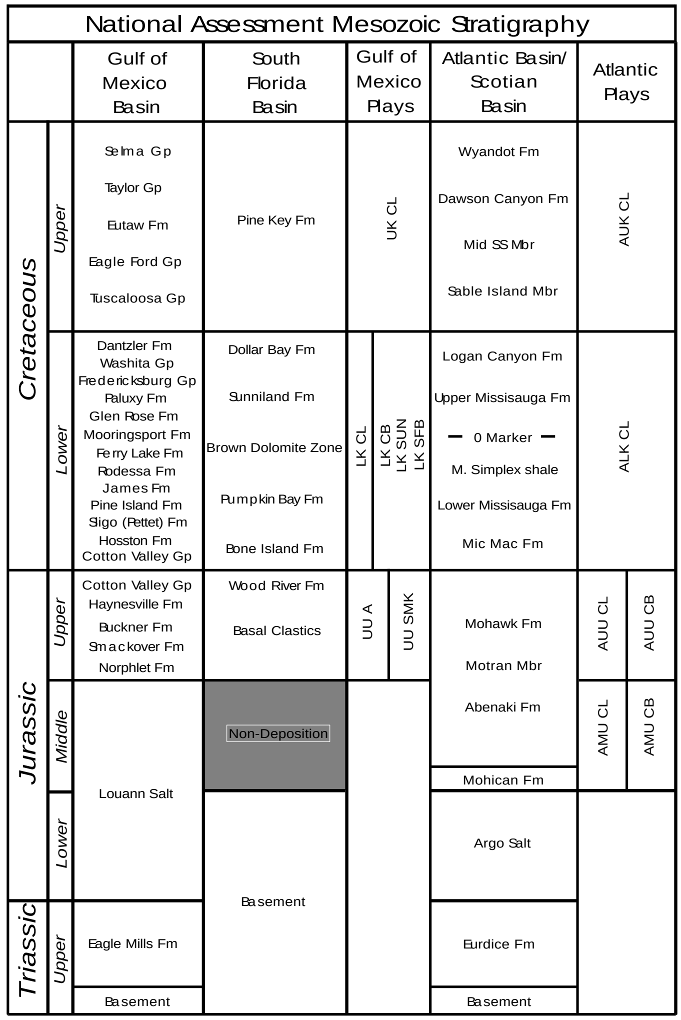


Figure 2. Physiographic map.

minimal. Potential reservoirs occur in the back-reef as oolitic, pelletal, or reef detritus grainstones, in the reef itself, and in the fore-reef as talus. The reef and back-reef deposits have the best potential for enhanced porosity due to subaerial exposure. Structures are controlled by shelf-edge reef buildups and shelf-edge normal faults. Traps are mainly stratigraphic on the carbonate platform. Combination stratigraphic and structural traps occur within the reef complex on the shelf edge and in reef talus on the slope. Potential source rocks include Jurassic shelf and slope shales. Geochemical analysis indicates organic matter to be primarily Type III with total organic carbon (TOC) ranging from 0.5 to 3 percent. The hydrocarbon evolution window (HEW) extends from approximately 7,000 to 18,000 feet. Jurassic lagoonal and platform carbonates may also provide good source rock potential. Seals are provided by upper Jurassic or lowermost Cretaceous carbonates, shales, and anhydrites.



Rock unit positions do not imply age relationships between basins.

Figure 3. Stratigraphic column.

The analog type field for the AUU CB play is the Black Lake Field, Natchitoches Parish, Louisiana. This field's production is from the Lower Cretaceous Sligo Formation of the Sligo-Stuart City reef trend (figure 3).

DISCOVERIES

Exploration in the Atlantic Federal OCS area consists of 46 exploration and 5 COST wells (the Mesozoic well database [wellmeso.dbf] is presented in the CD-ROM DataFiles directory). Three exploration wells, Shell Offshore Inc.'s 372-1, 586-1, and 587-1, in Wilmington Canyon penetrated the shelf-edge reef and back-reef facies of the AUU CB play. Good reservoir rock was encountered, but no hydrocarbons were detected.

ASSESSMENT RESULTS

Because the AUU CB play contains no Federal fields, productive upper Jurassic platform carbonate reservoirs of the onshore eastern Gulf of Mexico and the lower Cretaceous Sligo-Stuart City reef trend provide the analogs for input parameters used in this assessment (figure 2).

The onshore upper Jurassic platform carbonate analog comprises the Smackover, Buckner, and Haynesville Formations, and Cotton Valley lime in Louisiana, Mississippi, and Alabama (figure 3). This analog covers an area of 7.6 million acres (11,850 square miles). Exploration has a success rate of approximately 10 percent, and drilling is at a mature stage with approximately 60 to 90 percent of the analog explored. These analog fields contain an average of 35 percent oil, 22 percent gas, and 43 percent mixed hydrocarbons.

The lower Cretaceous Sligo-Stuart City reef trend analog comprises the Sligo Formation and Edwards Group (Fredericksburg Group equivalent) and covers an area of 104 million acres (162,435 square miles) (figure 3). Exploration has a success rate of approximately 10 percent, and drilling is at a mature stage with approximately 75 to 85 percent of the analog explored. These analog fields contain an average of 22 percent oil, 73 percent gas, and 5 percent mixed hydrocarbons.

The marginal probability of hydrocarbons for the AUU CB play is 0.85. Assessment results indicate that undiscovered resources are estimated to be zero at the 95th percentile but 0.435 Bbo and 3.152 Tcfg at the 5th percentile (table 1 and figure 4). The mean undiscovered resources are estimated at 0.198 Bbo and 1.257 Tcfg (0.422 BBOE). These undiscovered resources may occur in as many as 35 pools, which have an unrisked mean size range of 0.117 to 214.820 MMBOE (figure 5). These pools have an unrisked mean mean size estimated at 14.124 MMBOE.

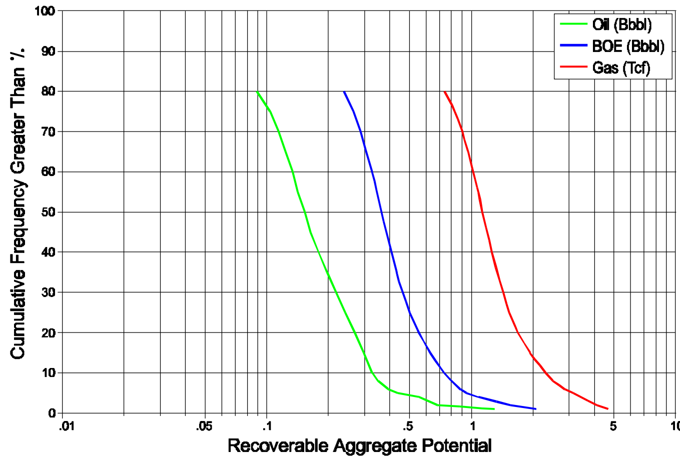


Figure 4. Cumulative probability distribution.

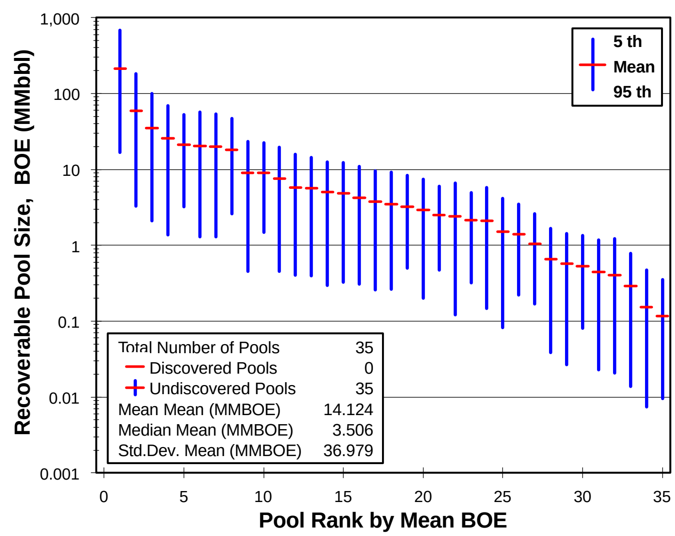


Figure 5. Pool rank plot.

Potential for discoveries extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 2).

Table 1. Assessment results.

Marginal Probability = 0.85	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	--	0.000	0.000	0.000
Mean	35	0.198	1.257	0.422
5th percentile	--	0.435	3.152	0.945
Total Endowment				
95th percentile	--	0.000	0.000	0.000
Mean	35	0.198	1.257	0.422
5th percentile	--	0.435	3.152	0.945

ATLANTIC UPPER JURASSIC TO UPPER CRETACEOUS BASIN FLOOR FAN (AUU-UK BFF) PLAY

The conceptual Atlantic Upper Jurassic to Upper Cretaceous Basin Floor Fan (AUU-UK BFF) play extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 1). The play occurs on the continental rise and consists of the distal portions of siliciclastic fan systems. The downdip limit of the play represents the basinward extent of clastic deposition during Late Jurassic to Late Cretaceous times. Potential basin floor fan reservoirs are typically thin-bedded sheet sands.

This play was not assessed due to low potential for thermally mature hydrocarbon source rocks in the relatively thin stratigraphic section of the continental rise.

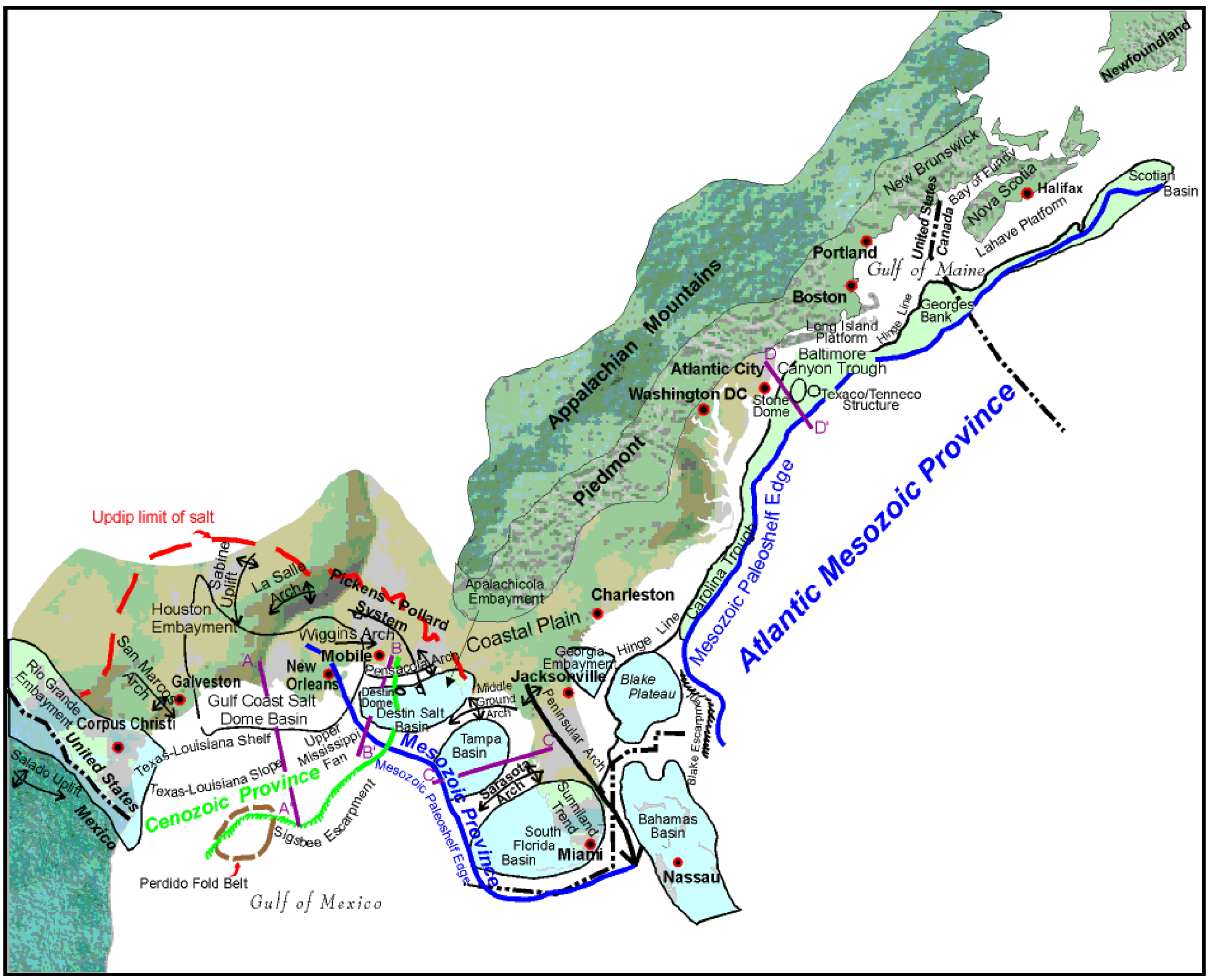


Figure 1. Physiographic map.

ATLANTIC UPPER JURASSIC TO LOWER CRETACEOUS TRANSITION ZONE (AUU-LK TZ) PLAY

The conceptual Atlantic Upper Jurassic to Lower Cretaceous Transition Zone (AUU-LK TZ) play in the Blake Plateau Area represents a transition zone from a mixed siliciclastic/carbonate regime to the north and a carbonate regime to the south in the Bahamas Basin (figure 1). Large low-relief anticlines may underlie the Blake Plateau. Potential reservoirs mainly include platform carbonates and minor amounts of deltaic clastics.

The play is considered to have low potential because the seismically mapped structures may not exist if current velocity assumptions are incorrect. Therefore, the AUU-LK TZ play was not assessed.

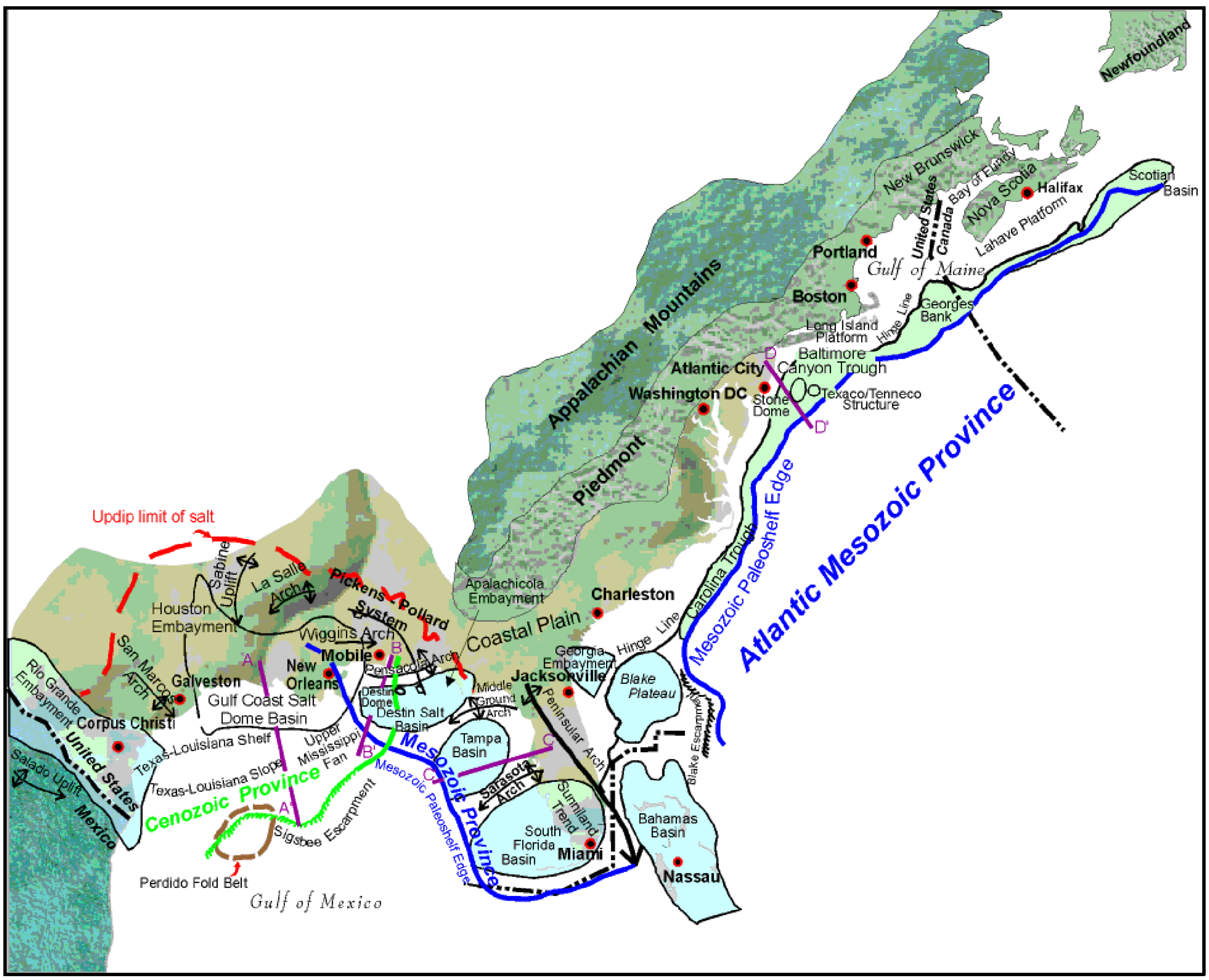


Figure 1. Physiographic map.

ATLANTIC MIDDLE JURASSIC (AMU) CHRONOZONE

CHRONOZONE DESCRIPTION

The Atlantic Middle Jurassic (AMU) chronozone corresponds to the *Gonyaulacysta pachyderma* and *Gonyaulacysta pectinigera* biozones. The middle Jurassic section in the Atlantic Basin consists of clastics and carbonates, each of which defines a play: the Atlantic Middle Jurassic Clastic (AMU CL) play and the Atlantic Middle Jurassic Carbonate (AMU CB) play. The clastics consist of deltaic complexes, barrier bars, and channel systems of retrogradational, aggradational, and progradational deposits. The carbonates consist of shallow-water limestone platforms and ramps, and possible pinnacle and patch reefs developed where deltaic clastic influx was minimal.

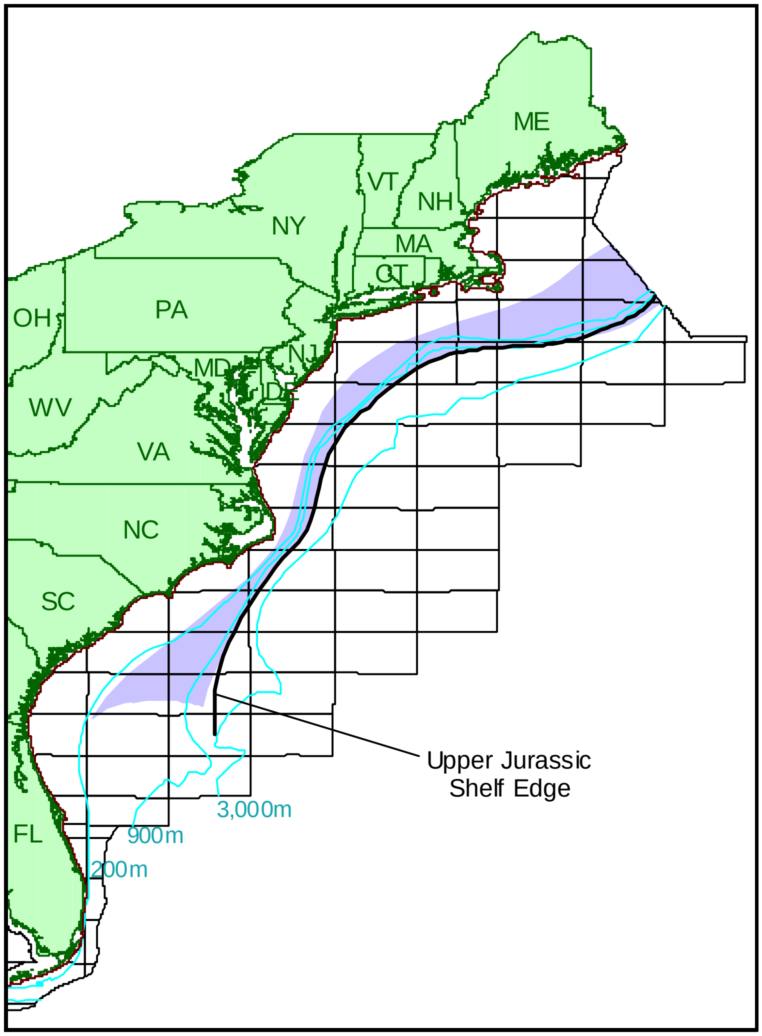


Figure 1. Map of assessed chronozone.

Reservoir potential in the chronozone extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 1). The updip reservoir potential is limited by the shoreward erosional limit of middle Jurassic clastics. The downdip reservoir potential is limited by the extent of the carbonate ramp.

DISCOVERIES

No pools in the chronozone have as yet been discovered in the Federal OCS.

ASSESSMENT RESULTS

The Atlantic plays in the middle Jurassic chronozone are not as yet productive. Assessment results indicate that undiscovered resources may occur in as many as 147 pools. These undiscovered resources are estimated to be zero at the 95th percentile but 1.163 Bbo and 10.426 Tcfg at the 5th percentile (table 1 and figure 2). At mean levels, 0.529 Bbo and 5.502 Tcfg (1.508 BBOE) are projected. The 147 undiscovered pools have an unrisked mean mean size of 12.134 MMBOE (figure 3). Of the two plays in the chronozone, the AMU CL play is estimated to contain 84 percent of the BOE mean total endowment for the chronozone.

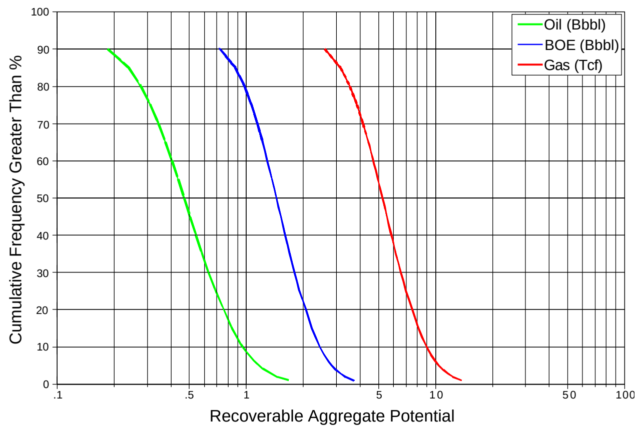


Figure 2. Cumulative probability distribution.

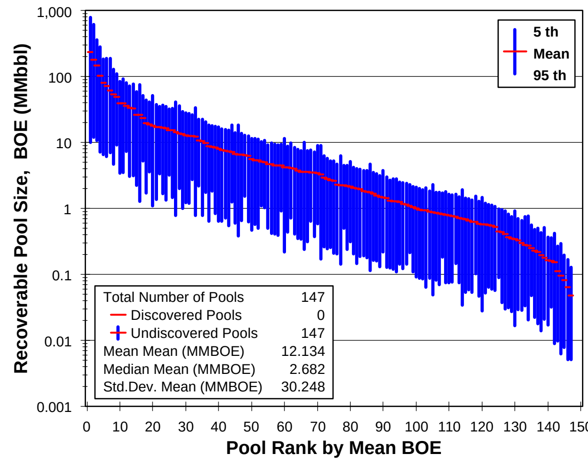


Figure 3. Pool rank plot.

Table 1. Assessment results.

Marginal Probability = 0.93	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	--	0.000	0.000	0.000
Mean	147	0.529	5.502	1.508
5th percentile	--	1.163	10.426	2.830
Total Endowment				
95th percentile	--	0.000	0.000	0.000
Mean	147	0.529	5.502	1.508
5th percentile	--	1.163	10.426	2.830

ATLANTIC MIDDLE JURASSIC CLASTIC (AMU CL) PLAY

PLAY DESCRIPTION

The frontier Atlantic Middle Jurassic Clastic (AMU CL) play occurs within the *Gonyaulacysta pachyderma* and *Gonyaulacysta pectinigera* biozones. This play extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 1 and figure 2).

The updip assessment limit was determined by the shoreward erosional limit of middle Jurassic sediments. Downdip, the middle Jurassic sediments of this play exhibit a lateral facies change from nearshore clastics to the platform carbonates of the Atlantic Middle Jurassic Carbonate (AMU CB) play.

The AMU CL play is stratigraphically and structurally similar to the Atlantic Lower Cretaceous Clastic (ALK CL) and the Atlantic Upper Jurassic Clastic (AUU CL) plays.

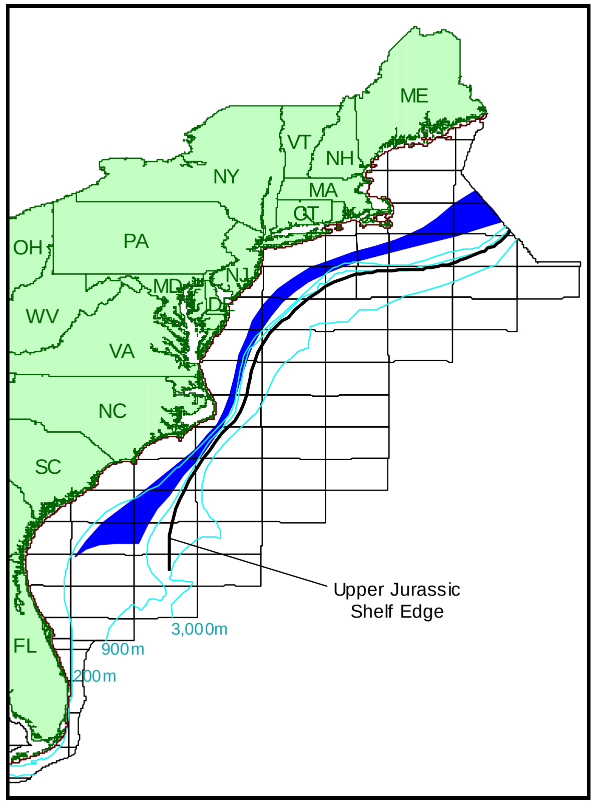


Figure 1. Map of assessed play.

PLAY CHARACTERISTICS

In the middle Jurassic, clastic sediments were eroded from the Appalachian Mountain System. During low stands of sea level, these sediments formed deltaic complexes. Potential middle Jurassic reservoirs may occur in deltaic complexes, barrier bars, and channel systems on the shelf.

Structures are related mainly to anticlines, growth faults, and normal faults. Potential source rocks include Jurassic shelf and slope shales. Geochemical analysis indicates organic matter to be primarily Type III with total organic carbon (TOC) ranging

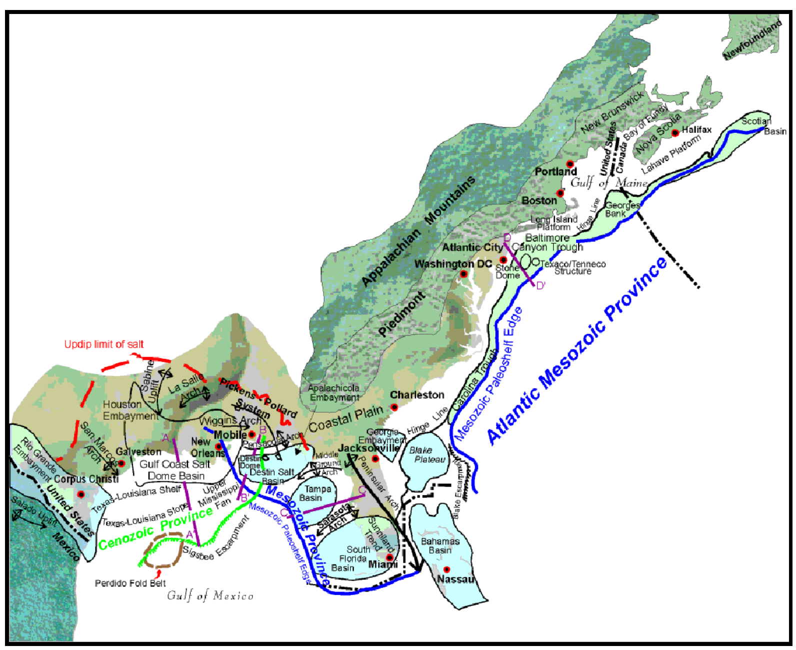


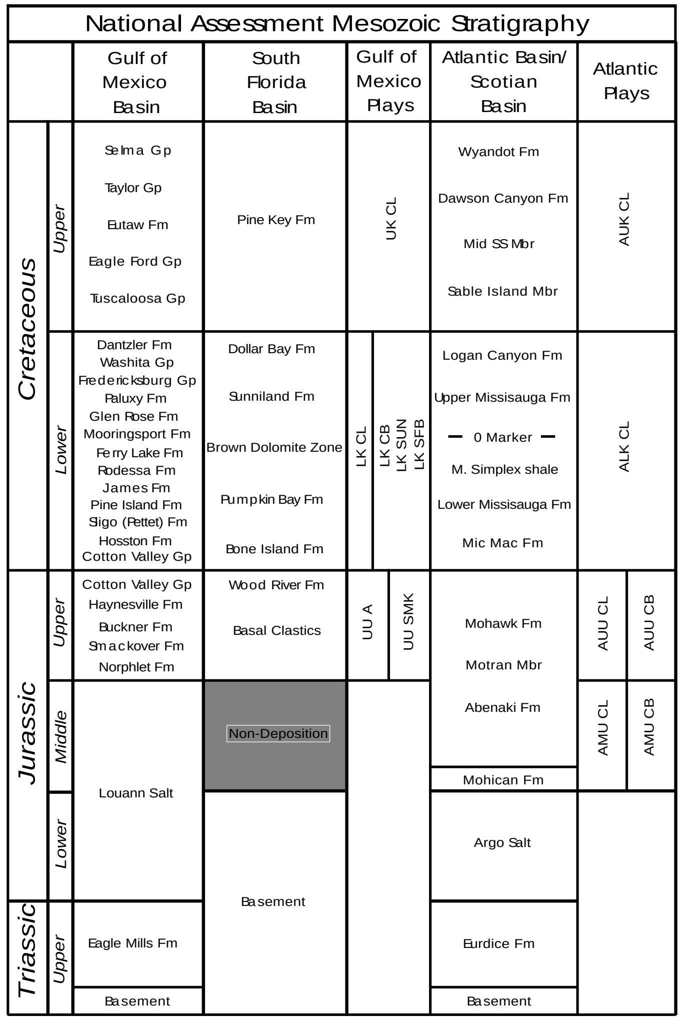
Figure 2. Physiographic map.

from 0.5 to 3 percent. The hydrocarbon evolution window (HEW) extends from approximately 7,000 to 18,000 feet. Jurassic lagoonal and platform carbonates may also provide good source rock potential. Seals are provided by middle or lowermost upper Jurassic limestones or by overlying shales.

The analog type field for the AMU CL play is the Thomasville Field, Rankin County, Mississippi. Production from the upper Jurassic clastic section in this field occurs from the Smackover Formation (figure 3).

DISCOVERIES

Exploration along the Atlantic Margin Federal OCS Area consists of 46 exploration and 5 COST wells (the Mesozoic well database [wellmeso.dbf] is presented in the CD-ROM DataFiles directory). Of the two wells that may have penetrated the AMU CL play, no commercial quantities of hydrocarbons were found.



Rock unit positions do not imply age relationships between basins.

Figure 3. Stratigraphic column.

ASSESSMENT RESULTS

Since the AMU CL play contains no Federal fields, productive upper Jurassic clastic sediments of the onshore eastern Gulf of Mexico and the Canadian offshore Scotian Basin provide the analogs for input parameters used in this assessment (figure 2).

Upper Jurassic reservoirs of the onshore eastern Gulf of Mexico and Scotian Basin were chosen as analogs for the AMU CL play because suitable middle Jurassic analogs were not recognized. The eastern Gulf of Mexico and the Atlantic Continental Margin first shared similar depositional environments and a common source area during the upper Jurassic. The onshore upper Jurassic clastic analog comprises the Smackover Formation and Cotton Valley Group of Mississippi and Alabama (figure 3). This analog encompasses an area of 6.2 million acres (9,750 square miles). Exploration in the analog has a success rate of approximately 10 percent, and drilling is at a mature stage with approximately 60 to 90 percent of the analog explored. These analog fields contain an average of 40 percent oil, 29 percent gas, and 31 percent mixed hydrocarbons. Fields producing from the well-established Norphlet trend were not used as analogs in this assessment because they produce from eolian sands, which are not analogous to the deltaic deposits in the AMU CL play.

The Scotian Basin upper Jurassic clastic analog comprises the Mic Mac Formation and covers an area of 35 million acres (54,700 square miles) (figure 3). Exploration in this analog has a success rate of approximately 30 percent, and drilling is at an immature stage with approximately 30 percent of the analog explored. This analog was used primarily for field size distribution parameters, as production data are not public record.

The marginal probability of hydrocarbons for the AMU CL play is 0.90. Assessment results indicate that undiscovered resources are estimated to be zero at the 95th percentile but 0.645 Bbo and 8.455 Tcfg at the 5th percentile (table 1 and figure 4). The mean undiscovered resources are estimated at 0.399 Bbo and 4.891 Tcfg (1.269 BBOE). These undiscovered resources may occur in as many as 120 pools, which have an unrisked mean size range of 0.048 to 236.540 MMBOE (figure 5). These pools have an unrisked mean mean size estimated at 11.786 MMBOE.

Potential for discoveries extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 2).

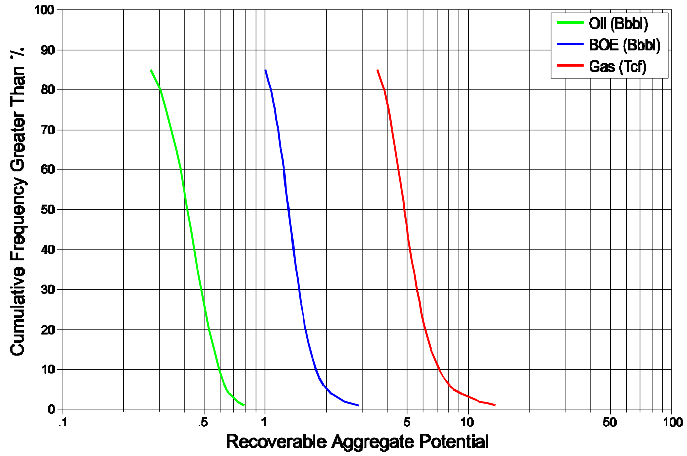


Figure 5. Cumulative probability distribution.

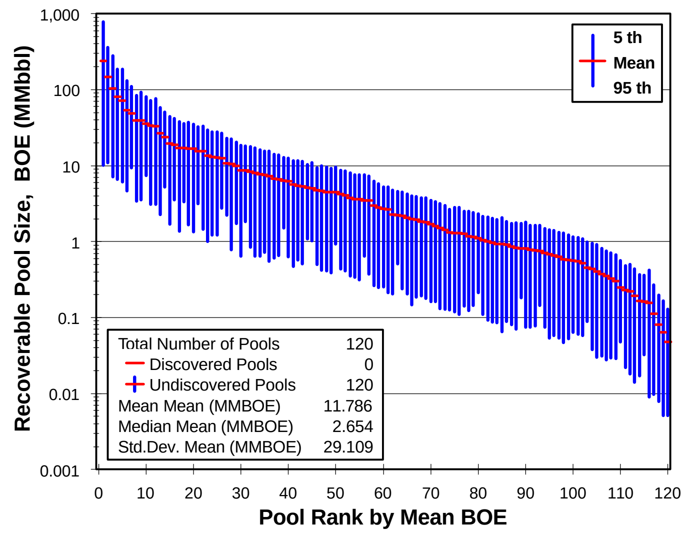


Figure 4. Pool rank plot.

Table 1. Assessment results.

Marginal Probability = 0.90	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	--	0.000	0.000	0.000
Mean	120	0.399	4.891	1.269
5th percentile	--	0.645	8.455	2.020
Total Endowment				
95th percentile	--	0.000	0.000	0.000
Mean	120	0.399	4.891	1.269
5th percentile	--	0.645	8.455	2.020

ATLANTIC MIDDLE JURASSIC CARBONATE (AMU CB) PLAY

PLAY DESCRIPTION

The frontier Atlantic Middle Jurassic Carbonate (AMU CB) play occurs within the *Gonyaulacysta pachyderma* and *Gonyaulacysta pectinigera* biozones. This play extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 1 and figure 2).

The AMU CB play is stratigraphically similar to the Atlantic Upper Jurassic Carbonate (AUU CB) play. However, the middle Jurassic limestone platform is much wider and extends farther shoreward, presumably because sediment influx had not extended as far basinward in middle Jurassic time.

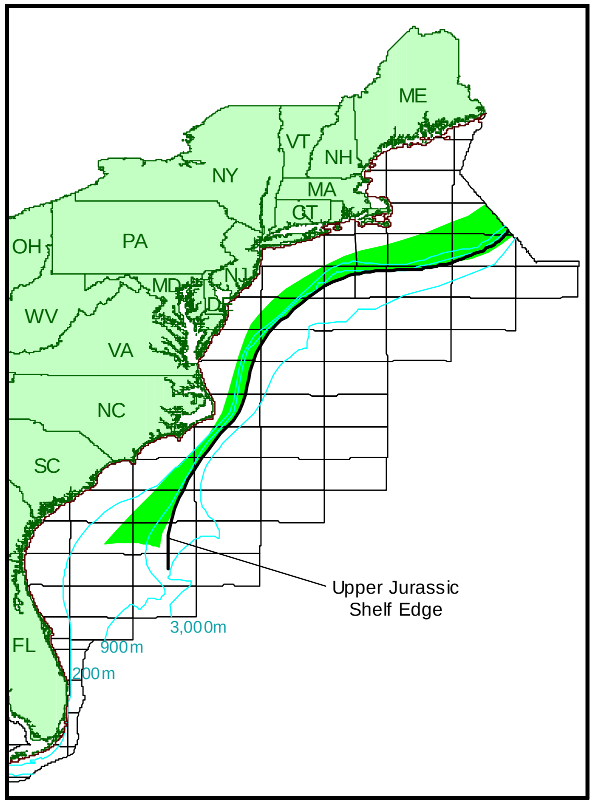


Figure 1. Map of assessed play.

PLAY CHARACTERISTICS

The AMU CB play consists of shallow-water limestone platforms and ramps that merge with the slope. Pinnacle and patch reefs may also occur. Shallow-water limestone platforms formed in the seaward portions of marginal basins where deltaic clastic influx was minimal. Potential reservoirs occur in porous bioclastic and pelletal carbonates that include pinnacle and patch reefs and associated reef talus. Hydrocarbons may also occur in carbonates deposited as shallow-water platform and deeper-water ramp facies. Structural closures over reefal buildups are possible, but traps are mainly stratigraphic. Potential source rocks include Jurassic shelf and slope shales. Geochemical analysis indicates organic matter to be primarily Type III with total organic carbon (TOC) ranging from 0.5 to 3 percent. The

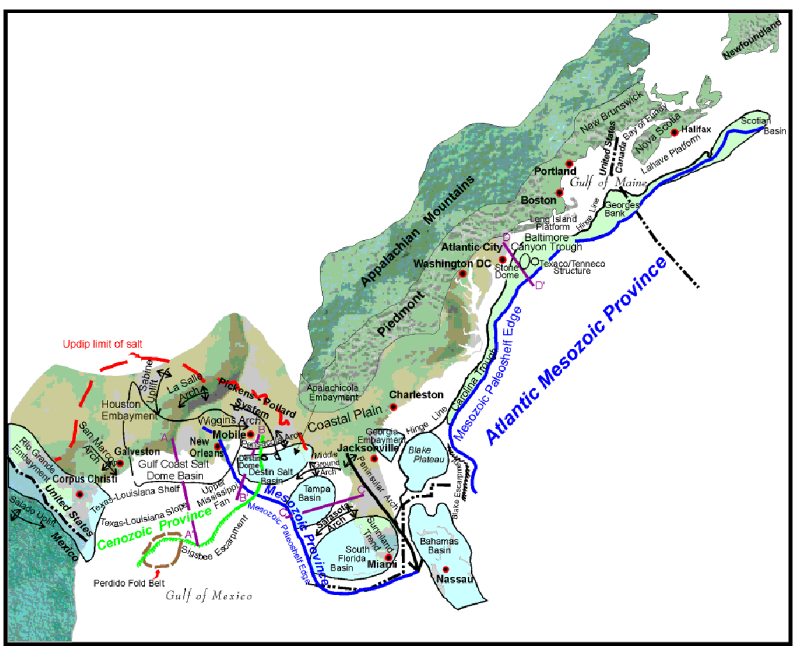


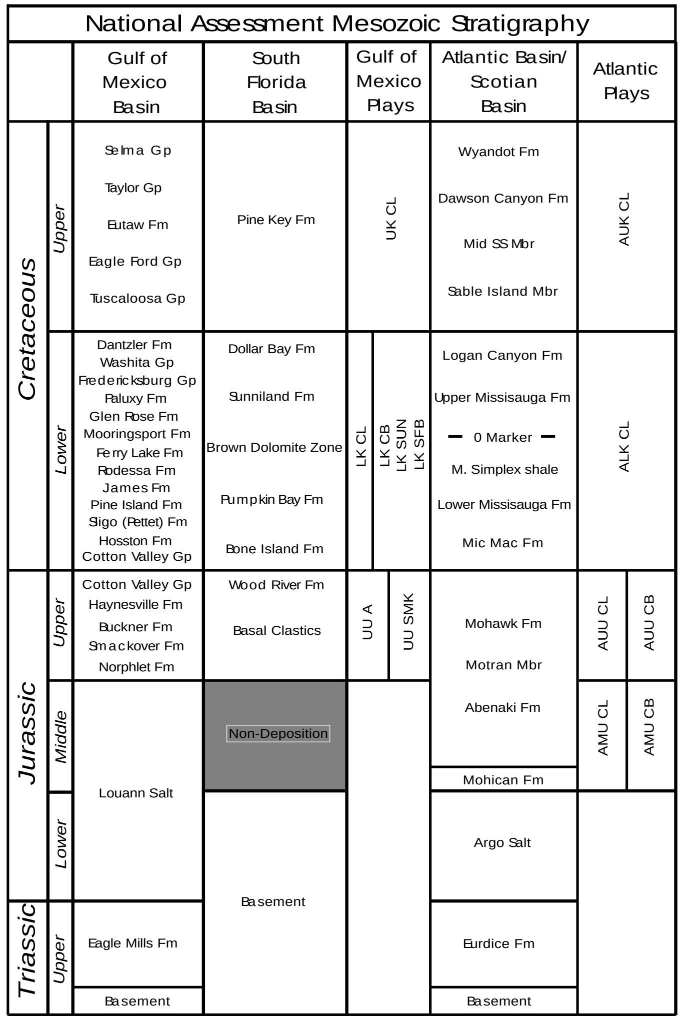
Figure 2. Physiographic map.

hydrocarbon evolution window (HEW) extends from approximately 7,000 to 18,000 feet. Jurassic lagoonal and platform carbonates may also provide good source rock potential. Seals are provided by middle or lowermost upper Jurassic carbonates, shales, and anhydrites.

The analog type field for the AMU CB play is the Chunchula Field, Mobile County, Alabama. This field's production is from the Upper Jurassic Smackover Formation (figure 3).

DISCOVERIES

Exploration in the Atlantic Federal OCS area consists of 46 exploration and 5 COST wells (the Mesozoic well database [wellmeso.dbf] is presented in the CD-ROM DataFiles directory). Of the 24 wells that may have penetrated this play, only one encountered hydrocarbons. Overpressured gas was encountered at almost 18,000 feet in probable middle Jurassic rocks in Texaco's Hudson Canyon 642-1 well. The flow was not measured nor was the presence of reservoir-quality rock established.



Rock unit positions do not imply age relationships between basins.

Figure 3. Stratigraphic column.

ASSESSMENT RESULTS

Since the AMU CB play contains no Federal fields, productive upper Jurassic platform carbonate reservoirs of the onshore eastern Gulf of Mexico and the lower Cretaceous Sligo-Stuart City reef trend provide the analogs for input parameters used in this assessment (figure 2).

The onshore upper Jurassic platform carbonate analog comprises the Smackover, Buckner, and Haynesville Formations, and Cotton Valley lime of Louisiana, Mississippi, and Alabama (figure 3). This analog covers an area of 7.6 million acres (11,850 square miles). Exploration has a success rate of approximately 10 percent, and drilling is at a mature stage with approximately 60 to 90 percent of the analog explored. These analog fields contain an average of 35 percent oil, 22 percent gas, and 43 percent mixed hydrocarbons.

The lower Cretaceous Sligo-Stuart City reef trend analog comprises the Sligo Formation and Edwards Group (Fredericksburg Group equivalent) and covers an area of 104 million acres (162,435 square miles) (figure 3). Exploration has a success rate of approximately 10 percent, and drilling is at a mature stage with approximately 75 to 85 percent of the analog explored. These analog fields contain an average of 22 percent oil, 73 percent gas, and 5 percent mixed hydrocarbons.

The marginal probability of hydrocarbons for the AMU CB play is 0.65. Assessment results indicate that undiscovered resources are estimated to be zero at the 95th percentile but 0.413 Bbo and 1.633 Tcfg at the 5th percentile (table 1 and figure 4). The mean undiscovered resources are estimated at 0.130 Bbo and 0.611 Tcfg (0.239 BBOE). These undiscovered resources may occur in as many as 27 pools, which have an unrisked mean size range of 0.097 to 179.490 MMBOE (figure 5). These pools have an unrisked mean mean size estimated at 13.680 MMBOE.

Potential for discoveries extends from the U.S.-Canadian border through the Carolina Trough to the Blake Plateau (figure 2).

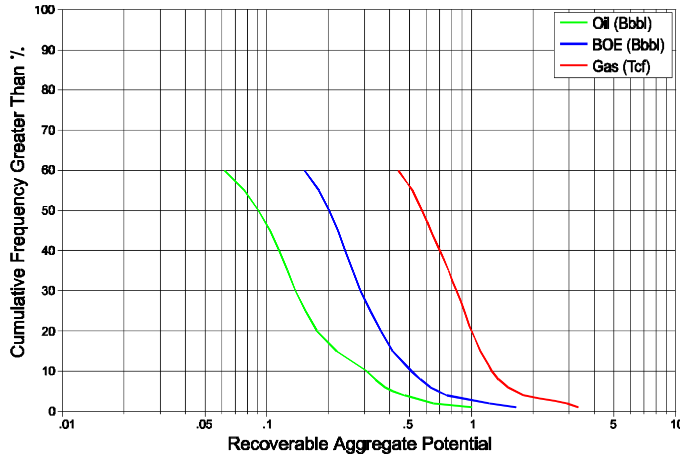


Figure 4. Cumulative probability distribution.

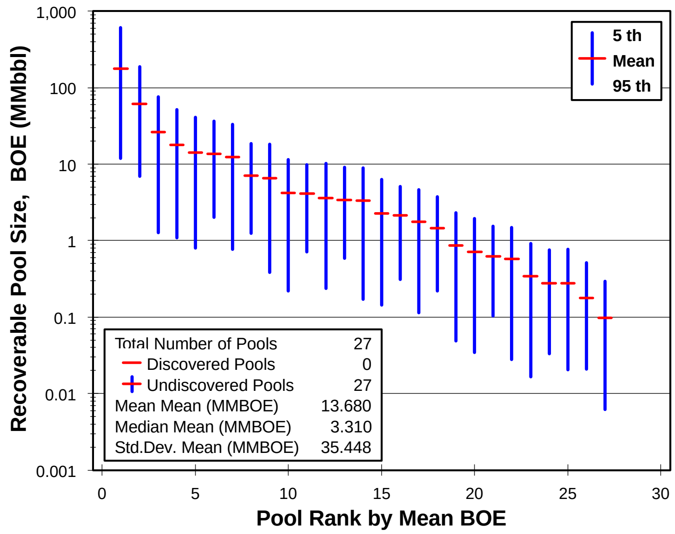


Figure 5. Pool rank plot.

Table 1. Assessment results.

Marginal Probability = 0.65	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	--	0.000	0.000	0.000
Mean	27	0.130	0.611	0.239
5th percentile	--	0.413	1.633	0.688
Total Endowment				
95th percentile	--	0.000	0.000	0.000
Mean	27	0.130	0.611	0.239
5th percentile	--	0.413	1.633	0.688

ATLANTIC LOWER JURASSIC (ALU) CHRONOZONE

The Atlantic Lower Jurassic (ALU) chronozone comprises only one play [see Atlantic Jurassic to Cretaceous Diapir (AU-K DIA) play].

ATLANTIC JURASSIC TO CRETACEOUS DIAPIR (AU-K DIA) PLAY

Salt diapirs within the conceptual Atlantic Jurassic to Cretaceous Diapir (AU-K DIA) play may occur seaward of the shelf edge from the Scotian Basin through the Carolina Trough (figure 1). Diapiric structures have been recognized on seismic data along the seaward edge of the Georges Bank Basin and Carolina Trough. Clastic or carbonate reservoirs may be associated with crestal, flank, or subsalt traps.

Because diapir-related structures have not yielded hydrocarbons in the adjacent Scotian Basin, the potential for future discoveries in the AU-K DIA play is considered to be low. Therefore, this play was not assessed.

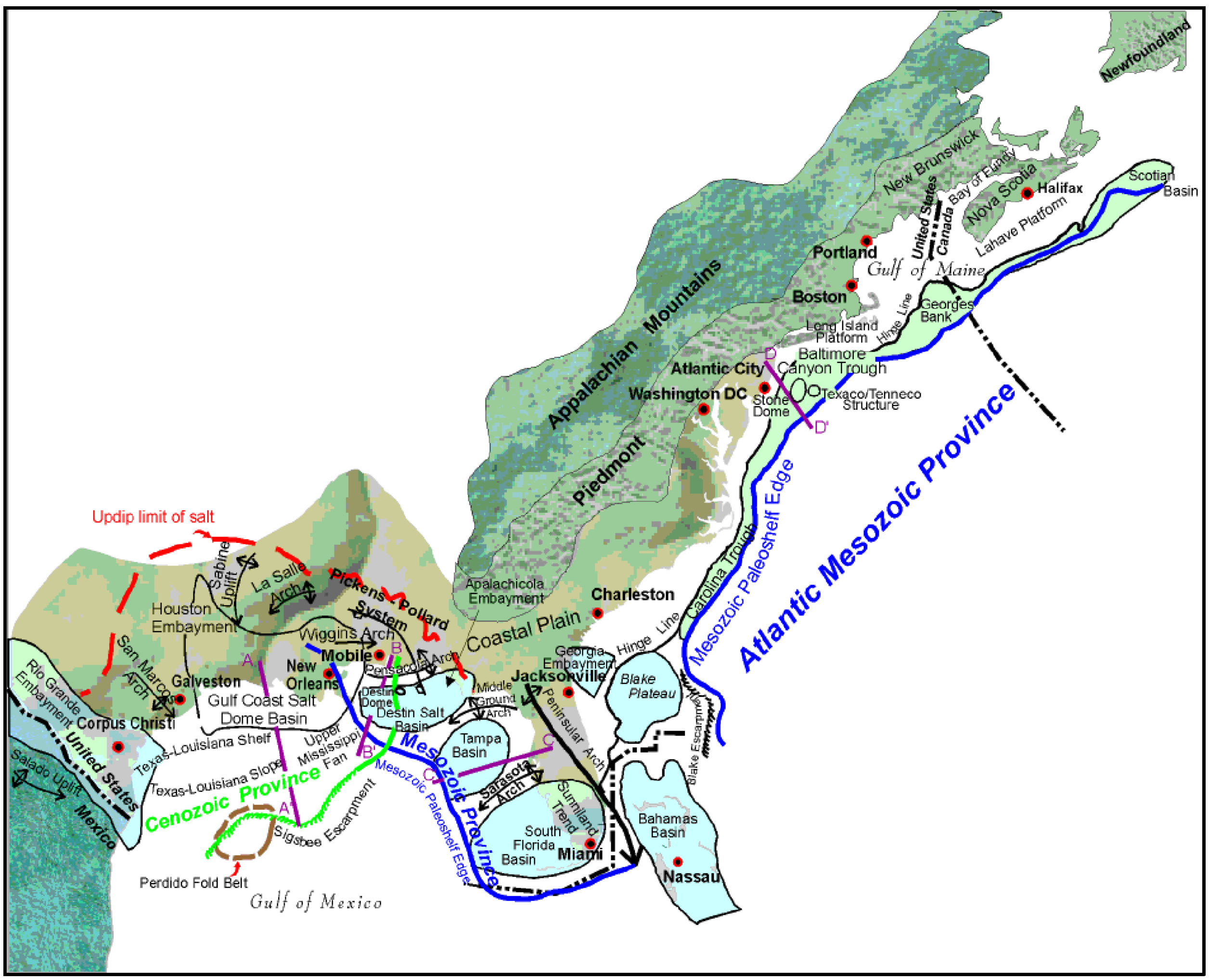


Figure 1. Physiographic map.

ATLANTIC UPPER TRIASSIC (AUTR) CHRONOZONE

The Atlantic Upper Triassic (AUTR) chronozone comprises two plays [see Atlantic Upper Triassic to Lower Jurassic Clastic Rift (ATR-LU CLR) play and Atlantic Upper Triassic to Lower Jurassic Carbonate Rift (ATR-LU CBR) play].

ATLANTIC TRIASSIC TO LOWER JURASSIC CLASTIC RIFT (ATR-LU CLR) PLAY

The conceptual Atlantic Triassic to Lower Jurassic Clastic Rift (ATR-LU CLR) play is characterized by a trend of Triassic to Lower Jurassic rift basins from eastern Newfoundland to the Carolinas (figure 1). The play includes continental and marine rift basins. Rift basin red bed deposits comprise alluvial, fluvial, eolian, and lacustrine sediments. The easternmost zone of rift basins, which comprise mainly marine carbonate-evaporite sequences of the Atlantic Triassic to Lower Jurassic Carbonate Rift (ATR-LU CBR) play, may also contain marine deltaic deposits.

The ATR-LU CLR play is considered to have low potential because of deep burial and thermal overmaturity of source rock and, therefore, was not assessed.

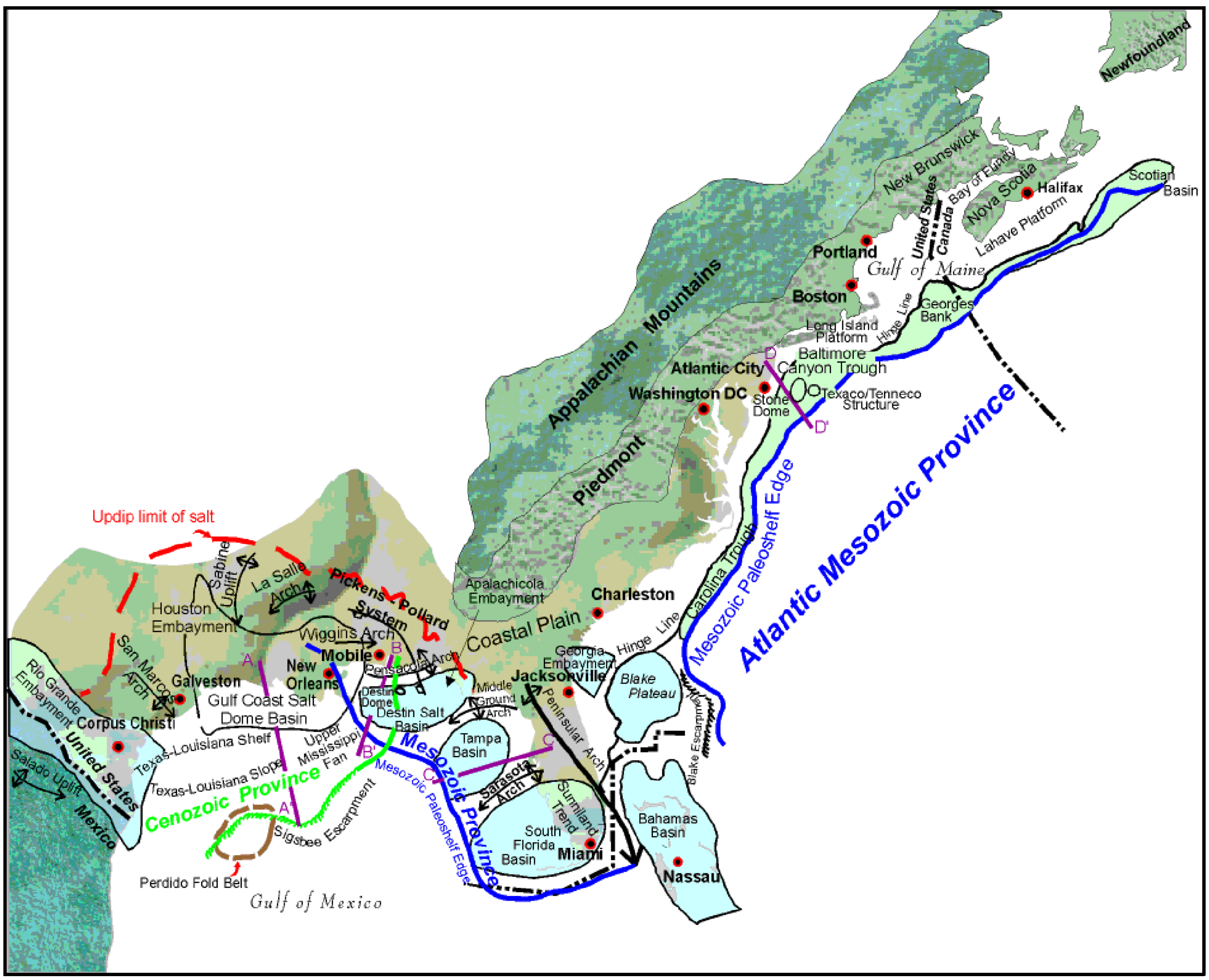


Figure 1. Physiographic map.

ATLANTIC TRIASSIC TO LOWER JURASSIC CARBONATE RIFT (ATR-LU CBR) PLAY

The conceptual Atlantic Triassic to Lower Jurassic Carbonate Rift (ATR-LU CBR) play is characterized by a trend of Triassic to Lower Jurassic rift basins from eastern Newfoundland to the Carolinas (figure 1). The play is identified seismically in the deep subsurface of the Georges Bank Area and occurs in the easternmost zone of rift basins. This play consists of carbonate-evaporite sequences of marine rift-basins. Prospective reservoir facies may include dolomites and platform limestones, as well as possible patch and pinnacle reefs.

The ATR-LU CBR play is considered to have low potential because of deep burial and thermal overmaturity of source rock and, therefore, was not assessed.

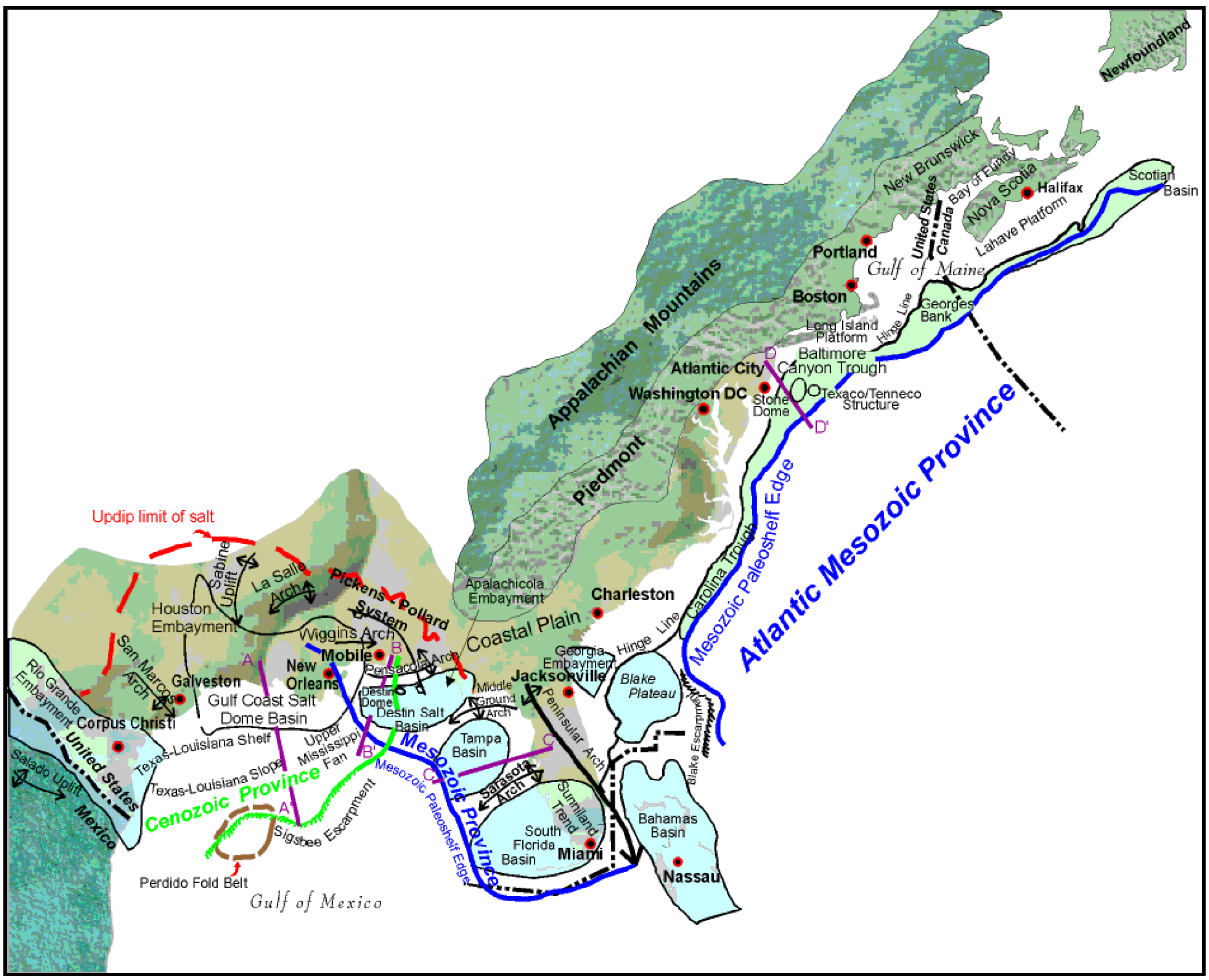


Figure 1. Physiographic map.

HOW TO CONTACT US

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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

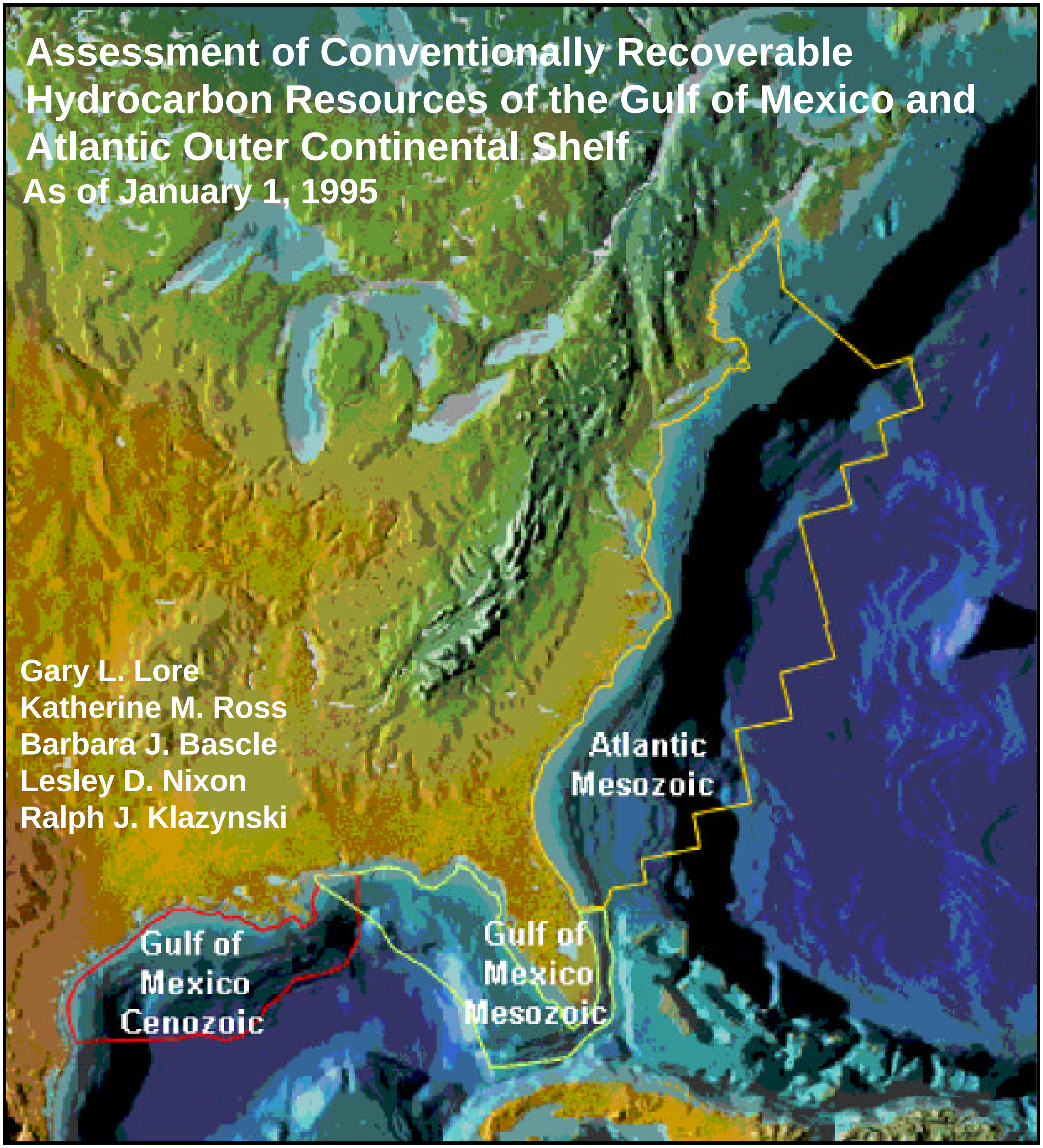
Managing America's offshore energy resources

Protecting America's coastal and marine environments

OCS Report
MMS 99-0034

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

As of January 1, 1995



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Minerals Management Service
Gulf of Mexico OCS Regional Office
Office of Resource Evaluation

New Orleans
June 1999

CONTENTS

Gulf of Mexico and Atlantic Margin Economic Results

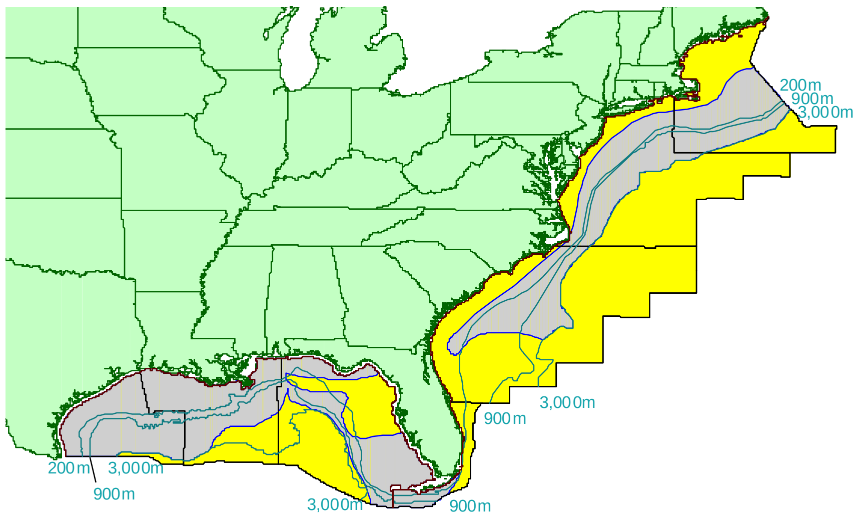

Figure 1. Gulf of Mexico and Atlantic Margin Map. The Margin is shaded in yellow, and the gray pattern indicates the extent of the assessed plays.

The Gulf of Mexico and Atlantic Margin includes submerged Federal lands from the U.S.-Canada International Boundary south to the U.S.-Mexico International Boundary (figure 1). Water depths in the Margin range from very shallow to more than 3,000m. Because water depth and distance from shore have a significant effect on engineering and cost factors, the undiscovered economically recoverable resources (UERR) were evaluated for three water depth ranges, 0-200m, 201-900m, and 901-3,000m (no resources were evaluated in water depths greater than 3,000m).

The mean total endowment for the Margin is predominantly gas, with 68 percent of the total resources occurring as gas (figure 2). There is a trend towards a less gas-prone bias in the deeper water depths, with the 0-200m water depth range consisting of 71 percent gas, the 201-900m range consisting of 56 percent gas, and the deepest water depth range consisting of 62 percent gas. The largest concentration of the mean total endowment (70% on a barrels-of-oil-equivalent [BOE] basis) occurs in water depths of less than 200m (figure 3 and figure 4). The 201-900m range has 11 percent, and the 901-3,000m range has 19 percent of the BOE mean total endowment.

The Gulf of Mexico Cenozoic Province portion of the Margin is well developed in the 0-200m range with an extensive infrastructure already in place, less so in the 201-900m range, and minimally in the 901-3,000m range. The two Mesozoic Provinces are still in their initial development phase. There has been production in the Margin's two shallower ranges, but as of the date of this study, only proved and unproved reserves and reserves appreciation occurred in the 901-3,000m range (table 1 for Assessment Results Total, table 2 for 0-200m, table 3 for 201-900m, and table 4 for 901-3,000m). Significant amounts of undiscovered conventionally recoverable resources (UCRR) have been assessed for all three water depth ranges, and the full- and half-cycle UERR for both the \$18/bbl and \$30/bbl scenarios are shown in table 5 (Economic Results Total), table 6 (0-200m), table 7 (201-900m), and table 8 (901-3,000m). These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the three water depth ranges and for the total Margin.

Assessment results indicate that the total Margin undiscovered economically recoverable resources are notable, with a range of 4.364 to 7.094 Bbo and 57.252 to 70.695 Tcfg at the 95th and 5th percentiles, respectively, for the full-cycle $18/bbl scenario. The mean economically recoverable resources are estimated at 5.350 Bbo and 63.295 Tcfg. A graphical representation of these results, incorporating every 5th-percentile result for UCRR and UERR, is presented in figure 5 (Results Graph Total), figure 6 (0-200m), figure 7 (201-900m), and figure 8 (901-3,000m). These graphs also present the half-cycle $18/bbl, and the full- and half-cycle $30/bbl scenario results. Because the economic model imports field sizes in BOE from the geologic model and then calculates the oil and gas content, the BOE results graph is typically a smooth curve. As expected, the accompanying oil and gas values exhibit more scatter because the gas/oil ratio can vary greatly from one field to another.

The mean total endowment for oil, gas, and BOE by the reserve and resource classification is shown in figure 9 (Mean Endowment Total), figure 10 (0-200m), figure 11 (201-900m), and figure 12 (901-3,000m). The pie charts presented can be used to determine what percentage of oil, gas, or BOE is a result of reserves or of undiscovered resources. For example, 41 percent of the gas in the Margin remains to be discovered, and 42 percent of the oil remains to be discovered (figure 9). Moreover, 21 percent of the gas, oil, and BOE mean total endowment is remaining to be discovered and is projected to be economically recoverable at the $18/bbl scenario.

Because estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions, they are presented here as price-supply curves. These curves describe a functional relationship between economically recoverable resources and product price and present the estimates of mean undiscovered economically recoverable oil and gas at any starting oil price up to $50/bbl. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the ***General Text, Methodology, UERR (Economically Recoverable), Detailed Discussion*** section. 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 are the mean curves. The full-cycle price-supply curves are shown in figure 13 (Full-Cycle P-S Curve Total), figure 14 (0-200m), figure 15 (201-900m), and figure 16 (901-3,000m). The half-cycle price-supply curves are shown in figure 17 (Half-Cycle P-S Curve Total), figure 18 (0-200m), figure 19 (201-900m), and figure 20 (901-3,000m).

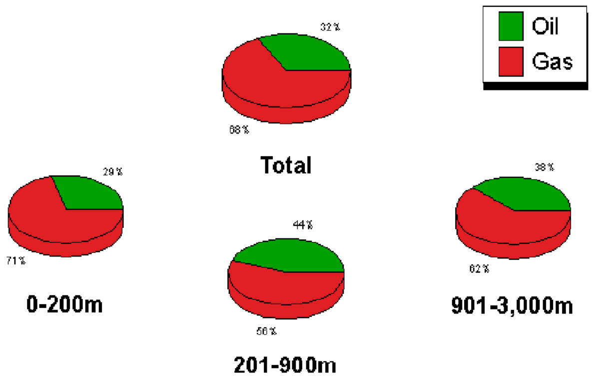

Figure 2. Gulf of Mexico and Atlantic Margin Percent Oil or Gas by Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

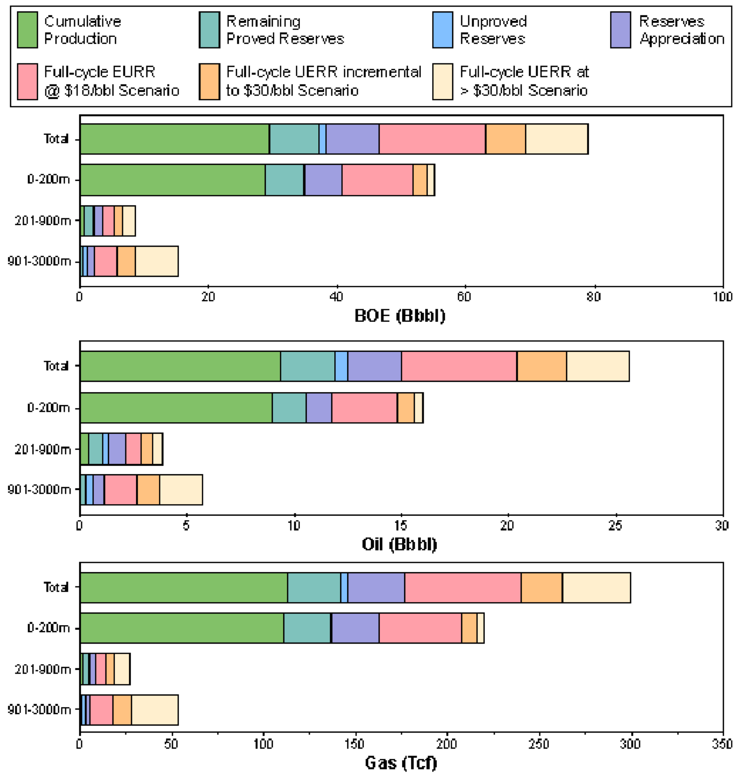

Figure 3. Gulf of Mexico and Atlantic Margin Mean Total Endowment by Water Depth Category.

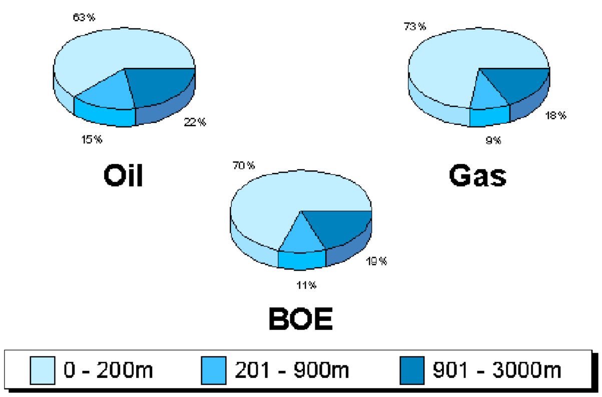

Figure 4. Gulf of Mexico and Atlantic Margin Mean Total Endowment by Resource Type and Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

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 Gulf of Mexico and Atlantic Margin Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	10.534	136.232	34.775
Cumulative production	8.938	110.943	28.678
Remaining proved	1.597	25.289	6.096
Unproved	0.033	0.761	0.168
Appreciation (P & U)	1.172	25.375	5.687
Undiscovered Conventionally Recoverable Resources			
95th percentile	3.881	53.916	13.474
Mean	4.292	57.315	14.491
5th percentile	4.576	63.854	15.938
Total Endowment			
95th percentile	15.620	216.283	54.105
Mean	16.032	219.683	55.121
5th percentile	16.316	226.222	56.569

Table 2. Gulf of Mexico and Atlantic Margin 0-200m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	1.043	4.753	1.889
Cumulative production	0.400	1.689	0.701
Remaining proved	0.643	3.064	1.188
Unproved	0.281	0.874	0.437
Appreciation (P & U)	0.778	3.044	1.320
Undiscovered Conventionally Recoverable Resources			
95th percentile	1.430	16.843	4.427
Mean	1.749	18.712	5.078
5th percentile	2.276	20.831	5.983
Total Endowment			
95th percentile	3.532	25.515	8.072
Mean	3.851	27.383	8.723
5th percentile	4.378	29.503	9.628

Table 3. Gulf of Mexico and Atlantic Margin 201-900m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.276	0.905	0.437
Cumulative production	0.000	0.000	0.000
Remaining proved	0.276	0.905	0.437
Unproved	0.324	1.969	0.675
Appreciation (P & U)	0.557	2.609	1.022
Undiscovered Conventionally Recoverable Resources			
95th percentile	3.839	44.978	11.842
Mean	4.571	47.868	13.088
5th percentile	6.406	51.163	15.510
Total Endowment			
95th percentile	4.997	50.461	13.976
Mean	5.729	53.352	15.222
5th percentile	7.564	56.646	17.643

Table 4. Gulf of Mexico and Atlantic Margin 901-3,000m Water Depth Assessment Results Table.

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 5. Total Gulf of Mexico and Atlantic Margin Economic Assessment Results Table.

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		2.651	40.514	9.860
Mean		3.043	45.512	11.142
5th percentile		3.385	52.431	12.714
Half-Cycle	1.00			
95th percentile		2.769	43.237	10.462
Mean		3.209	48.100	11.768
5th percentile		3.551	54.919	13.323
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		3.429	49.936	12.315
Mean		3.857	53.379	13.355
5th percentile		4.218	59.400	14.788
Half-Cycle	1.00			
95th percentile		3.527	50.646	12.539
Mean		3.924	54.133	13.556
5th percentile		4.277	60.227	14.994

Table 6. Gulf of Mexico and Atlantic Margin 0-200m Water Depth Economic Assessment Results Table.

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		0.485	3.961	1.190
Mean		0.782	5.633	1.784
5th percentile		1.294	8.650	2.833
Half-Cycle	1.00			
95th percentile		0.536	4.451	1.328
Mean		0.849	6.319	1.973
5th percentile		1.353	9.979	3.129
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.817	7.400	2.134
Mean		1.272	10.283	3.102
5th percentile		1.826	12.844	4.112
Half-Cycle	1.00			
95th percentile		0.997	8.758	2.556
Mean		1.349	11.245	3.350
5th percentile		1.869	13.726	4.312

Table 7. Gulf of Mexico and Atlantic Margin 201-900m Water Depth Economic Assessment Results Table.

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		0.808	8.859	2.384
Mean		1.497	12.140	3.657
5th percentile		3.196	15.620	5.975
Half-Cycle	1.00			
95th percentile		1.039	10.611	2.927
Mean		1.708	13.992	4.198
5th percentile		3.388	17.220	6.452
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		1.802	18.749	5.138
Mean		2.569	22.078	6.498
5th percentile		4.385	25.626	8.945
Half-Cycle	1.00			
95th percentile		1.984	20.819	5.689
Mean		2.822	24.603	7.200
5th percentile		4.641	28.461	9.705

Table 8. Gulf of Mexico and Atlantic Margin 901-3,000m Water Depth Economic Assessment Results Table.

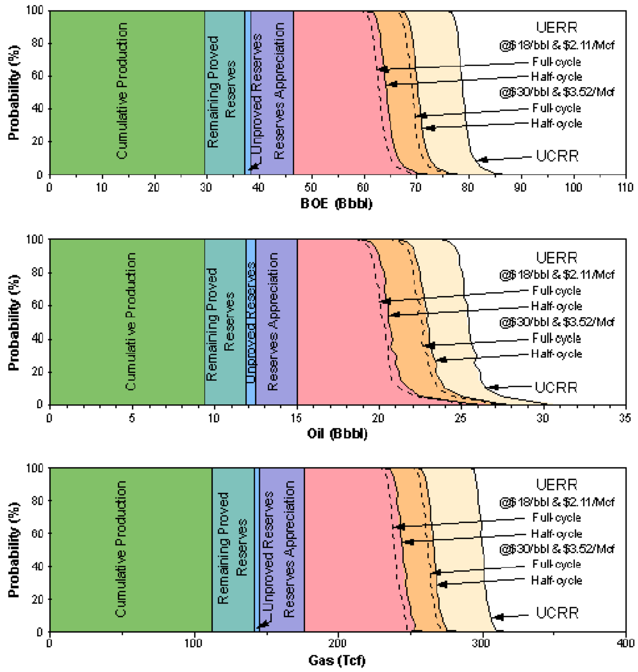

Figure 5. Gulf of Mexico and Atlantic Margin Total Endowment by Resource Category.

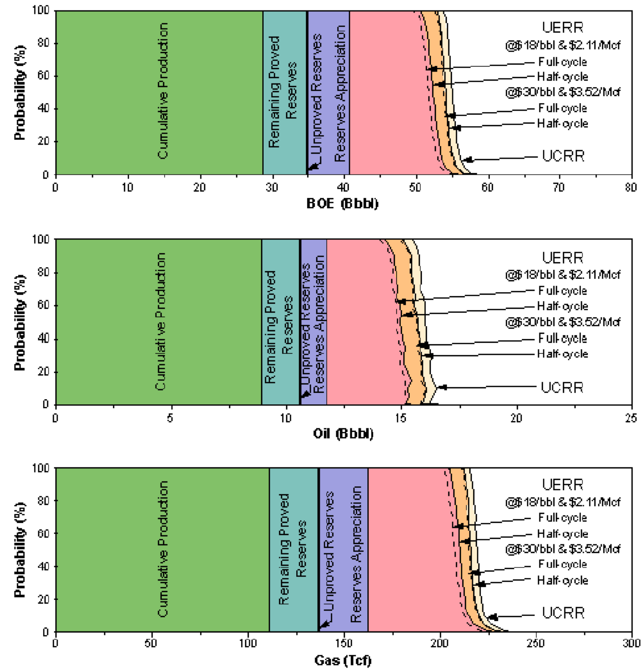

Figure 6. Gulf of Mexico and Atlantic Margin 0-200m Water Depth Total Endowment by Resource Category.

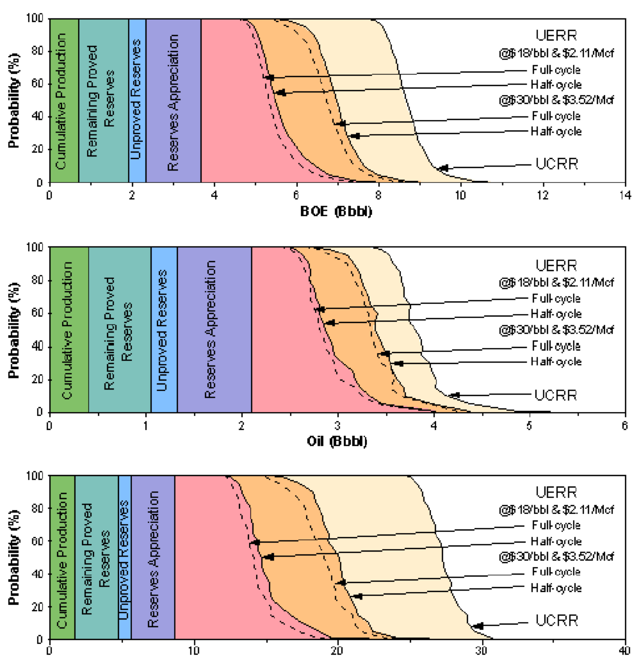

Figure 7. Gulf of Mexico and Atlantic Margin 201-900m Water Depth Total Endowment by Resource Category.

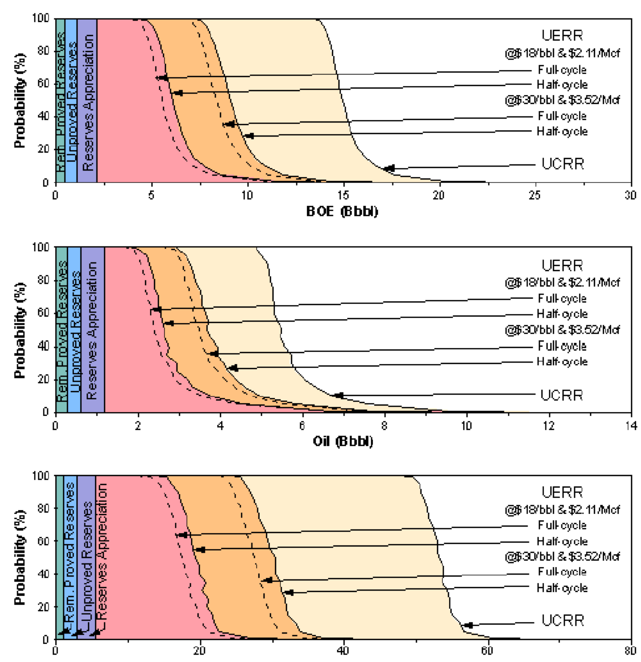

Figure 8. Gulf of Mexico and Atlantic Margin 901-3,000m Water Depth Total Endowment by Resource Category.

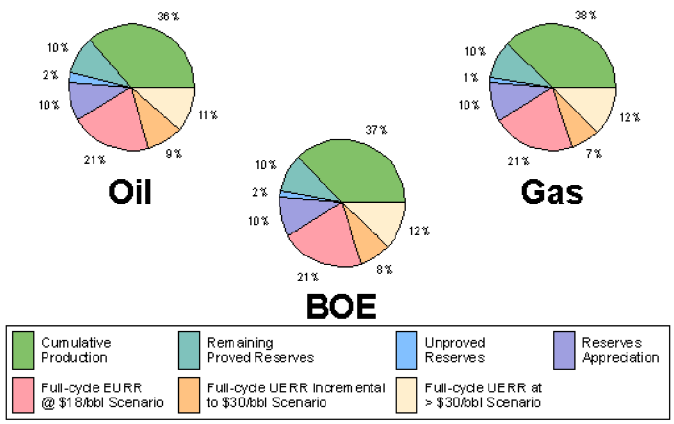

Figure 9. Total Gulf of Mexico and Atlantic Margin Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

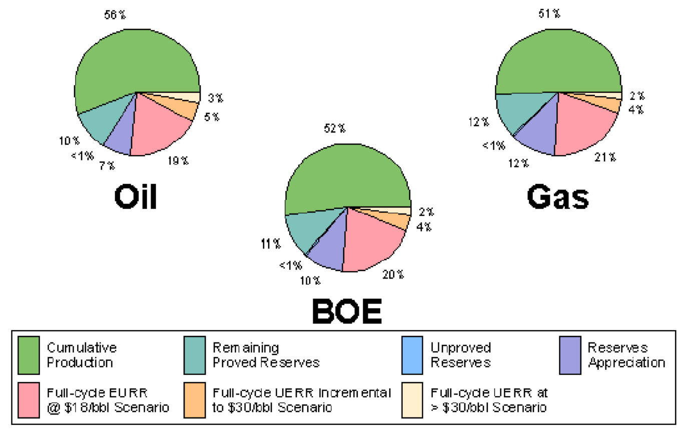

Figure 10. Gulf of Mexico and Atlantic Margin 0-200m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

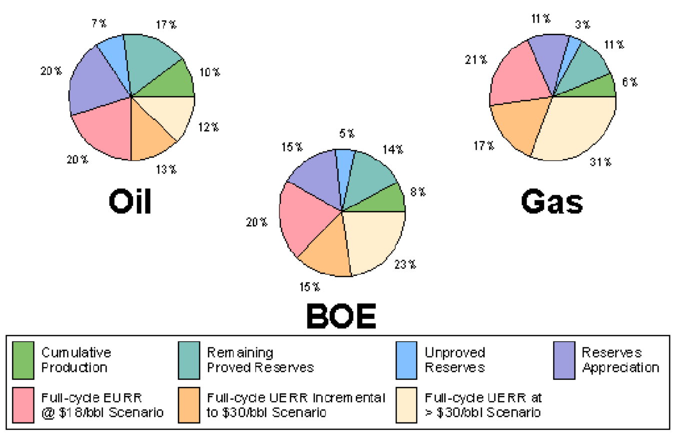

Figure 11. Gulf of Mexico and Atlantic Margin 201-900m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

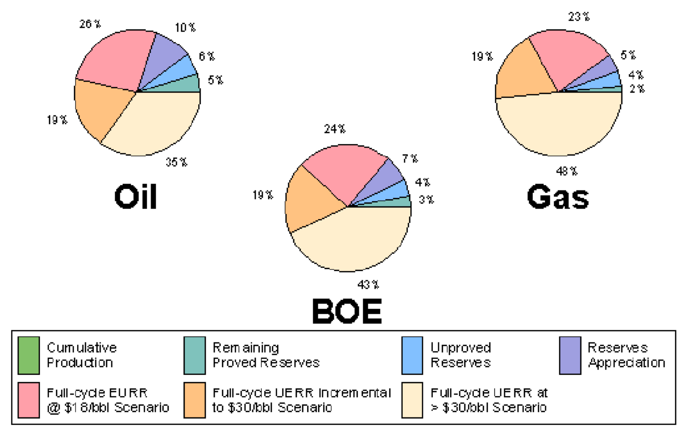

Figure 12. Gulf of Mexico and Atlantic Margin 901-3,000m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

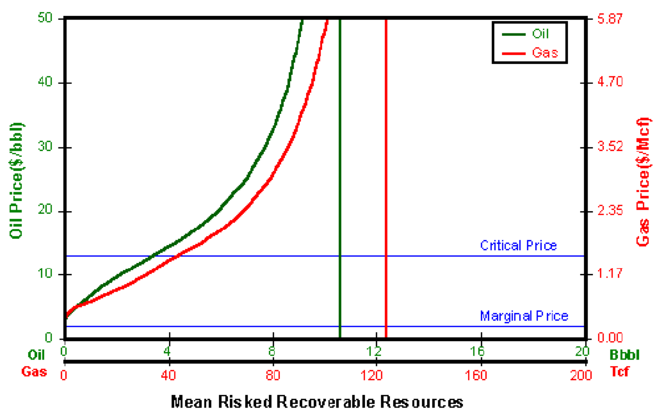

Figure 13. Total Gulf of Mexico and Atlantic Margin Full-Cycle Price-Supply Curve.

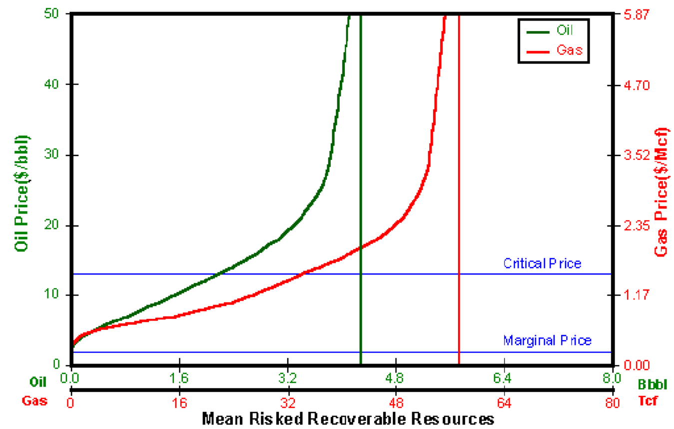

Figure 14. Gulf of Mexico and Atlantic Margin 0-200m Water Depth Full-Cycle Price-Supply Curve.

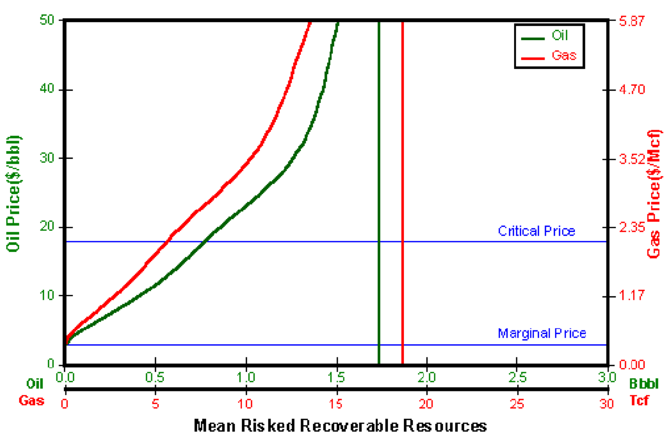

Figure 15. Gulf of Mexico and Atlantic Margin 201-900m Water Depth Full-Cycle Price-Supply Curve.

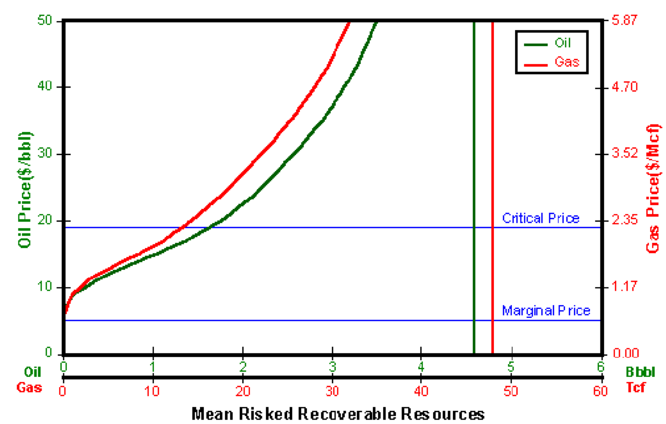

Figure 16. Gulf of Mexico and Atlantic Margin 901-3,000m Water Depth Full-Cycle Price-Supply Curve.

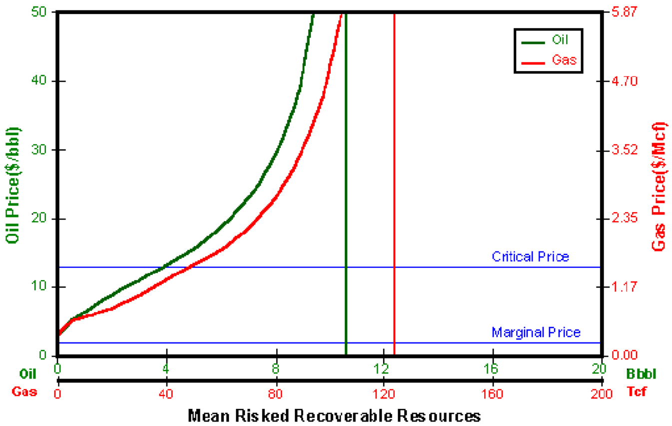

Figure 17. Total Gulf of Mexico and Atlantic Margin Half-Cycle Price-Supply Curve.

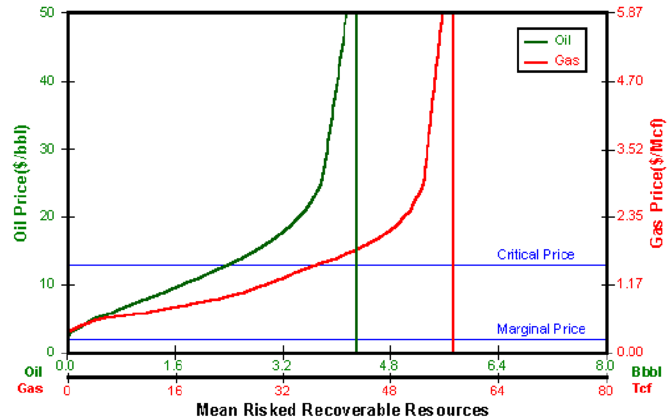

Figure 18. Gulf of Mexico and Atlantic Margin 0-200m Water Depth Half-Cycle Price-Supply Curve.

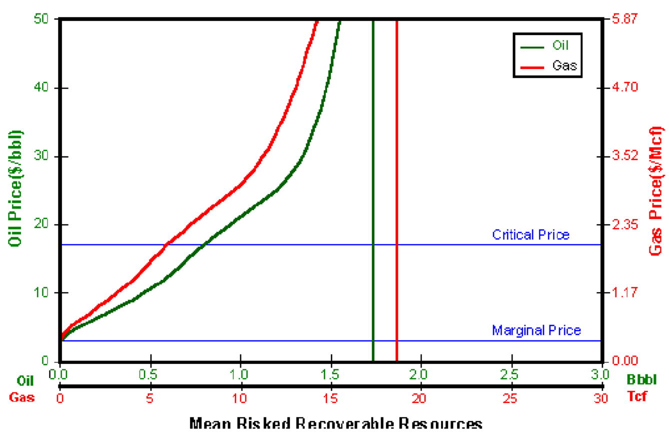

Figure 19. Gulf of Mexico and Atlantic Margin 201-900m Water Depth Half-Cycle Price-Supply Curve.

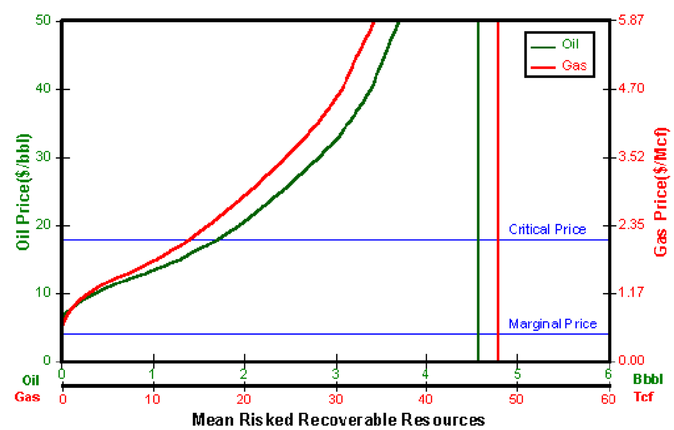

Figure 20. Gulf of Mexico and Atlantic Margin 901-3,000m Water Depth Half-Cycle Price-Supply Curve.

Gulf of Mexico Region Economic Results

The Gulf of Mexico Region includes submerged Federal lands offshore Texas, Louisiana, Mississippi, Alabama, and Florida, and extends to the U.S.-Mexico International Boundary in the west and the U.S.-Cuba International Boundary in the east (figure 1). Water depths in the Region range from very shallow to more than 3,000m. Because water depth and distance from shore have a significant effect on engineering and cost factors, the undiscovered economically recoverable resources (UERR) were evaluated for three water depth ranges, 0-200m, 201-900m, and 901-3,000m (no resources were evaluated in water depths greater than 3,000m).

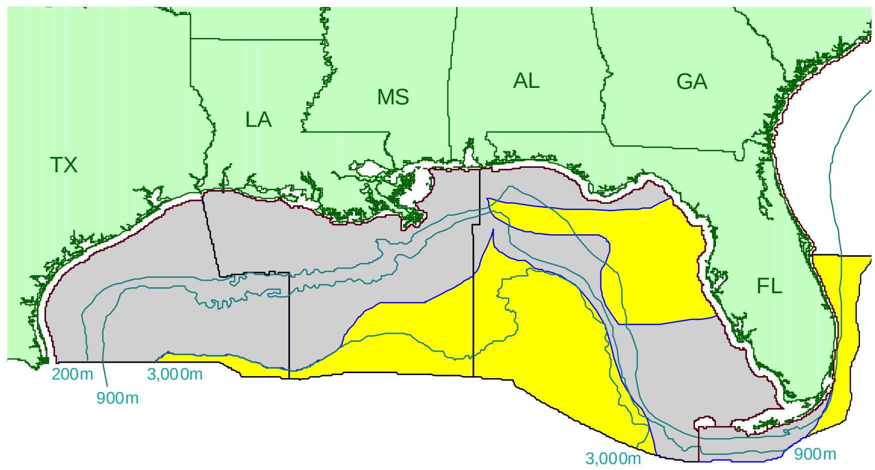

Figure 1. Gulf of Mexico Region Map. The Region is shaded in yellow, and the gray pattern indicates the extent of the assessed plays.

The mean total endowment for this Region is predominantly gas, with 67 percent of the total resources occurring as gas (figure 2). There is a trend towards a less gas-prone bias in the deeper water depths, with the 0-200m water depth range consisting of 71 percent gas, the 201-900m range consisting of 52 percent gas, and the deepest water depth range consisting of 61 percent gas. The largest concentration of the mean total endowment (74% on a barrels-of-oil-equivalent [BOE] basis) occurs in water depths of less than 200m (figure 3 and figure 4). The 201-900m range has roughly 9 percent, and the 901-3,000m range has 17 percent of the BOE mean total endowment.

The Region is well developed in the 0-200m range with an extensive infrastructure already in place, less so in the 201-900m range, and minimally in the 901-3,000m range. There has been production in the two shallower ranges, but as of the date of this study, only proved and unproved reserves and reserves appreciation occurred in the 901-3,000m range (table 1 for Assessment Results Total, table 2 for 0-200m, table 3 for 201-900m, and table 4 for 901-3,000m). Significant amounts of undiscovered conventionally recoverable resources (UCRR) have been assessed for all three water depth ranges, and the full- and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in table 5 (Economic Results Total), table 6 (0-200m), table 7 (201-900m), and table 8 (901-3,000m). These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the three water depth ranges and for the total Region.

Assessment results indicate that the total Region undiscovered economically recoverable resources are notable, with a range of 4.016 to 6.627 Bbo and 53.737 to

62.162 Tcfg at the 95th and 5th percentiles, respectively, for the full-cycle $18/bbl scenario. The mean economically recoverable resources are estimated at 4.941 Bbo and 57.941 Tcfg. A graphical representation of these results, incorporating every 5th-percentile result for UCRR and UERR, is presented in figure 5 (Results Graph Total), figure 6 (0-200m), figure 7 (201-900m), and figure 8 (901-3,000m). These graphs also present the half-cycle $18/bbl, and the full- and half-cycle $30/bbl scenario results. Because the economic model imports field sizes in BOE from the geologic model and then calculates the oil and gas content, the BOE results graph is typically a smooth curve. As expected, the accompanying oil and gas values exhibit more scatter because the gas/oil ratio can vary greatly from one field to another.

The mean total endowment for oil, gas, and BOE by the reserve and resource classification is shown in figure 9 (Mean Endowment Total), figure 10 (0-200m), figure 11 (201-900m), and figure 12 (901-3,000m). The pie charts presented can be used to determine what percentage of oil, gas, or BOE is a result of reserves or of undiscovered resources. For example, only 36 percent of the gas in the Region remains to be discovered, and only 35 percent of the oil remains to be discovered (figure 9). Moreover, 21 percent of the gas, oil, and BOE mean total endowment is remaining to be discovered and is projected to be economically recoverable at the $18/bbl scenario.

Because estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions, they are presented here as price-supply curves. These curves describe a functional relationship between economically recoverable resources and product price and present the estimates of mean undiscovered economically recoverable oil and gas at any starting oil price up to $50/bbl. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the ***General Text, Methodology, UERR (Economically Recoverable), Detailed Discussion*** section. 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 are the mean curves. The full-cycle price-supply curves are shown in figure 13 (Full-Cycle P-S Curve Total), figure 14 (0-200m), figure 15 (201-900m), and figure 16 (901-3,000m). The half-cycle price-supply curves are shown in figure 17 (Half-Cycle P-S Curve Total), figure 18 (0-200m), figure 19 (201-900m), and figure 20 (901-3,000m).

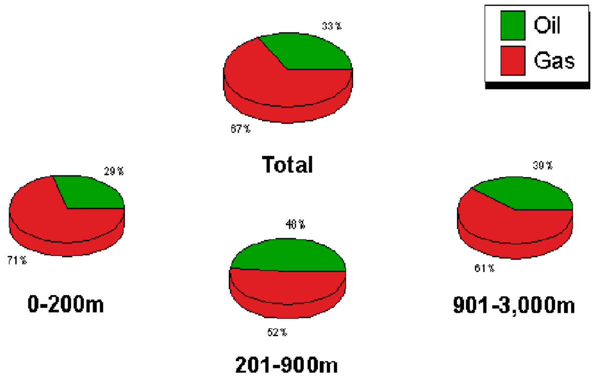

Figure 4 Gulf of Mexico Region Percent Oil or Gas by Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

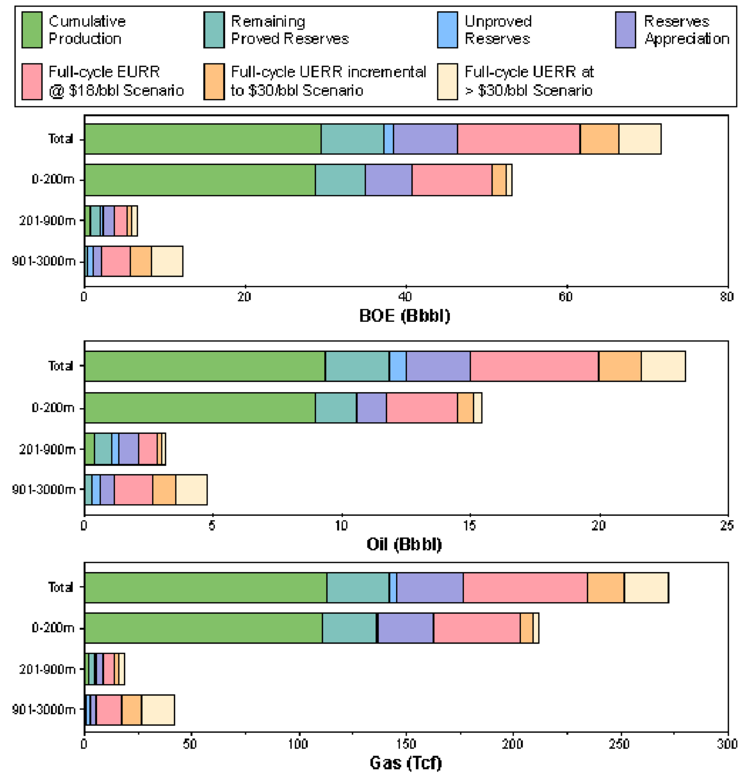

Figure 2. Gulf of Mexico Region Mean Total Endowment by Water Depth Category.

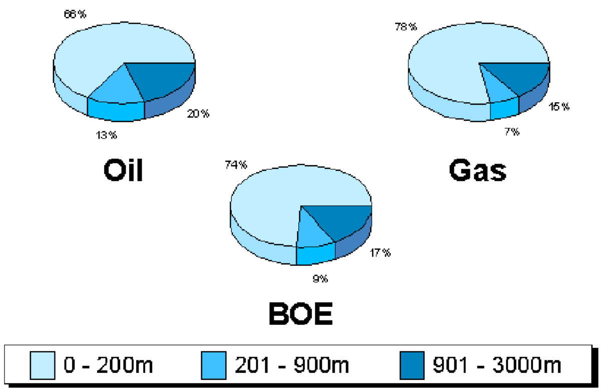

Figure 3. Gulf of Mexico Region Mean Total Endowment by Resource Type and Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

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 1. Total Gulf of Mexico Region Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	10.534	136.232	34.775
Cumulative production	8.938	110.943	28.678
Remaining proved	1.597	25.289	6.096
Unproved	0.033	0.761	0.168
Appreciation (P & U)	1.172	25.375	5.687
Undiscovered Conventionally Recoverable Resources			
95th percentile	3.296	47.936	11.825
Mean	3.712	49.331	12.490
5th percentile	4.178	50.721	13.203
Total Endowment			
95th percentile	15.035	210.304	52.456
Mean	15.452	211.699	53.120
5th percentile	15.918	213.089	53.834

Table 2. Gulf of Mexico Region 0-200m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	1.043	4.753	1.889
Cumulative production	0.400	1.689	0.701
Remaining proved	0.643	3.064	1.188
Unproved	0.281	0.874	0.437
Appreciation (P & U)	0.778	3.044	1.320
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.825	9.105	2.445
Mean	1.033	10.208	2.849
5th percentile	1.355	11.628	3.424
Total Endowment			
95th percentile	2.927	17.776	6.090
Mean	3.135	18.879	6.494
5th percentile	3.457	20.299	7.069

Table 3. Gulf of Mexico Region 201-900m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.276	0.905	0.437
Cumulative production	0.000	0.000	0.000
Remaining proved	0.276	0.905	0.437
Unproved	0.324	1.969	0.675
Appreciation (P & U)	0.557	2.609	1.022
Undiscovered Conventionally Recoverable Resources			
95th percentile	2.955	34.152	9.032
Mean	3.593	36.513	10.090
5th percentile	5.367	39.420	12.381
Total Endowment			
95th percentile	4.112	39.636	11.165
Mean	4.751	41.996	12.224
5th percentile	6.524	44.903	14.514

Table 4. Gulf of Mexico Region 901-3,000m Water Depth Assessment Results Table.

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		4.016	53.737	13.577
Mean		4.941	57.941	15.251
5th percentile		6.627	62.162	17.688
Half-Cycle	1.00			
95th percentile		4.350	58.428	14.747
Mean		5.306	62.300	16.391
5th percentile		6.967	66.495	18.799
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		5.697	71.606	18.439
Mean		6.639	75.298	20.038
5th percentile		8.241	79.251	22.343
Half-Cycle	1.00			
95th percentile		5.963	74.379	19.197
Mean		6.865	78.100	20.762
5th percentile		8.485	81.964	23.069

Table 5. Total Gulf of Mexico Region Economic Assessment Results Table.

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		2.374	38.807	9.279
Mean		2.771	40.722	10.017
5th percentile		3.186	42.653	10.775
Half-Cycle	1.00			
95th percentile		2.497	41.085	9.808
Mean		2.901	42.859	10.527
5th percentile		3.322	44.855	11.304
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		2.980	45.136	11.012
Mean		3.368	46.745	11.686
5th percentile		3.856	48.159	12.425
Half-Cycle	1.00			
95th percentile		3.018	45.852	11.177
Mean		3.423	47.318	11.843
5th percentile		3.905	48.730	12.575

Table 6. Gulf of Mexico Region 0-200m Water Depth Economic Assessment Results Table.

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		0.476	3.859	1.162
Mean		0.701	5.200	1.626
5th percentile		1.030	6.817	2.243
Half-Cycle	1.00			
95th percentile		0.513	4.381	1.292
Mean		0.736	5.633	1.739
5th percentile		1.056	7.383	2.369
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.651	5.993	1.718
Mean		0.870	7.244	2.159
5th percentile		1.196	8.747	2.752
Half-Cycle	1.00			
95th percentile		0.672	6.358	1.803
Mean		0.892	7.602	2.245
5th percentile		1.205	9.166	2.836

Table 7. Gulf of Mexico Region 201-900m Water Depth Economic Assessment Results Table.

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		0.830	8.627	2.365
Mean		1.477	12.053	3.621
5th percentile		3.170	15.275	5.888
Half-Cycle	1.00			
95th percentile		1.008	10.665	2.906
Mean		1.670	13.822	4.130
5th percentile		3.360	16.857	6.360
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		1.731	18.492	5.021
Mean		2.398	21.216	6.173
5th percentile		4.158	24.342	8.490
Half-Cycle	1.00			
95th percentile		1.873	20.385	5.500
Mean		2.545	23.056	6.648
5th percentile		4.303	26.086	8.944

Table 8. Gulf of Mexico Region 901-3,000m Water Depth Economic Assessment Results Table.

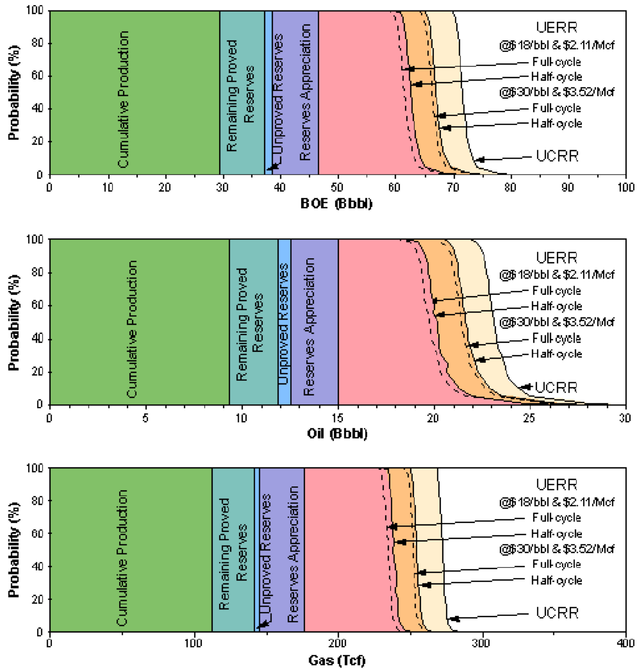

Figure 5. Gulf of Mexico Region Total Endowment by Resource Category.

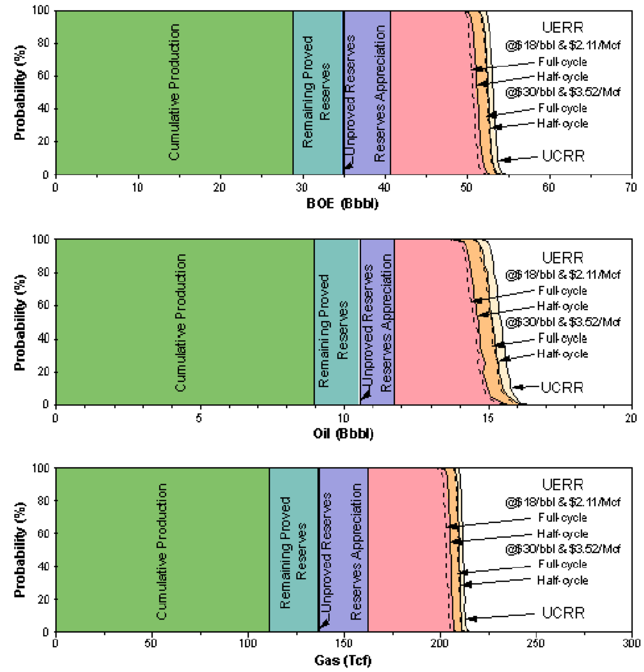

Figure 6. Gulf of Mexico Region 0-200m Water Depth Total Endowment by Resource Category.

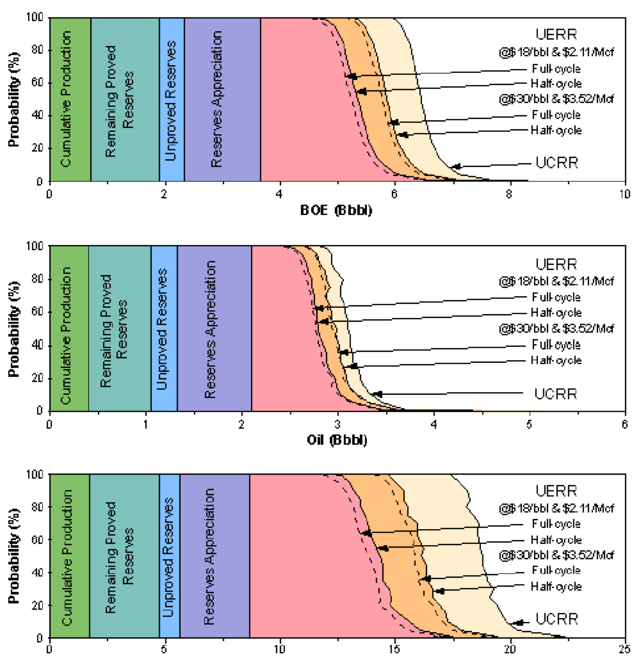

Figure 7. Gulf of Mexico Region 201-900m Water Depth Total Endowment by Resource Category.

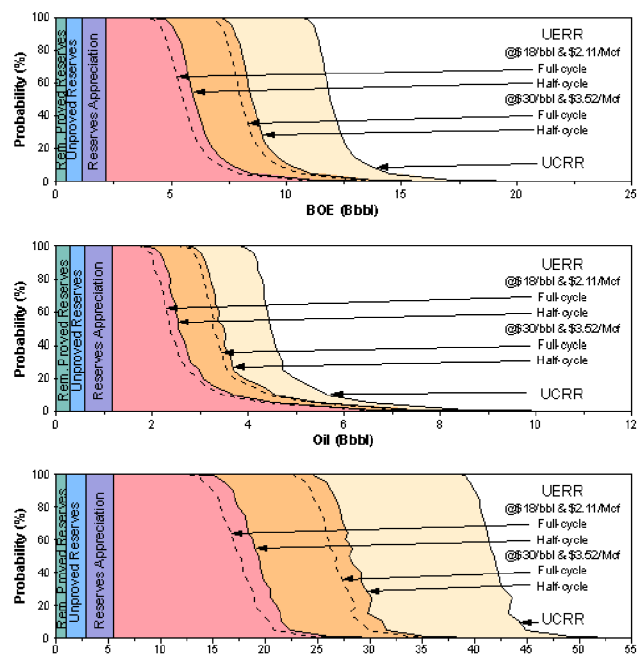

Figure 8. Gulf of Mexico Region 901-3,000m Water Depth Total Endowment by Resource Category.

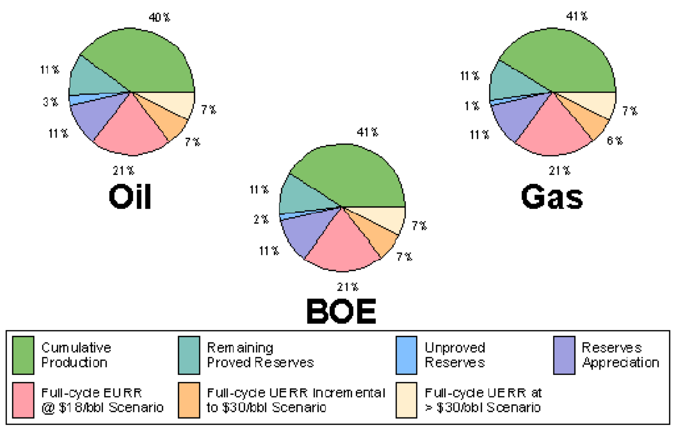

Figure 9. Total Gulf of Mexico Region Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

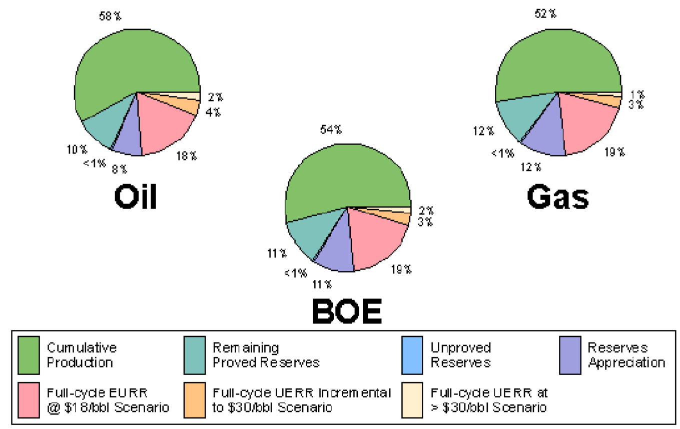

Figure 10. Gulf of Mexico Region 0-200m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

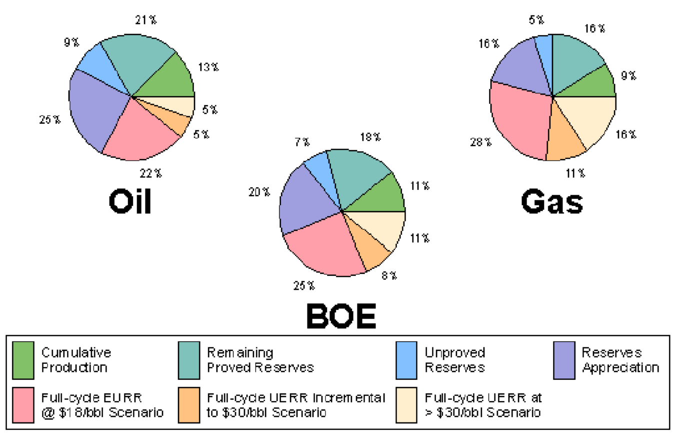

Figure 11. Gulf of Mexico Region 201-900m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

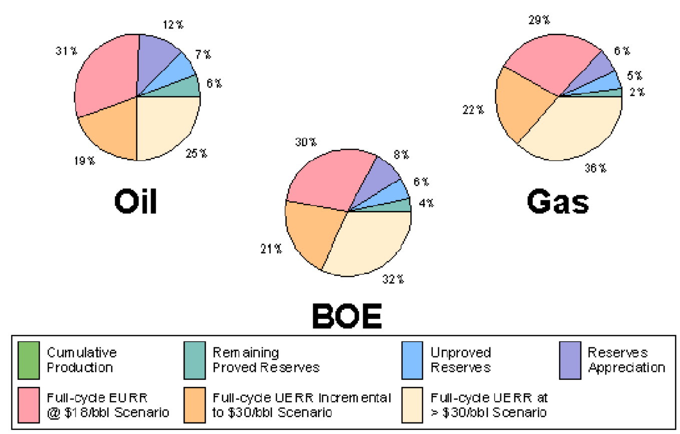

Figure 12. Gulf of Mexico Region 901-3,000m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

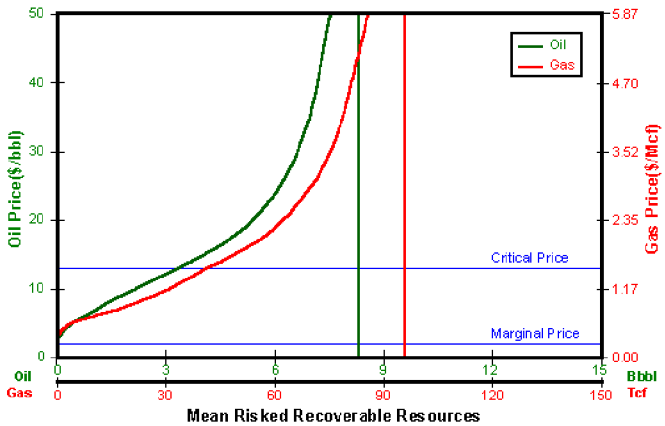

Figure 13. Total Gulf of Mexico Region Full-Cycle Price-Supply Curve.

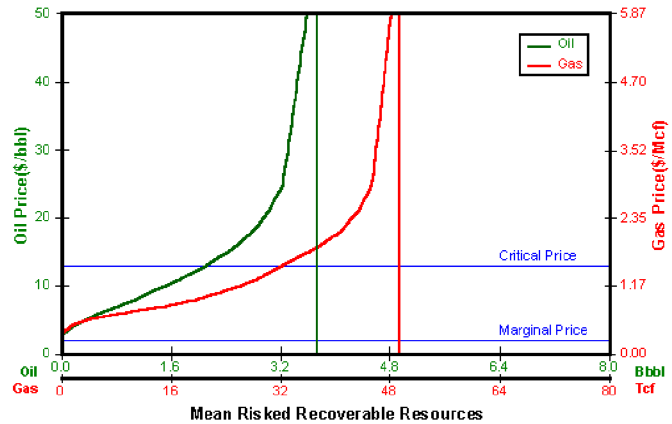

Figure 14. Gulf of Mexico Region 0-200m Water Depth Full-Cycle Price-Supply Curve.

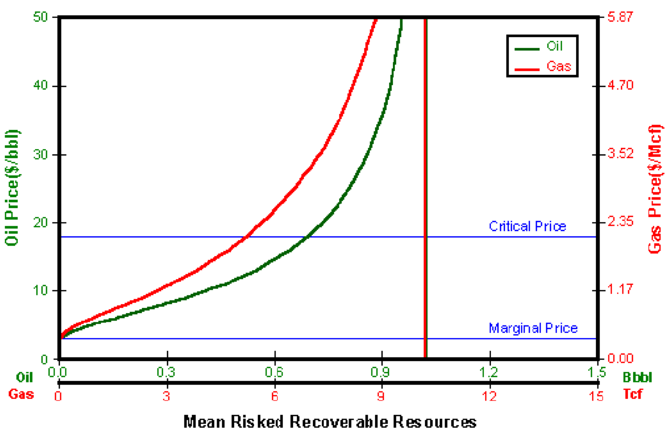

Figure 15. Gulf of Mexico Region 201-900m Water Depth Full-Cycle Price-Supply Curve.

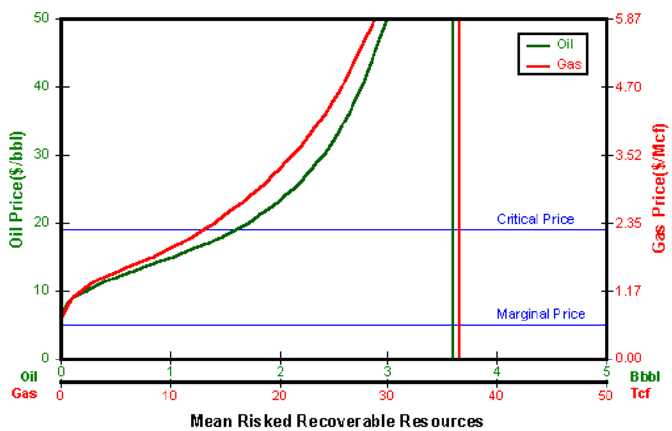

Figure 16. Gulf of Mexico Region 901-3,000m Water Depth Full-Cycle Price-Supply Curve.

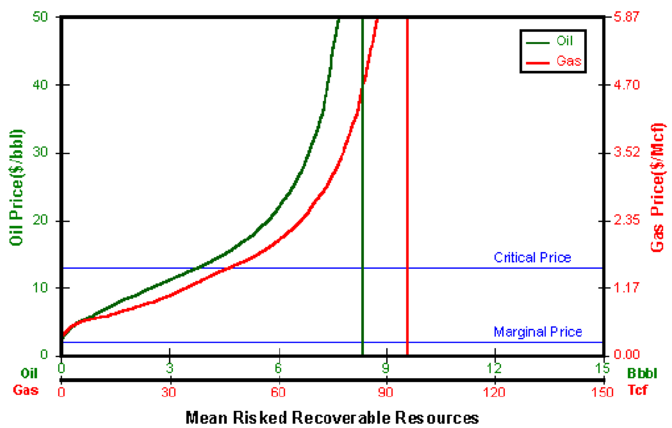

Figure 17. Total Gulf of Mexico Region Half-Cycle Price-Supply Curve.

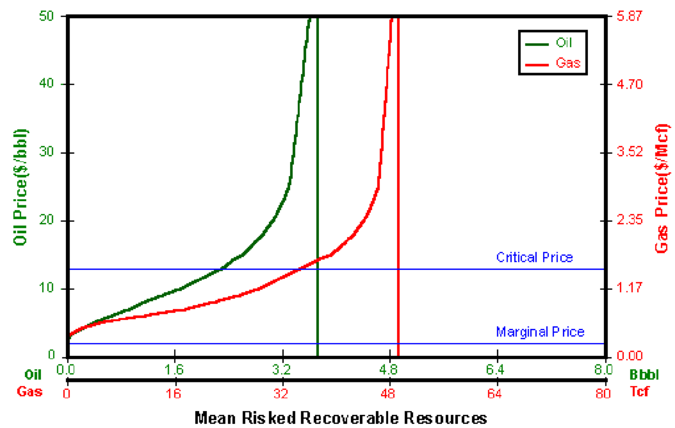

Figure 18. Gulf of Mexico Region 0-200m Water Depth Half-Cycle Price-Supply Curve.

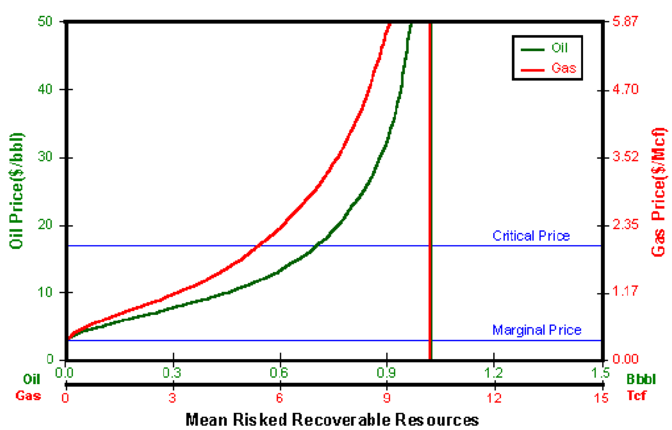

Figure 19. Gulf of Mexico Region 201-900m Water Depth Half-Cycle Price-Supply Curve.

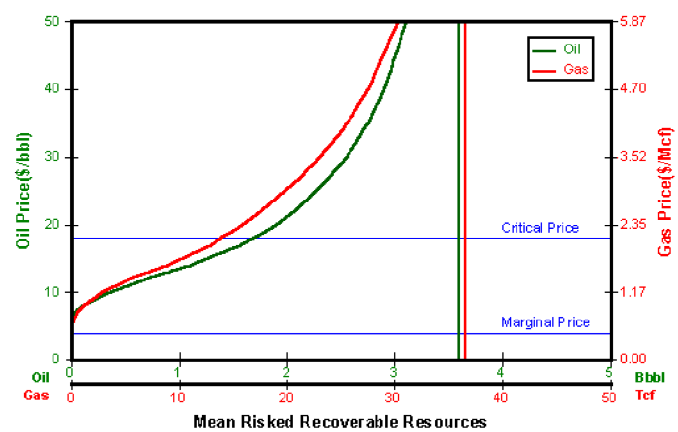

Figure 20. Gulf of Mexico Region 901-3,000m Water Depth Half-Cycle Price-Supply Curve.

Atlantic Region Economic Results

The Atlantic Region includes submerged Federal lands from the U.S.-Canada International Boundary south to offshore Florida (figure 1). Water depths in the Region range from very shallow to more than 3,000m. Because water depth and distance from shore have a significant effect on engineering and cost factors, the undiscovered economically recoverable resources (UERR) were evaluated for three water depth ranges, 0-200m, 201-900m, and 901-3,000m (no resources were evaluated in water depths greater than 3,000m).

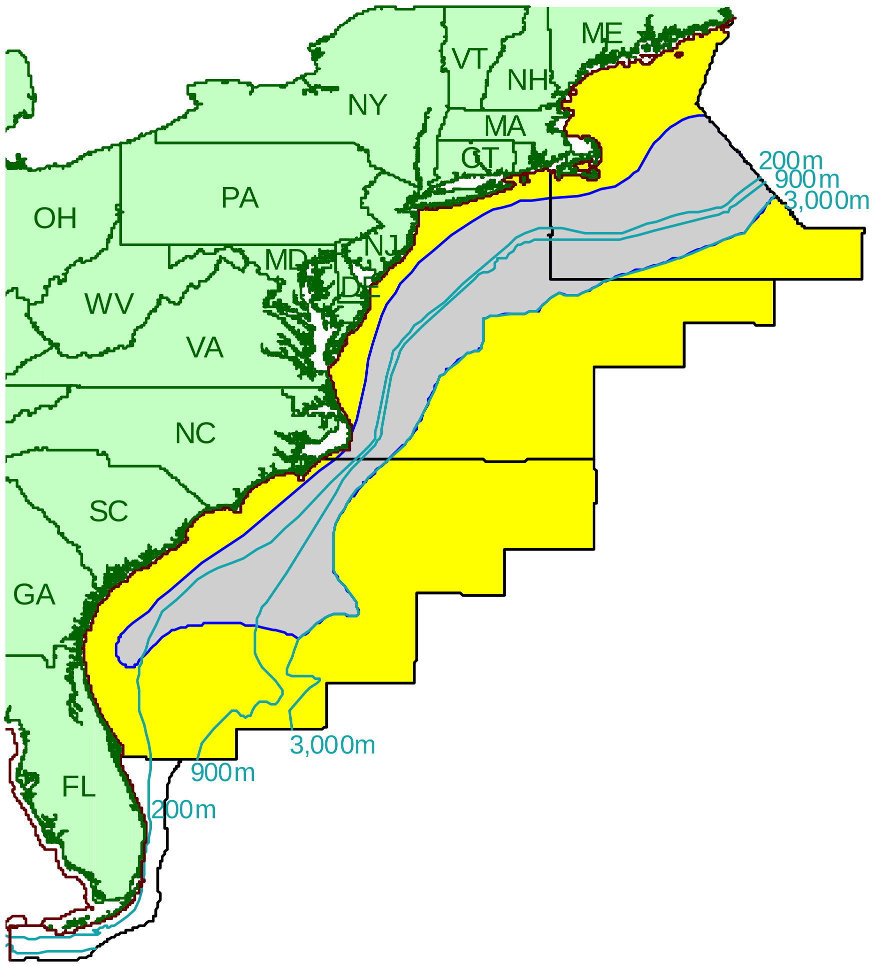

Figure 1. Atlantic Region Map. The Region is shaded in yellow, and the gray pattern indicates the extent of the assessed plays.

The mean total endowment for this Region is predominantly gas, with 68 percent of the total resources occurring as gas (figure 2). There is a very slight trend towards a less gas-prone bias in the deeper water depths, with the 0-200m water depth range consisting of 71 percent gas, the 201-900m range consisting of 68 percent gas, and the deepest water depth range consisting of 67 percent gas. The largest concentration of the mean total endowment (41% on a barrels-of-oil-equivalent [BOE] basis) occurs in water depths of more than 900m (figure 3 and figure 4). Each of the other two water depth ranges have 28 to 31 percent of the BOE mean total endowment.

The Region is not developed in any of the water depth ranges, and there is no infrastructure in place. As of the date of this study, there has been no production or reserves in any of the ranges (table 1 for Assessment Results Total, table 2 for 0-200m, table 3 for 201-900m, and table 4 for 901-3,000m). Undiscovered conventionally recoverable resources (UCRR) have been assessed for all three water depth ranges, and the full- and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in table 5 (Economic Results Total), table 6 (0-200m), table 7 (201-900m), and table 8 (901-3,000m). These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the three water depth ranges and for the total Region.

Assessment results indicate that the total Region undiscovered economically recoverable resources are modest, with a range of 0.000 to 0.808 Bbo and 0.000 to 11.688 Tcfg at the 95th and 5th percentiles, respectively, for the full-cycle $18/bbl scenario. The mean economically recoverable resources are estimated at 0.368 Bbo and 5.203 Tcfg. A graphical representation of these results, incorporating every 5th- percentile result for UCRR and UERR, is presented in figure 5 (Results Graph Total), figure 6 (0-200m), figure 7 (201-900m), and figure 8 (901-3,000m). These graphs also present the half-cycle $18/bbl, and the full- and half-cycle $30/bbl scenario results. Because the economic model imports field sizes in BOE from the geologic model and then calculates the oil and gas content, the BOE results graph is typically a smooth curve. As expected, the accompanying oil and gas values exhibit more scatter because the gas/oil ratio can vary greatly from one field to another.

The mean total endowment for oil, gas, and BOE by the reserve and resource classification is shown in figure 9 (Mean Endowment Total), figure 10 (0-200m), figure 11 (201-900m), and figure 12 (901-3,000m). The pie charts presented can be used to determine what percentage of oil, gas, or BOE is a result of reserves or of undiscovered resources. For example, all of the oil and gas in the Region remains to be discovered, and only 19 percent of the gas and 16 percent of the oil are projected to be economically recoverable at the $18/bbl scenario (figure 9). Therefore, 18 percent of the mean total endowment, on a BOE basis, is remaining to be discovered and is projected to be economically recoverable at the $18/bbl scenario.

Because estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions, they are presented here as price-supply curves. These curves describe a functional relationship between economically recoverable resources and product price and present the estimates of mean undiscovered economically recoverable oil and gas at any starting oil price up to $50/bbl. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the ***General Text, Methodology, UERR (Economically Recoverable), Detailed Discussion*** section. 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 are the mean curves. The full-cycle price-supply curves are shown in figure 13 (Full-Cycle P-S Curve Total), figure 14 (0-200m), figure 15 (201-900m), and figure 16 (901-3,000m). The half-cycle price-supply curves are shown in figure 17 (Half-Cycle P-S Curve Total), figure 18 (0-200m), figure 19 (201-900m), and figure 20 (901-3,000m).

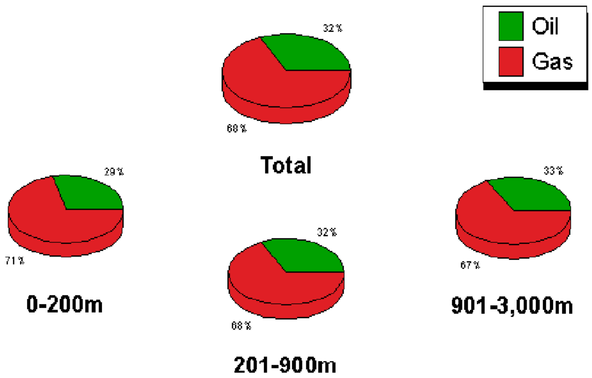

Figure 2. Atlantic Region Percent Oil or Gas by Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

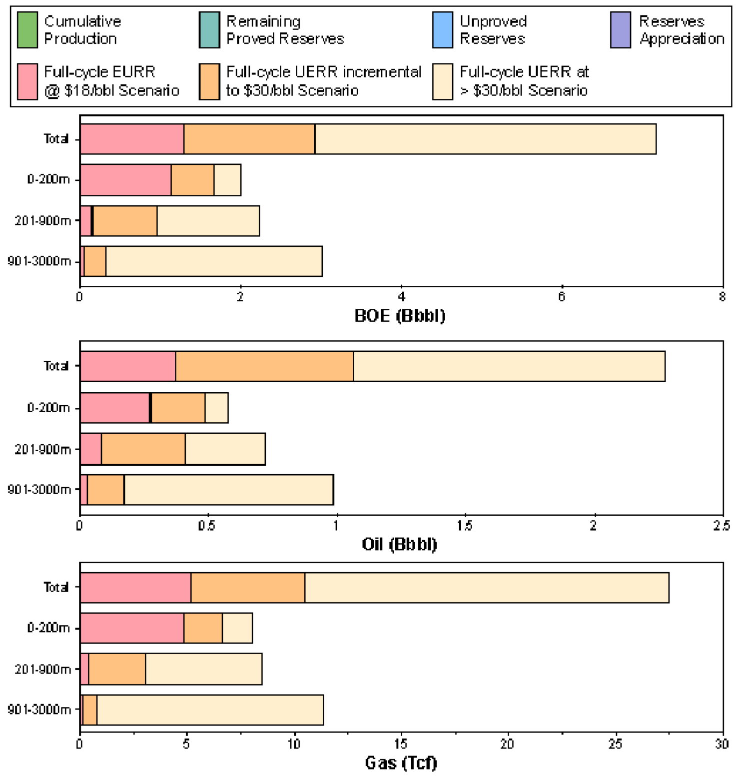

Figure 3. Atlantic Region Mean Total Endowment by Water Depth Category.

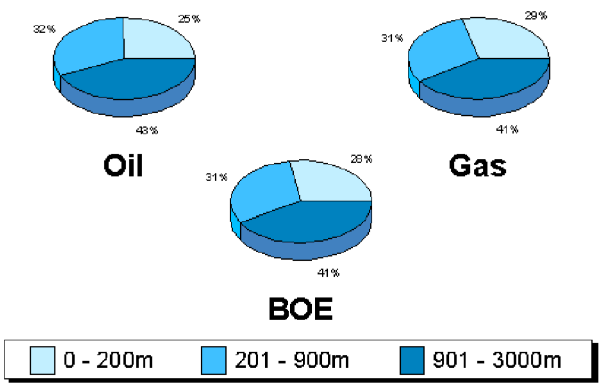

Figure 4. Atlantic Region Mean Total Endowment by Resource Type and Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

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 1. Total Atlantic Region Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.418	4.790	1.271
Mean	0.576	8.004	2.000
5th percentile	0.669	14.557	3.259
Total Endowment			
95th percentile	0.418	4.790	1.271
Mean	0.576	8.004	2.000
5th percentile	0.669	14.557	3.259

Table 2. Atlantic Region 0-200m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.524	6.994	1.769
Mean	0.722	8.512	2.236
5th percentile	0.995	10.519	2.867
Total Endowment			
95th percentile	0.524	6.994	1.769
Mean	0.722	8.512	2.236
5th percentile	0.995	10.519	2.867

Table 3. Atlantic Region 201-900m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.087	0.223	0.127
Mean	0.191	0.359	0.255
5th percentile	0.371	0.529	0.465
Total Endowment			
95th percentile	0.087	0.223	0.127
Mean	0.191	0.359	0.255
5th percentile	0.371	0.529	0.465

Table 4. Atlantic Region 901-3,000m Water Depth Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.92			
95th percentile		0.000	0.000	0.000
Mean		0.368	5.203	1.294
5th percentile		0.808	11.688	2.888
Half-Cycle	0.97			
95th percentile		0.125	1.154	0.331
Mean		0.452	5.989	1.518
5th percentile		0.910	12.404	3.118
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.587	5.855	1.628
Mean		1.063	10.479	2.927
5th percentile		1.644	16.444	4.570
Half-Cycle	1.00			
95th percentile		0.788	7.242	2.076
Mean		1.234	11.966	3.363
5th percentile		1.854	17.661	4.997

Table 5. Total Atlantic Region Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.90			
95th percentile		0.000	0.000	0.000
Mean		0.274	4.810	1.129
5th percentile		0.427	12.027	2.567
Half-Cycle	0.94			
95th percentile		0.037	0.378	0.105
Mean		0.313	5.279	1.252
5th percentile		0.447	12.398	2.653
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.338	3.361	0.936
Mean		0.486	6.653	1.669
5th percentile		0.578	13.179	2.923
Half-Cycle	1.00			
95th percentile		0.346	3.600	0.987
Mean		0.499	6.848	1.718
5th percentile		0.586	13.395	2.970

Table 6. Atlantic Region 0-200m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.22			
95th percentile		0.000	0.000	0.000
Mean		0.083	0.375	0.150
5th percentile		0.449	2.933	0.971
Half-Cycle	0.31			
95th percentile		0.000	0.000	0.000
Mean		0.118	0.652	0.234
5th percentile		0.519	3.629	1.165
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.95			
95th percentile		0.044	0.209	0.081
Mean		0.408	3.047	0.950
5th percentile		0.740	5.276	1.679
Half-Cycle	0.98			
95th percentile		0.225	1.514	0.495
Mean		0.463	3.622	1.108
5th percentile		0.809	5.648	1.814

Table 7. Atlantic Region 201-900m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.05			
95th percentile		0.000	0.000	0.000
Mean		0.026	0.104	0.045
5th percentile		0.146	0.656	0.262
Half-Cycle	0.08			
95th percentile		0.000	0.000	0.000
Mean		0.040	0.157	0.068
5th percentile		0.311	1.381	0.557
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.42			
95th percentile		0.000	0.000	0.000
Mean		0.173	0.798	0.315
5th percentile		0.638	3.572	1.273
Half-Cycle	0.63			
95th percentile		0.000	0.000	0.000
Mean		0.277	1.505	0.545
5th percentile		0.759	4.446	1.551

Table 8. Atlantic Region 901-3,000m Water Depth Economic Assessment Results Table.

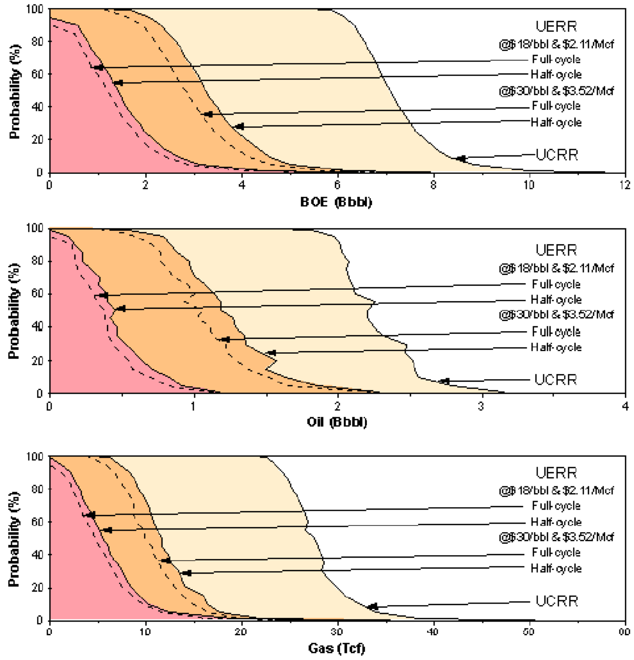

Figure 5. Atlantic Region Total Endowment by Resource Category.

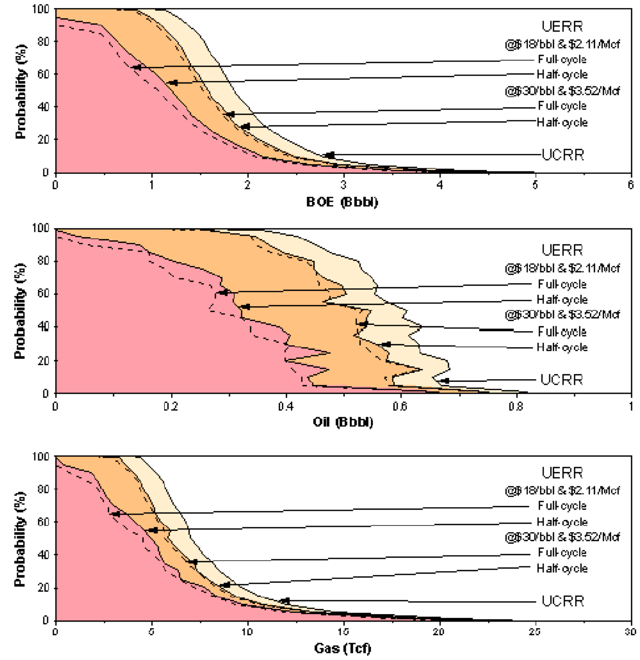

Figure 6. Atlantic Region 0-200m Water Depth Total Endowment by Resource Category.

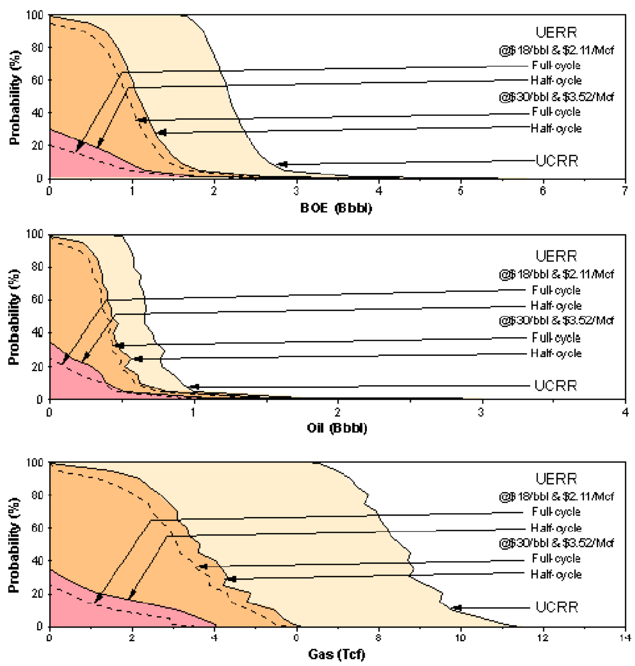

Figure 7. Atlantic Region 201-900m Water Depth Total Endowment by Resource Category.

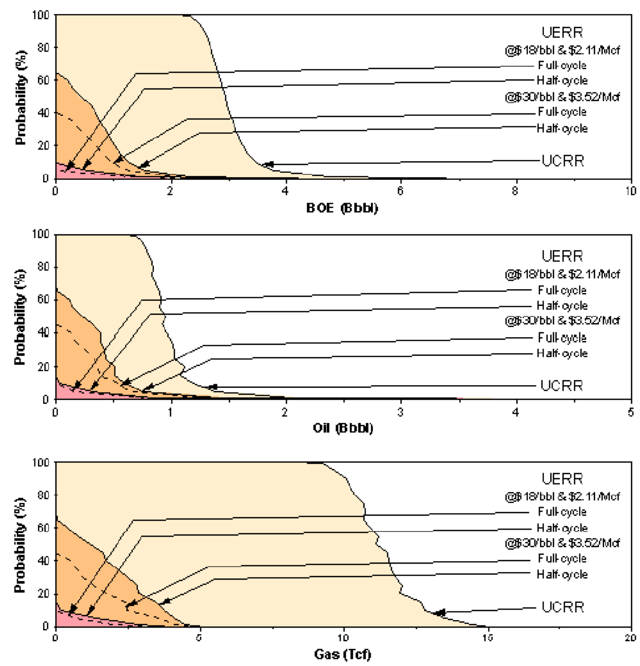

Figure 8. Atlantic Region 901-3,000m Water Depth Total Endowment by Resource Category.

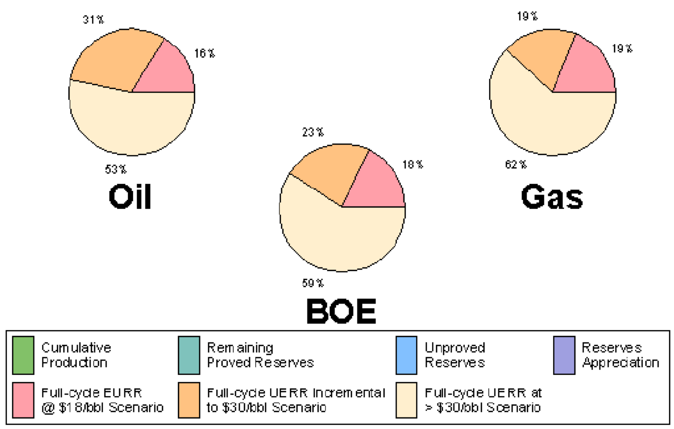

Figure 9. Total Atlantic Region Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

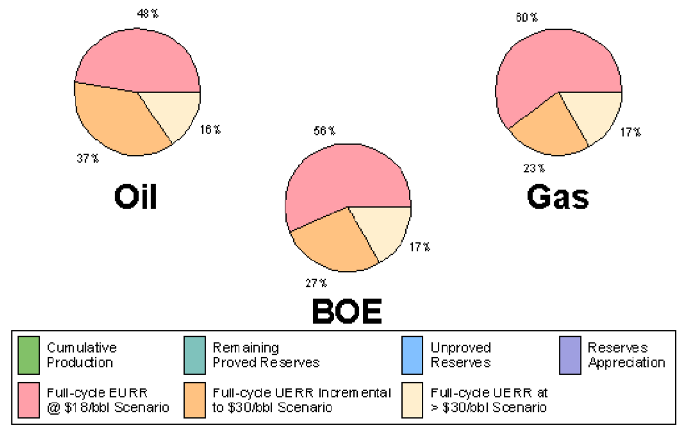

Figure 10. Atlantic Region 0-200m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

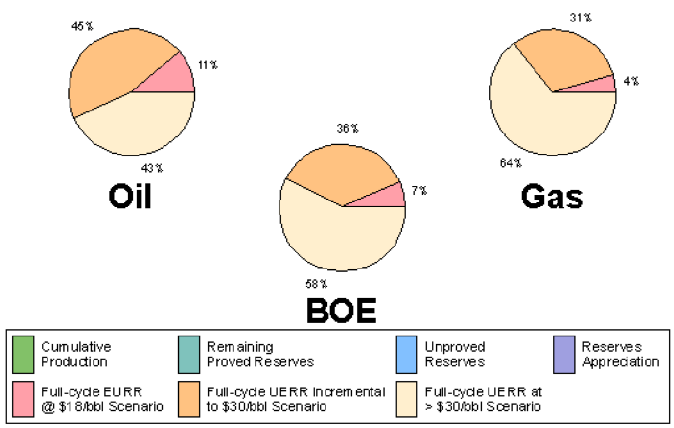

Figure 11. Atlantic Region 201-900m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

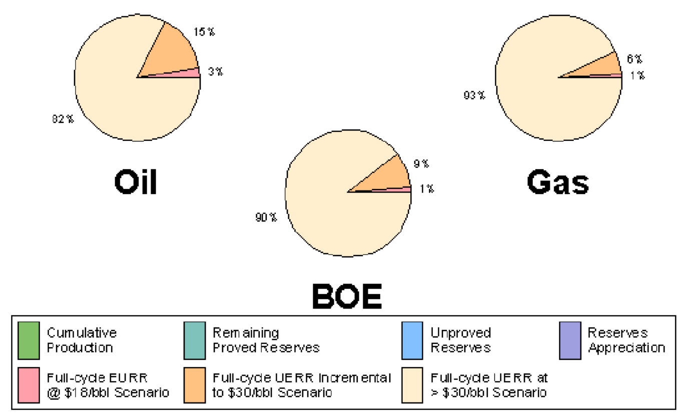

Figure 12. Atlantic Region 901-3,000m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

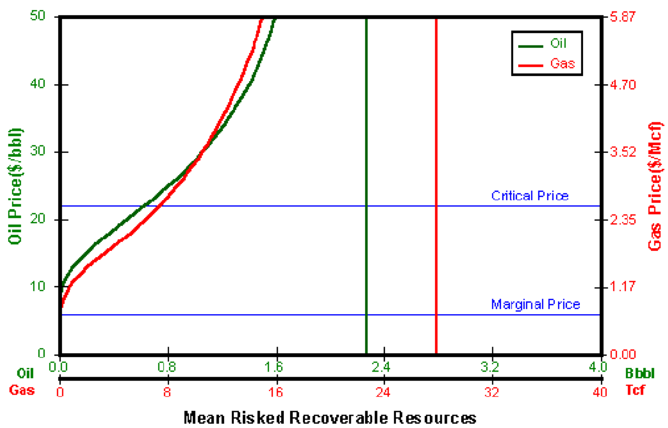

Figure 13. Total Atlantic Region Full-Cycle Price-Supply Curve.

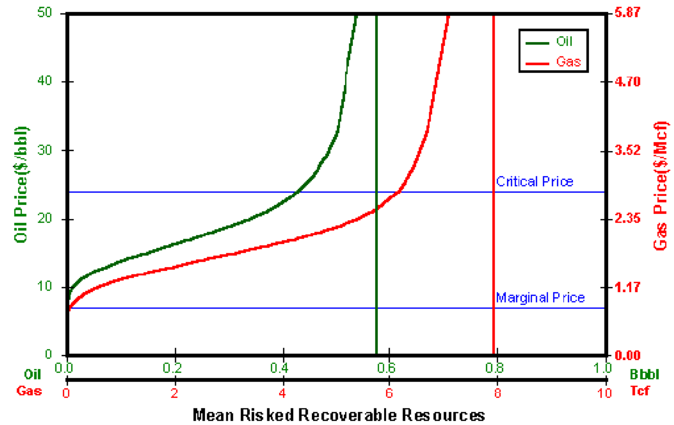

Figure 14. Atlantic Region 0-200m Water Depth Full-Cycle Price-Supply Curve.

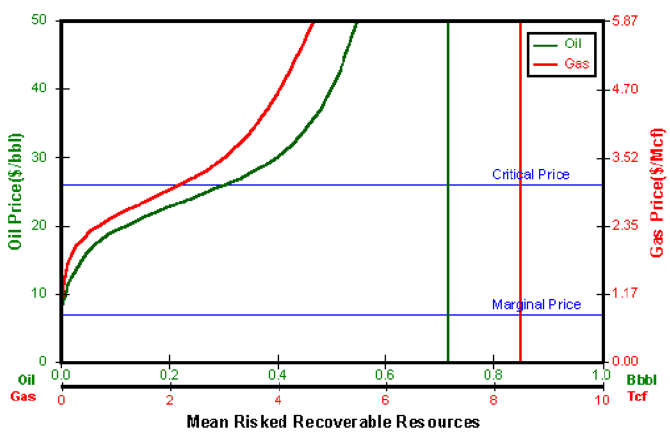

Figure 15. Atlantic Region 201-900m Water Depth Full-Cycle Price-Supply Curve.

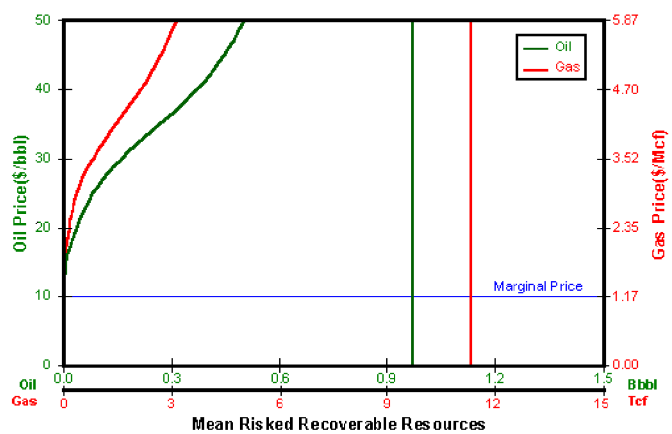

Figure 16. Atlantic Region 901-3,000m Water Depth Full-Cycle Price-Supply Curve.

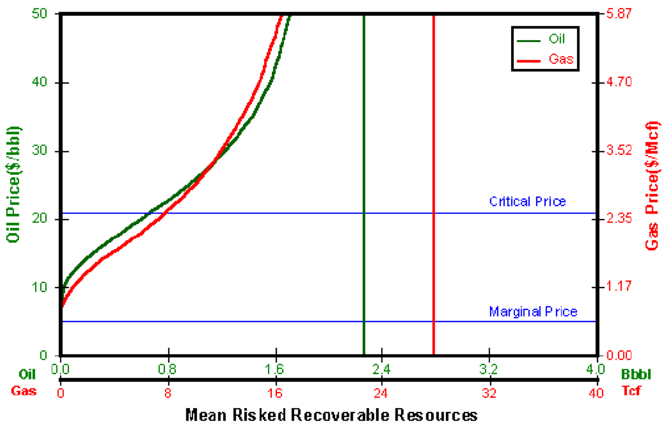

Figure 17. Total Atlantic Region Half-Cycle Price-Supply Curve.

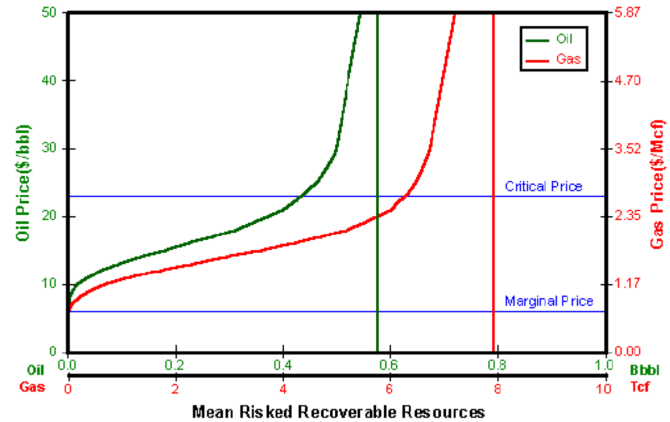

Figure 18. Atlantic Region 0-200m Water Depth Half-Cycle Price-Supply Curve.

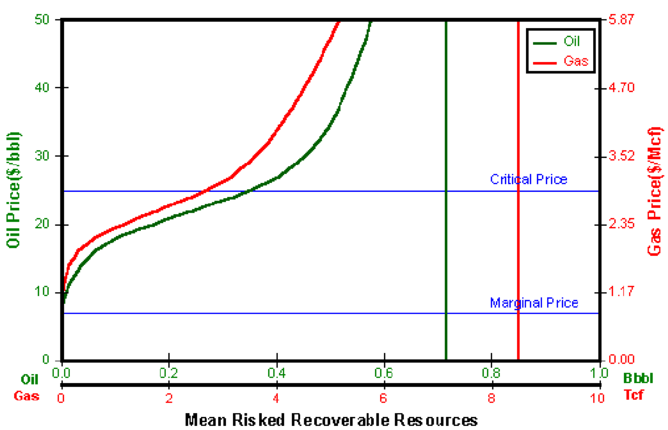

Figure 19. Atlantic Region 201-900m Water Depth Half-Cycle Price-Supply Curve.

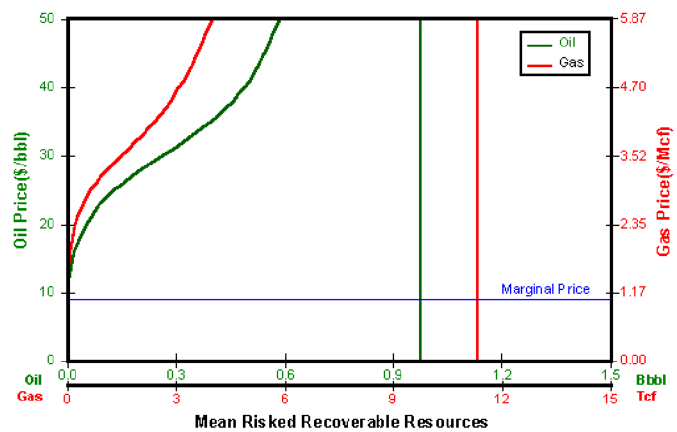

Figure 20. Atlantic Region 901-3,000m Water Depth Half-Cycle Price-Supply Curve.

Gulf of Mexico Cenozoic Province Economic Results

The Gulf of Mexico Cenozoic Province includes submerged Federal lands offshore Texas, Louisiana, Mississippi, and Alabama, and extends to the U.S.-Mexico International Boundary in the west (figure 1). Water depths in the Province range from very shallow to more than 3,000m. Because water depth and distance from shore have a significant effect on engineering and cost factors, the undiscovered economically recoverable resources (UERR) were evaluated for three water depth ranges, 0-200m, 201-900m, and 901-3,000m (no resources were evaluated in water depths greater than 3,000m).

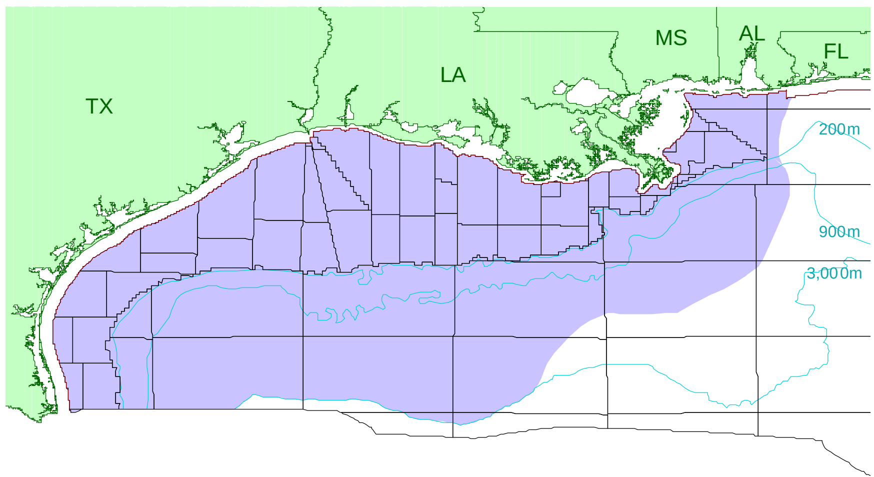

Figure 1. Gulf of Mexico Cenozoic Province Map. The shaded areas indicate the extent of the assessed plays in the Province.

The mean total endowment for this Province is predominantly gas, with 69 percent of the total resources occurring as gas (figure 2). There is a slight trend towards a less gas-prone bias in the deeper water depths, with the 0-200m water depth range consisting of 72 percent gas, the 201-900m range consisting of 53 percent gas, and the deepest water depth range consisting of 62 percent gas. The largest concentration of the mean total endowment (73% on a barrels-of-oil-equivalent [BOE] basis) occurs in water depths of less than 200m (figure 3 and figure 4). The 201-900m range has roughly 9 percent, and the 901-3,000m range has 18 percent of the BOE mean total endowment.

The Province is well developed in the 0-200m range with an extensive infrastructure already in place, less so in the 201-900m range, and minimally in the 901-3,000m range. There has been production in the two shallower ranges, but as of the date of this study, only proved and unproved reserves and reserves appreciation occurred in the 901-3,000m range (table 1 for Assessment Results Total, table 2 for 0-200m, table 3 for 201-900m, and table 4 for 901-3,000m). Significant amounts of undiscovered conventionally recoverable resources (UCRR) have been assessed for all three water depth ranges, and the full- and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in table 5 (Economic Results Total), table 6 (0-200m), table 7 (201-900m), and table 8 (901-3,000m). These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the three water depth ranges and for the total Province.

Assessment results indicate that the total Province undiscovered economically recoverable resources are significant, with a range of 3.005 to 5.338 Bbo and 48.764 to 56.780 Tcfg at the 95th and 5th percentiles, respectively, for the full-cycle $18/bbl scenario. The mean economically recoverable resources are estimated at 3.794 Bbo and 53.028 Tcfg. A graphical representation of these results, incorporating every 5th-percentile result for UCRR and UERR, is presented in figure 5 (Results Graph Total), figure 6 (0-200m), figure 7 (201-900m), and figure 8 (901-3,000m). These graphs also present the half-cycle $18/bbl, and the full- and half-cycle $30/bbl scenario results. Because the economic model imports field sizes in BOE from the geologic model and then calculates the oil and gas content, the BOE results graph is typically a smooth curve. As expected, the accompanying oil and gas values exhibit more scatter because the gas/oil ratio can vary greatly from one field to another.

The mean total endowment for oil, gas, and BOE by the reserve and resource classification is shown in figure 9 (Mean Endowment Total), figure 10 (0-200m), figure 11 (201-900m), and figure 12 (901-3,000m). The pie charts presented can be used to determine what percentage of oil, gas, or BOE is a result of reserves or of undiscovered resources. For example, only 34 percent of the gas in the Province remains to be discovered, and less than 30 percent of the oil remains to be discovered (figure 9). Moreover, 18 to 20 percent of the gas, oil, and BOE mean total endowment is remaining to be discovered and is projected to be economically recoverable at the $18/bbl scenario.

Because estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions, they are presented here as price-supply curves. These curves describe a functional relationship between economically recoverable resources and product price and present the estimates of mean undiscovered economically recoverable oil and gas at any starting oil price up to $50/bbl. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the ***General Text, Methodology, UERR (Economically Recoverable), Detailed Discussion*** section. 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 are the mean curves. The full-cycle price-supply curves are shown in figure 13 (Full-Cycle P-S Curve Total), figure 14 (0-200m), figure 15 (201-900m), and figure 16 (901-3,000m). The half-cycle price-supply curves are shown in figure 17 (Half-Cycle P-S Curve Total), figure 18 (0-200m), figure 19 (201-900m), and figure 20 (901-3,000m).

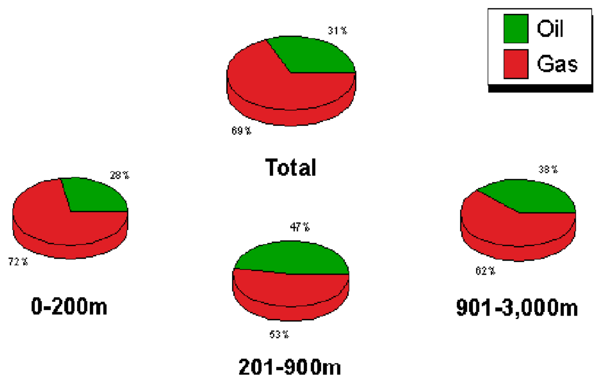

Figure 2. Gulf of Mexico Cenozoic Province Percent Oil or Gas by Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

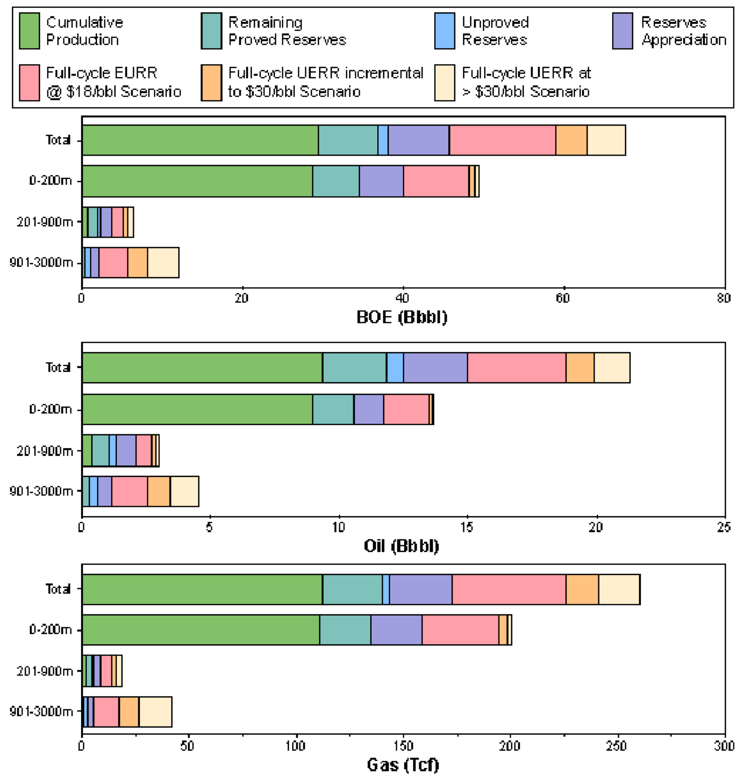

Figure 3. Gulf of Mexico Cenozoic Province Mean Total Endowment by Water Depth Category.

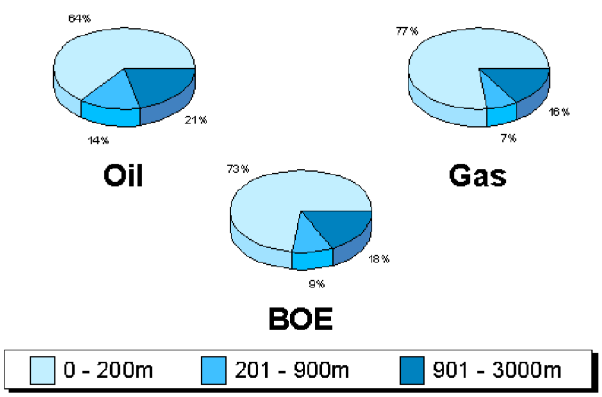

Figure 4. Gulf of Mexico Cenozoic Province Mean Total Endowment by Resource Type and Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	2,105	11.853	140.318	36.821
Cumulative production	--	9.337	112.434	29.344
Remaining proved	--	2.516	27.884	7.477
Unproved	67	0.638	3.006	1.172
Appreciation (P & U)	--	2.505	29.389	7.735
Undiscovered Conventionally Recoverable Resources				
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
Total Endowment				
95th percentile	--	19.424	247.479	63.927
Mean	3,966	21.287	260.266	67.598
5th percentile	--	23.580	274.352	71.705

Table 1. Total Gulf of Mexico Cenozoic Province Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	10.534	134.660	34.495
Cumulative production	8.938	110.745	28.643
Remaining proved	1.597	23.914	5.852
Unproved	0.032	0.164	0.061
Appreciation (P & U)	1.170	23.735	5.394
Undiscovered Conventionally Recoverable Resources			
95th percentile	1.747	40.131	8.888
Mean	1.934	41.759	9.365
5th percentile	2.132	43.618	9.893
Total Endowment			
95th percentile	13.484	198.689	48.838
Mean	13.671	200.317	49.314
5th percentile	13.869	202.176	49.843

Table 2. Gulf of Mexico Cenozoic Province 0-200m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	1.043	4.753	1.889
Cumulative production	0.400	1.689	0.701
Remaining proved	0.643	3.064	1.188
Unproved	0.281	0.874	0.437
Appreciation (P & U)	0.778	3.044	1.320
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.744	8.937	2.334
Mean	0.911	10.072	2.703
5th percentile	1.174	11.693	3.255
Total Endowment			
95th percentile	2.847	17.608	5.980
Mean	3.013	18.743	6.348
5th percentile	3.276	20.365	6.900

Table 3. Gulf of Mexico Cenozoic Province 201-900m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.276	0.905	0.437
Cumulative production	0.000	0.000	0.000
Remaining proved	0.276	0.905	0.437
Unproved	0.324	1.969	0.675
Appreciation (P & U)	0.557	2.609	1.022
Undiscovered Conventionally Recoverable Resources			
95th percentile	2.828	33.414	8.773
Mean	3.400	36.159	9.834
5th percentile	5.079	39.613	12.127
Total Endowment			
95th percentile	3.985	38.898	10.906
Mean	4.557	41.642	11.967
5th percentile	6.236	45.096	14.261

Table 4. Gulf of Mexico Cenozoic Province 901-3,000m Water Depth Assessment Results Table.

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		3.005	48.764	11.682
Mean		3.794	53.028	13.230
5th percentile		5.338	56.780	15.441
Half-Cycle	1.00			
95th percentile		3.253	52.603	12.613
Mean		4.053	56.600	14.125
5th percentile		5.632	60.148	16.334
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		4.175	64.580	15.666
Mean		4.927	68.220	17.066
5th percentile		6.539	71.732	19.302
Half-Cycle	1.00			
95th percentile		4.374	67.102	16.314
Mean		5.096	70.826	17.699
5th percentile		6.704	74.216	19.909

Table 5. Total Gulf of Mexico Cenozoic Province Economic Assessment Results Table.

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		1.600	33.984	7.647
Mean		1.759	35.818	8.132
5th percentile		1.982	37.656	8.682
Half-Cycle	1.00			
95th percentile		1.623	35.346	7.913
Mean		1.792	37.144	8.401
5th percentile		2.006	38.995	8.944
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		1.717	38.128	8.502
Mean		1.876	39.868	8.970
5th percentile		2.061	41.827	9.503
Half-Cycle	1.00			
95th percentile		1.715	38.606	8.584
Mean		1.884	40.284	9.053
5th percentile		2.075	42.166	9.577

Table 6. Gulf of Mexico Cenozoic Province 0-200m Water Depth Economic Assessment Results Table.

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		0.454	3.843	1.138
Mean		0.635	5.169	1.554
5th percentile		0.902	6.942	2.138
Half-Cycle	1.00			
95th percentile		0.489	4.175	1.232
Mean		0.665	5.584	1.659
5th percentile		0.935	7.335	2.240
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.609	5.863	1.652
Mean		0.772	7.163	2.047
5th percentile		1.045	8.790	2.609
Half-Cycle	1.00			
95th percentile		0.620	6.329	1.746
Mean		0.792	7.518	2.130
5th percentile		1.070	9.114	2.692

Table 7. Gulf of Mexico Cenozoic Province 201-900m Water Depth Economic Assessment Results Table.

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		0.738	8.743	2.294
Mean		1.406	12.016	3.544
5th percentile		3.069	15.715	5.865
Half-Cycle	1.00			
95th percentile		0.931	10.608	2.818
Mean		1.603	13.810	4.060
5th percentile		3.231	17.570	6.358
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		1.646	18.115	4.870
Mean		2.273	21.132	6.033
5th percentile		3.908	24.862	8.331
Half-Cycle	1.00			
95th percentile		1.810	20.020	5.372
Mean		2.416	22.975	6.504
5th percentile		4.064	26.616	8.799

Table 8. Gulf of Mexico Cenozoic Province 901-3,000m Water Depth Economic Assessment Results Table.

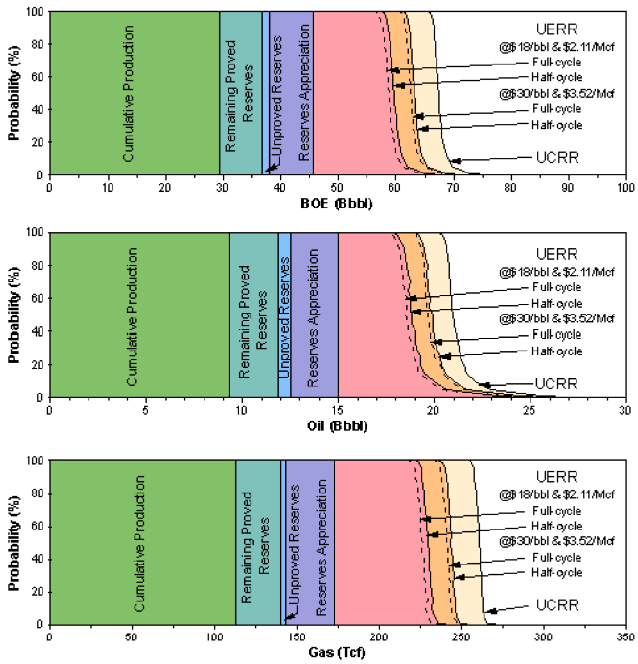

Figure 5. Gulf of Mexico Cenozoic Province Total Endowment by Resource Category.

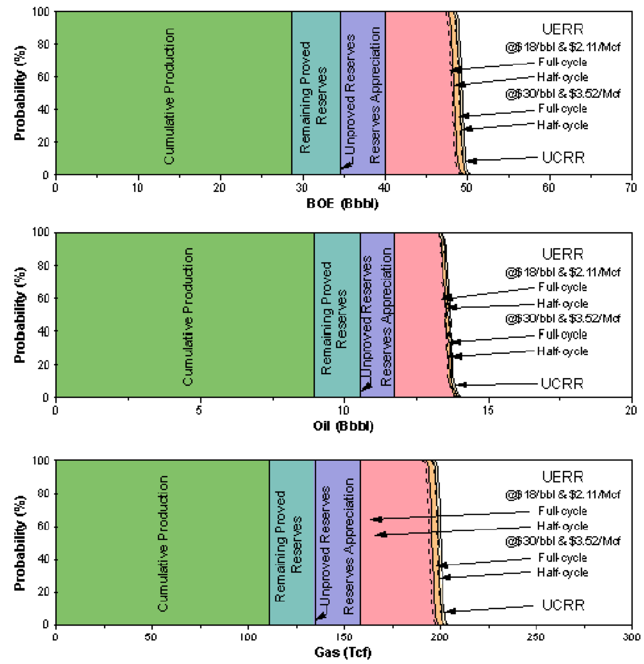

Figure 6. Gulf of Mexico Cenozoic Province 0-200m Water Depth Total Endowment by Resource Category.

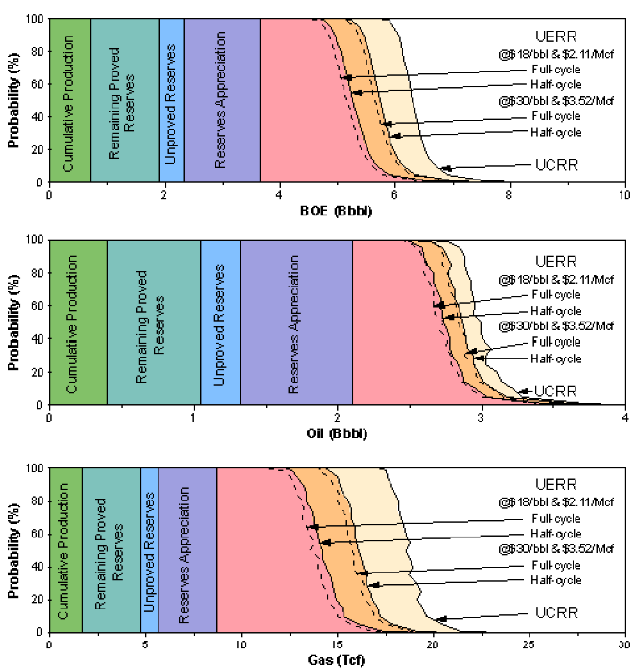

Figure 7. Gulf of Mexico Cenozoic Province 201-900M Water Depth Total Endowment by Resource Category.

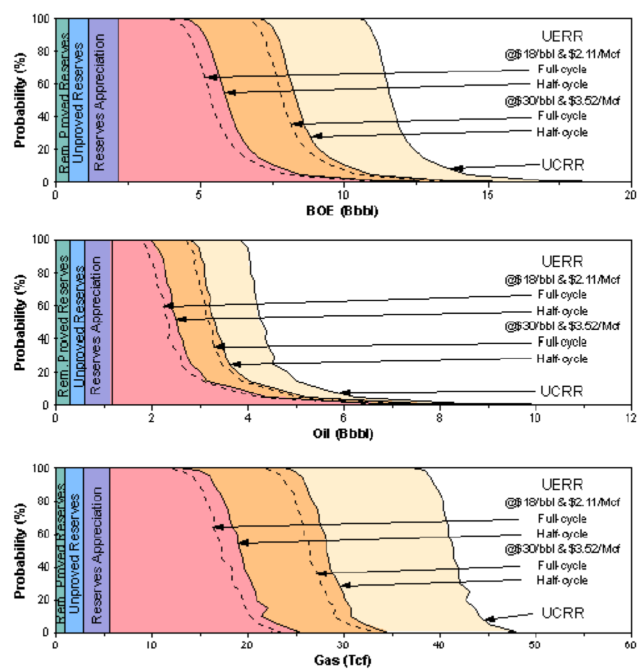

Figure 8. Gulf of Mexico Cenozoic Province 901-3,000m Water Depth Total Endowment by Resource Category.

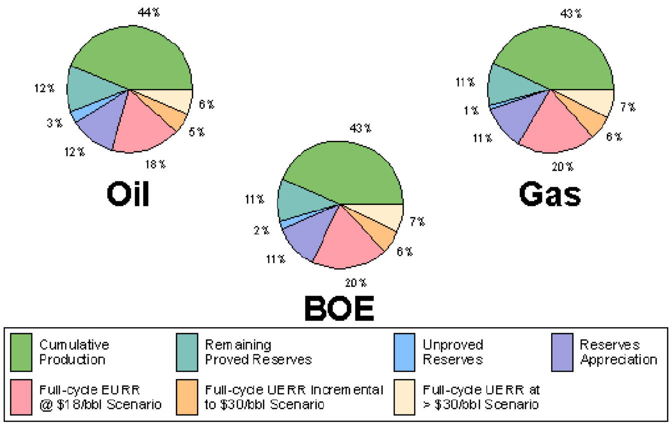

Figure 9. Total Gulf of Mexico Ceozoic Province Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

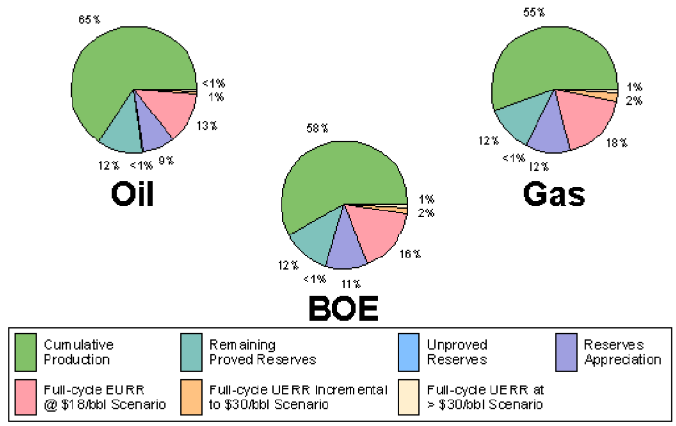

Figure 10. Gulf of Mexico Cenozoic Province 0-200m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

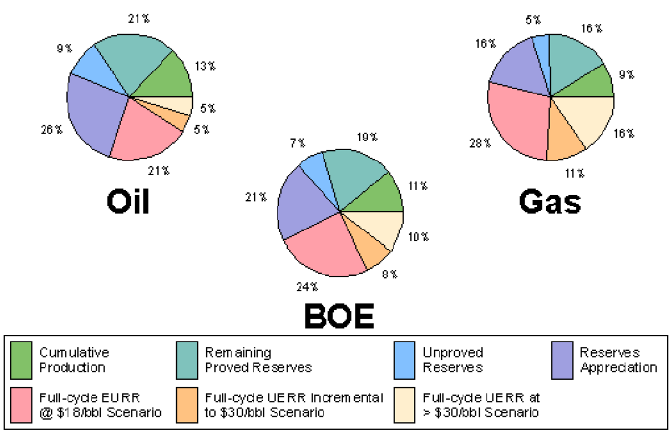

Figure 11. Gulf of Mexico Cenozoic Province 201-900m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

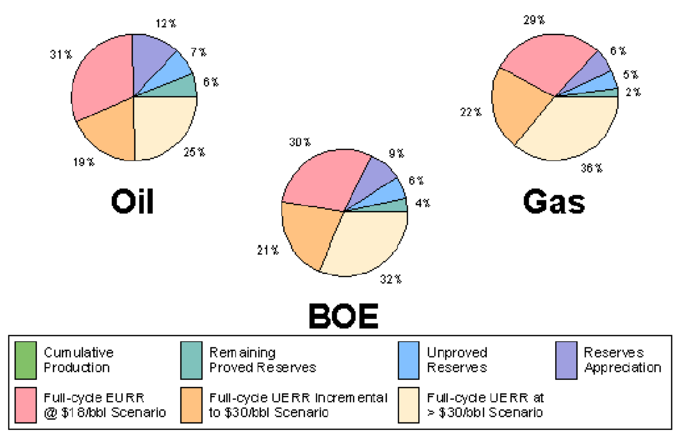

Figure 12. Gulf of Mexico Cenozoic Province 901-3,000m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

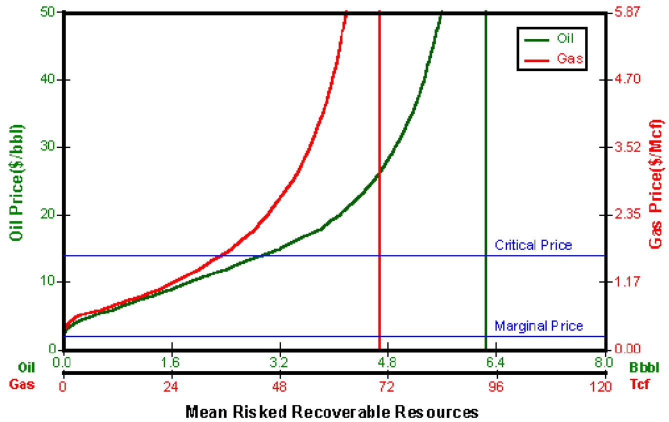

Figure 13. Total Gulf of Mexico Cenozoic Province Full-Cycle Price-Supply Curve.

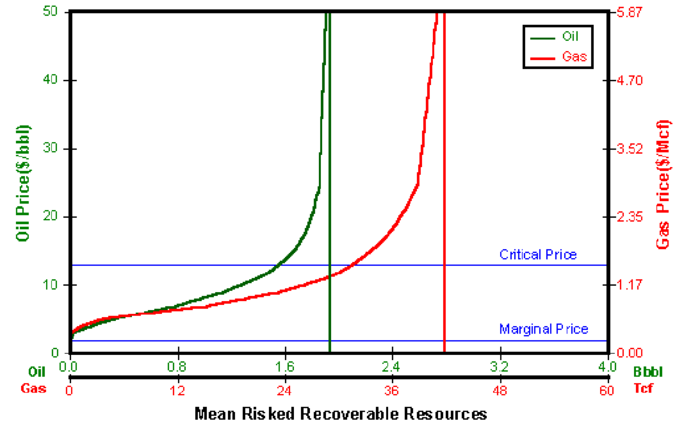

Figure 14. Gulf of Mexico Cenozoic Province 0-200m Water Depth Full-Cycle Price-Supply Curve.

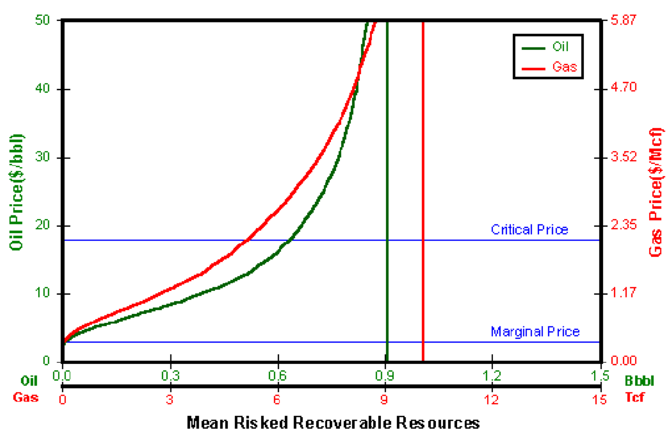

Figure 15. Gulf of Mexico Cenozoic Province 201-900m Water Depth Full-Cycle Price-Supply Curve.

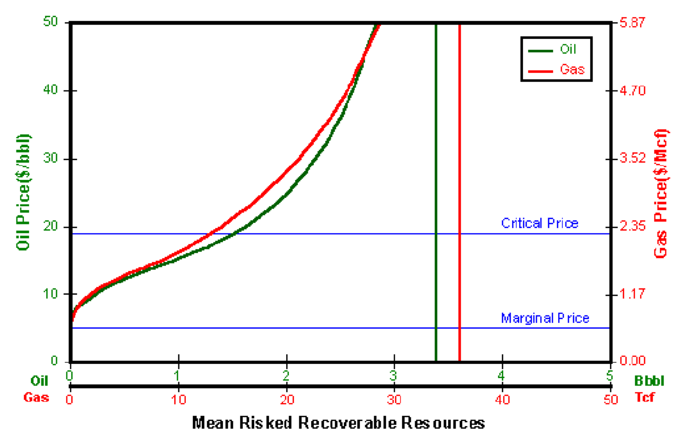

Figure 16. Gulf of Mexico Cenozoic Province 901-3,000m Water Depth Full-Cycle Price-Supply Curve.

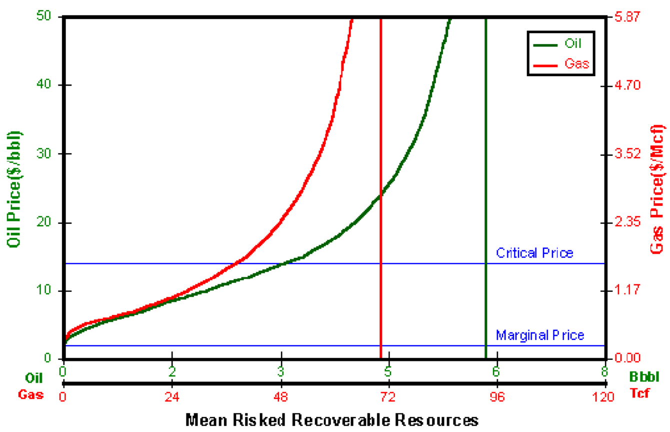

Figure 17. Total Gulf of Mexico Cenozoic Province Half-Cycle Price-Supply Curve.

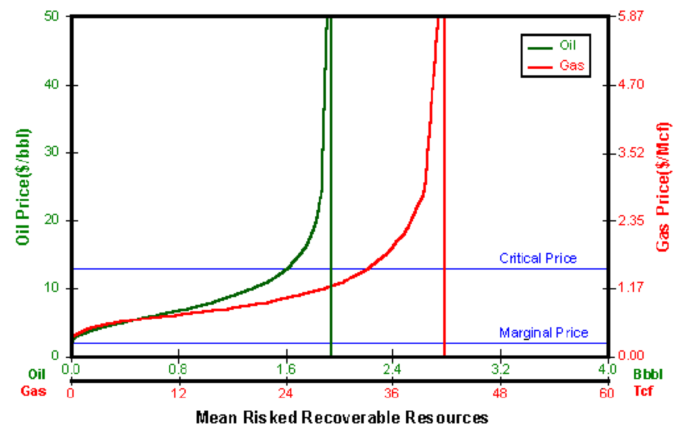

Figure 18. Gulf of Mexico Cenozoic Province 0-200m Water Depth Half-Cycle Price-Supply Curve.

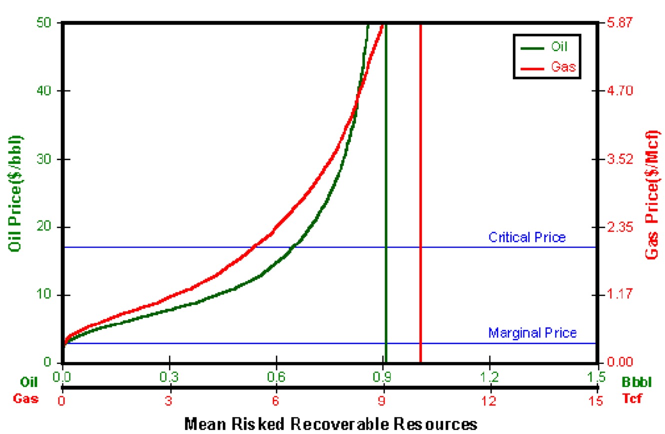

Figure 19. Gulf of Mexico Cenozoic Province 201-900m Water Depth Half-Cycle Price-Supply Curve.

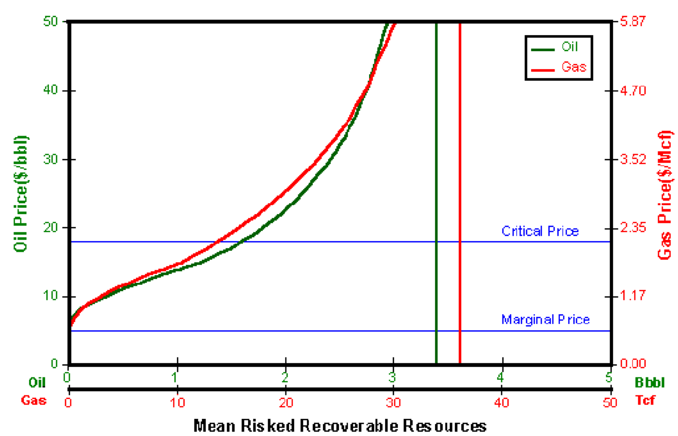

Figure 20. Gulf of Mexico Cenozoic Province 901-3,000m Water Depth Half-Cycle Price-Supply Curve.

Gulf of Mexico Mesozoic Province Economic Results

The Gulf of Mexico Mesozoic Province includes submerged Federal lands offshore Mississippi, Alabama, and Florida south to the U.S.-Cuba International Boundary (figure 1). Water depths in the Province range from very shallow to more than 3,000m. Because water depth and distance from shore have a significant effect on engineering and cost factors, the undiscovered economically recoverable resources (UERR) were evaluated for three water depth ranges, 0-200m, 201-900m, and 901-3,000m (no resources were evaluated in water depths greater than 3,000m).

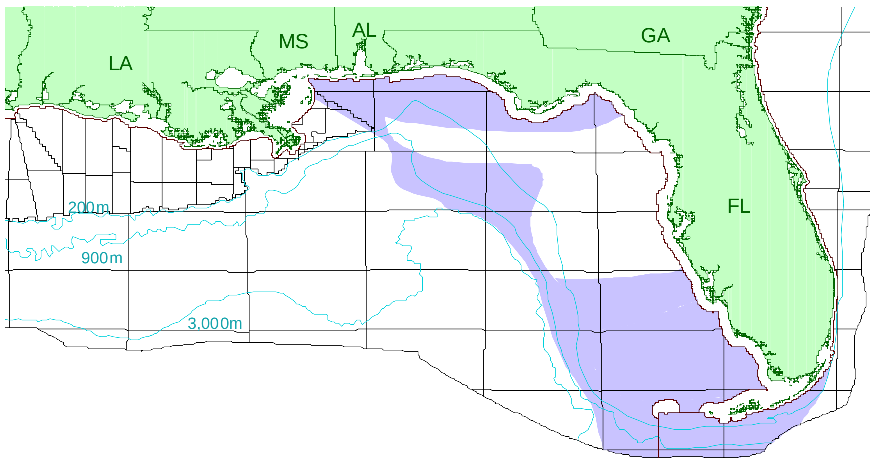

Figure 1. Gulf of Mexico Mesozoic Province Map. The shaded areas indicate the extent of the assessed plays in the Province.

The mean total endowment for this Province is almost equally distributed as oil and gas, with 49 percent of the total resources occurring as gas (figure 2). There is a definite trend towards a less gas-prone bias in the deeper water depths, with the 0-200m water depth range consisting of 53 percent gas, the 201-900m range consisting of 18 percent gas, and the deepest water depth range consisting of 25 percent gas. The largest concentration of the mean total endowment (91% on a barrels-of-oil-equivalent [BOE] basis) occurs in water depths of less than 200m (figure 3 and figure 4). Each of the other two water depth ranges have 3 to 6 percent of the BOE mean total endowment.

The Province is sparsely developed with minimal infrastructure in place in the 0-200m water depth range, and is not yet developed in the other two water depth ranges. As of the date of this study, there have been production and reserves only in the 0-200m range (table 1 for Assessment Results Total, table 2 for 0-200m, table 3 for 201-900m, and table 4 for 901-3,000m). Undiscovered conventionally recoverable resources (UCRR) have been assessed for all three water depth ranges, and the full- and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in table 5 (Economic Results Total), table 6 (0-200m), table 7 (201-900m), and table 8 (901-3,000m). These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the three water depth ranges and for the total Province.

Assessment results indicate that the total Province undiscovered economically recoverable resources are modest, with a range of 0.759 to 1.672 Bbo and 3.921 to 5.892 Tcfg at the 95th and 5th percentiles, respectively, for the full-cycle $18/bbl scenario. The mean economically recoverable resources are estimated at 1.154 Bbo and 4.969 Tcfg. A graphical representation of these results, incorporating every 5th- percentile result for

UCRR and UERR, is presented in figure 5 (Results Graph Total), figure 6 (0-200m), figure 7 (201-900m), and figure 8 (901-3,000m). These graphs also present the half-cycle $18/bbl, and the full- and half-cycle $30/bbl scenario results. Because the economic model imports field sizes in BOE from the geologic model and then calculates the oil and gas content, the BOE results graph is typically a smooth curve. As expected, the accompanying oil and gas values exhibit more scatter because the gas/oil ratio can vary greatly from one field to another.

The mean total endowment for oil, gas, and BOE by the reserve and resource classification is shown in figure 9 (Mean Endowment Total), figure 10 (0-200m), figure 11 (201-900m), and figure 12 (901-3,000m). The pie charts presented can be used to determine what percentage of oil, gas, or BOE is a result of reserves or of undiscovered resources. For example, most of the gas (67%) and almost all of the oil (99%) in the Province remain to be discovered. However, once development begins in earnest, 42 percent of the gas and 56 percent of the oil are projected to be economically recoverable at the $18/bbl scenario (figure 9). Therefore, almost half (49%) of the mean total endowment, on a BOE basis, is remaining to be discovered and is projected to be economically recoverable at the $18/bbl scenario.

Because estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions, they are presented here as price-supply curves. These curves describe a functional relationship between economically recoverable resources and product price and present the estimates of mean undiscovered economically recoverable oil and gas at any starting oil price up to $50/bbl. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the ***General Text, Methodology, UERR (Economically Recoverable), Detailed Discussion*** section. 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 are the mean curves. The full-cycle price-supply curves are shown in figure 13 (Full-Cycle P-S Curve Total), figure 14 (0-200m), figure 15 (201-900m), and figure 16 (901-3,000m). The half-cycle price-supply curves are shown in figure 17 (Half-Cycle P-S Curve Total), figure 18 (0-200m), figure 19 (201-900m), and figure 20 (901-3,000m).

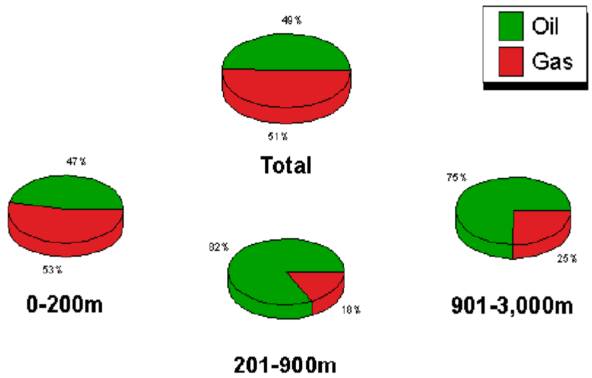

Figure 2. Gulf of Mexico Mesozoic Province Percent Oil or Gas by Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

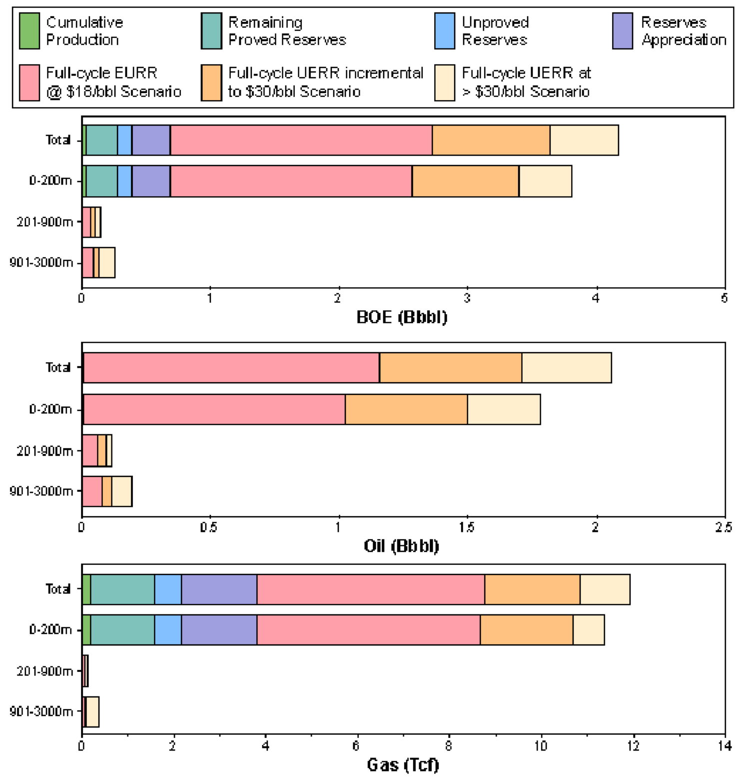

Figure 3. Gulf of Mexico Mesozoic Province Mean Total Endowment by Water Depth Category.

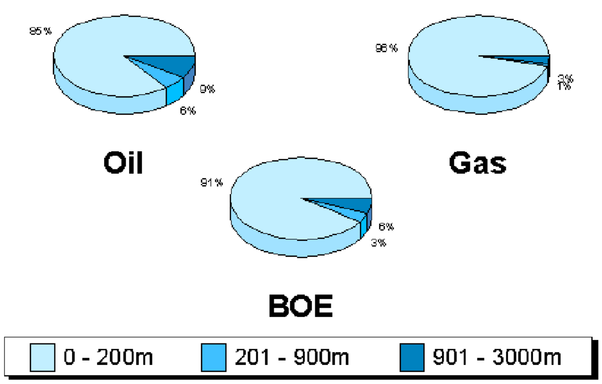

Figure 4. Gulf of Mexico Mesozoic Province Mean Total Endowment by Resource Type and Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

Marginal Probability = 1.00	Number of Pools	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves				
Original proved	9	<0.001	1.572	0.280
Cumulative production	--	<0.001	0.198	0.035
Remaining proved	--	<0.001	1.374	0.245
Unproved	2	0.001	0.597	0.107
Appreciation (P & U)	--	0.002	1.640	0.294
Undiscovered Conventionally Recoverable Resources				
95th percentile	--	1.360	7.106	2.678
Mean	179	2.053	8.108	3.495
5th percentile	--	2.933	9.194	4.455
Total Endowment				
95th percentile	--	1.363	10.915	3.359
Mean	190	2.056	11.917	4.176
5th percentile	--	2.936	13.003	5.136

Table 1. Total Gulf of Mexico Mesozoic Province Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	<0.001	1.572	0.280
Cumulative production	<0.001	0.198	0.035
Remaining proved	<0.001	1.374	0.245
Unproved	0.001	0.597	0.107
Appreciation (P & U)	0.002	1.640	0.294
Undiscovered Conventionally Recoverable Resources			
95th percentile	1.404	7.157	2.678
Mean	1.777	7.567	3.123
5th percentile	2.247	8.050	3.679
Total Endowment			
95th percentile	1.407	10.966	3.358
Mean	1.780	11.376	3.804
5th percentile	2.250	11.859	4.360

Table 2. Gulf of Mexico Mesozoic Province 0-200m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.071	0.091	0.087
Mean	0.117	0.139	0.142
5th percentile	0.190	0.225	0.230
Total Endowment			
95th percentile	0.071	0.091	0.087
Mean	0.117	0.139	0.142
5th percentile	0.190	0.225	0.230

Table 3. Gulf of Mexico Mesozoic Province 201-900m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.087	0.223	0.127
Mean	0.191	0.359	0.255
5th percentile	0.371	0.529	0.465
Total Endowment			
95th percentile	0.087	0.223	0.127
Mean	0.191	0.359	0.255
5th percentile	0.371	0.529	0.465

Table 4. Gulf of Mexico Mesozoic Province 901-3,000m Water Depth Assessment Results Table.

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		0.759	3.921	1.457
Mean		1.154	4.969	2.038
5th percentile		1.672	5.892	2.720
Half-Cycle	1.00			
95th percentile		0.835	4.982	1.721
Mean		1.266	5.792	2.297
5th percentile		1.796	6.612	2.972
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		1.259	6.530	2.421
Mean		1.706	7.024	2.956
5th percentile		2.225	7.477	3.555
Half-Cycle	1.00			
95th percentile		1.318	6.682	2.507
Mean		1.766	7.202	3.047
5th percentile		2.278	7.585	3.628

Table 5. Total Gulf of Mexico Mesozoic Province Economic Assessment Results Table.

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		0.727	3.606	1.369
Mean		1.021	4.874	1.889
5th percentile		1.497	5.889	2.545
Half-Cycle	1.00			
95th percentile		0.749	4.861	1.614
Mean		1.111	5.687	2.123
5th percentile		1.602	6.442	2.748
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		1.104	6.505	2.262
Mean		1.496	6.864	2.717
5th percentile		1.971	7.302	3.270
Half-Cycle	1.00			
95th percentile		1.164	6.660	2.349
Mean		1.543	7.027	2.794
5th percentile		2.017	7.464	3.345

Table 6. Gulf of Mexico Mesozoic Province 0-200m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.88			
95th percentile		0.000	0.000	0.000
Mean		0.061	0.048	0.070
5th percentile		0.140	0.137	0.164
Half-Cycle	0.92			
95th percentile		0.000	0.000	0.000
Mean		0.066	0.053	0.075
5th percentile		0.143	0.136	0.167
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.041	0.017	0.044
Mean		0.092	0.071	0.104
5th percentile		0.165	0.163	0.194
Half-Cycle	1.00			
95th percentile		0.044	0.027	0.049
Mean		0.094	0.077	0.108
5th percentile		0.168	0.159	0.196

Table 7. Gulf of Mexico Mesozoic Province 201-900m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.40			
95th percentile		0.000	0.000	0.000
Mean		0.077	0.054	0.086
5th percentile		0.300	0.223	0.340
Half-Cycle	0.47			
95th percentile		0.000	0.000	0.000
Mean		0.086	0.060	0.097
5th percentile		0.304	0.214	0.342
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.74			
95th percentile		0.000	0.000	0.000
Mean		0.118	0.089	0.134
5th percentile		0.318	0.233	0.360
Half-Cycle	0.81			
95th percentile		0.000	0.000	0.000
Mean		0.127	0.100	0.145
5th percentile		0.321	0.267	0.368

Table 8. Gulf of Mexico Mesozoic Province 901-3,000m Water Depth Economic Assessment Results Table.

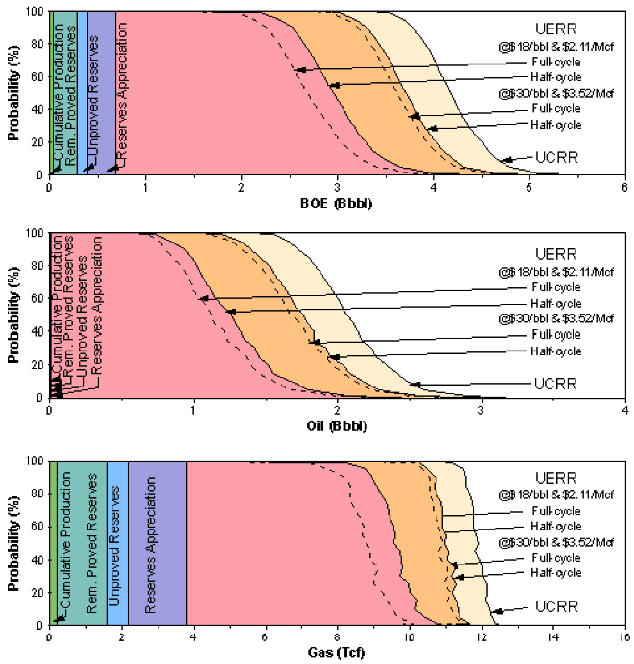

Figure 5. Gulf of Mexico Mesozoic Province Total Endowment by Resource Category.

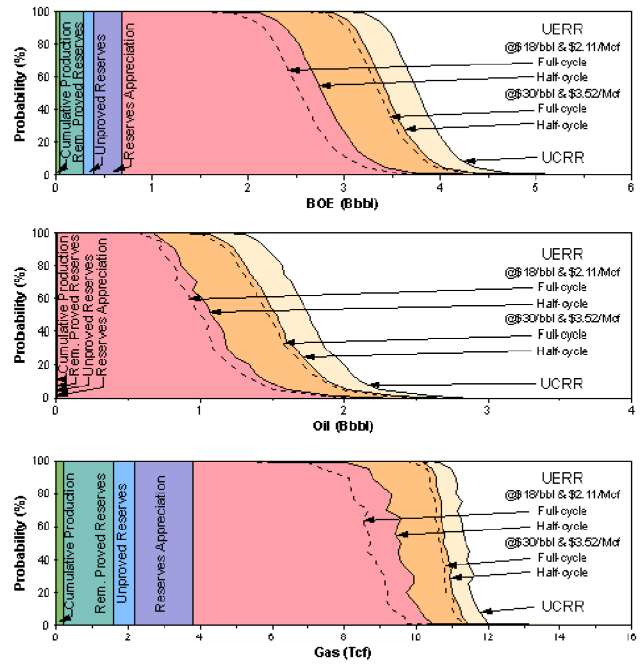

Figure 6. Gulf of Mexico Mesozoic Province 0-200m Water Depth Total Endowment by Resource Category.

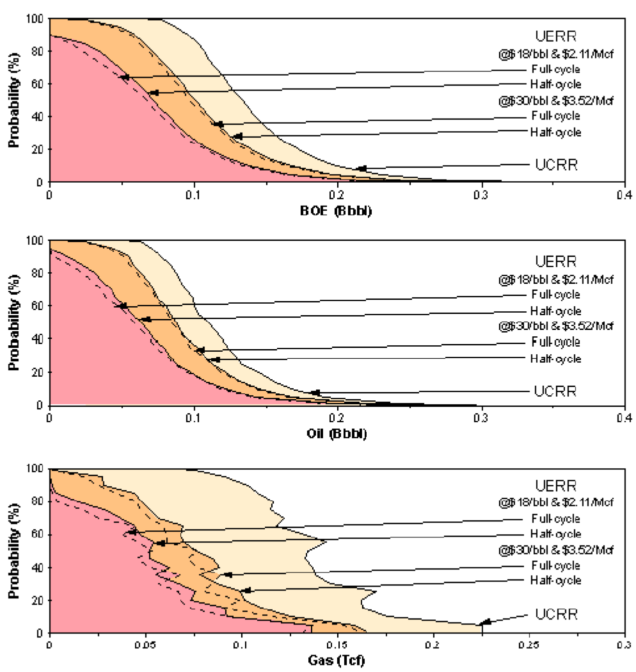

Figure 7. Gulf of Mexico Mesozoic Province 201-900m Water Depth Total Endowment by Resource Category.

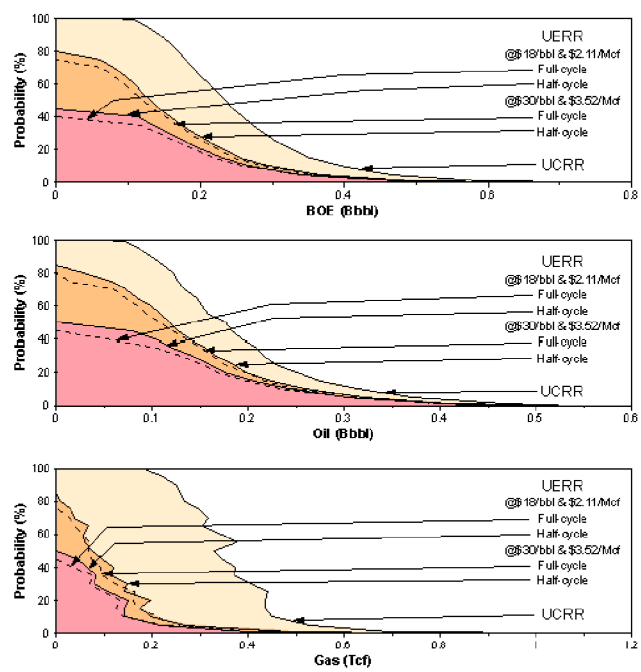

Figure 8. Gulf of Mexico Mesozoic Province 901-3,000m Water Depth Total Endowment by Resource Category.

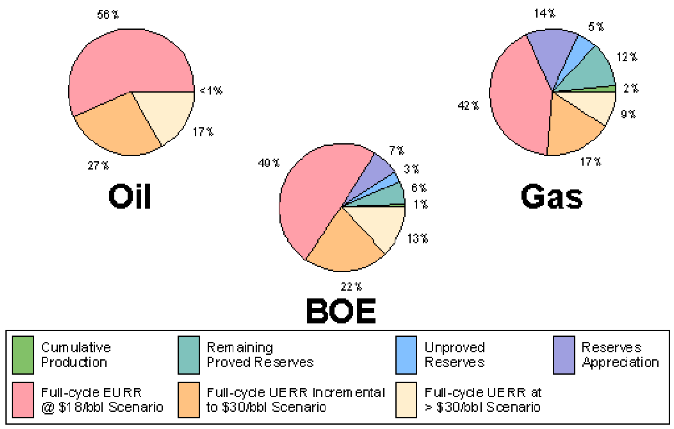

Figure 9. Total Gulf of Mexico Mesozoic Province Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

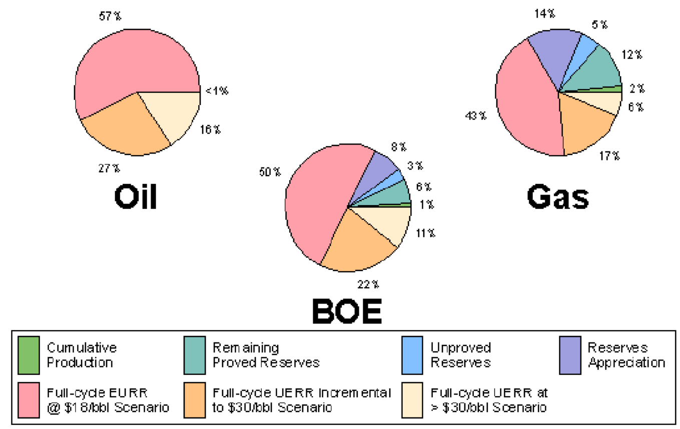

Figure 10. Gulf of Mexico Mesozoic Province 0-200m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

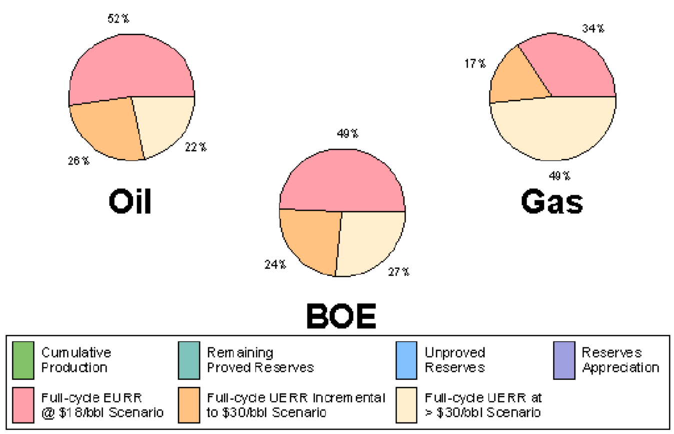

Figure 11. Gulf of Mexico Mesozoic Province 201-900m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

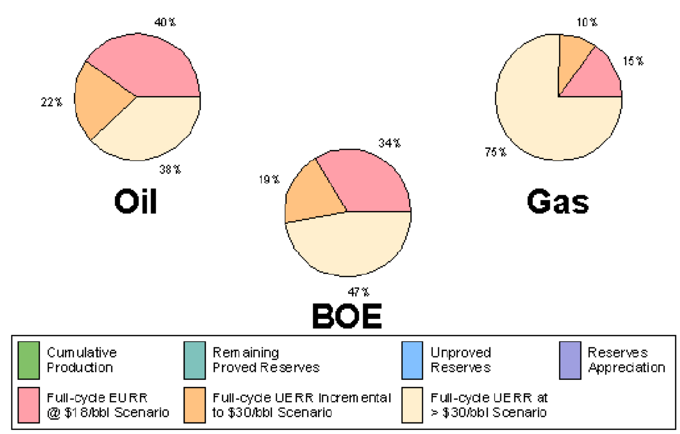

Figure 12. Gulf of Mexico Mesozoic Province 901-3,000m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

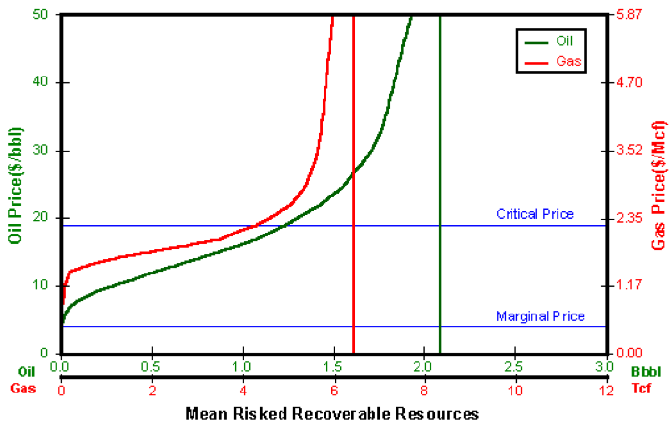

Figure 13. Total Gulf of Mexico Mesozoic Province Full-Cycle Price-Supply Curve.

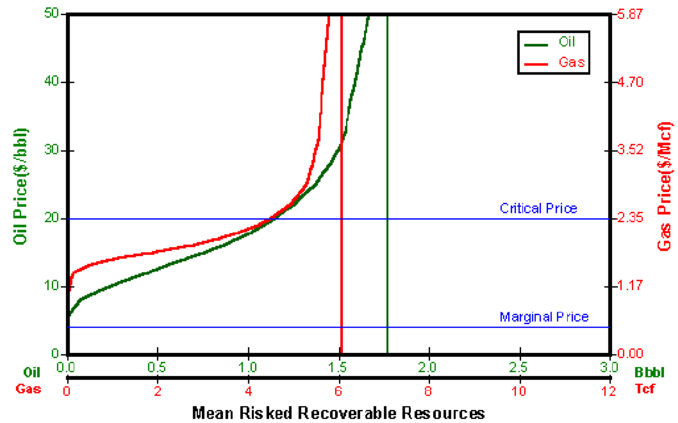

Figure 14. Gulf of Mexico Mesozoic Province 0-200m Water Depth Full-Cycle Price-Supply Curve.

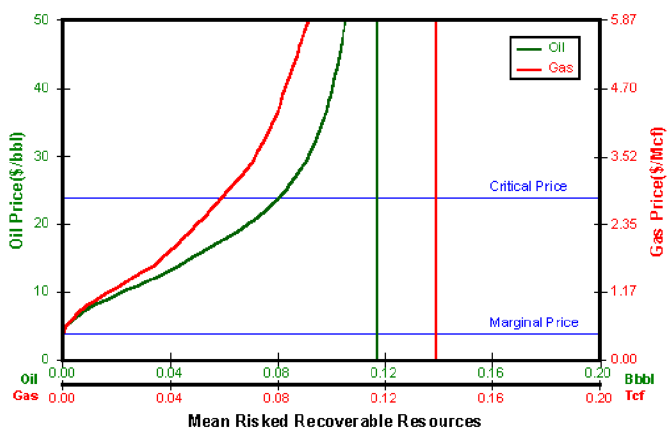

Figure 15. Gulf of Mexico Mesozoic Province 201-900m Water Depth Full-Cycle Price-Supply Curve.

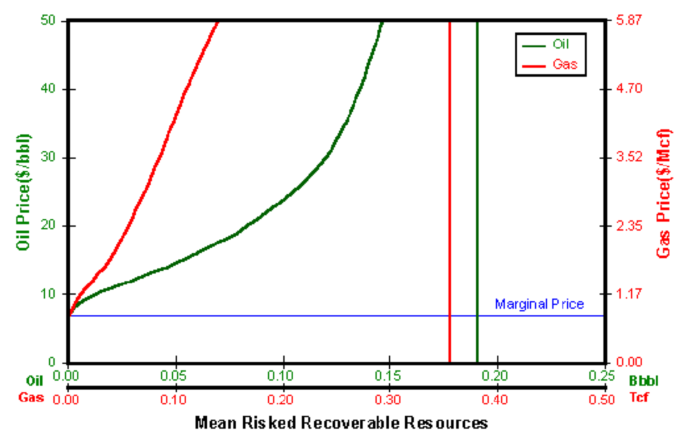

Figure 16. Gulf of Mexico Mesozoic Province 901-3,000m Water Depth Full-Cycle Price-Supply Curve.

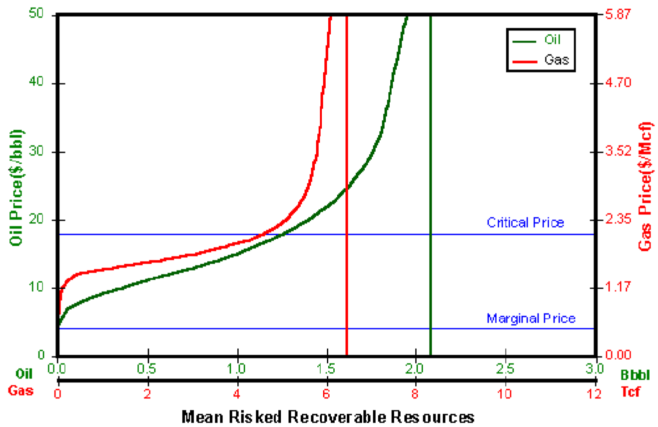

Figure 17. Total Gulf of Mexico Mesozoic Province Half-Cycle Price-Supply Curve.

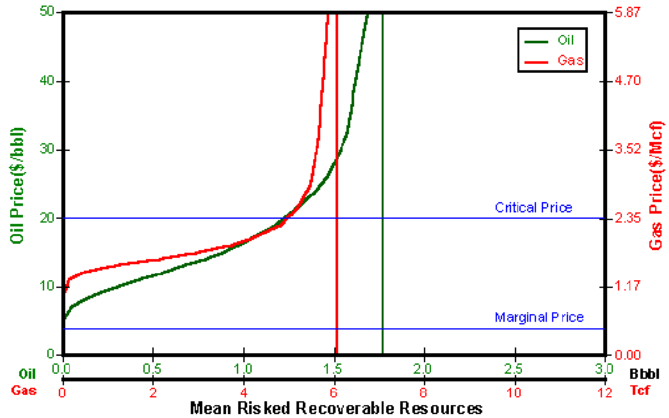

Figure 18. Gulf of Mexico Mesozoic Province 0-200m Water Depth Half-Cycle Price-Supply Curve.

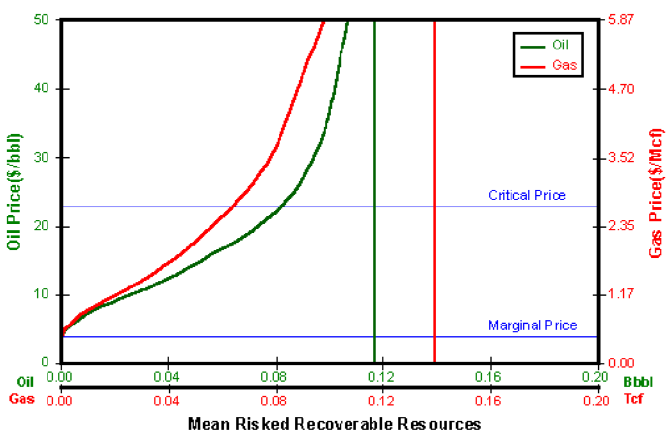

Figure 19. Gulf of Mexico Mesozoic Province 201-900m Water Depth Half-Cycle Price-Supply Curve.

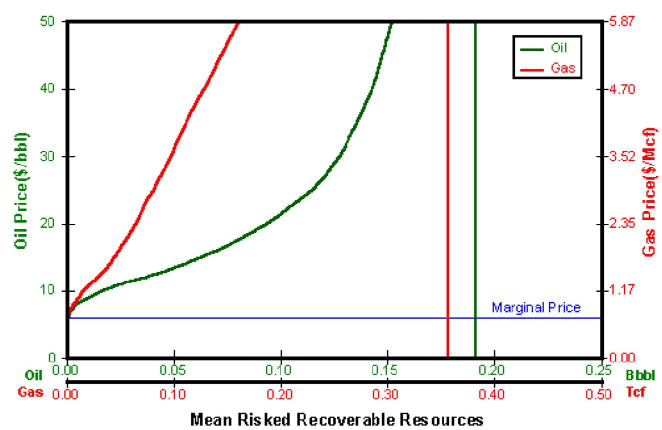

Figure 20. Gulf of Mexico Mesozoic Province 901-3,000m Water Depth Half-Cycle Price-Supply Curve.

Atlantic Mesozoic Province Economic Results

The Atlantic Mesozoic Province includes submerged Federal lands from the U.S.-Canada International Boundary south to offshore Florida (figure 1). Water depths in the Province range from very shallow to more than 3,000m. Because water depth and distance from shore have a significant effect on engineering and cost factors, the undiscovered economically recoverable resources (UERR) were evaluated for three water depth ranges, 0-200m, 201-900m, and 901-3,000m (no resources were evaluated in water depths greater than 3,000m).

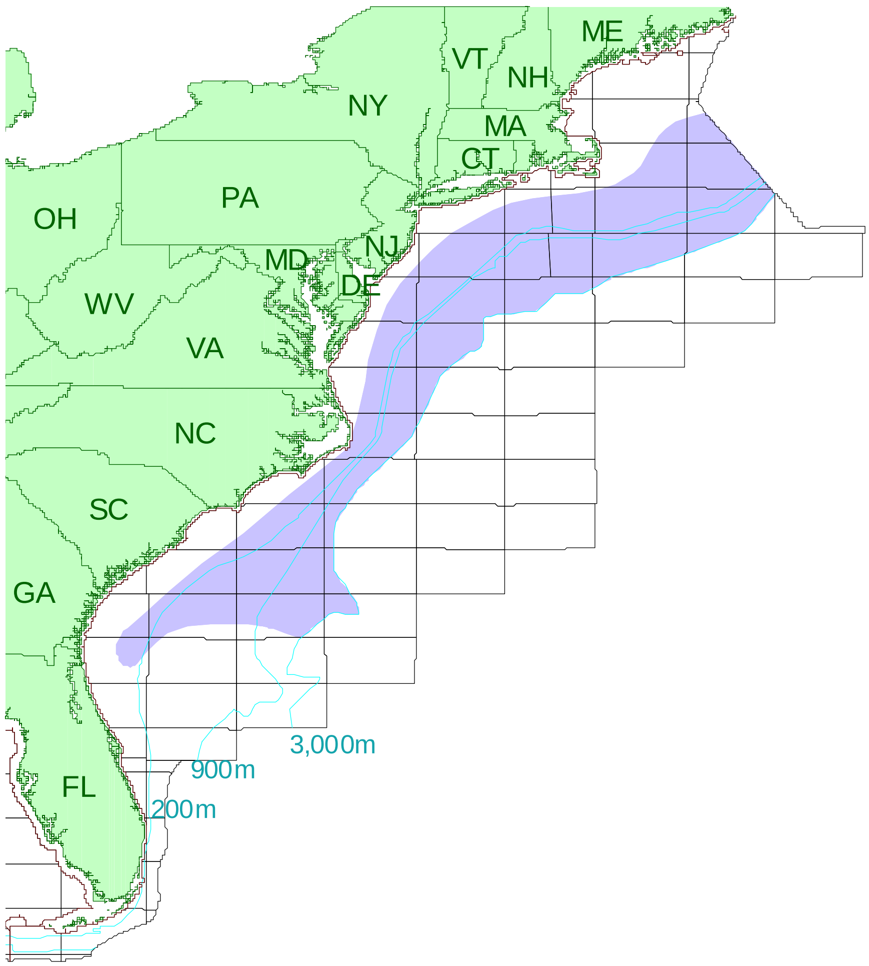

Figure 1. Atlantic Mesozoic Province Map. The shaded areas indicate the extent of the assessed plays in the Province.

The mean total endowment for this Province is predominantly gas, with 68 percent of the total resources occurring as gas (figure 2). There is a very slight trend towards a less gas-prone bias in the deeper water depths, with the 0-200m water depth range consisting of 71 percent gas, the 201-900m range consisting of 68 percent gas, and the deepest water depth range consisting of 67 percent gas. The largest concentration of the mean total endowment (41% on a barrels-of-oil-equivalent [BOE] basis) occurs in water depths of more than 900m (figure 3 and figure 4). Each of the other two water depth ranges have 28 to 31 percent of the BOE mean total endowment.

The Province is not developed in any of the water depth ranges, and there is no infrastructure in place. As of the date of this study, there has been no production or reserves in any of the ranges (table 1 for Assessment Results Total, table 2 for 0-200m, table 3 for 201-900m, and table 4 for 901-3,000m). Undiscovered conventionally recoverable resources (UCRR) have been assessed for all three water depth ranges, and the full- and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in table 5 (Economic Results Total), table 6 (0-200m), table 7 (201-900m), and table 8 (901-3,000m). These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the three water depth ranges and for the total Province.

Assessment results indicate that the total Province undiscovered economically recoverable resources are modest, with a range of 0.000 to 0.808 Bbo and 0.000 to 11.688 Tcfg at the 95th and 5th percentiles, respectively, for the full-cycle $18/bbl scenario. The mean economically recoverable resources are estimated at 0.368 Bbo and 5.203 Tcfg. A graphical representation of these results, incorporating every 5th- percentile result for UCRR and UERR, is presented in figure 5 (Results Graph Total), figure 6 (0-200m), figure 7 (201-900m), and figure 8 (901-3,000m). These graphs also present the half-cycle $18/bbl, and the full- and half-cycle $30/bbl scenario results. Because the economic model imports field sizes in BOE from the geologic model and then calculates the oil and gas content, the BOE results graph is typically a smooth curve. As expected, the accompanying oil and gas values exhibit more scatter because the gas/oil ratio can vary greatly from one field to another.

The mean total endowment for oil, gas, and BOE by the reserve and resource classification is shown in figure 9 (Mean Endowment Total), figure 10 (0-200m), figure 11 (201-900m), and figure 12 (901-3,000m). The pie charts presented can be used to determine what percentage of oil, gas, or BOE is a result of reserves or of undiscovered resources. For example, all of the oil and gas in the Province remains to be discovered, and only 19 percent of the gas and 16 percent of the oil are projected to be economically recoverable at the $18/bbl scenario (figure 9). Therefore, 18 percent of the mean total endowment, on a BOE basis, is remaining to be discovered and is projected to be economically recoverable at the $18/bbl scenario.

Because estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions, they are presented here as price-supply curves. These curves describe a functional relationship between economically recoverable resources and product price and present the estimates of mean undiscovered economically recoverable oil and gas at any starting oil price up to $50/bbl. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the ***General Text, Methodology, UERR (Economically Recoverable), Detailed Discussion*** section. 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 are the mean curves. The full-cycle price-supply curves are shown in figure 13 (Full-Cycle P-S Curve Total), figure 14 (0-200m), figure 15 (201-900m), and figure 16 (901-3,000m). The half-cycle price-supply curves are shown in figure 17 (Half-Cycle P-S Curve Total), figure 18 (0-200m), figure 19 (201-900m), and figure 20 (901-3,000m).

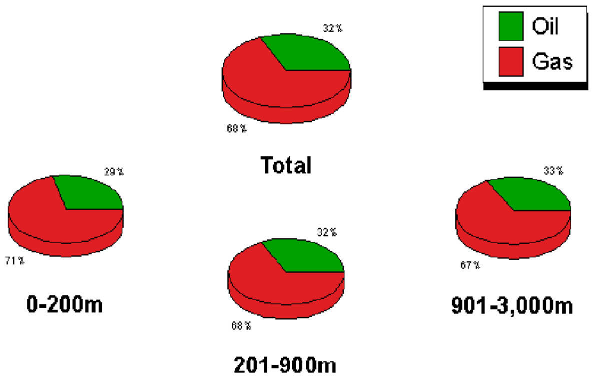

Figure 2. Atlantic Mesozoic Province Percent Oil or Gas by Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

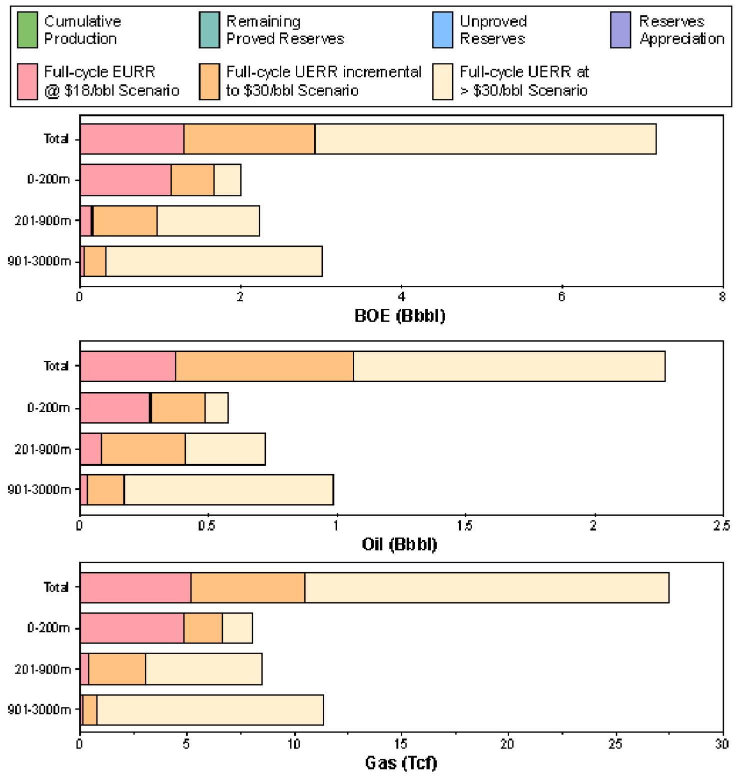

Figure 3. Atlantic Mesozoic Province Mean Total Endowment by Water Depth Category.

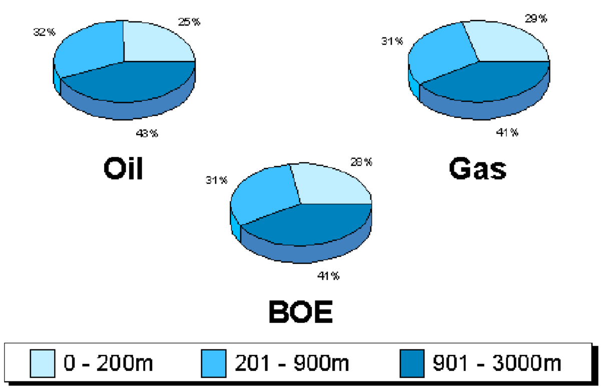

Figure 4. Atlantic Mesozoic Province Mean Total Endowment by Resource Type and Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

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 1. Total Atlantic Mesozoic Province Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.418	4.790	1.271
Mean	0.576	8.004	2.000
5th percentile	0.669	14.557	3.259
Total Endowment			
95th percentile	0.418	4.790	1.271
Mean	0.576	8.004	2.000
5th percentile	0.669	14.557	3.259

Table 2. Atlantic Mesozoic Province 0-200m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.524	6.994	1.769
Mean	0.722	8.512	2.236
5th percentile	0.995	10.519	2.867
Total Endowment			
95th percentile	0.524	6.994	1.769
Mean	0.722	8.512	2.236
5th percentile	0.995	10.519	2.867

Table 3. Atlantic Mesozoic Province 201-900m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.753	9.695	2.478
Mean	0.983	11.353	3.003
5th percentile	1.385	13.485	3.784
Total Endowment			
95th percentile	0.753	9.695	2.478
Mean	0.983	11.353	3.003
5th percentile	1.385	13.485	3.784

Table 4. Atlantic Mesozoic Province 901-3,000m Water Depth Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.92			
95th percentile		0.000	0.000	0.000
Mean		0.368	5.203	1.294
5th percentile		0.808	11.688	2.888
Half-Cycle	0.97			
95th percentile		0.125	1.154	0.331
Mean		0.452	5.989	1.518
5th percentile		0.910	12.404	3.118
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.587	5.855	1.628
Mean		1.063	10.479	2.927
5th percentile		1.644	16.444	4.570
Half-Cycle	1.00			
95th percentile		0.788	7.242	2.076
Mean		1.234	11.966	3.363
5th percentile		1.854	17.661	4.997

Table 5. Total Atlantic Mesozoic Province Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.90			
95th percentile		0.000	0.000	0.000
Mean		0.274	4.810	1.129
5th percentile		0.427	12.027	2.567
Half-Cycle	0.94			
95th percentile		0.037	0.378	0.105
Mean		0.313	5.279	1.252
5th percentile		0.447	12.398	2.653
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.338	3.361	0.936
Mean		0.486	6.653	1.669
5th percentile		0.578	13.179	2.923
Half-Cycle	1.00			
95th percentile		0.346	3.600	0.987
Mean		0.499	6.848	1.718
5th percentile		0.586	13.395	2.970

Table 6. Atlantic Mesozoic Province 0-200m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.22			
95th percentile		0.000	0.000	0.000
Mean		0.083	0.375	0.150
5th percentile		0.449	2.933	0.971
Half-Cycle	0.31			
95th percentile		0.000	0.000	0.000
Mean		0.118	0.652	0.234
5th percentile		0.519	3.629	1.165
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.95			
95th percentile		0.044	0.209	0.081
Mean		0.408	3.047	0.950
5th percentile		0.740	5.276	1.679
Half-Cycle	0.98			
95th percentile		0.225	1.514	0.495
Mean		0.463	3.622	1.108
5th percentile		0.809	5.648	1.814

Table 7. Atlantic Mesozoic Province 201-900m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.05			
95th percentile		0.000	0.000	0.000
Mean		0.026	0.104	0.045
5th percentile		0.146	0.656	0.262
Half-Cycle	0.08			
95th percentile		0.000	0.000	0.000
Mean		0.040	0.157	0.068
5th percentile		0.311	1.381	0.557
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.42			
95th percentile		0.000	0.000	0.000
Mean		0.173	0.798	0.315
5th percentile		0.638	3.572	1.273
Half-Cycle	0.63			
95th percentile		0.000	0.000	0.000
Mean		0.277	1.505	0.545
5th percentile		0.759	4.446	1.551

Table 8. Atlantic Mesozoic Province 901-3,000m Water Depth Economic Assessment Results Table.

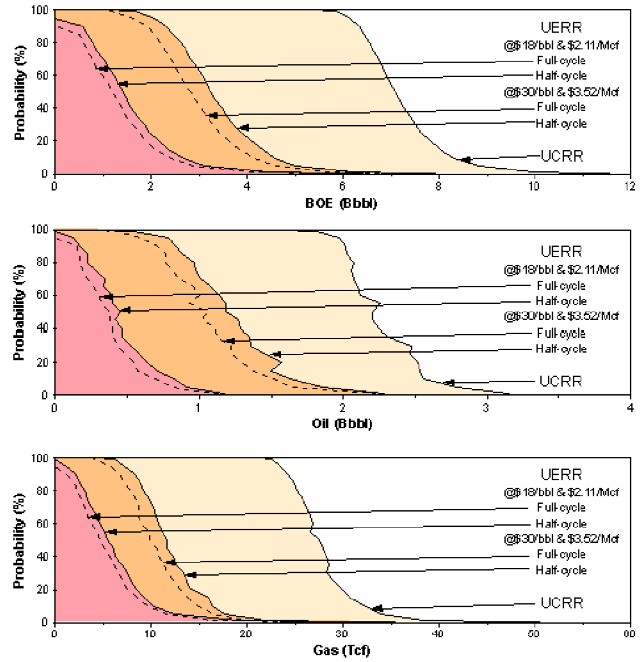

Figure 5. Atlantic Mesozoic Province Total Endowment by Resource Category.

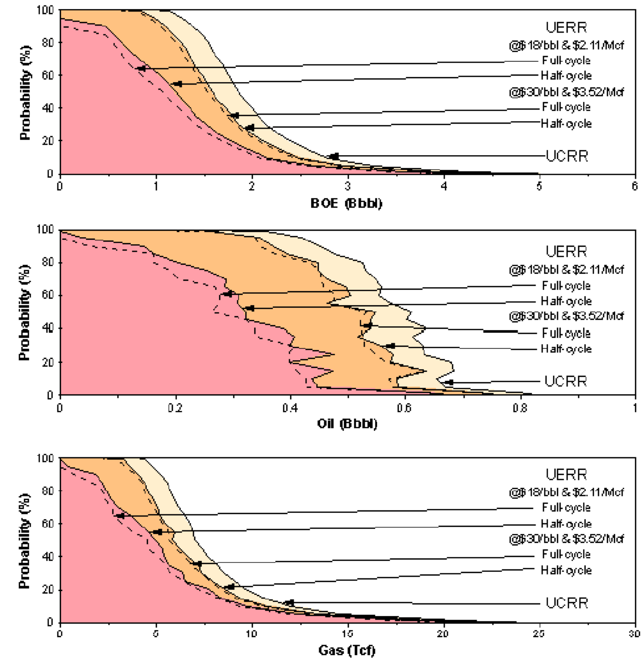

Figure 6. Atlantic Mesozoic Province 0-200m Water Depth Total Endowment by Resource Category.

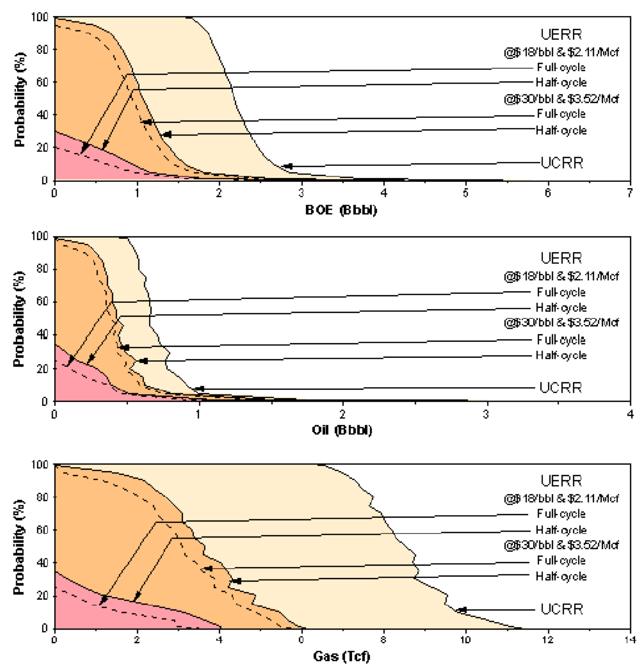

Figure 7. Atlantic Mesozoic Province 201-900m Water Depth Total Endowment by Resource Category.

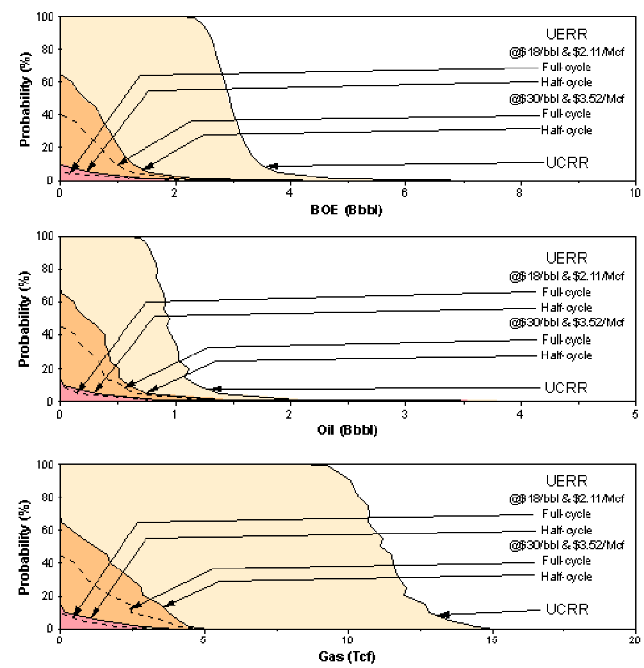

Figure 8. Atlantic Mesozoic Province 901-3,000m Water Depth Total Endowment by Resource Category.

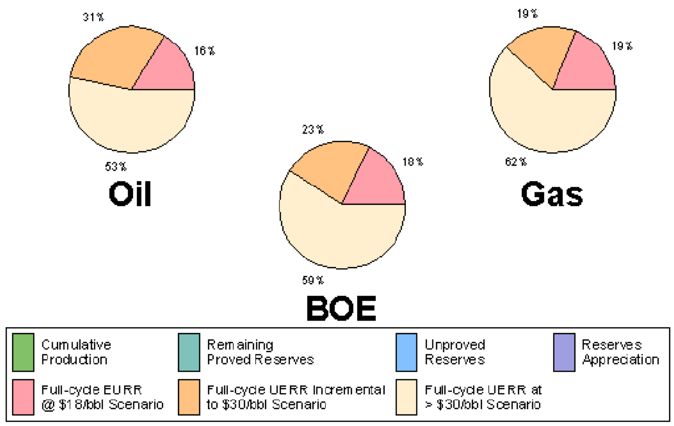

Figure 9. Total Atlantic Mesozoic Province Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

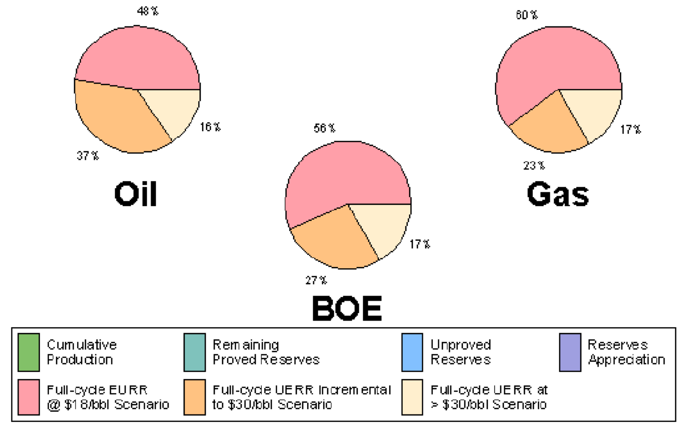

Figure 10. Atlantic Mesozoic Province 0-200m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

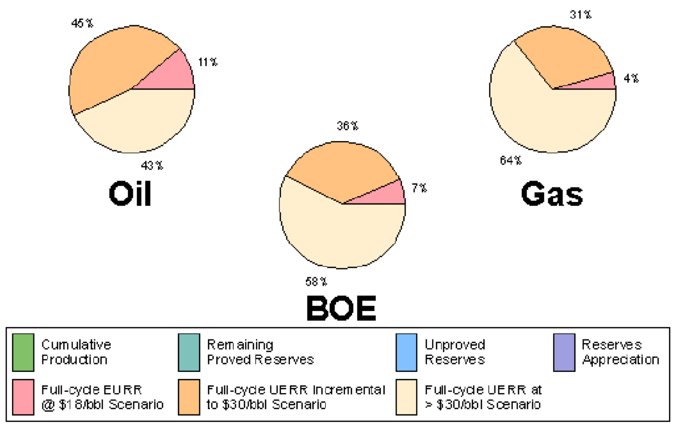

Figure 11. Atlantic Mesozoic Province 201-900m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

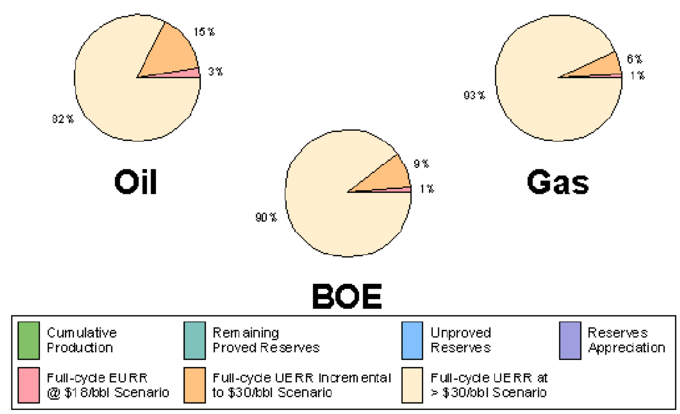

Figure 12. Atlantic Mesozoic Province 901-3,000m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

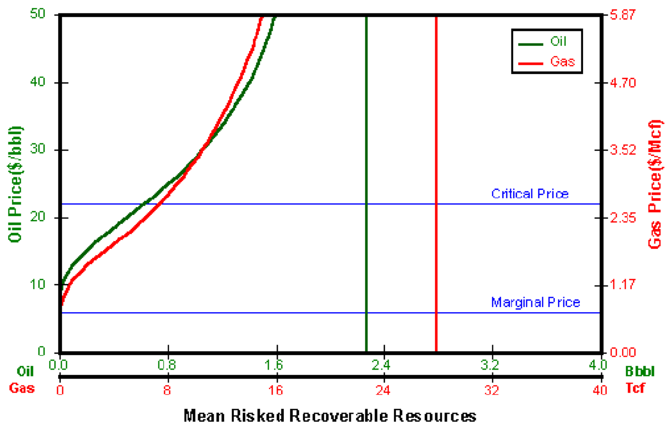

Figure 13. Total Atlantic Mesozoic Province Full-Cycle Price-Supply Curve.

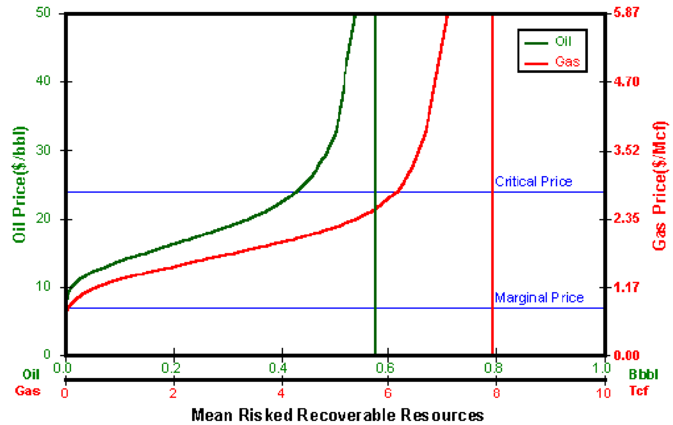

Figure 14. Atlantic Mesozoic Province 0-200m Water Depth Full-Cycle Price-Supply Curve.

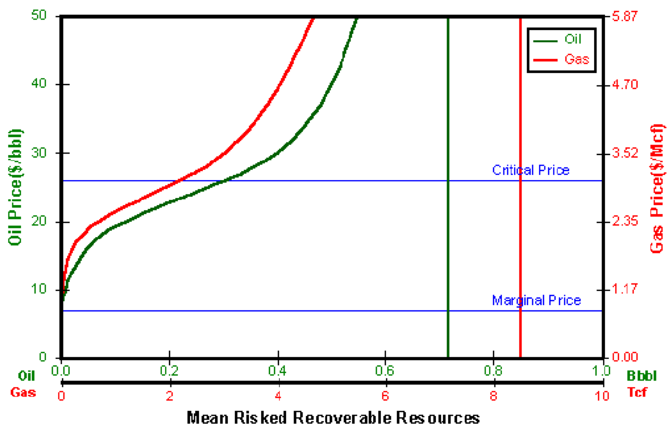

Figure 15. Atlantic Mesozoic Province 201-900m Water Depth Full-Cycle Price-Supply Curve.

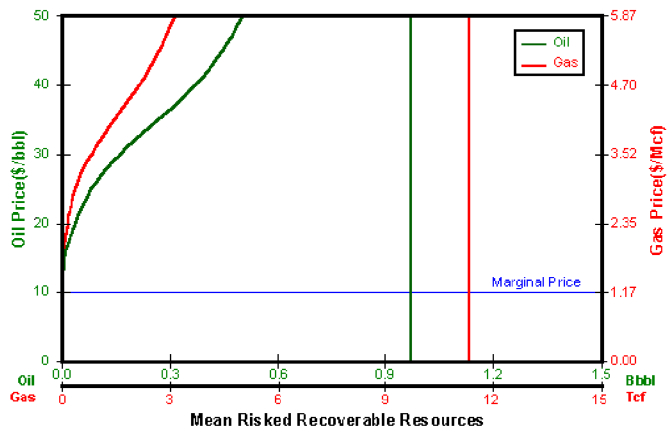

Figure 16. Atlantic Mesozoic Province 901-3,000m Water Depth Full-Cycle Price-Supply Curve.

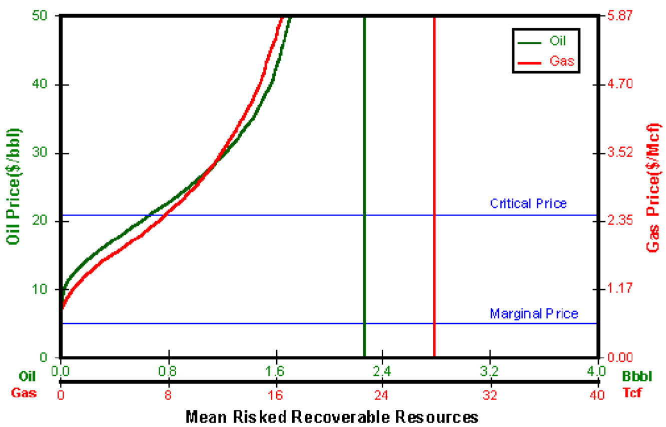

Figure 17. Total Atlantic Mesozoic Province Half-Cycle Price-Supply Curve.

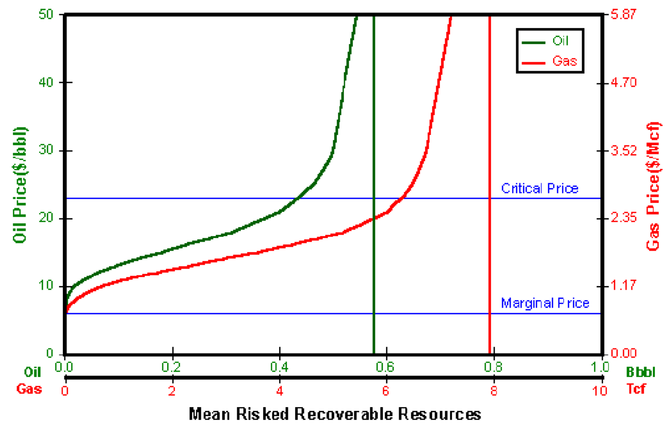

Figure 18. Atlantic Mesozoic Province 0-200m Water Depth Half-Cycle Price-Supply Curve.

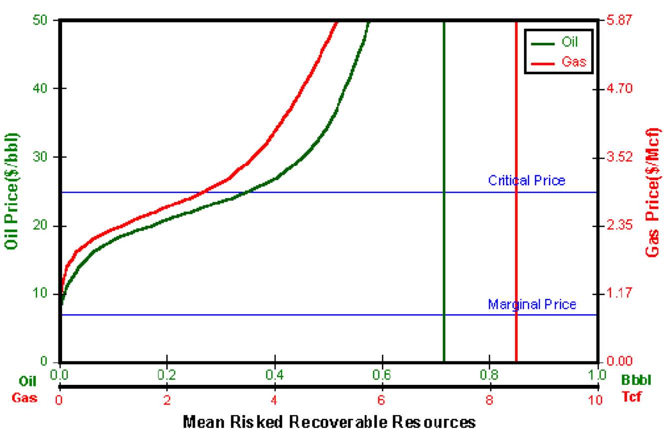

Figure 19. Atlantic Mesozoic Province 201-900m Water Depth Half-Cycle Price-Supply Curve.

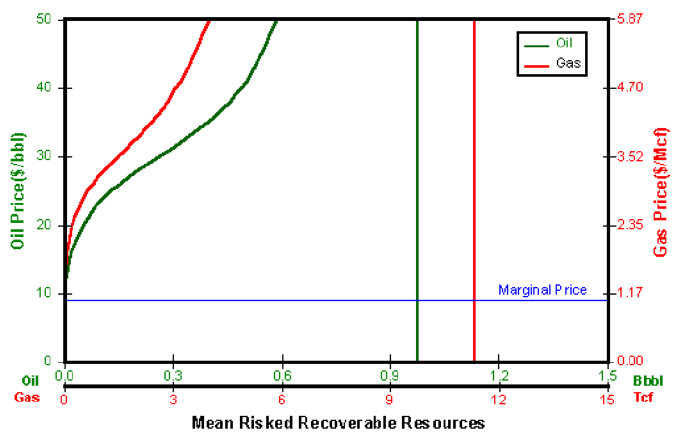

Figure 20. Atlantic Mesozoic Province 901-3,000m Water Depth Half-Cycle Price-Supply Curve.

Gulf of Mexico Western Planning Area Economic Results

The Gulf of Mexico Western Planning Area includes submerged Federal lands offshore Texas and Louisiana, and extends to the U.S.-Mexico International Boundary in the west (figure 1). Water depths in the planning area range from very shallow to more than 3,000m. Because water depth and distance from shore have a significant effect on engineering and cost factors, the undiscovered economically recoverable resources (UERR) were evaluated for three water depth ranges, 0-200m, 201-900m, and 901-3,000m (no resources were evaluated in water depths greater than 3,000m).

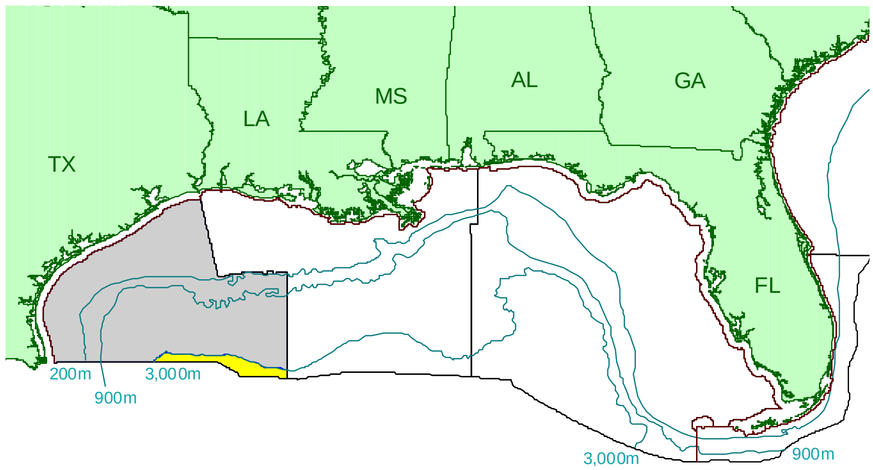

Figure 1. Gulf of Mexico Western Planning Area Map. The planning area is shaded in yellow, and the gray pattern indicates the extent of the assessed plays.

The mean total endowment for this planning area is predominantly gas, with 77 percent of the total resources occurring as gas (figure 2). There is a definite trend towards a less gas-prone bias in the deeper water depths, with the 0-200m water depth range consisting of 88 percent gas, and the deeper water depth ranges consisting of 60 percent gas. The majority of the mean total endowment (61% on a barrels-of-oil-equivalent [BOE] basis) occurs in water depths of less than 200m (figure 3 and figure 4).

The planning area is well developed in the 0-200m range with an extensive infrastructure already in place, less so in the 201-900m range, and very minimally in the 901-3,000m range. There has been production in the two shallower ranges, but as of the date of this study, only unproved reserves and reserves appreciation occurred in the 901-3,000m range (table 1 for Assessment Results Total, table 2 for 0-200m, table 3 for 201-900m, and table 4 for 901-3,000m). Significant amounts of undiscovered conventionally recoverable resources (UCRR) have been assessed for all three water depth ranges, and the full- and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in table 5 (Economic Results Total), table 6 (0-200m), table 7 (201-900m), and table 8 (901-3,000m). These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the three water depth ranges and for the total planning area.

Assessment results indicate that the total planning area undiscovered economically recoverable resources have a range of 1.053 to 3.260 Bbo and 20.110 to 26.386 Tcfg at the 95th and 5th percentiles, respectively, for the full-cycle $18/bbl scenario. The mean economically recoverable resources are estimated at 1.734 Bbo and 22.897 Tcfg. A graphical representation of these results, incorporating every 5th- percentile result for UCRR and UERR, is presented in figure 5 (Results Graph Total), figure 6 (0-200m), figure 7 (201-900m), and figure 8 (901-3,000m). These graphs also present the half-cycle \$18/bbl, and the full- and half-cycle \$30/bbl scenario results. Because the economic model imports field sizes in BOE from the geologic model and then calculates the oil and gas content, the BOE results graph is typically a smooth curve. As expected, the accompanying oil and gas values exhibit more scatter because the gas/oil ratio can vary greatly from one field to another.

The mean total endowment for oil, gas, and BOE by the reserve and resource classification is shown in figure 9 (Mean Endowment Total), figure 10 (0-200m), figure 11 (201-900m), and figure 12 (901-3,000m). The pie charts presented can be used to determine what percentage of oil, gas, or BOE is a result of reserves or of undiscovered resources. For example, 51 percent of the gas in the planning area remains to be discovered, while 70 percent of the oil remains to be discovered (figure 9). Moreover, 31 percent of the gas mean total endowment is remaining to be discovered and is projected to be economically recoverable at the \$18/bbl scenario.

Because estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions, they are presented here as price-supply curves. These curves describe a functional relationship between economically recoverable resources and product price and present the estimates of mean undiscovered economically recoverable oil and gas at any starting oil price up to \$50/bbl. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the ***General Text, Methodology, UERR (Economically Recoverable), Detailed Discussion*** section. 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 are the mean curves. The full-cycle price-supply curves are shown in figure 13 (Full-Cycle P-S Curve Total), figure 14 (0-200m), figure 15 (201-900m), and figure 16 (901-3,000m). The half-cycle price-supply curves are shown in figure 17 (Half-Cycle P-S Curve Total), figure 18 (0-200m), figure 19 (201-900m), and figure 20 (901-3,000m).

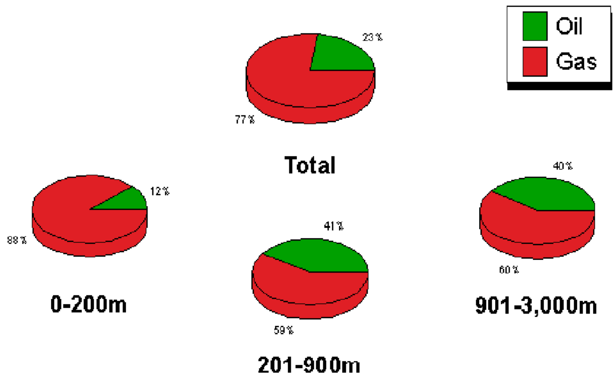

Figure 2. Gulf of Mexico Western Planning Area Percent Oil or Gas by Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

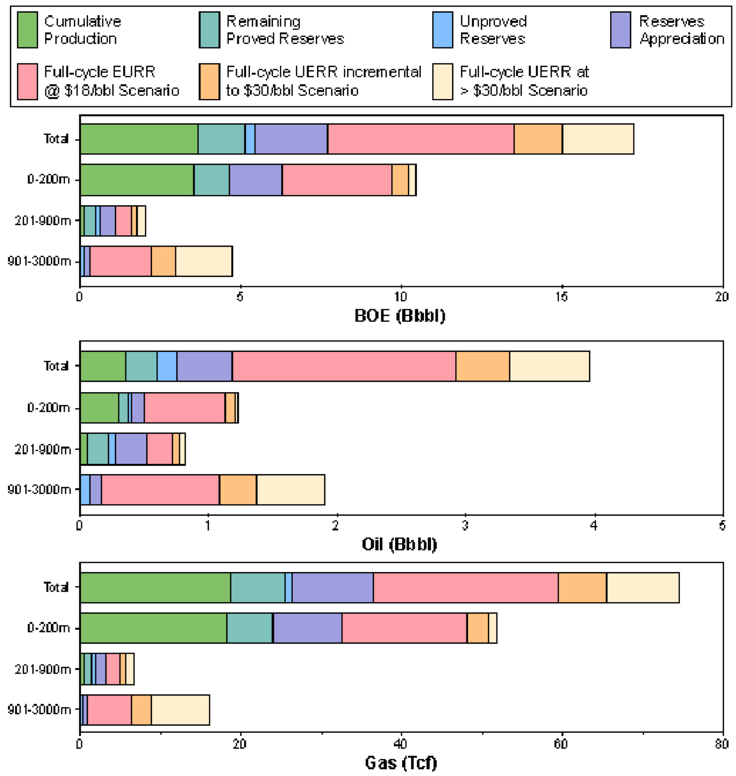

Figure 3. Gulf of Mexico Western Planning Area Mean Total Endowment by Water Depth Category.

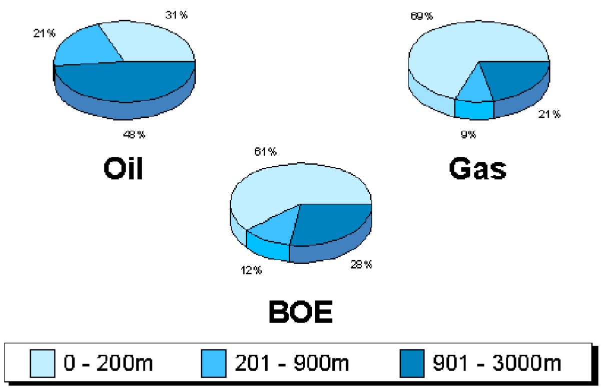

Figure 4. Gulf of Mexico Western Planning Area Mean Total Endowment by Resource Type and Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.596	25.449	5.125
Cumulative production	0.353	18.756	3.691
Remaining proved	0.243	6.693	1.434
Unproved	0.160	0.865	0.314
Appreciation (P & U)	0.430	10.233	2.251
Undiscovered Conventionally Recoverable Resources			
95th percentile	2.178	35.238	8.448
Mean	2.769	38.061	9.542
5th percentile	4.460	41.149	11.781
Total Endowment			
95th percentile	3.364	71.784	16.137
Mean	3.956	74.607	17.231
5th percentile	5.646	77.696	19.471

Table 1. Total Gulf of Mexico Western Planning Area Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.380	23.961	4.643
Cumulative production	0.299	18.232	3.543
Remaining proved	0.080	5.730	1.100
Unproved	0.016	0.031	0.021
Appreciation (P & U)	0.104	8.515	1.619
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.639	17.933	3.830
Mean	0.728	19.320	4.166
5th percentile	0.851	20.815	4.554
Total Endowment			
95th percentile	1.139	50.441	10.114
Mean	1.228	51.827	10.450
5th percentile	1.350	53.322	10.838

Table 2. Gulf of Mexico Western Planning Area 0-200m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.217	1.487	0.481
Cumulative production	0.054	0.524	0.147
Remaining proved	0.163	0.963	0.334
Unproved	0.063	0.437	0.141
Appreciation (P & U)	0.237	1.304	0.469
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.233	3.025	0.771
Mean	0.307	3.501	0.930
5th percentile	0.417	4.028	1.133
Total Endowment			
95th percentile	0.750	6.253	1.862
Mean	0.824	6.729	2.021
5th percentile	0.933	7.256	2.225

Table 3. Gulf of Mexico Western Planning Area 201-900m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.081	0.396	0.151
Appreciation (P & U)	0.089	0.414	0.163
Undiscovered Conventionally Recoverable Resources			
95th percentile	1.128	13.274	3.490
Mean	1.731	15.223	4.439
5th percentile	3.340	17.913	6.527
Total Endowment			
95th percentile	1.298	14.085	3.804
Mean	1.900	16.034	4.754
5th percentile	3.510	18.724	6.841

Table 4. Gulf of Mexico Western Planning Area 901-3,000m Water Depth Assessment Results Table.

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		1.053	20.110	4.632
Mean		1.734	22.897	5.808
5th percentile		3.260	26.386	7.955
Half-Cycle	1.00			
95th percentile		1.262	22.012	5.179
Mean		1.900	24.920	6.334
5th percentile		3.418	28.234	8.442
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		1.543	26.106	6.188
Mean		2.156	28.891	7.297
5th percentile		3.825	32.189	9.553
Half-Cycle	1.00			
95th percentile		1.653	27.652	6.574
Mean		2.259	30.517	7.689
5th percentile		3.916	33.796	9.930

Table 5. Total Gulf of Mexico Western Planning Area Economic Assessment Results Table.

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		0.530	14.162	3.050
Mean		0.630	15.564	3.399
5th percentile		0.742	17.219	3.806
Half-Cycle	1.00			
95th percentile		0.551	14.866	3.196
Mean		0.650	16.258	3.542
5th percentile		0.764	17.837	3.938
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.620	16.839	3.616
Mean		0.703	18.269	3.954
5th percentile		0.826	19.727	4.336
Half-Cycle	1.00			
95th percentile		0.620	17.138	3.669
Mean		0.707	18.529	4.004
5th percentile		0.829	19.995	4.387

Table 6. Gulf of Mexico Western Planning Area 0-200m Water Depth Economic Assessment Results Table.

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		0.122	1.082	0.314
Mean		0.204	1.796	0.523
5th percentile		0.313	2.580	0.772
Half-Cycle	1.00			
95th percentile		0.146	1.276	0.373
Mean		0.222	2.048	0.586
5th percentile		0.352	2.692	0.831
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.175	1.829	0.500
Mean		0.253	2.502	0.699
5th percentile		0.400	2.922	0.920
Half-Cycle	1.00			
95th percentile		0.184	2.086	0.555
Mean		0.264	2.693	0.743
5th percentile		0.391	3.227	0.965

Table 7. Gulf of Mexico Western Planning Area 201-900m Water Depth Economic Assessment Results Table.

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		0.276	3.053	0.820
Mean		0.916	5.508	1.896
5th percentile		2.535	8.496	4.046
Half-Cycle	1.00			
95th percentile		0.396	4.434	1.185
Mean		1.052	6.677	2.240
5th percentile		2.686	9.578	4.390
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.590	5.915	1.643
Mean		1.198	8.126	2.644
5th percentile		2.817	10.992	4.773
Half-Cycle	1.00			
95th percentile		0.678	7.148	1.950
Mean		1.288	9.316	2.946
5th percentile		2.903	12.175	5.069

Table 8. Gulf of Mexico Western Planning Area 901-3,000m Water Depth Economic Assessment Results Table.

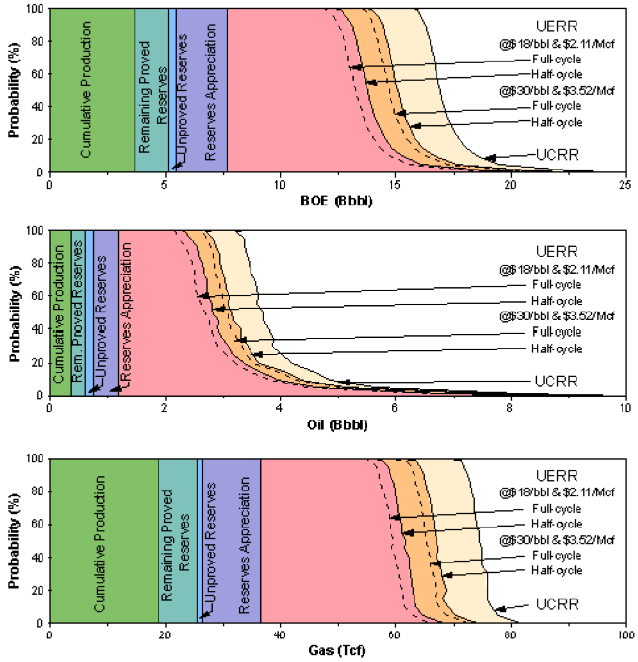

Figure 5. Gulf of Mexico Western Planning Area Total Endowment by Resource Category.

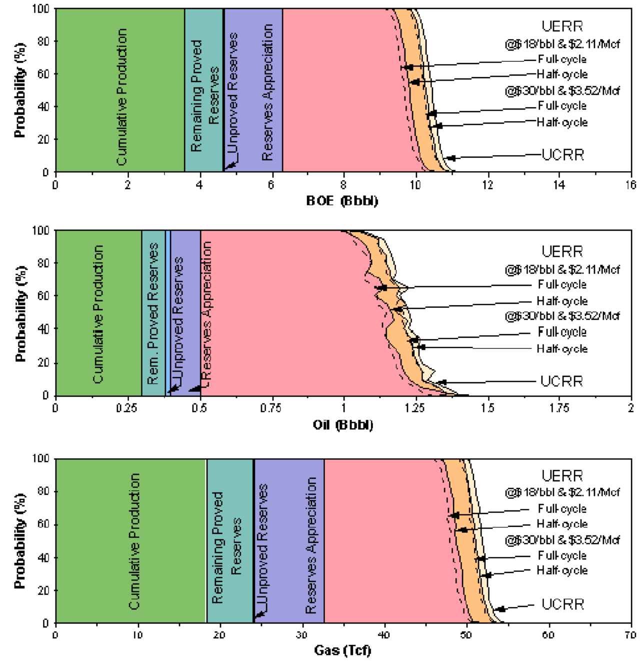

Figure 6. Gulf of Mexico Western Planning Area 0-200m Water Depth Total Endowment by Resource Category.

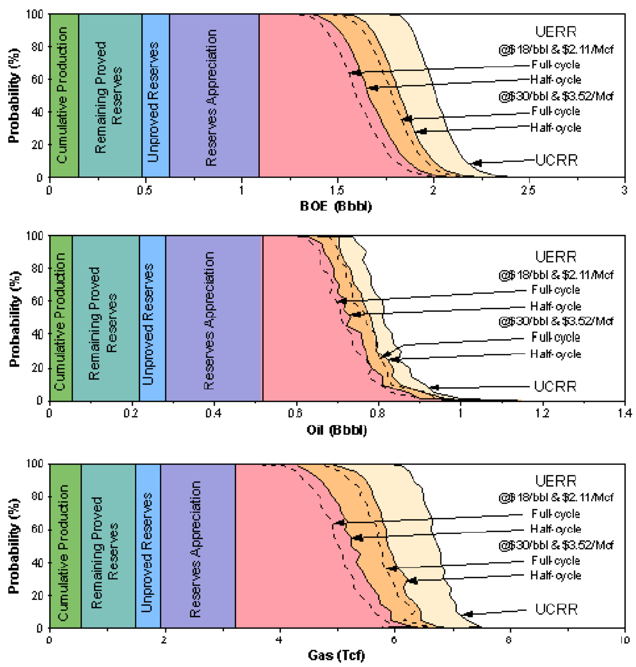

Figure 7. Gulf of Mexico Western Planning Area 201-900m Water Depth Total Endowment by Resource Category.

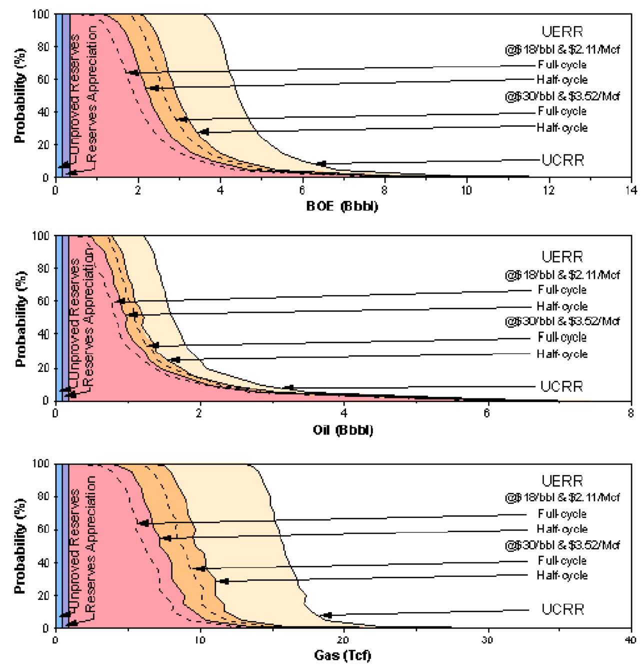

Figure 8. Gulf of Mexico Western Planning Area 901-3,000m Water Depth Total Endowment by Resource Category.

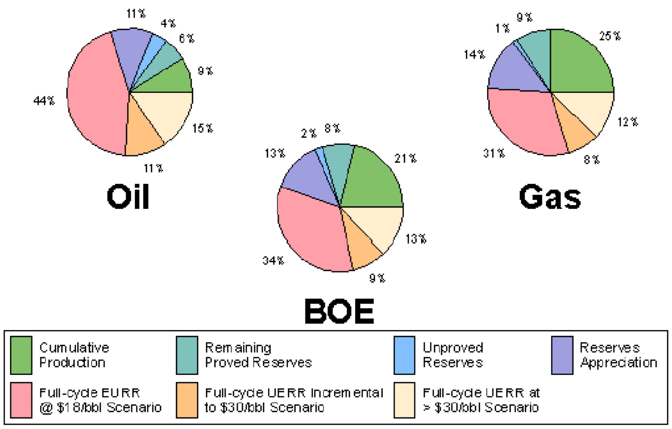

Figure 9. Total Gulf of Mexico Western Planning Area Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

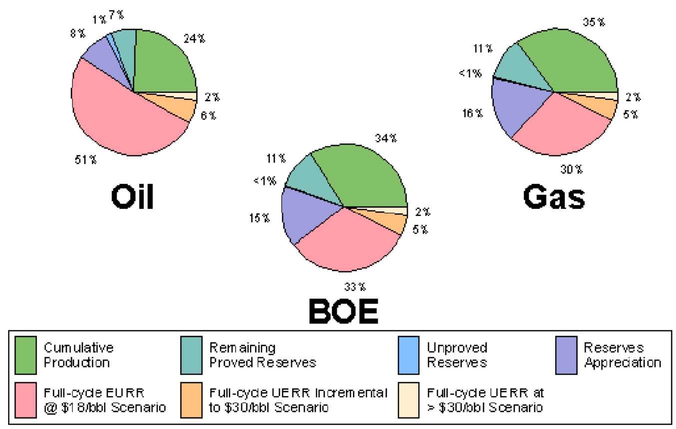

Figure 10. Gulf of Mexico Western Planning Area 0-200m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

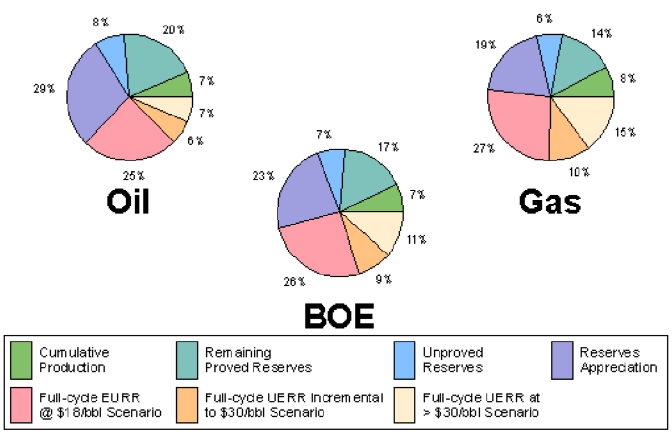

Figure 11. Gulf of Mexico Western Planning Area 201-900m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

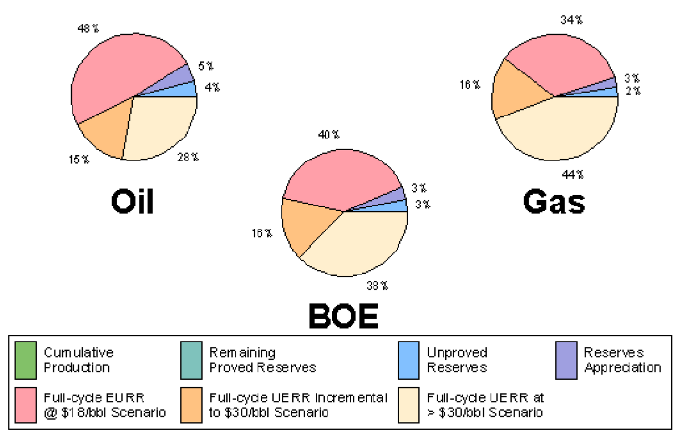

Figure 12. Gulf of Mexico Western Planning Area 901-3,000m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

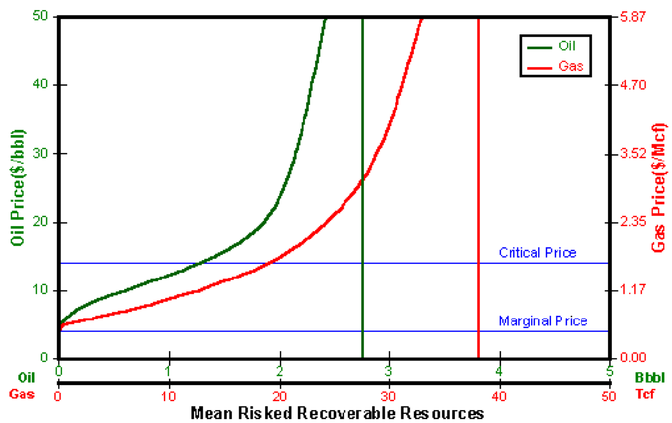

Figure 13. Total Gulf of Mexico Western Planning Area Full-Cycle Price-Supply Curve.

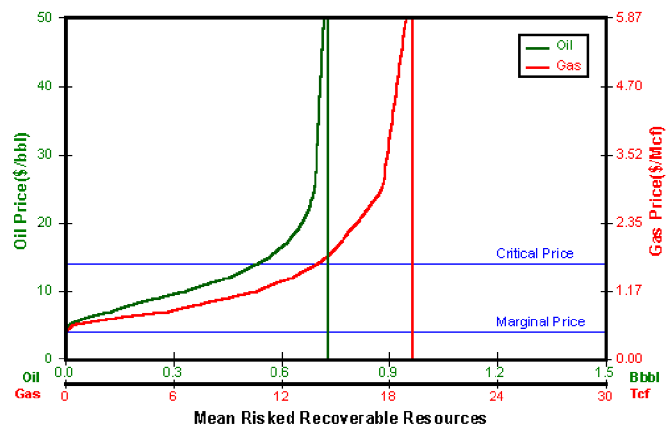

Figure 14. Gulf of Mexico Western Planning Area 0-200m Water Depth Full-Cycle Price-Supply Curve.

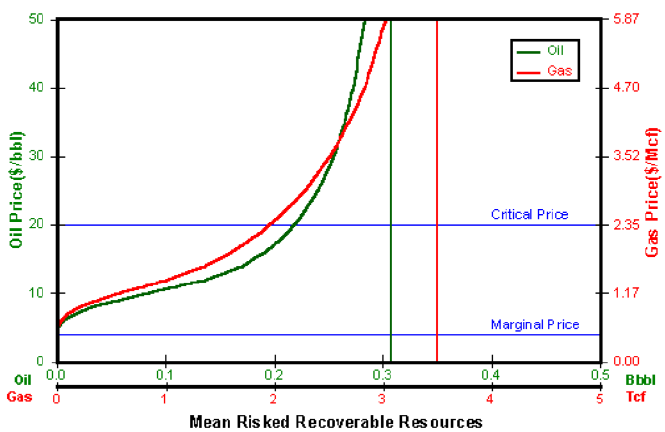

Figure 15. Gulf of Mexico Western Planning Area 201-900m Water Depth Full-Cycle Price-Supply Curve.

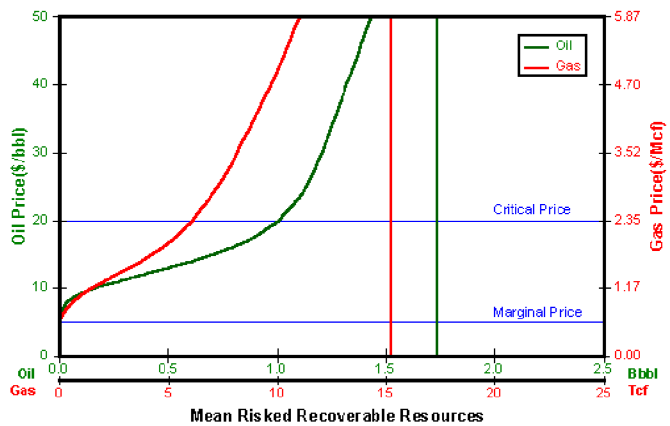

Figure 16. Gulf of Mexico Western Planning Area 901-3,000m Water Depth Full-Cycle Price-Supply Curve.

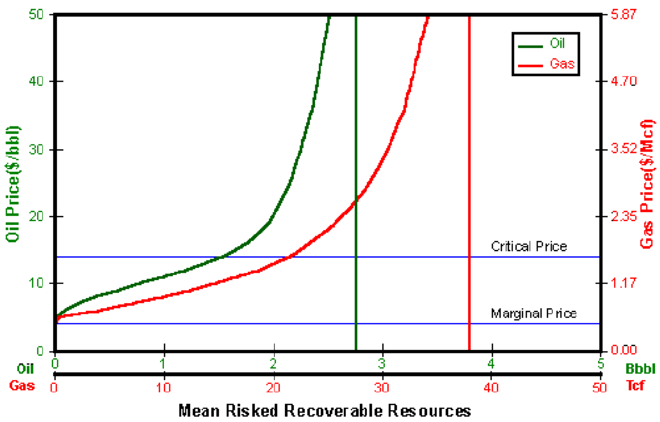

Figure 17. Total Gulf of Mexico Western Planning Area Half-Cycle Price-Supply Curve.

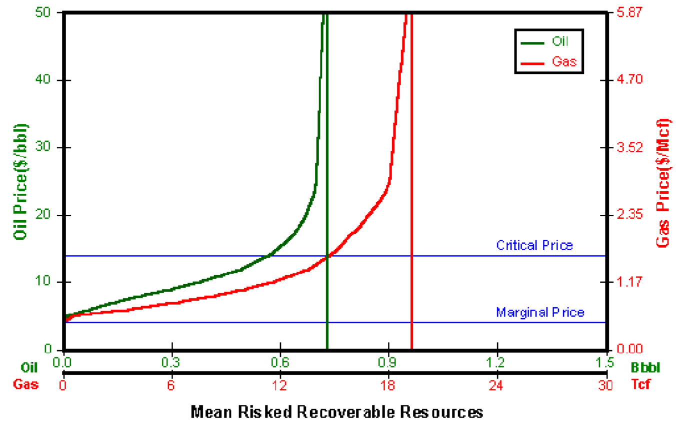

Figure 18. Gulf of Mexico Western Planning Area 0-200m Water Depth Half-Cycle Price-Supply Curve.

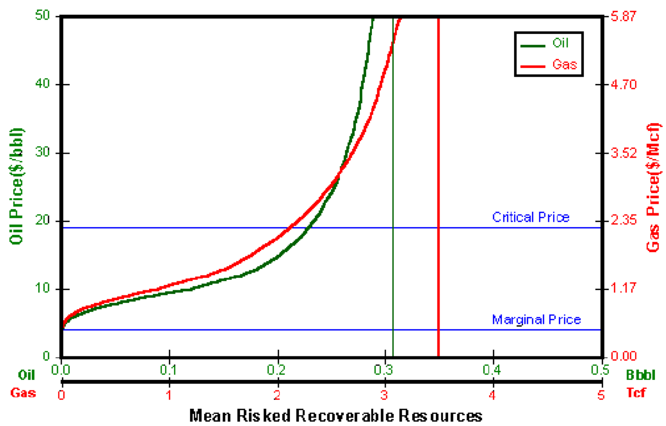

Figure 19. Gulf of Mexico Western Planning Area 201-900m Water Depth Half-Cycle Price-Supply Curve.

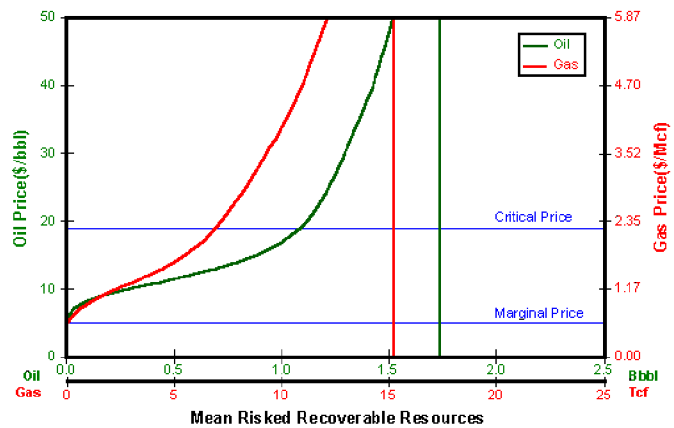

Figure 20. Gulf of Mexico Western Planning Area 901-3,000m Water Depth Half-Cycle Price-Supply Curve.

Gulf of Mexico Central Planning Area Economic Results

The Gulf of Mexico Central Planning Area includes submerged Federal lands offshore Louisiana, Mississippi, and Alabama, and extends to the U.S. International Boundary in the south (figure 1). Water depths in the planning area range from very shallow to more than 3,000m. Because water depth and distance from shore have a significant effect on engineering and cost factors, the undiscovered economically recoverable resources (UERR) were evaluated for three water depth ranges, 0-200m, 201-900m, and 901-3,000m (no resources were evaluated in water depths greater than 3,000m).

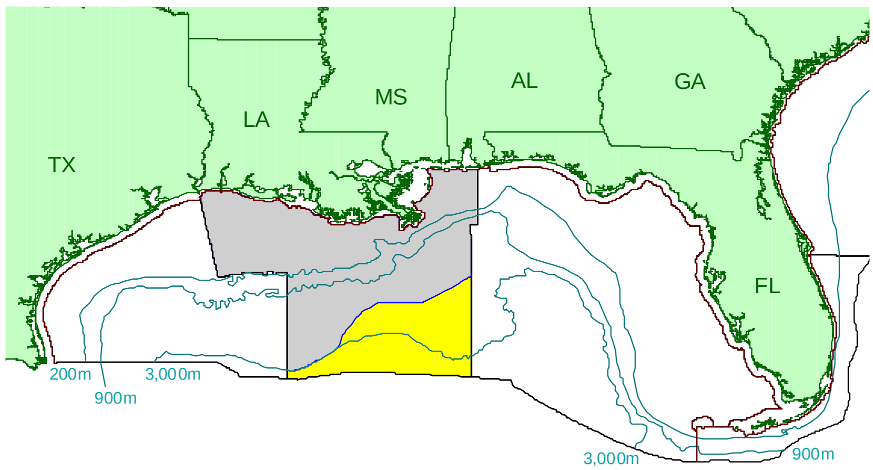

Figure 1. Gulf of Mexico Central Planning Area Map. The planning area is shaded in yellow, and the gray pattern indicates the extent of the assessed plays.

The mean total endowment for this planning area is predominantly gas, with 66 percent of the total resources occurring as gas (figure 2). There is a slight trend towards a less gas-prone bias in the deeper water depths, with the 0-200m water depth range consisting of 68 percent gas, and the deepest water depth range consisting of 63 percent gas. The majority of the mean total endowment (78% on a barrels-of-oil-equivalent [BOE] basis) occurs in water depths of less than 200m (figure 3 and figure 4).

The planning area is well developed in the 0-200m range with an extensive infrastructure already in place, less so in the 201-900m range, and minimally in the 901-3,000m range. There has been production in the two shallower ranges, but as of the date of this study, only proved and unproved reserves and reserves appreciation occurred in the 901-3,000m range (table 1 for Assessment Results Total, table 2 for 0-200m, table 3 for 201-900m, and table 4 for 901-3,000m buttons). Significant amounts of undiscovered conventionally recoverable resources (UCRR) have been assessed for all three water depth ranges, and the full- and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in table 5 (Economic Results Total), table 6 (0-200m), table 7 (201-900m), and table 8 (901-3,000m). These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the three water depth ranges and for the total planning area.

Assessment results indicate that the total planning area undiscovered economically recoverable resources have a range of 1.857 to 2.428 Bbo and 27.572 to 32.718 Tcfg at the 95th and 5th percentiles, respectively, for the full-cycle $18/bbl scenario. The mean economically recoverable resources are estimated at 2.115 Bbo and 30.216 Tcfg. A graphical representation of these results, incorporating every 5th- percentile result for UCRR and UERR, is presented in figure 5 (Results Graph Total), figure 6 (0-200m), figure 7 (201-900m), and figure 8 (901-3,000m). These graphs also present the half-cycle $18/bbl, and the full- and half-cycle $30/bbl scenario results. Because the economic model imports field sizes in BOE from the geologic model and then calculates the oil and gas content, the BOE results graph is typically a smooth curve. As expected, the accompanying oil and gas values exhibit more scatter because the gas/oil ratio can vary greatly from one field to another.

The mean total endowment for oil, gas, and BOE by the reserve and resource classification is shown in figure 9 (Mean Endowment Total), figure 10 (0-200m), figure 11 (201-900m), and figure 12 (901-3,000m). The pie charts presented can be used to determine what percentage of oil, gas, or BOE is a result of reserves or of undiscovered resources. For example, only 26 percent of the gas in the planning area remains to be discovered, and only 20 percent of the oil remains to be discovered (figure 9). Moreover, 16 percent of the gas mean total endowment is remaining to be discovered and is projected to be economically recoverable at the $18/bbl scenario.

Because estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions, they are presented here as price-supply curves. These curves describe a functional relationship between economically recoverable resources and product price and present the estimates of mean undiscovered economically recoverable oil and gas at any starting oil price up to $50/bbl. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the ***General Text, Methodology, UERR (Economically Recoverable), Detailed Discussion*** section. 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 are the mean curves. The full-cycle price-supply curves are shown in figure 13 (Full-Cycle P-S Curve Total), figure 14 (0-200m), figure 15 (201-900m), and figure 16 (901-3,000m). The half-cycle price-supply curves are shown in figure 17 (Half-Cycle P-S Curve Total), figure 18 (0-200m), figure 19 (201-900m), and figure 20 (901-3,000m).

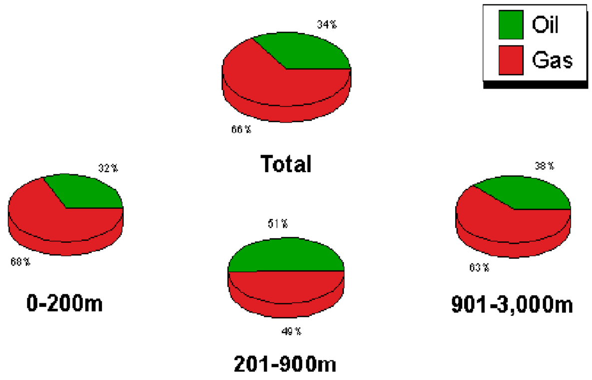

Figure 2. Gulf of Mexico Central Planning Area Percent Oil or Gas by Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

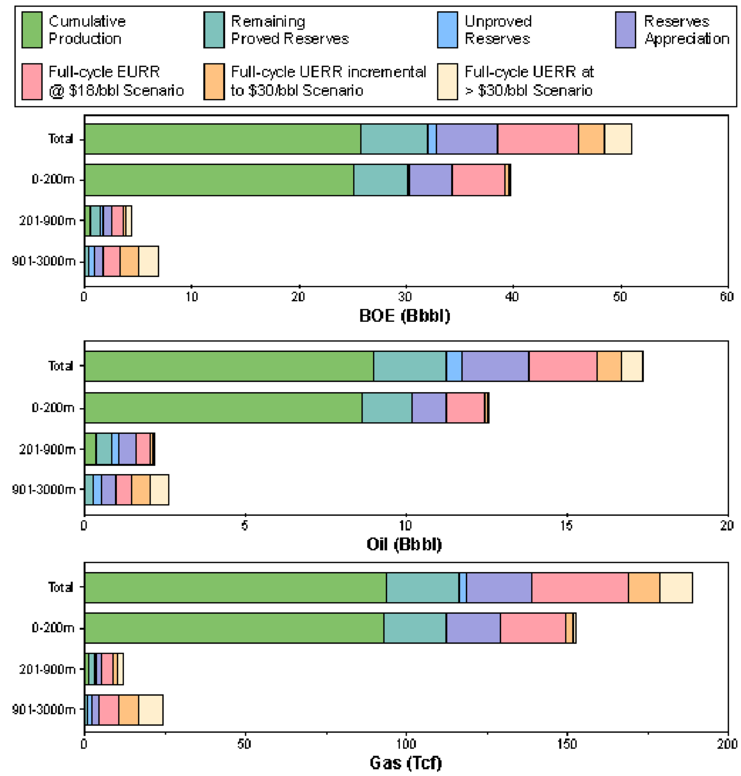

Figure 3. Gulf of Mexico Central Planning Area Mean Total Endowment by Water Depth Category.

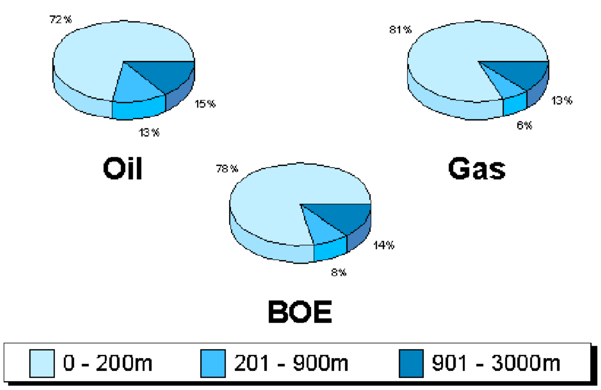

Figure 4. Gulf of Mexico Central Planning Area Mean Total Endowment by Resource Type and Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	11.257	116.442	31.976
Cumulative production	8.984	93.877	25.688
Remaining proved	2.273	22.565	6.288
Unproved	0.478	2.209	0.871
Appreciation (P & U)	2.077	20.264	5.683
Undiscovered Conventionally Recoverable Resources			
95th percentile	3.317	48.175	11.889
Mean	3.550	49.978	12.443
5th percentile	3.809	52.061	13.073
Total Endowment			
95th percentile	17.130	187.090	50.420
Mean	17.363	188.893	50.973
5th percentile	17.622	190.976	51.604

Table 1. Total Gulf of Mexico Central Planning Area Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	10.155	112.271	30.132
Cumulative production	8.638	92.712	25.135
Remaining proved	1.516	19.559	4.997
Unproved	0.017	0.278	0.066
Appreciation (P & U)	1.068	16.477	4.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	1.215	22.410	5.202
Mean	1.342	23.565	5.535
5th percentile	1.524	24.538	5.890
Total Endowment			
95th percentile	12.454	151.436	39.400
Mean	12.581	152.591	39.733
5th percentile	12.763	153.564	40.088

Table 2. Gulf of Mexico Central Planning Area 0-200m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.826	3.266	1.408
Cumulative production	0.346	1.165	0.553
Remaining proved	0.481	2.101	0.854
Unproved	0.218	0.436	0.295
Appreciation (P & U)	0.541	1.741	0.851
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.451	5.660	1.458
Mean	0.604	6.581	1.775
5th percentile	0.874	8.334	2.357
Total Endowment			
95th percentile	2.036	11.103	4.012
Mean	2.189	12.024	4.329
5th percentile	2.459	13.777	4.911

Table 3. Gulf of Mexico Central Planning Area 201-900m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.276	0.905	0.437
Cumulative production	0.000	0.000	0.000
Remaining proved	0.276	0.905	0.437
Unproved	0.244	1.494	0.510
Appreciation (P & U)	0.468	2.046	0.832
Undiscovered Conventionally Recoverable Resources			
95th percentile	1.528	18.766	4.868
Mean	1.605	19.840	5.135
5th percentile	1.678	21.021	5.418
Total Endowment			
95th percentile	2.516	23.211	6.646
Mean	2.593	24.286	6.914
5th percentile	2.665	25.467	7.197

Table 4. Gulf of Mexico Central Planning Area 901-3,000m Water Depth Assessment Results Table.

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		1.857	27.572	6.763
Mean		2.115	30.216	7.492
5th percentile		2.428	32.718	8.250
Half-Cycle	1.00			
95th percentile		1.945	29.416	7.179
Mean		2.216	31.904	7.893
5th percentile		2.557	34.306	8.661
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		2.636	37.436	9.297
Mean		2.863	39.758	9.937
5th percentile		3.164	41.988	10.635
Half-Cycle	1.00			
95th percentile		2.695	38.400	9.527
Mean		2.925	40.673	10.162
5th percentile		3.224	42.914	10.860

Table 5. Total Gulf of Mexico Central Planning Area Economic Assessment Results Table.

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		1.095	19.453	4.557
Mean		1.212	20.713	4.898
5th percentile		1.406	21.695	5.267
Half-Cycle	1.00			
95th percentile		1.117	20.350	4.738
Mean		1.236	21.570	5.074
5th percentile		1.434	22.531	5.443
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		1.158	21.517	4.986
Mean		1.295	22.618	5.320
5th percentile		1.488	23.565	5.681
Half-Cycle	1.00			
95th percentile		1.168	21.705	5.030
Mean		1.302	22.808	5.361
5th percentile		1.487	23.789	5.720

Table 6. Gulf of Mexico Central Planning Area 0-200m Water Depth Economic Assessment Results Table.

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		0.281	2.214	0.675
Mean		0.431	3.382	1.032
5th percentile		0.692	5.200	1.617
Half-Cycle	1.00			
95th percentile		0.285	2.484	0.727
Mean		0.445	3.565	1.079
5th percentile		0.693	5.450	1.663
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.357	3.669	1.010
Mean		0.520	4.683	1.353
5th percentile		0.780	6.571	1.950
Half-Cycle	1.00			
95th percentile		0.362	3.830	1.044
Mean		0.529	4.846	1.391
5th percentile		0.800	6.654	1.984

Table 7. Gulf of Mexico Central Planning Area 201-900m Water Depth Economic Assessment Results Table.

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		0.352	4.186	1.097
Mean		0.477	6.190	1.578
5th percentile		0.601	8.195	2.060
Half-Cycle	1.00			
95th percentile		0.424	4.848	1.286
Mean		0.538	6.816	1.751
5th percentile		0.667	8.759	2.226
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.946	11.059	2.914
Mean		1.051	12.509	3.276
5th percentile		1.148	14.118	3.660
Half-Cycle	1.00			
95th percentile		1.006	11.587	3.068
Mean		1.094	13.078	3.421
5th percentile		1.186	14.725	3.806

Table 8. Gulf of Mexico Central Planning Area 901-3,000m Water Depth Economic Assessment Results Table.

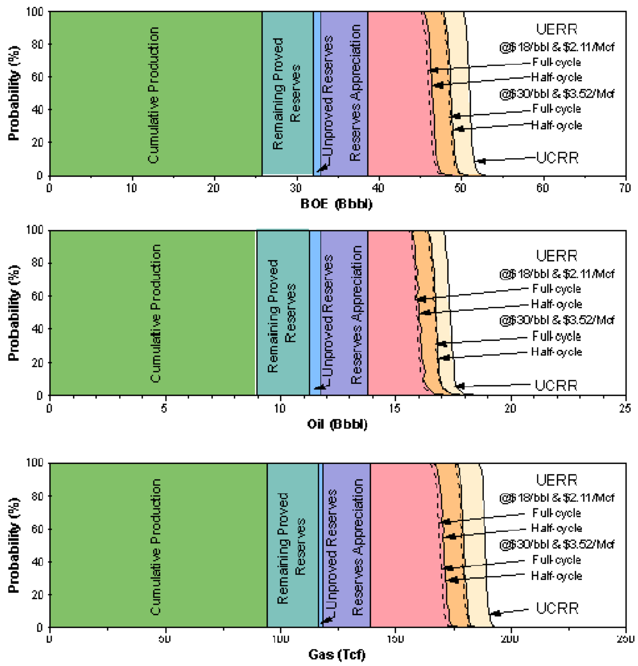

Figure 5. Gulf of Mexico Central Planning Area Total Endowment by Resource Category.

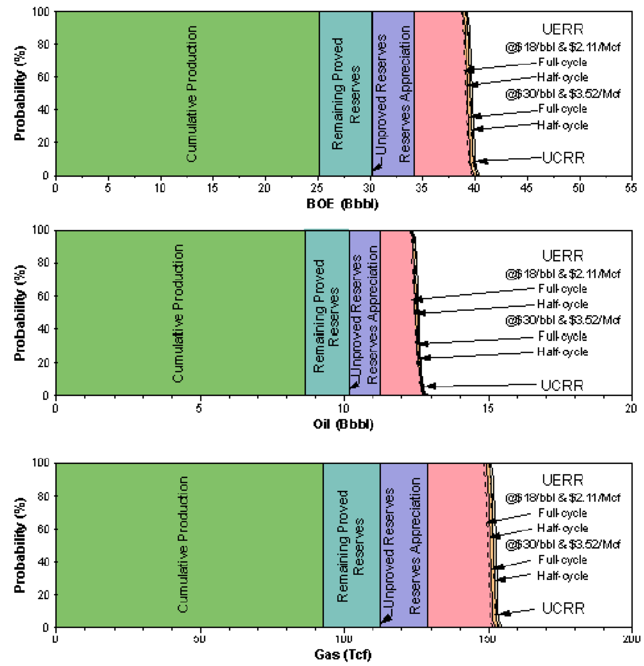

Figure 6. Gulf of Mexico Central Planning Area 0-200m Water Depth Total Endowment by Resource Category.

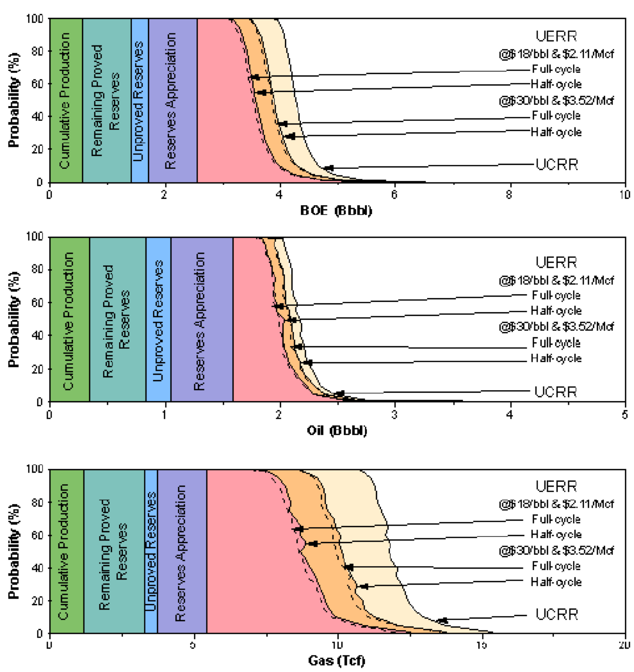

Figure 7. Gulf of Mexico Central Planning Area 201-900m Water Depth Total Endowment by Resource Category.

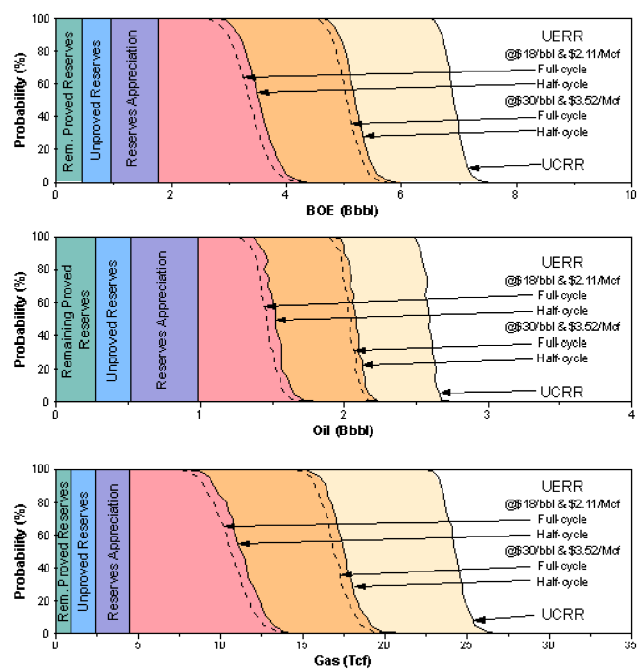

Figure 8. Gulf of Mexico Central Planning Area 901-3,000m Water Depth Total Endowment by Resource Category.

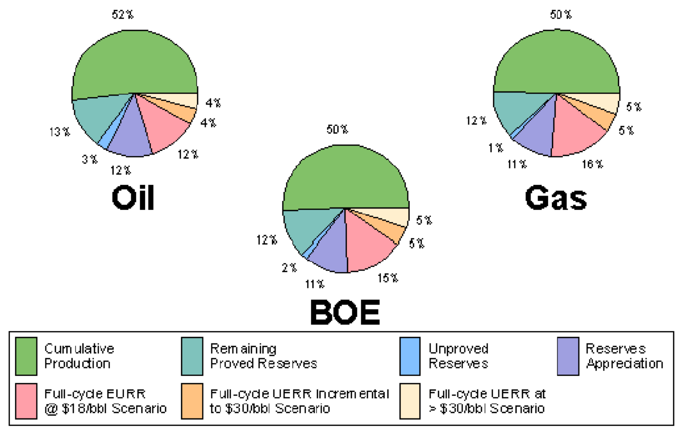

Figure 9. Total Gulf of Mexico Central Planning Area Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

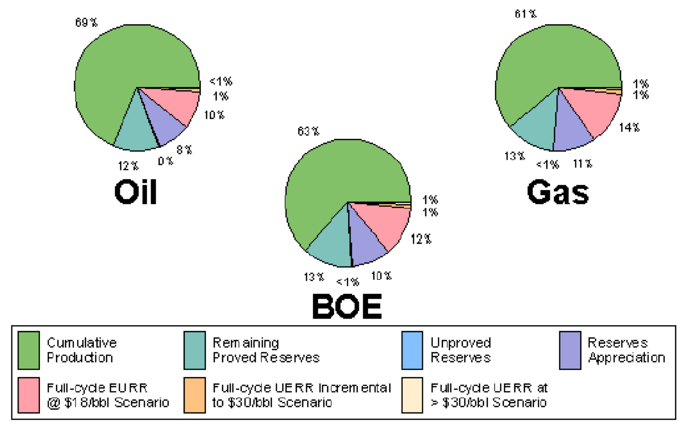

Figure 10. Gulf of Mexico Central Planning Area 0-200m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

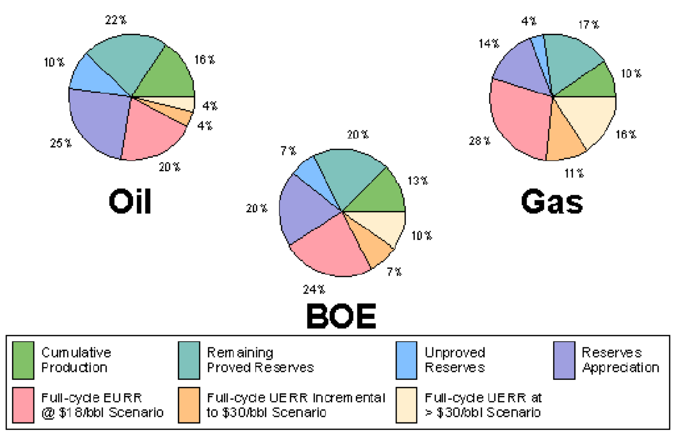

Figure 11. Gulf of Mexico Central Planning Area 201-900m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

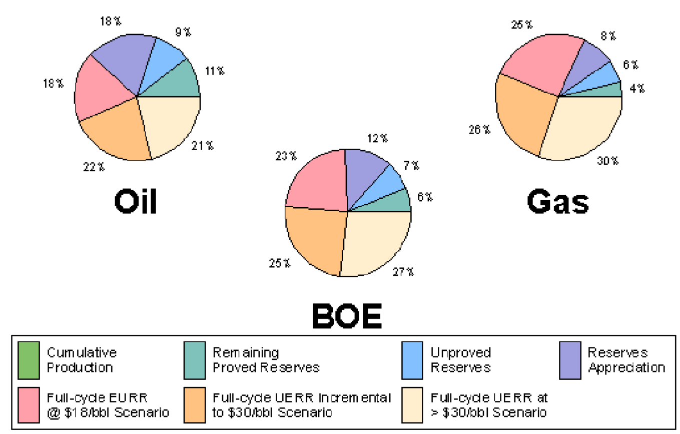

Figure 12. Gulf of Mexico Central Planning Area 901-3,000m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

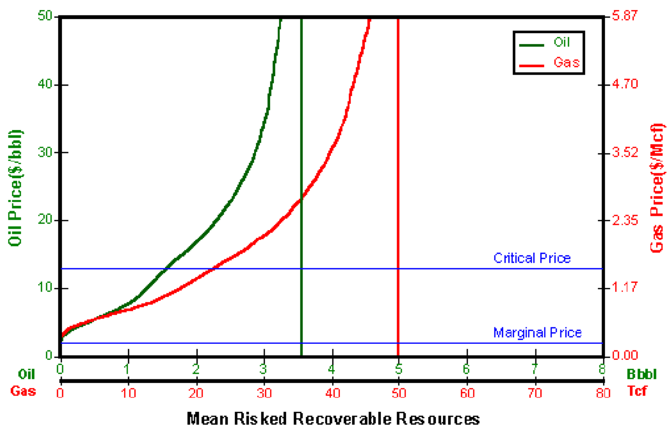

Figure 13. Total Gulf of Mexico Central Planning Area Full-Cycle Price-Supply Curve.

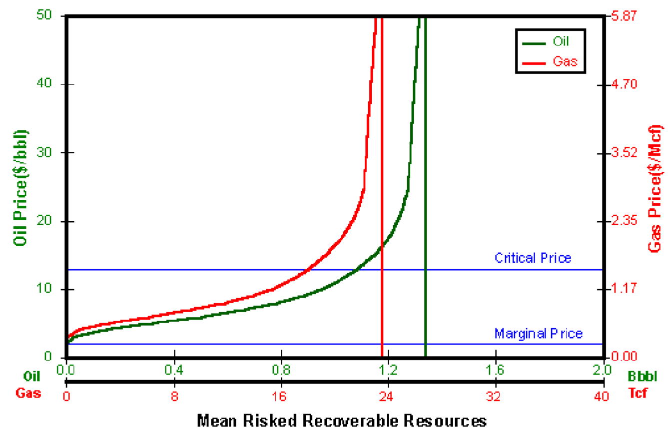

Figure 14. Gulf of Mexico Central Planning Area 0-200m Water Depth Full-Cycle Price-Supply Curve.

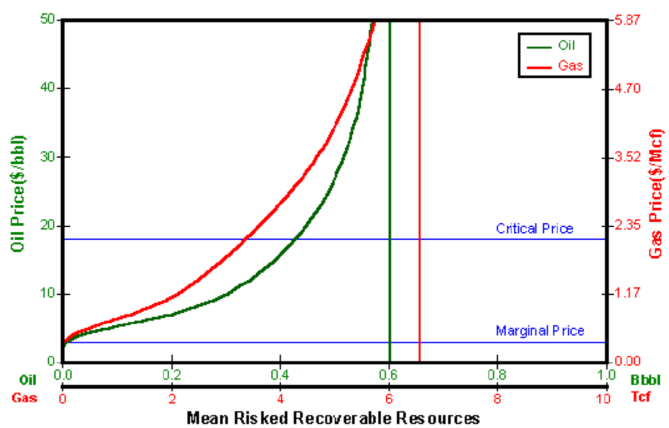

Figure 15. Gulf of Mexico Central Planning Area 201-900m Water Depth Full-Cycle Price-Supply Curve.

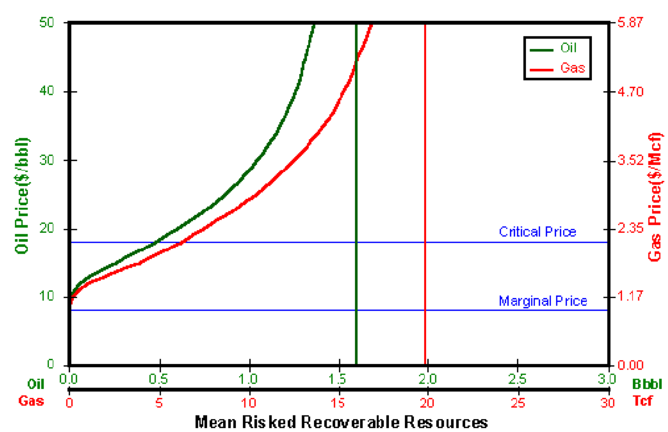

Figure 16. Gulf of Mexico Central Planning Area 901-3,000m Water Depth Full-Cycle Price-Supply Curve.

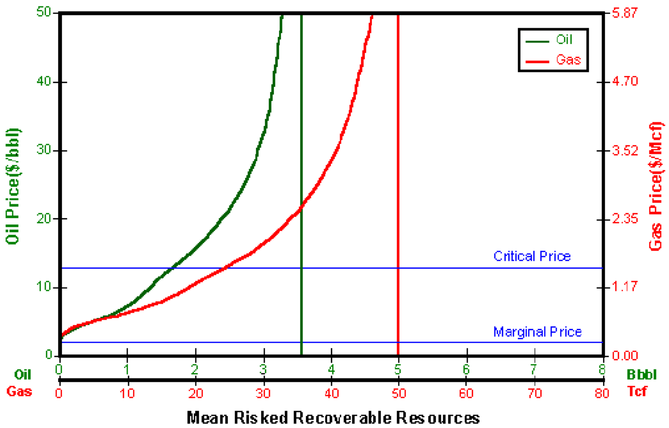

Figure 17. Total Gulf of Mexico Central Planning Area Half-Cycle Price-Supply Curve.

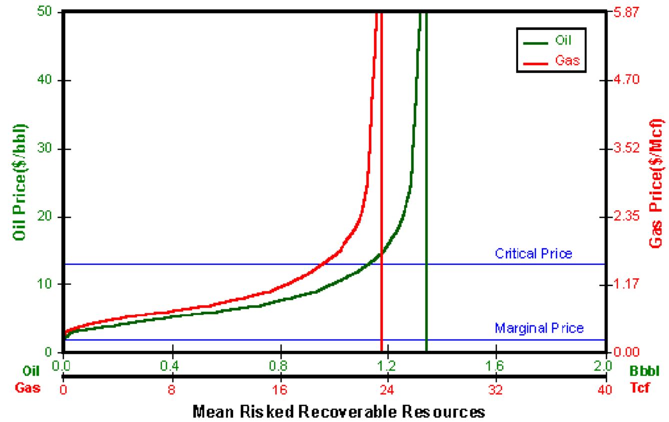

Figure 19. Gulf of Mexico Central Planning Area 0-200m Water Depth Half-Cycle Price-Supply Curve.

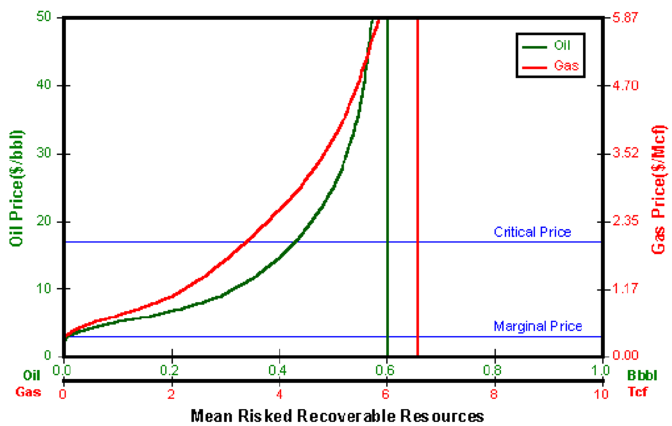

Figure 19. Gulf of Mexico Central Planning Area 201-900m Water Depth Half-Cycle Price-Supply Curve.

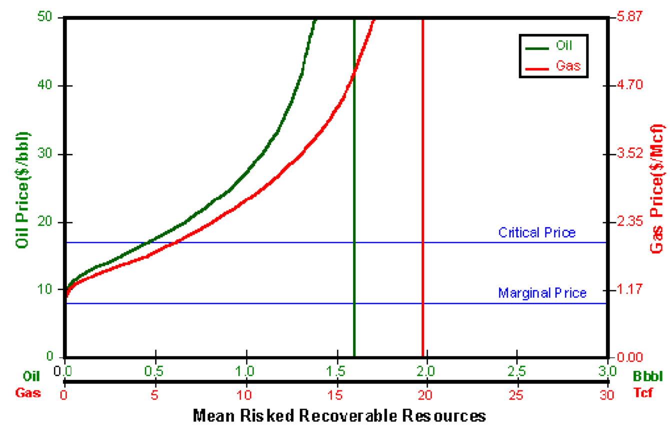

Figure 20. Gulf of Mexico Central Planning Area 901-3,000m Water Depth Half-Cycle Price-Supply Curve.

Gulf of Mexico Eastern Planning Area Economic Results

The Gulf of Mexico Eastern Planning Area includes submerged Federal lands offshore Alabama and Florida, and extends to the U.S.-Cuba International Boundary in the south (figure 1). Water depths in the planning area range from very shallow to more than 3,000m. Because water depth and distance from shore have a significant effect on engineering and cost factors, the undiscovered economically recoverable resources (UERR) were evaluated for three water depth ranges, 0-200m, 201-900m, and 901-3,000m (no resources were evaluated in water depths greater than 3,000m).

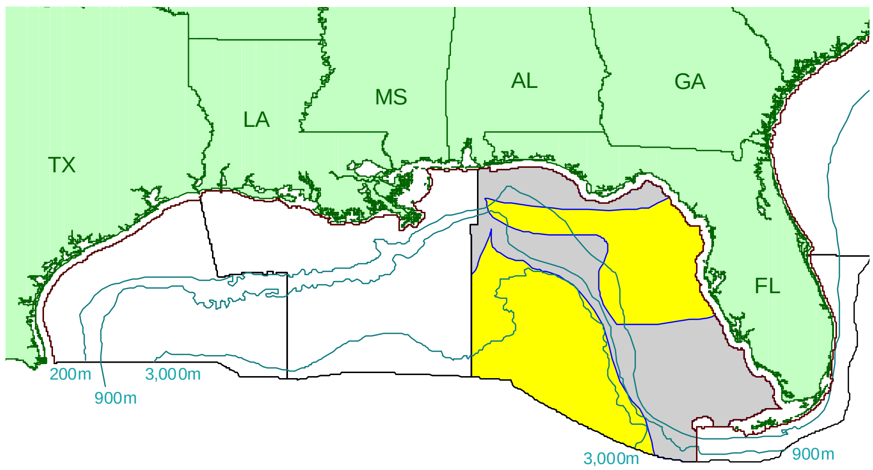

Figure 1. Gulf of Mexico Eastern Planning Area Map. The planning area is shaded in yellow, and the gray pattern indicates the extent of the assessed plays.

The mean total endowment for this planning area is a mix of oil and gas, with 45 percent of the total resources occurring as gas (figure 2). There is a slight trend towards a more gas-prone bias in the deeper water depths, with the 0-200m water depth range consisting of 44 percent gas, and the deepest water depth range consisting of 54 percent gas. The majority of the mean total endowment (81% on a barrels-of-oil-equivalent [BOE] basis) occurs in water depths of less than 200m (figure 3 and figure 4).

The planning area is not well developed in any of the water depth ranges, and there is little to no infrastructure in place. As of the date of this study, there has been no production or proved reserves in any of the ranges, but there are unproved reserves and reserves appreciation in the 0-200m and 901-3,000m ranges (table 1 for Assessment Results Total, table 2 for 0-200m, table 3 for 201-900m, and table 4 for 901-3,000m). Undiscovered conventionally recoverable resources (UCRR) have been assessed for all three water depth ranges, and the full- and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in table 5 (Economic Results Total), table 6 (0-200m), table 7 for (201-900m), and table 8 (901-3,000m buttons). These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the three water depth ranges and for the total planning area.

Assessment results indicate that the total planning area undiscovered economically recoverable resources have a range of 0.676 to 1.508 Bbo and 3.492 to 5.601 Tcfg at the 95th and 5th percentiles, respectively, for the full-cycle $18/bbl scenario. The mean economically recoverable resources are estimated at 1.071 Bbo and 4.476 Tcfg. A graphical representation of these results, incorporating every 5th- percentile result for UCRR and UERR, is presented in figure 5 (Results Graph Total), figure 6 (0-200m), figure 7 (201-900m), and figure 8 (901-3,000m). These graphs also present the half-cycle $18/bbl, and the full- and half-cycle $30/bbl scenario results. Because the economic model imports field sizes in BOE from the geologic model and then calculates the oil and gas content, the BOE results graph is typically a smooth curve. As expected, the accompanying oil and gas values exhibit more scatter because the gas/oil ratio can vary greatly from one field to another.

The mean total endowment for oil, gas, and BOE by the reserve and resource classification is shown in figure 9 (Mean Endowment Total), figure 10 (0-200m), figure 11 (201-900m), and figure 12 (901-3,000m). The pie charts presented can be used to determine what percentage of oil, gas, or BOE is a result of reserves or of undiscovered resources. For example, 88 percent of the gas in the planning area remains to be discovered, while 99 percent of the oil remains to be discovered (figure 9). Moreover, 52 percent of the mean total endowment, on a BOE basis, is remaining to be discovered and is projected to be economically recoverable at the $18/bbl scenario.

Because estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions, they are presented here as price-supply curves. These curves describe a functional relationship between economically recoverable resources and product price and present the estimates of mean undiscovered economically recoverable oil and gas at any starting oil price up to $50/bbl. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the ***General Text, Methodology, UERR (Economically Recoverable), Detailed Discussion*** section. 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 are the mean curves. The full-cycle price-supply curves are shown in figure 13 (Full-Cycle P-S Curve Total), figure 14 (0-200m), figure 15 (201-900m), and figure 16 (901-3,000m). The half-cycle price-supply curves are shown in figure 17 (Half-Cycle P-S Curve Total), figure 18 (0-200m), figure 19 (201-900m), and figure 20 (901-3,000m).

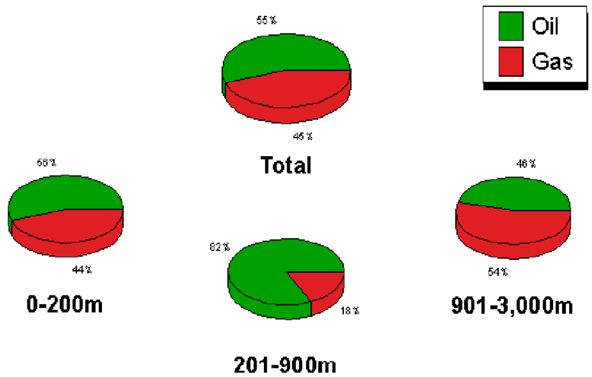

Figure 2. Gulf of Mexico Eastern Planning Area Percent Oil or Gas by Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

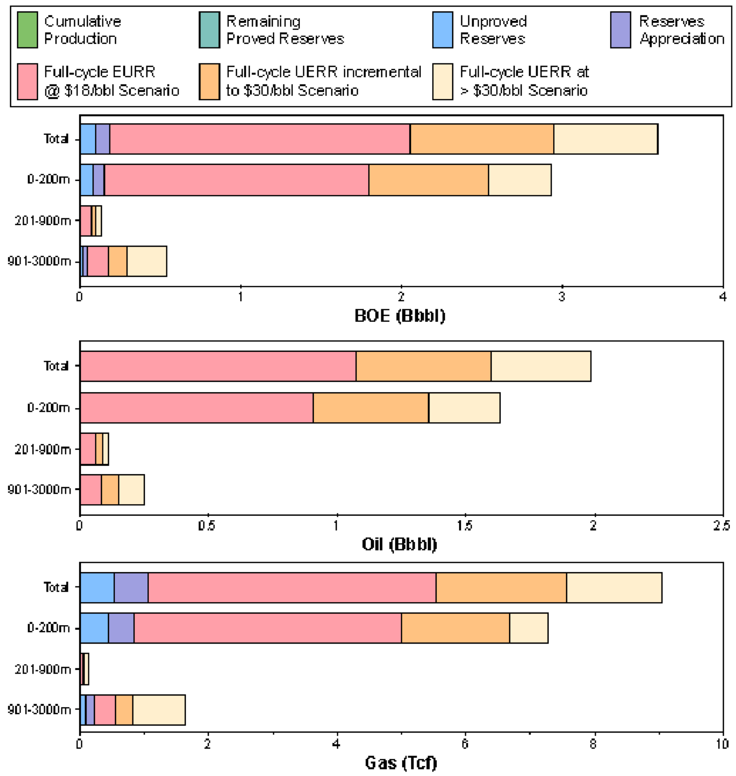

Figure 3. Gulf of Mexico Eastern Planning Area Mean Total Endowment by Water Depth Category.

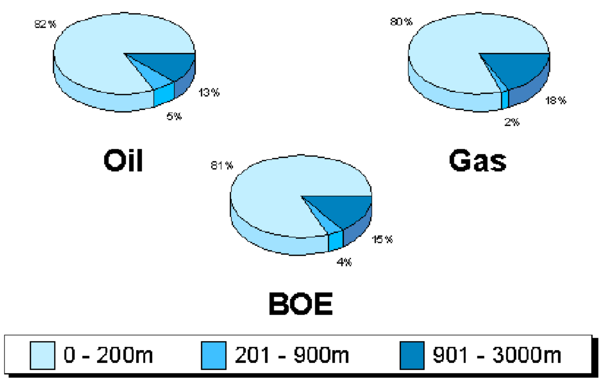

Figure 4. Gulf of Mexico Eastern Planning Area Mean Total Endowment by Resource Type and Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	<0.001	0.530	0.094
Appreciation (P & U)	<0.001	0.531	0.095
Undiscovered Conventionally Recoverable Resources			
95th percentile	1.575	7.466	2.903
Mean	1.985	7.981	3.406
5th percentile	2.451	8.722	4.003
Total Endowment			
95th percentile	1.575	8.527	3.092
Mean	1.986	9.042	3.594
5th percentile	2.452	9.782	4.192

Table 1. Total Gulf of Mexico Eastern Planning Area Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	<0.001	0.451	0.080
Appreciation (P & U)	<0.001	0.383	0.068
Undiscovered Conventionally Recoverable Resources			
95th percentile	1.269	6.117	2.357
Mean	1.630	6.439	2.776
5th percentile	2.086	6.725	3.283
Total Endowment			
95th percentile	1.269	6.951	2.506
Mean	1.630	7.273	2.925
5th percentile	2.086	7.559	3.431

Table 2. Gulf of Mexico Eastern Planning Area 0-200m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.064	0.092	0.080
Mean	0.109	0.138	0.133
5th percentile	0.180	0.229	0.220
Total Endowment			
95th percentile	0.064	0.092	0.080
Mean	0.109	0.138	0.133
5th percentile	0.180	0.229	0.220

Table 3. Gulf of Mexico Eastern Planning Area 201-900m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	<0.001	0.078	0.014
Appreciation (P & U)	<0.001	0.148	0.026
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.151	0.938	0.318
Mean	0.249	1.408	0.500
5th percentile	0.391	2.247	0.791
Total Endowment			
95th percentile	0.151	1.164	0.358
Mean	0.249	1.634	0.540
5th percentile	0.391	2.474	0.831

Table 4. Gulf of Mexico Eastern Planning Area 901-3,000m Water Depth Assessment Results Table.

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		0.676	3.492	1.298
Mean		1.071	4.476	1.868
5th percentile		1.508	5.601	2.504
Half-Cycle	1.00			
95th percentile		0.763	4.337	1.535
Mean		1.170	5.220	2.099
5th percentile		1.640	6.283	2.758
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		1.196	5.691	2.208
Mean		1.597	6.509	2.756
5th percentile		2.072	7.346	3.379
Half-Cycle	1.00			
95th percentile		1.243	6.012	2.312
Mean		1.658	6.747	2.858
5th percentile		2.130	7.618	3.485

Table 5. Total Gulf of Mexico Eastern Planning Area Economic Assessment Results Table.

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		0.599	3.272	1.181
Mean		0.909	4.177	1.652
5th percentile		1.358	4.764	2.206
Half-Cycle	1.00			
95th percentile		0.656	4.182	1.400
Mean		1.002	4.839	1.863
5th percentile		1.457	5.300	2.400
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.996	5.464	1.969
Mean		1.356	5.838	2.395
5th percentile		1.820	6.109	2.907
Half-Cycle	1.00			
95th percentile		1.041	5.617	2.040
Mean		1.403	5.968	2.465
5th percentile		1.870	6.272	2.986

Table 6. Gulf of Mexico Eastern Planning Area 0-200m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.88			
95th percentile		0.000	0.000	0.000
Mean		0.059	0.047	0.067
5th percentile		0.137	0.134	0.161
Half-Cycle	0.92			
95th percentile		0.000	0.000	0.000
Mean		0.064	0.053	0.073
5th percentile		0.139	0.145	0.164
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.034	0.013	0.036
Mean		0.086	0.070	0.098
5th percentile		0.160	0.154	0.187
Half-Cycle	1.00			
95th percentile		0.040	0.024	0.044
Mean		0.088	0.077	0.102
5th percentile		0.160	0.167	0.190

Table 7. Gulf of Mexico Eastern Planning Area 201-900m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.51			
95th percentile		0.000	0.000	0.000
Mean		0.080	0.322	0.138
5th percentile		0.232	1.502	0.499
Half-Cycle	0.61			
95th percentile		0.000	0.000	0.000
Mean		0.093	0.382	0.161
5th percentile		0.254	1.524	0.525
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.91			
95th percentile		0.000	0.000	0.000
Mean		0.147	0.594	0.253
5th percentile		0.301	1.667	0.598
Half-Cycle	0.95			
95th percentile		0.023	0.033	0.029
Mean		0.162	0.682	0.284
5th percentile		0.301	1.790	0.620

Table 8. Gulf of Mexico Eastern Planning Area 901-3,000m Water Depth Economic Assessment Results Table.

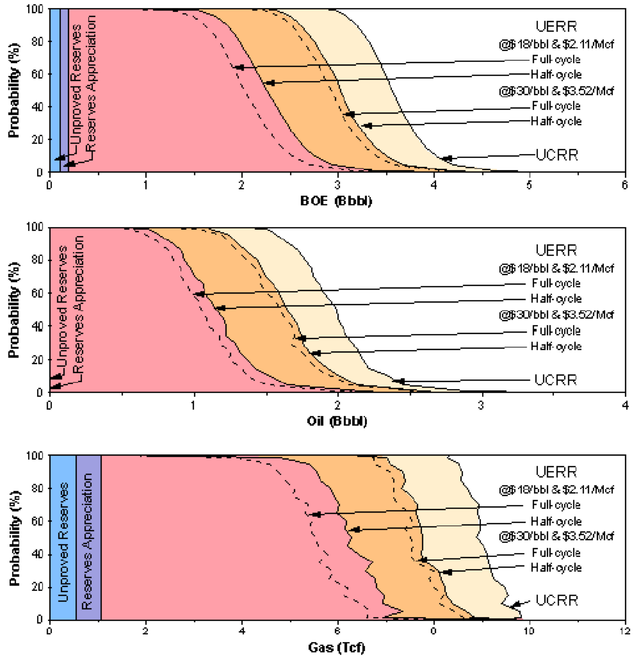

Figure 5. Gulf of Mexico Eastern Planning Area Total Endowment by Resource Category.

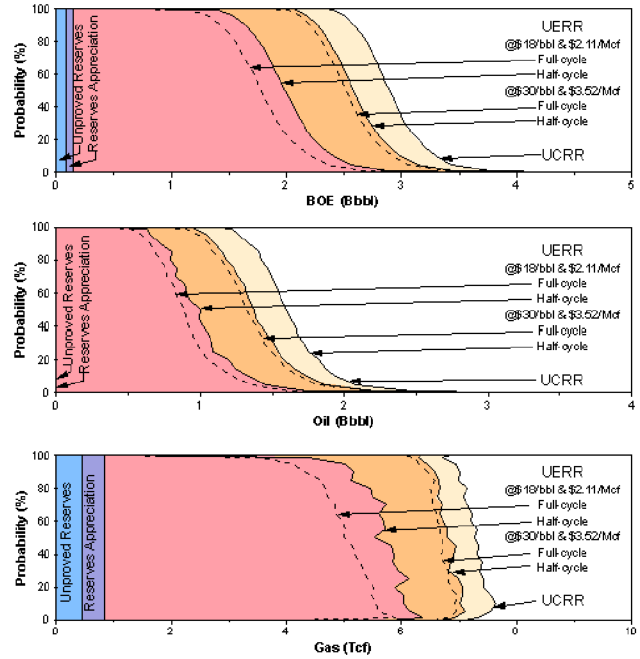

Figure 6. Gulf of Mexico Eastern Planning Area 0-200m Water Depth Total Endowment by Resource Category.

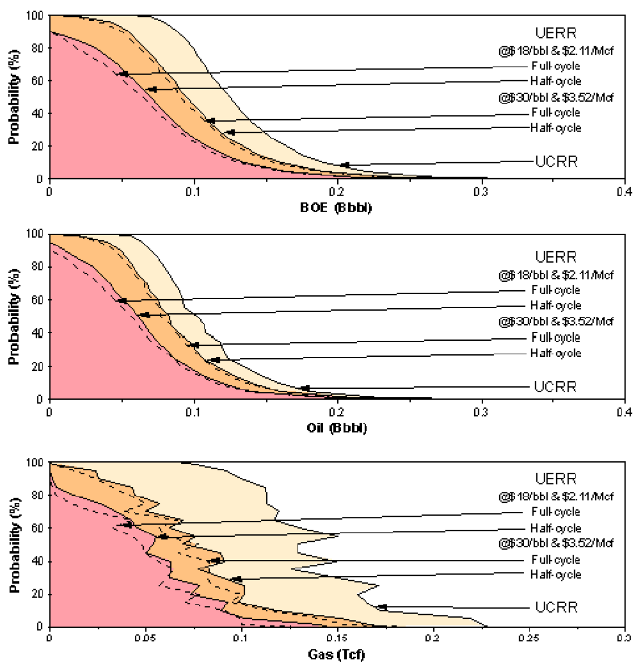

Figure 7. Gulf of Mexico Eastern Planning Area 201-900m Water Depth Total Endowment by Resource Category.

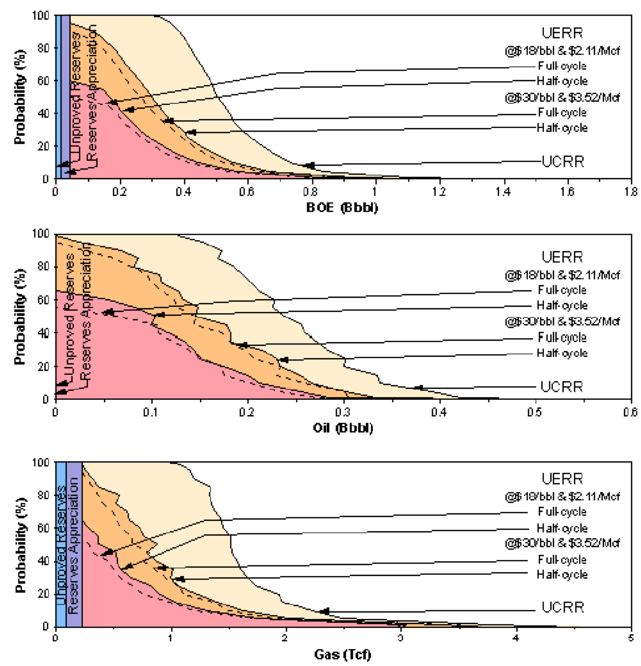

Figure 8. Gulf of Mexico Eastern Planning Area 901-3,000m Water Depth Total Endowment by Resource Category.

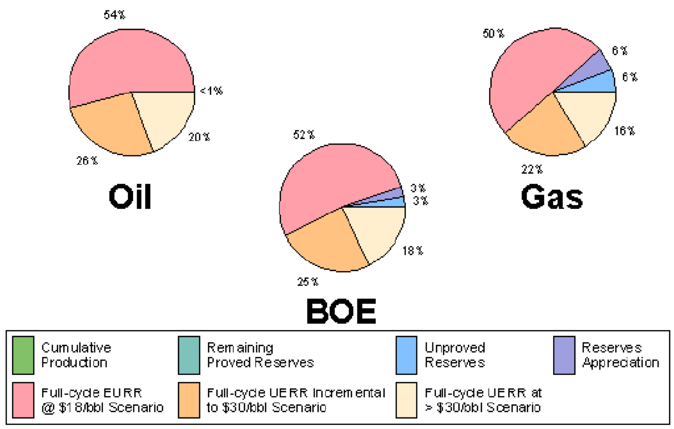

Figure 9. Total Gulf of Mexico Eastern Planning Area Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

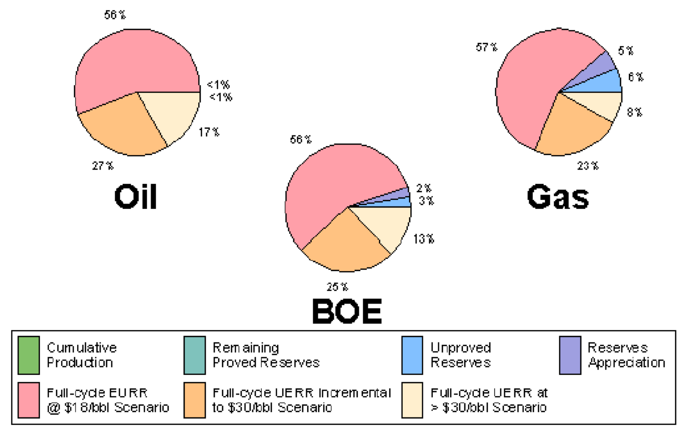

Figure 10. Gulf of Mexico Eastern Planning Area 0-200m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

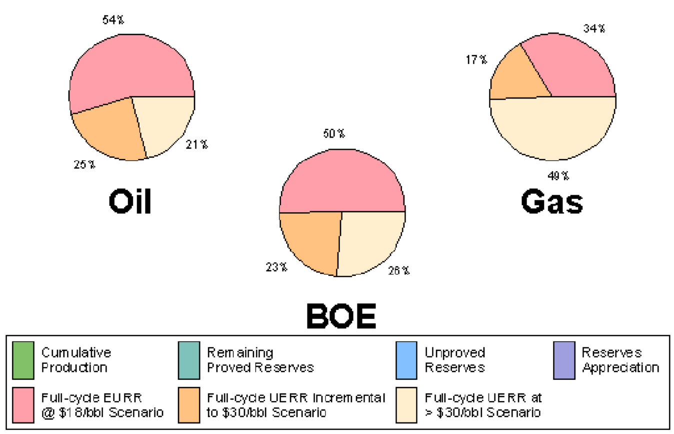

Figure 11. Gulf of Mexico Eastern Planning Area 201-900m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

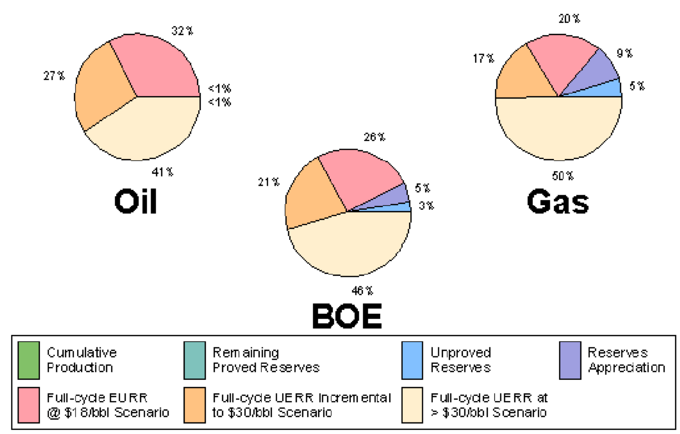

Figure 12. Gulf of Mexico Eastern Planning Area 901-3,000m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

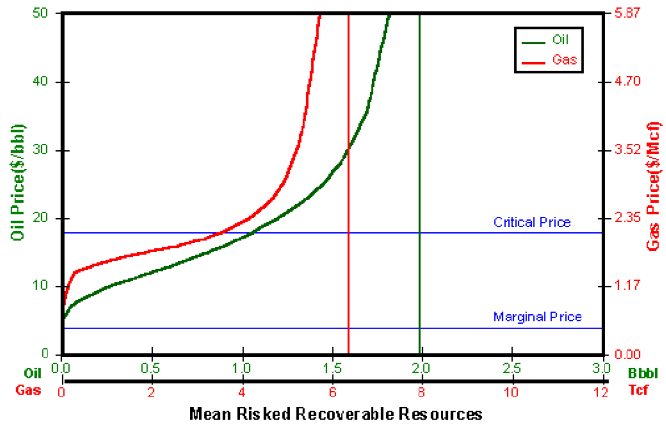

Figure 13. Total Gulf of Mexico Eastern Planning Area Full-Cycle Price-Supply Curve.

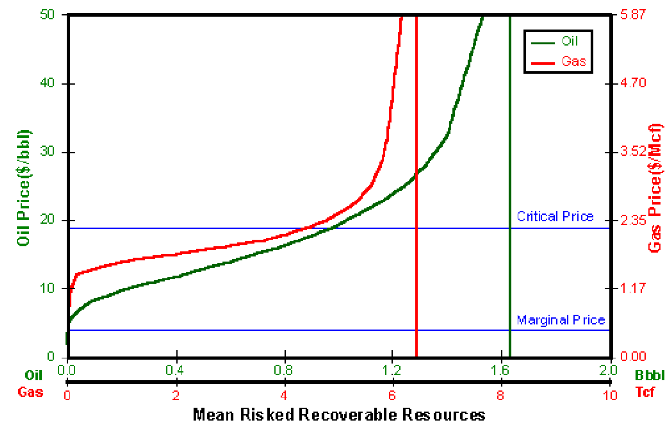

Figure 14. Gulf of Mexico Eastern Planning Area 0-200m Water Depth Full-Cycle Price-Supply Curve.

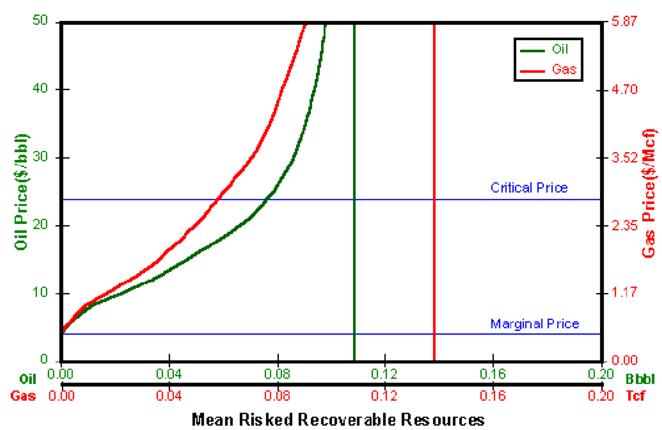

Figure 15. Gulf of Mexico Eastern Planning Area 201-900m Water Depth Full-Cycle Price-Supply Curve.

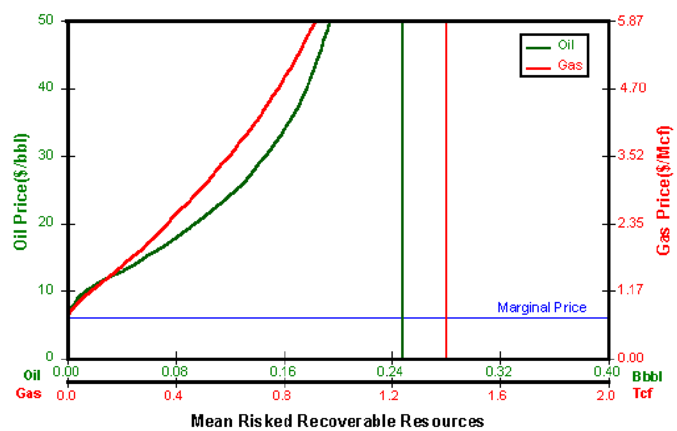

Figure 16. Gulf of Mexico Eastern Planning Area 901-3,000m Water Depth Full-Cycle Price-Supply Curve.

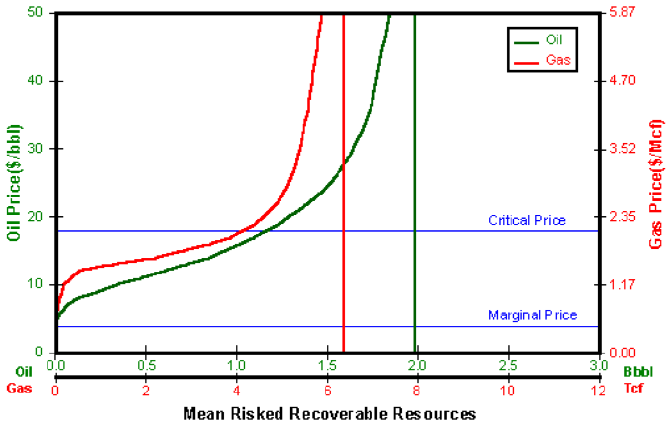

Figure 17. Total Gulf of Mexico Eastern Planning Area Half-Cycle Price-Supply Curve.

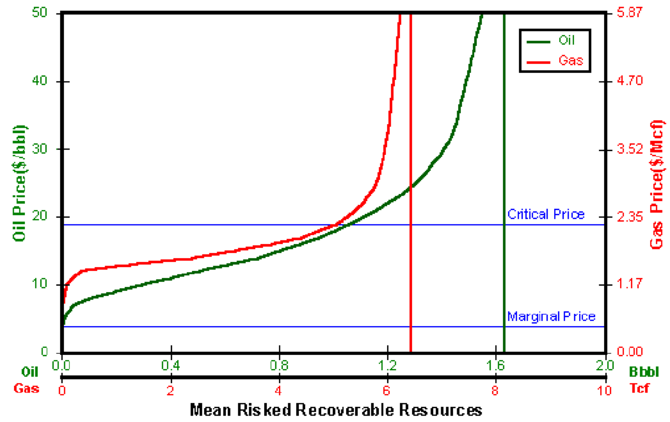

Figure 18. Gulf of Mexico Eastern Planning Area 0-200m Water Depth Half-Cycle Price-Supply Curve.

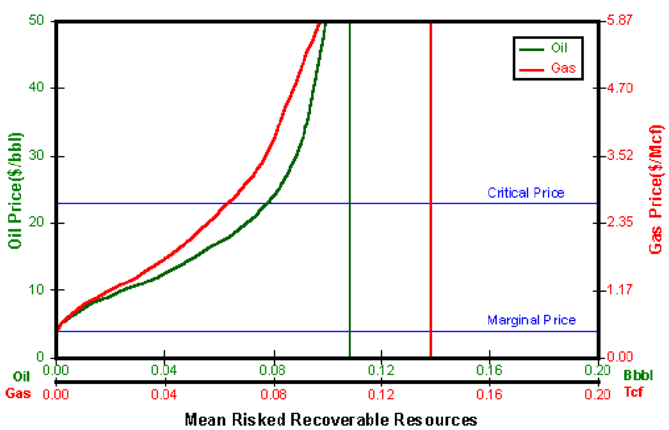

Figure 19. Gulf of Mexico Eastern Planning Area 201-900m Water Depth Half-Cycle Price-Supply Curve.

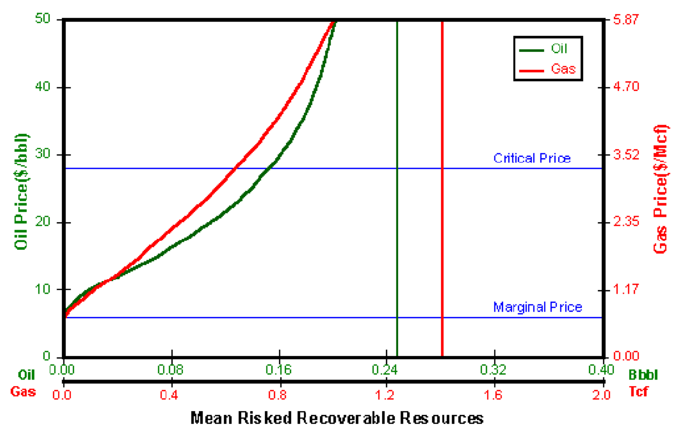

Figure 20. Gulf of Mexico Eastern Planning Area 901-3,000m Water Depth Half-Cycle Price-Supply Curve.

Florida Straits Planning Area Economic Results

The Florida Straits Planning Area includes submerged Federal lands offshore Florida, and extends to the U.S.-Cuba International Boundary in the south and the U.S.-Bahama International Boundary in the East (figure 1). Water depths in the planning area range from very shallow to more than 900m. Because water depth and distance from shore have a significant effect on engineering and cost factors, the undiscovered economically recoverable resources (UERR) were evaluated for three water depth ranges, 0-200m, 201-900m, and 901-3,000m (no resources were evaluated in water depths greater than 3,000m).

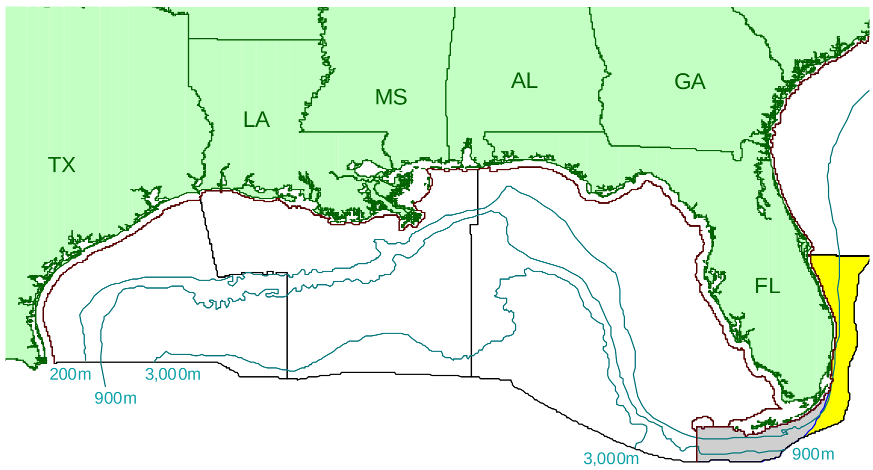

Figure 1. Florida Straits Planning Area Map. The planning area is shaded in yellow, and the gray pattern indicates the extent of the assessed plays.

The mean total endowment for this planning area is predominantly oil, with 91 percent of the total resources occurring as oil (figure 2). There is a trend towards a more gas-prone bias in the deeper water depths, with the 0-200m water depth range consisting of 1 percent gas, and the deepest water depth range consisting of 23 percent gas. The majority of the mean total endowment (63% on a barrels-of-oil-equivalent [BOE] basis) occurs in water depths of less than 900m (figure 3 and figure 4).

The planning area is not developed in any of the water depth ranges, and there is no infrastructure in place. As of the date of this study, there has been no production or reserves in any of the ranges (table 1 for Assessment Results Total, table 2 for 0-200m, table 3 for 201-900m, and table 4 for 901-3,000m). Undiscovered conventionally recoverable resources (UCRR) have been assessed for all three water depth ranges, and the full- and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in table 5 (Economic Results Total), table 6 (0-200m), table 7 (201-900m), and table 8 (901-3,000m). These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the three water depth ranges and for the total planning area.

Assessment results indicate that the total planning area undiscovered economically recoverable resources are minimal, with a range of 0.000 to 0.022 Bbo and 0.000 to 0.009 Tcfg at the 95th and 5th percentiles, respectively, for the full-cycle $18/bbl scenario. The mean economically recoverable resources are estimated at 0.008 Bbo and 0.003 Tcfg. A graphical representation of these results, incorporating every 5th- percentile result for UCRR and UERR, is presented in figure 5 (Results Graph Total), figure 6 (0-200m), figure

7 (201-900m), and figure 8 (901-3,000m). These graphs also present the half-cycle $18/bbl, and the full- and half-cycle $30/bbl scenario results. Because the economic model imports field sizes in BOE from the geologic model and then calculates the oil and gas content, the BOE results graph is typically a smooth curve. As expected, the accompanying oil and gas values exhibit more scatter because the gas/oil ratio can vary greatly from one field to another.

The mean total endowment for oil, gas, and BOE by the reserve and resource classification is shown in figure 9 (Mean Endowment Total), figure 10 (0-200m), figure 11 (201-900m), and figure 12 (901-3,000m). The pie charts presented can be used to determine what percentage of oil, gas, or BOE is a result of reserves or of undiscovered resources. For example, all of the oil and gas in the planning area remains to be discovered, and only 15 percent of the gas and 26 percent of the oil are projected to be economically recoverable at the $18/bbl scenario (figure 9). Moreover, 26 percent of the mean total endowment, on a BOE basis, is remaining to be discovered and is projected to be economically recoverable at the $18/bbl scenario.

Because estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions, they are presented here as price-supply curves. These curves describe a functional relationship between economically recoverable resources and product price and present the estimates of mean undiscovered economically recoverable oil and gas at any starting oil price up to $50/bbl. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the ***General Text, Methodology, UERR (Economically Recoverable), Detailed Discussion*** section. 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 are the mean curves. The full-cycle price-supply curves are shown in figure 13 (Full-Cycle P-S Curve Total), figure 14 (0-200m), figure 15 (201-900m), and figure 16 (901-3,000m). The half-cycle price-supply curves are shown in figure 17 (Half-Cycle P-S Curve Total), figure 18 (0-200m), figure 19 (201-900m), and figure 20 (901-3,000m).

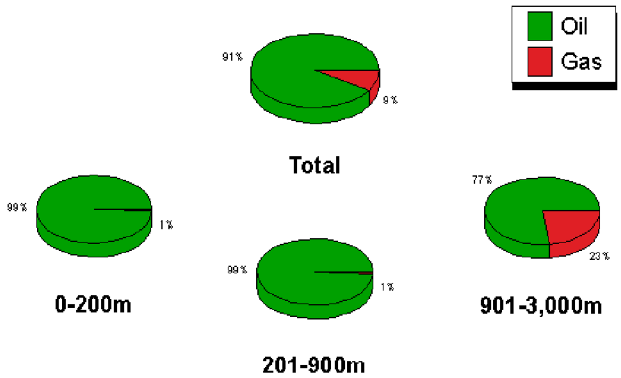

Figure 2. Florida Straits Planning Area Percent Oil or Gas by Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

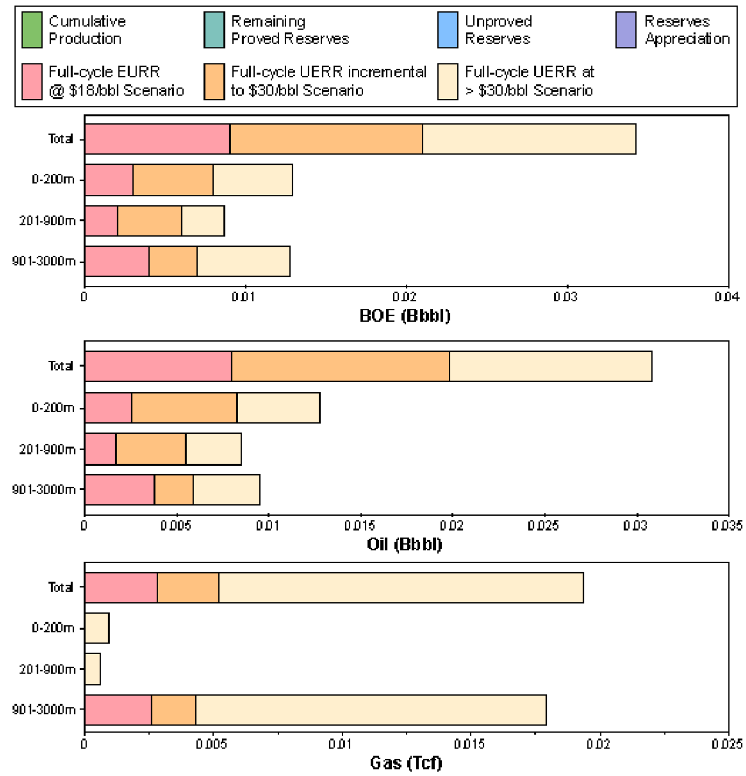

Figure 3. Florida Straits Planning Area Mean Total Endowment by Water Depth Category.

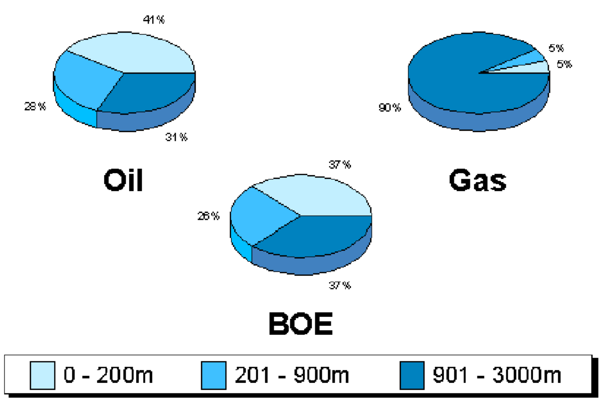

Figure 4. Florida Straits Planning Area Mean Total Endowment by Resource Type and Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.022	0.014	0.025
Mean	0.031	0.019	0.034
5th percentile	0.044	0.025	0.048
Total Endowment			
95th percentile	0.022	0.014	0.025
Mean	0.031	0.019	0.034
5th percentile	0.044	0.025	0.048

Table 1. Florida Straits Planning Area Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.009	0.001	0.009
Mean	0.013	0.001	0.013
5th percentile	0.019	0.001	0.019
Total Endowment			
95th percentile	0.009	0.001	0.009
Mean	0.013	0.001	0.013
5th percentile	0.019	0.001	0.019

Table 2. Florida Straits Planning Area 0-200m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.006	<0.001	0.006
Mean	0.009	0.001	0.009
5th percentile	0.013	0.001	0.013
Total Endowment			
95th percentile	0.006	<0.001	0.006
Mean	0.009	0.001	0.009
5th percentile	0.013	0.001	0.013

Table 3. Florida Straits Planning Area 201-900m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.004	0.011	0.006
Mean	0.010	0.018	0.013
5th percentile	0.019	0.026	0.023
Total Endowment			
95th percentile	0.004	0.011	0.006
Mean	0.010	0.018	0.013
5th percentile	0.019	0.026	0.023

Table 4. Florida Straits Planning Area 901-3,000m Water Depth Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.67			
95th percentile		0.000	0.000	0.000
Mean		0.008	0.003	0.009
5th percentile		0.022	0.009	0.024
Half-Cycle	0.75			
95th percentile		0.000	0.000	0.000
Mean		0.009	0.003	0.010
5th percentile		0.024	0.010	0.025
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.009	0.001	0.010
Mean		0.020	0.005	0.021
5th percentile		0.034	0.010	0.036
Half-Cycle	1.00			
95th percentile		0.010	0.002	0.010
Mean		0.021	0.006	0.022
5th percentile		0.034	0.011	0.036

Table 5. Florida Straits Planning Area Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.45			
95th percentile		0.000	0.000	0.000
Mean		0.003	<0.001	0.003
5th percentile		0.009	<0.001	0.009
Half-Cycle	0.51			
95th percentile		0.000	0.000	0.000
Mean		0.003	<0.001	0.003
5th percentile		0.010	<0.001	0.010
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.004	<0.001	0.004
Mean		0.008	<0.001	0.008
5th percentile		0.014	0.001	0.015
Half-Cycle	1.00			
95th percentile		0.004	<0.001	0.004
Mean		0.009	<0.001	0.009
5th percentile		0.015	0.001	0.015

Table 6. Florida Straits Planning Area 0-200m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.45			
95th percentile		0.000	0.000	0.000
Mean		0.002	<0.001	0.002
5th percentile		0.006	<0.001	0.006
Half-Cycle	0.51			
95th percentile		0.000	0.000	0.000
Mean		0.002	<0.001	0.002
5th percentile		0.007	<0.001	0.007
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.002	<0.001	0.002
Mean		0.006	<0.001	0.006
5th percentile		0.010	<0.001	0.010
Half-Cycle	1.00			
95th percentile		0.003	<0.001	0.003
Mean		0.006	<0.001	0.006
5th percentile		0.010	<0.001	0.010

Table 7. Florida Straits Planning Area 201-900m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.39			
95th percentile		0.000	0.000	0.000
Mean		0.004	0.003	0.004
5th percentile		0.015	0.011	0.017
Half-Cycle	0.47			
95th percentile		0.000	0.000	0.000
Mean		0.004	0.003	0.005
5th percentile		0.015	0.011	0.017
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.74			
95th percentile		0.000	0.000	0.000
Mean		0.006	0.004	0.007
5th percentile		0.016	0.011	0.018
Half-Cycle	0.80			
95th percentile		0.000	0.000	0.000
Mean		0.006	0.005	0.007
5th percentile		0.016	0.013	0.018

Table 8. Florida Straits Planning Area 901-3,000m Water Depth Economic Assessment Results Table.

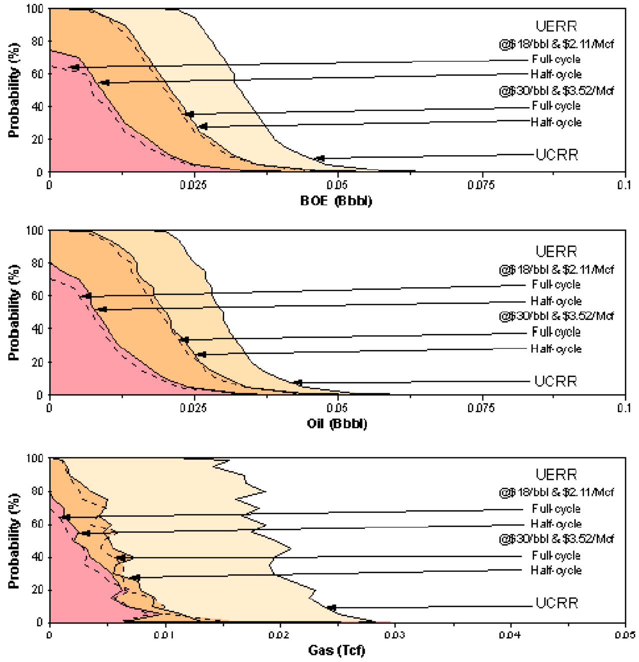

Figure 5. Florida Straits Planning Area Total Endowment by Resource Category.

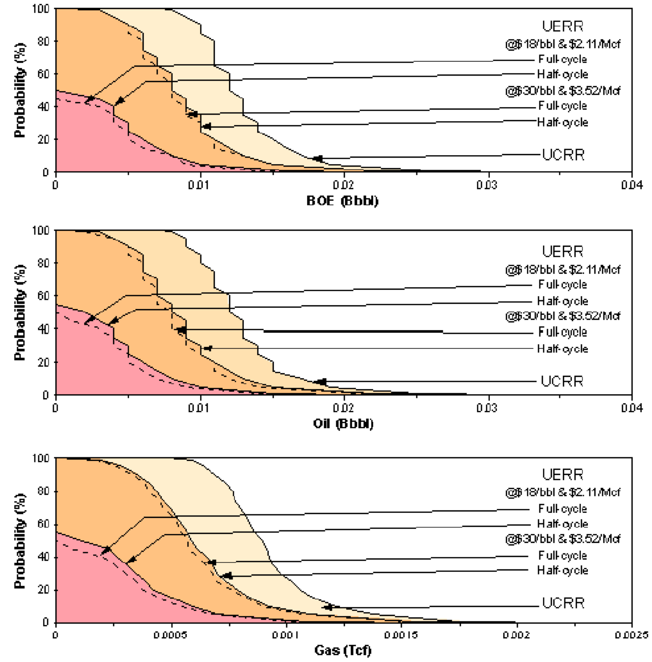

Figure 6. Florida Straits Planning Area 0-200m Water Depth Total Endowment by Resource Category.

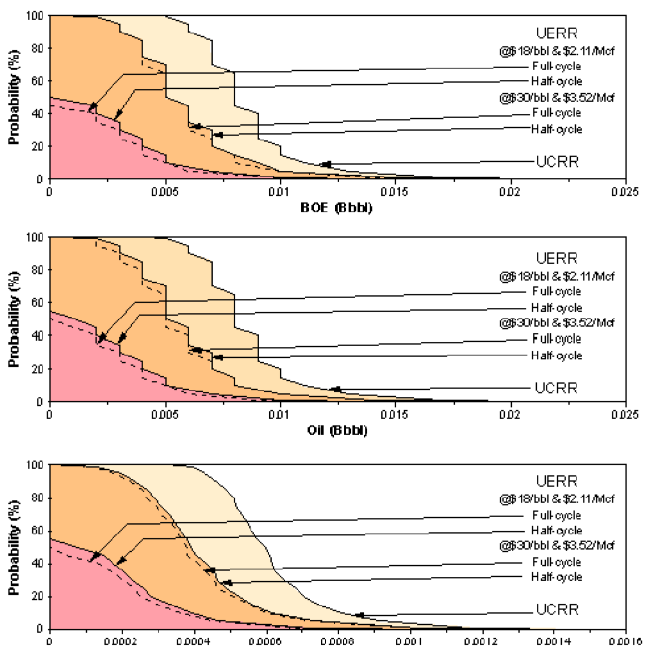

Figure 7. Florida Straits Planning Area 201-900m Water Depth Total Endowment by Resource Category.

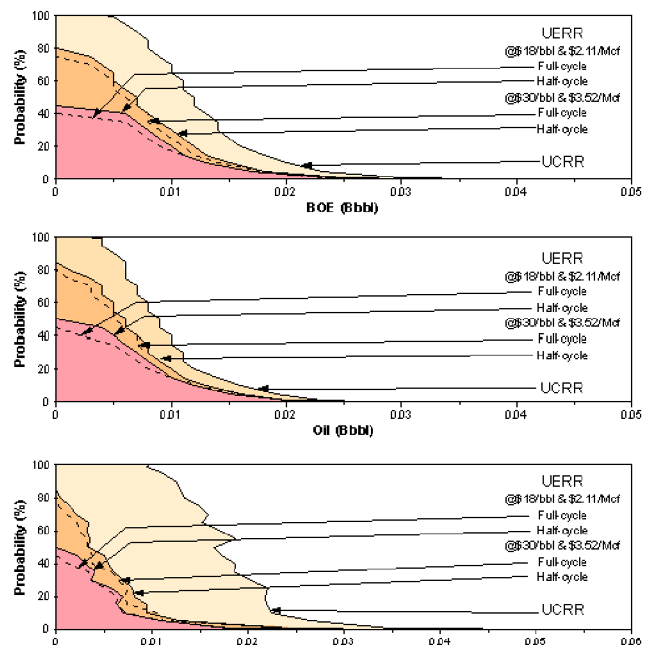

Figure 8. Florida Straits Planning Area 901-3,000m Water Depth Total Endowment by Resource Category.

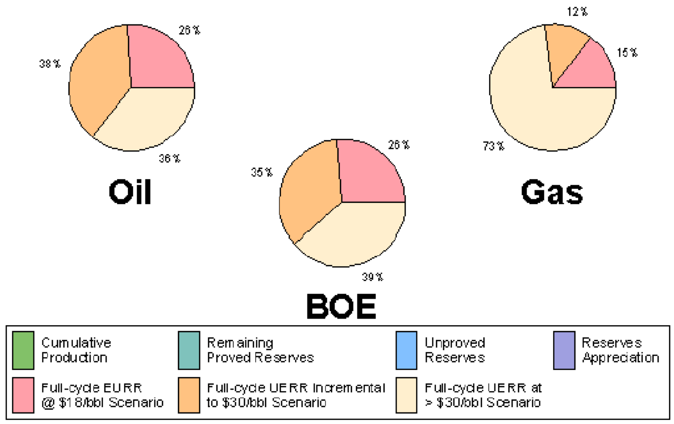

Figure 9. Florida Straits Planning Area Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

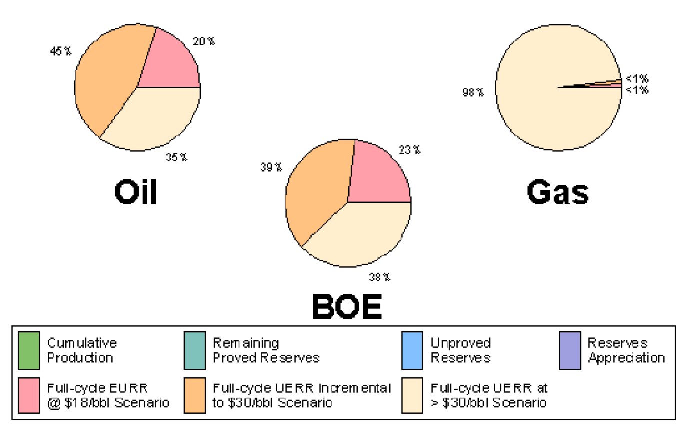

Figure 10. Florida Straits Planning Area 0-200m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

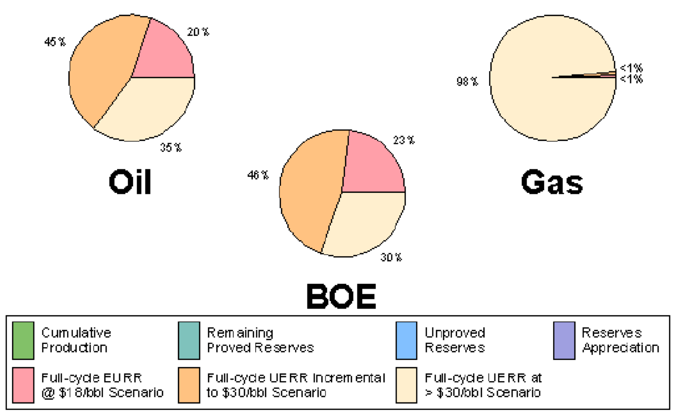

Figure 11. Florida Straits Planning Area 201-900m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

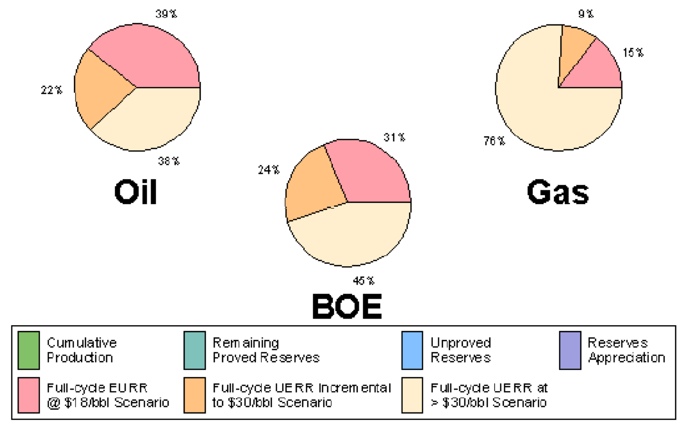

Figure 12. Florida Straits Planning Area 901-3,000m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

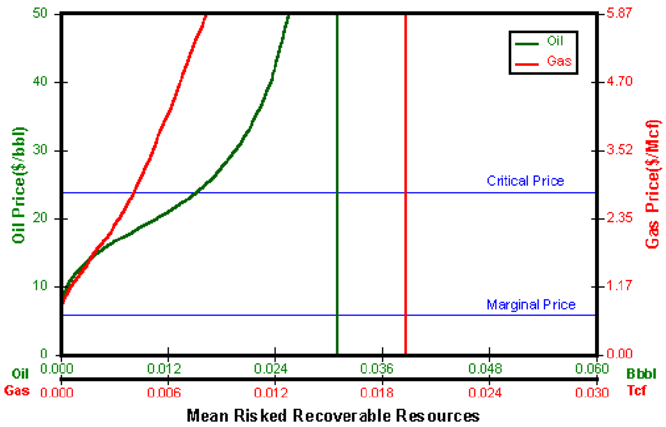

Figure 13. Florida Straits Planning Area Full-Cycle Price-Supply Curve.

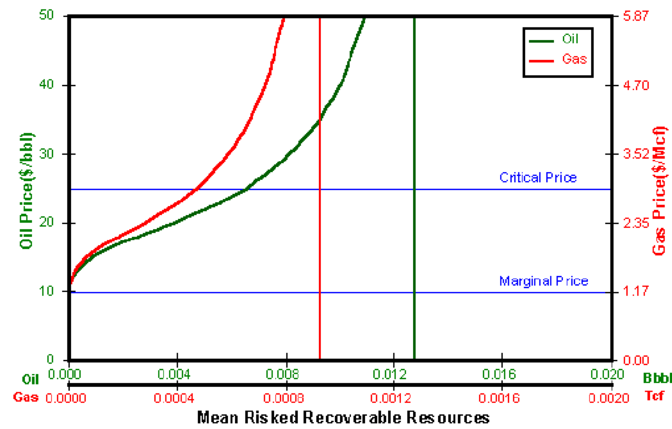

Figure 14. Florida Straits Planning Area 0-200m Water Depth Full-Cycle Price-Supply Curve.

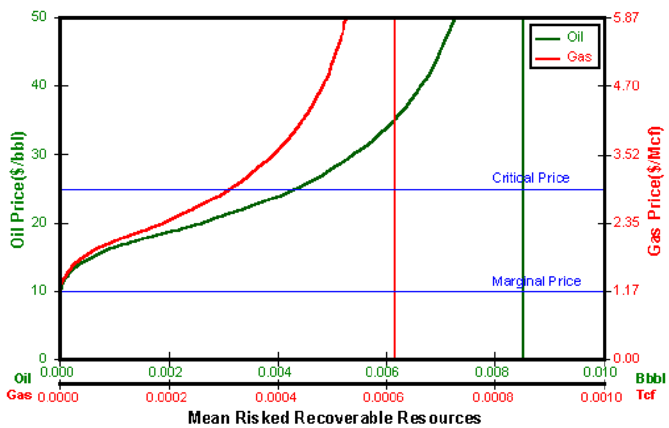

Figure 15. Florida Straits Planning Area 201-900m Water Depth Full-Cycle Price-Supply Curve.

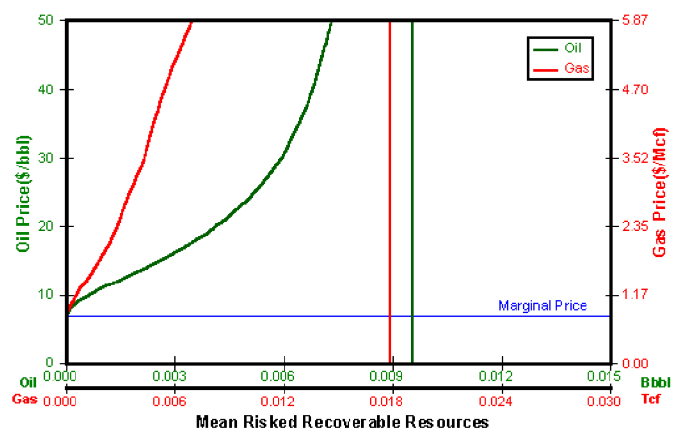

Figure 16. Florida Straits Planning Area 901-3,000m Water Depth Full-Cycle Price-Supply Curve.

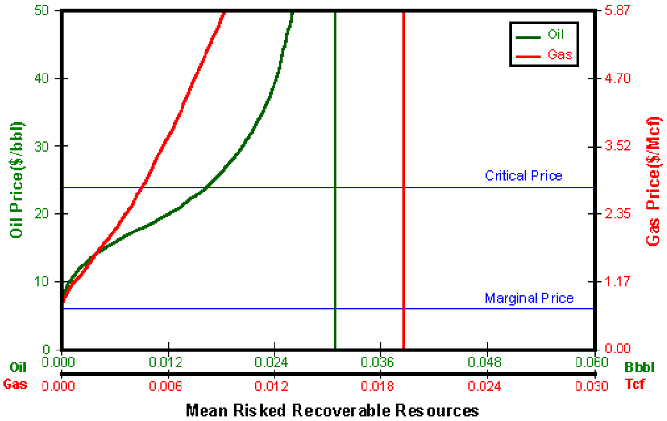

Figure 17. Florida Straits Planning Area Half-Cycle Price-Supply Curve.

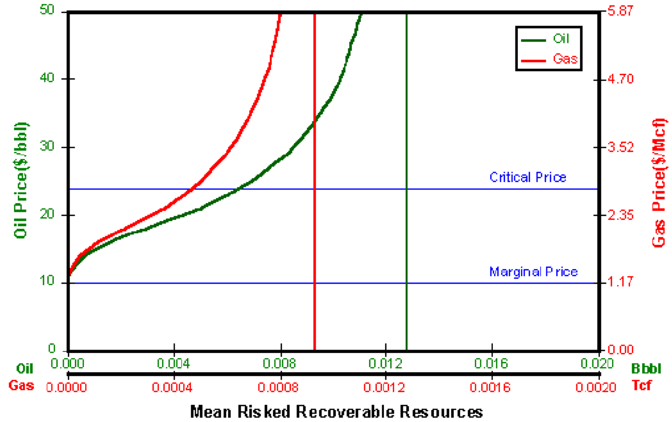

Figure 18. Florida Straits Planning Area 0-200m Water Depth Half-Cycle Price-Supply Curve.

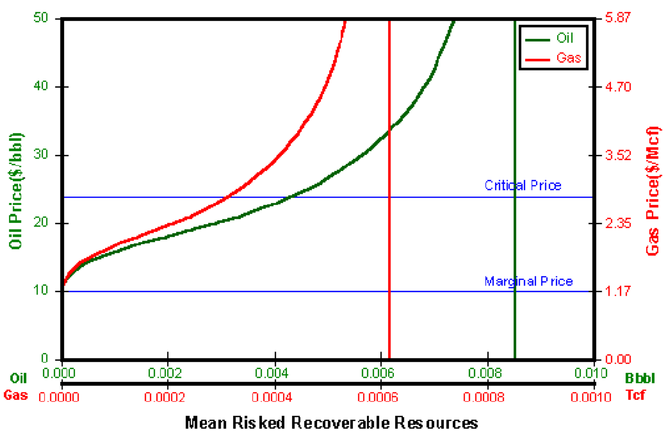

Figure 19. Florida Straits Planning Area 201-900m Water Depth Half-Cycle Price-Supply Curve.

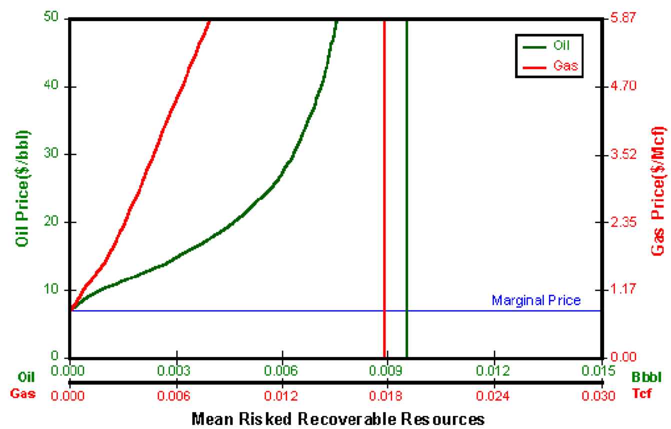

Figure 20. Florida Straits Planning Area 901-3,000m Water Depth Half-Cycle Price-Supply Curve.

North Atlantic Planning Area Economic Results

The North Atlantic Planning Area includes submerged Federal lands offshore Maine, New Hampshire, and Massachusetts, and extends to the U.S.-Canada International Boundary in the north (figure 1). Water depths in the planning area range from very shallow to more than 3,000m. Because water depth and distance from shore have a significant effect on engineering and cost factors, the undiscovered economically recoverable resources (UERR) were evaluated for three water depth ranges, 0-200m, 201-900m, and 901-3,000m (no resources were evaluated in water depths greater than 3,000m).

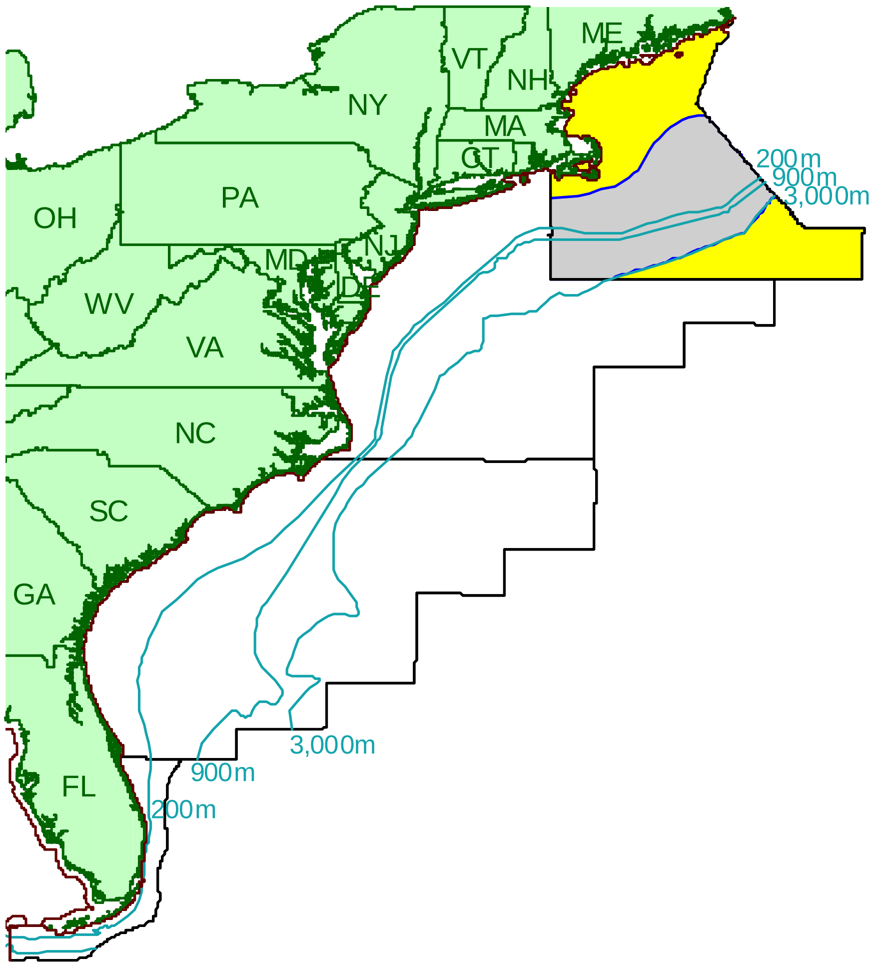

Figure 1. North Atlantic Planning Area Map. The planning area is shaded in yellow, and the gray pattern indicates the extent of the assessed plays.

The mean total endowment for this planning area is predominantly gas, with 69 percent of the total resources occurring as gas (figure 2). There is a very slight trend towards a less gas-prone bias in the deeper water depths, with the 0-200m water depth range consisting of 71 percent gas, the 201-900m range consisting of 70 percent gas, and the deepest water depth range consisting of 68 percent gas. The largest concentration of the mean total endowment (42% on a barrels-of-oil-equivalent [BOE] basis) occurs in water depths of more than 900m (figure 3 and figure 4). Each of the other two water depth ranges have 29 percent of the BOE mean total endowment.

The planning area is not developed in any of the water depth ranges, and there is no infrastructure in place. As of the date of this study, there has been no production or reserves in any of the ranges (table 1 for Assessment Results Total, table 2 for 0-200m, table 3 for 201-900m, and table 4 for 901-3,000m). Undiscovered conventionally recoverable resources (UCRR) have been assessed for all three water depth ranges, and

the full- and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in table 5 (Economic Results Total), table 6 (0-200m), table 7 (201-900m), and table 8 (901-3,000m). These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the three water depth ranges and for the total planning area.

Assessment results indicate that the total planning area undiscovered economically recoverable resources are limited, with a range of 0.000 to 0.219 Bbo and 0.000 to 3.871 Tcfg at the 95th and 5th percentiles, respectively, for the full-cycle $18/bbl scenario. The mean economically recoverable resources are estimated at 0.113 Bbo and 1.707 Tcfg. A graphical representation of these results, incorporating every 5th- percentile result for UCRR and UERR, is presented in figure 5 (Results Graph Total), figure 6 (0-200m), figure 7 (201-900m), and figure 8 (901-3,000m). These graphs also present the half-cycle $18/bbl, and the full- and half-cycle $30/bbl scenario results. Because the economic model imports field sizes in BOE from the geologic model and then calculates the oil and gas content, the BOE results graph is typically a smooth curve. As expected, the accompanying oil and gas values exhibit more scatter because the gas/oil ratio can vary greatly from one field to another.

The mean total endowment for oil, gas, and BOE by the reserve and resource classification is shown in figure 9 (Mean Endowment Total), figure 10 (0-200m), figure 11 (201-900m), and figure 12 (901-3,000m). The pie charts presented can be used to determine what percentage of oil, gas, or BOE is a result of reserves or of undiscovered resources. For example, all of the oil and gas in the planning area remains to be discovered, and only 19 percent of the gas and 16 percent of the oil are projected to be economically recoverable at the $18/bbl scenario (figure 9). Therefore, 18 percent of the mean total endowment, on a BOE basis, is remaining to be discovered and is projected to be economically recoverable at the $18/bbl scenario.

Because estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions, they are presented here as price-supply curves. These curves describe a functional relationship between economically recoverable resources and product price and present the estimates of mean undiscovered economically recoverable oil and gas at any starting oil price up to $50/bbl. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the ***General Text, Methodology, UERR (Economically Recoverable), Detailed Discussion*** section. 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 are the mean curves. The full-cycle price-supply curves are shown in figure 13 (Full-Cycle P-S Curve Total), figure 14 (0-200m), figure 15 (201-900m), and figure 16 (901-3,000m). The half-cycle price-supply curves are shown in figure 17 (Half-Cycle P-S Curve Total), figure 18 (0-200m), figure 19 (201-900m), and figure 20 (901-3,000m).

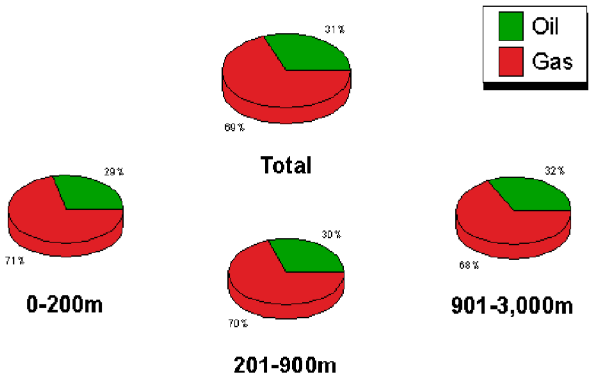

Figure 2. North Atlantic Planning Area Percent Oil or Gas by Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

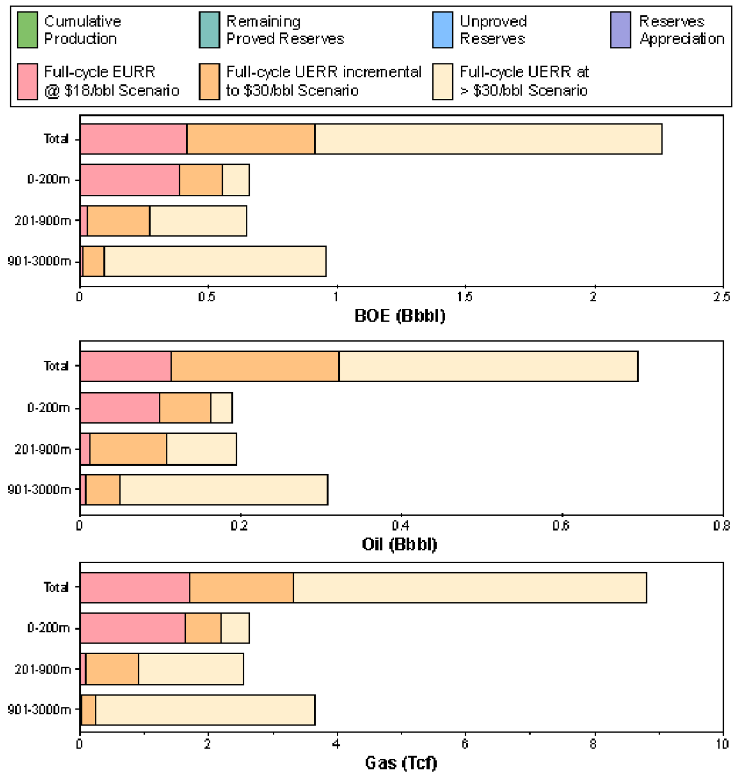

Figure 3. North Atlantic Planning Area Mean Total Endowment by Water Depth Category.

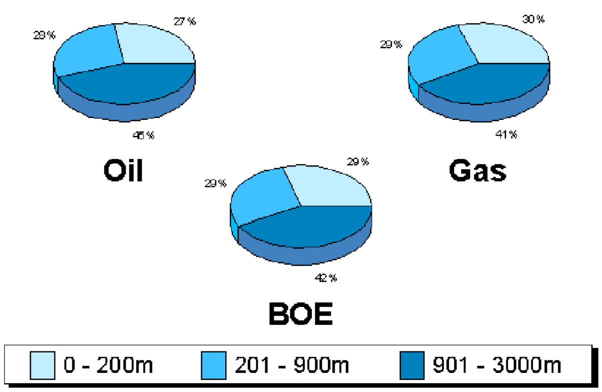

Figure 4. North Atlantic Planning Area Mean Total Endowment by Resource Type and Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.596	7.523	1.935
Mean	0.693	8.812	2.261
5th percentile	0.806	10.910	2.747
Total Endowment			
95th percentile	0.596	7.523	1.935
Mean	0.693	8.812	2.261
5th percentile	0.806	10.910	2.747

Table 1. Total North Atlantic Planning Area Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.138	1.581	0.419
Mean	0.190	2.641	0.660
5th percentile	0.221	4.804	1.075
Total Endowment			
95th percentile	0.138	1.581	0.419
Mean	0.190	2.641	0.660
5th percentile	0.221	4.804	1.075

Table 2. North Atlantic Planning Area 0-200m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.149	2.093	0.522
Mean	0.194	2.549	0.647
5th percentile	0.257	3.053	0.801
Total Endowment			
95th percentile	0.149	2.093	0.522
Mean	0.194	2.549	0.647
5th percentile	0.257	3.053	0.801

Table 3. North Atlantic Planning Area 201-900m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.238	3.153	0.799
Mean	0.309	3.651	0.958
5th percentile	0.407	4.364	1.184
Total Endowment			
95th percentile	0.238	3.153	0.799
Mean	0.309	3.651	0.958
5th percentile	0.407	4.364	1.184

Table 4. North Atlantic Planning Area 901-3,000m Water Depth Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.91			
95th percentile		0.000	0.000	0.000
Mean		0.113	1.707	0.417
5th percentile		0.219	3.871	0.908
Half-Cycle	0.95			
95th percentile		0.024	0.250	0.069
Mean		0.139	1.937	0.484
5th percentile		0.274	4.171	1.017
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.202	1.884	0.538
Mean		0.322	3.328	0.914
5th percentile		0.440	5.555	1.428
Half-Cycle	1.00			
95th percentile		0.237	2.182	0.626
Mean		0.373	3.767	1.043
5th percentile		0.519	6.031	1.592

Table 5. Total North Atlantic Planning Area Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.91			
95th percentile		0.000	0.000	0.000
Mean		0.099	1.626	0.388
5th percentile		0.157	3.942	0.859
Half-Cycle	0.95			
95th percentile		0.024	0.230	0.065
Mean		0.112	1.784	0.430
5th percentile		0.164	4.061	0.886
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.112	1.123	0.312
Mean		0.164	2.200	0.555
5th percentile		0.194	4.350	0.968
Half-Cycle	1.00			
95th percentile		0.115	1.195	0.328
Mean		0.167	2.263	0.570
5th percentile		0.191	4.444	0.982

Table 6. North Atlantic Planning Area 0-200m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.10			
95th percentile		0.000	0.000	0.000
Mean		0.012	0.092	0.028
5th percentile		0.120	0.873	0.276
Half-Cycle	0.16			
95th percentile		0.000	0.000	0.000
Mean		0.020	0.155	0.047
5th percentile		0.144	1.075	0.335
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.90			
95th percentile		0.000	0.000	0.000
Mean		0.107	0.905	0.268
5th percentile		0.186	1.519	0.457
Half-Cycle	0.96			
95th percentile		0.054	0.390	0.124
Mean		0.122	1.079	0.314
5th percentile		0.193	1.658	0.489

Table 7. North Atlantic Planning Area 201-900m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.05			
95th percentile		0.000	0.000	0.000
Mean		0.007	0.026	0.011
5th percentile		0.037	0.165	0.066
Half-Cycle	0.08			
95th percentile		0.000	0.000	0.000
Mean		0.010	0.040	0.017
5th percentile		0.082	0.334	0.142
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.42			
95th percentile		0.000	0.000	0.000
Mean		0.050	0.238	0.092
5th percentile		0.196	1.063	0.385
Half-Cycle	0.63			
95th percentile		0.000	0.000	0.000
Mean		0.083	0.467	0.166
5th percentile		0.223	1.402	0.472

Table 8. North Atlantic Planning Area 901-3,000m Water Depth Economic Assessment Results Table.

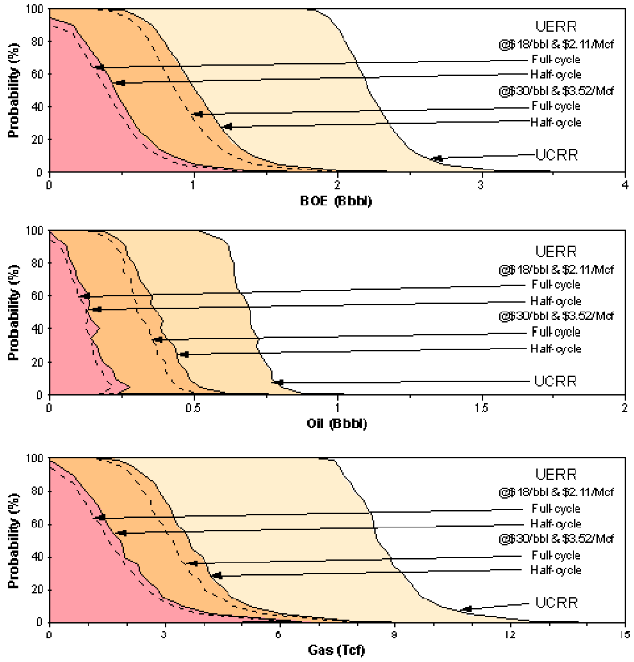

Figure 5. North Atlantic Planning Area Total Endowment by Resource Category.

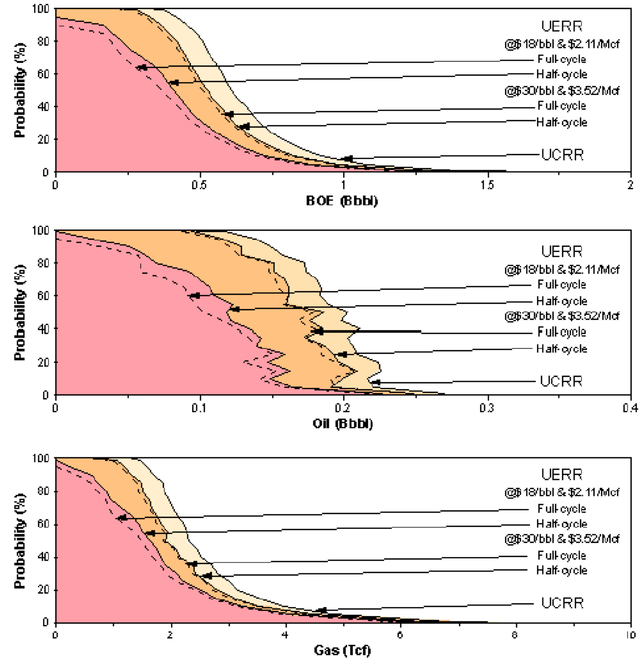

Figure 6. North Atlantic Planning Area 0-200m Water Depth Total Endowment by Resource Category.

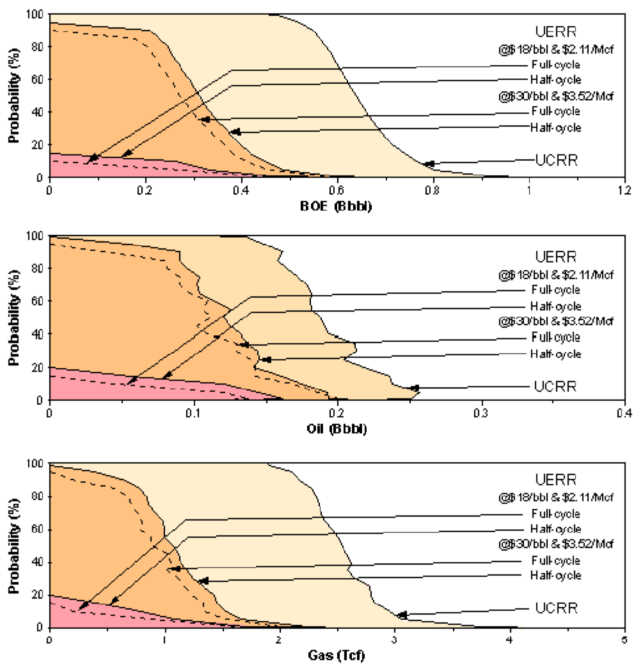

Figure 7. North Atlantic Planning Area 201-900m Water Depth Total Endowment by Resource Category.

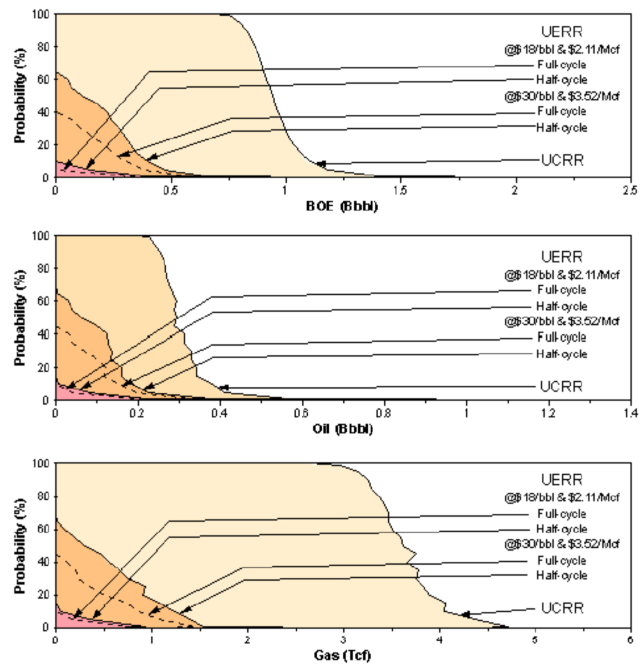

Figure 8. North Atlantic Planning Area 901-3,000m Water Depth Total Endowment by Resource Category.

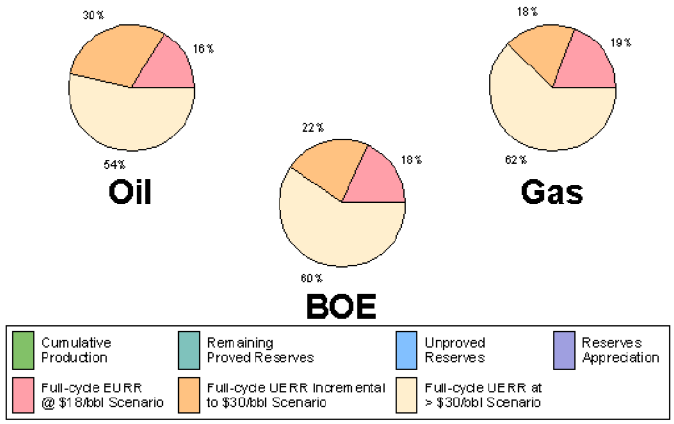

Figure 9. Total North Atlantic Planning Area Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

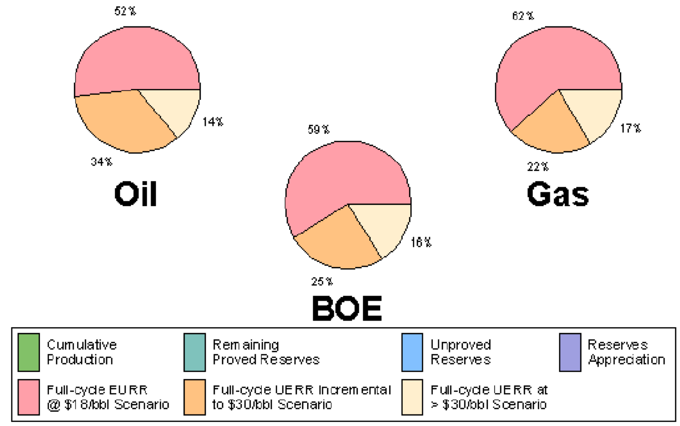

Figure 10. North Atlantic Planning Area 0-200m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

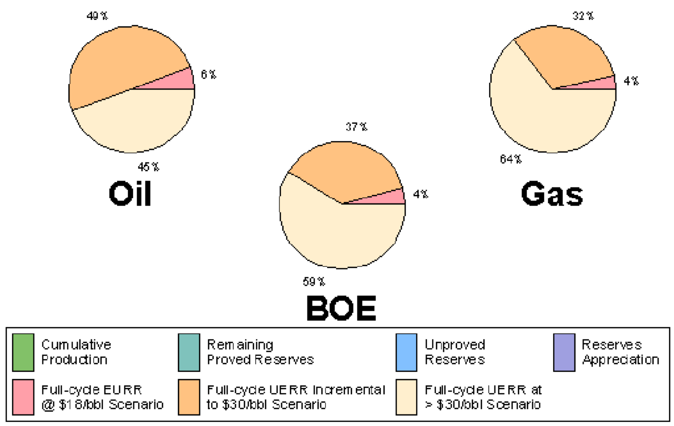

Figure 11. North Atlantic Planning Area 201-900m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

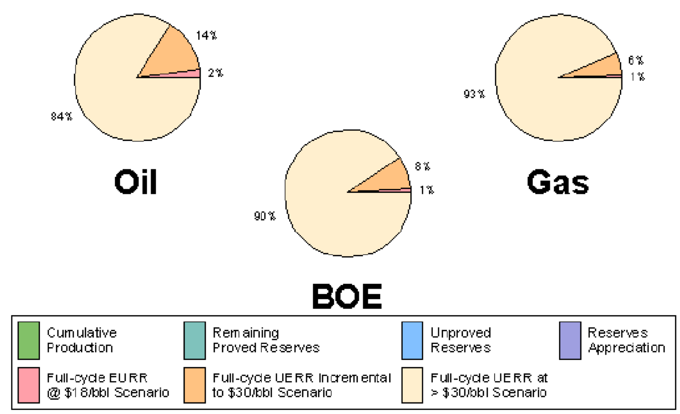

Figure 12. North Atlantic Planning Area 901-3,000m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

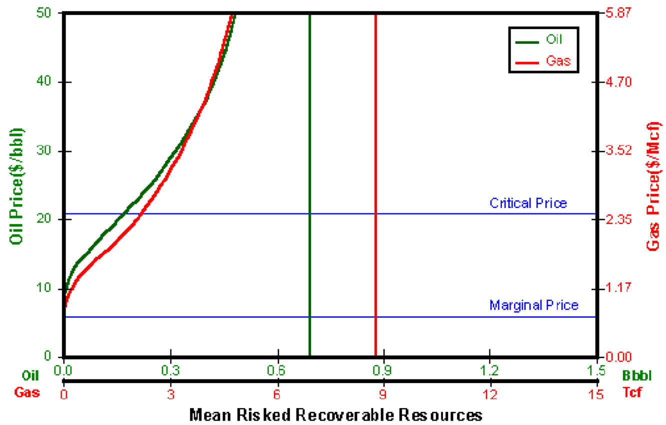

Figure 13. Total North Atlantic Planning Area Full-Cycle Price-Supply Curve.

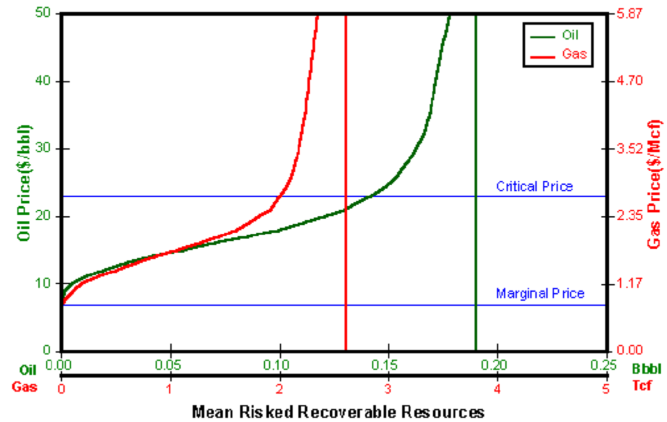

Figure 14. North Atlantic Planning Area 0-200m Water Depth Full-Cycle Price-Supply Curve.

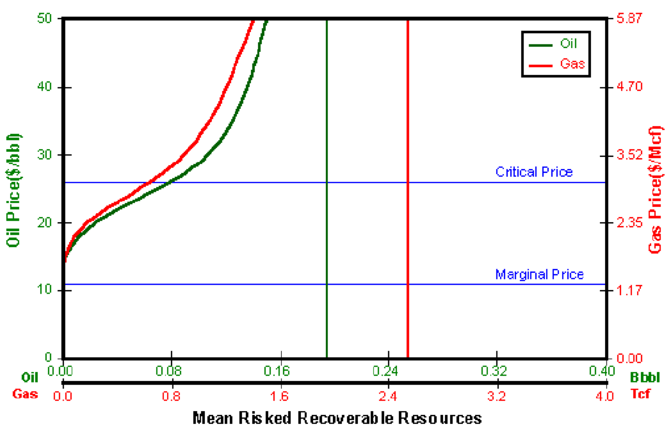

Figure 15. North Atlantic Planning Area 201-900m Water Depth Full-Cycle Price-Supply Curve.

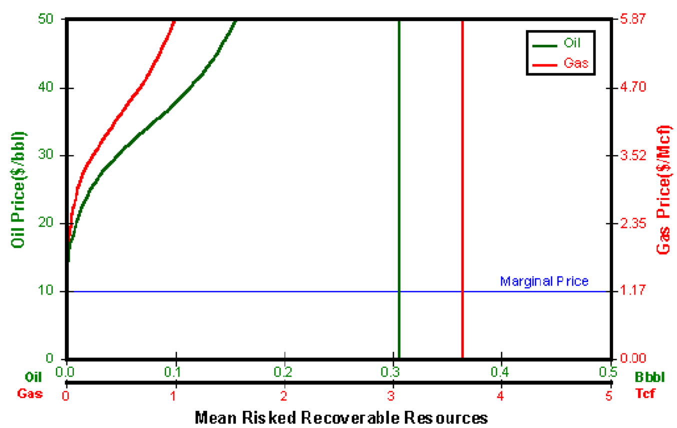

Figure 16. North Atlantic Planning Area 901-3,000m Water Depth Full-Cycle Price-Supply Curve.

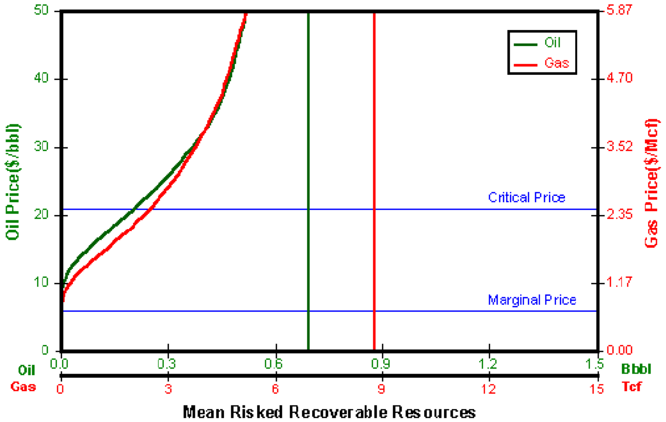

Figure 17. Total North Atlantic Planning Area Half-Cycle Price-Supply Curve.

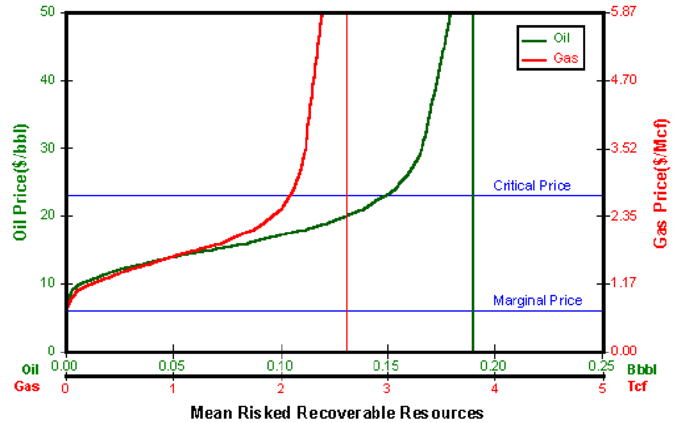

Figure 18. North Atlantic Planning Area 0-200m Water Depth Half-Cycle Price-Supply Curve.

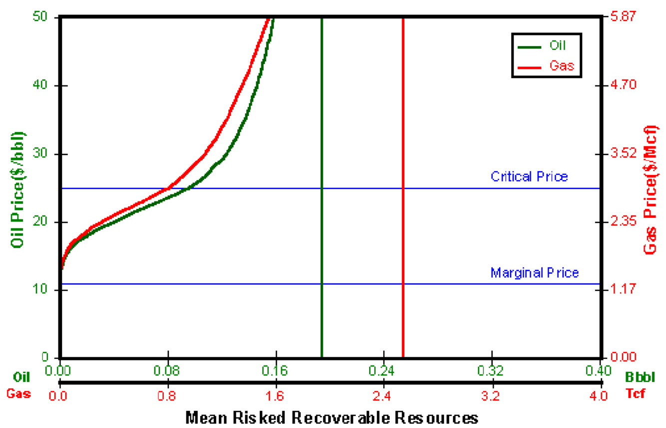

Figure 19. North Atlantic Planning Area 201-900m Water Depth Half-Cycle Price-Supply Curve.

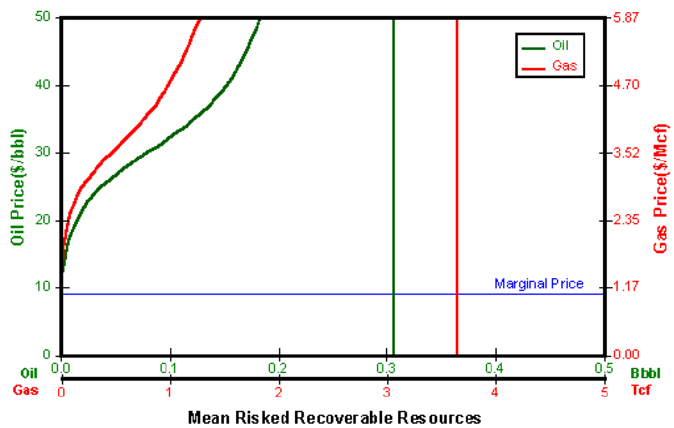

Figure 20. North Atlantic Planning Area 901-3,000m Water Depth Half-Cycle Price-Supply Curve.

Mid-Atlantic Planning Area Economic Results

The Mid-Atlantic Planning Area includes submerged Federal lands offshore Rhode Island, Connecticut, New York, New Jersey, Delaware, Maryland, Virginia, and North Carolina (figure 1). Water depths in the planning area range from very shallow to more than 3,000m. Because water depth and distance from shore have a significant effect on engineering and cost factors, the undiscovered economically recoverable resources (UERR) were evaluated for three water depth ranges, 0-200m, 201-900m, and 901-3,000m (no resources were evaluated in water depths greater than 3,000m).

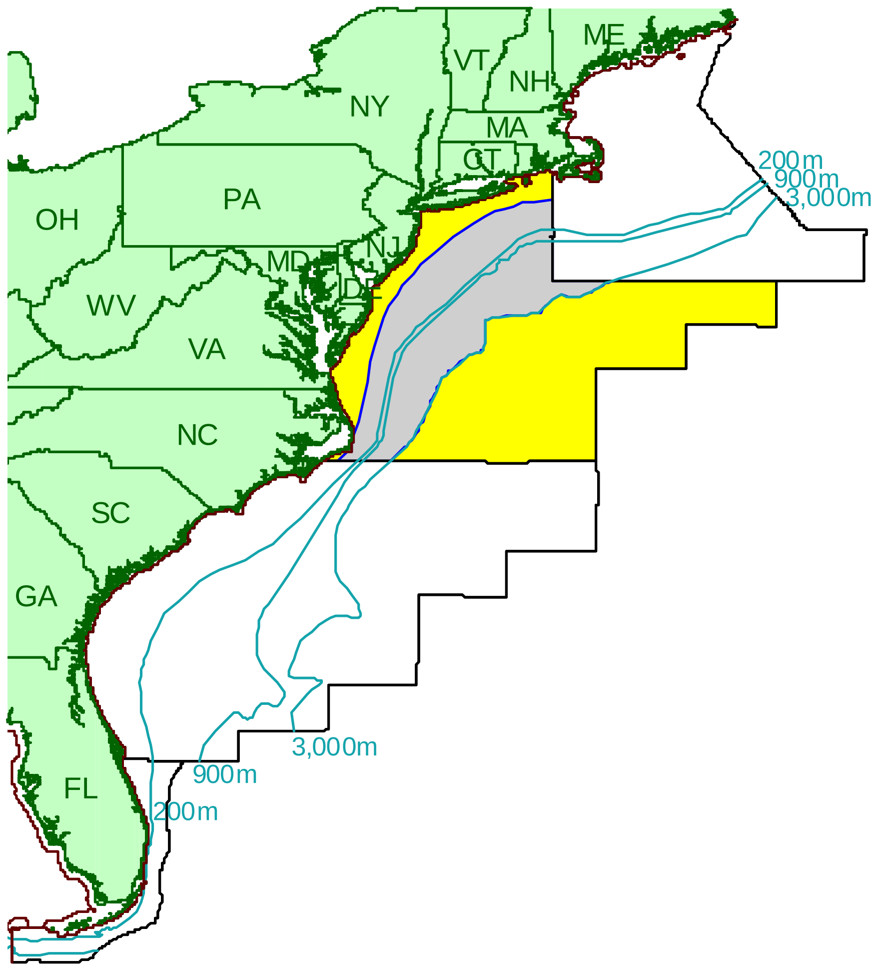

Figure 1. Mid-Atlantic Planning Area Map. The planning area is shaded in yellow, and the gray pattern indicates the extent of the assessed plays.

The mean total endowment for this planning area is predominantly gas, with 68 percent of the total resources occurring as gas (figure 2). There is a slight trend towards a less gas-prone bias in the deeper water depths, with the 0-200m water depth range consisting of 71 percent gas, the 201-900m range consisting of 69 percent gas, and the deepest water depth range consisting of 66 percent gas. The largest concentration of the mean total endowment (44% on a barrels-of-oil-equivalent [BOE] basis) occurs in water depths of more than 900m (figure 3 and figure 4). Each of the other two water depth ranges have 27 to 29 percent of the BOE mean total endowment.

The planning area is not developed in any of the water depth ranges, and there is no infrastructure in place. As of the date of this study, there has been no production or reserves in any of the ranges (table 1 for Assessment Results Total, table 2 for 0-200m, table 3 for 201-900m, and table 4 for 901-3,000m). Undiscovered conventionally recoverable resources (UCRR) have been assessed for all three water depth ranges, and

the full- and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in table 5 (Economic Results Total), table 6 (0-200m), table 7 (201-900m), and table 8 (901-3,000m). These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the three water depth ranges and for the total planning area.

Assessment results indicate that the total planning area undiscovered economically recoverable resources are limited (although they are larger than those in the North Atlantic Planning Area), with a range of 0.016 to 0.263 Bbo and 0.081 to 4.143 Tcfg at the 95th and 5th percentiles, respectively, for the full-cycle $18/bbl scenario. The mean economically recoverable resources are estimated at 0.132 Bbo and 1.795 Tcfg. A graphical representation of these results, incorporating every 5th- percentile result for UCRR and UERR, is presented in figure 5 (Results Graph Total), figure 6 (0-200m), figure 7 (201-900m), and figure 8 (901-3,000m). These graphs also present the half-cycle $18/bbl, and the full- and half-cycle $30/bbl scenario results. Because the economic model imports field sizes in BOE from the geologic model and then calculates the oil and gas content, the BOE results graph is typically a smooth curve. As expected, the accompanying oil and gas values exhibit more scatter because the gas/oil ratio can vary greatly from one field to another.

The mean total endowment for oil, gas, and BOE by the reserve and resource classification is shown in figure 9 (Mean Endowment Total), figure 10 (0-200m), figure 11 (201-900m), and figure 12 (901-3,000m). The pie charts presented can be used to determine what percentage of oil, gas, or BOE is a result of reserves or of undiscovered resources. For example, all of the oil and gas in the planning area remains to be discovered, and only 19 percent of the gas and 17 percent of the oil are projected to be economically recoverable at the $18/bbl scenario (figure 9). Therefore, 18 percent of the mean total endowment, on a BOE basis, is remaining to be discovered and is projected to be economically recoverable at the $18/bbl scenario.

Because estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions, they are presented here as price-supply curves. These curves describe a functional relationship between economically recoverable resources and product price and present the estimates of mean undiscovered economically recoverable oil and gas at any starting oil price up to $50/bbl. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the ***General Text, Methodology, UERR (Economically Recoverable), Detailed Discussion*** section. 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 are the mean curves. The full-cycle price-supply curves are shown in figure 13 (Full-Cycle P-S Curve Total), figure 14 (0-200m), figure 15 (201-900m), and figure 16 (901-3,000m). The half-cycle price-supply curves are shown in figure 17 (Half-Cycle P-S Curve Total), figure 18 (0-200m), figure 19 (201-900m), and figure 20 (901-3,000m).

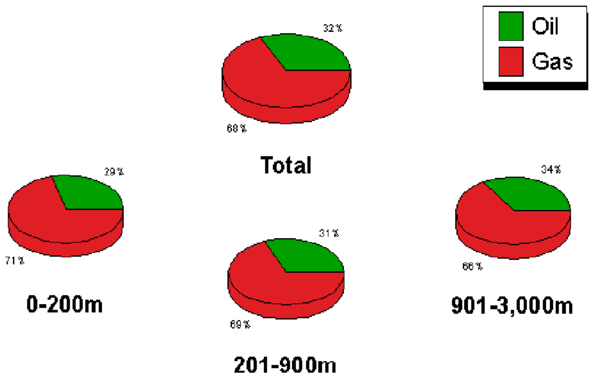

Figure 2. Mid-Atlantic Planning Area Percent Oil or Gas by Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

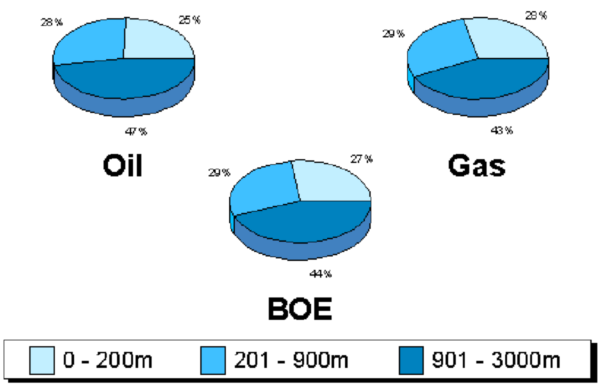

Figure 4. Mid-Atlantic Planning Area Mean Total Endowment by Resource Type and Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

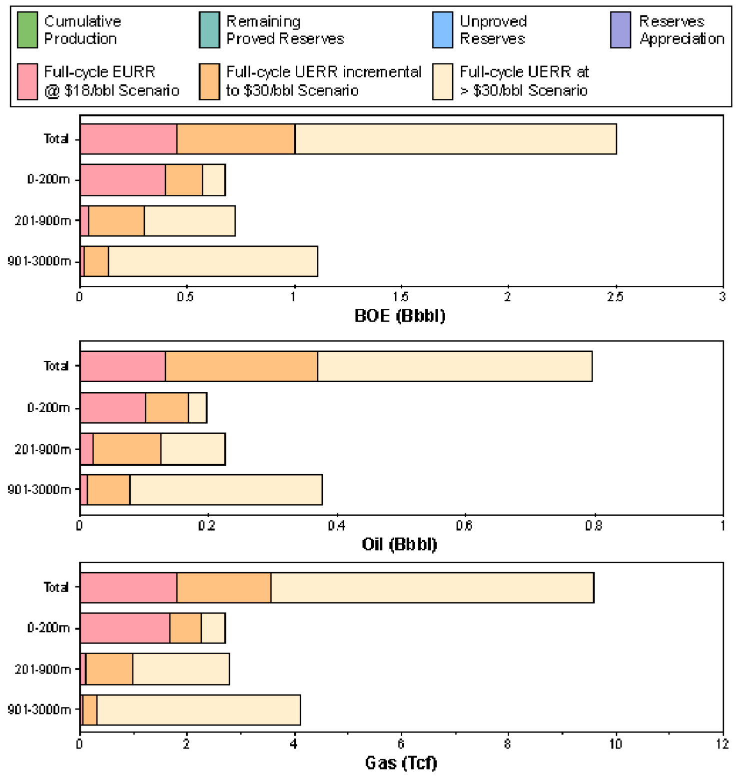

Figure 3. Mid-Atlantic Planning Area Mean Total Endowment by Water Depth Category.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.666	8.144	2.116
Mean	0.796	9.588	2.502
5th percentile	1.004	11.624	3.072
Total Endowment			
95th percentile	0.666	8.144	2.116
Mean	0.796	9.588	2.502
5th percentile	1.004	11.624	3.072

Table 1. Total Mid-Atlantic Planning Area Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.142	1.629	0.432
Mean	0.196	2.721	0.680
5th percentile	0.227	4.949	1.108
Total Endowment			
95th percentile	0.142	1.629	0.432
Mean	0.196	2.721	0.680
5th percentile	0.227	4.949	1.108

Table 2. Mid-Atlantic Planning Area 0-200m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.168	2.316	0.580
Mean	0.226	2.783	0.722
5th percentile	0.293	3.415	0.901
Total Endowment			
95th percentile	0.168	2.316	0.580
Mean	0.226	2.783	0.722
5th percentile	0.293	3.415	0.901

Table 3. Mid-Atlantic Planning Area 201-900m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.271	3.482	0.891
Mean	0.376	4.110	1.107
5th percentile	0.588	5.011	1.479
Total Endowment			
95th percentile	0.271	3.482	0.891
Mean	0.376	4.110	1.107
5th percentile	0.588	5.011	1.479

Table 4. Mid-Atlantic Planning Area 901-3,000m Water Depth Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.94			
95th percentile		0.016	0.081	0.031
Mean		0.132	1.795	0.451
5th percentile		0.263	4.143	1.000
Half-Cycle	0.97			
95th percentile		0.045	0.456	0.126
Mean		0.160	2.068	0.528
5th percentile		0.349	4.166	1.090
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.207	1.971	0.557
Mean		0.369	3.566	1.003
5th percentile		0.580	5.796	1.611
Half-Cycle	1.00			
95th percentile		0.256	2.426	0.688
Mean		0.424	4.066	1.148
5th percentile		0.655	6.269	1.770

Table 5. Total Mid-Atlantic Planning Area Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.91			
95th percentile		0.000	0.000	0.000
Mean		0.102	1.675	0.400
5th percentile		0.162	4.061	0.885
Half-Cycle	0.95			
95th percentile		0.024	0.237	0.067
Mean		0.116	1.838	0.443
5th percentile		0.169	4.184	0.913
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.116	1.157	0.322
Mean		0.169	2.267	0.572
5th percentile		0.199	4.482	0.997
Half-Cycle	1.00			
95th percentile		0.119	1.231	0.338
Mean		0.173	2.332	0.587
5th percentile		0.197	4.579	1.011

Table 6. Mid-Atlantic Planning Area 0-200m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.21			
95th percentile		0.000	0.000	0.000
Mean		0.021	0.103	0.039
5th percentile		0.140	0.824	0.286
Half-Cycle	0.29			
95th percentile		0.000	0.000	0.000
Mean		0.032	0.190	0.066
5th percentile		0.152	1.231	0.371
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.94			
95th percentile		0.006	0.022	0.010
Mean		0.126	0.978	0.300
5th percentile		0.217	1.663	0.513
Half-Cycle	0.98			
95th percentile		0.077	0.454	0.157
Mean		0.144	1.173	0.352
5th percentile		0.227	1.853	0.557

Table 7. Mid-Atlantic Planning Area 201-900m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.04			
95th percentile		0.000	0.000	0.000
Mean		0.011	0.044	0.019
5th percentile		0.036	0.199	0.071
Half-Cycle	0.07			
95th percentile		0.000	0.000	0.000
Mean		0.021	0.073	0.034
5th percentile		0.157	0.638	0.271
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.40			
95th percentile		0.000	0.000	0.000
Mean		0.077	0.313	0.132
5th percentile		0.309	1.298	0.540
Half-Cycle	0.61			
95th percentile		0.000	0.000	0.000
Mean		0.114	0.561	0.214
5th percentile		0.340	1.713	0.645

Table 8. Mid-Atlantic Planning Area 901-3,000m Water Depth Economic Assessment Results Table.

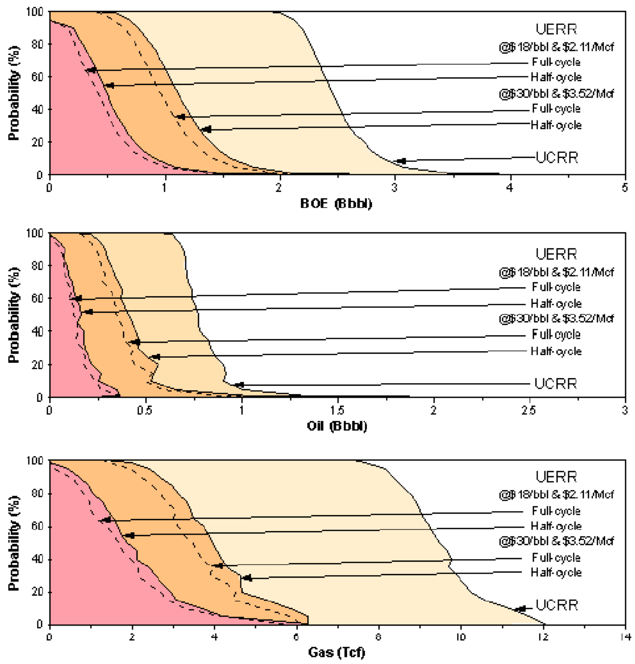

Figure 5. Mid-Atlantic Planning Area Total Endowment by Resource Category.

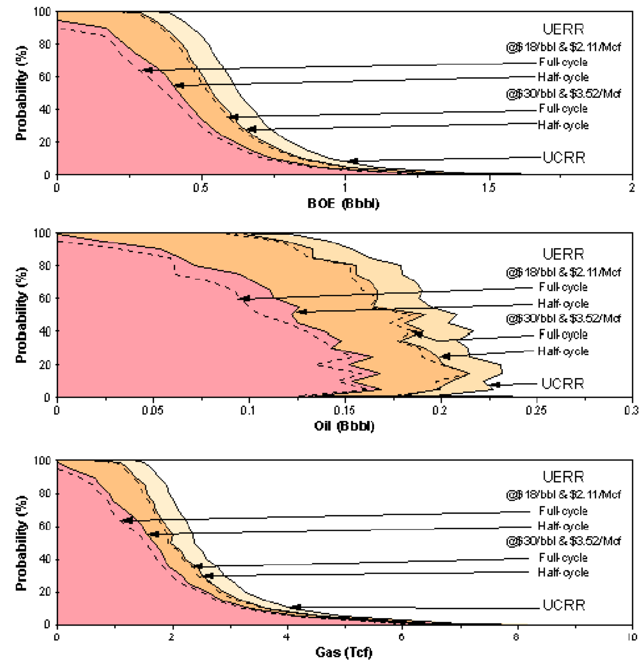

Figure 6. Mid-Atlantic Planning Area 0-200m Water Depth Total Endowment by Resource Category.

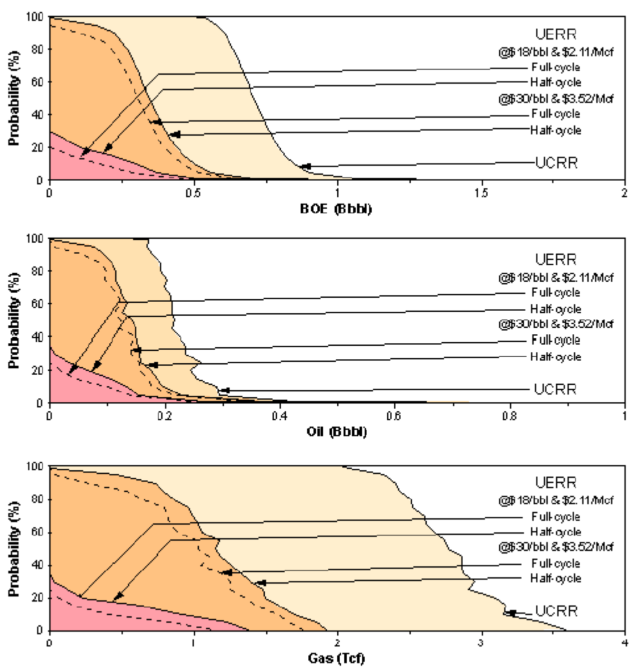

Figure 7. Mid-Atlantic Planning Area 201-900m Water Depth Total Endowment by Resource Category.

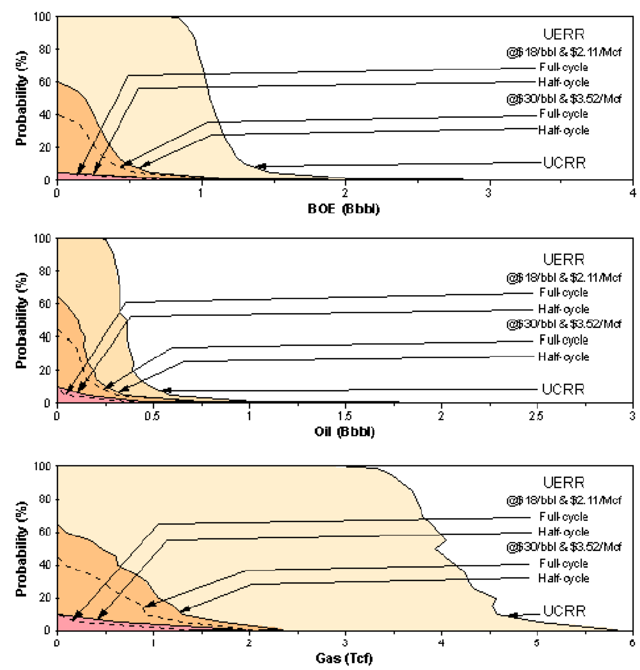

Figure 8. Mid-Atlantic Planning Area 901-3,000m Water Depth Total Endowment by Resource Category.

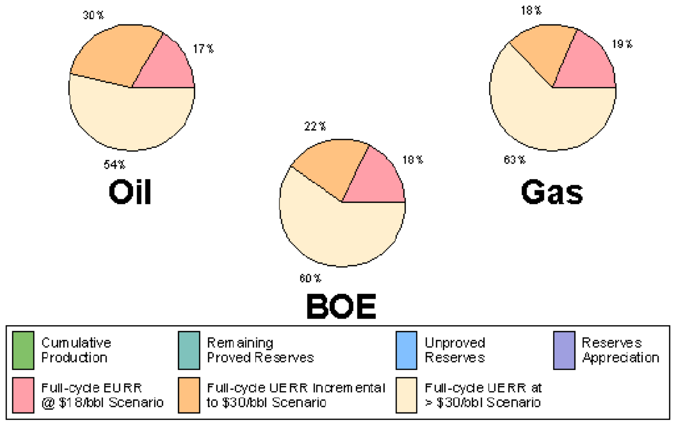

Figure 9. Total Mid-Atlantic Planning Area Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

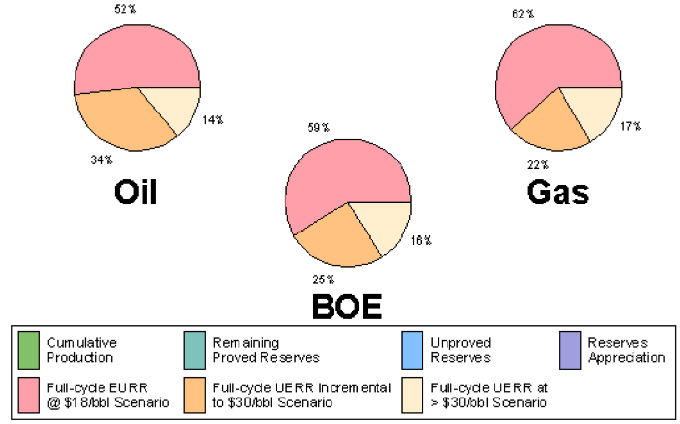

Figure 10. Mid-Atlantic Planning Area 0-200m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

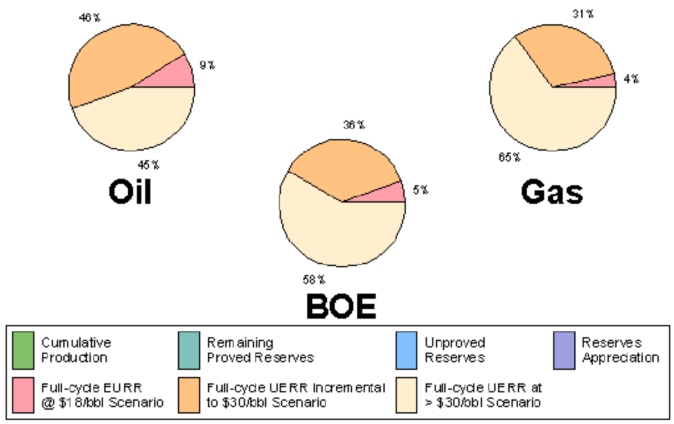

Figure 11. Mid-Atlantic Planning Area 201-900m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

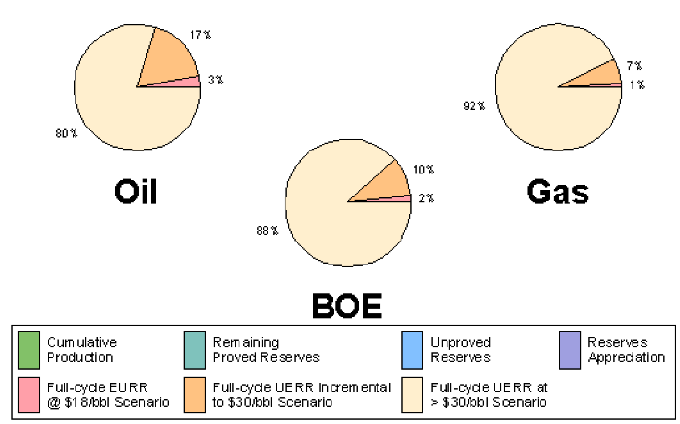

Figure 12. Mid-Atlantic Planning Area 901-3,000m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

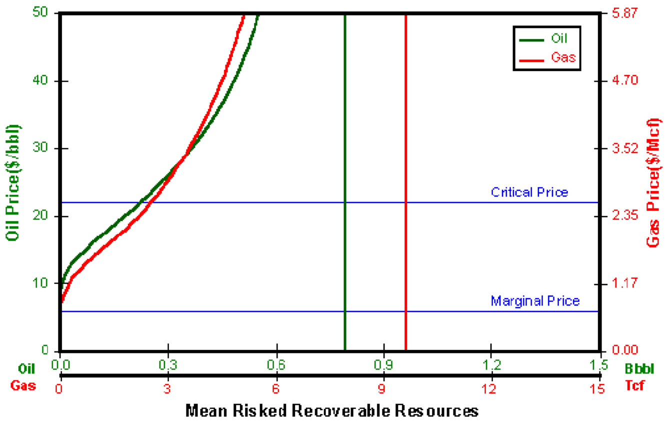

Figure 13. Total Mid-Atlantic Planning Area Full-Cycle Price-Supply Curve.

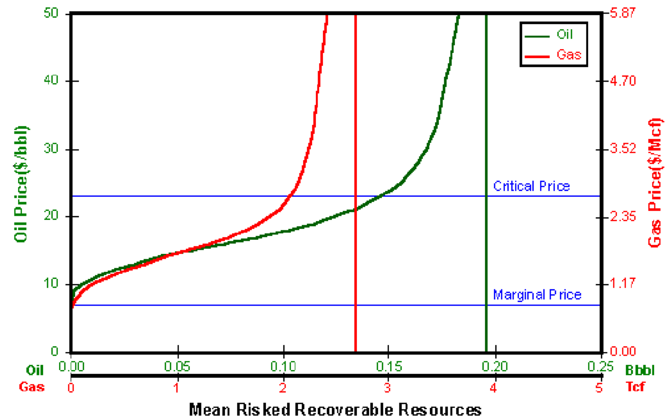

Figure 14. Mid-Atlantic Planning Area 0-200m Water Depth Full-Cycle Price-Supply Curve.

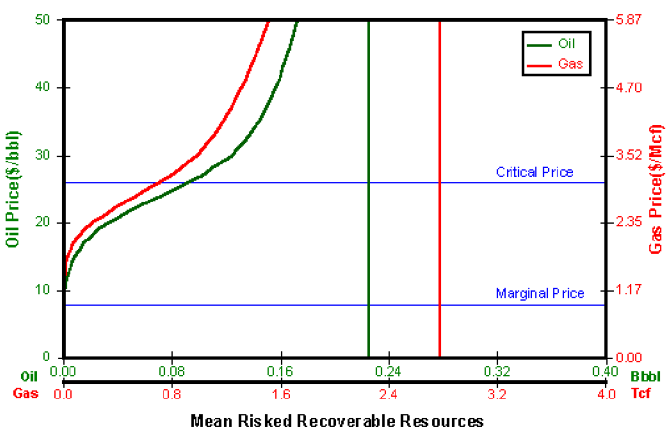

Figure 15. Mid-Atlantic Planning Area 201-900m Water Depth Full-Cycle Price-Supply Curve.

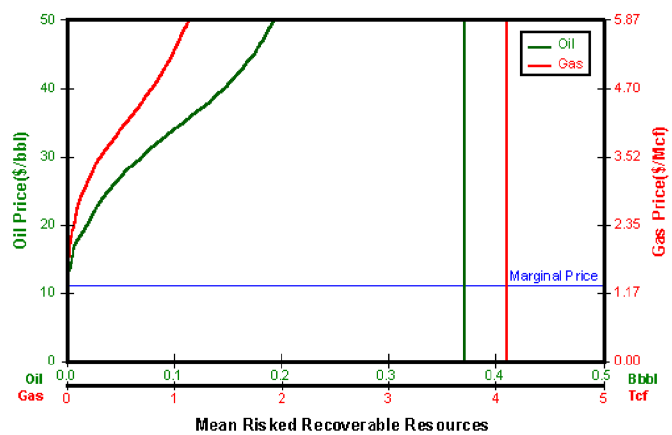

Figure 16. Mid-Atlantic Planning Area 901-3,000m Water Depth Full-Cycle Price-Supply Curve.

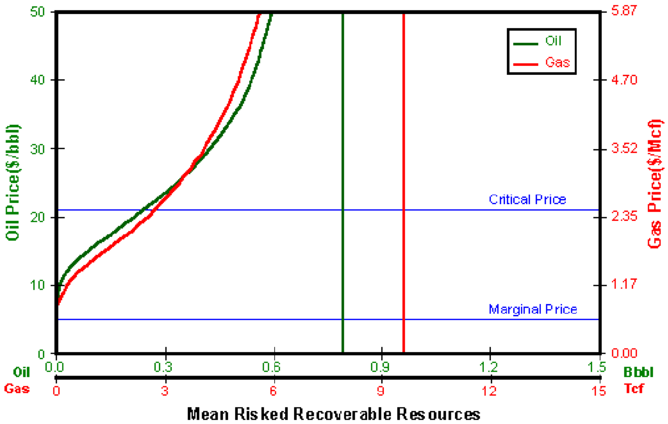

Figure 17. Total Mid-Atlantic Planning Area Half-Cycle Price-Supply Curve.

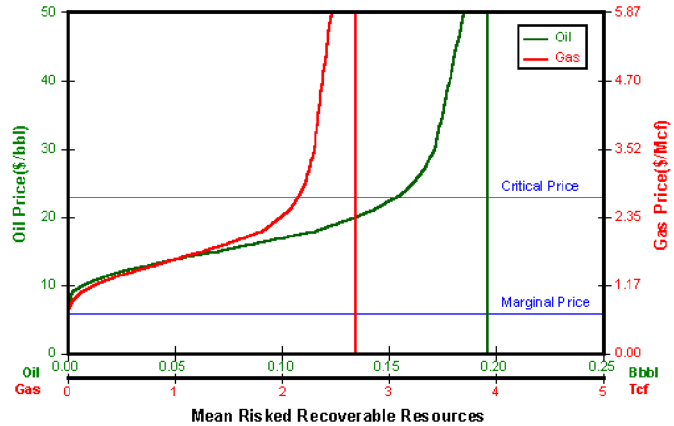

Figure 18. Mid-Atlantic Planning Area 0-200m Water Depth Half-Cycle Price-Supply Curve.

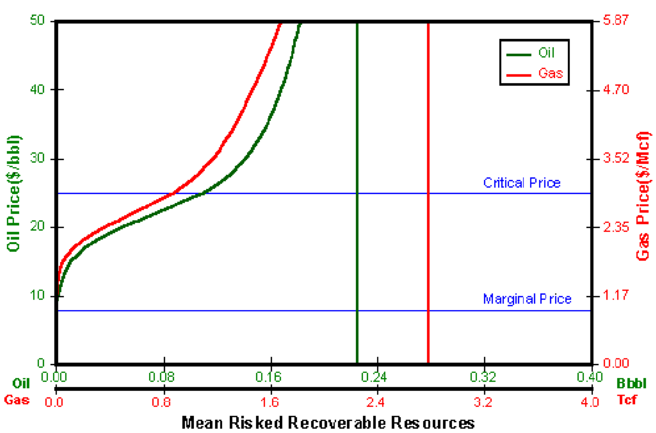

Figure 19. Mid-Atlantic Planning Area 201-900m Water Depth Half-Cycle Price-Supply Curve.

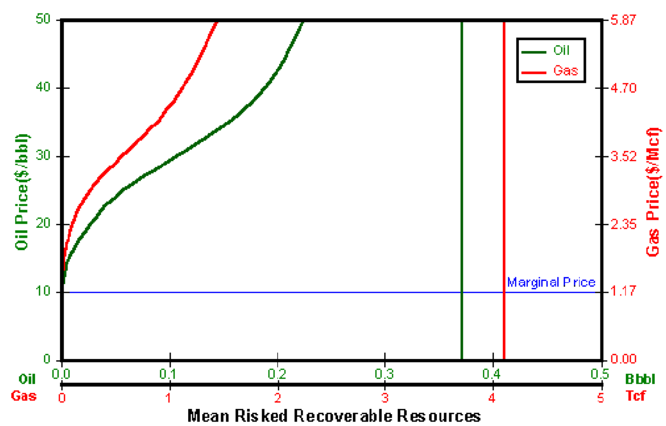

Figure 20. Mid-Atlantic Planning Area 901-3,000m Water Depth Half-Cycle Price-Supply Curve.

South Atlantic Planning Area Economic Results

The South Atlantic Planning Area includes submerged Federal lands offshore North Carolina, South Carolina, Georgia, and Florida (figure 1). Water depths in the planning area range from very shallow to more than 3,000m. Because water depth and distance from shore have a significant effect on engineering and cost factors, the undiscovered economically recoverable resources (UERR) were evaluated for three water depth ranges, 0-200m, 201-900m, and 901-3,000m (no resources were evaluated in water depths greater than 3,000m).

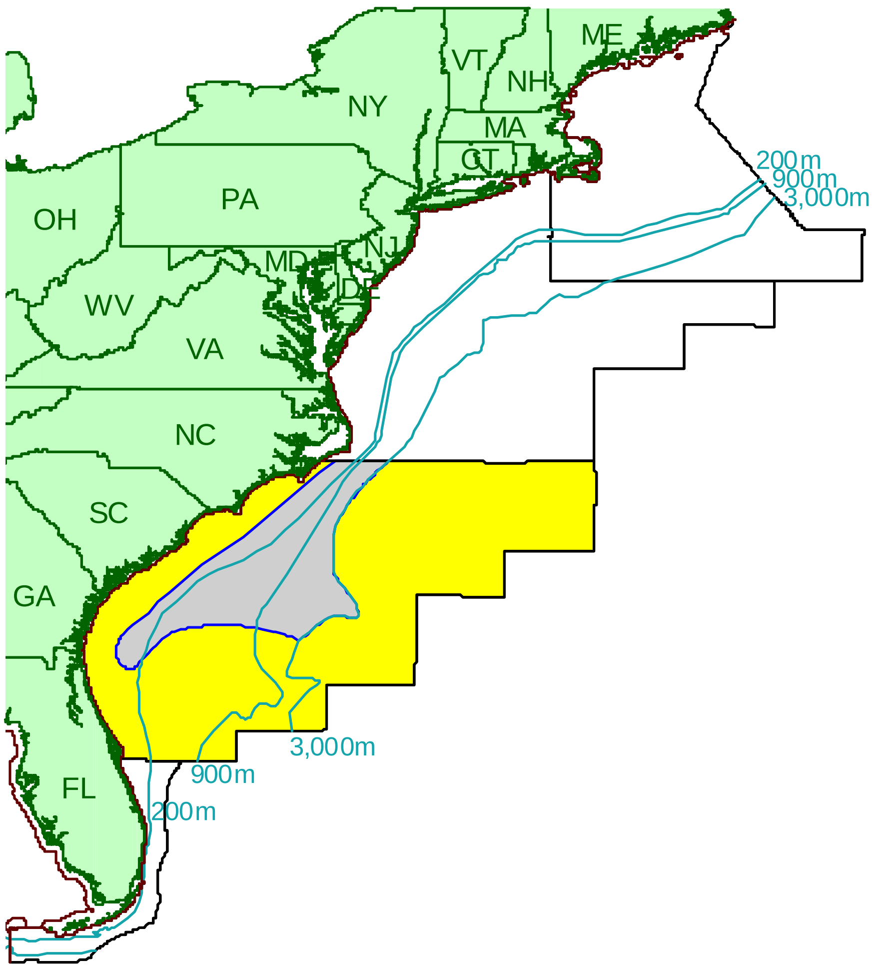

Figure 1. South Atlantic Planning Area Map. The planning area is shaded in yellow, and the gray pattern indicates the extent of the assessed plays.

The mean total endowment for this planning area is predominantly gas, with 68 percent of the total resources occurring as gas (figure 2). There is a slight trend towards a less gas-prone bias in the deeper water depths, with the 0-200m water depth range consisting of 71 percent gas, the 201-900m range consisting of 65 percent gas, and the deepest water depth range consisting of 68 percent gas. The largest concentration of the mean total endowment (38% on a barrels-of-oil-equivalent [BOE] basis) occurs in water depths of more than 900m (figure 3 and figure 4). Each of the other two water depth ranges have 27 to 35 percent of the BOE mean total endowment.

The planning area is not developed in any of the water depth ranges, and there is no infrastructure in place. As of the date of this study, there has been no production or reserves in any of the ranges (table 1 for Assessment Results Total, table 2 for 0-200m, table 3 for 201-900m, and table 4 for 901-3,000m). Undiscovered conventionally recoverable resources (UCRR) have been assessed for all three water depth ranges, and

the full- and half-cycle UERR for both the $18/bbl and $30/bbl scenarios are shown in table 5 (Economic Results Total), table 6 (0-200m), table 7 (201-900m), and table 8 (901-3,000m). These tables present the mean, 5th-, and 95th-percentile results for oil, gas, and BOE for each of the three water depth ranges and for the total planning area.

Assessment results indicate that the total planning area undiscovered economically recoverable resources are limited (although they are larger than those in either the North or Mid-Atlantic Planning Areas), with a range of 0.021 to 0.323 Bbo and 0.124 to 4.364 Tcfg at the 95th and 5th percentiles, respectively, for the full-cycle $18/bbl scenario. The mean economically recoverable resources are estimated at 0.152 Bbo and 1.826 Tcfg. A graphical representation of these results, incorporating every 5th- percentile result for UCRR and UERR, is presented in figure 5 (Results Graph Total), figure 6 (0-200m), figure 7 (201-900m), and figure 8 (901-3,000m). These graphs also present the half-cycle $18/bbl, and the full- and half-cycle $30/bbl scenario results. Because the economic model imports field sizes in BOE from the geologic model and then calculates the oil and gas content, the BOE results graph is typically a smooth curve. As expected, the accompanying oil and gas values exhibit more scatter because the gas/oil ratio can vary greatly from one field to another.

The mean total endowment for oil, gas, and BOE by the reserve and resource classification is shown in figure 9 (Mean Endowment Total), figure 10 (0-200m), figure 11 (201-900m), and figure 12 (901-3,000m). The pie charts presented can be used to determine what percentage of oil, gas, or BOE is a result of reserves or of undiscovered resources. For example, all of the oil and gas in the planning area remains to be discovered, and only 19 percent of the oil, gas, and BOE are projected to be economically recoverable at the $18/bbl scenario (figure 9).

Because estimates of undiscovered economically recoverable resources are sensitive to price and technology assumptions, they are presented here as price-supply curves. These curves describe a functional relationship between economically recoverable resources and product price and present the estimates of mean undiscovered economically recoverable oil and gas at any starting oil price up to $50/bbl. An extensive discussion of price-supply curves, and the methodology used to generate them, can be found in the ***General Text, Methodology, UERR (Economically Recoverable), Detailed Discussion*** section. 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 are the mean curves. The full-cycle price-supply curves are shown in figure 13 (Full-Cycle P-S Curve Total), figure 14 (0-200m), figure 15 (201-900m), and figure 16 (901-3,000m). The half-cycle price-supply curves are shown in figure 17 (Half-Cycle P-S Curve Total), figure 18 (0-200m), figure 19 (201-900m), and figure 20 (901-3,000m).

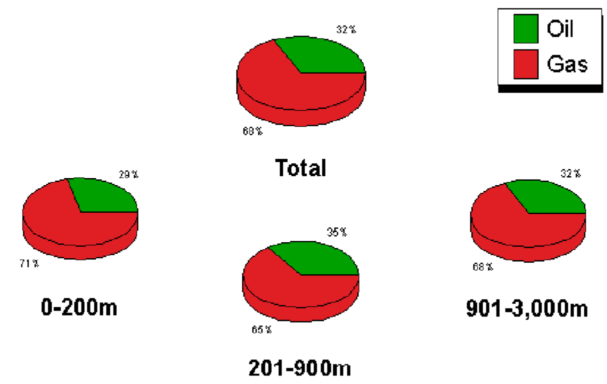

Figure 2. South Atlantic Planning Area Percent Oil or Gas by Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

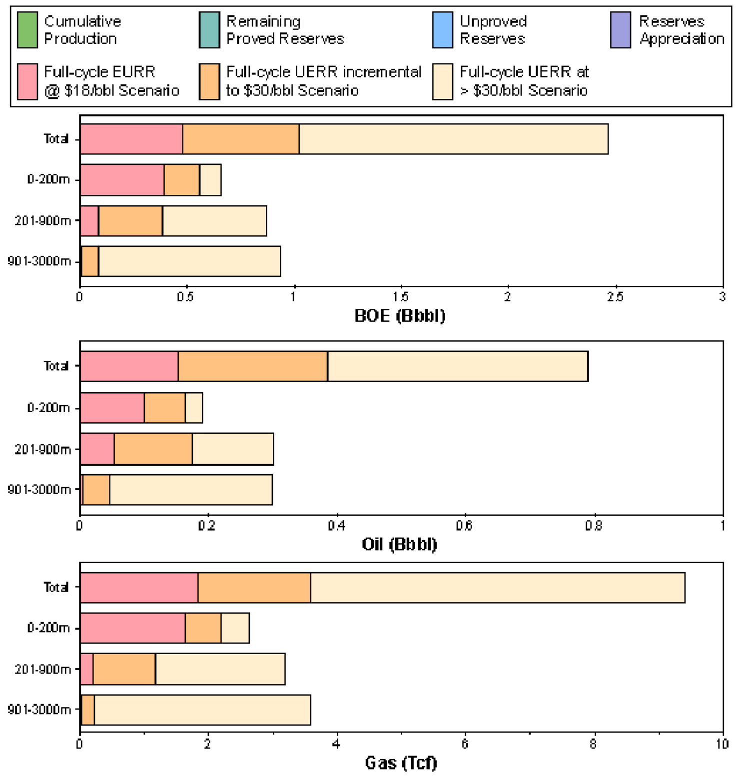

Figure 3. South Atlantic Planning Area Mean Total Endowment by Water Depth Category.

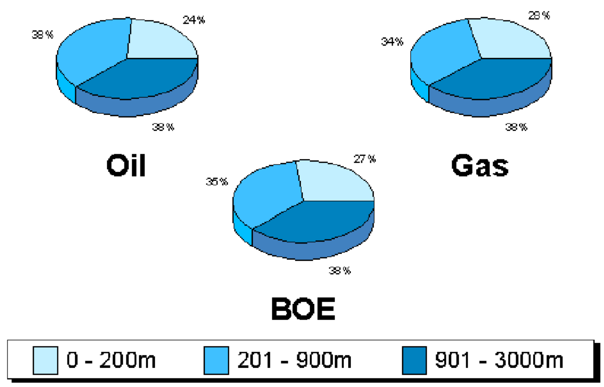

Figure 4. South Atlantic Planning Area Mean Total Endowment by Resource Type and Water Depth. The sum of the percentage values may not equal 100 percent due to independent rounding.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.676	7.822	2.068
Mean	0.789	9.396	2.461
5th percentile	1.029	11.643	3.101
Total Endowment			
95th percentile	0.676	7.822	2.068
Mean	0.789	9.396	2.461
5th percentile	1.029	11.643	3.101

Table 1. Total South Atlantic Planning Area Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.138	1.581	0.419
Mean	0.190	2.641	0.660
5th percentile	0.221	4.804	1.075
Total Endowment			
95th percentile	0.138	1.581	0.419
Mean	0.190	2.641	0.660
5th percentile	0.221	4.804	1.075

Table 2. South Atlantic Planning Area 0-200m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.198	2.532	0.649
Mean	0.302	3.184	0.868
5th percentile	0.521	4.164	1.262
Total Endowment			
95th percentile	0.198	2.532	0.649
Mean	0.302	3.184	0.868
5th percentile	0.521	4.164	1.262

Table 3. South Atlantic Planning Area 201-900m Water Depth Assessment Results Table.

Marginal Probability = 1.00	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Reserves			
Original proved	0.000	0.000	0.000
Cumulative production	0.000	0.000	0.000
Remaining proved	0.000	0.000	0.000
Unproved	0.000	0.000	0.000
Appreciation (P & U)	0.000	0.000	0.000
Undiscovered Conventionally Recoverable Resources			
95th percentile	0.235	3.101	0.786
Mean	0.299	3.592	0.938
5th percentile	0.390	4.249	1.146
Total Endowment			
95th percentile	0.235	3.101	0.786
Mean	0.299	3.592	0.938
5th percentile	0.390	4.249	1.146

Table 4. South Atlantic Planning Area 901-3,000m Water Depth Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.94			
95th percentile		0.021	0.124	0.043
Mean		0.152	1.826	0.477
5th percentile		0.323	4.364	1.099
Half-Cycle	0.97			
95th percentile		0.048	0.506	0.138
Mean		0.183	2.086	0.554
5th percentile		0.413	4.542	1.221
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.210	1.997	0.565
Mean		0.384	3.578	1.020
5th percentile		0.620	5.971	1.683
Half-Cycle	1.00			
95th percentile		0.268	2.437	0.702
Mean		0.440	4.078	1.165
5th percentile		0.675	6.425	1.818

Table 5. Total South Atlantic Planning Area Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.91			
95th percentile		0.000	0.000	0.000
Mean		0.099	1.626	0.388
5th percentile		0.157	3.942	0.859
Half-Cycle	0.95			
95th percentile		0.024	0.230	0.065
Mean		0.112	1.784	0.430
5th percentile		0.164	4.061	0.886
$30.00/bbl and $3.52/Mcf				
Full-Cycle	1.00			
95th percentile		0.112	1.123	0.312
Mean		0.164	2.200	0.555
5th percentile		0.194	4.350	0.968
Half-Cycle	1.00			
95th percentile		0.115	1.195	0.328
Mean		0.167	2.263	0.570
5th percentile		0.191	4.444	0.982

Table 6. South Atlantic Planning Area 0-200m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.22			
95th percentile		0.000	0.000	0.000
Mean		0.052	0.203	0.088
5th percentile		0.280	1.199	0.494
Half-Cycle	0.31			
95th percentile		0.000	0.000	0.000
Mean		0.066	0.303	0.120
5th percentile		0.302	1.463	0.562
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.95			
95th percentile		0.035	0.143	0.061
Mean		0.176	1.161	0.382
5th percentile		0.425	2.143	0.806
Half-Cycle	0.98			
95th percentile		0.081	0.593	0.187
Mean		0.196	1.367	0.440
5th percentile		0.447	2.344	0.864

Table 7. South Atlantic Planning Area 201-900m Water Depth Economic Assessment Results Table.

Undiscovered Economically Recoverable Resources	Marginal Probability	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
$18.00/bbl and $2.11/Mcf				
Full-Cycle	0.05			
95th percentile		0.000	0.000	0.000
Mean		0.005	0.021	0.009
5th percentile		0.029	0.135	0.053
Half-Cycle	0.08			
95th percentile		0.000	0.000	0.000
Mean		0.008	0.033	0.014
5th percentile		0.066	0.272	0.115
$30.00/bbl and $3.52/Mcf				
Full-Cycle	0.42			
95th percentile		0.000	0.000	0.000
Mean		0.045	0.223	0.085
5th percentile		0.191	1.000	0.369
Half-Cycle	0.63			
95th percentile		0.000	0.000	0.000
Mean		0.078	0.448	0.158
5th percentile		0.209	1.343	0.448

Table 8. South Atlantic Planning Area 901-3,000m Water Depth Economic Assessment Results Table.

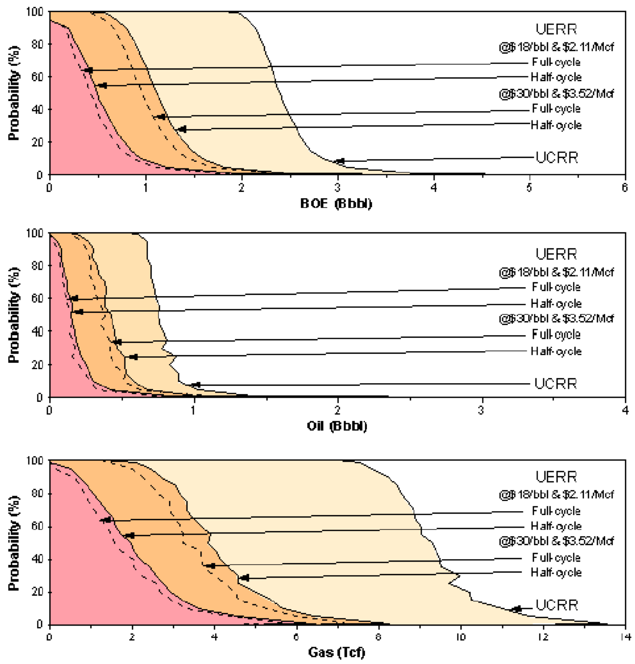

Figure 5. South Atlantic Planning Area Total Endowment by Resource Category.

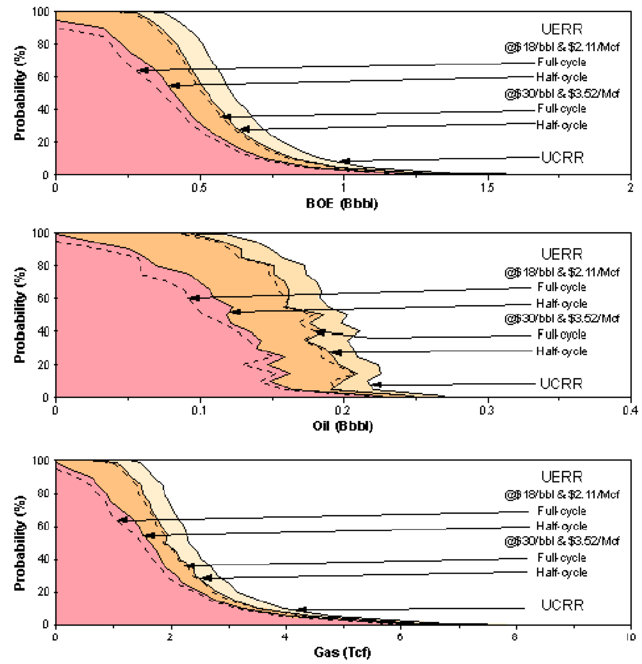

Figure 6. South Atlantic Planning Area 0-200m Water Depth Total Endowment by Resource Category.

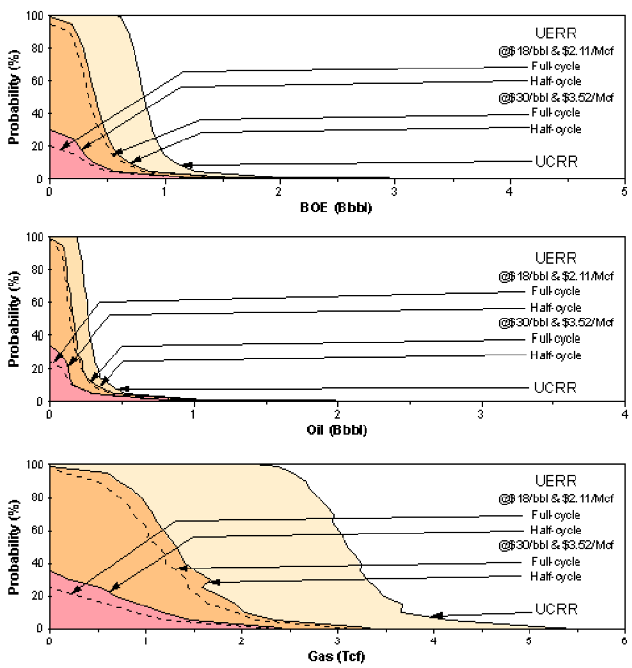

Figure 7. South Atlantic Planning Area 201-900m Water Depth Total Endowment by Resource Category.

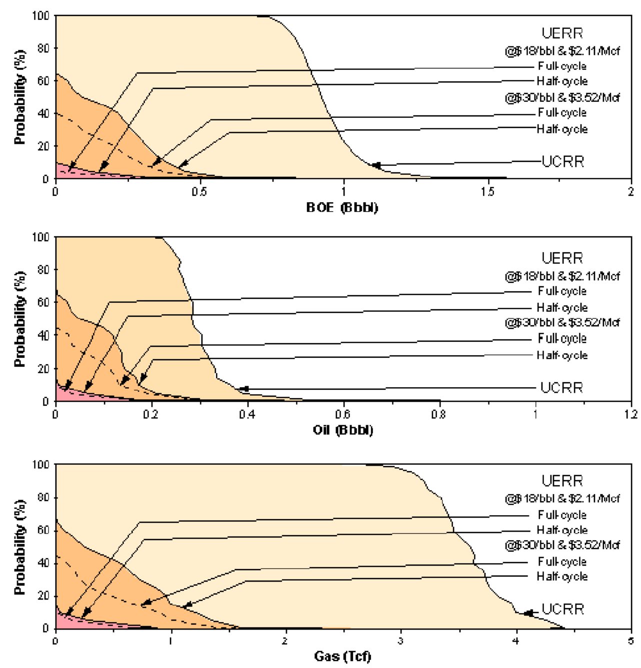

Figure 8. South Atlantic Planning Area 901-3,000m Water Depth Total Endowment by Resource Category.

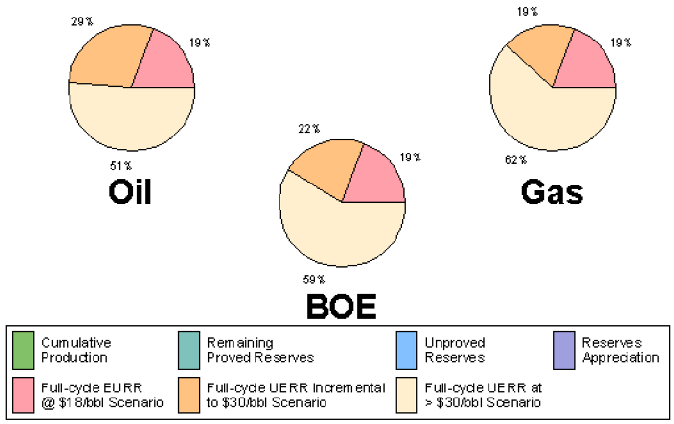

Figure 9. Total South Atlantic Planning Area Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

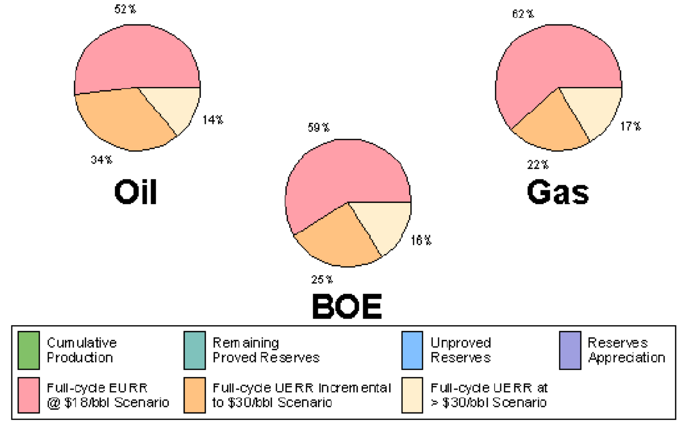

Figure 10. South Atlantic Planning Area 0-200m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

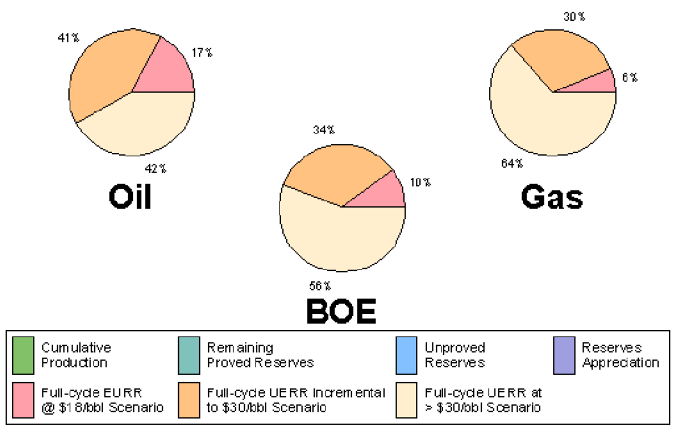

Figure 11. South Atlantic Planning Area 201-900m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

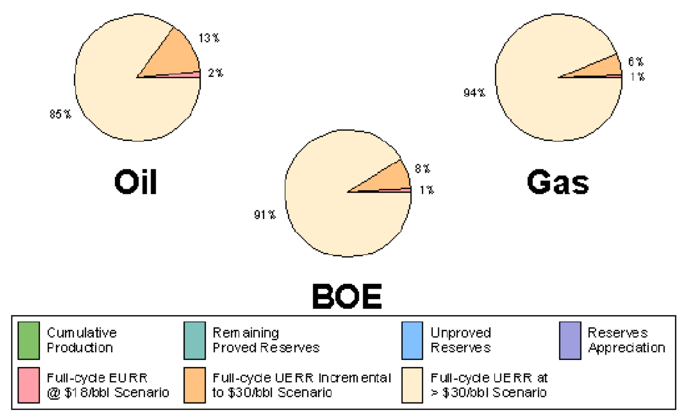

Figure 12. South Atlantic Planning Area 901-3,000m Water Depth Mean Total Endowment by Resource Type. The sum of the percentage values may not equal 100 percent due to independent rounding.

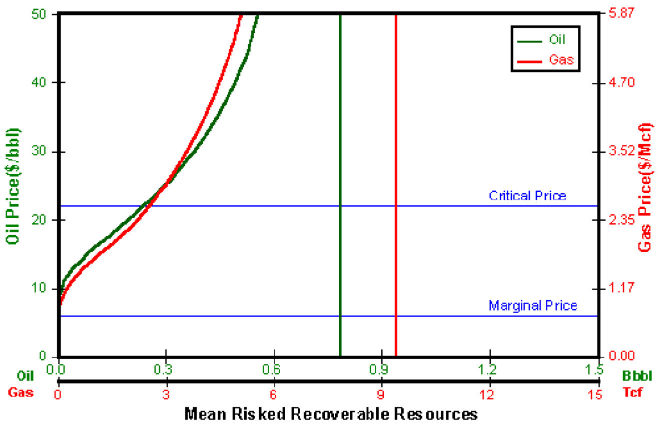

Figure 13. Total South Atlantic Planning Area Full-Cycle Price-Supply Curve.

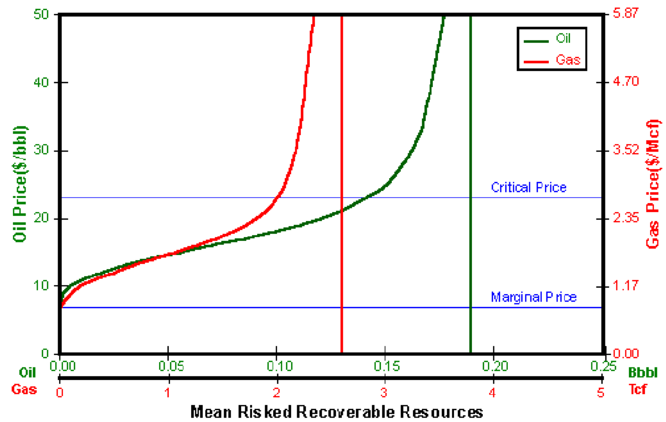

Figure 14. South Atlantic Planning Area 0-200m Water Depth Full-Cycle Price-Supply Curve.

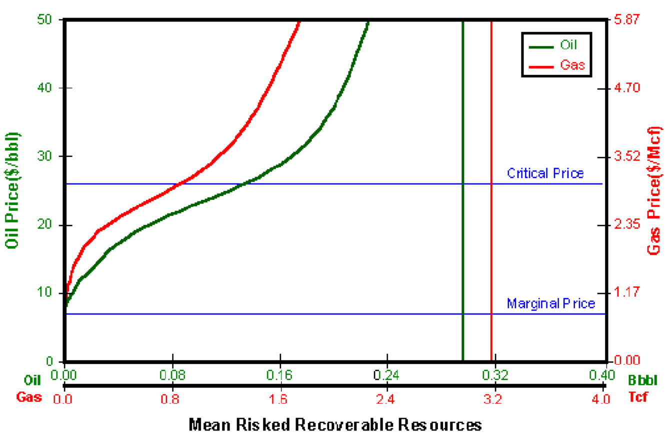

Figure 15. South Atlantic Planning Area 201-900m Water Depth Full-Cycle Price-Supply Curve.

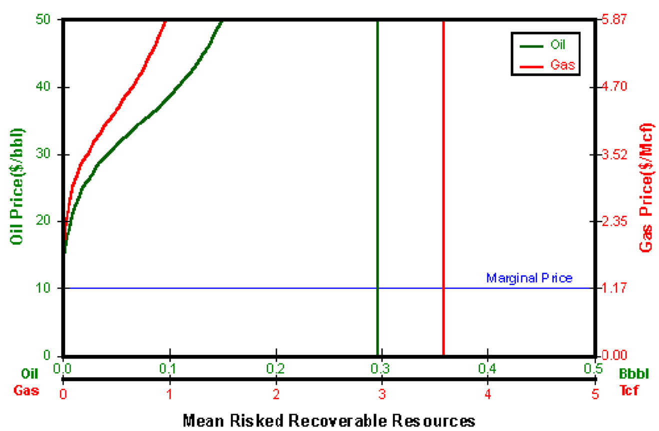

Figure 16. South Atlantic Planning Area 901-3,000m Water Depth Full-Cycle Price-Supply Curve.

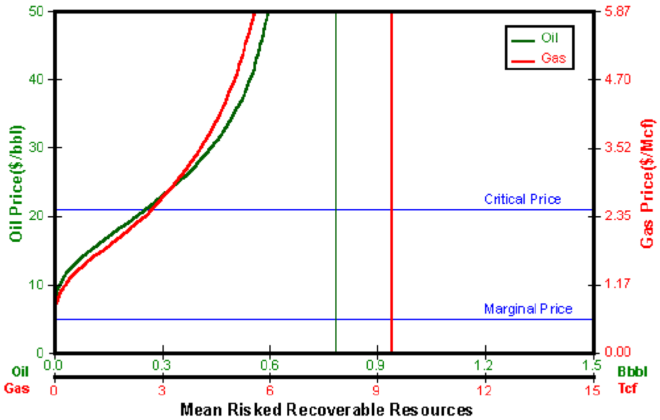

Figure 17. Total South Atlantic Planning Area Half-Cycle Price-Supply Curve.

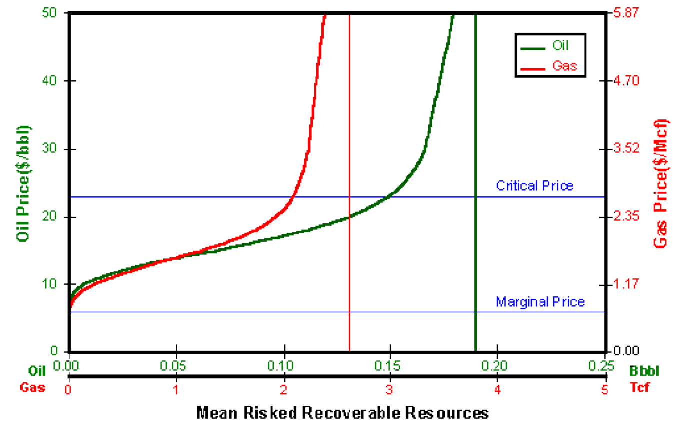

Figure 18. South Atlantic Planning Area 0-200m Water Depth Half-Cycle Price-Supply Curve.

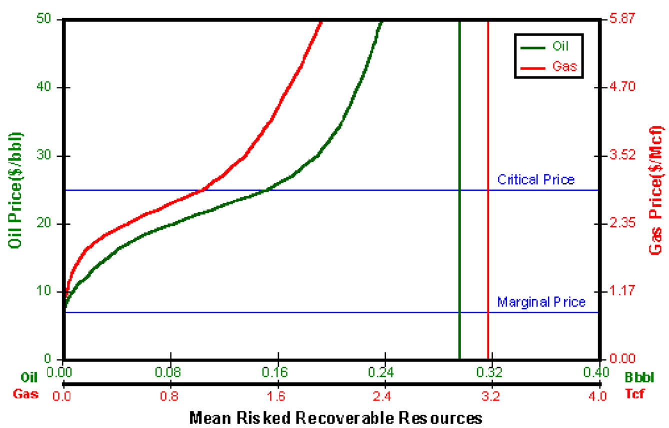

Figure 19. South Atlantic Planning Area 201-900m Water Depth Half-Cycle Price-Supply Curve.

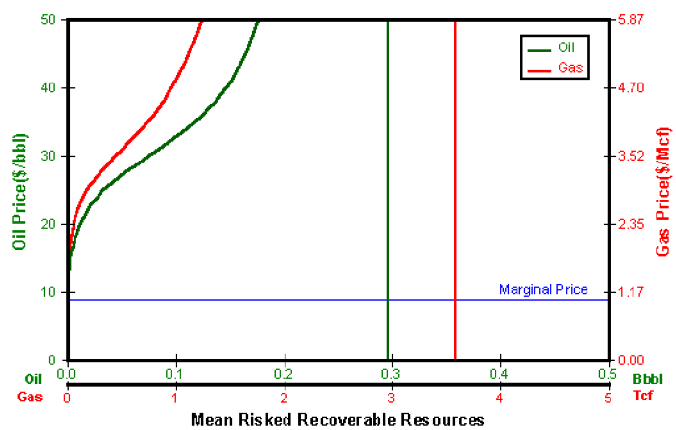

Figure 20. South Atlantic Planning Area 901-3,000m Water Depth Half-Cycle Price-Supply Curve.

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New Orleans, LA 70123-2394
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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